REPORT

Enabling the European hydrogen economy

May 2021

Publication	Prepared by	Approved by
Enabling the European hydrogen economy	Emma Woodward (emma.woodward@auroraer.com) Olivia Han Charles Forbes	Felix Chow-Kambitsch Evangelos Gazis

AURORA ENERGY RESEARCH

Aurora Energy Research provides data and analytics on UK, European, and global energy markets delivered in accessible forms whenever clients need it. Our analysis is designed to inform our clients' critical decisions. Abstracting from the short-term noise inherent in energy markets, we specialise in understanding the industry-shaping issues. Our core belief is that rigorous modelling, rooted in robust theory and supported by detailed data, yields powerful insight over the medium to long run.

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Overview of study

Hydrogen is set to play an important role in the EU's[1] decarbonisation strategy, providing c.7-21% of its final energy demand by 2050. Many sectors, particularly hard-to-abate sectors such as steel production, will be difficult or impossible to decarbonise through electrification alone; and without the widespread use of hydrogen the EU is unlikely to reach its decarbonisation objectives. Hydrogen is already an important feedstock for many chemical processes, but is currently produced via Steam-Methane Reforming (SMR) or Auto-Thermal reforming (ATR), using natural gas as a fuel without carbon capture and storage (CCS), resulting in emissions of 8-12 kgCO2/kgH2. For decarbonisation targets to be met, there must be a transition towards the use of decarbonised hydrogen.

There is ongoing debate on how best the EU should approach the development of a hydrogen economy and a number of critical policy decisions made today will shape how the hydrogen economy evolves over the coming decades. Policy support should be focused on the development of scenarios that will optimise the rapid decarbonisation of otherwise hard-to-abate sectors, whilst minimising full life cycle emissions and reducing costs.

This report summarises the findings from Aurora's study on European hydrogen scenarios and addresses key questions which need to be considered, including:

- How can Europe's potential to produce hydrogen be maximised?
- How can hydrogen be produced in the cheapest manner?
- How can full-lifecycle emissions from hydrogen production be minimised?
- What policy support is needed to support the development of this scenario?

This is an Aurora study sponsored by a consortium of European energy consumers and producers[2]

[1] Countries covered in this report include the EU-27, Norway & Switzerland. References to the Rest of EU should be assumed to include Switzerland.

[2] This Aurora study is sponsored by a consortium of European energy consumers and producers comprising ArcelorMittal, EDF, Fortum and UPM.

Executive Summary

- The use of hydrogen can help decarbonise the industrial, transport and heating sectors, with the potential to reach c.642-2,015 TWh hydrogen demand (representing c. 7-21% of total energy demand) by 2050 across the EU.
- Europe will be able to produce enough hydrogen to meet its demand using renewable and decarbonised electricity, however only if all forms of renewable and decarbonised electricity are considered.
- This will be cheaper than if imports are required and will result in fewer overall emissions.
- Restricting hydrogen supply to production from additional new-build renewables only may risk supply becoming a bottleneck for the size of the hydrogen system and may also result in higher costs and a reliance on hydrogen imports.
- Policy interventions should support the development of a scenario where full life cycle emissions are minimised.
- A simplified, technology-agnostic definition of hydrogen for the Guarantees of Origin (GoO) scheme, based on full life cycle emissions, would better encourage the growth of the hydrogen sector while still maintaining a low-carbon outcome.
- Sector and project specific Carbon Contracts for Difference (CCfDs) can support the decarbonisation of otherwise hard-to-abate industrial sectors.
- Demand mandates can act as a strong tool for directing the switch to hydrogen.

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Hydrogen Demand Forecast

While electrification offers a solution to decarbonise many areas of the economy, hydrogen is a necessary option in certain hard-to-abate sectors, including parts of the industrial, transport and heating sectors. Hydrogen demand is anticipated to reach 492 TWh in our central scenario in 2030 and to increase rapidly by 2050 as the EU's transition to a decarbonised energy system takes place; with 1,010 TWh of demand forecast in our central scenario in 2050, representing c.11% of the EU's total energy demand.

Current demand for hydrogen in the EU stands at c.313 TWh/a, which is mostly utilised in refineries or as industrial feedstock, for example in ammonia production. Most of this hydrogen is produced using natural gas (via SMR or ATR without CCS, generally known as grey hydrogen), resulting in emissions of 8-12 kgCO2/kgH2 produced.

In 2030, hydrogen demand will continue to be driven by its use in industrial sectors in all scenarios studied. There will be minimal demand from transport and heating as the roll-out of infrastructure that would allow the widespread uptake of hydrogen in these sectors will not take place in this timeframe.

In 2050, the industrial sector is still forecast to dominate hydrogen demand in all scenarios. The penetration of hydrogen into the transport sector is uncertain; electric vehicles (EVs) are increasingly widespread, particularly for small and personal vehicles. The use of hydrogen in transport is therefore likely to be greatest in heavy goods vehicles and mass transport, as well as in shipping and aviation. In countries with a high reliance on natural gas for heating, a switch to hydrogen is possible, but will face competition from other more efficient technologies such as heat pumps and district heating.

Countries with large industrial bases, as well as higher populations and GDPs, will therefore dominate the demand for hydrogen: in 2050 Germany will make up c.29% of total forecast demand for hydrogen in our central case; with Germany, France, Italy and the Netherlands together comprising 62% of the total.

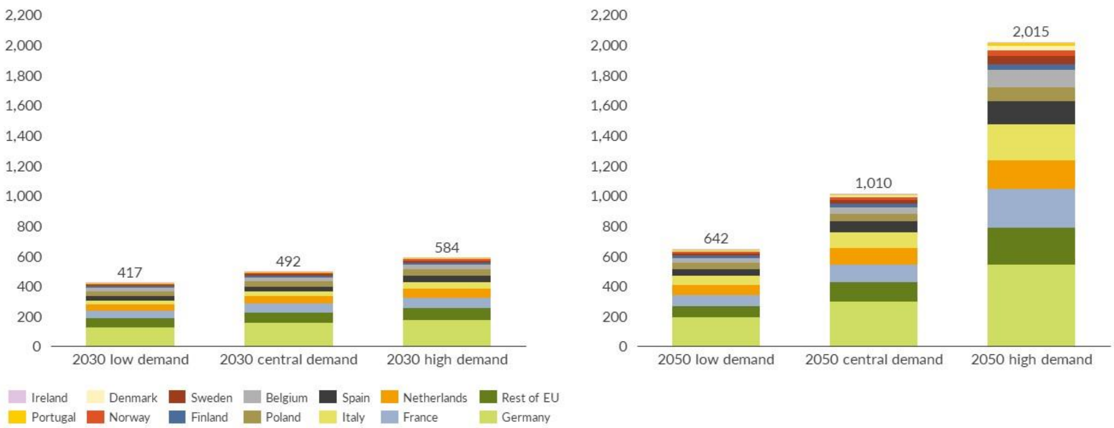
In our conservative scenario, we assume all hydrogen uptake is slow across all countries and it plays a small part in meeting overall energy demand in the EU by 2050, whereas in our optimistic scenario, hydrogen plays a key role in decarbonising the economy. In our central scenario we have assumed differing rates of hydrogen penetration in sectors and countries across Europe – driven by current policy, regulatory and macroeconomic factors, drivers for supply and demand, and the potential to transport and store hydrogen.

Demand analysis

Germany is anticipated to dominate the demand for hydrogen, followed by France, Italy and the Netherlands

Potential H_2 demand, 2030 TWh[1]

Potential H_2 demand, 2050 TWh[1]



1) Using the Higher Heating Value.

Source: Aurora Energy Research

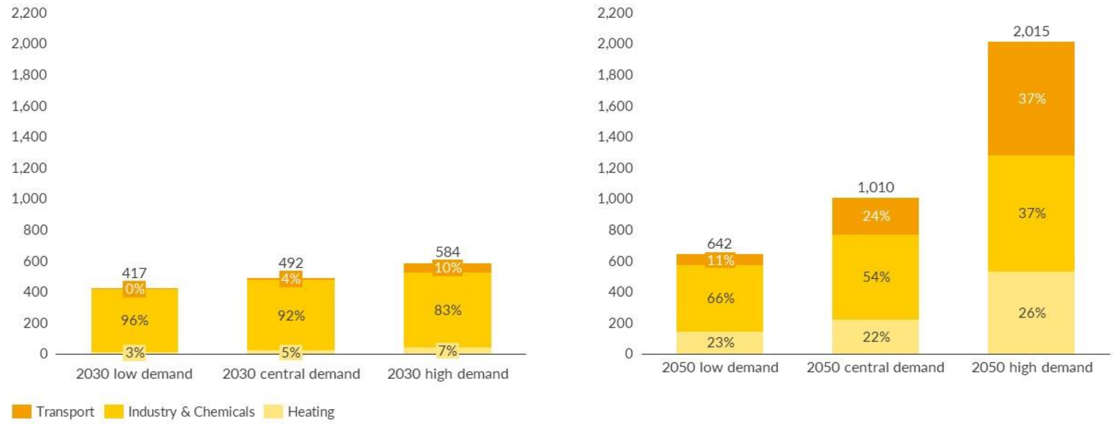
Exhibit 1. Total hydrogen demand by country

Demand analysis

Hydrogen demand will be greatest in the industry and chemicals sector, followed by transport and heating

Potential H_2 demand, 2030 TWh

Potential H_2 demand, 2050 TWh



1) Heavy Good Vehicles 2)Switching to hydrogen or hydrogen-derived fuels

Sources: Aurora Energy Research.

Exhibit 2. Hydrogen demand by sector

Hydrogen in Industry & Chemicals

Demand for hydrogen is currently driven by demand for feedstock in the chemicals sector but it is a promising emissions reduction pathway for other hard-to-abate industrial sectors, replacing fossil fuels as a high temperature heat source. Demand for hydrogen will be led by five main sectors: high value chemicals (including methanol), ammonia, refineries, steel, and cement (in cement manufacture hydrogen can be used as a heat source but could also be combined with CO_2 produced during cement manufacture to produce chemicals such as methanol).

Some industrial sectors will be difficult or impossible to decarbonise via electrification and so demand for hydrogen in industry is anticipated to continue to dominate overall demand for hydrogen. Hydrogen provision at industrial hubs will require less infrastructure build-out than for its use in heating or transport, allowing faster penetration of hydrogen into the sector. In our high scenario 95% of the hard-to-abate sectors listed above have been decarbonised through the use of hydrogen by 2050. In our low scenario, 70% of these segments have been decarbonised through hydrogen – with the overall size of the industrial sector shrinking.

Hydrogen in Transport

There is significant but uncertain potential for hydrogen switching within the transport sector. Electric Vehicles (EVs) are becoming increasingly widespread, particularly for small and personal vehicles, and many countries, including the Netherlands, Germany, Norway and France, are investing heavily in charging infrastructure to support and accelerate the roll-out of this technology. It is therefore unlikely that hydrogen will be heavily utilised in small and personal vehicles, particularly given its inefficiencies compared to EVs.

However, for heavy goods vehicles and mass transport, technological challenges surrounding battery ranges means electrification may not be a practical option for decarbonisation, with the deployment of hydrogen presenting a viable alternative. Infrastructure build-out will be crucial for the commercial deployment of hydrogen in transport, especially for long-distance freight where pan-European deployment of infrastructure will be necessary. In our high scenario c.34% of energy in land-based transport is provided by hydrogen by 2050, driven by widespread deployment in heavy goods vehicles and mass transport. In our low scenario just c.4% of total energy in land-based transport is provided by hydrogen, dominated by its use in buses and rail.

The use of ammonia in shipping and hydrogen-derived synthetic fuels in aviation presents a viable decarbonisation pathway for these sectors, which will be hard to abate via other means. Hydrogen-derived synthetic fuel can directly replace fossil fuels and so can be rolled out without the requirement for technological modifications. Synthetic fuels are less efficient than battery powered vehicles or vehicles directly fueled by hydrogen, so their use is anticipated to be limited to the aviation sector, where other pathways to decarbonisation are limited. The direct use of hydrogen as a fuel source in aviation has not been considered, owing to the immaturity of this technology. Decarbonising shipping will also be challenging, but utilising ammonia as a fuel source presents a possible pathway. Existing fleets would need to be converted, requiring significant investments. Therefore, it is assumed ammonia in shipping will not be widely-rolled out until the 2030's. By 2050, in our high scenario we have assumed 20% of all energy in aviation in shipping and aviation is provided by ammonia or hydrogen-derived synthetic fuels. In our low scenario, we have assumed just 1% of energy in these sectors is provided by these fuels, with fossil fuels and biofuels dominating these sectors.

Hydrogen in Heating

The uptake of hydrogen in heating will be slow until at least the 2030s, given the very high level of infrastructure investments required. Gas distribution grids would need to be repurposed, or dedicated new pipelines constructed, to deliver hydrogen to households, while boilers and other gas appliances would need to be replaced or refurbished. However, in countries with an abundance of older, poorly insulated housing stock and a high reliance on natural gas, switching to hydrogen-based heating would require fewer behavioural changes from householders than switching to heat pumps. Less investment in the refurbishment of buildings would be required in this scenario.

However, hydrogen is not the most efficient option for the decarbonisation of heating. The electrification of heating through the deployment of heat pumps is a viable option, and is already widespread in many countries in Europe, meaning the technology is proven. But for countries with older, poorly insulated housing stock, significant investment in building refurbishment by householders would be required for this technology to be deployed, and widespread penetration of electrified heat would require the reinforcement of the power grid in many countries.

Alternatives could include further roll-out of district heating or the use of biomass. There is potential for hydrogen to replace fossil fuels in district heating in some areas via a switch to combined heat and power (CHP) generation with hydrogen.

In our high scenario, we have assumed that hydrogen becomes a major source of energy for heating across Europe, especially in countries where heating is predominantly met by natural gas at present, providing 32% of overall heating demand. However, in both our low and central scenario demand for hydrogen in heating is limited at 8% and 12% of total demand respectively, focused on countries which currently rely on natural gas. The electrification of heating prevails in these scenarios.

Policy decisions would be required to support the deployment of hydrogen in heating. In countries where such decisions were taken, it would be likely that hydrogen would replace the majority of energy for heating currently supplied by natural gas, especially in countries in northwest Europe, whilst countries that already have largely electrified heating, such as Norway and Sweden, have little incentive to switch.

Hydrogen production potential

- The volumes of hydrogen that could be produced from new-build renewable capacity only will not be sufficient to meet our central demand forecast.
- By allowing the use of all forms of renewable and decarbonised electricity, the EU could produce enough hydrogen to meet demand in both 2030 and 2050, avoiding imports and a reliance on fossil-fuel derived hydrogen.

As hydrogen demand rises, changes to hydrogen production methods will need to take place, to prevent an overall rise in emissions. It is widely anticipated that hydrogen production will take place either through electrolysis, or through the reformation of natural gas, which would have to be coupled with CCS. To ensure hydrogen production does not result in an increase in emissions, electrolysis should only take place using low carbon sources of electricity and care must be taken to ensure hydrogen production does not result in an overall increase in the carbon intensity of the grid. Most hydrogen production will therefore come from new-build renewables – chiefly new-build wind and solar. However, limiting hydrogen production in this way will result in a supply gap which would hamper decarbonisation efforts and increase the EU's reliance on imports. The supply gap could be filled by allowing hydrogen production from all forms of decarbonised electricity, by imports, or by allowing production of hydrogen from SMR/ATR + CCS.

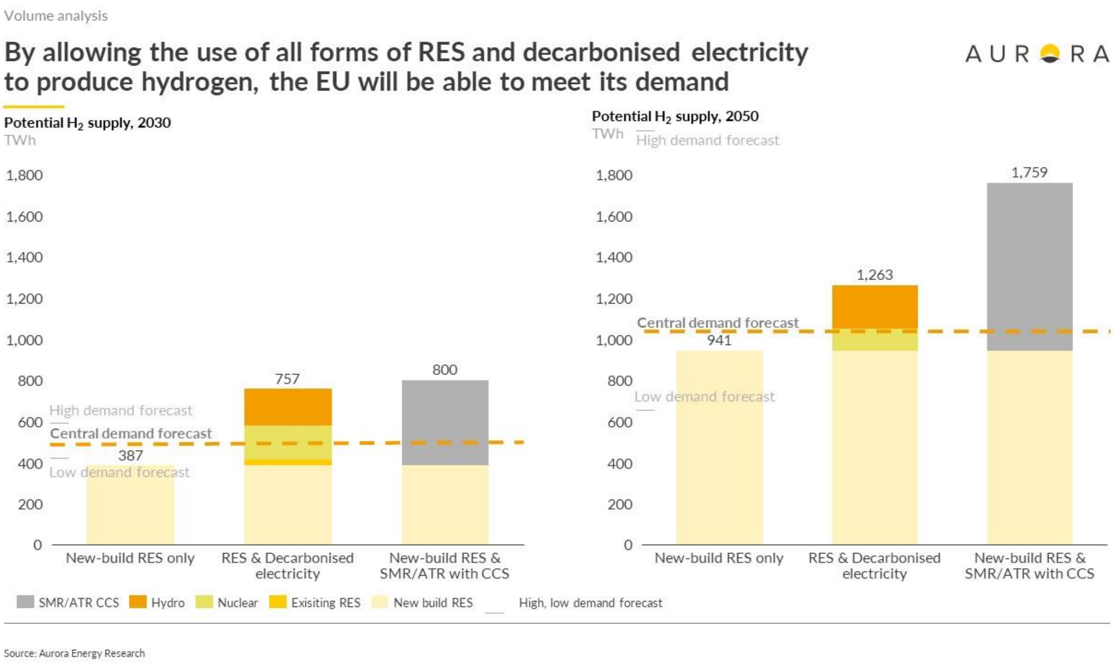


Exhibit 3. Hydrogen production potential

New-build RES Scenario

A first approach to ensure hydrogen production in EU will not result in higher emissions could be to only allow hydrogen production from dedicated, additional renewables, i.e. if it is produced by electrolysers that are temporally and geographically linked to specific renewable plants that were commissioned for the purpose of hydrogen production. This would ensure electricity was not being taken from the grid that would otherwise be used for the decarbonisation of the power sector and the direct electrification of other sectors of the economy. This approach has been laid out in the Renewable Energy Directive (RED II), especially for the transport sector, and has the advantage that it guarantees that hydrogen production comes from verified renewable sources.

However, our analysis shows that even in a high renewable deployment scenario[3] there will be insufficient installation capacity to produce enough hydrogen from new-build renewables alone to meet projected hydrogen demand in our central case in the EU both in 2030 and 2050. Therefore, imports would be required. As laid out in later sections of the report, this approach has numerous disadvantages. It will result in higher hydrogen production and transport costs, as well as higher overall full lifecycle emissions resulting from hydrogen production. This is especially true once the costs and emissions of imported hydrogen has been accounted for.

Renewable and decarbonised electricity scenario

An alternative scenario would be to allow hydrogen produced from all forms of renewable and decarbonised electricity to be considered. This approach has several key advantages; it would reduce grid curtailment of existing wind and solar plants and would allow electrolysers to operate at much higher load factors as they would not be correlated to a specific renewable plant, thereby reducing costs. It also would allow production potential from other decarbonised electricity, such as nuclear or hydropower, to be maximised. In this scenario, hydrogen production from renewable and decarbonised electricity takes place only at times the overall carbon intensity of the grid would not increase, meaning electrolysers are not running inflexibly on grid electricity.

The EU could produce enough hydrogen to meet projected demand if all forms of renewable and decarbonised electricity was used, without the overall carbon intensity of the grid increasing.

New-build RES and SMR/ATR + CCS scenario

In this scenario, hydrogen production takes place from new-build, additional renewables with further volumes of hydrogen produced via SMR or ATR, coupled with CCS. Production of hydrogen in this way could only take place in countries with suitable sites for long-term geological storage of CO2. SMR and ATR are the most common methods of hydrogen production today, but CCS is still in its infancy and there are considerable technical challenges that must be overcome before it could be deployed at scale. CCS will also result in residual emissions, so producing hydrogen in this way is unlikely to be widely gain broad policy support as tool for decarbonisation in the EU. Certain countries, most notably Germany, have already stated they are openly against the use of SMR/ATR with CCS for hydrogen production.

[3] In this scenario, a maximum of 606GW wind and 1,134GW solar is installed across the EU by 2050.

Case Study

As well as considering the volumes of hydrogen that can be produced in each scenario, it is worth considering how hydrogen production interacts with hydrogen demand.

Example – Hydrogen demand in a refinery

In this example, hydrogen production from electrolysis is required to replace hydrogen produced by SMR (without CCS) in a refinery. Hydrogen is produced from a 30MW electrolyser, where electricity is purchased from a renewable plant through a PPA agreement. To conform to RED II directives, electricity must be purchased through a bilateral contract from a renewable source that is temporally and geographically correlated to the electrolyser. To conform with additionality requirements, the PPA agreement must be in place before a FID is taken on the electrolyser. The electrolyser is then only able to operate when the renewable plant is operating.

If the renewable plant also has a 30MW capacity, no balancing is required, and all electricity taken from the renewable plant is utilised for electrolysis. If the renewable plant has a higher capacity than the electrolyser, at certain times additional volumes of electricity must be sold. However, owing to the RED II directives, grid electricity could not be purchased at times the renewable plant was not in operation, to increase the load factor of the electrolyser and provide a constant stream of hydrogen to the refinery. Therefore, high volumes of hydrogen storage would be required, and the refinery may also rely on more polluting forms of hydrogen to meet its continuous demand.

However, if the electrolyser was able to purchase volumes of renewable or decarbonised electricity from the grid, load factors would increase significantly, and hydrogen production could take place more continuously. This would reduce requirements for storage capacity and limit the possibility more polluting forms of hydrogen were used for refining purposes.

Costs of hydrogen economy

The total cost of meeting hydrogen demand can be reduced by €16.2 billion (c.24%) in 2030 and by €19 billion (c.19%) in 2050, if all forms of renewable and decarbonised electricity was used to produce hydrogen, compared to a scenario where only new-build, additional renewables was used. This is after considering the costs of producing, storing and transporting hydrogen within Europe, as well as importing sufficient volumes of hydrogen from outside Europe to meet residual demand.

In 2030, allowing the production of hydrogen from SMR/ATR + CCS would result in a similar decrease in total costs. By 2050, producing hydrogen through renewable and decarbonised electricity is the cheapest available scenario, reducing costs by €4 billion (5%) compared to a scenario where SMR/ATR + CCS is used.

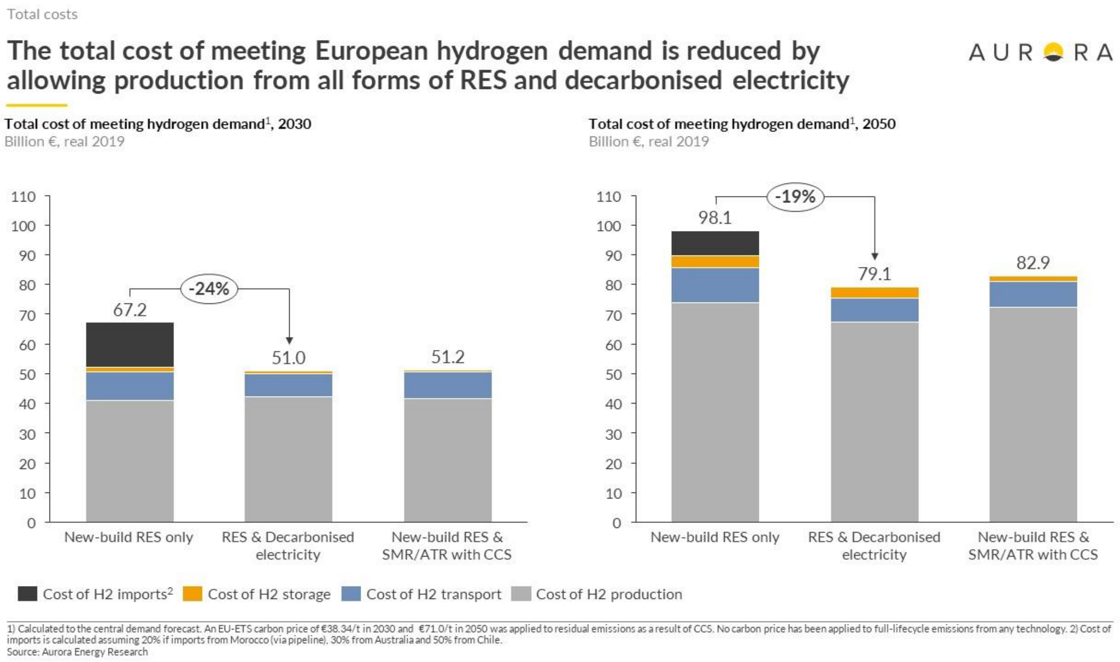


Exhibit 4. Total cost of meeting hydrogen demand

The cheapest hydrogen can be produced when all forms of renewable and decarbonised electricity are utilised

The levelised cost of hydrogen (LCOH) is the best indicator for comparing the economics for different types of hydrogen, taking into account all production costs across the lifetime of the asset.

In a scenario where all hydrogen is produced from additional new-build renewables only, the LCOH is driven by the levelised cost of electricity (LCOE) of new-build renewables. The cheapest hydrogen that can be produced in this way is by utilising onshore wind in Sweden and solar in Spain in both 2030 and 2050. The LCOH can be reduced by up to 7-8% if electrolysers are co-located with RES plants, as no grid connection is required, resulting in reduced CAPEX costs. By 2050, a higher volume of electrolysers would have to be deployed in this scenario owing to the lower load factors achieved, as electrolysers can only operate when co-located or temporally linked renewable plants are operating. Additionally, if all electrolysers were co-located with RES plants then hydrogen transport costs would likely be higher as hydrogen would then have to be transported to demand centres.

In the alternative scenario where all forms of renewable and decarbonised electricity are used to produce decarbonised hydrogen, the average LCOH would be reduced. In this scenario, electrolysers have access to cheaper, decarbonised grid electricity, can be located closer to hydrogen demand centres and can operate at higher load factors as they are not tied to any specific renewable plant. Electrolysers would also be deployed more rapidly before 2030, resulting in faster learning rates and consequently reduced CAPEX costs.

Hydrogen produced through SMR or ATR, with CCS, is cheaper than most forms of hydrogen production via electrolysis, especially in the early years of the forecast, and so in a scenario where the supply gap is filled by hydrogen produced in this way the average LCOH total cost of hydrogen production could be reduced, compared to if only new-build, additional renewables were utilised. In 2030, allowing hydrogen production from SMR or ATR with CCS would give a similar decrease in LCOH compared with using renewable and decarbonised electricity. By 2050, the lowest average LCOH can be achieved by using renewable and decarbonised grid electricity, as electricity costs fall.

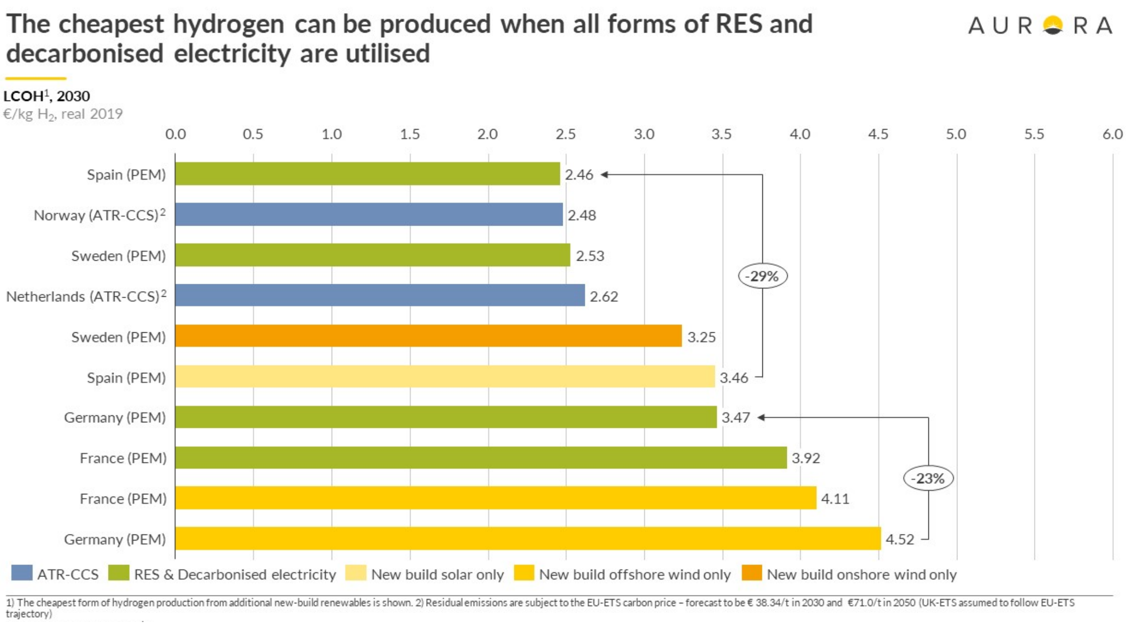


Exhibit 5. LCOH in 2030[4]

[4] LCOE calculated using Capex (including grid connection, certification, installation and development costs) and Opex costs

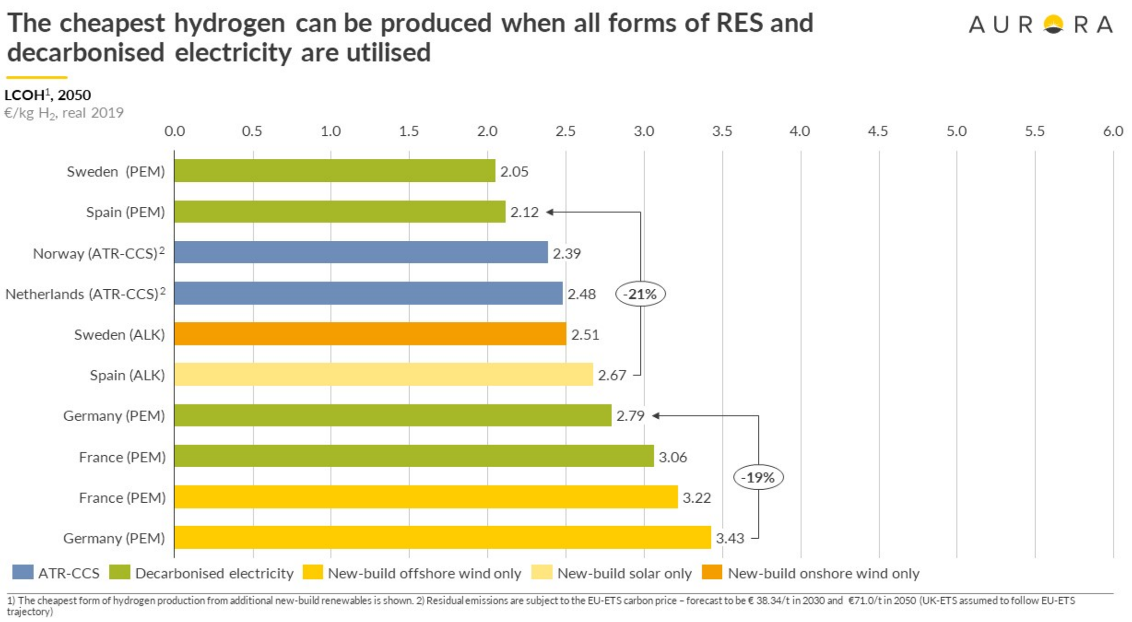


Exhibit 6. LCOH in 2050

Levels of required top-up subsidies[5] are lowest in a scenario where all hydrogen produced from all forms of renewable and decarbonised electricity is utilised

The development of a hydrogen economy will require subsidy support. The LCOH of the cheapest available form of hydrogen will set the price consumers would pay for hydrogen and for hydrogen with a higher LCOH, a top up subsidy would be needed to enable its widespread deployment. The cheapest hydrogen can be produced in the Nordics and in Spain, if all forms of renewable and decarbonised electricity are considered. However, as volumes of hydrogen that can be produced from these sources are insufficient to meet all European demand, levels of top-up subsidy support required are compared to a counterfactual where all hydrogen is produced from SMR/ATR + CCS. In countries where hydrogen can be produced at a lower cost, no top-up subsidy is required.

Top-up subsidy requirements could be reduced by €0.80/kgH_2 (56%) in 2030 and €0.28/kgH_2 (76%) by 2050 by allowing the production of decarbonised hydrogen from all forms of RES and decarbonised electricity, compared to a scenario where only new-build renewables were used.

[5] Top-up subsidy requirements are compared to a counter-factual where all hydrogen is produced through ATR with CCS, and represents the additional level of support the average kg of H_2 needs in each scenario to become competitive with H2 produced through ATR-CCS.

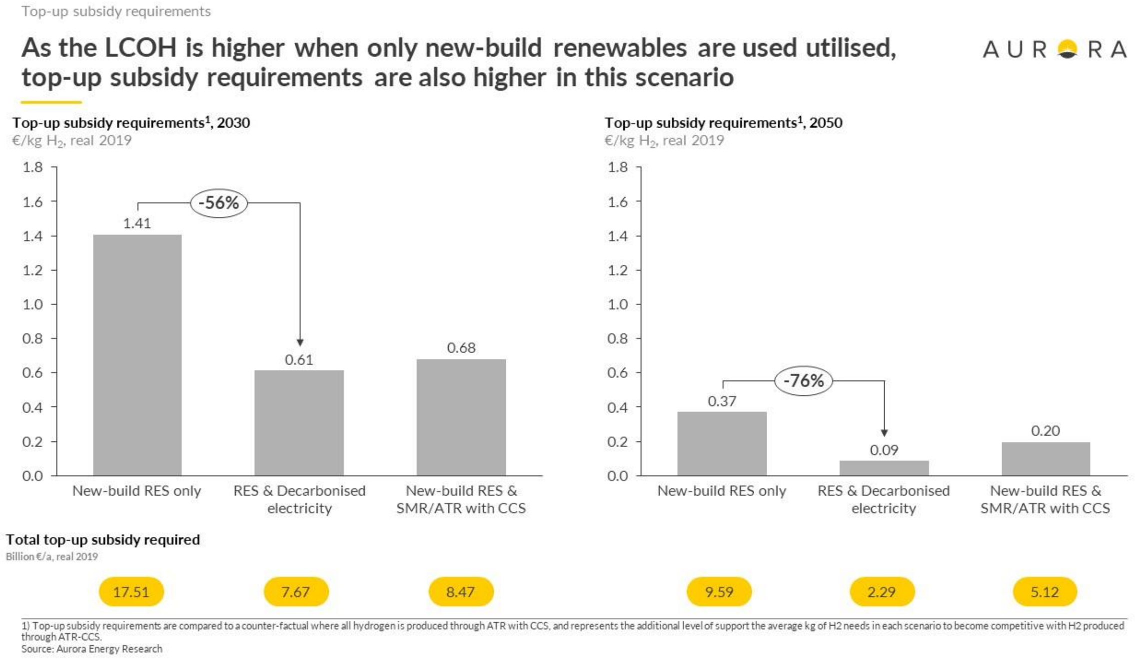


Exhibit 7. Top-up subsidy requirements

Hydrogen transport and storage costs are reduced if hydrogen is produced from all renewable and decarbonised electricity

For a hydrogen economy to develop, pan-European transport will be required, to transport hydrogen from countries such as Spain and Sweden, which will be able to produce volumes of decarbonised hydrogen in excess of their demand, to countries such as Germany, which will face a significant deficit. Transport within countries will also be required, to transfer hydrogen from production facilities to demand centres. This can take place via pipeline or via truck.

In a scenario where all forms of renewable and decarbonised electricity could be used to produce hydrogen, transport costs per kg of hydrogen transported between and within European countries would be 25% lower than if only new-build, additional renewables were used in 2030 and 35% lower in 2050. This is because if only new-build, additional renewables were used for hydrogen production, the average distance hydrogen would have to be transported is greater, as renewable production typically takes place far from demand centres. In addition, smaller total volumes of hydrogen would be transported, resulting in lower pipeline utilisation. If all forms of renewable and decarbonised electricity are utilised for hydrogen production, and there is no requirement for an electrolyser to be temporally or geographically linked to a specific renewable plant, hydrogen production can take place closer to demand centres, resulting in reduced transport costs.

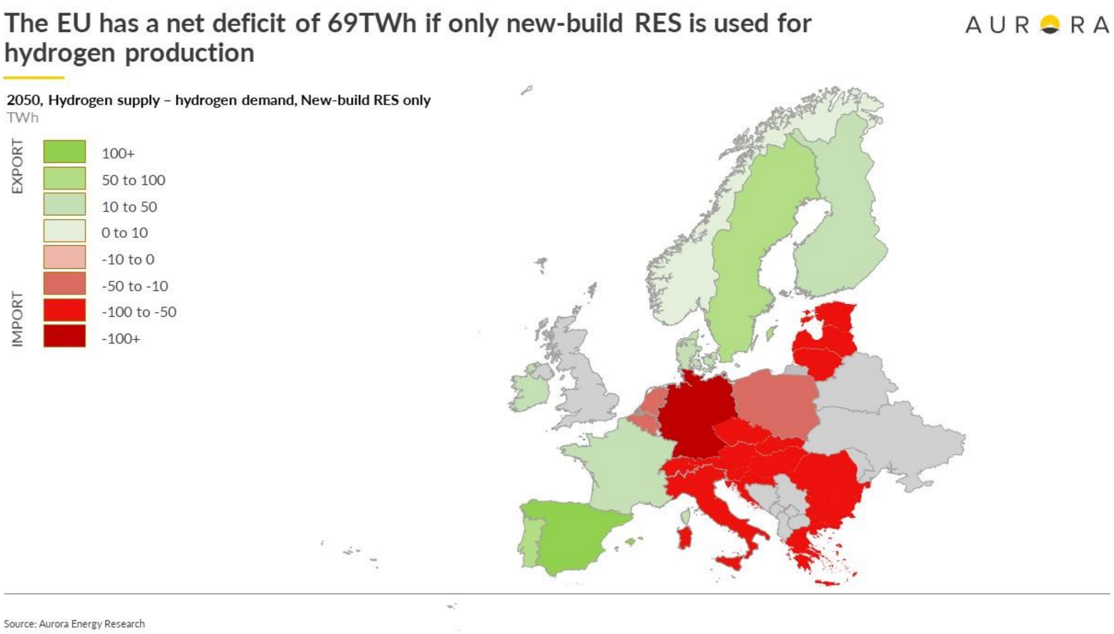


Exhibit 8: Hydrogen supply and demand if only new-build, additional RES is utilised for hydrogen produced

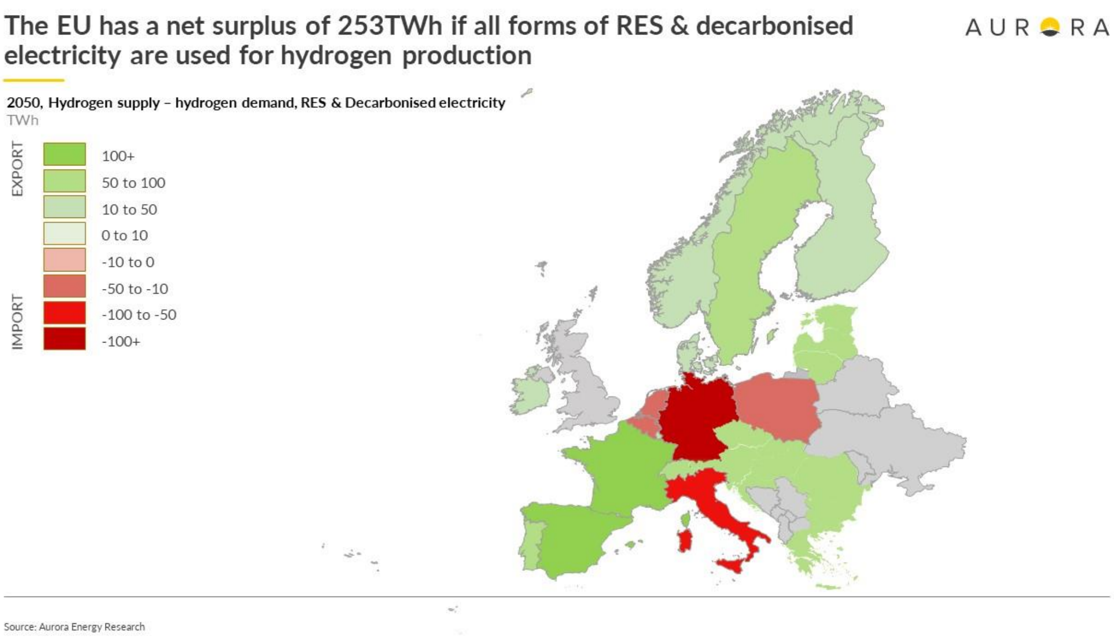


Exhibit 9: Hydrogen supply and demand if all forms of renewable and decarbonised electricity are utilised for hydrogen production

Hydrogen storage will also be required in all scenarios as hydrogen produced from intermittent renewables is not dispatchable at times of peak hydrogen demand. However, storage is only a minor component of the total cost of a hydrogen economy. Storage can either take place in salt caverns (at a cost of €0.27/kgH_2) or in above ground storage (at a cost of €6.37/kgH_2). The total required capacity of hydrogen storage can be reduced by 4% in 2050 if all forms of renewable and decarbonised electricity are used for hydrogen production.[6] This is because some of the seasonal variations in hydrogen production driven by wind and solar can be mitigated through generation from other renewable and decarbonised electricity. In this scenario we have only considered hydrogen production from renewable and decarbonised grid electricity at times when the carbon intensity of the grid would not be affected. Therefore, hydrogen storage is still required in this scenario.

Storage costs could also be reduced using ATR/SMR derived hydrogen as this can be dispatched at will.

[6] Hydrogen storage capacity is calculated on an inter-day basis. Intra-day storage requirements have not been considered as part of this report.

Hydrogen production & grid congestion

Hydrogen production is often touted as a solution to grid constraint issues, which are expected to become more significant across Europe as large thermal plants are retired and the volumes of installed intermittent renewable capacity increases. Optimal sites for renewable plants are often situated far from major demand centres, but transmission networks are generally not designed to transmit power from remote locations. At times of high renewable generation, curtailment is often required, meaning renewable capacity is not utilised optimally. This problem is expected to increase as more renewable power is brought online and significant investment will be required in reinforcements of the grid to mitigate this. Hydrogen production could help alleviate these constraints as production could take place at times of high electricity generation and low demand, providing electrolysers are sited optimally. A full analysis of how electrolysers should be sited across Europe to minimise constraints and how this would affect the need for investment into the grid has not been undertaken as part of this analysis but would need to be carefully considered.

In a scenario where all hydrogen was produced from new-build, additional renewables (whether from co-located or temporally and geographically linked renewables) it is assumed that significant volumes of hydrogen would be produced in remote locations and transported to demand centres. This would reduce requirements to transport electricity from remote locations to demand centres. However, in this scenario the curtailment of existing renewables would continue as electrolysers would not have the flexibility to utilise electricity from existing renewables, even if located in the same geographical area, even at times the electrolysers would otherwise be idle. In this scenario, hydrogen production would only provide minimal flexibility on the grid.

If all forms of renewable and decarbonised electricity were utilised for hydrogen production, the curtailment of existing renewables for grid management purposes would be prevented. In this scenario other forms of decarbonised electricity such as nuclear would also be utilised for hydrogen production, and dispatch of electricity from these plants could therefore also be optimised. This would likely result in electrolysers being situated closer to demand centres, as they would access volumes of renewable and decarbonised electricity from the grid as opposed to specific plants. As electrolysers can operate more flexibly in this scenario, overall grid constraints could be minimised. However, care would be required to ensure electrolysers were optimally located to do this.

Importing hydrogen would result in higher costs and emissions

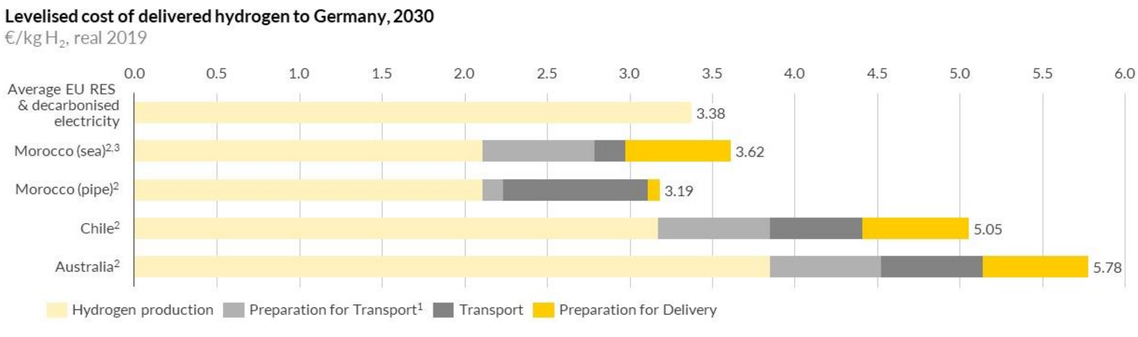
If hydrogen were only to be produced from new-build additional renewables, the supply gap could be filled via imports. It is assumed only hydrogen produced from renewable or decarbonised electricity would be imported. The most likely countries of origin would be Chile, Morocco or Australia where volumes of decarbonised hydrogen could be produced from solar generation.

From Morocco, hydrogen imports would most likely be transported via pipeline[7], whereas imports from Australia and Chile would be via ship, necessitating a conversion to ammonia. The cheapest available imports to Europe, after production, preparation for transport, transport and delivery costs were considered would be from Morocco. However, it is unlikely that imports from Morocco, or other North African countries, alone would be sufficient to fill the supply gap due to the need to decarbonise the power system here[8].

In 2030, imports from Chile and Australia would be 50% and 71% more expensive respectively than the average LCOH that could be produced from all forms of renewable and decarbonised electricity after ammonia conversion costs and transport costs are considered.

In addition, shipping hydrogen would have a significant emissions cost (see section 4), resulting in higher overall full lifecycle emissions in this scenario.

When considering hydrogen imports, an additional challenge for policymakers will be to develop a level playing field among hydrogen producers inside and outside of Europe, to ensure hydrogen imports are subject to the same traceability criteria as locally produced hydrogen.



1) Preparation for transport includes conversion into ammonia, preparation for delivery includes conversion from ammonia to H2. 2) H2 production costs in Morocco, Australia & Chile were calculated based on a discounted wholesale price. 3) Transports costs assume new-build pipeline
Source: Aurora Energy Research, IEA

Exhibit 10. Cost of hydrogen imports[9]

[7] Costs are calculated on the basis a new-build pipeline is constructed, as opposed to the conversion of the existing pipeline from Morocco to Spain. Delivery costs shown are calculated on the basis that hydrogen is delivered to port in Germany but do not include costs of further distribution of hydrogen within country.

[8] A level playing field between hydrogen producers inside and outside the EU is assumed, therefore volumes of solar electricity in Morocco (and other countries) would first be required for the decarbonisation of the grid.

[9] LCOH for Chile, Australia and Morocco were calculated using discounted grid prices

Emissions

Considering full life cycle emissions, per unit emissions are lowest when hydrogen from both renewable and decarbonised electricity is considered.

For the EU to meet its decarbonisation objectives, emissions from hydrogen production must be minimised. Although the production of decarbonised hydrogen does not result in direct carbon emissions, all forms of hydrogen production have associated emissions on a full life-cycle basis. Allowing hydrogen production from all forms of renewable and decarbonised electricity would reduce emissions by 18.7% when compared to emissions from new-build, additional renewables only. These figures only take in account full life cycle emissions as a result of hydrogen production. However, if hydrogen was imported in order to bridge the supply gap in the new-build renewables only scenario, there would be additional emissions resulting from the production and shipping of these volumes.

Full life cycle emissions in a scenario with hydrogen production from SMR/ATR + CCS are 66% higher in 2030 and 60% higher in 2050 than a scenario where all hydrogen was produced from decarbonised electricity. Because of this, hydrogen produced through SMR/ATR + CCS is unlikely to become a widely accepted tool for decarbonisation.

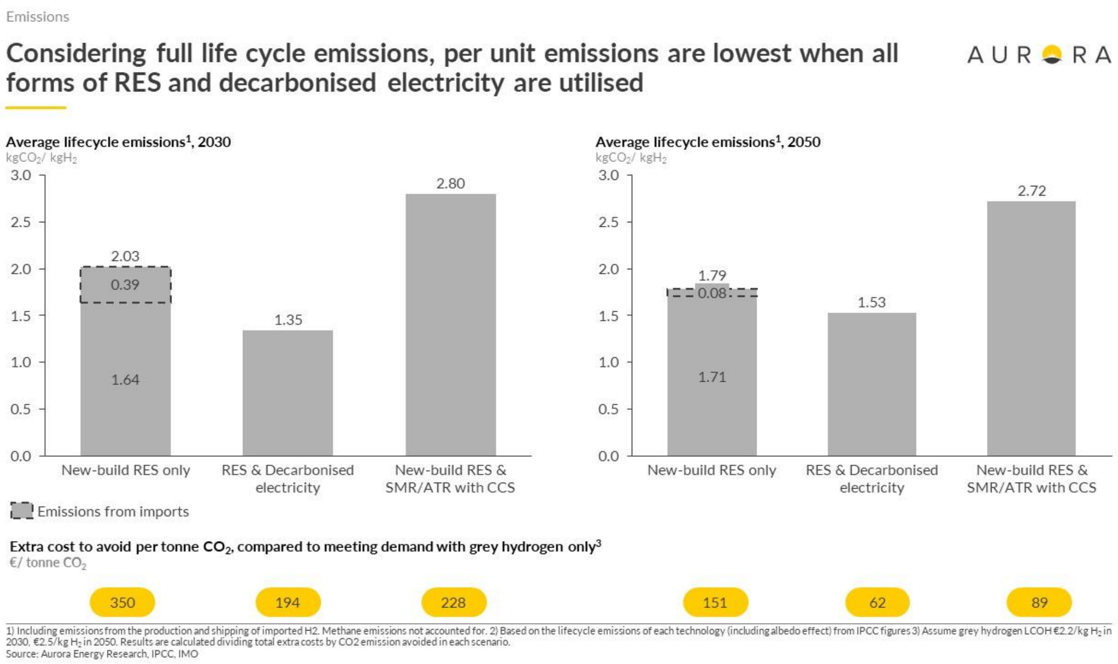


Exhibit 11. Carbon emissions

Policy support

Hydrogen has the potential to become a key part of the EU's future energy system, with demand in 2050 reaching 1,010 TWh in our central case. The EU will be able to produce enough hydrogen to meet this demand if all forms of renewable and decarbonised electricity are utilised for hydrogen production, without increasing the overall carbon intensity of the grid. However, relying on additional, new-build renewables alone would result in a substantial supply gap. A scenario where all forms of renewable and decarbonised electricity were used to produce hydrogen would also be cheaper, requires less subsidy support and would result in fewer overall emissions than a scenario where hydrogen production only came from new-build renewables, especially after the costs and emissions of imports have been accounted for.

Policy support should be focused on encouraging the development of low carbon scenarios, with the criteria regarding which forms of hydrogen production to support based on full lifecycle CO_2 emission reductions. Careful consideration should be given to how the traceability of decarbonised hydrogen can be ensured, as a means of tracking hydrogen would allow the preferred types of hydrogen to be recognised by policy makers and consumers. Consideration should also be given to the support mechanisms that could be used to encourage hydrogen production and use, and to mandates that could be implemented to drive a switch to hydrogen.

Any decision on which types of hydrogen production to support has implications on production costs and volume potential. The carbon intensity of hydrogen production must also be carefully considered if the wider introduction of hydrogen into the European energy system is to result in overall emissions reductions. Whilst electrolysis is often seen as 'clean', it will still result in emissions which will depend on the carbon intensity of the electricity used; for a grid-connected electrolyser operating at full capacity this depends on the overall carbon intensity of the grid. For many countries in the EU, a reliance on thermal plants means the carbon intensity of hydrogen produced through grid-connected electrolysers is higher then hydrogen produced through SMR or ATR (without CCS). Therefore, producing hydrogen from grid electricity will not neccessarily help decarbonisation targets to be met.

One option under discussion as part of the RED II directives is for hydrogen production to be supported, provided that the overall carbon intensity of hydrogen produced is less than 3.4 $kgCO_2/kgH_2$, or 70% below the carbon intensity of hydrogen produced through SMR/ATR without CCS (the EU Taxonomy for sustainable activities sets a lower limit of 3.0 $kgCO_2/kgH_2$). Today the Norwegian, Swedish and French grids have sufficiently low average carbon intensities that hydrogen production could take place from grid-connected electrolysers operating at full capacity[10]; Finland is also currently very close to this threshold, with ongoing decarbonisation efforts likely to reduce its grid carbon intensity further in the near future. By 2030, in a high RES scenario, grid carbon intensities in Denmark, Spain and Portugal will also allow hydrogen production below this threshold. Under this approach, carbon intensities are averaged across the year, meaning for some half hourly periods emissions are still above this threshold. Only limited volumes of hydrogen production could take place

[10] Assuming an electrolyser efficiency of 70%, operating at full capacity

without the overall carbon intensity of the grid increasing due to the increased demand from electrolysis.[11] A total of 469.6TWhH_2 could be produced with such a threshold in place in 2030.

In other countries, hydrogen could only be produced from grid-connected electrolysers operating at time of high renewable and decarbonised electricity generation, which would likely require a guarantee of origin scheme to be implemented.

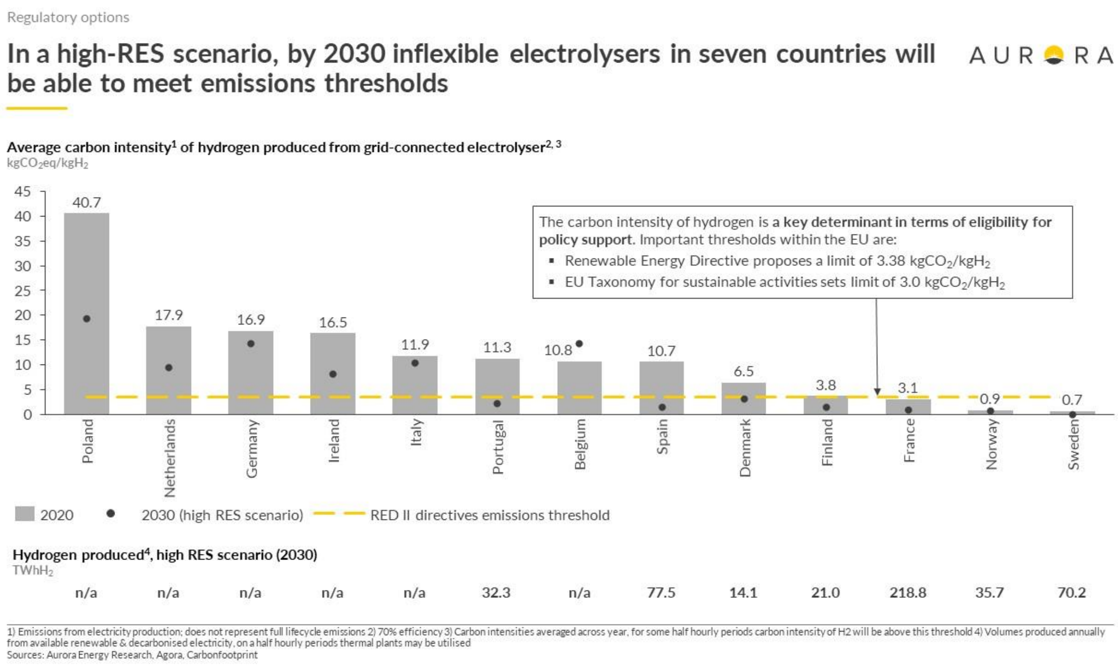


Exhibit 12: Grid carbon intensities

Another potential policy option under consideration is to restrict hydrogen production to that produced from new-build, additional renewables only, as laid out in the RED II directives. However, this risks supply becoming a bottleneck for the size of the hydrogen system and may result in a reliance on imports, which would push up both costs and emissions. Allowing all forms of renewable and decarbonised electricity to be utilised for hydrogen production would increase volume potential and lower the cost of hydrogen but is not directly compatible with current RED II directives.

[11] Potential volumes of hydrogen that can be produced have been calculated using assumed available volumes of renewable and other decarbonised electricity averaged over an annual basis. For some half hourly periods overall grid intensities will increase as thermal electricity is used at times of low renewable generation.

Guarantees of Origin Schemes

Whilst Guarantees of Origins (GoOs) are not a direct support mechanism and do not allow decarbonisation in themselves, they can reallocate the costs of decarbonisation to customers willing to pay for it. A simplified, technology-agnostic definition of hydrogen for the GoO scheme, based on full life cycle emissions from hydrogen production would minimise emissions, whilst allowing hydrogen demand to be met.

CertifHy

CertifHy is the first EU-wide hydrogen GoO scheme, similar to more established green electricity GoOs that track the origin of production. It covers either hydrogen produced from renewable energy - defined as 'Green Hydrogen' - or from non-renewable low carbon energy sources (nuclear, fossil with CCS) - defined as 'Low Carbon Hydrogen'. The scheme is technology neutral, providing the requirement to comply with the definitions is met. Any technology that can provide evidence that the defined requirements for hydrogen produced are met are included in the scope of the CertifHy scheme. Technologies producing hydrogen as by-product are also included in the CertifHy scope, if transparent and unambiguous information about the main product is included in the GoO and the basis of the emissions allocation complies with the principles of the scheme.

CertifHy 3 is a three-year project to implement a harmonised hydrogen GoO scheme across Europe and beyond, building a market for hydrogen GoO trade. Phase 3 of the scheme works to design certification for compliance with RED II renewable fuels. To be compliant with RED II targets and principles, the CertifHy 3 GoOs and certifications would focus on hydrogen produced from new-build, additional renewable sources only. This would exclude hydrogen produced from existing renewables and other decarbonised electricity, limiting the volumes that could be produced under the scheme. It also would not support hydrogen produced from electricity with GoOs from the power sector. This is contradictory to the purpose of the GoO scheme in the power sector.

Alternative GoO scheme

A simplified, technology-agnostic definition of low carbon hydrogen, based on a GoO scheme, would better encourage the growth of the hydrogen sector while maintaining a low emission outcome. When determining which hydrogen production methods should be supported based on the GoO scheme, a carbon emissions threshold based on full life-cycle emissions should be set. Hydrogen production methods that fall under this threshold would have access to a low carbon hydrogen GoO, giving access to support schemes. With such an approach, emissions thresholds do not refer to the overall carbon intensity of the grid; electrolysers will procure electricity from a renewable or low carbon source under an electricity GoO.

Carbon Contracts for Difference

A Carbon Contracts for Difference (CCfD) scheme would provide a payment for avoided carbon emissions which could be applied across multiple sectors. This would mitigate the pitfalls of a carbon price, whilst driving cost effective decarbonisation.

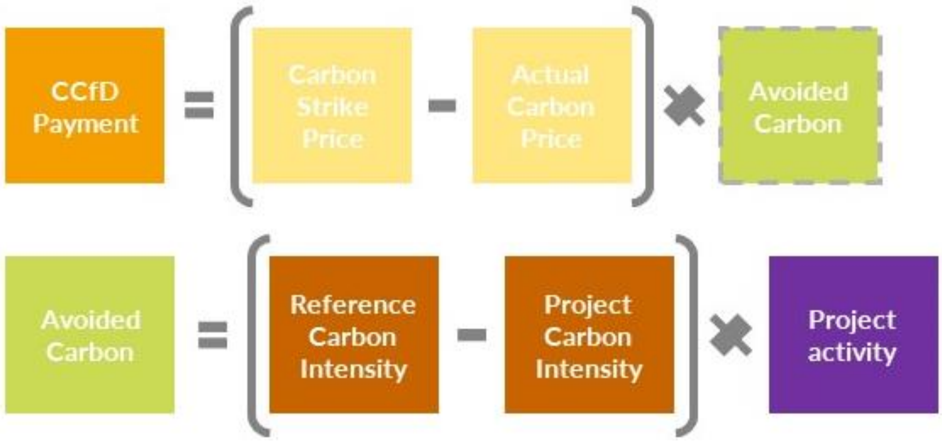


Exhibit 13: CCfD payment calculator

For emissions targets to be reached, a shift to new technologies is required, particularly in the industrial sector. In many cases, new technologies that drive emissions reductions are more costly than carbon intense alternatives and will require additional support until the technology can become established. A carbon price can assist in this, as a higher carbon price will make the carbon-emitting alternative more costly. However, current EU-ETS prices are generally too low to support this goal. Future carbon prices are also highly uncertain, as they are subject to both market and political uncertainties, meaning securing funding for abatement projects is challenging.

CCfDs would be designed to hedge against volatile carbon prices. Under a CCfD scheme, investors would be guaranteed a carbon price needed to finance their project. When the actual carbon price is below the pre-determined strike price, projects would be compensated the difference for each unit of carbon displaced. A guaranteed strike price therefore provides needed certainty to investors.

The amount of carbon a project helps avoid depends on the carbon intensity of its own activity and the carbon intensity of the activity it displaces (reference carbon intensity). The reference carbon intensity could be calculated differently depending on the trade-offs of complexity and effective incentivisation of decarbonisation.

CCfDs could therefore incentivise the displacement of fossil fuels in industrial processes and provide support for the switch to hydrogen; with both demand and supply sides benefitting. There are several key questions that would need to be addressed.

How could the carbon strike price be designed?

In order for a CCfD scheme to be effective, sector-specific or project-specific CCfDs would be needed, with specific strike prices. A scheme with a single strike price across all industries would mean that for many of the hardest-to-abate sectors the strike price would be too low to enable decarbonisation to take place.

How could CCfDs be auctioned?

Sector-specific auctions, with quotas, would fairly allocate CCfDs across all sectors, allowing segments such as steel to realise the full potential of decarbonised hydrogen.

Would a CCfD scheme be implemented at a national or EU level?

A CCfD scheme would likely be implemented at a national level, however efforts would have to be made to ensure compatibility with state aid rules.

What would the duration of a CCfD be?

CCfD contracts should also be designed to cover the full investment period of a project. Decarbonisation of many industrial sectors through the use of hydrogen would introduce high levels of technological and financial risks and many years would be required before a new process could be optimised. Support would be needed for the entire investment period in order for a project to be successful.

Demand mandates

Demand mandates are a strong tool for directing the switch to hydrogen or hydrogen-derived fuels produced from RES and decarbonised electricity.

At present, almost all hydrogen used within the EU is produced via SMR or ATR, without CCS. For decarbonisation targets to be met, there must be a transition towards the use of less-emitting forms of hydrogen. Introducing mandates for the use of hydrogen produced from renewable and decarbonised electricity could help to achieve this. Targets for the penetration of less-emitting forms of hydrogen should be gradually introduced, with the goal of phasing out the use of SMR and ATR without CCS in existing industrial processes by 2030. Boosting the demand for hydrogen produced from renewable and decarbonised electricity in this way would support the early deployment of electrolysers, driving a faster reduction in CAPEX costs and therefore a more rapid reduction in the LCOH. Mandating the use of hydrogen produced from renewable and decarbonised electricity would also provide a clear indicator to investors as to the long-term viability of projects.

Under the RED II directives, mandates are laid out for the use of renewable fuels, with minimum targets laid out for the use of biofuels, advanced biofuels, renewable electricity, and renewable fuels of non-biological origin (RFNBO) in transport. Hydrogen and hydrogen-derived synthetic fuels therefore count towards these targets, provided that GHG emissions are lower than 70% of fossil fuels. Under present guidelines, these fuels are to be produced using additional, new build renewables only. However, this requirement will limit the volumes of hydrogen that can be produced, whilst increasing costs, compared to if all forms of renewable and decarbonised electricity were used for hydrogen production. Clear support should be provided to hydrogen and hydrogen-derived fuels produced from all renewable and decarbonised electricity and these volumes should be included within demand mandates to avoid hydrogen supply becoming a bottleneck for decarbonisation. However, the use of hydrogen-derived synthetic fuels in transport should be limited to the otherwise difficult to decarbonise aviation sector due to their costs and inefficiency.

There have been suggestions that the blending of hydrogen into existing gas networks could be an early step on the path towards a wider hydrogen economy and mandates for the blending of hydrogen produced from renewable or decarbonised electricity with natural gas in local networks could provide a pathway to emissions reductions in domestic heating. However, blending with natural gas would diminish the value of hydrogen. In addition, the levels on blending that could safely take place vary between networks and any introduction of a hydrogen blend would need an extensive study period to ensure its safety, incurring additional costs. This may be inappropriate for a measure designed as a short-term step towards wider decarbonisation. Blending will also affect the design of gas infrastructure and cross-border operability, which may risk fragmenting Europe's gas markets if different blends were permissible in neighbouring countries. Therefore, mandates for hydrogen blending are unlikely to be a suitable driver of demand.

The use of demand mandates for hydrogen produced from RES and decarbonised electricity could increase energy costs, compared to scenarios where fossil fuels or fossil fuel derived hydrogen was utilised. Therefore, additional policy support to help energy users decarbonise may be required to complement the use of mandates.

Conclusions

The use of hydrogen will be necessary in many sectors if the EU's decarbonisation targets are to be met. Policy decisions taken today will have a major impact on how this hydrogen is produced, which will impact both the volumes produced and the overall costs of the future hydrogen economy. As all forms of hydrogen production result in full life cycle emissions, any decisions on which forms of hydrogen production should be supported will also impact future CO2 emissions.

Current policy favours a scenario where hydrogen production takes place through new-build, additional renewables only, that are temporally and geographically linked to specific electrolysers. Whilst this would guarantee electricity utilised for hydrogen production had come from a renewable source, this scenario will not allow the optimal development of a European hydrogen economy as insufficient volumes of hydrogen would be produced at a higher cost and with higher full life cycle emissions than alternatives.

Our analysis shows that the preferable solution would be a scenario where all forms of renewable and decarbonised electricity could be utilised in hydrogen production. In this scenario, the EU would be able to produce enough hydrogen to meet demand in both 2030 and 2050 in our central case. Total costs of producing hydrogen would also be lower, meaning required top-up subsidies would be reduced. The costs of transporting and storing hydrogen in this scenario would also be reduced, and imports from outside the EU would not be required. Importantly, this scenario would also result in lower full life cycle CO2 emissions.

Therefore, policies to support the production of hydrogen from all forms of renewable and decarbonised electricity should be implemented and policy support should be based on full life cycle emissions resulting from the production of hydrogen. Additional consideration should be given to how the demand for hydrogen produced from renewable or decarbonised electricity can be supported; CCfD schemes and demand mandates are the strongest demand-side support options.

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