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COST OF RENEWABLE HYDROGEN PRODUCED ONSITE AT HYDROGEN REFUELING STATIONS IN EUROPE

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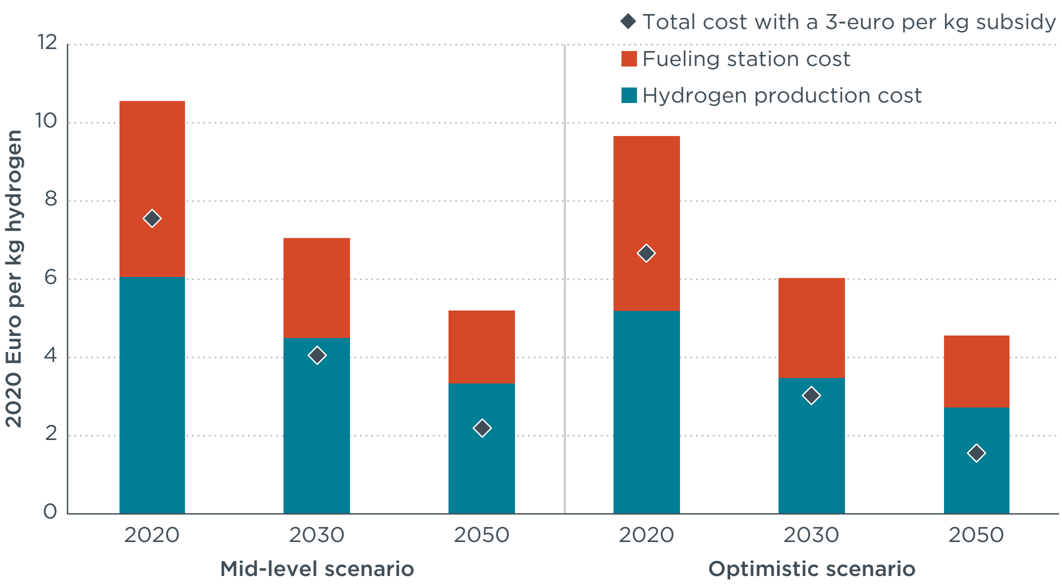
EXECUTIVE SUMMARY

Renewable hydrogen produced using 100% renewable electricity for water electrolysis is a near-zero greenhouse gas (GHG) energy source that the European Union (EU) could use in its decarbonization efforts. Renewable hydrogen can potentially be used across the economy, including in transportation. When used in transportation, hydrogen would need to be supplied to a hydrogen refueling station (HRS). The hydrogen can be produced at a central facility and transported to the HRS or directly produced onsite at the HRS. Unlike centralized production, onsite hydrogen production avoids fuel transportation from the production site to the HRS, which can be costly and inefficient. In this study, we investigate the at-the-pump renewable hydrogen price at an HRS using onsite electrolysis in EU countries.

We use a discounted cash flow model to estimate the cost of producing renewable hydrogen using wind and solar electricity in 26 EU countries during the 2020 to 2050 timeframe, using a mid-level and an optimistic cost scenario. We include the cost of building and operating a HRS. We also evaluate the potential impacts of providing financial support, using a 3-euro per kg hydrogen subsidy for renewable hydrogen production as an illustrative example.

Figure ES1 shows the EU average at-the-pump price for onsite renewable hydrogen, the breakdown into hydrogen production (teal bar) and fueling cost (orange bar), and the total cost when a 3-euro per kg subsidy is provided (grey diamond). Using the mid-level scenario and a 30% HRS utilization rate, we estimate the EU average at-the-pump price of onsite renewable hydrogen to be 11 euros per kg hydrogen in 2020. We expect renewable hydrogen production costs to decline in the future due to technological improvements in both renewable electricity generation and in electrolysis, including likely cost reductions in electrolyzers. We expect the levelized cost of HRS infrastructure to decline on a per kg hydrogen basis mainly due to increased utilization rates, which we assume to be 50% in 2030 and 70% in 2050. Regardless of these cost reduction assumptions, even our optimistic estimate of 6 euros per kg hydrogen is significantly higher than the 2030 target of 1.8 euros per kg announced by the president of the European Commission (European Commission, 2021c). Financial incentives are necessary to reach the EC cost target. A 3-euro per kg hydrogen production subsidy can shorten the cost reduction trajectory by 10 years and could enable cost parity with diesel fuel on an energy basis before 2030.



ES1. At-the-pump hydrogen price averaged across 26 EU countries, using a mid-level cost scenario and an optimistic cost scenario.

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INTRODUCTION

Renewable hydrogen produced from water electrolysis using 100% renewable electricity has been supported under multiple EU policies and strategies. The Hydrogen Strategy communication emphasized the priority to develop renewable hydrogen and laid out staged targets of capacity installation from 2020 to 2050: at least 6 gigawatt (GW) installed and 1 million tonnes of production by 2024, 40 GW and 10 million tonnes of production by 2030, and commercial scale by 2050 (European Commission, 2020a). However, the total installed electrolysis hydrogen capacity in the EU was about 0.12 GW in 2020 (International Energy Agency, 2021). The European Commission's proposed revision to the Renewable Energy Directive (REDII) includes an ambitious target for 2.6% of total transport energy to be renewable fuels of non-biological origin (RFNBOs), which includes renewable hydrogen (European Commission, 2021a). The Commission has also proposed targets for the deployment of hydrogen refueling stations (HRS) in cities and along highways in its proposed revision of the Regulation on deployment of the alternative fuels infrastructure (European Commission, 2021b).

When renewable hydrogen is produced at a central plant, it must be transported to an HRS for use in hydrogen vehicles, either by truck or pipeline. Trucking is easier to deploy during early market stages, when hydrogen demand is low and transport distance is short (IEA, 2019). Pipeline transport fits better, from economic and operational perspectives, as demand and distance increase; however, hydrogen pipelines require careful planning and significant upfront investment for construction of the infrastructure (Baldino et al., 2020). Both transport cases can contribute significantly to the final delivered cost of renewable hydrogen to the HRS. Therefore, an emerging idea is to produce renewable hydrogen onsite at an HRS, eliminating the need for truck or pipeline transport. This has been experimented with in California, with 3 operational and 6 planned onsite electrolysis HRSs by 2016 (Baronas & Achtelik, 2017).

The purpose of this study is to investigate the economics of onsite electrolysis of renewable hydrogen in the EU. In particular, we estimate current and future at-the-pump onsite electrolysis hydrogen prices, i.e., the fuel price that consumers pay at the HRS. To align with the EU's decarbonization target, we consider only renewable electricity as the energy source, because this is the single pathway that can provide deep decarbonization with lower risks of uncertainties in GHG emissions (Zhou et al., 2021). While both gaseous hydrogen and liquid hydrogen could be used in the road sector, this study analyzes only gaseous hydrogen.

METHODOLOGY

The at-the-pump hydrogen price consists of two main components, hydrogen production cost and HRS cost. In reality, consumers would also need to pay fuel taxes. We assume that EU policymakers would exempt hydrogen from fuel taxes as an incentive for meeting hydrogen deployment goals, especially for renewable electrolysis hydrogen. Therefore, we do not include fuel tax as a part of the at-the-pump price.

HYDROGEN PRODUCTION COST

To estimate the cost of producing renewable electrolysis hydrogen in Europe, we follow the discounted cash flow (DCF) model in (Christensen, 2020), with adjustments in some underlying data assumptions. The result from a DCF model is the levelized production cost of a product, in this case hydrogen, that enables an investment to be economically viable. Generally, the main components of a DCF model include the capital cost of facility construction and equipment purchases, the annual operational cost of running the facility, and revenues from product sales. In Table 1, we list the assumptions of key input parameters in our renewable hydrogen DCF model. Like Christensen (2020), we consider three different types of electrolyzers: alkaline, proton membrane exchange, and solid oxide.

Table 1. Assumptions of renewable electrolysis hydrogen production parameters. LHV = lower heating value.

Input parameters	Data assumptions		
Installed capacity	1 $MW_{input\ power}$ (about 500kg hydrogen output per day)		
Capacity factor	95%		
Contingency factor	1.2		
	Alkaline electrolyzer	**Proton exchange membrane**	**Solid oxide electrolyzer**
System capital cost in 2020 (2020 euro/$kW_{input\ power}$)	Mid-level: 840	Mid-level: 1,005	Mid-level: 1,144
	Optimistic: 485	Optimistic: 327	Optimistic: 575
System capital cost reduction in the future	Mid-level: 2% annually		
	Optimistic: 2.5% annually		
Electrical efficiency in 2020 (LHV-based) (kWh/kg hydrogen)	48	56	42
Electrical efficiency in 2050 (LHV-based) (kWh/kg hydrogen)	42	46	38
Electrolyzer lifetime in 2020 (hours)	75,000	60,000	20,000
Electrolyzer lifetime in 2050 (hours)	125,000	125,000	87,500
Output pressure (bar)	15	30	15
Fixed annual operational cost	4% of system capital cost		
Water price	Country-specific		
Renewable electricity price	Country specific; determined endogenously in the cashflow model		
Oxygen price	0.13 euro per m^3 oxygen		

Sources: Baronas & Achtelik, 2017; Brynolf et al., 2018; Matute et al., 2019; Christensen, 2020; Advanced Gas Technologies, 2021

We chose a relatively small capacity for hydrogen production (installed capacity of 1 megawatt (MW) of electricity and producing around 500 kg hydrogen per day), which we believe would be appropriate to match the capacity of a single HRS (Baronas & Achtelik, 2017). The actual hydrogen production amount is dependent on both the capacity factor, which defines how often a plant can run, and the electrolyzer's conversion efficiency. We assume the hydrogen production facility is connected to the electricity grid, meaning that the capacity factor could theoretically reach 100% since the grid is running constantly. In this study, we assume a 95% capacity factor to account for potential electricity distribution losses and system downtime, similar to previous studies (Matute et al., 2019). This capacity factor relates to hydrogen production only and is irrelevant to the utilization rate of the HRS, which will be discussed in a later section. While the grid is unlikely to be 100% renewable in the near term, we assume that the hydrogen facility financially supports an additional renewable producer through a long-term electricity purchase agreement, such as a Power Purchase Agreement (PPA). We provide more details on electricity price later in this section.

Electrical efficiency determines the amount of hydrogen output from a certain amount of energy input based on hydrogen's lower heating value (LHV). Both electrolyzer efficiency and electrolyzer lifetime vary by electrolyzer type and are likely to improve in the future. We use the same 2020 and 2050 assumptions for the two parameters as Christensen (2020) and assume a linear trend for the years in between. Output pressure, which also differs by electrolyzer, determines the electricity need to compress hydrogen to the target fueling pressure at 700 bar for fuel cell vehicles (FCVs). We calculate the compression electricity consumption based on each electrolyzer's output pressure and the 700-bar target and estimate compression electricity cost using our modeled, country-specific renewable electricity price, which we explain below.

The system capital cost includes the costs of the electrolyzer stack and the balance of plant (BOP). The stack is where water is split into hydrogen and oxygen. The BOP refers to other equipment required for other parts of the system, such as treating the incoming water and electricity, and processing hydrogen output, including purification. This system cost differs by electrolyzer type and has a huge range. Christensen (2020) used a comprehensive literature review on electrolysis hydrogen capital costs to arrive at costs for a mid-level scenario that reflects the market average, and an optimistic scenario that represents the lower end of the cost range. In this study, we use Christensen's (2020) cost values and cost reduction assumptions for both scenarios, as shown in Table 1. In addition to the system capital cost, we include a contingency factor to account for potential upfront costs in project design and construction to derive total capital cost, as in Christensen (2020).

We assume the annual fixed operational cost of maintenance and labor to be 4% of the system capital cost, similar to previous studies (Brynolf et al., 2018; Matute et al., 2019). The variable operational cost of feedstock and utility depends on the actual hydrogen production amount. This cost includes water and electricity; the latter is used in both hydrogen production and compression.

We estimate current and future renewable electricity in each of the 26 EU countries endogenously within our model, also using a DCF model following the methodology in Christensen (2020). This model calculates the levelized production cost of renewable electricity, which is the contract price of a PPA. Specifically, we collect the capital and operational costs of solar and wind power plants from NREL (2021), which is able to represent the renewable electricity industry in western countries. We collect EU country-specific solar and wind capacity factors from Joint Research Centre (2018), amended via personal communication. This dataset does not provide a capacity factor for Malta; therefore, we exclude this country from our analysis. For the future renewable electricity price projection, we follow the cost reduction rate and capacity factor improvement rate from NREL (2021). Because the hydrogen plant is grid-connected, the hydrogen producer must also pay electricity transmission and distribution (T&D) fees. Therefore, on top of the modeled levelized cost of renewable electricity, we add the country-specific electricity grid and tax fees projected for future years by Searle & Christensen (2018).

Oxygen is a by-product of water electrolysis and we assume hydrogen producers would sell oxygen to bring in additional revenue. There is very limited information on the wholesale price of oxygen and we use the cost from Advanced Gas Technologies (2021). We do not include hydrogen storage under our hydrogen production DCF model. Hydrogen storage cost is covered as a part of the HRS cost in the section below.

In addition to the key parameters shown in Table 1, financial assumptions (Table 2) play important roles in affecting the levelized production cost. We assume the hydrogen producer adopts a mixture of 60% debt financing and 40% equity financing. The loan interest rate defines the cost of debt financing, while return on equity defines the cost of equity financing. We use the weighted average cost of capital (WACC), which considers both debt and equity costs, as the discount rate in the DCF model. These financial assumptions are informed by previous techno-economic studies (Steward et al., 2008; IEA, 2019; Matute et al., 2019; NREL, 2021). We collect EU country-specific corporate tax rates from OECD Stat (2021). All costs reported in the results of this study are in constant 2020 euros.

Table 2. Financial assumptions on hydrogen production

Inflation	2%
Corporate tax rate	2020 country-specific tax rate
Debt:equity ratio	60%:40%
Loan interest rate	4%
Return on equity	16%

HYDROGEN FUELING COST

European Commission (2021b) provides EU estimates of HRS capital and operational costs in 2020 and future years at three HRS capacities—400 kg, 1000 kg, and 2500 kg hydrogen per day. The capital cost includes upfront investment in three components: the hydrogen storage tank, the compressor, and dispensers. The annual fixed operational cost is assumed to be 4% of the capital cost. However, we understand that these cost numbers do not include the capital costs of a hydrogen purification device, nor the cost of electricity used for hydrogen compression and purification.

FCVs have a stringent requirement that the purity of supplied hydrogen be at least 99.97%. In our model, we include purification in the cost estimate of hydrogen production, which would result in high purity, meeting FCVs' operational requirement (IRENA, 2020). In addition, this study assumes the produced and purified hydrogen is used for fueling directly, meaning that potential contamination during hydrogen transport is avoided. Therefore, there is no need for hydrogen purification again at the fueling site. For compression, we already include compression electricity under the hydrogen production cost model, as described in the above section. As a result, EC's HRS numbers fit the purpose of this study.

To match our assumption of hydrogen production capacity in Table 1, we convert the 400kg-capacity HRS capital cost and operational cost into levelized per kg hydrogen cost for storage, compression and dispensing, assuming a 15-year lifetime HRS (European Commission, 2021b). It is unlikely that the HRS is going to be utilized to its full capacity, especially not in the early stages of hydrogen market development. Therefore, we factor in a HRS utilization rate when doing cost conversion. While there is very limited information on the HRS utilization rate, we assume a 30% HRS utilization rate in 2020, increasing to 50% in 2030 and 70% in 2050 based on previous analyses (Rajon Bernard et al., 2021; Minjares et al., 2021). We assume the same HRS cost across the 26 EU countries in this study.

AT-THE-PUMP PRICE

The at-the-pump hydrogen price is the sum of the hydrogen production cost and the fueling infrastructure cost. The at-the-pump hydrogen price varies by country as a result of variations in parameters of the hydrogen production DCF model, namely the price of renewable electricity, the electricity grid fee, the water price, and corporate taxes. We provide another scenario in which a government subsidy is provided to drive down the price of renewable hydrogen production. With the ambitious targets of renewable hydrogen set by the Commission, we expect that EU member states will need to take substantial and robust measures to help meet them. However, at the current stage, it is not clear what the total value signal from hydrogen policies will be in the EU countries. Therefore, for an illustrative policy support scenario, we assume a 3-euro per kg hydrogen (i.e., 0.86-euro per diesel-equivalent liter) subsidy for renewable hydrogen production, similar to a proposed subsidy for renewable hydrogen in the United States (Heinrich, 2021).

RESULTS AND DISCUSSION

In this section, we present the estimated current and future at-the-pump price of renewable hydrogen produced onsite at an HRS in the 26 modeled EU countries, excluding Malta, due to lack of information. We also discuss the impact of the hypothetical 3-euro per kg hydrogen policy support. We present in the Appendix our estimated electricity prices, which are key impacting parameters in the cost of electrolysis hydrogen, for each of the 26 countries.

Figure 1 shows the at-the-pump price of hydrogen as well as its breakdown into hydrogen production cost and fueling cost. While hydrogen production cost varies among countries, which we present in Figure 2, numbers in Figure 1 are averaged across the 26 EU countries analyzed in our model. We show the mid-level cost scenario and optimistic scenario for 2020 and future cost projections in 2030 and 2050. The difference between mid-level and optimistic scenarios is a result of different hydrogen production costs, while we assume the same HRS cost for the two scenarios. The diamonds in Figure 1 indicate the at-the-pump price if a 3-euro per kg hydrogen production subsidy is applied. All cost numbers here and after are in 2020 euros.

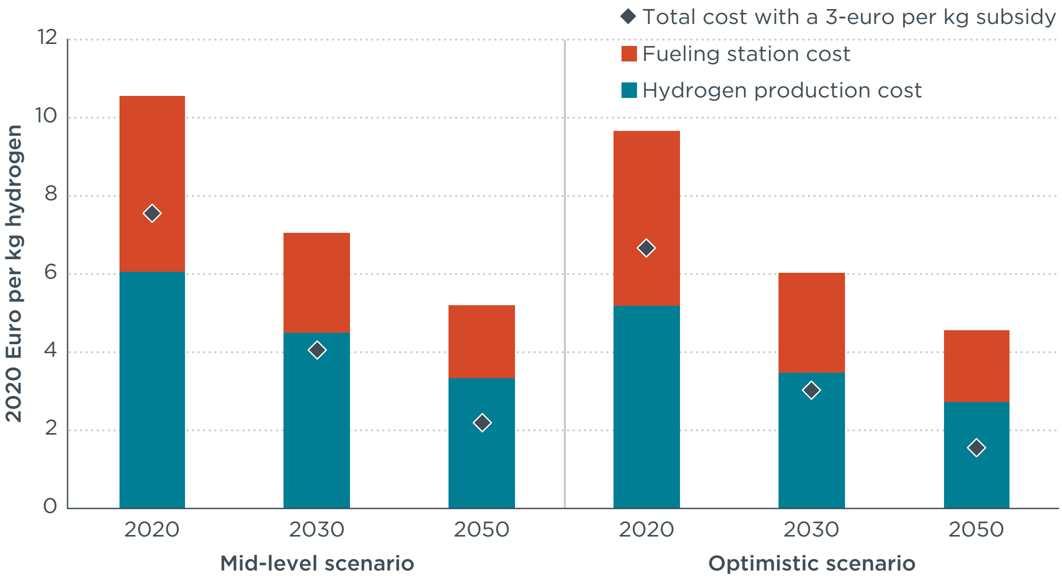

Figure 1. At-the-pump hydrogen price averaged across EU countries, using a mid-level cost scenario and an optimistic cost scenario.

We estimate the mid-level EU average at-the-pump price of onsite renewable hydrogen to be 11 euros per kg in 2020, decreasing to 5 euros in 2050. Our estimates, regardless of year and scenario, are all significantly higher than the European Commission target of 1.8 euros per kg hydrogen by 2030 (European Commission, 2021c).

Hydrogen production cost is the largest contributor to the levelized price of hydrogen at the pump. This is because of the high capital investment in both renewable electricity generation and water electrolysis. As both technologies improve, we estimate the at-the-pump hydrogen price to be 30% cheaper in 2030 and 50% cheaper in 2050 compared to the 2020 level. Hydrogen fueling infrastructure cost decreases in the future as a response to both lower upfront capital costs and higher utilization rates of the fueling station. Our optimistic scenario would result in about a 15% to 35% lower hydrogen production cost than the mid-level cost scenario, depending on the year and country. However, how realistic it is to reach the optimistically low price is in question.

In the near term, subsidies could be a more promising way to lower price. Of particular note, a 3-euro per kg hydrogen production subsidy can shorten the cost reduction trajectory by 10 years, as the subsidized 2020 price almost reaches the unsubsidized 2030 price (Figure 1). Moreover, the subsidy could enable renewable hydrogen to reach cost parity with diesel fuel on an energy basis by 2030—0.034 euros per MJ for hydrogen compared to 0.038 euros per MJ for diesel. This diesel price is based on the average EU retail diesel price in 2019 (European Commission, 2020b), which is likely to increase at an annual rate of 1.3% from 2020 to 2050 (U.S. Energy Information Administration, 2021). On the other hand, comparing hydrogen and diesel on an energy basis probably is somewhat incomplete; vehicle efficiency should also be considered. An energy economy ratio (EER) that reflects the difference in distance travelled between two fuels is used to account for this factor when comparing different fuels. Hydrogen FCVs are more efficient than conventional trucks and the EER is around 1.3 (Mao et al., 2021). This means that hydrogen FCVs can travel 1.3 times as far as diesel trucks using the same amount of energy. Therefore, if considering both increasing diesel price and vehicle efficiency, the 3-euro per kg subsidy is likely to enable hydrogen to be cost-competitive with diesel well before 2030, from a fuel cost perspective. A forthcoming ICCT study will evaluate the total cost of ownership of hydrogen FCVs, which includes not only fuel costs but also vehicle costs.

Some may question the cost-effectiveness of onsite electrolysis at HRS due to its limited production capacity compared to big, central production hydrogen plants. Indeed, bigger plants can drive production costs down through economies of scale. However, these economies of scale apply only to the balance of plant components rather than to the electrolyzer stacks themselves, which are unlikely to increase in size but only in number. On the other hand, bigger plants may suffer from operational pressure and efficiency loss system-wide due to the increased number of stacks used (IRENA, 2020; Stöckl et al., 2021). In addition, onsite electrolysis at HRS avoids the significant cost of hydrogen transport, which includes the substantial upfront investment to build pipelines and the cost of additional hydrogen purification required post-delivery. For example, hydrogen can be contaminated from oil lubricants in pipeline compressors that keep the hydrogen flowing. And the long and challenging process of planning, commissioning, and regulating new hydrogen pipelines must also be considered (Baldino et al., 2020). Previous studies have analyzed the cost of onsite electrolysis, as well as central electrolysis production with pipeline transport, and found the costs of these two forms to be very similar (Stöckl et al., 2021; Vijayakumar et al., 2021).

We compare this study's estimated renewable electrolysis hydrogen production costs, not including HRS cost, with the cost numbers provided in previous studies. In Figure 2, we show both average and minimum renewable hydrogen production costs across the 26 EU countries, based on both mid-level and optimistic scenarios. For a direct comparison, we compare other EU studies rather than other regions. For the year 2020, our estimates of mid-level and optimistic scenarios both fall within the study range, which is 3 to 6.5 euros per kg hydrogen. However, for the year 2050, our estimates of the average EU renewable hydrogen cost from either scenario are higher than those from other studies. Only the minimum cost from our model, which is 1.2 euros per kg hydrogen in Croatia indicated in Figure 3, is within the range. Variations in cost estimates among studies can be caused by multiple factors, including different production capacities, renewable electricity prices, and financial assumptions, especially the rate of return.

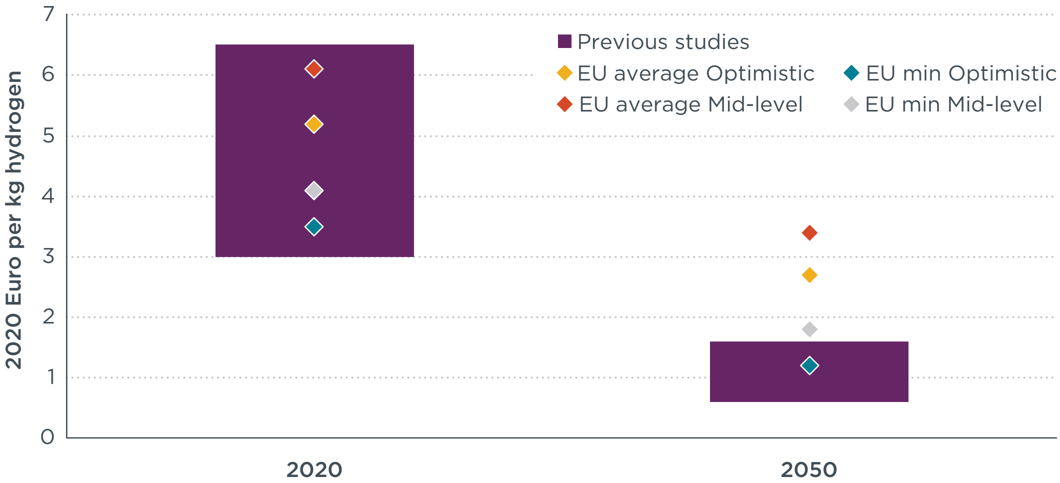

Figure 2. Comparison of EU's renewable hydrogen production cost in this study and previous studies, excluding fueling station cost. Sources: (Bertuccioli et al., 2014; Glenk & Reichelstein, 2019; IEA, 2019; Proost, 2019; IRENA, 2020; Bhandari & Shah, 2021; International Energy Agency, 2021; Squadrito et al., 2021; Tengler et al., 2021)

In Figure 3, we present the 2020 and 2050 renewable hydrogen production costs in each of the 26 countries, using the mid-level cost scenario, not including HRS cost. Variations among countries are a result of different prices of renewable electricity, electricity grid and tax fees, water prices, and the WACC (which is the result of country-specific corporate taxes). While the estimated EU average production cost in 2020 is 6 euros per kg, shown in Figure 2, the cost could vary significantly among countries, from 4 euros per kg in Sweden to 8.5 euros per kg in Italy—more than double the minimum. This variation is largely caused by the variation in renewable electricity price, which comprises both the levelized cost of electricity (LCOE) and T&D fees. For example, we estimate Sweden's renewable LCOE in 2020 to be 40 euros per MWh with an additional 22 euros per MWh T&D fees, whereas in Italy the LCOE and T&D fees is 78 and 64 euros per MWh respectively (Table A1). Sweden has low renewable LCOE due to its high wind capacity factor of 31%. From 2020 to 2050, the extent of cost reduction also varies among countries, mainly due to different trends in future electricity T&D costs (Table A1). To drive down the cost of hydrogen, there could be a separate incentive for renewable electricity used for hydrogen production.

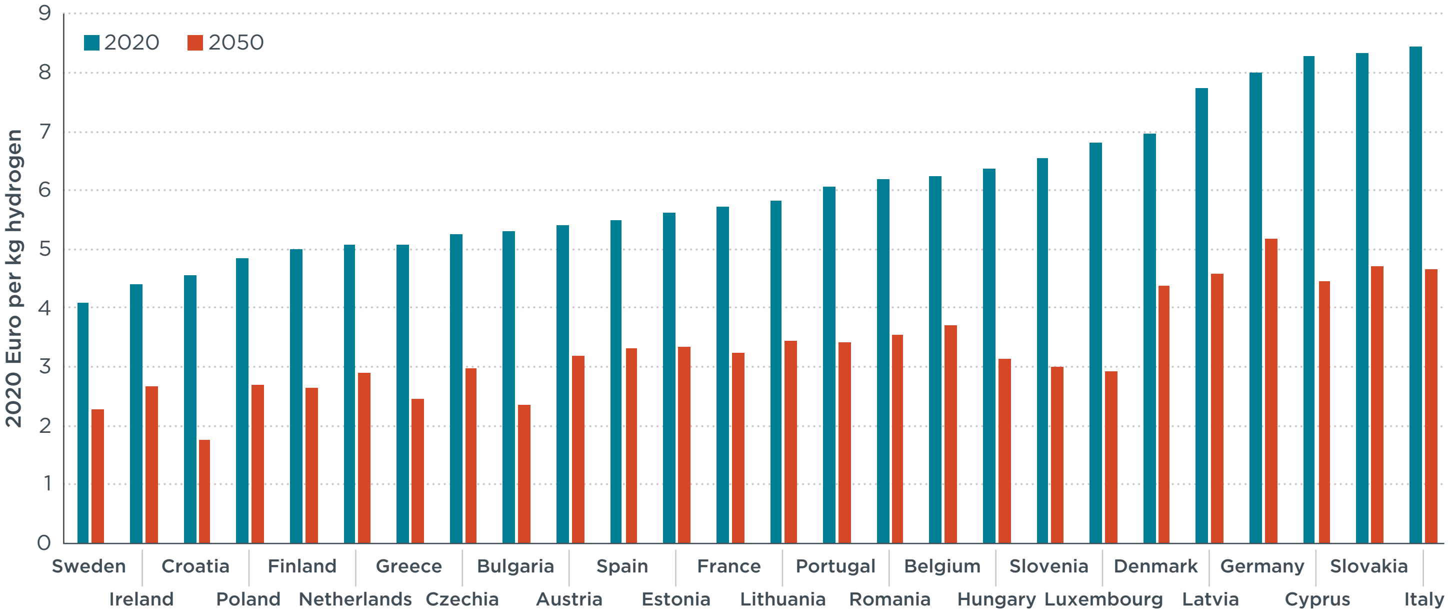

Figure 3. Estimated hydrogen production cost in 2020 and 2050 in 26 EU countries using mid-level cost scenario. Malta does not have a renewable capacity factor and thus is not modeled.

While we assume the onsite electrolysis facility is connected to the grid in our cost model, EU's grid is unlikely to be powered by 100% renewable energy in the near term. Therefore, stringent regulations are needed to ensure that (1) the electricity used is renewable and (2) the renewable electricity is additional. A recent ICCT study found that electrolysis hydrogen using grid electricity has significantly higher GHG emissions than renewable hydrogen and fails to meet the 70% GHG reduction threshold in the REDII, even when taking into account a 2030 grid with a higher share of renewables (Zhou et al., 2021). This finding indicates that using any portion of fossil electricity to produce electrolysis hydrogen would greatly affect the climate implications of that hydrogen and potentially undermine EU's broader decarbonization targets. This finding also emphasizes the need for robust regulations regarding the additionality of renewable electricity used in hydrogen production. Using Guarantees of Origin (GOs), renewable electricity certificates, and Power Purchase Agreements (PPAs), long-term electricity purchase contracts, combined with certificates showing that the renewable electricity used for hydrogen is not incentivized by other policies, can meet the purpose (Timpe et al., 2017; Malins, 2019; Searle & Zhou, 2021).

CONCLUSIONS

Renewable hydrogen produced onsite at a refueling station could play a role in EU's decarbonization strategy. Although onsite electrolysis tends to have higher hydrogen production costs than central production due to limited production capacity, previous studies have found that the at-the-pump prices of these two forms are similar after considering the additional hydrogen transport cost needed for central production. In this study, we estimate the EU average at-the-pump price of onsite renewable hydrogen to be 11 euros per kg hydrogen in 2020, decreasing to 7 euros per kg hydrogen in 2030 and 5 euros per kg hydrogen in 2050. These prices are significantly higher than the European Commission's target of 1.8 euros per kg hydrogen by 2030.

Onsite renewable electrolysis is still expensive and needs policy support to be economically viable. If a 3-euro per kg hydrogen subsidy were provided to renewable hydrogen production, the industry could advance down the price curve by 10 years. Moreover, this subsidy amount can enable cost parity, from a fuel cost perspective, of onsite electrolysis renewable hydrogen and diesel before 2030.

Beyond financial support for hydrogen production, robust regulations on the source of electricity are crucial to ensure the true climate benefit from renewable hydrogen. Regulations are not only needed to ensure that 100% renewable electricity is used, but more importantly, that the renewable electricity being used is in fact additional.

APPENDIX

Table A1 shows the estimated renewable electricity price in the 26 European countries in this study, excluding Malta due to lack of a renewable capacity factor. LCOE is the levelized production cost of renewable electricity and LCOE+T&D is the electricity price that includes grid and tax fees, which is used as an input to our hydrogen cost model. While we model both solar and wind prices in each country, whichever provides the lower electricity price is used to estimate hydrogen cost in our model. Therefore, the “Renewable type” column in Table A1 indicates the cheaper renewable technology for each country and the corresponding electricity prices are shown as the numbers in Table A1. The cheaper renewable type might switch in the future due to different change rates in capital costs and capacity factors between solar and wind.

Table A1. Estimated renewable electricity price in the 26 European countries in 2020 and 2050. LCOE is the levelized cost of electricity. LCOE+T&D considers electricity grid and tax fees and is used to estimate the cost of hydrogen production in this study. Values in the table correspond to the cheaper of solar or wind renewables. Unit: 2020 euros per MWh.

	2020			2050		
Country	**LCOE**	**LCOE+T&D**	**Renewable type**	**LCOE**	**LCOE+T&D**	**Renewable type**
Austria	46	86	Wind	28	70	Wind
Belgium	55	102	Wind	34	83	Wind
Bulgaria	70	87	Solar	33	52	Solar
Croatia	72	72	Wind	39	39	Solar
Cyprus	109	142	Wind	67	101	Wind
Czechia	51	84	Wind	31	65	Wind
Denmark	64	116	Wind	39	98	Wind
Estonia	48	91	Wind	29	74	Wind
Finland	56	79	Wind	34	58	Wind
France	55	91	Wind	33	71	Wind
Germany	58	133	Wind	36	114	Wind
Greece	60	81	Wind	30	54	Solar
Hungary	71	107	Wind	35	71	Solar
Ireland	38	70	Wind	23	60	Wind
Italy	78	142	Solar	37	104	Solar
Latvia	72	131	Wind	44	103	Wind
Lithuania	53	96	Wind	32	77	Wind
Luxembourg	94	112	Solar	45	64	Solar
Netherlands	48	79	Wind	29	62	Wind
Poland	48	78	Wind	30	60	Wind
Portugal	53	97	Solar	25	75	Solar
Romania	62	102	Wind	35	80	Solar
Slovakia	75	142	Wind	39	106	Solar
Slovenia	84	109	Wind	41	66	Solar
Spain	49	88	Wind	30	73	Solar
Sweden	40	62	Wind	25	49	Wind
Arithmetic average	**61**	**99**	**-**	**34**	**75**	**-**

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