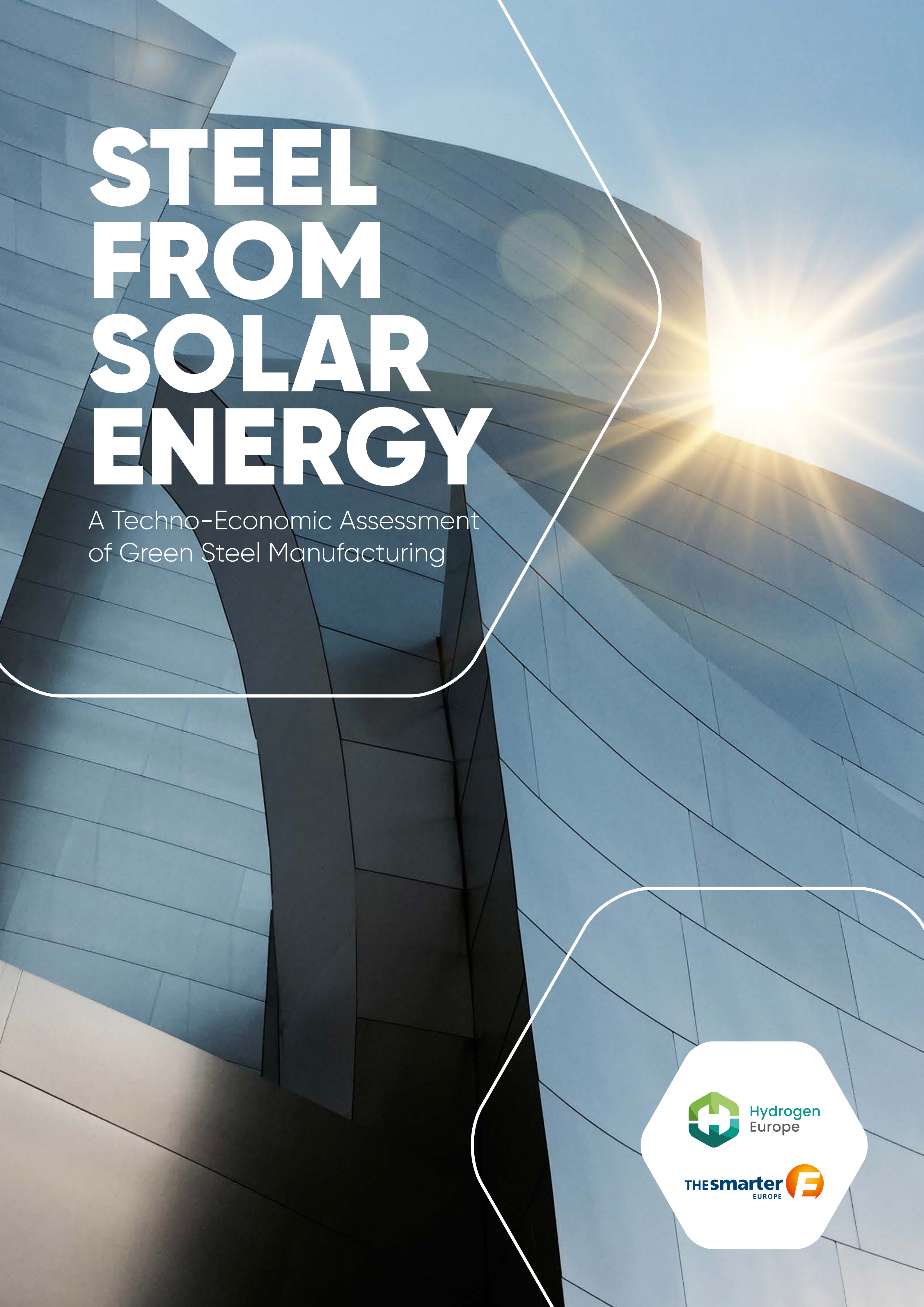
STEEL FROM SOLAR ENERGY

A Techno-Economic Assessment of Green Steel Manufacturing



Hydrogen Europe

THE smarter E EUROPE

ABOUT THE AUTHORS

This report has been prepared by **Hydrogen Europe** and it is supported by **The smarter E Europe**, Europe's largest platform for the energy industry, taking place annually at Messe München, Munich, Germany.

The focus is on renewable energies, decentralization and digitization of the energy industry as well as cross-sector solutions from the electricity, heat and transport sectors for a smart and sustainable energy supply.

The smarter E Europe brings together the four exhibitions Intersolar Europe, ees Europe, Power2Drive Europe and EM-Power Europe.

With the Green Hydrogen Forum and Expo, The smarter E Europe offers a cross-industry and cross-sector meeting point for companies from all over the world with the aim of bringing hydrogen, fuel cells, electrolysis and power-to-gas to the markets more quickly.

The following authors have contributed to this report: **Grzegorz Pawelec** and **Joana Fonseca.**

01 List of abbreviations

AE	Alkaline electrolysis
ATR	Autothermal reforming
BAT	Best available technology
BESS	Battery energy storage system
BF	Blast furnace
BFG	Blast furnace gas
BOP	Balance of plant
BOF	Basic oxygen furnace
CAPEX	Capital expenditures
CBAM	Carbon border adjustment mechanism
CCS	Carbon capture and storage
CCU	Carbon capture and utilization
CDA	Carbon direct avoidance
COG	Coke oven gas
CS	Crude steel
DRI	Direct reduced iron
DRP	Direct reduction process
DSR	Demand side response
EAF	Electric arc furnace
EHB	European Hydrogen Backbone
ETS	Emission trading system
EU	European Union
EUA	European Union Allowance
FF55	Fit For 55 legislative package
FID	Final investment decision
GHG	Greenhouse gas
GO	Guarantees of origin
HBI	Hot-briquetted iron
HHV	Higher heating value
ICE	Internal combustion engine
IED	Industrial Energy Directive
IEA	International Energy Agency
ISP	Integrated steel plant
LCOE	Levelized cost of electricity
LCOH	Levelized cost of hydrogen
LHV	Lower heating value
LOHC	Liquid organic hydrogen carrier
MS	Member States
OPEX	Operating expenses
PEM	Proton exchange membrane
PV	Photovoltaic
PI	Process integration
RE	Renewable energy
RED II	Revised Renewable Energy Directive (Directive 2009/28/EC)
RED III	Proposed revision off the RED II, included in the FF55 package
RES	Renewable energy source
RFCS	Research Fund for Coal and Steel
SMR	Steam methane reforming
tpa	tonnes per year
tpd	tonnes per day
TSO	Transmission System Operator

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Introduction

Hydrogen Europe is the leading European hydrogen and fuel cell association that promotes clean and low carbon hydrogen as the enabler of a zero-emission society. It currently represents more than 350 entities, including 285 industry members, 32 national associations and 20 EU regions. Its member companies are of all sizes and represent the entire hydrogen value chain, from production to transport, distribution and final end-use of hydrogen. As such, Hydrogen Europe represents the common interests shared by stakeholders of the hydrogen industry in the EU.

The association partners with the European Commission in the innovation program Clean Hydrogen Joint Undertaking (CH), supporting R&I activities targeting the development of hydrogen technologies.

Hydrogen Europe supports low- or zero-carbon hydrogen production pathways in order to enable a zero-emission society and promotes hydrogen technologies as a way to achieve Paris Agreement the climate targets. It fully adheres to the European Union's target of carbon neutrality by 2050 and supports the European Commission's objectives to develop and integrate more renewable energy sources into the European energy mix.

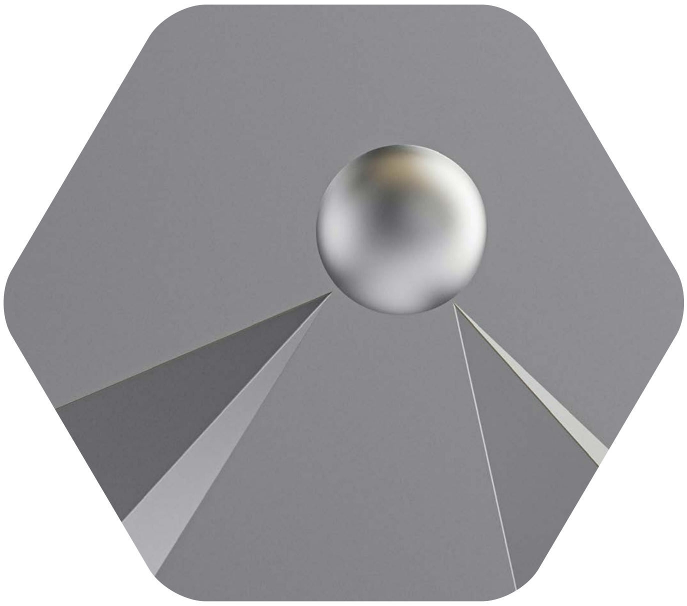
As a non-profit trade association, Hydrogen Europe plays a crucial role in promoting best practices, helping companies become more competitive, formulating effective public policies, providing market, policy and technical intelligence, and networking support to its members. Thanks to its broad and various membership, Hydrogen Europe has a full overview of the industrial and market landscape and a direct, privileged connection with the hydrogen and fuel cell industry.

The following **publication contains a techno-economic analysis of using solar energy to decarbonise steel production in the EU via hydrogen-based direct reduction of iron ore coupled with an electric arc furnace (DRI/EAF).** The analysis is based on a comparative levelized cost of product approach, with the BF/BOF benchmark being the counterfactual scenario.

The purpose of this analysis is to assess the viability of using solar energy (and renewable energy in general) for the decarbonisation of steel manufacturing and to identify the boundary conditions for this approach to become economically feasible.

Given that the analysis focuses only on one available technology, the results of this report should not be seen as a recommendation of the best available solution for the decarbonisation of steel but rather as an attempt to provide deeper insight specifically targeting the use of renewable hydrogen for steelmaking.

Although there are many pathways to produce clean hydrogen, this analysis includes exclusively hydrogen produced from renewable energy – mostly solar PV, hence not all conclusions might be equally applicable for hydrogen-based DRI/EAF projects which use other sources of hydrogen.



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Executive summary

The purpose of this analysis was to assess the viability of using solar energy (and renewable energy in general) for the decarbonisation of steel manufacturing and to identify the boundary conditions for this approach to become economically feasible. The analysis specifically focused on hydrogen-based direct reduction of iron ore coupled with an electric arc furnace (H2-DRI-EAF), by comparing the levelized cost of steel with the BF-BOF benchmark.

The importance of tackling the GHG emissions from the steel sector is obvious as it is responsible for around 4% of the GHG emissions in Europe. At the same time, the sector generates around 2,6 million jobs making it an important part of the EU economy, which demands careful consideration about what is the cost-optimal pathway for decarbonisation.

Depending on the system's energy efficiency, the BF-BOF route usually has a carbon footprint between 1,6 to 2,0 tonnes of CO2 per tonne of crude steel produced, with the EU average being around 1,9 tonnes of CO2 per tonne of steel.

While direct emissions in the H2-DRI-EAF route are reduced almost to zero, the final carbon footprint of this approach would rely on the carbon intensity of electricity used – both for hydrogen production as well as to operate the electric arc furnace. Considering the amount of electricity consumption, for the process to be beneficial from the point of view of net GHG emissions, the maximum carbon intensity of electricity used **cannot exceed 513 gCO2 per kWh.** This means that careful consideration should be given to the source of electricity used.

If the H2-DRI-EAF process is based on renewable electricity significant GHG emission savings could be obtained. However, in order to use exclusively renewable energy, several key challenges would have to be addressed.

The first one is cost. When, when assessing crude steel production costs, it is important to note that due to the current high energy prices caused by post-covid economic recovery coupled with insufficient natural gas storage reserve and the Russian invasion of Ukraine, the market conditions present currently are not a perfect representation of the long-term profitability of the BF-BOF route. Although energy prices are expected to fall, it is unclear over what timeline it will happen and if the prices will fall back to pre-crisis levels or if in the new equilibrium they will be noticeably higher than previously. For this reason, the analysis in this report is conducted using two distinct price development scenarios:

- **High prices scenario** – assuming current high energy prices,
- **Adjusted prices scenario** – with energy prices adjusted down to reflect potential future long term fossil fuels price levels.

With an estimated current hydrogen delivery price (including production, transportation and storage) of 5,3 EUR/kg, both in the 'High prices' and in the 'Adjusted prices' scenario total green steel production costs are higher than the BF-BOF benchmark, with the difference being 126 EUR and 203 EUR per tonne of crude steel respectively. **For a typical ICE passenger car, this would translate to an added cost of 100 – 170 EUR per vehicle.**

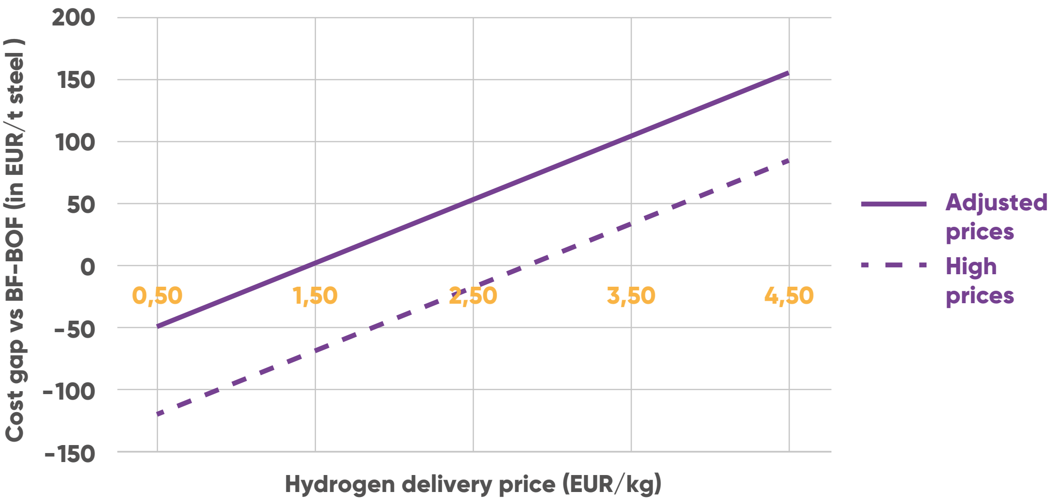
According to our estimates, in order to achieve a break-even, the hydrogen delivery price would have to be below 3,0 EUR/kg - in the 'high prices' scenario and below 1,5 EUR/kg - in the 'adjusted prices' scenario. **The estimated CO2 break-even price is 140 EUR/t for both price scenarios.**

It should be noted however that these estimations are a reflection of the current electrolyser and solar PV costs. It is expected that a further decrease of the solar PV technology costs, coupled with a reduction in electrolyser CAPEX, resulting from scaling-up and automation of the manufacturing process, should lead to a significant fall in renewable hydrogen production costs in the coming decade. Electrolyser CAPEX alone, are expected to fall by around ¾ compared to current levels – enough to enable renewable hydrogen production costs with low-cost renewable energy, to reach 1,5 USD/kg by 2025[1]. If the green hydrogen production costs fall down as predicted, by 2025-2030 it should be possible to eliminate the cost gap entirely – even in a scenario with low fossil fuel prices.

In the meantime however, if the end consumers are not willing to pay a green premium for a fossil-free steel, significant financial support would be needed.

1 / https://www.rechargenews.com/transition/nel-to-slash-cost-of-electrolysers-by-75-with-green-hydrogen-at-same-price-as-fossil-h2-by-2025/2-1-949219

Figure 1: COST GAP OF THE H2-DRI-EAF ROUTE VS THE BF-BOF ROUTE, DEPENDING ON ELECTROLYSIS CAPEX AND SOLAR PV LCOE. **Source:** OWN ELABORATION.



The second big challenge is the scale. The total capacity of all installed BF-BOF plants in the EU is around 103 Mt of hot metal per year. Switching all of those plants to hydrogen-based DRI/EAF could potentially save up to 196 Mt of GHG emissions per year but in order to do so would require up to 5,3 Mt of renewable hydrogen and up to 370 TWh of additional renewable electricity generation (including EAF electricity consumption).

Converting just a single steel plant with a capacity of 4 Mt of crude steel per year (EU average) would require 1,2-1,3 GW of electrolysis running at full load, 3,3 billion EUR of capital investment (including 1,2 billion EUR for electrolysis) and between 10,2 to 21,7 ha of land for the electrolysis plant (and additional area for new renewable power deployment). If variable renewable electricity is used and the electrolyser cannot be operated at constant full load, the challenge becomes even bigger. When using exclusively solar PV for hydrogen production, the required electrolysis power would grow to around 4,5-5,0 GW, driving up the required CAPEX to almost 7 billion EUR for a single plant of average capacity.

Multiplied by the number of plants across the EU, the sector will need to access both debt and equity finance (in large amounts) to accompany the public support. Coupled with the existing cost gap, raising the necessary funds will be extremely challenging – especially in light of the foreseen free allowances phase-out.

The third big challenge is the necessity to provide a constant supply of hydrogen to the reduction shaft. When hydrogen production is based entirely on variable renewable energy, like solar PV or onshore/offshore wind, a significant amount of operational storage is needed. While underground hydrogen storage in salt caverns offers a cost-effective solution, underground salt formations are not uniformly available across the whole EU. Furthermore, multiple salt caverns might be needed for a single steel plant.

Finally, securing access to a sufficient amount of low-cost renewables will also be a challenge – especially in the northern part of Europe.

While imports of renewable hydrogen are most likely inevitable for some EU countries, because of the low hydrogen break-even price, the steel sector will remain a challenging market for imported hydrogen. Although the business case can be improved by using waste heat for dehydrogenation or direct use of ammonia in the DRP. Decoupling direct reduction from EAF using renewable briquetted iron as the “hydrogen carrier” to deliver renewable energy to EAF units in the EU is also an option.

Another possibility, for areas with a shortage of renewable resources, is to produce hydrogen in situ, with electricity delivered through the power grid. In this case however, ensuring a steady supply of hydrogen remains a challenge, as available storage options are expensive.

As a result, if the final version of the RED III would include a very strict (1h) temporal correlation requirement for renewable hydrogen production, it would create a significant obstacle the deployment of DRI-EAF based on renewable hydrogen. On the other hand allowing 24h balancing of renewable energy production with its consumption for hydrogen production, would allow to increase RE share in hydrogen production to over 80% without any additional storage - significantly reducing capital demands and thus increasing economic attractiveness of green hydrogen use in the steel sector.

Yet, despite all the challenges, the industry is clearly responding to the ever-increasing pressure to decarbonise and many companies are already stepping forward as the front runners in the transition. Several projects all over Europe, led by key stakeholders such as ArcelorMittal, LKAB, SSAB, Thyssenkrupp, Vattenfall and others, are already in development and will play a major role in the ramp-up of the necessary technology and proving the business case for green steel.

04 The steel industry today

The EU steel industry output in 2020 was around 183 Mt with roughly 60% of that being produced in BF/BOF. The industry is responsible for around 4% of the GHG emissions in Europe. At the same time, the sector generates around 2,6 million jobs making it an important part of the EU economy.

4.1. Industry size

Steel is a metal alloy made of iron and carbon that plays a big role in today's society. Because it is such a versatile material with different grades and types, steel can be used in many different applications and is a basic engineering material, essential in any developed economy. Steel is highly used in construction, mechanical equipment, automotive and transport industries, and more. Currently, the steel industry in Europe generates around 2,6 million jobs - 12,2% of those direct and 87,8% indirect - and has a Gross Value Added of 148 bn EUR with 25 bn EUR from direct activities[2].

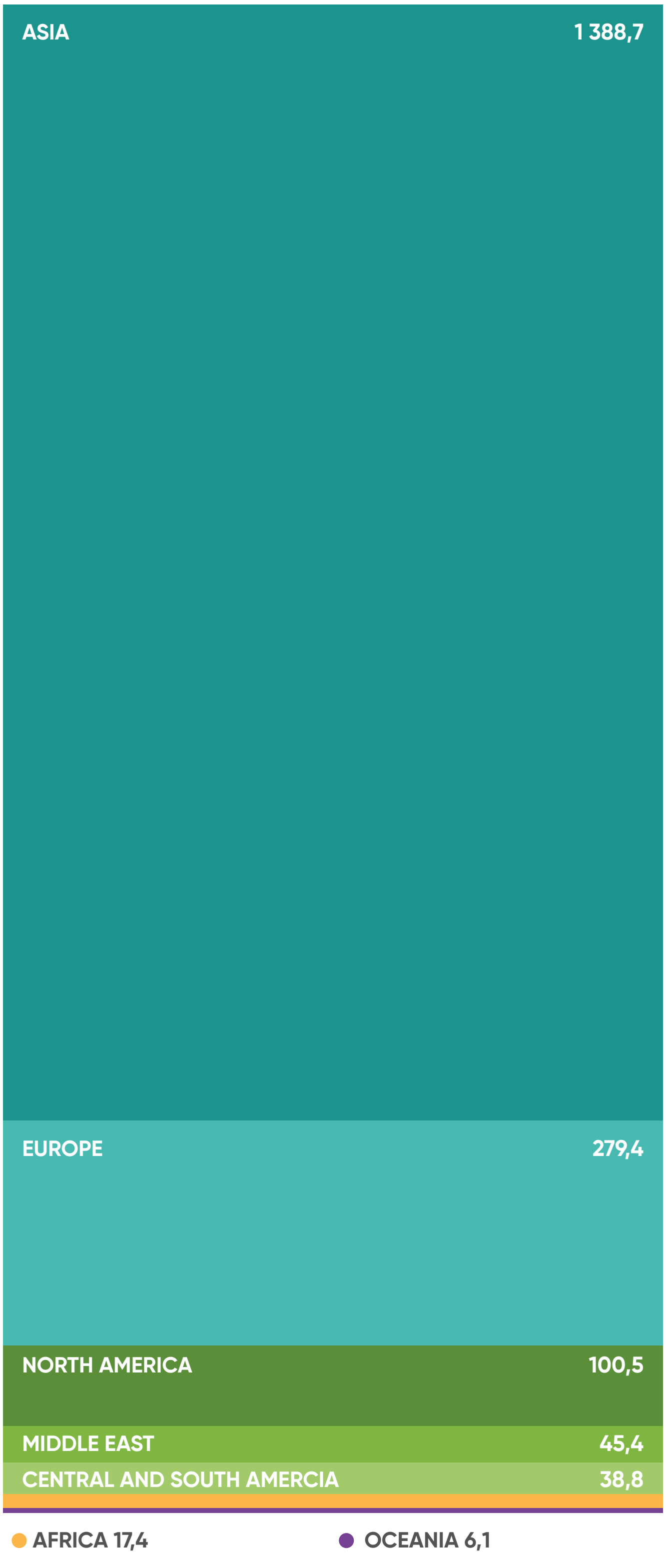
Most of the steel production in the world takes place in China, representing a share of 57,7%. With 279 Mt produced in 2020, Europe stands at15% of the world's total steel production of 1 828 Mt.[3]

The EU currently:

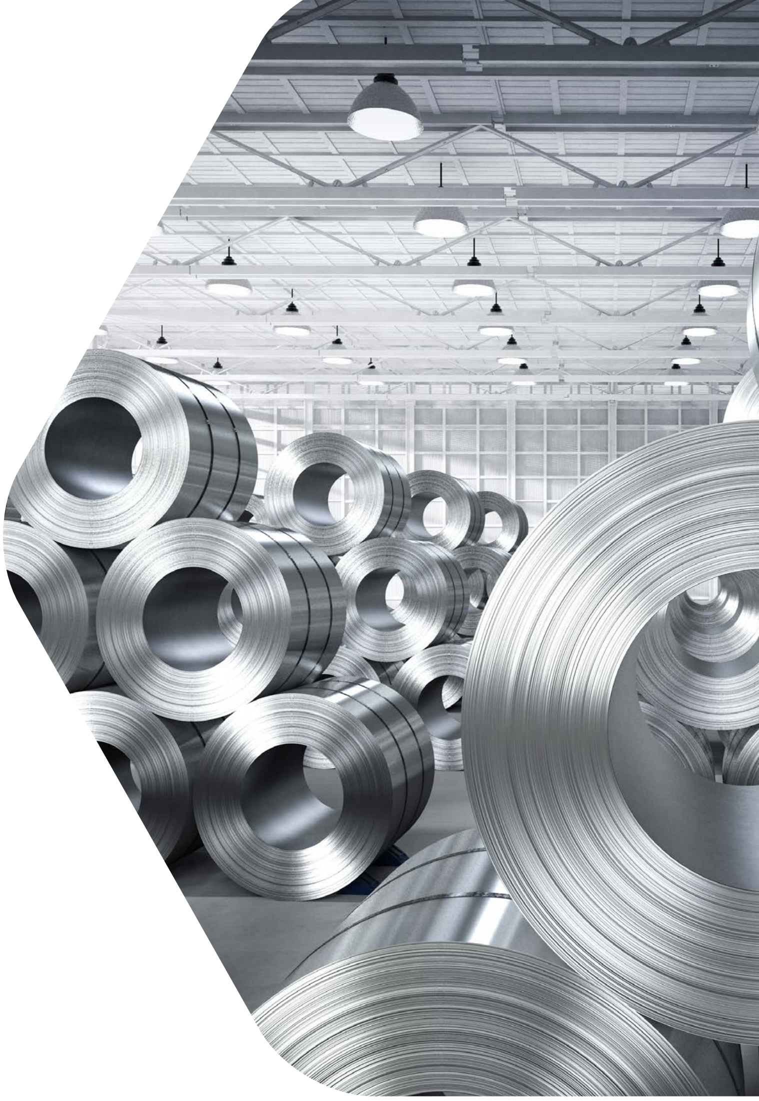
Exports 17,7 Mt of steel, mostly to other countries in Europe and North and Central America;

Imports 21,2 Mt annually, coming especially from other countries in Europe and Asia.

Figure 2: WORLD STEEL PRODUCTION (MT) IN 2020.
Source: WORLD STEEL ASSOCIATION.



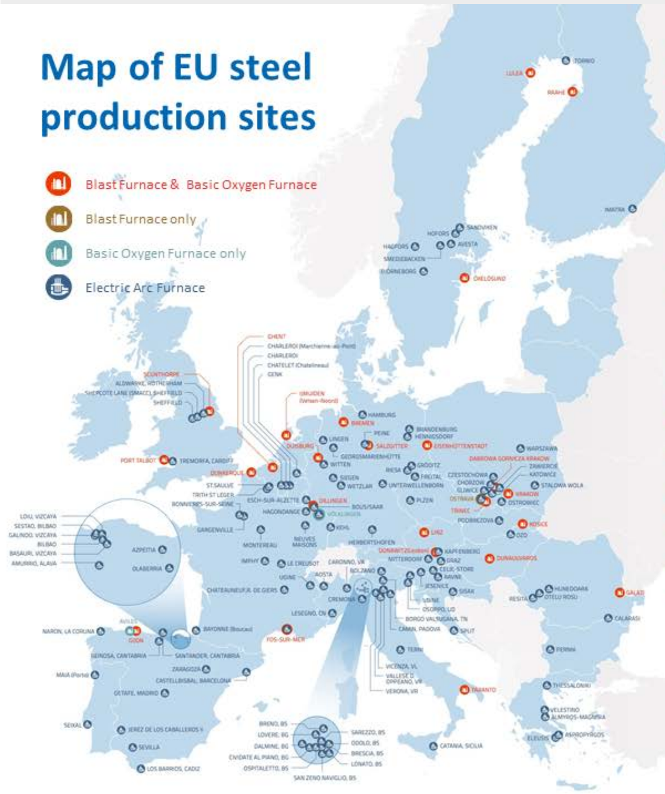
2 / Oxford Economics, The Impact of the European Steel Industry on the EU Economy, 2019.
3 / EUROFER, European Steel in Figures, 2019.



4.2. Production and consumption of steel in Europe

Production of steel can be split into **primary production** (achieved using a Blast Furnace/Basic Oxygen Furnace, also known as the integrated route) or **secondary production** (with the recycling of steel scrap in an Electric Arc Furnace). Considering the entire EU, Norway and the United Kingdom, at the end of 2020, the total annual capacity was **111,7 Mt/year** (24 BF/BOF plants) for primary steel production and **89,8 Mt/year** (132 EAF plants) for secondary steel production.

Figure 3: STEEL INSTALLATIONS IN THE EU.
Source: EUROFER.



Blast Furnace & Basic Oxygen Furnace

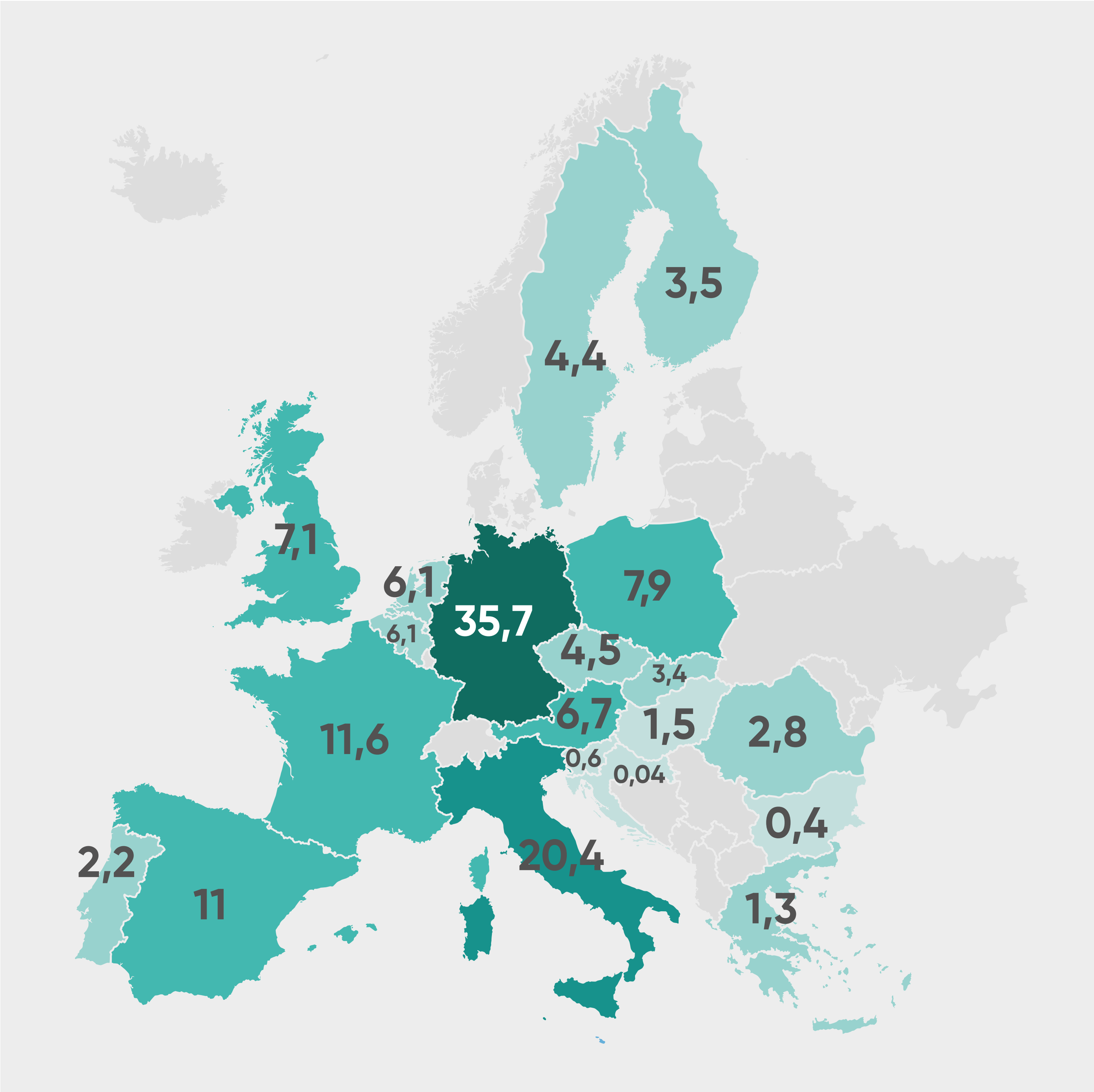
Location	Hot Metal Capacity ('000 tonnes/ year)	Finished Steel Capacity ('000 tonnes/ year)	No. of furnaces
AUSTRIA			
DONAWITZ (Leoben)	1370	1570	2
LINZ	4340	6000	3
BELGIUM			
GHENT	4430	5000	2
CZECH REPUBLIC			
OSTRAVA	3200		3 – BF only
TRINEC	2100	2400	2
FINLAND			
RAAHE	2400	2600	2
FRANCE			
DUNKERQUE	6800	6750	3
FOS SUR MER	5160	5100	2
GERMANY			
BREMEN	3960	3800	2
DILLINGEN	4790	2760	2
DUISBURG	11600	11560	4
EISENHÜTTENSTADT	2340	2400	2
SALZGITTER	4800	5200	3
VÖLKLINGEN		3240	BOF only
HUNGARY			
DUNAUJVAROS	1310	1650	2
ITALY			
TARANTO	9590	11500	4
NETHERLANDS			
IJMUIDEN (Velsen Noord)	6310	7500	2
POLAND			
DABROWA GORNICZA	4500	5000	2
KRAKOW	1310	2600	1
ROMANIA			
GALATI	3250	3200	2
SLOVAKIA			
KOSICE	2850	4500	2
SPAIN			
AVILES		4200	BOF only
GIJON	4480	1200	2
SWEDEN			
LULEA	2200	2200	1
OXELÖSUND	1800	1700	2
UNITED KINGDOM			
PORT TALBOT	4770	4900	2
SCUNTHORPE	3590	3200	3

Electric Arc Furnace

Location	Capacity ('000 tonnes/ year)	No. of furnaces
AUSTRIA		
GRAZ	365	1
KAPFENBERG	180	1
MITTERDORF	300	1
BELGIUM		
CHARLEROI	850	1
CHARLEROI (Marchienne au Pont)	350	1
CHATELET (Chatelineau)	1000	1
GENK	1200	2
BULGARIA		
PERNIK	1000	2
CROATIA		
SISAK	350	1
SPLIT	185	1
CZECH REPUBLIC		
OSTRAVA	120	1
PLZEN	150	2
FINLAND		
IMATRA	360	1
TORNIO	1300	2
FRANCE		
BAYONNE (Boucau)	1200	1
BONNIERES SUR SEINE	550	1
CHATEAUNEUF,R. DE GIERS	100	1
FOS SUR MER	480	1
GARGENVILLE	700	1
HAGONDANGE	460	1
IMPHY	90	1
LE CREUSOT	150	1
MONTEREAU	720	1
NEUVES MAISONS	800	1
ST.SAULVE	730	1
TRITH ST LEGER	800	1
UGINE	250	2
GERMANY		
BOUS/SAAR	350	1
BRANDENBURG	1800	2
FREITAL	90	1
GEORGSMARIENHÜTTE	1100	1
GRÖDITZ	100	1
HAMBURG	1100	1
HENNIGSDORF	1000	2
HERBERTSHOFEN	1180	2
KEHL	2500	2
LINGEN	620	1
PEINE	1000	1
RIESA	900	1
SIEGEN	600	1
SIEGEN	150	1
UNTERWELLENBORN	1100	1
VÖLKLINGEN	300	1
WETZLAR	400	1
WITTEN	480	1
GREECE		
ALMYROS MAGNISIA	1200	1
ASPROPYRGOS	400	1
ELEUSIS	800	1
THESSALONIKI	600	1
VELESTINO	450	1
HUNGARY		
OZD	400	1
ITALY		
AOSTA	260	1
BOLZANO	200	2
BORGO VALSUGANA, TN	600	1
BRENO, BS	100	1
BRESCIA, BS	1200	2
BRESCIA, BS	650	1
CAMIN, PADOVA	600	1
CARONNO, VA	780	1
CATANIA, SICILIA	500	1
CIVIDATE AL PIANO, BG	250	1
CREMONA	3850	2
DALMINE, BG	700	1
LESEGNO, CN	600	1
LONATO, BS	1100	1
LONATO, BS	600	1
LOVERE, BG	150	1
ODOLO, BS	900	1
OSOPPO, UD	2200	1
OSPITALETTO, BS	150	1
SAN ZENO NAVIGLIO, BS	800	1
SAREZZO, BS	540	1
TERNI	1450	2
UDINE	500	1
UDINE	770	1
VALLESE D. OPPEANO, VR	450	1
VERONA, VR	1250	2
VICENZA	170	1
VICENZA, VL	1200	1
LUXEMBOURG		
ESCH SUR ALZETTE	2250	2
POLAND		
CHORZOW	145	1
CZESTOCHOWA	800	1
GLIWICE	250	1
KATOWICE	65	1
OSTROWIEC	900	1
STALOWA WOLA	240	1
WARSZAWA	750	1
ZAWIERCIE	1340	2
PORTUGAL		
MAIA (Porto)	600	1
SEIXAL	1100	1
ROMANIA		
CALARASI	470	1
HUNEDOARA	550	1
OTELU ROSU	830	1
RESITA	450	1
SLOVAKIA		
PODBREZOVA	350	1
SLOVENIA		
CELJE STORE	150	1
JESENICE	500	1
RAVNE	140	1
SPAIN		
AMURRIO, ALAVA	150	1
AMURRIO, ALAVA	360	1
AZPEITIA	800	1
BASAURI, VIZCAYA	740	1
BILBAO	1100	1
CASTELLBISBAL, BARCELONA	2400	2
GALINDO, VIZCAYA	400	1
GETAFE, MADRID	600	1
JEREZ DE LOS CABALLEROS II	1300	1
LOIU, VIZCAYA	130	1
LOS BARRIOS, CADIZ	1200	3
NARON, LA CORUNA	700	1
OLABERRIA	2450	1
REINOSA, CANTABRIA	240	1
SANTANDER, CANTABRIA	750	1
SESTAO, BILBAO	2000	2
SEVILLA	1300	2
ZARAGOZA	500	1
SWEDEN		
AVESTA	500	1
BJÖRNEBORG	95	1
HAGFORS	120	1
HOFORS	500	1
SANDVIKEN	200	1
SMEDJEBACKEN	480	1
UNITED KINGDOM		
ALDWARKE, ROTHERHAM	1220	2
SHEFFIELD	150	1
SHEPCOTE LANE (SMACC), SHEFFIELD	500	1
TREMORFA, CARDIFF	1200	1

The actual total production of steel in the EU was around 183 Mt in 2020, with 60% BF/BOF production and 40% EAF production. **The biggest producer in Europe is Germany, with 35.7 Mt of steel produced in 2020, followed by Italy, France and Spain.**

Figure 4: STEEL PRODUCTION IN EUROPE IN 2020, MT.



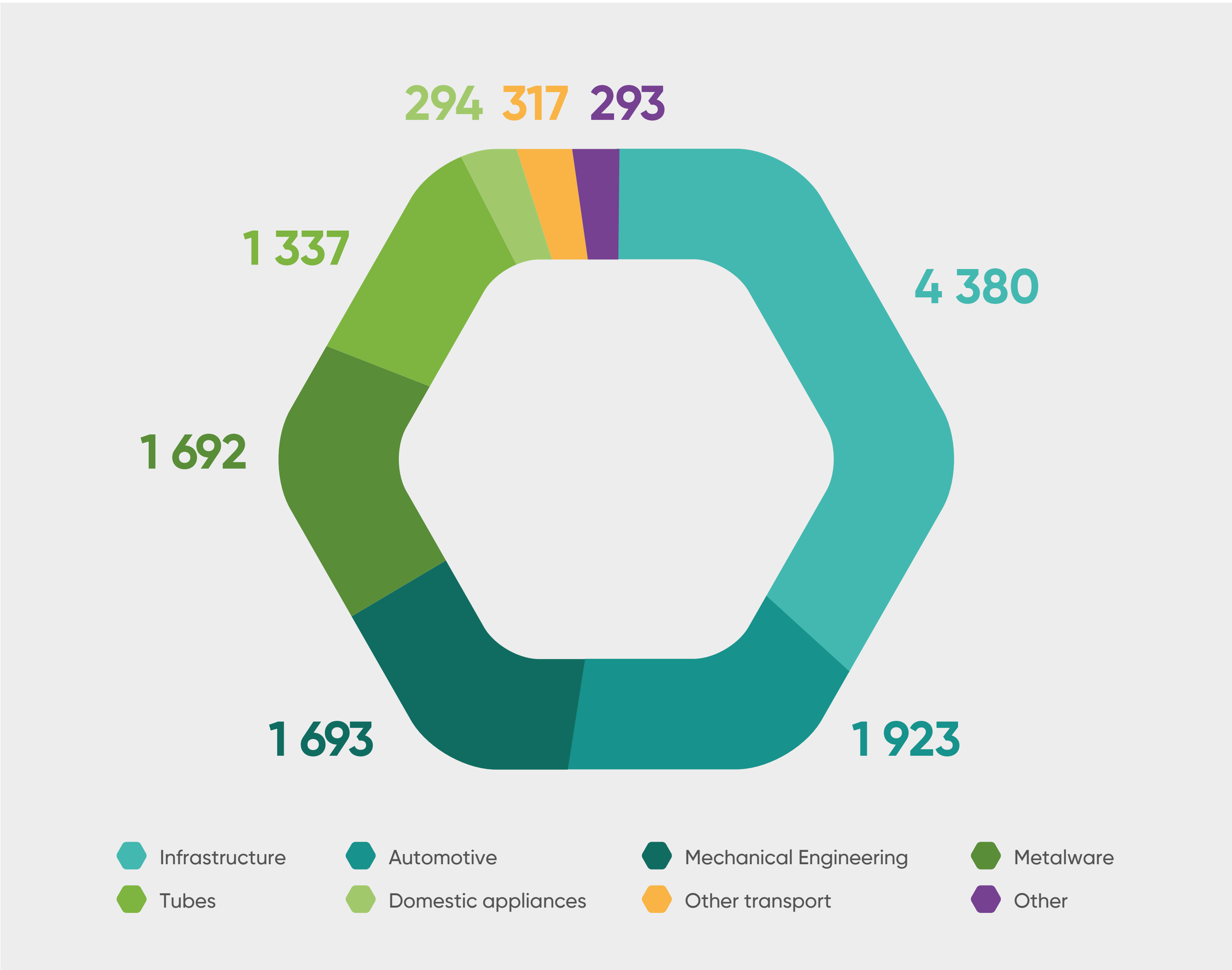
Steel consumed in the EU is a mix of domestic production and imports from third countries. Because steel producers can sell their final product to distributors or directly to end-users, a distinction between apparent and real steel consumption is often made:

- Apparent steel consumption covers the entire volume of steel delivered to the market, which includes the amount of steel currently kept in stock by distributors;
- Real steel consumption accounts only for the steel consumed by the end-using sectors in their processes.

In 2020, the apparent consumption of steel was 136 Mt compared to 142 Mt of real consumption. **Real consumption exceeded apparent consumption in 2020 because inventories were being withdrawn.**

Worldwide, **the construction and infrastructure sectors have the highest share of consumption of steel,** followed by the mechanical equipment sector. In Europe, the sector in which steel is used the most is construction and infrastructure, with 38% of the share. The second biggest consumer is the automotive industry, with 16% of the total consumption, followed by the manufacturing of mechanical engineering products (machinery), with 15%.

Figure 5: STEEL CONSUMPTION IN THE EU BY APPLICATION.



4.3. Financial standing and challenges

Steel plays a major role in industrialized economies and is, therefore, one of the focus points in developing regions, where demand is expected to increase significantly in the upcoming years. In these regions, such as the Middle East, India and Southeast Asia, plans to deploy new steelmaking capacity in the next decade keep being announced. In the developed countries, however, the demand curve is now forecasted to remain flat. In reality, the unforeseen COVID-19 pandemic hit the global economy to such an extent that forecasts of increased worldwide demand did not materialize, and in most regions, this demand even decreased. This has led to an aggravation of the already existing overcapacity issue, which threatens the health of the steel economy.

Overcapacity

While steel production in the EU had already suffered a decrease of 6% in 2019 compared to 2018, in 2020, with amplified economic impacts resulting from the COVID-19 pandemic, a production decrease of 11,5% was observed compared to the previous year. In the same year, 40 Mt of capacity were temporarily shut down in Europe due to the pandemic. The decreasing trend was similar in most regions of the world. The outlier is China, which saw a production increase of 7% in 2020. Because China is the biggest steel producer in the world, global steel production has remained constant despite the effect of the pandemic in other areas of the world.

The steelmaking production capacity, on the other hand, has increased significantly in the past year despite the poor market conditions. With 37,6 Mt per year of additional capacity deployed in 2020, global steelmaking capacity rose to 2 453 Mt per year, with a gap between production and capacity of 624,9 Mt, which translates into 74,5% utilization, two percentage points lower than the previous year[4]. In Europe alone, capacity utilization dropped to 63% in 2020[5].

One of the main causes of overcapacity is the continuous deployment of new steel plants in developing regions. These regions currently import most of their supply and are now making efforts to create domestic capacity to supply their development objectives. In Southeast Asia, for example, capacity growth is outpacing real demand. Projects are being commissioned with the prospect of growth in demand, which is not materialvizing partly due to the pandemic.

Overcapacity is a real threat to the steel market as it leads to the under-utilization of assets, which in turn leads to low-profit margins. At the company level, profitability issues can cause plants to be shut down and result in job losses. It is estimated that, on average, a 1% decrease in capacity utilization leads to a 0,3% decrease in the EBIT of the company.[6] Furthermore, global overcapacity can facilitate CO2 leakage - if steel production in Europe is not competitive enough compared to some extra-EU countries with low or non-existent CO2 taxes, consumers can opt for suppliers from outside of the EU, offering significantly lower prices. Besides leading to an increase in global CO2 emissions (as European steel plants are less carbon-intensive than the global average), a situation like this could also lead to a significant number of lost EU jobs.

Future steel demand

The COVID-19 pandemic has made it difficult to predict future developments in the industry and the demand for steel in Europe. As the world recovers, demand could be set to increase, but in Europe, it is foreseen to decrease until 2023 still, as many consumers like the automotive sector have relocated their production facilities outside of the continent and raw material prices remain volatile. In the long-term, however, global steel demand has the potential to reach 2 500 Mt by 2050[7]. Demand in developed countries

4 / OECD, Latest developments in steel capacity, 2021.
5 / McKinsey & Company, The future of the European steel industry, 2021.
6 / Directorate for Science, Technology and Industry, Steel Committee, Evaluating the current state of the steel industry: work in progress, 2013, https://one.oecd.org/document/DSTI/SU/SC(2013)19/en/pdf
7 / S. Yu, J. Lehne, N. Blahut, and M. Charles, 1.5 Steel: decarbonising the steel sector in Paris compatible pathways 2021, https://www.e3g.org/publications/1-5c-steel-decarbonising-the-steel-sector-in-paris-compatible-pathways/

will increase as they plan to expand their infrastructure and urbanization. In developed countries, demand is expected to become rather stable, with steel still needed in many emerging and evolving sectors, namely in energy with the deployment of new renewable energy infrastructure.

Future deployment of steel plants

Aside from new deployment projects, most countries have a big share of old blast furnace installations that are reaching end-of-life and require new investments to remain operational. Around 1 090 Mt of coal-based capacity furnaces will reach the end of their operational lifetime in the next decade, - 71% of the BF/BOF currently in service globally and 5% in the EU[8]. To reach the climate targets by 2050, these reinvestments need to consider low-carbon technologies, otherwise, emissions will not be cut in time, even with carbon capture and storage measures. To achieve the 1,5ºC target, 50% emission reductions are needed by 2030 and 95% needed by 2050 in the steel sector[9]. Because coal-based furnaces cannot be fully decarbonized and present an average lifetime of 15-20 years, investing in this technology at this point can result in a lock-in of fossil fuel-based steel manufacturing.

To sum up, the steel industry is currently at a crossroads and important decisions need to be taken. New emerging economies are wanting to increase domestic capacity and most of the planned new steel mills in the pipeline are relying on coal-based steelmaking technology. Meanwhile, in the developed countries, the question is what to do with the old facilities, as many of them will soon need reinvestments. With the increasing overcapacity observed, it will make sense to completely shut down certain BF/BOF facilities, which requires due policy and attention to the replacement of jobs. Alternatively, also considering the increasingly more stringent policy taxing CO2 emissions and supporting the deployment of green technologies, these plants can be retrofitted using less-emitting production methods. Action must be taken now to ensure that the sector can achieve the required climate targets and remain economically viable.

4.4. Current emissions

The EU steel industry currently accounts for 221 Mt of GHG emissions annually (including both direct and indirect emissions).[10]

The primary route, in which steel is produced from iron ore, is the Blast Furnace/Basic Oxygen Furnace (BF/BOF) process, also known as the integrated process for comprising several steps that can even take place at different plants. The main inputs to this process are iron ore, converted into pellets or sinter in the pellet/sinter plants, and coking coal which must first be converted into coke. The outputs from these preliminary processes are then fed into the Blast Furnace, together with hot air, forming a reducing atmosphere that will **reduce the iron pellets into pig iron** (also called "hot metal" in the liquid form).

8 / Agora Energiewende, https://www.agora-energiewende.de/en/service/global-steel-transformation-tracker/
9 / SHA S. YUYu, JOHANNA J. LEHNELehne, NINA N. BLAHUTBlahut, and MOLLY M. CHARLESCharles, 1.5 Steel: decarbonising the steel sector in Paris compatible pathways 2021.
10 / EC: Commission staff working document towards competitive and clean European steel, 2021, Commission Staff Working Document - https://ec.europa.eu/info/sites/default/files/swd-competitive-clean-european-steel_en.pdf

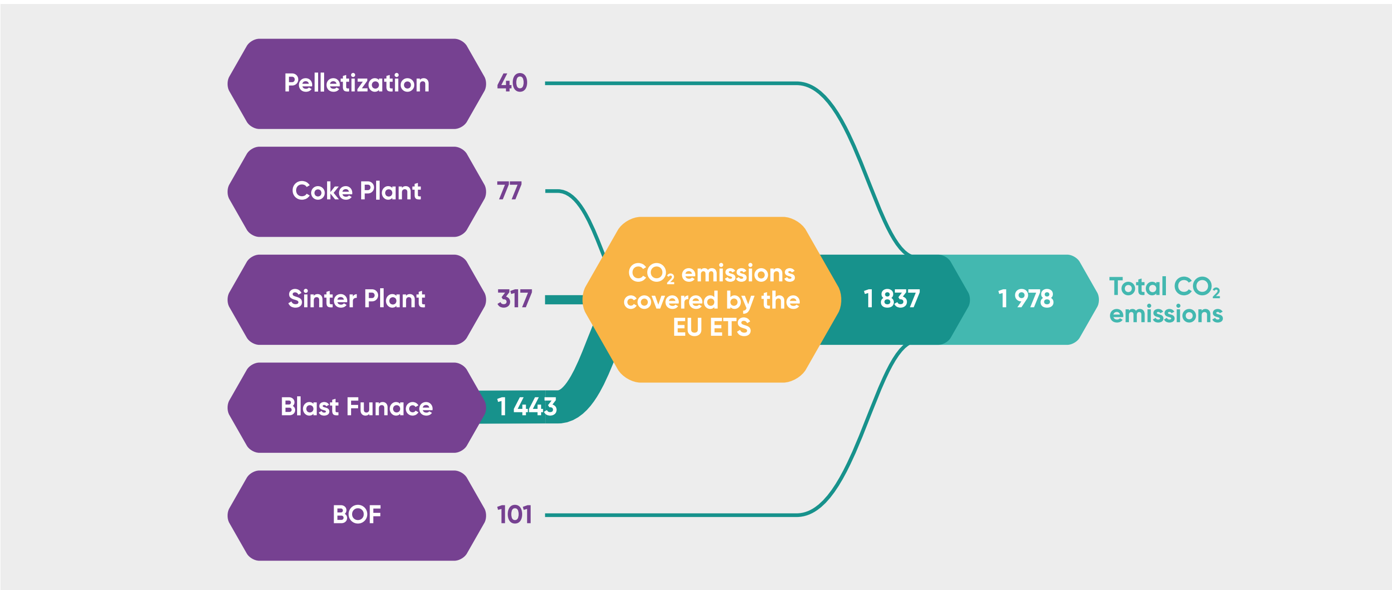
The hot metal produced in this process is then fed to the BOF. Some other inputs such as limestone and burnt lime are added to the process to increase the purity of steel. Besides feeding into the chemical processes occurring to reduce iron ore into steel, coal is also the main source of fuel for these energy-demanding processes, which results in high amounts of CO2 emissions. Certain gases can, however, be produced as by-products in one unit and be fed into other units, increasing the energy efficiency of the plant.

The average BF/BOF can require as much as 18 GJ of energy per tonne of steel produced[11]. CO2 emissions, however, are associated not only with the energy needs but also with the chemical reactions taking place in the process. Depending on the system's energy efficiency, the BF/BOF usually translates into CO2 emissions between 1,6 to 2,0 tonnes of CO2 per tonne of crude steel produced. In the EU, the average facility emits around 1,9 tonnes of CO2 per tonne of steel.

It should be noted that most – but not all GHG emissions from steel manufacturing are covered by the EU Emission Trading System. The EU ETS covers only emissions from the coke plant, sinter plant as well as blast furnace, which are responsible for the majority of emissions. Upstream emissions from iron ore pelletization (or mining) as well as emissions downstream of the blast furnace are not included.

In the secondary route, steel scrap is recycled into new steel products. Here, an Electric Arc Furnace (EAF) is used to melt the steel scrap. The EAF route is significantly less energy-demanding (6,8 GJ per tonne of steel) and its ability to resort to electricity instead of coal is already less carbon-intensive than the BF/BOF alternative. CO2 emissions can vary significantly for this route. When used to produce steel from 100% scrap, both direct emissions from the burning of a small amount of natural gas and coal and indirect emissions from the production of electricity take place. Today, emissions associated with this route amount to around 0,4 tonnes of CO2 per tonne of steel produced, on average, in the EU. However, significant variation can be observed from country to country, as most emissions are directly linked to the carbon intensity of the electricity mix. In Sweden, nearly zero emissions can be achieved, whereas in Poland the emission factor is significantly higher. Downstream processes are also a source of CO2 emissions, for both the BF/BOF and the EAF route, where heat is usually produced through the burning of fossil fuels.

Figure 6: EXAMPLE GHG EMISSIONS FROM A BF/BOF STEEL MANUFACTURING PROCESS IN THE EU (IN KG OF CO2e PER TONNE OF CRUDE STEEL).



11 / Excel tool for European Standard EN 19694-2: Stationary source emissions — Determination of greenhouse gas (GHG) emissions in energy-intensive industries.

05 Decarbonisation of the steel industry

The total capacity of all installed BF/BOF plants in the EU is around 103 Mt of hot metal per year. Switching all of those plants to hydrogen-based DRI could potentially save up to 196 Mt of GHG emissions per year. To do so would require up to 5,3 Mt of renewable hydrogen and up to 370 TWh of additional renewable electricity generation (including EAF electricity consumption).

With the steel industry being responsible for 4% of the GHG emissions in Europe[12], clear steps towards decarbonising the sector are necessary but require companies to invest significant amounts of capital and to be able to manage higher costs of steel production. In order to make the transition to a carbon-neutral industry while preserving competitiveness, a robust policy framework and relevant funding initiatives are necessary to ramp up the progress and innovation in the sector.

Various measures have already been implemented in the EU. The European Industrial Strategy, presented in March 2020 and updated in May 2021, lays down the instruments to support the EU's transition towards climate neutrality and digital leadership. One of the pillars of this strategy includes making sure Europe reaches carbon-neutrality by 2050, for which comprehensive measures to modernise and decarbonise energy-intensive industries, promote energy efficiency and strengthen carbon leakage tools are a priority. In particular, the European Clean Hydrogen Alliance was created to accelerate the decarbonisation of industry.

This chapter contains a brief introduction to the various technology pathways for partial or full decarbonisation of the sector. Different policy measures and funding opportunities created at the EU level will be presented, highlighting the pressure that the steel sector will deal with in the upcoming years towards a green transition but also the investment tools provided to support such a transition.

5.1. Selected policy incentives

EU Emissions trading System

The EU Emissions Trading Scheme was first launched in 2005 and is an effective tool to insert a decreasing cap on GHG emissions from the industry, the power sector and aviation. This scheme is in operation in all EU countries, as well as Iceland, Liechtenstein and Norway. Under this system, a limited amount of GHG that can be emitted is imposed on each sector, and emission allowances are then traded as needed. At the end of the reporting period, each installation must present enough emission allowances to cover its real emissions or face heavy fines in case of failing to do so. The possibility of trading allowances ensures that emissions cuts occurs in those sectors where it is less costly to do so.

In energy-intensive industries like steel manufacturing, a system like the ETS adds such costs to the production process that it has a material impact on the price of the final product. As a result, if no additional measures are taken, this may lead to carbon leakage, i.e., an increase in imported steel that has not been taxed on CO2 emissions and is therefore cheaper. One of the measures in place to avoid CO2 leakage is the free allocation of emission allowances to energy-intensive industries like steel. The allocation of allowances is based on benchmarks that are set for each

12 / European Parliamentary Research Service, Carbon-free steel production, 2021.

product specifically. For the period between 2021 and 2025, benchmarks are to be defined based on the performance of the 10% most efficient installations covered by the EU ETS producing the respective product in the years of 2016/2017 (in contrast with previous benchmarks, where 2008/2009 installations were considered).

When an installation produces more than one product covered by the ETS, it can be sub-divided into different sub-installations where the different benchmarks apply. This happens to be the case for steel plants where all intermediate products are manufactured in the same facility, as steel benchmarks are set for many of them. From 2021 to 2025, the benchmark for coke and sintered ore are set at 0,217 tCO2/t and 0,157 tCO2/t, respectively. Meanwhile, the benchmark to produce hot metal from blast furnaces is set at 1,288 tCO2/t (3% decrease compared to 2013-2020 values) and the one for EAF crude steel is 0,215 tCO2 per ton of steel (24% decrease compared to 2013-2020, mostly due to the reduced carbon intensity of the power sector)[13]. Additional emitting activities are accounted for via the heat and fuel benchmarks, which are 47,3 tCO2e/TJ and 42,6 tCO2e/TJ respectively. Benchmarks set for 2021-2025 are subject to an annual reduction rate between a minimum of 0,2% for the sectors with lower innovation uptake (that is the case for the BF/BOF production route) and a maximum annual rate of 1,6% for the sectors with higher innovation uptake (that is the case for the EAF production route).

Table 1: EU ETS BENCHMARKS FOR STEEL MANUFACTURING ACTIVITIES.

Product benchmark	Benchmark value for 2022 (t CO2e/t)	Annual reduction rate
Coke	0,217	1,6%
Sintered ore	0,157	0,5%
Hot metal	1,288	0,2%
EAF carbon steel	0,215	1,6%
EAF high alloy steel	0,268	1,6%

The number of emissions allowances allocated free of charge for a given year corresponds to the value of the relevant product benchmark multiplied by the relevant product-related historical activity level and other correction factors[14]. One EUA gives the holder the right to emit one tonne of carbon dioxide or the equivalent amount of other GHGs. Installations that end up emitting more than their ETS benchmark will therefore have to buy extra allowances in the market, or reduce their emissions. It is worth mentioning that the ETS is currently only considering direct emissions in the BF/BOF production route, which leaves behind the emissions associated with the production of electricity, mining and transportation of coal and other important sources. For EAF steel, indirect emissions are determined, considering the total electricity consumed within the system boundaries[15]. Additionally, benchmarked products include only crude steel rather than finished products, therefore emissions associated with downstream processes are also not included.[16]

EUA prices fluctuate with time, but they generally tend to increase as the benchmarks for free allocation continue to decrease. A steep increase in prices was observed throughout the year 2021, reaching a record of around 95 EUR/tCO2e in February 2022.[17] The EU ETS is a key tool driving the decarbonisation of the sector, as it adds significant costs for high CO2 intensive steel plants.

An integrated steel plant (ISP) using the BF/BOF process, with its own coke plant which produces its own sintered iron ore, would receive in total around 1 560 free allowances per each 1 000 tonnes of hot metal it produces. Assuming average EU steel plant emission factors, the plant would however require around 1 910 allowances per each 1 000 tonnes of hot metal, meaning an additional 350 allowances would have to be bought on the market, adding around 26,6 EUR/t to the hot metal production cost (assuming 95 EUR/t of CO2). The added cost without free allowances would be 181,6 EUR/t.

Assuming that this is an average plant producing 3 000 kt of hot metal per year, the total additional costs generated

13 / Official Journal of the European Union, 2021/447, https://eur-lex.europa.eu/eli/reg_impl/2021/447
14 / https://ec.europa.eu/clima/eu-action/eu-emissions-trading-system-eu-ets/free-allocation/allocation-industrial-installations_en
15 / Official Journal of the European Union, 2011/278, https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32011D0278&from=EN
16 / Responsible Steel, Proposals and consultation questions on GHG emission requirements for the certification of steel products, 2020, https://www.responsiblesteel.org/wp-content/uploads/2020/09/ResponsibleSteel-GHG-Requirements-for-Steel-Product-Certification-for-Consultation-Draft-1-0.pdf
17 / Sandbag, https://sandbag.be/index.php/carbon-price-viewer/

by the EU ETS would be around 59 MEUR per year. On the other hand, considering the same production of crude steel in a recycling plant with EAF technology, 0,645 Mt EUA would be allocated for free and 0,774 EUA would have to be purchased, corresponding to 74 M EUR in carbon costs.

Table 2: EXAMPLE CALCULATION OF ADDED COSTS GENERATED BY THE EU ETS FOR STEEL MANUFACTURERS.

Product benchmark	Production (t/year)	Emissions (t CO2e)[18]	Estimated free allocation (EUA)	Carbon costs (EUR/year)
Coke	975	274 950	211 575	6 020 625
Sintered ore	3 930	974 640	617 010	33 974 850
Hot metal	3 000	4 485 000	3 864 000	58 995 000
EAF carbon steel	3 000	1 419 000	645 000	73 530 000

Note: assuming EUA price of 95 EUR per tCO2.

Carbon Border Adjustment Mechanismstem

Considering the carbon leakage issue, the European Commission has proposed another measure aiming at intervening in the market of energy-intensive industries. The Carbon Border Adjustment Mechanism (CBAM) aims to impose fees on the carbon content of imported goods to the EU, similar to the fees applied on domestic products, providing a level playing field between producers. If importers can prove that a carbon tax has already been paid during the production of the imported goods, however, the price can be reduced.

In theory, the measure aims to address the displacement of GHG emissions of energy-intensive industries due to the introduction of climate policies, i.e. “carbon leakage”. In practice, however, there are multiple issues with the current proposal which might make the transition of the steel sector to low carbon solutions more difficult.

One issue is related to the planned phase-out of free allowances. The phase-out has been introduced to make sure the industry is not being “double-protected” both by free allocation of allowances and carbon taxes applied to imported goods. Starting in 2026, the phase-out would begin by reducing free allowance coverage from 100% to 90%, followed by a reduction of 10 percentage points per year until getting to a full phase-out by 2035.

The consequence of the phase-out of free allowances is that, while CBAM will protect EU steelmakers from extra-EU competition on the internal market, it will still result in higher steel prices in the EU.

On one hand, this will have a profoundly negative impact on the cost competitiveness of EU steel-consuming industries producing predominantly for export. An example of an affected sector might be the shipbuilding industry, where steel costs have a significant share in the total ship manufacturing costs. As the sector is already battling with low-profit margins, an increase in domestic steel costs will make them less competitive against Far East shipbuilders and further weaken the European shipbuilding industry. The most affected by this will be the steel industry itself, as CBAM will make European steel uncompetitive on the world markets.

Furthermore, with the current high emission allowances costs, the phase-out of free allowances will expose EU steel companies to extremely high additional costs, at a

18 / Assuming 0.270 t CO2/t of coke, 0.287 t CO2e/t of sinter, 1.42 t CO2e/t hot metal and 0.473 t CO2/t crude EAF steel.

time when they will be faced with a significant call on their resources to develop and deploy low carbon technologies, needed for the EU net-zero targets in 2050.

As per the estimations of EUROFER, the FF55 CBAM and EU ETS market reform could result in 384 M EUR of additional costs in the year 2030 alone for a representative average primary steel plant (4 Mt crude steel production per year). Even a steel plant that would switch one of its Blast Furnaces to zero-carbon hydrogen-based DRI would face additional costs of 270 M EUR per year – which is an amount similar to an investment required for a new H2 DRI unit with an annual capacity of 1 Mt.

Industrial Emissions Directive

The Industrial Emissions Directive was first adopted in 2010 and regulates the emission of pollutants in industrial installations. Not only does it cover GHG to protect the environment but also air pollutant gases and water pollutant solvents that could harm public health. The emission control is made through the implementation of permits to operate, which include requirements to use the Best Available Techniques (BAT), which are the industry best practice standards that help protect the environment, defined by experts. The IED is currently under revision, with the European Commission wishing to strengthen its role in limiting the contribution of the industrial processes to GHG emissions and be fully consistent with the EU's Green Deal and FF55 goals.

The steel sector is included under the scope of IED. All steel plants which produce at least 20 t/h of crude steel or hot rolling mills producing 2,5 t/h or above need to have an IED permit to operate[19]. At this point, to avoid duplication of regulation, permits for the steel installations shall not include emission limit values for direct emission of greenhouse gas as they are already included in the ETS scheme. Steel installations will be particularly monitored on their blast furnace and coke oven gases in terms of CO, SO2, NOx composition and concentration of dust.

EU Taxonomy

As ambitious climate goals are being set all over the world, future investments must be directed towards the right sustainable technologies. This requires, however, that a consensus is achieved on what can be considered environmentally sustainable. The EU Taxonomy establishes a list of green economic activities and provides specific criteria, as well as benchmarks, to evaluate their true sustainability. This way, a common language is created, protecting investors from so-called *"greenwashing"* and promoting investment in low- or zero-emission technologies.

The Taxonomy Regulation was published on 22 June 2020, entering into force on 12th July 2020. Specific criteria were set for activities to be accounted as sustainable. Steel production is included among the activities listed in the EU Taxonomy. The main criteria to be complied with is that hot metal produced via BF/BOF must lead to emissions not exceeding 1,331 t CO2e/t of hot metal and EAF steel must not exceed emissions of 0,209 tCO2e/t of steel.

5.2. Technology pathways for decarbonisation

The steelmaking sector has a long history of innovation aimed at its emission intensity. The recent Green Steel for Europe project has defined four promising technology routes as highly relevant going forward.

- The **first** one is based on conventional BF-BOF plants (blast furnace, basic oxygen furnace), into which a number of add-on CO2 mitigation technologies are incorporated (PI, CCU). This route can be considered a short-term solution.

- The **second** is based on the utilisation of direct reduction based on natural gas or hydrogen, in which all ironmaking and steelmaking units are replaced by new production methods.

- The **third** technology route comprises technologies based on smelting reduction. This includes, on the one hand, the iron bath reactor smelting reduction option, in which the ironmaking part is replaced and, on the

19 / https://www.spglobal.com/platts/en/market-insights/latest-news/metals/090821-eu-steel-braces-for-tighter-ghg-emission-curbs-in-run-up-to-ied-review

other hand, hydrogen plasma smelting reduction, which enables the direct transformation of iron ore into liquid steel.

The **fourth** technology route refers to the electricity-based steelmaking by iron ore electrolysis. It can either be carried out at low temperatures (alkaline iron electrolysis; replacement of the iron-making part) or at high temperatures (molten oxide electrolysis; direct production of liquid state metal from oxide feedstock).[20]

Each of those routes comes with its own unique set of challenges, benefits and maturity levels, which each translate into different framework conditions required for their successful implementation.

The following table contains a short summary of key features of each technology.

Table 3: COMPARISON OF KEY TECHNOLOGY PATHWAYS FOR STEELMAKING DECARBONISATION.

Technology pathway	Key benefits	Key challenges
Optimised BF-BOF	• Can be relatively easily integrated with existing steel plants. • Fully scalable to even the largest integrated steel plants. • High implementation readiness. • Combining CCU with biomass as fuel can potentially lead to negative emissions. • Costs of developing new CO2 storage and transport facilities can be shared with other sectors as the technology is not unique to steelmaking. • Low CAPEX related to replacement of fossil fuels with biomass.	• CCS alone leads to limited GHG emission savings (20%). • Replacing fossil fuels with biomass also does not allow to fully eliminate GHG emissions. • In order to achieve carbon-neutral steel making multiple approaches have to be combined (carbon capture, carbon utilization in the chemical industry, use of biomass as fuel). • Low public acceptance for CCS. • Limited availability of sustainable biomass sources (other than crop-based), considering the demand from aviation and maritime sectors. • Production costs are still linked with volatile fossil fuel prices. • Relatively high CAPEX.
Direct reduction	• Up to 100% decarbonisation pathway with the use of renewable hydrogen. • High TRL. • Costs of developing new H2 storage and transport facilities can be shared with other sectors as hydrogen will be used in other sectors as well. • Would be possible to gradually move towards full decarbonisation by using a mixture of natural gas and renewable hydrogen as a reducing agent. • Electrolysers can provide extra flexibility for electricity grid operators.	• The process requires iron ore pellets, which if produced outside of the EU can still lead to carbon leakage (although pelletization is relatively less carbon-intensive compared to other elements of the BF-BOF steel production process). The use of fluidized bed reactors would allow using iron ore fines but is less developed. • A high amount of renewable hydrogen demand . • For onsite electrolysis - difficult to implement in large steel plants, especially if located in areas with no access to low-cost

20 / Green Steel for Europe Consortium, Technology Assessment and Roadmapping (Deliverable 1.2), 2021.

	• the ability to feed DRI as HBI into a BF-BOF system means existing conventional brownfield plants can be used while shaft furnace/ EAF production is ramped up. • Stable production costs. • Hydrogen production can be decoupled from DRI/EAF which allows locating hydrogen production in places with access to abundant and cheap renewable energy. • For hydrogen-based routes, the possibility to integrate by-product oxygen.	renewable energy or areas with grid congestion issues. • For remote electrolysis (located near renewable energy source and not necessarily near the steel plant) implementation would require hydrogen storage and transportation infrastructure. • Would require more renewable energy than direct electrolysis of iron ore.
Smelting reduction	• High TRL for Iron bath reactor smelting reduction.	• Without CCS allows only limited CO_2 savings (20%, and 80% with CCS). • Achieving full decarbonisation would require the use of renewable hydrogen in the plasma state in a plasma arc reactor. • No information on CAPEX or OPEX . • Medium TRL for the hydrogen plasma smelting reduction.
Iron ore electrolysis	• Up to 100% decarbonisation pathway with the use of renewable electricity • Skipping the upstream stages such as H_2 production, electrolytic processes have the potential to become the most energy-efficient steelmaking methods. • Potentially significantly lower CAPEX as, in the case of electrolysis, only very few aggregates are needed.	• Low TRL, especially for molten oxide electrolysis. • Electrolysis needs to be done at the steel plant which limits the possibility to tap into cheap but remote sources of renewable energy. • Inflexible operation compared to H_2 direct reduced iron methods mean that the process might add to grid congestion issues. • The need for a constant feed of electricity makes it next to impossible to implement the technology with a requirement to use exclusively renewable energy as grid energy would be required.

Source: based on Green Steel for Europe Consortium, “Technology Assessment and Roadmapping (Deliverable 1.2)”, 2021 and Roland Berger, “The future of steelmaking – How the European steel industry can achieve carbon neutrality”, 2020.

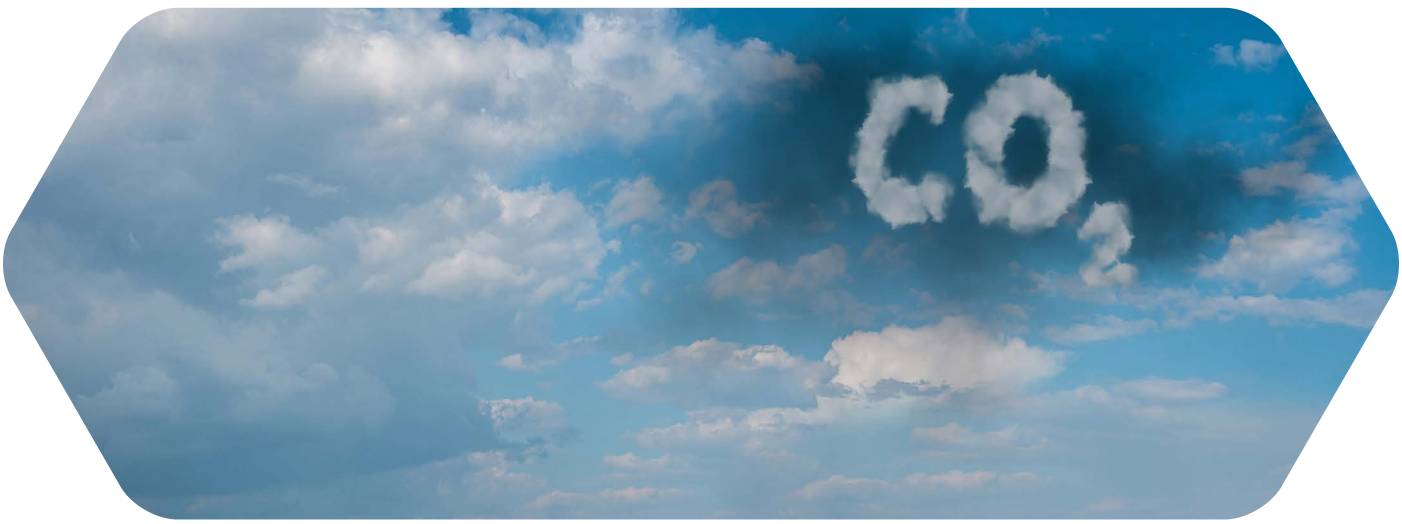
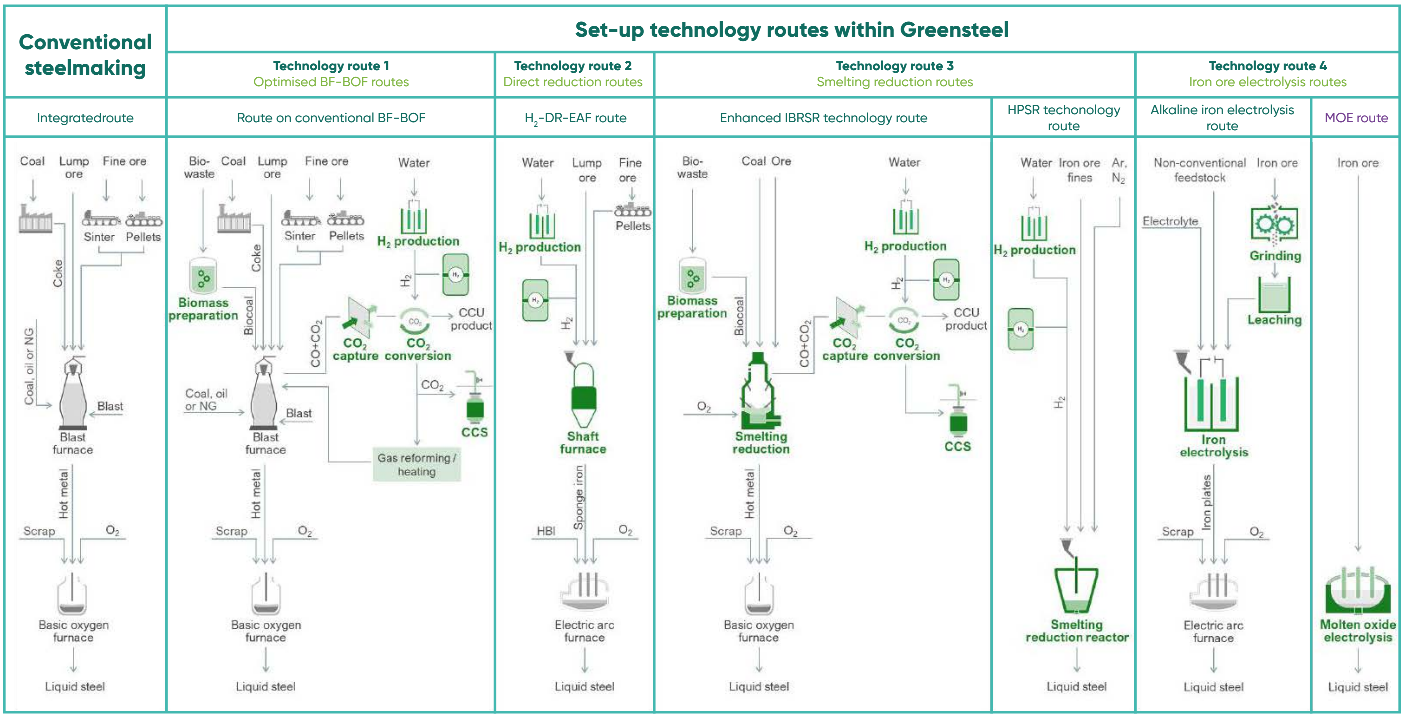


Figure 7: OVERVIEW OF THE SET-UP OF TECHNOLOGY ROUTES IN COMPARISON TO THE INTEGRATED STEELMAKING ROUTE.
Source: GREEN STEEL FOR EUROPE CONSORTIUM, TECHNOLOGY ASSESSMENT AND ROADMAPPING (DELIVERABLE 1.2), 2021.

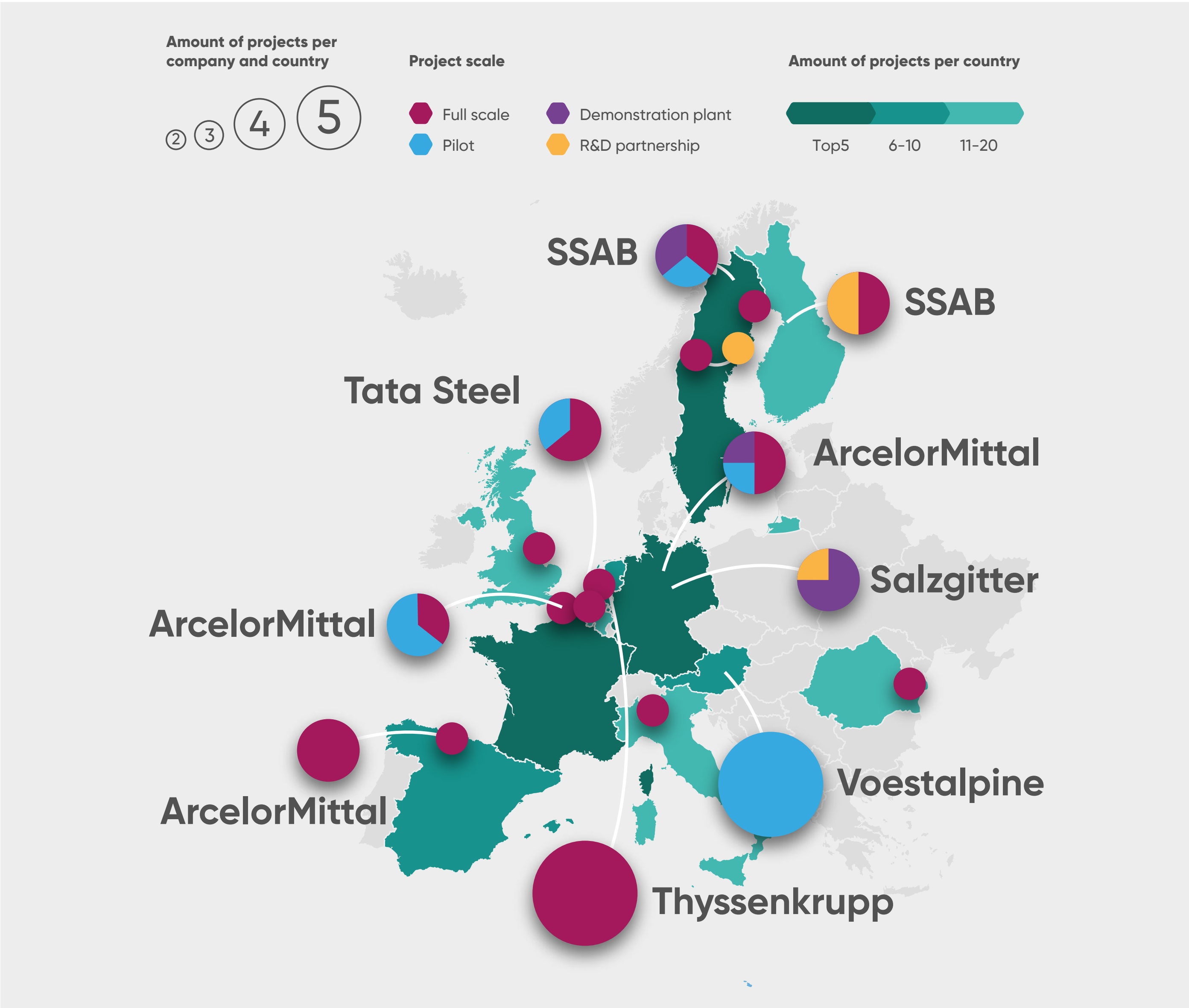


5.3. Selected projects

According to the steel projects tracker[21] developed and maintained by The Leadership Group for Industry Transition (LeadIT), as of June 2021, there were 47 projects worldwide, which were being developed with the purpose of decarbonisation of steel manufacturing. The most active of all steel companies was ArcelorMittal, involved in a total of 8 projects at various stages of development, with 4 of those being full-scale industrial projects. 21 out of 47 projects in the tracker were hydrogen-based direct reduction projects.

Even though many green steel projects deserve recognition, from the point of view of this study, three H2-DRI projects deserve a special mention. Although all three of them will implement similar technologies, they are significantly different when it comes to the way they will supply hydrogen.

Figure 8: GREEN STEEL PROJECTS TRACKER.
Source: WWW.INDUSTRYTRANSITION.ORG/GREEN-STEEL-TRACKER



21 / https://www.industrytransition.org/green-steel-tracker/

HYBRIT

The HYBRIT project is a collaboration between SSAB, LKAB and Vattenfall[22].

The project will replace coal-based blast furnaces with hydrogen-based direct reduction technology. The HYBRIT initiative will demonstrate a complete industrial value chain for fossil-free hydrogen-based iron and steelmaking.

The project will produce approximately 1,35 million tonnes of hydrogen reduced iron (sponge iron) annually, to be used for producing crude steel amounting to approximately 25% of Sweden's total production. This will reduce greenhouse gas emissions by 14,3 million tonnes of CO2 over the first 10 years of operation[23].

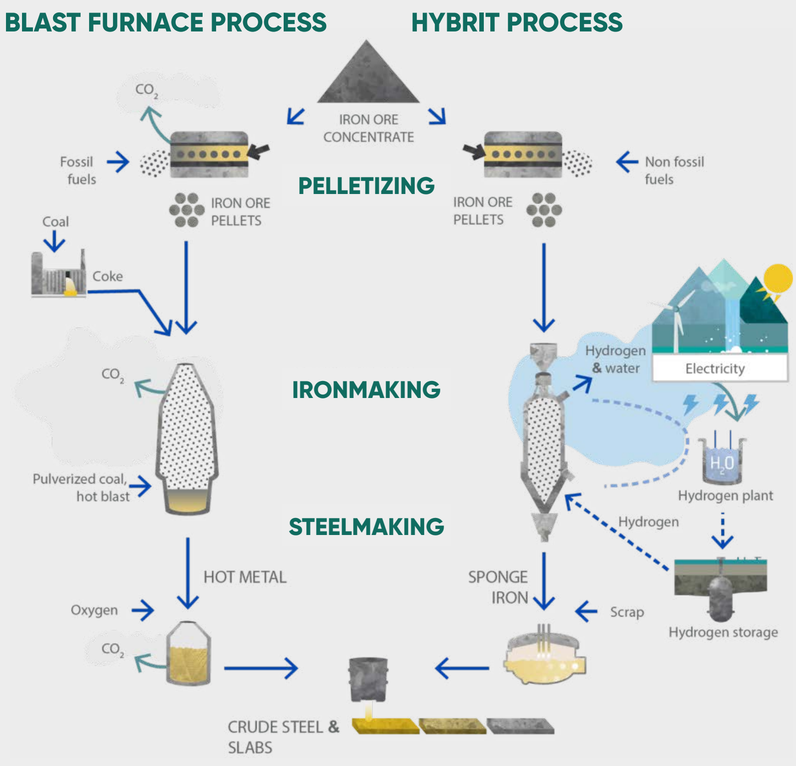
A new facility will be established for first-of-a-kind hydrogen-based direct reduction, with 500 MW of fossil-free electrolysis in Gällivare. Furthermore, SSAB will replace its blast furnaces by an electric furnace in Oxelösund.

As steel making has a significant place in Sweden's economy, the HYBRIT technology has the potential to reduce Sweden's total carbon dioxide emissions by at least ten per cent.

At the end of 2021, the HYBRIT project officially received support from the European Union, as one of seven innovative projects under the first call for large scale projects of the Innovation Fund. The project will receive a total of 143 million EUR.

What makes the project unique among the EU based green steel projects is that it is located in a country that already has an almost zero-emission electricity grid. As a result, the electricity for hydrogen generation can be sourced from the grid on an almost continuous basis without having to depend on variable renewable energy sources – thus enabling a high electrolyser capacity factor without the need for expensive hydrogen storage solutions (the project includes hydrogen storage – but only for buffering purpose).

Figure 9: THE HYBRIT PROJECT.
Source: www.hybritdevelopment.se



22 / More information at https://www.hybritdevelopment.se/
23 / According to the Innovation Fund calculation methodology, which is different to GHG accounting under the ETS.

HyDeal España

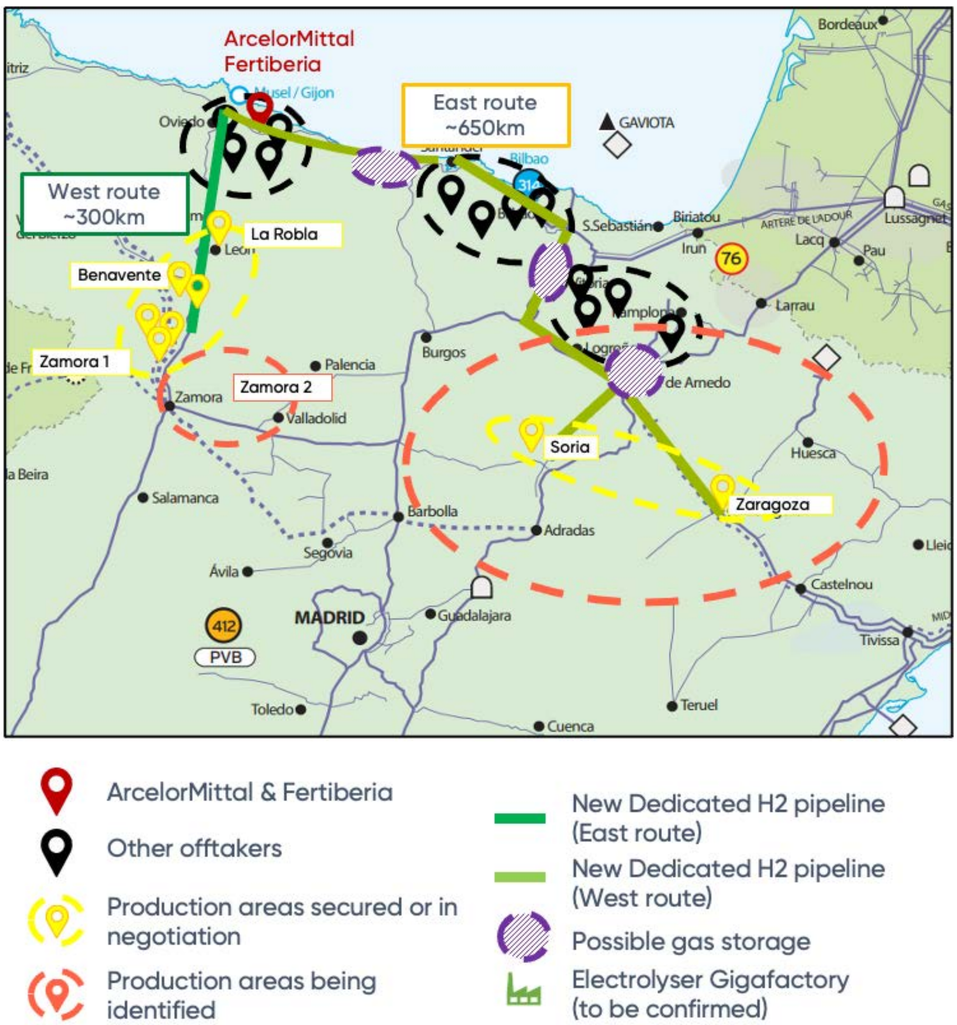
HyDeal España is developed in collaboration with DH2 Energy, ArcelorMittal, Enagás, Fertiberia and Soladvent. The project is a pioneering at-scale green hydrogen supply system in Europe, leveraging highly competitive solar PV sources in Spain, to decarbonize Asturias' industrial base, while ensuring cost competitiveness.

The project will involve a total solar PV plants capacity of ~4,3 GWp to ~9,5 GWp with a direct connection to ~3,4 GW to ~7,4 GW of electrolysis, making it the largest mature green hydrogen project in Europe. This will allow to produce and supply between ~200kt to ~330kt of low-cost green hydrogen by 2025 to 2030 to Asturias industrial players, with ArcelorMittal and Fertiberia as a key first off-takers supporting project development.

This project uses an integrated hydrogen system ("hub") approach, developing upstream (solar PV and hydrogen generation), midstream (underground hydrogen storage and pipelines) and downstream, at the same time allowing the development of large scale off-site green hydrogen generation plants, capturing the best cost production conditions while bringing bankability to all project's assets.

The aggregation of hydrogen demand into a single "portfolio" of large industrial off-takers enables project developers to unlock large scale potential and share effects on midstream costs. This is achieved through mixing demand profiles to optimize system costs of supply, allowing series effects on hydrogen plants building and learning curve and reducing the off-take and supply risk.

Figure 10: HYDEAL España PROJECT.
Source: HYDROGEN EUROPE LIGHTHOUSE PROJECTS WEBINAR.



The project is currently entering its 'pre-launch' phase which will lead to the first FID in September 2022 and should result in the first hydrogen deliveries in the second half of 2025.

Together with White Dragon, Green Falcon, HySynergy and bLion, HyDeal España is part of the Lighthouse Initiative developed by Hydrogen Europe.

HyDeal España is also part of a larger HyDeal vision which includes a total of 67 GW of solar-based electrolysis in Spain, to deliver hydrogen at cost competitive prices via pipelines to industrial off-takers in the North-Western Europe by 2030. HyDeal was recently named by IRENA as the largest green hydrogen project in the world.

Compared to the HYBRIT project, the hydrogen supply strategy is completely different. Whereas in the case of the HYBRIT project, electrolysis will be installed onsite at the steel plant, in case of HyDeal, the electrolysers will be directly coupled with individual solar PV plants. This will allow the project to escape electricity networks costs and fees, significantly reducing the costs of renewable electricity.

There are of course also drawbacks of such an approach. First, instead of electricity networks costs, the projects will have to carry the CAPEX and operating costs of transporting hydrogen via the newly constructed hydrogen pipelines (responsibility of Enagás). Fortunately, costs of transporting hydrogen via pipeline are around 5-10 x lower than electricity grid costs per unit of energy.

Secondly, the electrolysers won't be able to operate at base load and will have to follow the load of the solar PV assets. Even though the electrolysers are slightly underpowered vs solar PV (electrolyser power is roughly equal to 80% of solar PV plants they will be connected to), they will still be able to operate only for around 2 600 full load hours per year.

Another drawback of this setup is the fact that it will require more hydrogen storage than is the case with HYBRIT, as storage will be needed not only as a buffer but also to level out the hydrogen supply on a daily and seasonal basis, in order to be able to supply a steady stream of hydrogen to industrial off-takers throughout the year.

Figure 11: PROJECTS INCLUDED IN THE HYDROGEN EUROPE LIGHTHOUSE INITIATIVE.
Source: HYDROGEN EUROPE.

HyDeal España

- ~330 kt/y prod.
- 7,9 Mt/y saved
- 1,14 bcm/y replaced

White Dragon

- ~283 kt/y prod.
- 5,3 Mt/y saved
- 0,98 bcm/y replaced

Green Falcon

- ~180 kt/y prod.
- 1,6 Mt/y saved
- 0,62 bcm/y replaced

HySynergy

- ~150 kt/y prod.
- 1,5 Mt/y saved
- 0,52 bcm/y replaced

bLion

- ~380 kt/y prod.
- 4,0 Mt/y saved
- 1,32 bcm/y replaced

Yet, even considering all these drawbacks, taking advantage of cheap solar PV availability in Spain, the project aims to be able to produce and deliver renewable hydrogen to industrial end-users at a cost-competitive price of **1,6 – 1,8 EUR/kg** – including costs of storage and transportation by pipeline.

SALCOS

In many ways, the SALCOS project (**SA**lzgitter **L**ow **CO**2 **S**teelmaking)[24], developed by the German steelmaker Salzgitter, is similar to the two previously described projects. Here too the central elements of the concept are electricity from renewable sources and its use in the production of hydrogen by means of electrolysis. This green hydrogen will be then used in a direct reduction plant, to replace the coal currently used in the conventional blast furnace process.

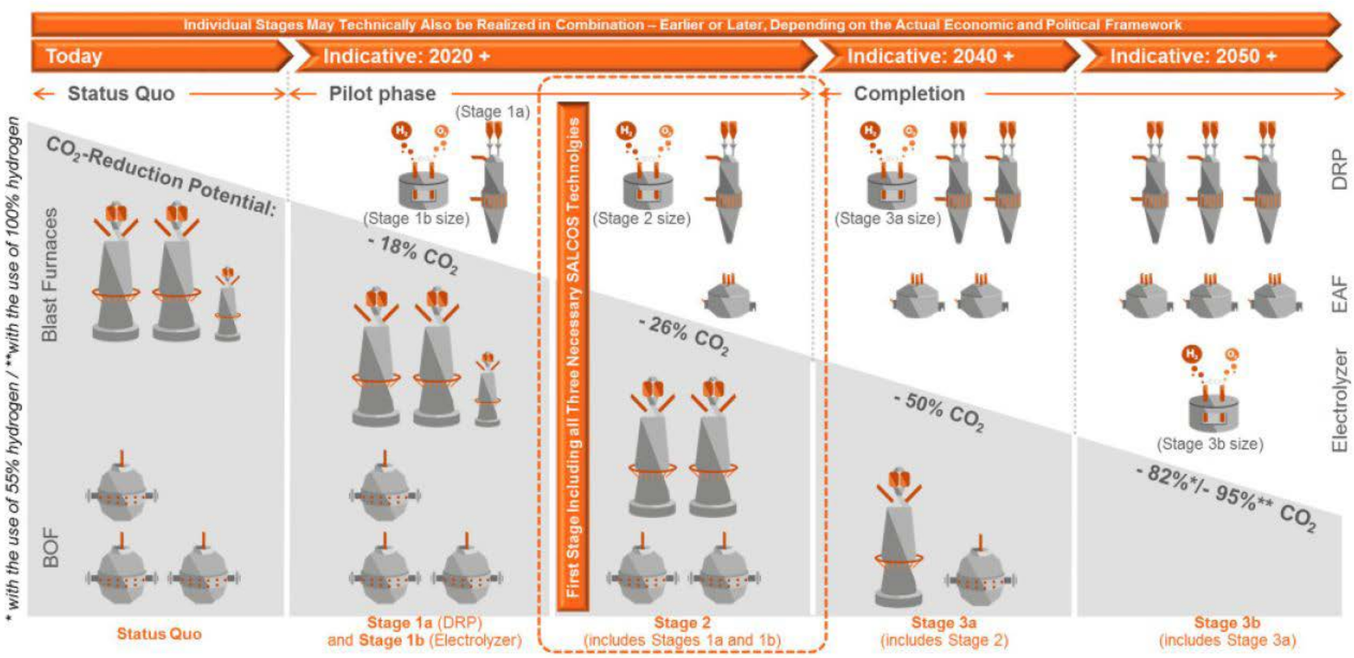
Yet, in this case, the project promotors face some significant challenges compared to the previous two projects.

First, the project is located in Germany, where, even though considerable efforts have been made over the last decade, the average carbon intensity of electricity grid cannot be considered low-carbon. Using electricity, with a GHG intensity equal to the average for Germany in 2020 (311 gCO2/kWh), producing hydrogen via water electrolysis, would result in hydrogen with a GHG footprint of 15,5 tCO2 per tonne of hydrogen (i.e. more than 50% higher than hydrogen produced from natural gas without CCS). Even if using such hydrogen for steelmaking would still lead to CO2 savings, using the same approach the HYBRIT project is not a sustainable long-term solution.

On the other hand, replicating the HyDeal approach would also be near impossible. The steel plants are located in a heavily industrialized area, with next to no local access to low-cost renewables, therefore local hydrogen production with a direct connection to RES is also not an option at scale.

The plant location is relatively far away from the North Sea potential offshore wind parks so delivering renewable hydrogen produced from those assets would require around 250 km of hydrogen pipelines as well as underground storage facilities. Neither of those is impossible, as transporting hydrogen via pipelines over such a distance is still a relatively low-cost solution and there are plenty of potential salt

Figure 12: SALCOS PROJECT.
Source: SALZGITTER.



24 / More information available at: https://salcos.salzgitter-ag.com/en/index.html

caverns suitable for underground storage in that region of Germany. The development of those pipelines and storage facilities would take many years and cannot be considered a short-term solution.

Faced with those issues, the Direct Reduction Process (DRP) in the SALCOS project can utilize any ratio of hydrogen and natural gas as the reducing agent.

The natural gas based DRI process is not new and is already employed on a major scale – although mostly outside Europe. However, to date, no such flexible operation of direct reduction systems with natural gas and hydrogen has been achieved on an industrial scale anywhere in the world. Nevertheless, the present findings from large-scale trials suggest that no fundamental difficulties are to be expected.

This offers a flexible decarbonisation solution that could be implemented immediately, gradually increasing the share of renewable hydrogen as it grows in availability, and gradually replacing further BF-BOF with new DRI-EAF units. According to data made public by Salzgitter, SALCOS will offer significant GHG savings potential. In the first stage of its development, CO2 emissions should fall by up to 26% by around the year 2025. If the entire steel production in Salzgitter were to be converted to the new method with direct reduction plants, electrolysers and electric arc furnaces, a reduction in CO2 emissions of up to 95% could be achieved.[25]

5.4. Funding opportunities

To meet policy objectives, industry needs to invest in new technologies that will cut emissions of CO2 and other GHG. Capital is thus needed not only for the transition to occur within the installations but also to carry out the required research and innovation. For this reason, public and private funding opportunities are key to ramp-up the process of decarbonisation.

This section focuses on public funding opportunities that include the steel sector within their scope and therefore represent an incentive for the deployment of green technologies.

Funding instruments often target specific phases of the transition. Horizon Europe, for example, targets Research and Innovation (R&I) initiatives, while the Innovation Fund is well suited to fund big deployment projects.[26]

Horizon Europe

Horizon Europe is the main EU funding tool for R&I projects designed to boost the EU's industrial competitiveness and fight against climate change. Over the course of 2021 to 2027, a total budget of 95,5 billion EUR is available to fund projects within the scope of 3 different Pillars: Pillar I - Excellent Service, Pillar II - Global Challenges and European Industrial Competitiveness and Pillar III - Innovative Europe. Many projects regarding new green technologies for the steel sector can fall within the scope of Pillar II. Overall, Horizon Europe presents a great opportunity for the sector to see its R&I initiatives funded.

The Clean Steel Partnership largely supports the transformation of the steel industry and the breakthrough of novel technologies taking advantage of its two financial pillars, Horizon Europe and the Research Fund for Coal and Steel (RFCS). Similarly, the Clean Hydrogen Partnership, with approximately 1 bn EUR in grants over 7 years, promotes

25 / https://salcos.salzgitter-ag.com/en/index.html
26 / A more comprehensive look into available funding sources for steel projects available at https://www.estep.eu/assets/Uploads/D2.4-Funding-opportunities-to-decarbonise-the-EU-steel-industry.pdf as well as https://ec.europa.eu/growth/industry/strategy/hydrogen/funding-guide_en

funding of innovation projects where hydrogen is applied to the production of steel.

Research Fund for Coal and Steel

A different programme, steered by the European Coal and Steel Community, aims at co-financing research and innovation projects as well in the areas of coal and steel, creating synergies with other initiatives such as Horizon Europe. The budget includes 55 million EUR every year to be awarded to universities, research centres and private companies alike. The Programme covers core production processes; new products and applications, quality control, utilisation and conversion of resources, safety at work, environmental protection by reduction of emissions from coal use and steel production.

Important Projects of Common European Interest

Important Projects of Common European Interest (IPCEI) are large projects with cutting-edge ambitions that can play a major role in the growth of the European economy and industry.

To qualify as an IPCEI, a project must show its importance quantitatively or qualitatively. It should either be particularly large in size or scope and/or imply a very considerable level of technological or financial risk. Normally, IPCEIs are projects that would not see their investments financed by the market on their own and therefore need some form of public funds or state aid, which can come in the form of grant subsidies, tax relief, and purchase of goods on preferential terms, etc. It must be clear that without the aid the project's realisation would be impossible or take place at a smaller scale. IPCEI projects can tackle Innovation or First Industrial Deployment, which makes this an important tool to help innovative new technologies get deployed. An IPCEI must also involve different Member States and count on private financing besides the public funding that it plans to access.

Innovation Fund

The European Union Innovation Fund comprises a budget of more than 25 bn EUR[27] to be granted over the course of 10 years and is looking to help highly innovative and low-carbon technologies, both for big flagship projects (over 7,5 M EUR CAPEX) and smaller-scale projects (below 7,5 M EUR CAPEX).

The criteria for project acceptance are the potential for greenhouse gases emission avoidance, degree of innovation, project maturity, scalability and cost-efficiency. If projects are rejected due to poor maturity but fulfil the requirements, they can be offered Project Development Assistance (PDA) in a dedicated programme provided by the European Investment Bank. If selected to receive a grant, projects can receive up to 60% of the costs related to innovation covered, including CAPEX and OPEX for a period of up to 10 years. ETS Innovation Fund can be also mixed with other subsidies (e.g. at the national level).[28]

This Fund represents a big opportunity for steel projects to access public funding necessary for their transition. During the first call for projects that took place in 2021, the HYBRIT project in Sweden was selected. As mentioned above, it purports to deploy innovative technologies to produce carbon-free steel using green hydrogen. The second call for projects was launched in November 2021 and welcomes both resubmissions and new applications, with a budget of 1,5 billion EUR.

It is worth mentioning that there are other tools provided by the EU that can indirectly facilitate the funding of new investments in the steel sector at the national level. The Recovery and Resilience Plan, for example, provides significant help to Member States to make new investments, bounce back from the economic hit of the pandemic and strengthen the competitiveness of the EU. From the total fund granted to each Member State, 37% must be applied to green transition initiatives and 20% to the digital transition of industry.

25 / https://salcos.salzgitter-ag.com/en/index.html
26 / A more comprehensive look into available funding sources for steel projects available at https://www.estep.eu/assets/Uploads/D2.4-Funding-opportunities-to-decarbonise-the-EU-steel-industry.pdf as well as https://ec.europa.eu/growth/industry/strategy/hydrogen/funding-guide_en
27 / he budget depends on the price of EUA and might change.
28 / https://www.euinnovationfund.eu/

06 Assumptions of the techno- economic analysis

Converting a single steel plant with a capacity of 4 Mt of crude steel per year would require: 1,3 GW of electrolysis, 3,3 billion EUR of capital investment (including 1,2 billion EUR for electrolysis) and between 10,2 to 21,7 ha of land for the electrolysis plant (and additional area for new renewable power deployment).

However, when using exclusively solar PV for hydrogen production, the required electrolysis power to produce the required amount of hydrogen would grow to around 5,0 GW, driving up the required CAPEX to 6,8 billion EUR for a single plant of average capacity.

6.1 Methodology

The economic comparison of different options has been evaluated using an approach similar to Levelized Cost of Product – in the sense that the final costs borne by steel plant operators include actualized investment (CAPEX) and operating (OPEX) costs of different options and are expressed relative to the amount of product produced (tonnes of crude steel).

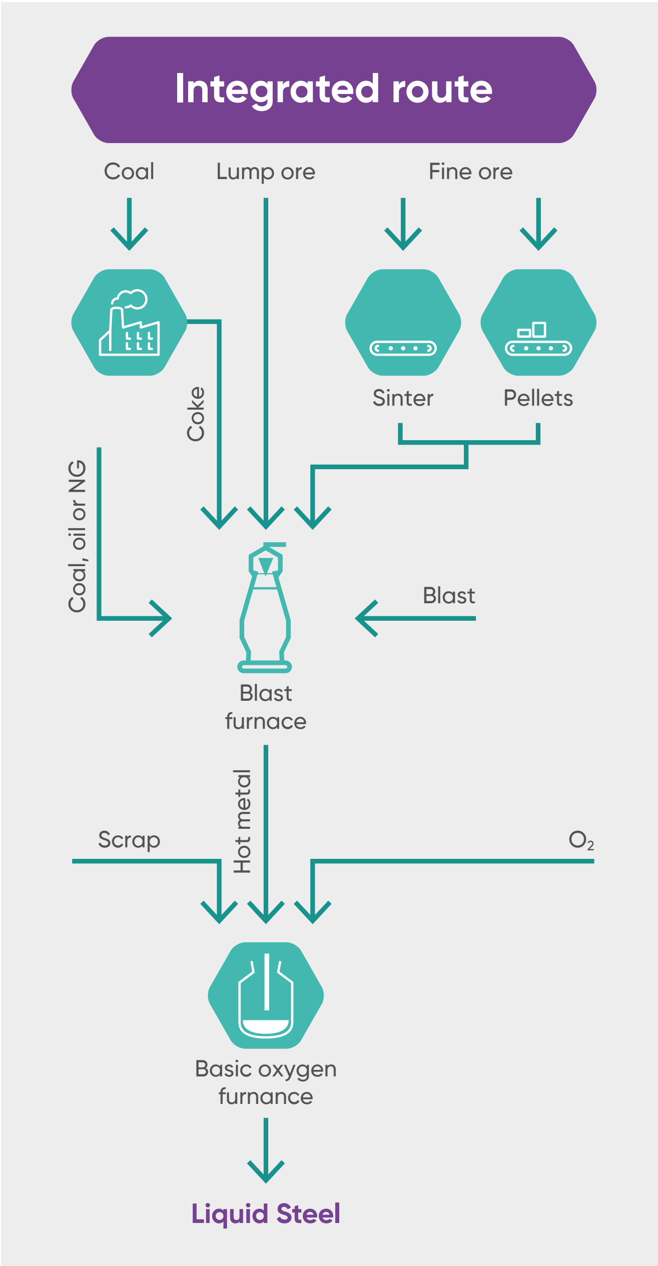
The discount rate used to actualize investment costs has been fixed at 6% p.a. in real terms.

For the purpose of this analysis, we assume no green premium on the price of “green steel”.

6.2 Counterfactual scenario

The basis for all analysis is a comparison with the established benchmark primary method of crude steel production from iron ore – i.e. BF – BOF, with coke acting as the reduction agent.

Figure 13: SETUP OF THE BF-BOF ROUTE USED AS A BENCHMARK.
Source: ADOPTED AFTER: GREEN STEEL FOR EUROPE CONSORTIUM, TECHNOLOGY ASSESSMENT AND ROADMAPPING (DELIVERABLE 1.2), 2021.



The total energy demand of this route has been calculated at around 19 GJ/tSteel with most of it being coking coal for the production of coke as well coal used as fuel in the blast furnace. At the same time, the BF-BOF route generates a surplus of coke oven gas (COG) of around 2,2 GJ per tonne of crude steel.

In addition to COG, the BF-BOF route also produces several by-products, most notably around 265 kg/t of ironmaking slag as well as 231 kg/t of granulated slag. In the case of switching to the hydrogen-based DRI-EAF route, both COG and granulated slag would no longer be available.

For the purpose of the analysis, we assume that the value of surplus COG is equal to the natural gas price (on a EUR per MJ basis). The price of granulated slag was set at 40 EUR/t.

When assessing crude steel production costs, it is important to note that due to the current high energy prices caused by post-covid economic recovery coupled with insufficient natural gas storage reserve and the Russian invasion of Ukraine, the market conditions present currently are not a good representation of the long-term profitability of the BF-BOF route.

Similar effects can be seen when comparing renewable hydrogen costs with substitute fossil fuels like natural gas or grey hydrogen. Up until the second half of 2021 renewable hydrogen production costs in the EU were not cost-competitive with hydrogen produced from natural gas. The costs of the latter were around 1,5 EUR/kg, which for renewable hydrogen was achievable only in an extremely limited number of locations in the EU with uniquely favourable solar irradiation or wind conditions (e.g. south of Spain for solar PV or Ireland for onshore wind). Due to the recent increase in natural gas prices, however, the cost relationship has completely reversed. With natural gas prices at 150 EUR/MWh (as of mid of March 2022), coupled with carbon EUA at 90 EUR/t, grey hydrogen production costs rose so much, that even renewable hydrogen produced in the most challenging locations, like solar PV based hydrogen in central or northern Europe was suddenly cost-competitive.

Figure 14: ASSUMED MATERIAL AND ENERGY FLOWS FOR THE PRODUCTION OF 1 TONNE OF CRUDE STEEL IN A REFERENCE BF-BOF INTEGRATED STEEL PLANT.
Source: HYDROGEN EUROPE BASED ON EUROPEAN STANDARD EN 19694-2.
Note: COG – COKE OVEN GAS, BFG – BLAST FURNACE GAS.

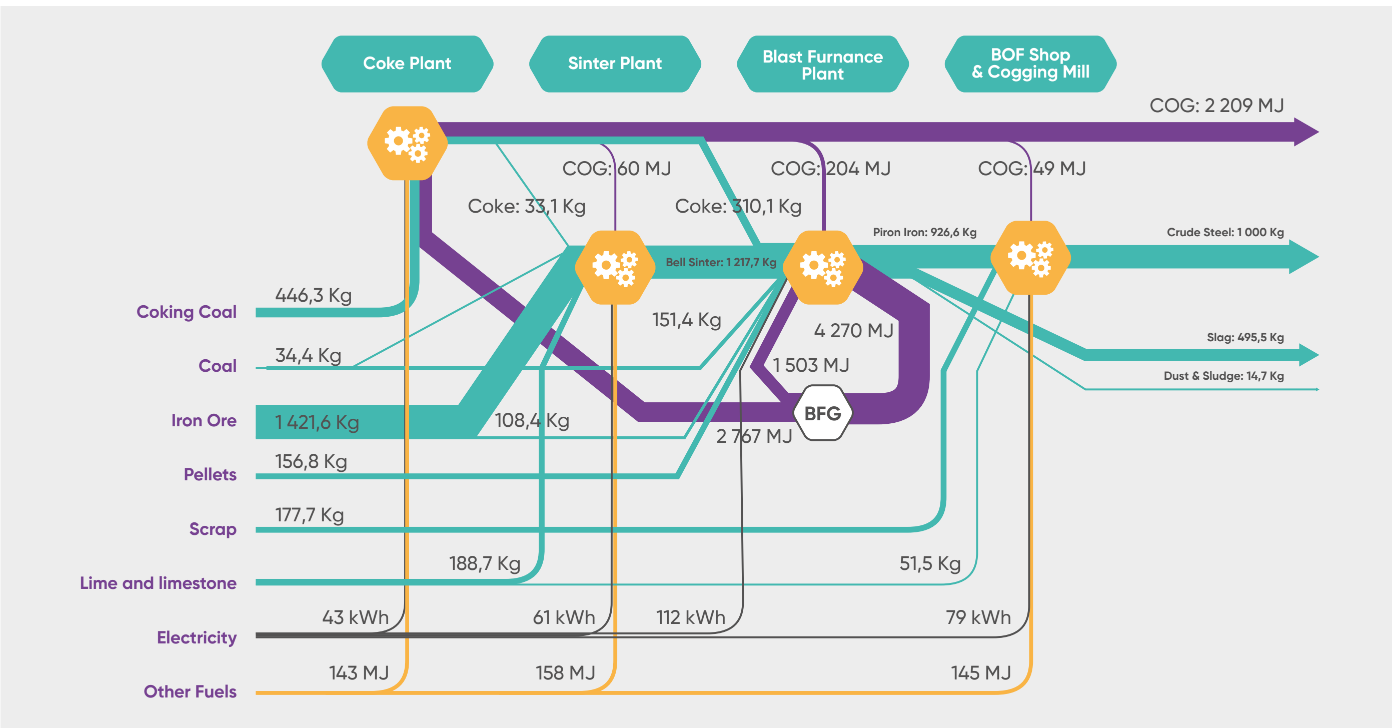
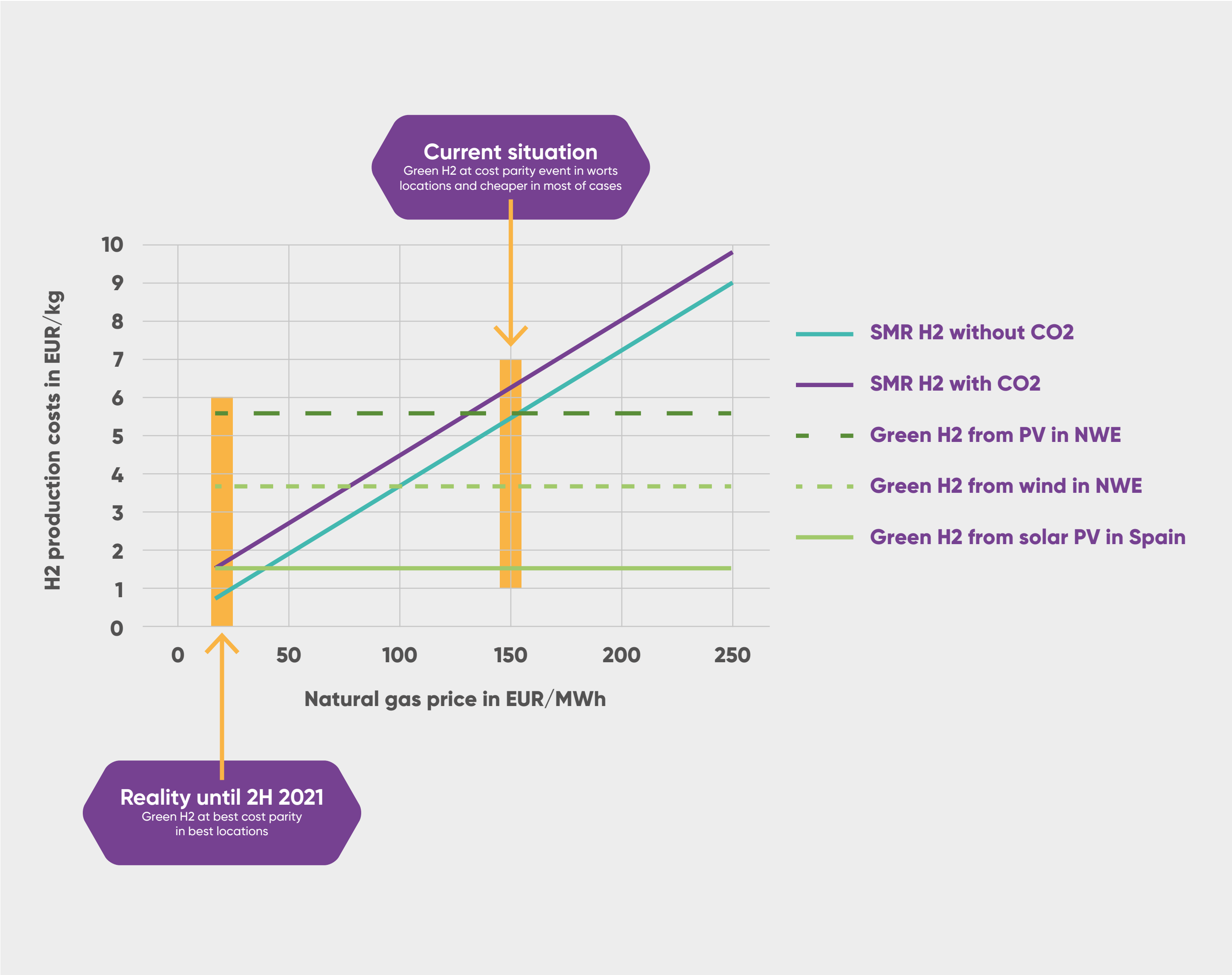


Figure 15: COMPARISON OF RENEWABLE AND FOSSIL FUEL-BASED HYDROGEN PRODUCTION COSTS BEFORE AND AFTER THE RECENT SPIKE IN ENERGY PRICES.
Source: HYDROGEN EUROPE.



For steelmaking, the energy commodity with the highest impact on final production costs is coking coal, which reached new record levels late in 2020 (even up to 600 USD/t). If high prices of coking coal would persist for a prolonged time, not only would it increase the cost of producing steel via the BF-BOF route in absolute terms but also relative to other routes – including hydrogen-based direct reduction, potentially accelerating the green transition in steelmaking.

Another commodity that has a significant impact on final crude steel production prices in the BF-BOF route is steel scrap, which can be used together with pig iron as a final input to the Basic Oxygen Furnace[29]. Historically the price of scrap was around 200-250 EUR/t, whereas currently, the prices are around 600 EUR/t. Furthermore, Russia – one of the largest scrap exporters has just imposed an export tax on scrap (in force starting from 01.04.2022) as high as

29 / The European Standard EN 19694-2 gives a standard share of scrap as 15,6%.

290 EUR/t, which limits the possibility of the market price falling to its previous levels anytime soon.

Similar record high prices can be seen in the natural gas and electricity markets which also impact total crude steel costs.

Nevertheless, in the long term, the current high energy prices are unsustainable and are expected to fall. It is however still unclear over what timeline that will happen and if the prices will fall back to pre-crisis levels or will new equilibrium prices still be noticeably higher than previously.

For this reason, the analysis in this report is conducted using two distinct price development scenarios:

- **High prices scenario** – assuming the current energy prices,
- **Adjusted prices scenario** – with current energy prices adjusted down (based on subjective expert opinion) to reflect potential future long term fossil fuels price levels.

For the BF-BOF route, the unit costs for both scenarios have been presented in the table below:

Table 4: KEY TECHNO-ECONOMIC ASSUMPTIONS FOR THE BF-BOF ROUTE.
Source: OWN ANALYSIS.

Cost item	Unit	High prices	Ajusted prices
Coal	EUR/t	165,0	50,0
Coking coal	EUR/t	230,0	66,5
Grid electricity	EUR/MWh	160,0	60,0
Electricity network costs	EUR/MWh	20,0	20,0
Iron ore	EUR/t	145,0	145,0
Lime	EUR/t	100,0	100,0
Natural gas	EUR/MWh	80,0	30,0
Steel scrap	EUR/t	400,0	220,0
Granulated Slag	EUR/t	40,0	40,0
CO2 EUA	EUR/t	80,0	40,0

Following the above assumptions, the production costs for crude steel have been estimated at 695 EUR/t with the current high electricity and energy prices and 506 EUR/t assuming a future market correction.

Both of these cost estimates are high relative to historical costs but are a good reflection of the current situation in the steel market – with steel prices at **record high levels of more than 1200 EUR/t.**

Figure 16: ESTIMATED REFERENCE CRUDE STEEL PRODUCTION COSTS IN THE BF-BOF ROUTE (IN EUR/T).
Source: HYDROGEN EUROPE.

The largest cost item is iron ore accounting for almost 250 EUR/t of crude steel (CS) in both scenarios. Together with depreciation and other fixed costs (labour and O&M), the costs which are less dependent on the current energy prices amount to around 337 EUR/tCS.

Costs of coal (hard coal and coke) contribute around 108 EUR/tCS in the high prices scenario and 31 EUR/tCS in the adjusted prices scenario. Another key cost element is the CO2 price which varies between 76 and 152 EUR/t of steel in the two scenarios (assuming no free allowances).

This cost range (roughly 500-700 EUR/tCS) will be used in the rest of the paper as a benchmark to assess the economic feasibility of green steel options. If renewable steel production costs would fall below the lower of these two values, it would mean that such an option would be financially viable even without subsidies, whereas costs higher than the upper limit of the estimated benchmark would require additional financial support.

6.3 The technical setup for the production of green steel

DRI-EAF

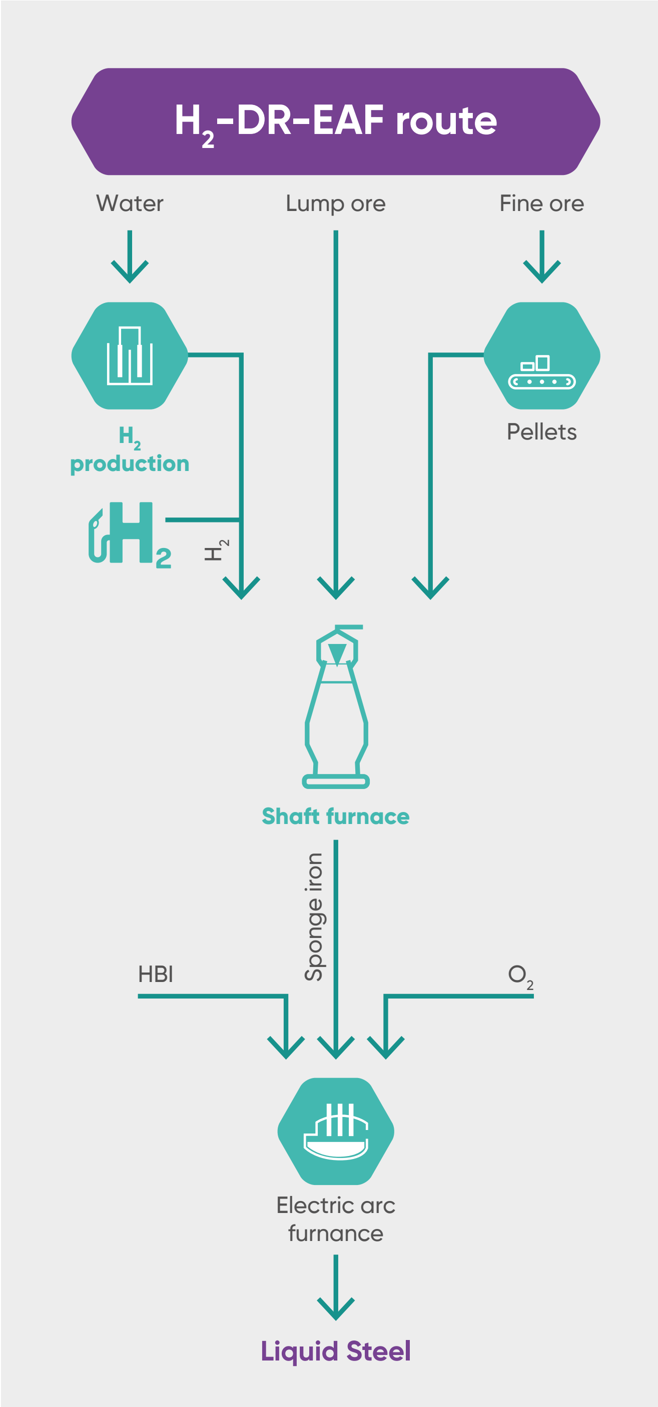
The H2 DRI route is based on the concept of using hydrogen as the iron-reducing agent replacing coking coal, to produce direct reduced iron (sponge iron) briquettes, as opposed to pig iron, that are later used as feedstock to an electric arc furnace to produce liquid steel.

The first commercial-scale plant has been in operation since 1999 in Trinidad and Tobago and had a capacity of 65 tonnes per year.

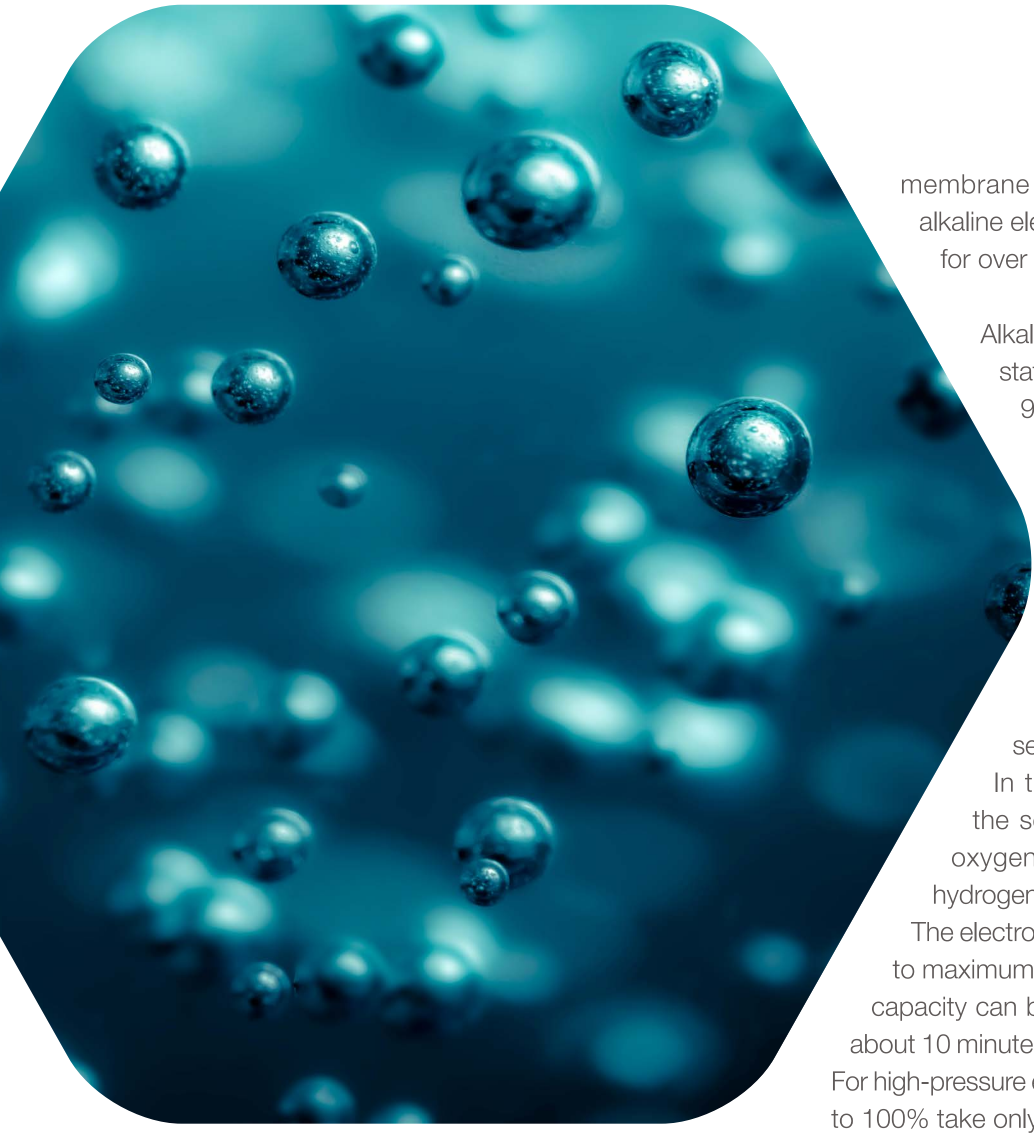
The EAF part of the process proceeds almost exactly as in a standard EAF used to produce steel from scrap in the so-called secondary steel making process. Materials that contain iron, such as scrap, are melted directly using electrical power. The resulting product from this process is liquid steel rather than pig iron, as in blast furnaces. For process engineering and metallurgical reasons, oxygen nitrogen and coal are inserted into the liquid steel.[30]

The Investment costs for a direct reduction shaft with an annual 1 Mt crude steel production capacity are estimated to be around 320 million EUR. These costs are complemented by significant additional costs for the EAF (for the conversion of DRI into crude steel), for which the reference values are 184 EUR/t of crude steel. In total, a new H2-DRI-EAF plant might require a capital investment of around 504 million EUR per 1 Mt of annual crude steel production capacity. These cost figures do not include the adaption of existing brownfield integrated plants where BF and BOF would be replaced. These costs can be significant since they might include the adaption of most internal and external supply chains (raw materials, residues and by-products, gas distribution system and power supply).[31] **Considering that, on average, an integrated steel plant in the EU has around 4 Mt of crude steel capacity, a switch to the H2-DRI-EAF route of similar capacity would require an investment of more than 2 billion EUR** (without investment in electrolysers).

Figure 17: SETUP OF THE BF-BOF ROUTE USED AS A BENCHMARK.
Source: ADOPTED AFTER: GREEN STEEL FOR EUROPE CONSORTIUM, TECHNOLOGY ASSESSMENT AND ROADMAPPING (DELIVERABLE 1.2), 2021.



30 / A. Otto, M. Robinius, T. Grube1, S. Schiebahn A. Praktiknjo and D.Stolten, Power-to-Steel: Reducing CO2through theIntegration of Renewable Energy and Hydrogen intothe German Steel Industry 2017.
31 / Green Steel for Europe Consortium, Investment Needs (Deliverable D2.2), 2021.



Water electrolysis

Hydrogen for the DR process can be produced in a variety of different ways which determine the carbon emissions associated with its later use in steel making. While hydrogen produced from nuclear energy or autothermal reforming of natural gas with CCS can be low or zero-emission (or even have negative emissions if certain bio-feedstocks would be used), for this study, we consider only hydrogen produced exclusively from renewable energy via water electrolysis.

For industrial large-scale applications, currently, there are two dominant electrolysis methods, thus two types of electrolysers that are most likely to be used at multi-megawatt- and gigawatt-scale. The first is polymeric proton exchange membrane (PEM) electrolysis and the second is alkaline electrolysis (AE), the latter has been in use for over a century[32].

Alkaline water electrolysis' operation is mainly stationary at low operating temperatures (40-90 °C) and pressures (1-30 bar). Polymer electrolyte membrane electrolysis is also operated at low temperatures (20-100 °C), but at higher pressure levels (30-50 bar)[33].

Alkaline electrolysers use a liquid electrolyte (in most cases, potassium hydroxide - KOH solution) with a porous separator between the anode and cathode. In this case, hydroxide ions pass through the separator via the liquid solution to form oxygen and water. At the second electrode, hydrogen is co-generated with the hydroxide ions. The electrolysis process can be started and brought to maximum production in less than 30 minutes. The capacity can be changed between 15% and 100% in about 10 minutes for an alkaline atmospheric electrolyser. For high-pressure electrolysers, capacity changes from 10% to 100% take only seconds or less.

PEM technology uses a solid polymer electrolyte membrane and direct current to separate hydrogen (via protons) and oxygen from water. The electrolyte in a PEM-type electrolyser allows for selective transport of H+ protons from the anode through the membrane to the cathode, preventing hydrogen and oxygen from mixing.

The main advantage of the PEM technology is that it has the capacity for a dynamic range of operation from 0 to 100% making it ideal for hydrogen production using excess renewable energy with time-varying available power. Another advantage is the possibility of obtaining ultra-pure hydrogen (purity class >=5,0 or >=99,999%). It is also compact, reliable and maintenance-free, suitable for small and medium-sized industrial applications, although it is now also in operation for large-scale applications due to its modularity.

32 / Alkaline electrolysis is an established industrial process – used currently at scale in the Chlor-Alkali industry (chlorine production via electrolysis of brine).
33 / Green Steel for Europe Consortium, "Technology Assessment and Roadmapping (Deliverable 1.2)", 2021.

Using the direct reduction method with renewable hydrogen as the reducing agent would require around 51 kg of renewable hydrogen per tonne of crude steel[34].

This means that a single average ISP, with a primary steel production capacity of 4 Mt per year, would require around 204 kt of renewable hydrogen supply per year.

The decomposition reaction of water to hydrogen is highly endothermic. To drive the reaction by electrical energy, a minimum energy input of 39,4 kWh/kg of hydrogen is required, but additional losses in the electrolysis stack, electrical transformation and rectification or hydrogen drying, increase t required energy input to 53-57 kWh/kg (4,7-5,1 kWh/Nm3) for state-of-the-art electrolyser systems . With large scale systems, some BOP energy savings can be achieved, reducing the overall energy consumption. For multi-MW electrolysis plants using alkaline technology, **50 kWh per kg hydrogen as nominal electricity consumption is already feasible, based on new stacks.** For PEM technology due to higher heat losses the reference energy consumption is around 55 kWh/kg H2.

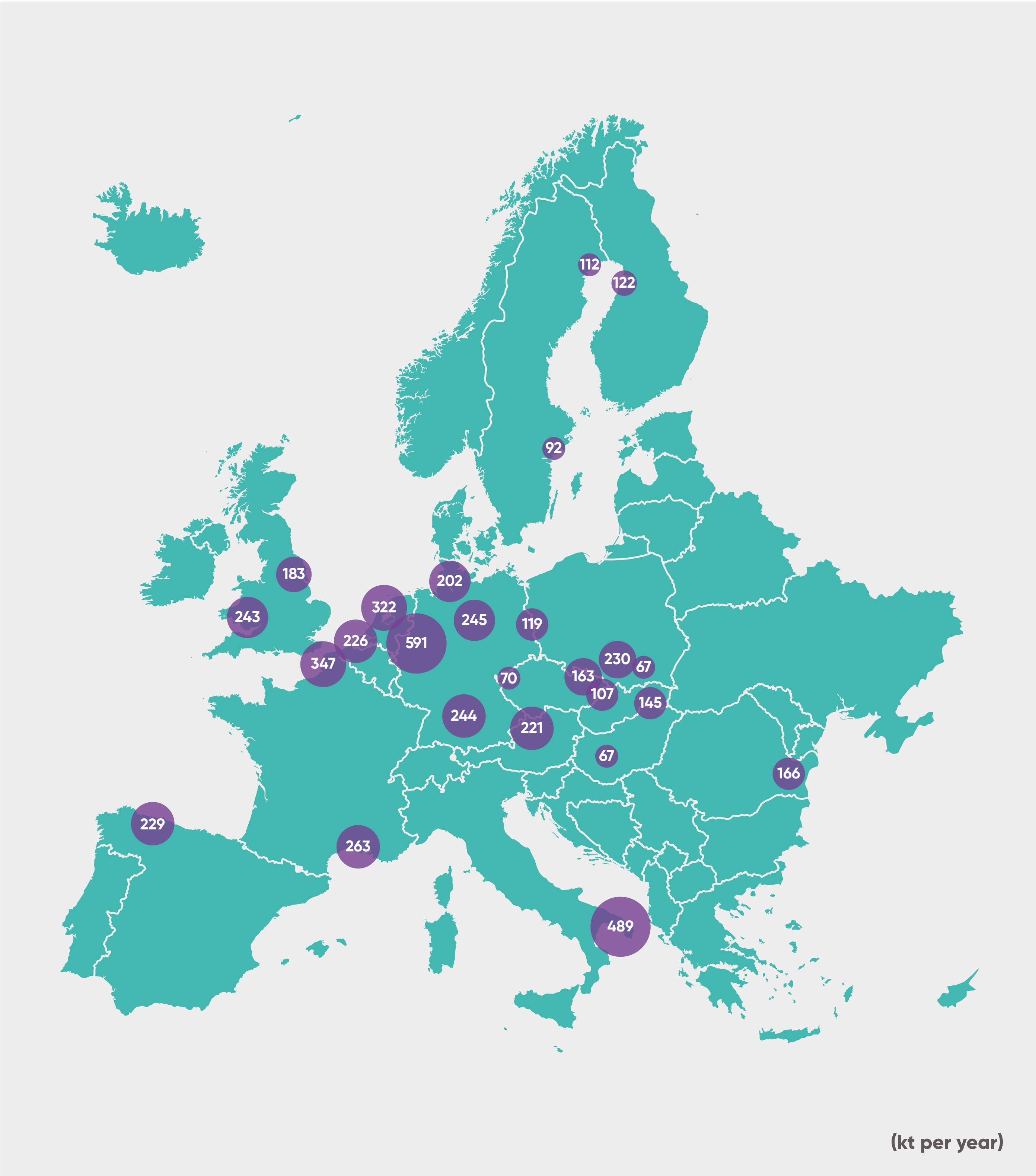
Assuming electrolyser efficiency of around 50 kWh per 1 kg of hydrogen output, hydrogen generation alone would require 2,55 MWh per 1 tonne of crude steel. On top of that, the EAF requires an additional 753 kWh[35] of electricity per tonne of steel. Together with the supply of compressed air, nitrogen and high-pressure oxygen and additional electricity consumption for ore heating, **total electricity needs are estimated at around 3,6 MWh per tonne of crude steel.**

Thus, total additional renewable electricity demand would be 14,4 TWh per year, including 10,2 TWh for water electrolysis. **Converting the entire EU fleet of blast furnaces into DRI-EAF would require up to 5,3 million tonnes of renewable hydrogen and an additional renewable electricity demand of around 370 TWh.**

Significant clusters of energy demand would in turn emerge in North Western Europe (NL, BE and the Ruhr Valley in Germany), Taranto in Italy and around the Silesia region in Poland/Czechia.

34 / Estimated based on: V. Vogl, M. Åhman, L. J. Nilsson, Assessment of hydrogen direct reduction for fossil-free steelmaking, Journal of Cleaner Production, 2018.
35 / Assuming 100% DRI feed into the EAF. Introducing steel scrap would reduce the EAF electricity demand by ass much as 86 kWh per tonne of steel for 100% scrap input scenario.

Figure 18: POTENTIAL DEMAND FOR RENEWABLE HYDROGEN DEMAND FOR USE IN STEEL MANUFACTURING IN THE EU.
Source: HYDROGEN EUROPE. ASSUMING 51 KG OF HYDROGEN PER 1 TONNE OF HOT METAL AND REPLACEMENT OF ALL EXISTING BF-BOF PLANTS INTO DRI/EAF WITH NO SCRAP INPUT.



The estimated capital costs for a multi-MW scale industrial electrolysis plant amount to 600 EUR/kW for Alkaline electrolyser technology and 900 EUR/kW for PEM electrolyser technology.

Both investment costs, as well as specific electricity consumption, are expected to fall in the coming years, due to a combination of further R&D developments, economies of scale and manufacturing automation. Industry experts at Hydrogen Europe estimate that CAPEX for alkaline electrolysers should drop to 400 EUR/kW and 500 EUR/kW for PEM electrolysers, while energy efficiency should improve to around 48 kWh/kg of hydrogen for both technologies.

Those costs however include only costs for installation on a brownfield site where fundament/building and necessary connections are readily available. In a greenfield project additional expenses related to site preparation, transformers and rectifiers should be included in capital costs. For an investment where the electrolyser will not be directly coupled with renewables but will draw energy from the grid, additional costs related to grid connection can be significant – especially for multi-MW units where an additional grid upgrade might be needed.

Adding those additional costs, along with expenses for engineering, project management, construction supervision and management, commissioning, project management, investor supervision etc, **we estimate total investment costs to be around 950 EUR/kW for alkaline technology and 1 250 EUR/kW for PEM electrolysers (without any contingencies).**

Another key consideration is the required land area for the investment in an electrolysis plant. The surface requirements needed for a GW-scale alkaline electrolysis facility amount to 10-17 ha. The maximum for PEM is 13 ha and the minimum requirement is 8 ha.[36]

By combining all the above costs, it's evident that the transition from the BF-BOF to the H2-DRI-EAF route, based on renewable energy will pose significant challenges. By assuming a baseload operation of 8 000 h pa, converting a single steel plant with a capacity of 4 Mt of crude steel per year would require:

- 1,3 GW of electrolysis,
- 3,3 billion EUR of capital investment (including 1,2 billion EUR for electrolysis),
- between 10,2 to 21,7 ha of land for the electrolysis plant (and additional area for new renewable power deployment).

Table 5: EXPECTED AE AND PEM DEVELOPMENT KPIS.
Source: CLEAN HYDROGEN JOINT UNDERTAKING, STRATEGIC RESEARCH AND INNOVATION AGENDA, 2022.

Item	Unit	SoA	2024	2030
AE CAPEX	EUR/kW	600	480	400
AE OPEX	EUR/(kg/d)/y	50	43	35
AE electricity consumption	kWh/kg	50	49	48
PEM CAPEX	EUR/kW	900	700	500
PEM OPEX	EUR/(kg/d)/y	41	30	21
PEM electricity consumption	kWh/kg	55	52	48

36 / Institute for Sustainable Process Technology, Integration of Hydrohub GW Electrolysis Facilities in Five Industrial Clusters, 2020.

However, when using exclusively renewable energy for hydrogen production, baseload operation in most cases won't be possible – especially if the RES of choice is solar PV. This will further increase required investments for electrolysers. Even assuming a solar PV capacity factor of 2 000 to 2 200 hours pa, the electrolysis power required to produce the required amount of hydrogen would grow to around 5,0 GW, driving up the required CAPEX to 6,8 billion EUR for a single plant of average capacity.

6.4 GHG emission savings

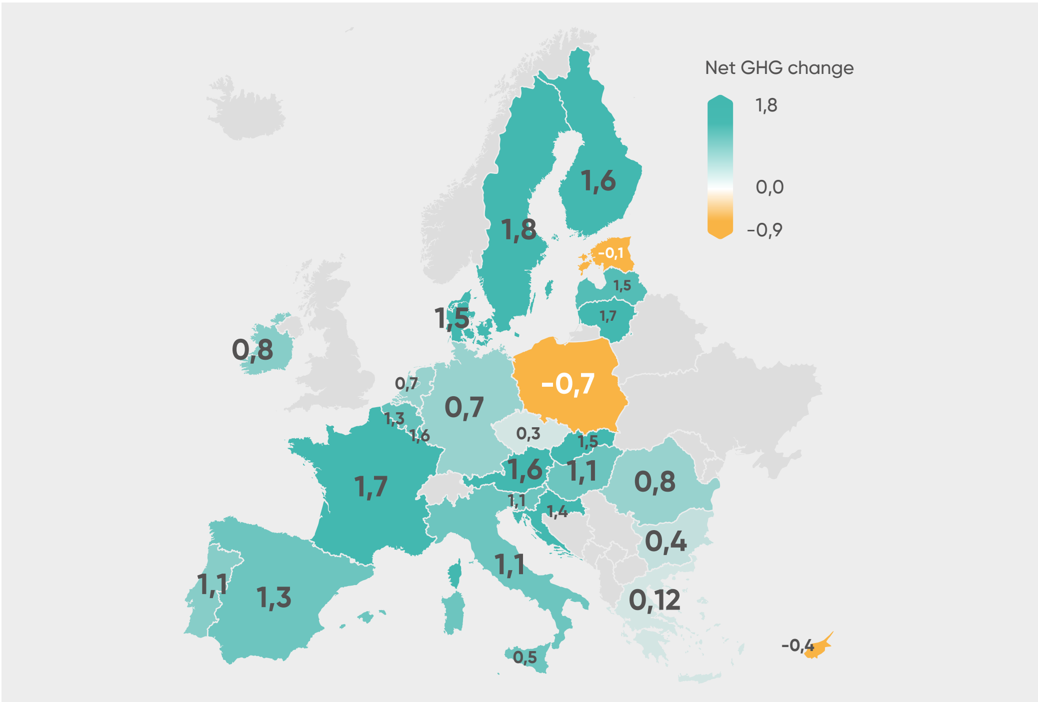
Because the process is heavily electrified, the total GHG abatement will rely on the carbon intensity of electricity. However, it should also be noted that even using exclusively renewable electricity is not sufficient for producing zero-emission steel. Some CO2 emissions will still be generated downstream from the steel plant – e.g. during the extraction and generation of iron ore and limestone, as well as within the steel making process itself – related to lime calcination and through the addition of carbon as an essential component of steel.

On the other hand, those emissions are relatively small - at around 53 kg CO2 per tonne of steel, which is only 2,8% of total emissions from the BF/BOF route. Further reduction of these emissions would be possible by using bio-methane or bio-coal as the carbon source and the substitution of lime with other materials that can provide the functions of lime in the EAF, namely slag foaming, sulphur removal and slag basicity adjustment.[37]

Considering the amount of electricity consumption, for the process to be beneficial from a net GHG emissions point of view, the maximum carbon intensity of electricity used in the process cannot exceed 513 gCO2 per kWh. Based on the carbon intensity of grid electricity in various EU countries, out of all the EU Member States with an existing fleet of blast furnaces, Poland would be the only country, in which switching to the H2-DRI-EAF route, while relying on grid electricity only, would result in a net increase of emissions[38].

If all electricity would come exclusively from renewable sources, the total GHG saving potential of converting all BF in the EU to H2-DRI-EAF would reduce annual GHG emissions by **close to 200 Mt of CO2e.**

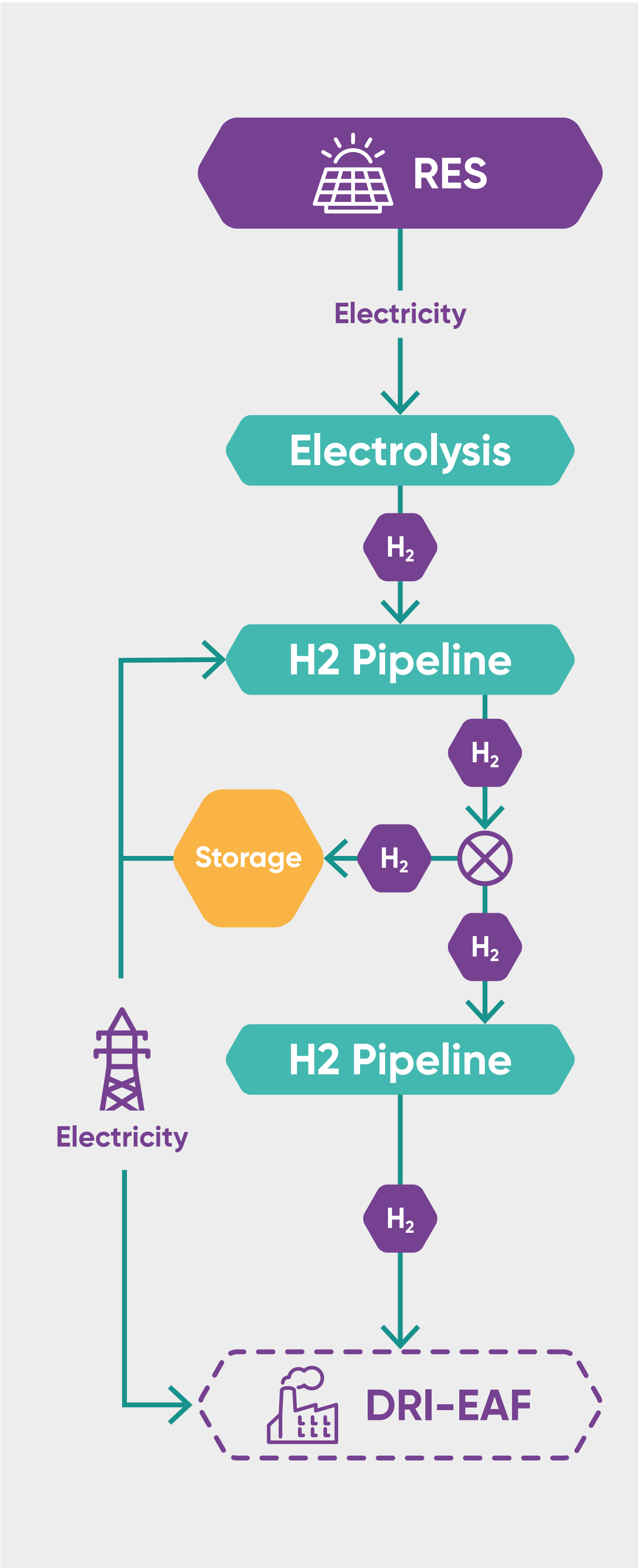
Figure 19: NET GHG SAVINGS FOR THE H2-DRI-EAF ROUTE ASSUMING GRID ELECTRICITY IS USED FOR THE PROCESS (IN TCO2E PER TONNE OF CRUDE STEEL).



37 / V. Vogl, M. Åhman, L. J. Nilsson, Assessment of hydrogen direct reduction for fossil-free steelmaking, Journal of Cleaner Production, 2018.
38 / Estonia and Cyprus would be the other ones but there are currently no BF/BOF steel plants there.

07 Assessment of the H2-DRI-EAF route

Figure 20: GENERAL SETUP OF HYDROGEN SUPPLY.
Source: HYDROGEN EUROPE.



Both in the 'High prices' and in the 'Adjusted prices' scenarios, total green steel production costs are higher than the BF-BOF benchmark, with the difference being 126 EUR and 203 EUR per tonne of crude steel respectively, with a hydrogen delivery price of 5,3 EUR/kg. The estimated CO2 break-even price is 140 EUR/t.

7.1 General setup

In the base case scenario, we assume hydrogen production would be decoupled from the steel plant and would be produced in dedicated electrolysis plants with direct connection to renewable sources, avoiding any transmission of electricity via the grid. Hydrogen would then be transported to the steel plant via a pipeline. Because the reduction shaft needs to operate at baseload, additional hydrogen storage would be needed. Only electricity needed to operate the EAF would be taken from the grid. Some electricity would also be needed to drive the pipeline and storage compressors as well.

A real-life example of such a setup is the aforementioned HyDeal España Project where up to 9,5 GW of solar PV will supply electricity to 7,4 GW of electrolysers to produce enough hydrogen to partially decarbonise local industrial steel and ammonia manufacturing facilities.

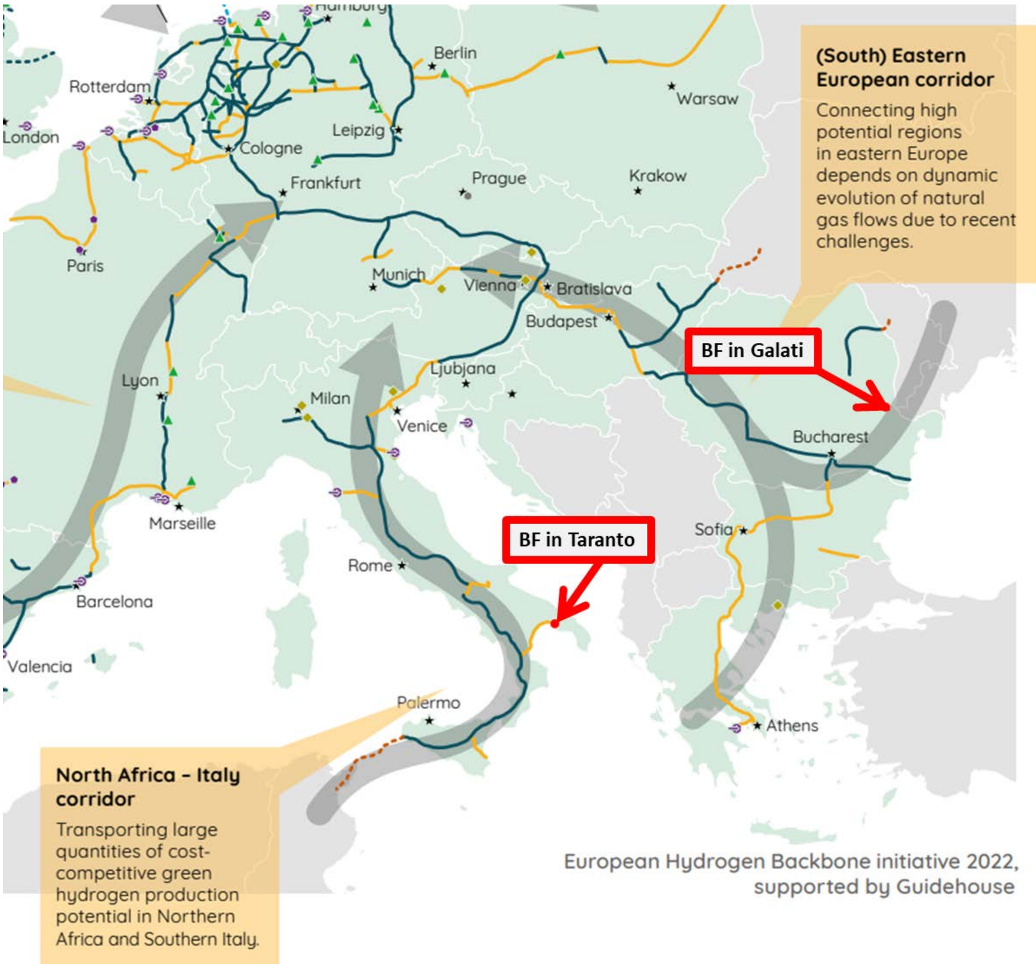


Figure 21: LOCATION OF THE STEEL PLANT IN GALATI AND TARANTO RELATIVE TO PLANNED HYDROGEN BACKBONE CORRIDORS. **Source:** GUIDEHOUSE, EUROPEAN HYDROGEN BACKBONE, A EUROPEAN HYDROGEN INFRASTRUCTURE; VISION COVERING 28 COUNTRIES, APRIL 2022.

Looking at other BF-BOF locations in the EU, this approach could also potentially be replicated in Galati in Romania, using favourable solar resources in either Romania, Bulgaria or even Ukraine. Romania is also one of the EU countries with the highest technical potential for the development of underground hydrogen storage in salt caverns[39]. Another potential location could be Taranto in Puglia, Italy, in which case hydrogen could be produced in Sicily, Libya or Tunisia.

In both cases, the steel plants are located near the priority hydrogen infrastructure corridors identified by the European natural gas TSOs, although in the case of Taranto, hydrogen storage could be a challenge, as the only available storage options in the vicinity are depleted gas fields, which are not well suited for flexible operational storage of hydrogen[40].

Hydrogen production

Taking the example of Romania, given the available solar irradiation conditions, it would be possible to achieve a PV output of around 1 600 – 1 700 kWh per 1 kW of installed power. The estimated LCOE for utility-scale solar PV in this region would be around 44 EUR/MWh.

By optimizing electrolyser power relative to the solar PV power at around 70%, the resulting electrolyser utilization

39 / Caglayan, Dilara & Weber, Nikolaus & Heinrichs, Heidi & Linssen, Jochen & Robinius, Martin & Kukla, Peter & Stolten, Detlef. (2020). Technical potential of salt caverns for hydrogen storage in Europe. International Journal of Hydrogen Energy. 45. 10.1016/j.ijhydene.2019.12.161.
40 / See for example: O. Kruck, F. Crotogino, HyUnder Deliverable D(4): “Benchmarking of Selected Storage Options”, 2014.

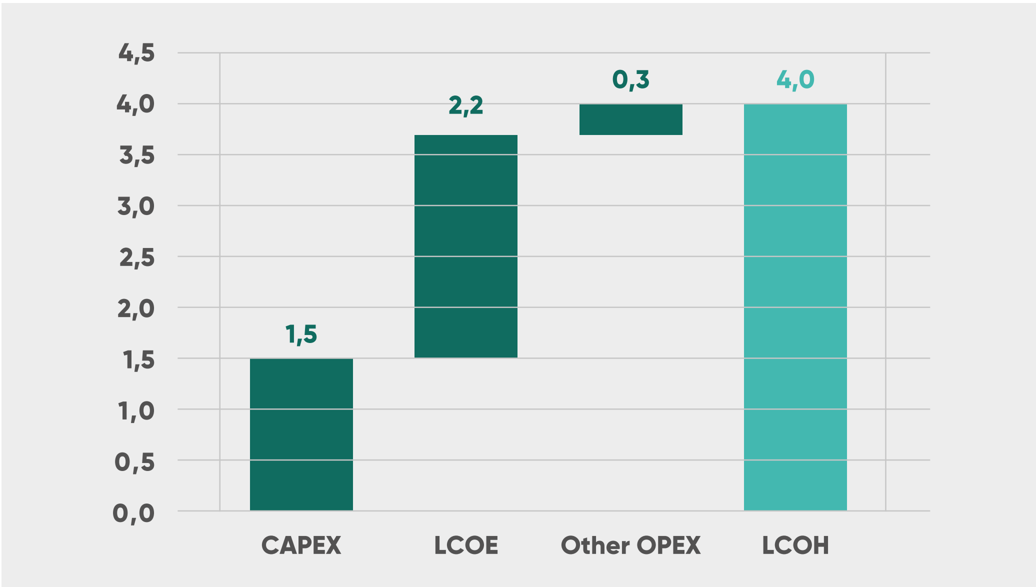
would be around 2 260 full load hours pa. This means that in order to generate the required amount of hydrogen necessary to supply a H2-DRI-EAF plant with a capacity of 4Mt of crude steel per year[41], the total hydrogen generation system would have to consist of:

- Solar PV plants with a total power of 6,4 GW.
- Electrolysis plant with a total power of 4,5 GW.

We estimate that the total CAPEX for an electrolysis plant of this size would amount to around EUR 4,3 bn, which would result in a levelized cost of hydrogen of (LCOH) of 4,0 EUR/kg.

It should be noted that these estimations are a reflection of the current electrolyser and solar PV costs. It is expected that a further decrease of the solar PV technology costs, coupled with a reduction in electrolyser CAPEX, resulting from scaling-up and automation of the manufacturing process, should lead to a significant fall in renewable hydrogen production costs in the coming decade. Electrolyser CAPEX alone, are expected to fall by around ¾ compared to current levels – enough to enable renewable hydrogen production costs with low-cost renewable energy, to reach 1,5 USD/kg by 2025[42]. According to BNEF's new report, "1H 2022 Hydrogen Market Outlook", Chinese alkaline electrolyser systems cost around 300 USD per kW already in 2021 which was 2/3 below European equivalents[43]. Expected cost reductions are also reflected in the KPIs of several projects funded via the European Green Deal call, with a targeted CAPEX of 400-480 EUR/kW.[44 45] The impact of these potential cost reductions has been presented in the sensitivity analysis chapter.

Figure 22: ESTIMATED LCOH (IN EUR/KG. **Source:** OWN ESTIMATIONS.



41 / The blast furnaces at the steel plant in Galati have a capacity of 3,25 Mt per year, yet for the sake of consistency and comparability of analysed scenarios, in all cases the analysis was done for a plant with a capacity of 4 Mt (close to EU average).
42 / https://www.rechargenews.com/transition/nel-to-slash-cost-of-electrolysers-by-75-with-green-hydrogen-at-same-price-as-fossil-h2-by-2025/2-1-949219
43 / BNEF, 1H 2022 Hydrogen Market Outlook, 2022.
44 / https://cordis.europa.eu/project/id/101036935
45 / https://cordis.europa.eu/project/id/101036908

Hydrogen transportation

Since in this scenario, hydrogen production would be geographically separated from the DRI-EAF plant, it would need to be transported from its production site to the place of demand. While it's technically feasible to deliver hydrogen using a variety of methods, given the scale of consumption, the only viable route of delivery is via pipelines.

The TSOs involved in the European Hydrogen Backbone (EHB) initiative, estimate that transporting hydrogen over 1,000 km using an onshore pipeline would cost 0,11 – 0,21 EUR/kg of hydrogen transported (3,3 – 6,3 EUR/MWh). These figures confirm that the EHB is an attractive and cost-effective option for long-distance transport of hydrogen[46].

Assuming a length of 500 km, we estimate that the total costs of transportation by pipeline would in this case amount to 0,48 EUR/kg of hydrogen, with a total additional CAPEX for the pipeline transport system of around 804 M EUR[47]. These costs could be further reduced if a larger pipeline would be built to serve other customers as well.

Table 6: OVERVIEW OF UNIT CAPITAL COSTS AND LEVELIZED COST OF PIPELINE TRANSPORT FOR DIFFERENT PIPELINE TYPES.
Source: GUIDEHOUSE, EUROPEAN HYDROGEN BACKBONE, A EUROPEAN HYDROGEN INFRASTRUCTURE; VISION COVERING 28 COUNTRIES, APRIL 2022.

Pipeline specifications		GW[28]	Pipeline Capex	Compression Capex	LCOH	Unit
Small	New	1,2	1,5	0,09	0,16	€/kg/200km
	Repurposed	1,2	0,3	0,09	0,05	
Medium	New	4,7	2,2	0,32	0,35	€/kg/1 000km
	Repurposed	3,6	0,4	0,14	0,12	
Large	New	13	2,8	0,62	0,19	
	Repurposed	13	0,5	0,62	0,09	
Offshore Medium	New	4,7	3,7	0,54	0,60	
	Repurposed	3,6	0,4	0,23	0,15	
Offshore Large	New	13	4,8	1,06	0,32	
	Repurposed	13	0,5	1,06	0,14	

46 / Guidehouse, European Hydrogen Backbone, A European Hydrogen Infrastructure; Vision Covering 28 Countries, April 2022.
47 / Assuming dedicated system scaled to the needs of the project, with hydrogen storage placed roughly in the middle of the pipeline overall pipeline length. Utilization factor for the part between the electrolyser and storage assumed to be equal to that of the electrolyser, capacity utilization for the part between the storage and DRI-EAF plant assumed to be equal to the DRI-EAF capacity factor.

Hydrogen storage

Taking into account the intermittence of solar PV power generation and the fact that the reduction shaft is designed to operate in a continuous mode, including hydrogen storage in the project set-up is a necessity.

Given solar PV variability in the area used as an example for this analysis, over the previous 4 years we estimate that a total storage of around 47 000 tonnes of hydrogen (around 23% of annual consumption) would be needed to ensure enough hydrogen is available at all times to provide continuous delivery of hydrogen to the DRI-EAF plant.

Around 2 800 tonnes would be provided by the pipeline system itself, the rest would need to be ensured by dedicated storage. For storage of this size, the only viable solution is large scale underground storage.

There are multiple possibilities to store hydrogen underground. These include, salt caverns, rock caverns, depleted gas fields and aquifers and several other possibilities. A feasibility analysis performed by the HyUnder project consortium in 2013 shows, however, that the most suitable storage solution would be salt caverns, followed by depleted gas fields and aquifers.

While depleted gas fields and aquifers have some significant advantages (lower cost and large storage capacity) these options have some significant drawbacks linked to the operational model evaluated in this paper. These drawbacks include:

- risk of geo-chemical or microbiological reactions with hydrogen, potentially resulting in hydrogen losses,
- a large amount of cushion gas required – even around 50% of working storage capacity,
- requirement for steady operation, which makes this solution suitable for long term seasonal storage with only one cycle of injection and release per year.

Figure 23: ESTIMATED NEED FOR HYDROGEN STORAGE TO ENSURE A CONTINUOUS FLOW OF HYDROGEN TO THE REDUCTION SHAFT.
Source: HYDROGEN EUROPE BASED ON SOLAR PV VARIABILITY BASED ON DATA RETRIEVED FROM THE JRC PV GIS TOOL HTTPS://RE.JRC.EC.EUROPA.EU/PVG_TOOLS/EN/TOOLS.HTML#MR

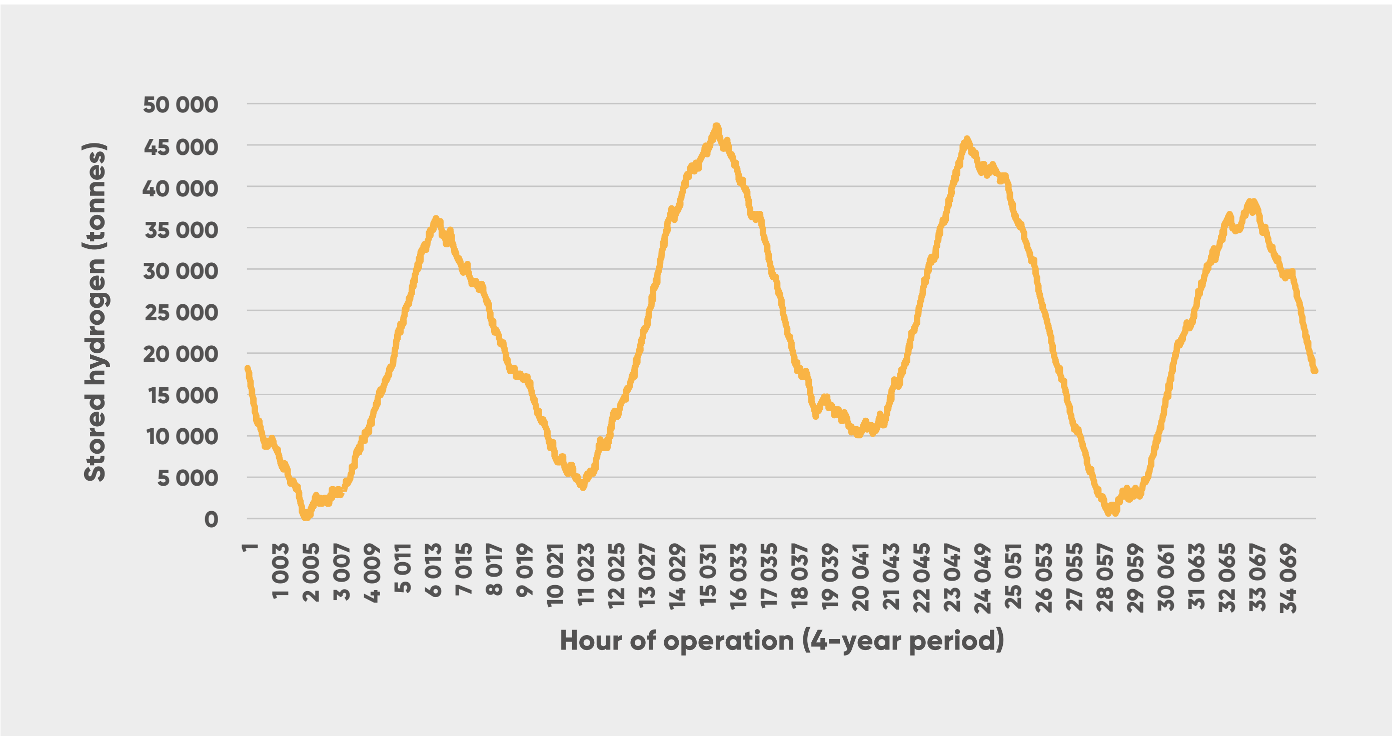


Figure 24: BENCHMARKING RESULTS FOR HIGH PRESSURE HYDROGEN STORAGE OPTIONS.
Source: O. KRUCK, F. CROTOGINO, HYUNDER, D(4)– "BENCHMARKING OF SELECTED STORAGE OPTIONS", 2013.

	Salt Caverns	Depleted Oil Fields	Depleted Gas Field	Aquifers	Lined Rock Caverns	Ulined Rock Caverns	Abandoned Salt Mines	Abandoned Limestone M.	Abandoned Coal Mines	Pipe Storage	**Weighting Coefficient**
Safety											
Tightness of Storage	Very good	Good	Very good	Very good	Good	Good	Fair	Poor	Insufficient	Very good	2
Feasibility to prove tightness	Very good	Very good	Very good	Good	Fair	Poor	Insufficient	Insufficient	Insufficient	Very good	2
Practical experience	Very good	Poor	Poor	Poor	Fair	Fair	Fair	Poor	Insufficient	Very good	2
Technical feasibility											
Working gas capacity	Good	Very good	Very good	Very good	Fair	Poor	Good	Poor	Fair	Insufficient	1,5
Flexibility	Very good	Fair	Fair	Fair	Good	Good	Good	Good	Good	Very good	1,5
Content of impurities	Very good	Poor	Fair	Good	Very good	Good	Very good	Very good	Poor	Very good	1,5
Damage to storage by reactions	Very good	Poor	Poor	Poor	Very good	Very good	Very good	Very good	Poor	Very good	1,5
Investment costs											
Exploration efforts	Good	Good	Very good	Poor	Fair	Fair	Good	Good	Fair	Very good	1
CAPEX	Good	Good	Very good	Good	Poor	Poor	Good	Good	Good	Insufficient	1
Operation											
Static and dynamic stability	Very good	Good	Good	Good	Very good	Good	Fair	Fair	Fair	Very good	0,5
OPEX	Very good	Fair	Good	Good	Very good	Fair	Good	Good	Poor	Very good	0,5
Rank	1	5	2	3	4	6					

Rating

Very good · Good · Fair · Poor · Insufficient

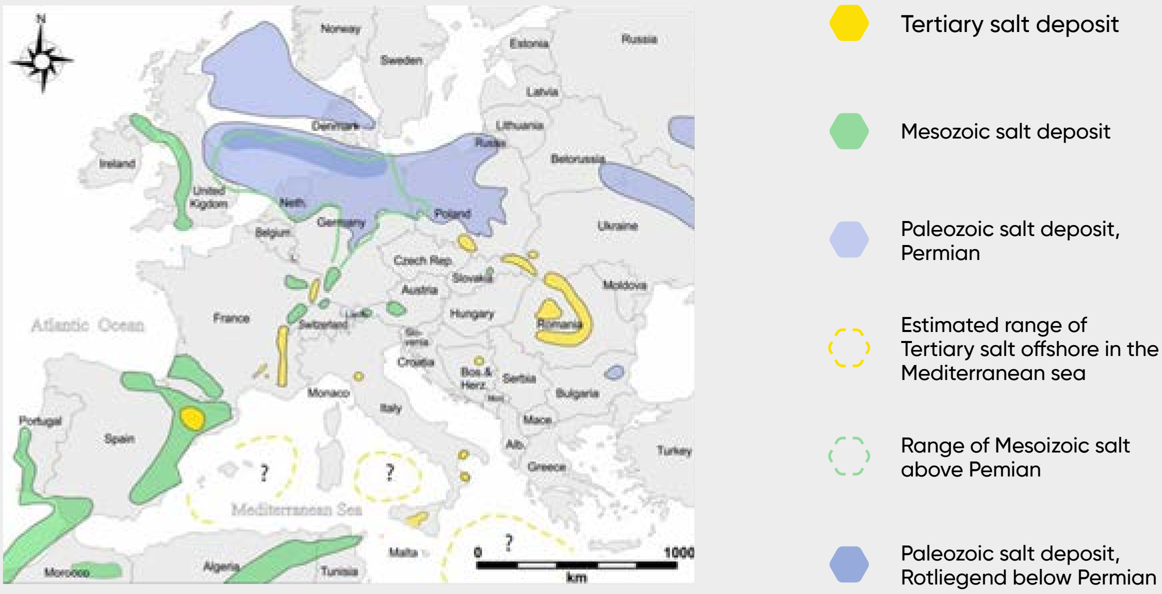
Hydrogen has been successfully stored at a large scale for industrial applications for many years. For example, underground gas storage sites in salt caverns were used to store hydrogen in the Teesside chemical complex in the UK for many years. The industrial and chemicals sector is very experienced in handling and storing large quantities of hydrogen in salt caverns (Gulf coast). Europe's industrial actors have tremendous experience in storing large quantities of natural gas in porous or natural caverns. Large-scale hydrogen industrial storage sites are linked with the pipeline networks in the Benelux region and in Teesside, UK.

Some of the salt caverns, which are used to store natural gas today, could be repurposed to store hydrogen. If that is not an option, underground salt caverns are located in many places in Europe and new storage facilities could be developed. As mentioned previously, Romania is one of the EU Member States with favourable conditions to develop new underground hydrogen storage capacities. At around 1 000 TWh, it has the second-largest technical potential for onshore storage in salt caverns in the EU (after Poland).[48]

Current capital expenditures needed to develop new salt cavern storage are around 35 EUR/kg of hydrogen storage capacity[49], which means that the additional CAPEX for the underground storage system needed to ensure a continuous flow of hydrogen to the reduction shaft would amount to **EUR 1,5 billion.**

The levelized cost of storage has been estimated at 0,86 EUR/kg.

Figure 25: SALT DEPOSITS IN EUROPE.
Source: A. GILLHAUS, P.L. HORWATH, "COMPILATION OF GEOLOGICAL AND GEOTECHNICAL DATA OF WORLDWIDE DOMAL SALT DEPOSITS AND DOMAL SALT CAVERN FIELDS", SMRI RESEARCH REPORT 2007-SMRI, 2008.



48 / Caglayan, Dilara & Weber, Nikolaus & Heinrichs, Heidi & Linssen, Jochen & Robinius, Martin & Kukla, Peter & Stolten, Detlef. (2020). Technical potential of salt caverns for hydrogen storage in Europe. International Journal of Hydrogen Energy. 45. 10.1016/j.ijhydene.2019.12.161.
49 / Source: Clean Hydrogen Joint Undertaking, Strategic Research and Innovation Agenda, 2022.

7.2 Green steel production costs analysis

H2-DRI-EAF crude steel production costs

Adding up the estimated hydrogen supply chain costs, the total hydrogen delivery price to the DRI-EAF facility in the analysed scenario would amount to **5,3 EUR/kg,** with the biggest contributing factors being the estimated solar PV LCOE (41%) and electrolyser CAPEX (29%).

As mentioned, besides hydrogen production, the other key electricity consumer in the H2-DRI-EAF setup is the electric arc furnace, which, together with other less significant electricity uses, e.g. ore heating, would require approximately 4,2 TWh of electricity. In the base case scenario, we assume that all this electricity (as well as electricity needed to power the pipeline and storage compressors) would be drawn from the grid at a cost equal to the assumed wholesale electricity price.

Figure 26: ESTIMATED HYDROGEN DELIVERY PRICE (IN EUR/KG).
Source: HYDROGEN EUROPE .

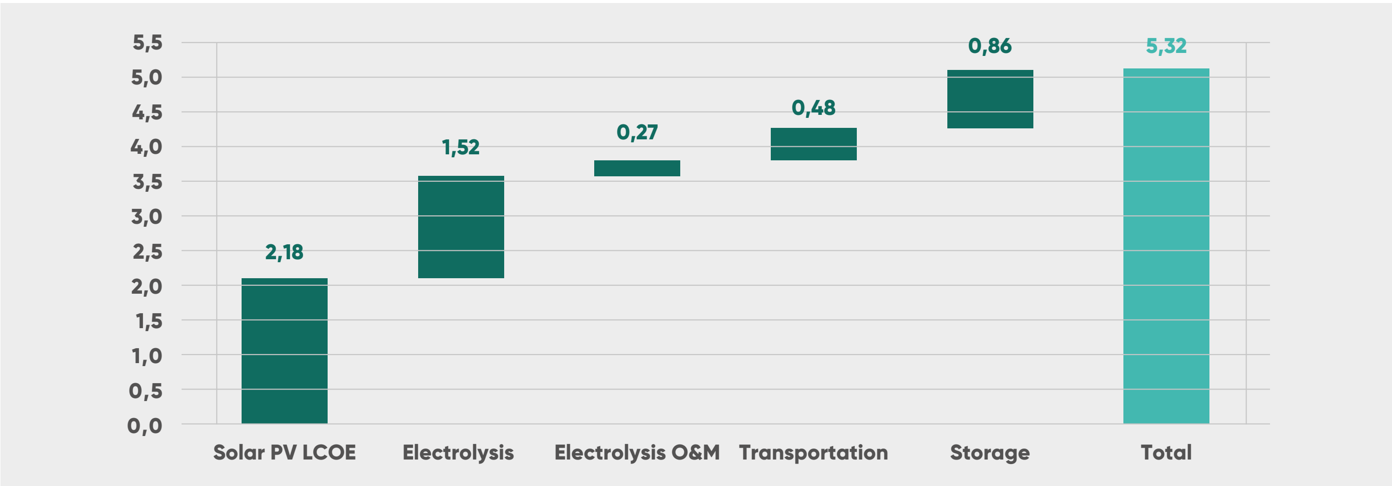
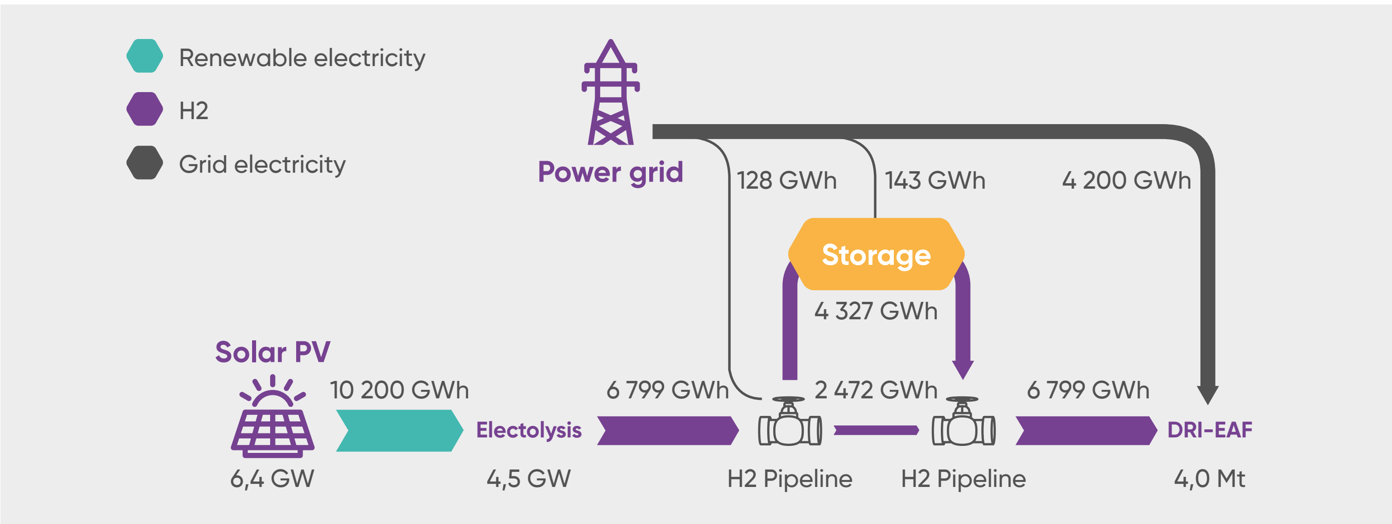


Figure 27: ESTIMATED ENERGY FLOWS – BASE CASE SCENARIO.
Source: HYDROGEN EUROPE.



Such a setup would mean that the total carbon footprint of the crude steel would still depend on the carbon intensity of the grid electricity. However, even in the case of countries with the most carbon-intensive grid-mix, like Poland, the overall GHG balance would be positive.

In addition to electricity, the DRI-EAF installation would of course have to be fed with iron ore (alternatively a mix of iron ore and steel scrap) and other consumables like lime, alloys, and graphite electrodes and small amounts of carbon (either as coal or natural gas). Still – by far the two most important cost factors would be the cost of hydrogen, responsible for around 1/3 of the total levelized costs of crude steel production.

However, all costs included, both in the *High prices* (using current high energy prices) and in the Adjusted prices (prices adjusted to take into account anticipated correction on the energy market) scenario, total green steel production costs are higher than the BF-BOF benchmark, with the difference being 120 EUR and 197 EUR per tonne of crude steel respectively.

Figure 28: NET GHG EMISSIONS IN TONNES OF CO2 PER TONNE OF STEEL.
Source: HYDROGEN EUROPE.

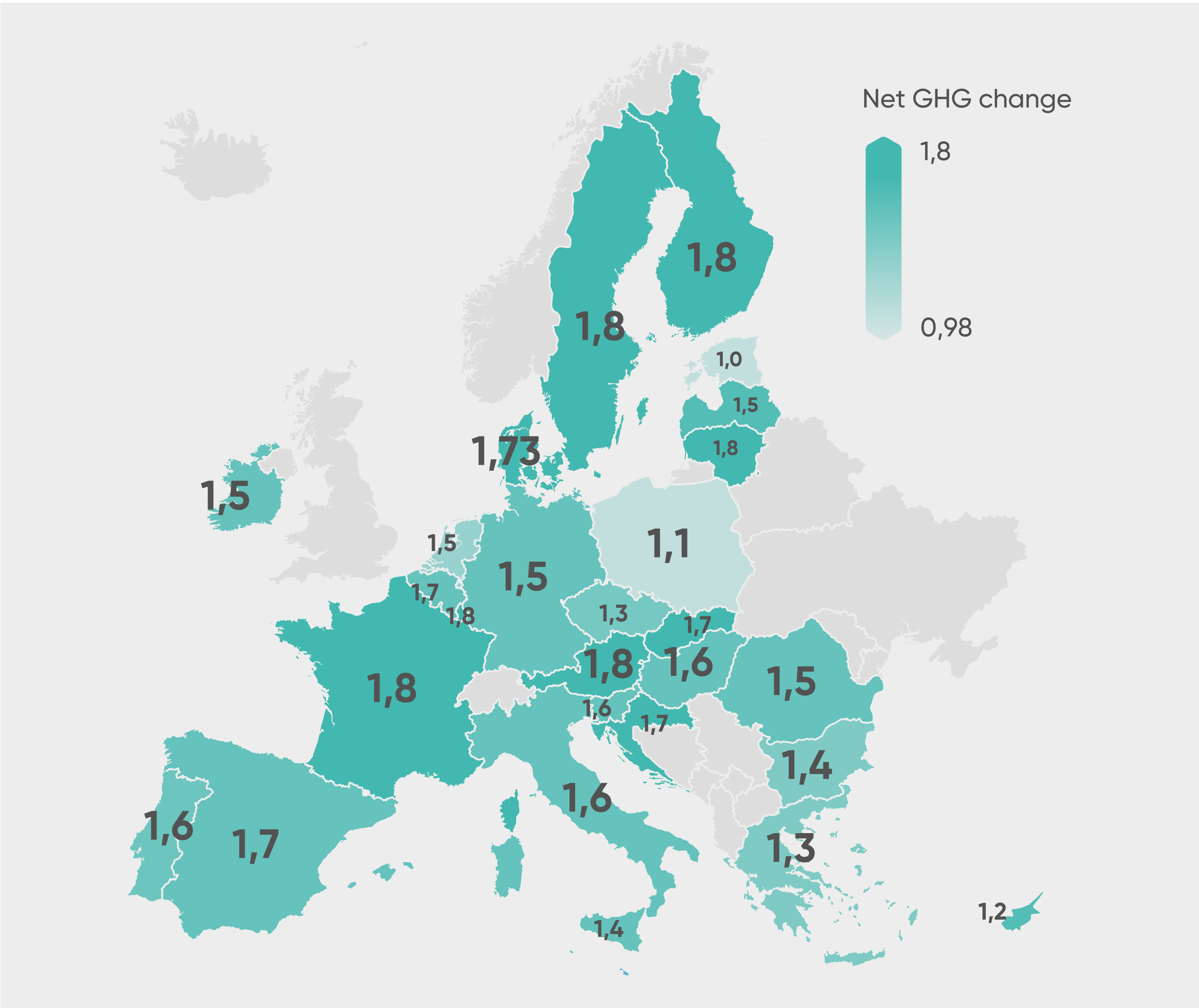
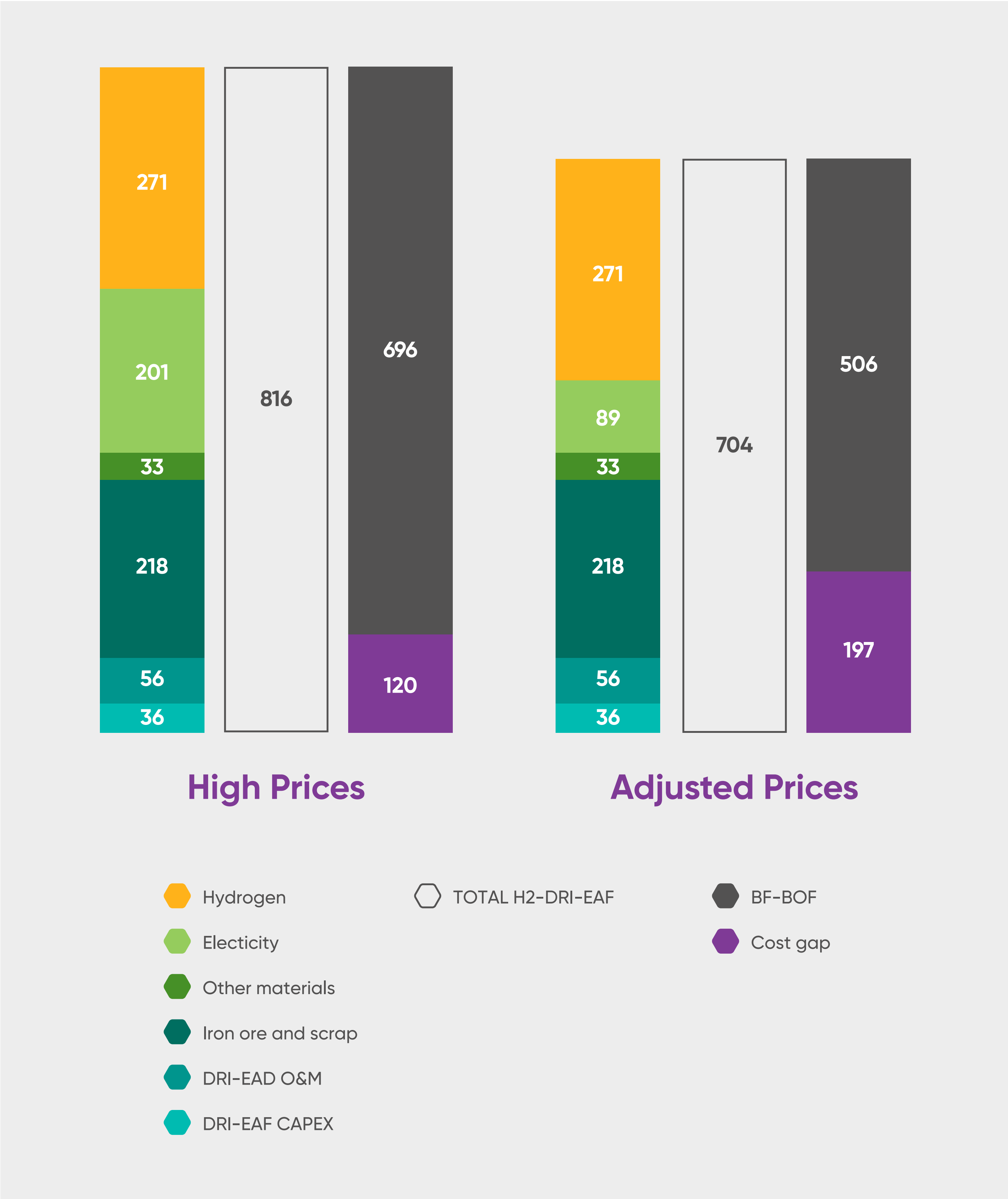


Figure 29: ESTIMATED LEVELIZED GREEN STEEL PRODUCTION COSTS (IN EUR/T).
Source: HYDROGEN EUROPE.



It should however be noted that the situation changes quite dramatically in case green hydrogen production is placed in a location with higher and more evenly spread solar irradiation. For example changing the hydrogen production location from Romania to Tunisia, would have the following impacts:

Table 7: IMPACT OF LOCATION CHOICE ON PROJECT PROFITABILITY.
Source: HYDROGEN EUROPE.

Item	Romania (base case)	Tunisia
PV installed power	6,4 GW	4,4 GW
PV LCOE	44 EUR/MWh	29 EUR/MWh
Electrolysis power	4,5 GW	3,3 GW
Hydrogen LCOH	4,0 EUR/kg	2,9 EUR/kg
Required storage	47 000 t	20 500 t
Storage cost	0,9 EUR/kg	0,36 EUR/kg
H2 delivery price	5,3 EUR/kg	3,7 EUR/kg
Cost gap vs BF-BOF	120 EUR/t in high prices scenario 197 EUR/t in adjusted prices scenario	37 EUR/t in high prices scenario 115 EUR/t in adjusted prices scenario

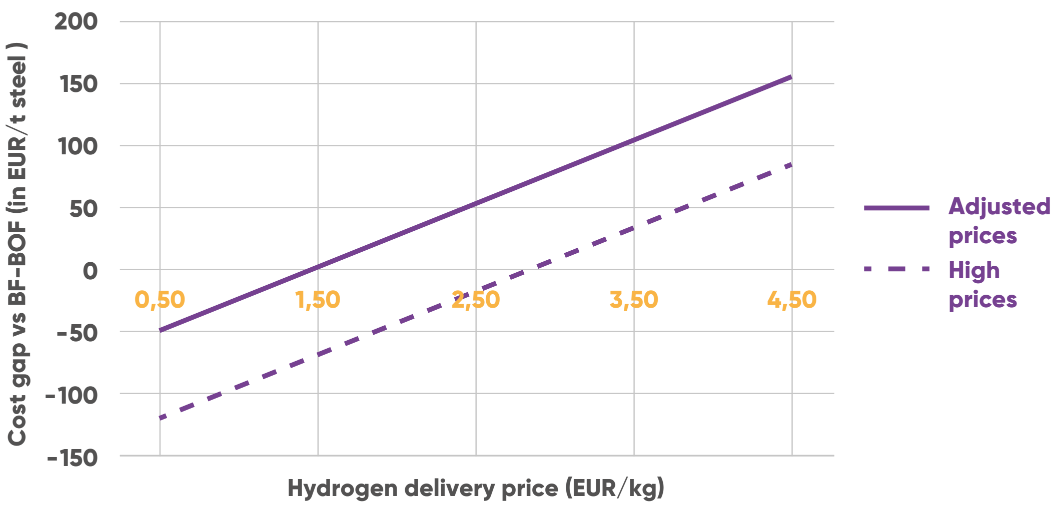
Furthermore. there are several potential optimization strategies as well as some risk-heavy assumptions which can have a significant impact on the overall profitability of this approach. The key elements have been presented in the section below.

Green hydrogen break-even point

The base case scenario is based on a relatively high estimated renewable hydrogen cost of 4,0 EUR/kg. As noted previously, renewable hydrogen production costs are expected to fall in the coming decade due to a combination of factors, including economies of scale resulting from scaling up and automatization of electrolysers manufacturing and further fall of the LCOE for solar PV, and renewable energy in general.

According to our estimates, in order for the project to achieve break-even, the hydrogen delivery price would have to be below 3,0 EUR/kg - in the 'high prices' scenario and below 1,5 EUR/kg - in the 'adjusted prices' scenario.

Figure 30: COST GAP OF THE H2-DRI-EAF ROUTE VS THE BF-BOF ROUTE, DEPENDING ON ELECTROLYSIS CAPEX AND SOLAR PV LCOE. **Source:** HYDROGEN EUROPE.



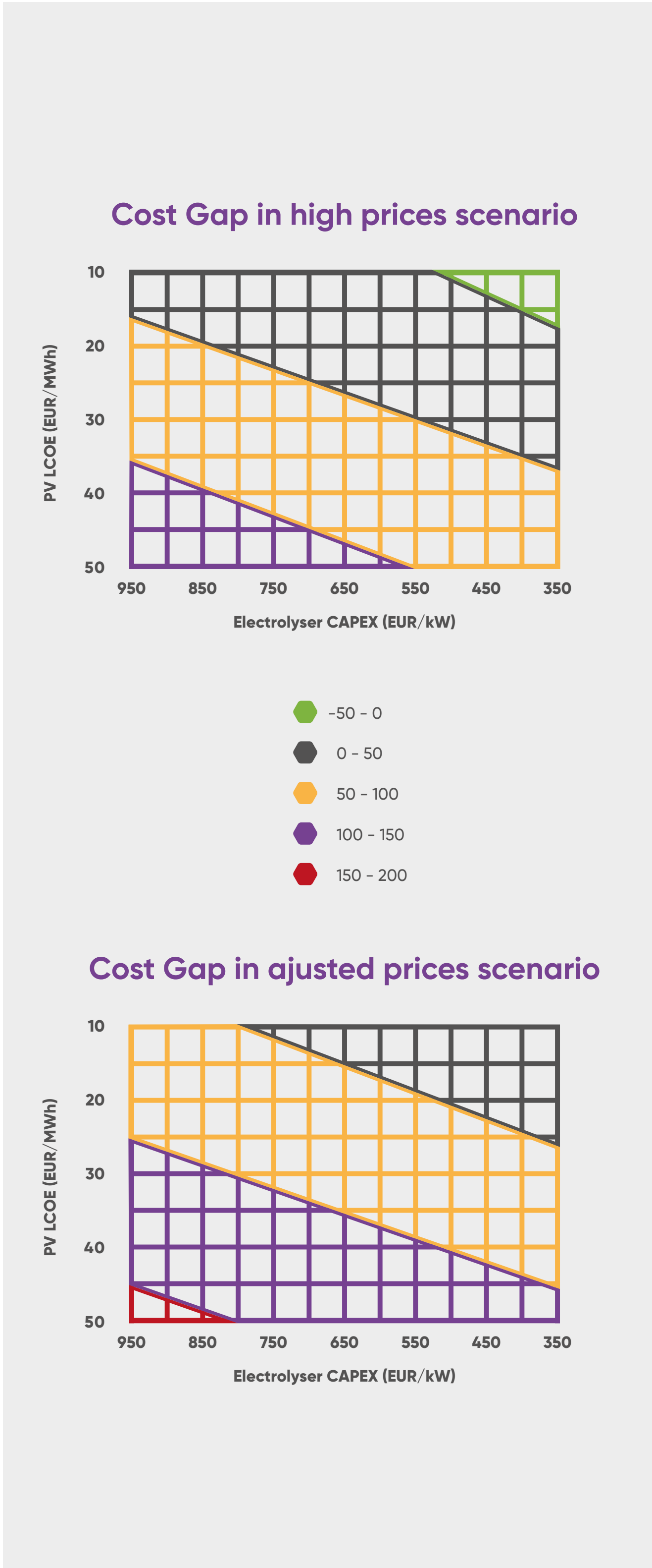
However, storage and transportation costs alone contribute around 1,3 EUR/kg to the hydrogen delivery price. If those costs remain unchanged, in order to reach the desired final price level, both the electrolyser CAPEX and solar PV LCOE would have to fall significantly.

The following graphs show the expected impact on green steel production profitability as a result of a change in either RES LCOE or electrolyser CAPEX.

In the 'adjusted prices' scenario, even a very significant reduction in both cost factors wouldn't make the investment profitable. In the 'high prices' scenario, to reach a break-even investment , an electrolysis CAPEX of 350 EUR/kW combined with solar LCOE of 15 EUR/MWh would be required (or 500 EUR/kW with LCOE of 10 EUR/MWh).

In both scenarios, the CO2 break-even price is around 140 EUR/t.

Figure 31: COST GAP (IN EUR/T OF STEEL) OF THE H2-DRI-EAF ROUTE VS THE BF-BOF ROUTE, DEPENDING ON ELECTROLYSIS CAPEX AND SOLAR PV LCOE. **Source:** HYDROGEN EUROPE.



Other potential revenues

The base case scenario assumes that besides a change in the steel production method, the switch to the H2-DRI-EAF route would not result in cash flow changes in any other areas (other than lost benefits from the loss of COG generation). However, there are several potential opportunities, which, if implemented might materially change the profitability of the investment.

These opportunities include:

- Sales of free allowances
- Demand Side Response
- Oxygen sales

SALES OF FREE ALLOWANCES

As part of the recent Fit-for-55 package, the European Commission hasproposed a carbon market reform. This proposed reform purports to include all hydrogen generation facilities in the EU ETS (not only thermal reforming plants as it is currently) with a hydrogen generation capacity of more than 25 tpd – a threshold which should be easily cleared by all power-to-gas projects in the steel sector.

As a consequence of this change, renewable hydrogen projects which meet the criteria would receive up to 6,84 free allowances for each tonne of hydrogen production. At the current EUA price level of around 80 EUR/t, and considering that around 51 kg of hydrogen is needed per 1 tonne of crude steel in the H2-DRI-EAF route, sales of free allowances would generate **additional revenues of around EUR 112 million, closing the cost gap to BF-BOF by around 28 EUR/t of crude steel.**

DEMAND SIDE RESPONSE

According to the IEA, 500 GW of demand response should be brought onto the market by 2030 to meet the pace of expansion required in the 2050 Net Zero Emissions Scenario[50].

For the H2-DRI-EAF route, only the shaft furnace requires a continuous operation. The electric arc furnace is a batch process (approximately 2 h per batch) which opens up an opportunity for flexible operations through the conversion of DRI to HBI. DRI cannot be stored but compaction to HBI allows for long-term storage and transport over long distances, which in turn opens the way for new operational strategies. When combined with HBI storage, the EAF process can, as a batch process, be flexible on a day-to-day basis and would enable production strategies that react to electricity markets in a dynamic manner.[51]

The EAF power demand is around 0,75 MWh per tonne of crude steel, meaning that an EAF with a capacity of 4 Mtpa would require a power connection of around 340 MW, which could theoretically be offered at demand-side response capacity auction.

Taking the example of the Belgian electricity market capacity mechanism recently approved by the EC, the first “pay-as-bid” auction launched in late 2021, has resulted in a procurement of 4,5 GW of capacity with an overall volume-weighted average price of 31,7 EUR/kW per year.

If successful in an auction, this could bring close to EUR 11 million additional revenues per year. Given the total plant capacity, it would reduce the overall cost gap between BF-BOF and DRI-EAF by around 3 EUR/t. While, certainly not a ‘game-changer’ at present, as more and more dispatchable fossil-fuel power plants are phased out, the value of DSR as a service could grow in the coming years.

OXYGEN SALES

Next to hydrogen, water electrolysis generates also by-product oxygen – roughly 8 tonnes of oxygen per 1 tonne of hydrogen. It is standard practice in most power-to-gas installations to just vent oxygen into the atmosphere. Yet - this approach is mostly a consequence of the fact that in small scale installations it makes little economic sense to valorise oxygen unless there is a potential off-taker in situ. In the case of Giga-watt scale water electrolysis facilities, venting oxygen into the atmosphere might be a wasted opportunity.

As mentioned, a 4 Mtpa green steel plant requires around 204 ktpa of hydrogen, this, in turn, means a total by-product oxygen stream of around 1,6 Mtpa. With a market price of around 60 EUR/t, the total market value of the by-product oxygen would be close to EUR 100 million per year. Of course, whether it would be possible to tap into these revenues would need to be assessed case-by-case as this would in most cases require an additional investment in oxygen liquefaction and storage facility. Assuming a 10% profit margin, it could reduce steel production costs by around 2,5 EUR/t.

What is equally important though - considering that the current benchmark method for oxygen generation is cryogenic air separation, which uses non-trivial amounts of electricity, using by-product oxygen from water electrolysis, powered with renewable energy, would lead to both energy savings as well as GHG emission avoidance.

Assuming an oxygen emission factor of 0,26 gCO2/kg[52], replacing 1,6 Mtpa oxygen would potentially reduce GHG emissions by an equivalent of around 424 tonnes of CO2 per year.

50 / https://www.iea.org/reports/demand-response
51 / V. Vogl, M. Åhman, L. J. Nilsson, Assessment of hydrogen direct reduction for fossil-free steelmaking, Journal of Cleaner Production, 2018.
52 / Based on: Variny, M.; Jediná, D.; Rimár, M.; Kizek, J.; Kšiňanová, M. Cutting Oxygen Production-Related Greenhouse Gas Emissions by Improved Compression Heat Management in a Cryogenic Air Separation Unit. Int. J. Environ. Res. Public Health 2021, 18, 10370. https://doi.org/10.3390/ijerph181910370

08 Scenario analysis

While imports of renewable hydrogen are most likely inevitable for some EU countries, because of low hydrogen break even price, the steel sector will remain a challenging market for imported hydrogen. Although business case can be improved by using waste heat for dehydrogenation or direct use of ammonia in the DRP. Decoupling direct reduction from EAF using renewable briquetted iron as the "hydrogen carrier" to deliver renewable energy to EAF units in the EU is also an option.

Another possibility, for areas with shortage of renewable resources, is to produce hydrogen in situ, with electricity delivered through the power grid. In this case however, ensuring steady supply of hydrogen remains a challenge, as available storage options are expensive.

8.1 Hydrogen supply scenarios

As the main source of renewable energy for hydrogen generation is solar PV, the results of the presented analysis are obviously strongly connected to the available solar irradiation conditions in the area where the project would be located.

The available solar irradiation in North-Western or Central Europe is significantly smaller than in Southern Europe, North Africa or the Middle East, where the same solar panel can produce up to 2-3 times more energy. This will be reflected in lower renewable hydrogen production costs and will have an impact on the feasibility of using such hydrogen for green steel production.

The graph below shows an estimated range of current green hydrogen production costs in in the various EU Member States in 2020, given the irradiation conditions available in each country. The graph clearly illustrates that the decarbonisation of steel production from locally produced renewable hydrogen won't be possible in some EU Member States, which will have to rely on other types of RES (e.g. offshore wind) or imported hydrogen.

Figure 32: LEVELIZED COST OF HYDROGEN (EUR/KG) FROM UTILITY-SCALE PV IN 2020.
Source: HYDROGEN EUROPE, CLEAN HYDROGEN MONITOR 2021.

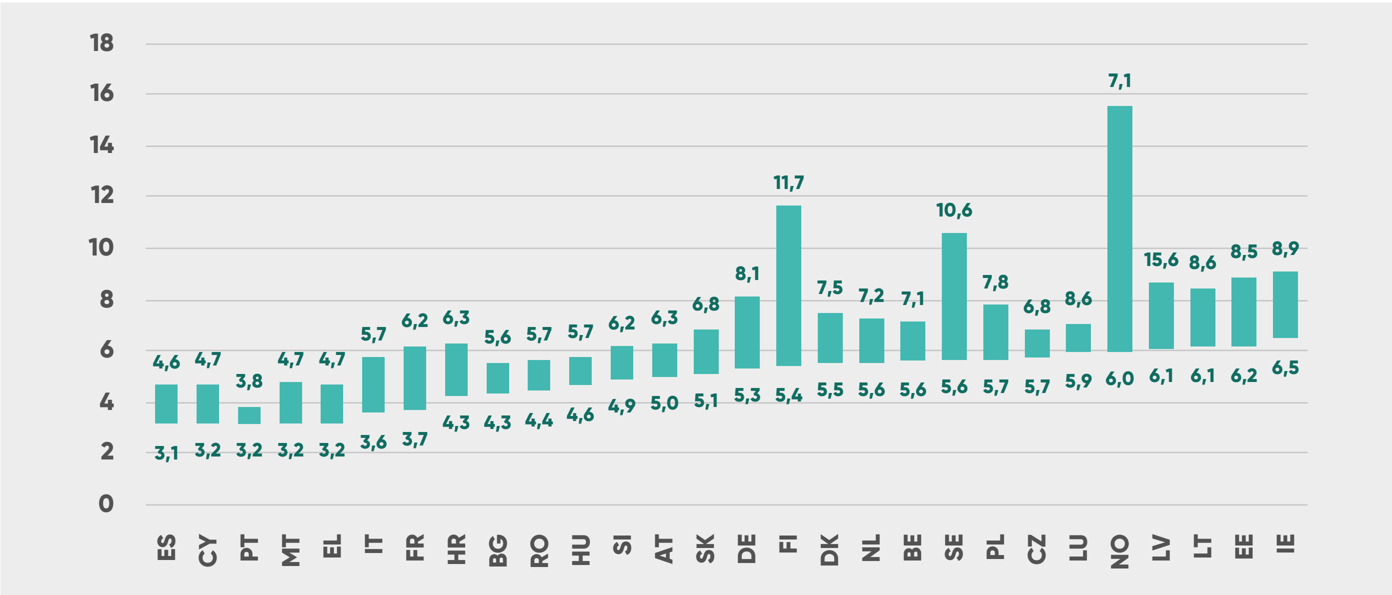
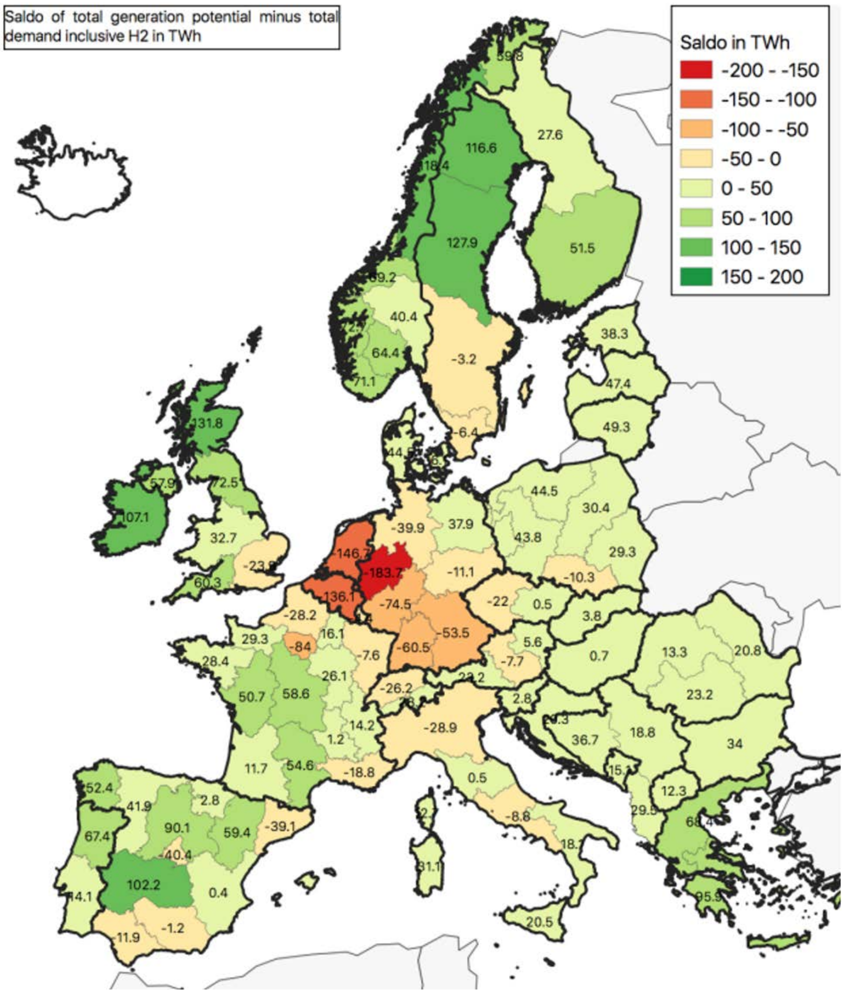


Figure 33: BALANCE OF RENEWABLE GENERATION POTENTIAL AND DEMAND WITH ELECTRICITY FOR HYDROGEN IN EUROPE 2050.
Source: WUPPERTAL INSTITUT FÜR KLIMA, UMWELT, ENERGIE.



Besides purely economic considerations, in some areas with intensive steel industry – like North-Western Europe or Silesia (PL), demand for hydrogen will be larger than what can possibly be produced locally, given the high population density in those areas and shortage of renewable resources.

Europe, in general, is also expected to maintain its reliance on energy imports in the future[53].

53 / See for example the RED II impact assessment by the EC or TYNDP 2022 projections prepared by ENTSOe and ENTSOg.

In countries with low carbon intensity power generation, like France, or the Nordic countries, the low-capacity factor of solar PV can be compensated by drawing electricity from the grid. On the contrary, in countries like Poland (as already shown), relying on the grid isn't viable, as it would lead to an overall increase in GHG emissions.

Considering those EU location differences and related challenges, we briefly analyse potential alternative scenarios below for scoping a solar-based, power-to-gas project, in the steel sector.

These alternative scenarios include:

- **Upscaling RES.** In the base case scenario, the solar PV was sized so that it would generate enough energy required for the production of hydrogen needed to decarbonise a 4 Mt steel plant. Electricity consumption for the EAF was assumed to be drawn from the grid. In certain locations with abundant solar PV resources, it might be however possible to up-scale RES to the point where it could also be used to supply the electricity needed by the EAF.

- **Imported hydrogen.** In locations where there is a lack of low-cost renewables and where new renewables are needed as a priority for power grid decarbonisation, the only option to switch to the H2-DRI-EAF route might be through importing renewable hydrogen from outside of the EU.

- **Grid-connected electrolysis**. In areas where there is a shortage of renewable resources, and where it is not possible, (e.g. due to geological constraints or high population density), to build new large scale underground storage or hydrogen pipelines, hydrogen production in situ - with electrolysers connected to the power grid might be electrolysis supplied by the power grid might be the only available option. In such a scenario a centralized hydrogen production would be fully integrated with the DRI-EAF plant. All electricity for hydrogen generation and EAF would go through the power grid. In order to deal with RES variability, a combination of measures, like small local buffer H2 storage, BESS and overcapacity of RES or electrolyser would have to be employed. On the other hand, grid-connected electrolysis would offer additional potential benefits (and revenue opportunities) from ancillary services provided to the electricity grid operator.

8.2 Upscaling RES

In the base case, it was assumed that the solar PV installation would be off-grid, which determines the optimal RES to electrolyser power ratio. To maximize electrolyser capacity utilization as well as avoid excess RES curtailment, in the base case, we assumed a total of 4,5 GW of electrolysis connected (most likely in several locations) to solar PV farms with a total installed capacity of 6,4 GW.

If, however, there would be a possibility to connect the solar PV power plants to the grid and export excess generation - which could not be utilized by the electrolyser - it would allow to further up-scale the solar PV plants and thus further increase the capacity factor of the electrolyser. A higher capacity factor of the electrolyser would in turn not only decrease the levelized cost of hydrogen but also reduce the required amount of storage (as with a smoother production profile, more hydrogen could be delivered directly to the DRI-EAF plant avoiding storage).

Furthermore, the current regulatory framework, as it is defined in the Renewable Energy Directive (RED II), only puts additionality and temporal correlation requirements on the renewable electricity used for hydrogen generation. No such obligation exists for direct electricity consumption in industry - for example to power the electric arc furnace. It would be therefore possible to export excess renewable electricity generation from the solar PV assets to the grid and then later “claim it” for the purpose of proving the renewable character of electricity used for EAF – irrespective of whether the electricity was generated at a time when it was consumed or not.

It is, therefore, possible to design the project set up in such a way, that solar PV assets would generate a roughly equivalent amount of excess electricity to the electricity demand of the DRI-EAF installation.

In order to achieve this result in the set location in Romania (given local solar irradiation conditions), the total installed

power of the solar PV plant would have to be around 9 GW (with a grid connection of around 4,2 GW).

In addition to covering all electricity demand with renewable energy generation, such an approach would also result in a reduction of the required hydrogen storage capacity by 4 000 tonnes and a reduction of electrolyser capacity required to produce the needed amount of hydrogen (due to higher utilization) from 4,4 GW to 3,7 GW.

The advantage of this approach is that it allows the production of fully renewable steel via the electricity guarantees of origin (GO) scheme. Being able to use low-cost renewable electricity for a higher portion of the electricity consumption, as well as increased electrolyser utilization reduces the gap to the BF-BOF route by around 20 EUR/tCS in both price scenarios, lowering the CO2 break-even point to 120 EUR/tCO2 (from 140 EUR/tCO2 in the base case scenario).

Figure 34: ENERGY FLOWS IN WITH OVERSIZED SOLAR PV.
Source: HYDROGEN EUROPE.

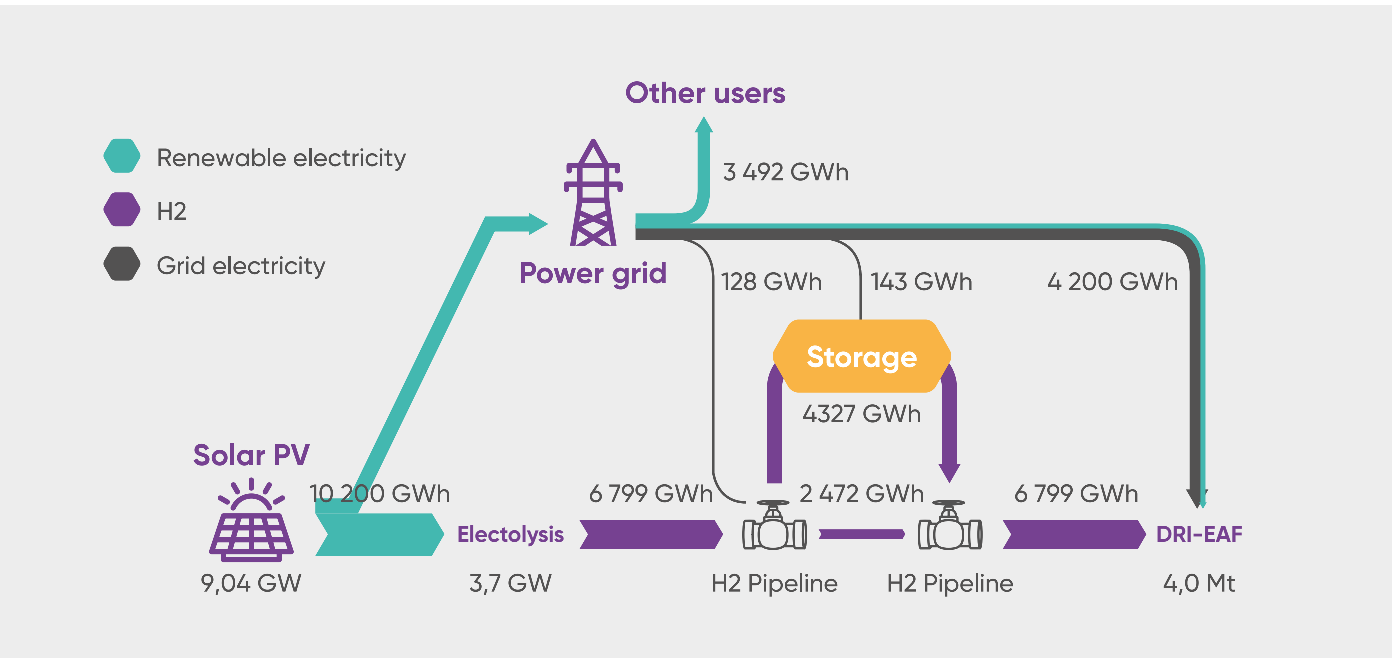
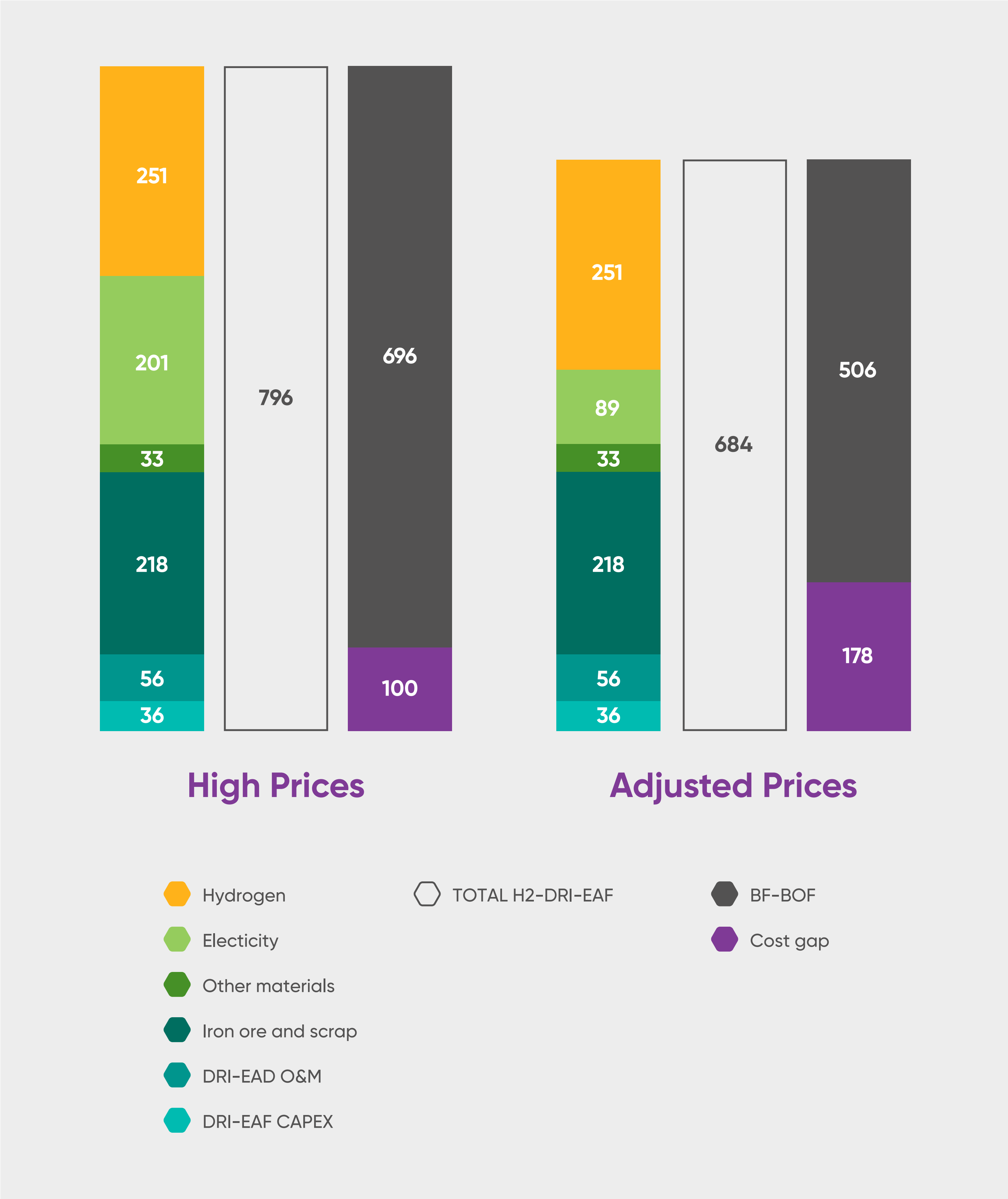


Figure 35: ESTIMATED LEVELIZED GREEN STEEL PRODUCTION COSTS (IN EUR/T).
Source: HYDROGEN EUROPE.



The results suggest that the upscaling of renewables relative to the electrolyser is a sound strategy. There are, however, several potential limitations. First the solar PV plant would have to have access to the power grid. For gigawatt-scale installations, like the ones needed for the steel sector, it is likely that the PV farms would be located in remote areas where possibilities for power grid connections might be limited – even if the power connection would need to cover only a fraction of the total PV farm installed power.

Second, negotiating a favourable PPA with a PV farm developer for such an arrangement would clearly be more challenging. The variability of the residual RES output would be significantly higher than the standard solar PV production profile. Consequently, it would not be a very attractive product on the PPA market, leaving the spot day-ahead electricity market as the only option. This would increase the overall risk of the RES project, potentially increasing the asking price above the "standard" LCOE level.

Another challenge is related to the sheer scale of the required RES capacity. As shown, given that at least 6 GW of solar PV would be needed to decarbonise an average-size steel plant, to make a meaningful impact on the electrolyser capacity factor, any RES over-dimensioning, would have to be measured in gigawatts as well.

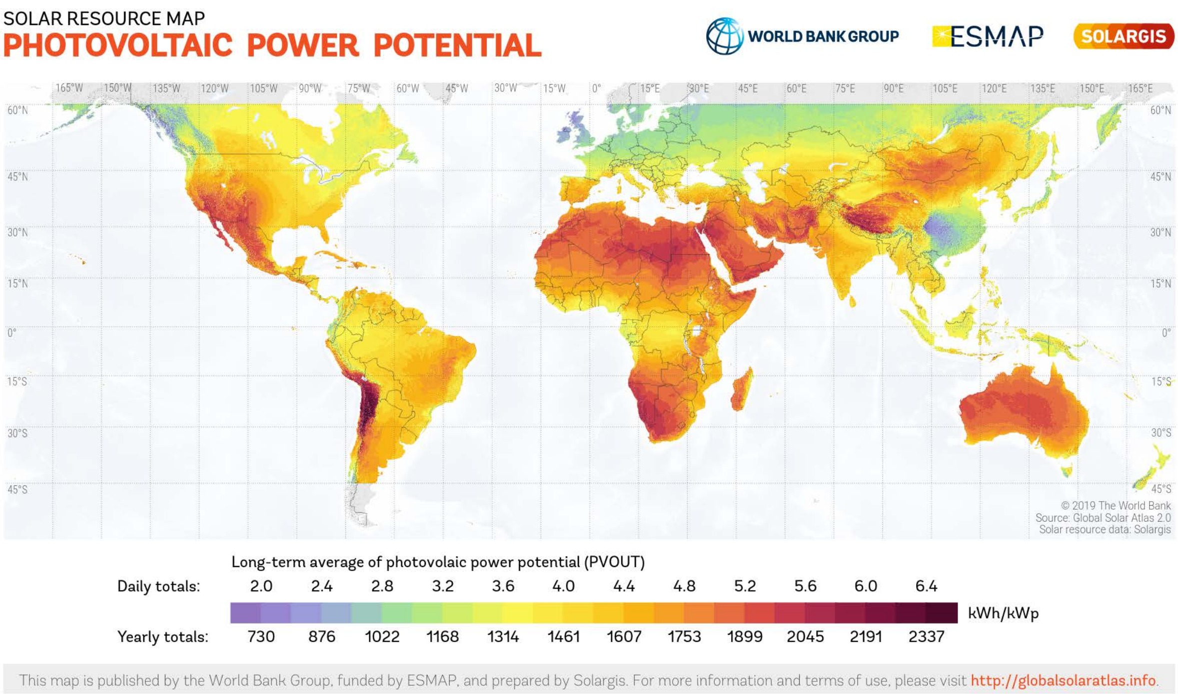
Taking all of the above into consideration, it is extremely difficult to see the RES upscaling strategy being considered outside of smaller projects, in the maximum range of 100-200 MW of electrolysis.

8.3 Imported hydrogen

In locations where there is a lack of low-cost renewables and where new renewables are needed as a priority for power grid decarbonisation, the only option to switch to the H2-DRI-EAF route might be through the use of renewable hydrogen imported from outside of the EU.

An example of such case might be Poland. Both primary steel production plants are located in heavily industrialized areas, with below average conditions for both onshore wind as well as solar PV developments. While the Baltic Sea offers some opportunities for low-cost renewable energy developments in the future, due to the fact that the Polish power mix is one of the most carbon intensive in the entire EU most offshore wind farms developers, are primarily targeting the electricity market and dedicated hydrogen production is rarely considered. It is therefore difficult to see that in the short to medium term, it would be possible

Figure 36: GLOBAL PV POWER POTENTIAL. **Source:** THE WORLD BANK GROUP. HTTP://GLOBALSOLARATLAS.INFO



to produce renewable hydrogen in Poland at a cost level and in quantities required to decarbonise the Polish primary crude steel production.

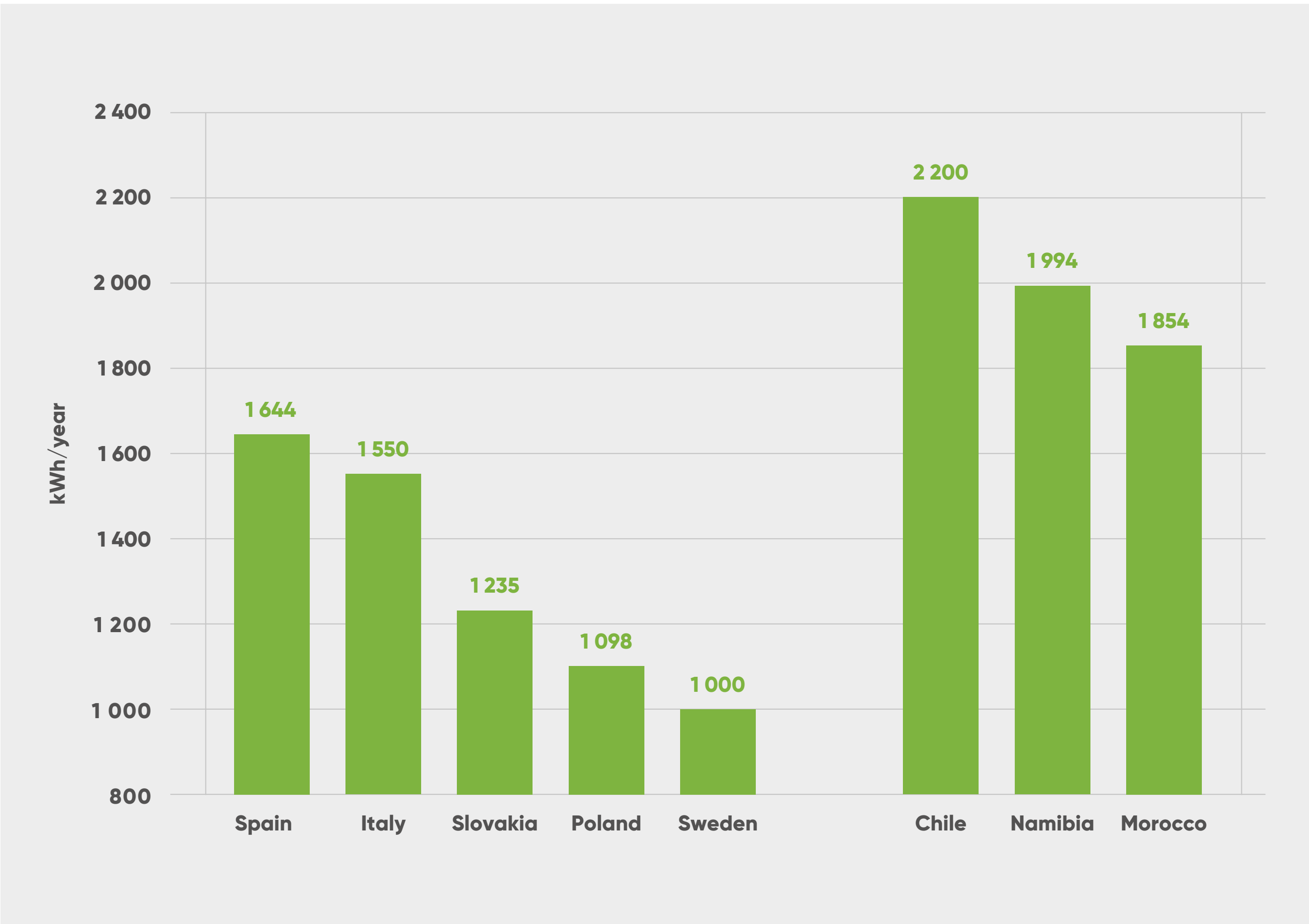
On the other hand, renewable energy potential significantly varies depending on geography and some parts of world are comparatively better suited for low-cost renewable energy production than Europe.

The World Bank provides an overview of solar irradiation and wind speeds in the world providing information on the most efficient production spots for wind and solar, and as the World Bank's Global Solar Atlas shows there are large variations in solar irradiation both within Europe as well as compared to some of the countries with the highest solar irradiation outside of Europe.

The difference in annual solar PV yield can be substantial. In Poland every 1 kWp of solar PV (without PV tracking) produces at most around 1 100 kWh, while the same panel, for the same investment, produces close to 1 900 kWh in Morocco, almost 2 000 KWh in Namibia and 2 200 KWh in Chile.

These large differences in solar productivity directly translate into different production costs of hydrogen around the world. The IEA in their latest Global Hydrogen Review estimated that by 2030 the hydrogen production cost in Namibia or Saudi Arabia could reach 1,5 EUR/kg with production costs in Chile even below that. The difference between central or northern Europe vs southern Europe and outside of Europe on large scale can be even 3-4 EUR/kg.[54]

Figure 37: ANNUAL SOLAR PV YIELD PER 1 KWP (WITHOUT TRACKING).
Source: HYDROGEN EUROPE BASED ON DATA FROM HTTP://GLOBALSOLARATLAS.INFO



However, importing hydrogen to Europe from other continents will involve a lengthy and complicated logistics chain.

For liquefied hydrogen the supply chain would somewhat resemble the LNG supply chain with hydrogen production and liquefaction in the country of origin, in turn shipping and regasification terminals in the country of destination, where preferably hydrogen would be injected into local hydrogen grids.

A similar process would apply to other hydrogen carriers like ammonia or methanol whereby liquefaction would be replaced with fuel synthesis. The benefit of using other carriers than pure hydrogen is that they offer higher energy density, reducing transportation costs. Furthermore, in case of ammonia and methanol there are already multiple sea terminals in operation in Europe, as well as ships capable of transporting them, since ammonia and methanol are already globally traded commodities. On the other hand, the benefits of higher energy density can be outweighed by additional costs of dehydrogenation (e.g. ammonia cracking) in the country of destination. Being able to avoid dehydrogenation costs by using those 'carriers' directly, can greatly improve the business case.

Figure 38: LIQUEFIED HYDROGEN SUPPLY CHAIN.
Source: HYDROGEN EUROPE.

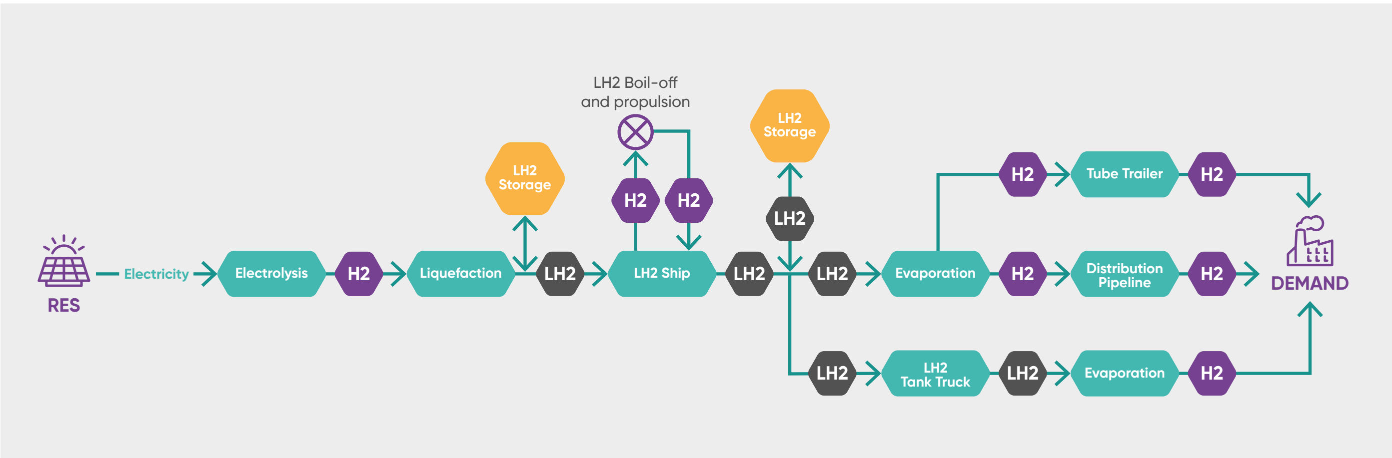
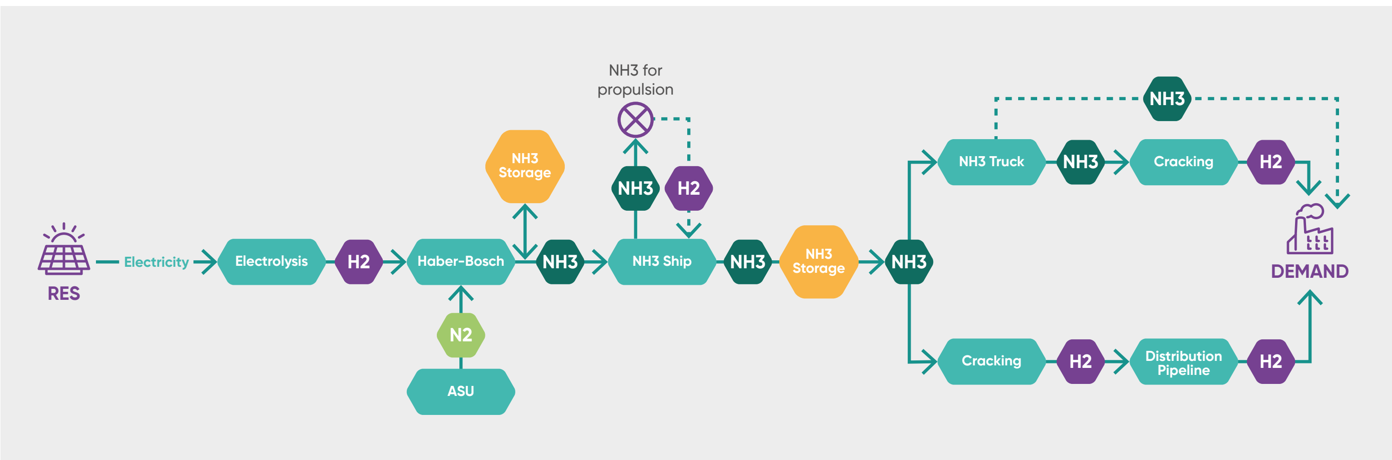


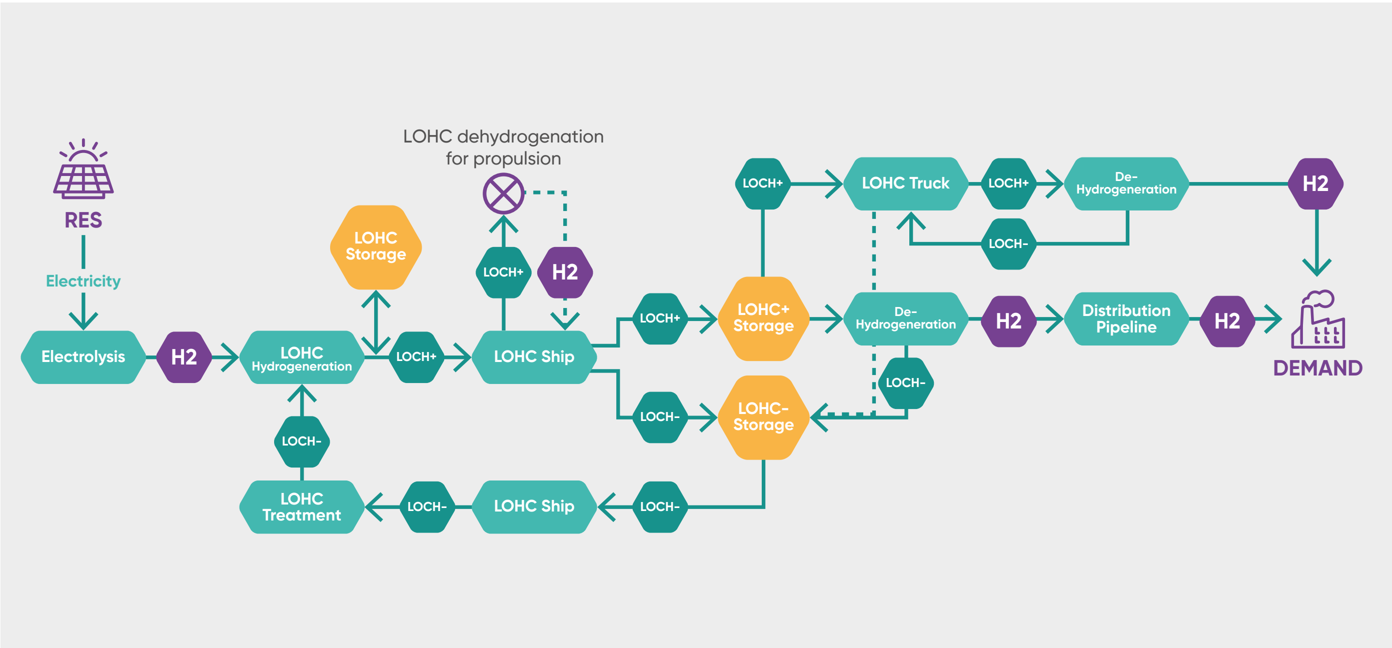
Figure 39: SUPPLY CHAIN FOR HYDROGEN IMPORT USING AMMONIA AS HYDROGEN CARRIER.
Source: HYDROGEN EUROPE.



54 / https://www.iea.org/reports/global-hydrogen-review-2021

The supply chain for LOHC would be slightly more complicated as it would have to include logistics of both hydrogenated and dehydrogenated carrier. On the other had it would allow to use the extensive and large scale infrastructure used for transportation and storage of petroleum products.

Figure 40: SUPPLY CHAIN FOR HYDROGEN IMPORT USING LOHC AS HYDROGEN CARRIER.
Source: HYDROGEN EUROPE.



It's unfortunately extremely difficult to estimate the exact costs of imported hydrogen as it's a function of multiple variables, including the cost of hydrogen production in the country of origin of course but also hydrogen transportation costs, storage requirements, further distribution costs in the country of destination, etc.

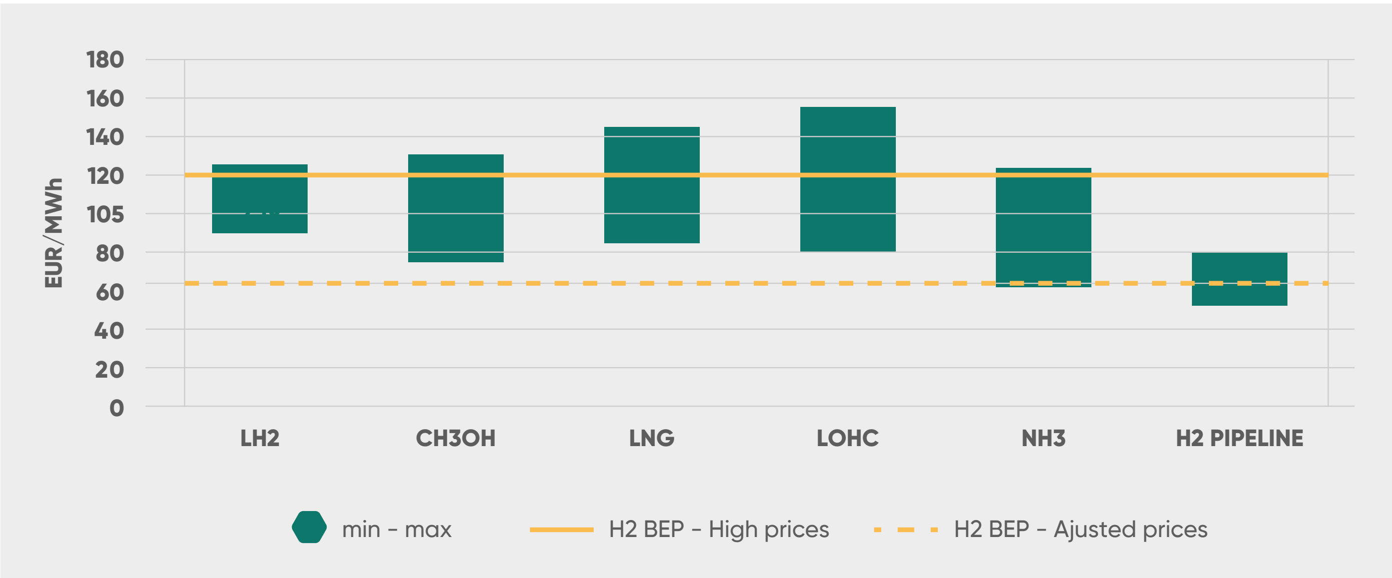
As was previously calculated the required break-even price of delivery for hydrogen is around 1,5 EUR/kg in the 'adjusted prices' scenario and 3,0 EUR/kg in the 'high prices scenario'. This means that if the current high prices on energy markets were to fall (i.e. the adjusted prices scenario') hydrogen imports for use in the steel sector would be extremely challenging, since the breakeven point is already close to the lowest hydrogen production costs. If 1,5 EUR/kg is the required level, the only viable option for using imported hydrogen is pipeline transport, which limits the importing countries to the MENA region, Turkey, UK, Norway or Ukraine. For all hydrogen shipping options, even the most optimistic estimates have a higher end price than the required 1,5 EUR/kg.

Consequently, in countries with no access to low-cost renewables, a better alternative for steel decarbonisation might be to use waste-to-hydrogen technologies or to use "blue" hydrogen instead (or next to) renewable hydrogen. Hydrogen produced in a natural gas-fired autothermal reforming (ATR) plant with CCS promises a 95% CO2 emission reduction, with the added advantage of steady hydrogen flow. A similar effect could be achieved using zero-emission nuclear power to supply the electrolysers.

On the other hand, if the current high energy prices were to persist, hydrogen imported by ships from destinations further away than the EU neighbouring countries could be viable – as is shown on the below graph depicting hydrogen import costs estimates from various recent studies.

Figure 41: COMPARISON OF HYDROGEN IMPORT COSTS TO THE REQUIRED BREAK-EVEN COST.
Source: HYDROGEN EUROPE.
Note: THE COST RANGE IS DEFINED BASED ON RESULTS FROM VARIOUS STUDIES AND COUNTRIES, WHERE **LOWER RANGE** IS MOST OPTIMISTIC STUDY AND LOWEST COST EXPORT COUNTRY AND **HIGHER RANGE** IS THE MOST PESSIMISTIC STUDY FROM HIGHEST COST EXPORT COUNTRY. ALL OPTIONS OTHER THAN "H2 PIPELINE" ARE BASED ON IMPORTS VIA SHIPPING.
Studies included are:

- TYNDP2022.
- Hydrogen Import Coalition final report.
- ENTEC – The role of renewable hydrogen import and storage to scale up the EU deployment of renewable hydrogen.
- Import options for chemical energy carriers from renewable sources to Germany.
- Cost of long-distance energy transmission by different carriers.
- Methanol as a renewable energy carrier: An assessment of production and transportation costs for selected global locations.
- Energy efficiency and economic assessment of imported energy carriers based on Renewable electricity.
- Internal study by Hydrogen Europe.



One should also note that there are several potential additional pathways which could make the import option for steelmaking more attractive, but which demand further research and case-by-case analysis.

First, for hydrogen carriers like ammonia, methanol or LOHC, one of key costs of the entire supply chain, sometimes responsible for more than 1/3 of all costs is the dehydrogenation step, i.e. extracting hydrogen back from those carriers. Whether its ammonia cracking or LOHC dehydrogenation, usually those processes require heat. In industrial settings like steel plants, there might exist plenty synergy opportunities to use existing waste heat sources and reduce the costs of dehydrogenation – potentially even almost to zero.

Secondly, direct use of ammonia in the direct reduction of iron ore, is an emerging alternative that could solve the reconversion losses in H2 shipping using ammonia as a carrier[55].

55 / J. C. Laguna, J. Duerinck, F. Meinke-Hubeny, J. Valee, Carbon-free steel production ;Cost reduction options and usage of existing gas infrastructure, EU Panel for the Future of Science and Technology, March 2021, ISBN: 978-92-846-7891-4.

Finally, in case of steel production using the H2-DRI-EAF route, it is possible to decouple the H2-DRI from EAF installation. It would therefore be possible, instead of importing hydrogen, to use hydrogen directly in the country of origin in a reduction shaft and use the renewable briquetted iron as the "hydrogen carrier" to deliver renewable energy to EAF units in the EU.

8.4 Grid-connected electrolysis

Practical considerations

In areas where there is a shortage of renewable resources, and where it is not possible to build new large scale underground storage and hydrogen pipelines, e.g. due to geological constraints or high population density - hydrogen production in situ, with electrolysis supplied with energy via the power grid, might be the only available option.

This might be the case, for example, for steel plants in North-Western Europe, for which the base option described in the previous chapter might not be available until after the European Hydrogen Backbone is in place (after 2030).

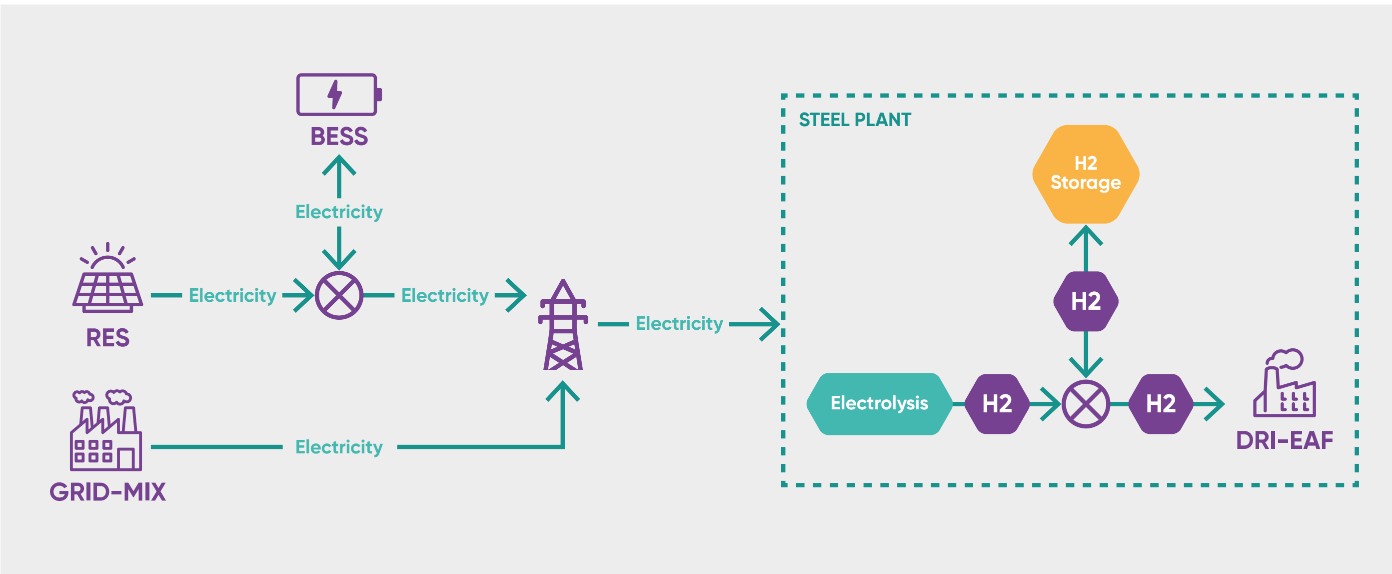
In such a scenario a centralized hydrogen production would be fully integrated with the DRI-EAF plant. All electricity for hydrogen generation and EAF would go through the power grid.

A real-life example of this approach would be the HYBRIT project in Sweden.

The biggest challenge of this approach – especially if one would like to use exclusively solar PV as the main source of energy - would be to manage the variability of energy supply. Direct reduction shaft needs to run continuously, which also means hydrogen supply would have to be steady throughout the year.

The direct equivalent of the previous approach would be to use solar PV in combination with BESS, instead of underground hydrogen storage and, instead of 'flattening' the hydrogen supply profile, using batteries storage, to smoothen the electricity supply curve. Given the size of the necessary storage, however, this would be impractical. Even a small battery storage, sufficient just for 4 hours of electricity consumption of an electrolyser at an H2-DRI-EAF plant operating at baseload with a capacity of 4 Mt of crude steel per year, would require a battery storage capacity of close to 4,7 GWh (i.e. 3 x larger than the world's biggest battery

Figure 42: BASIC SCHEMATIC DIAGRAM OF GREEN STEEL PRODUCTION WITH LOCAL, GRID-CONNECTED ELECTROLYSIS.
Source: HYDROGEN EUROPE.



storage facility in Moss Landing, US). It would still, however, be highly insufficient for a steel plant of this size, as in order to ensure a steady flow of hydrogen to a reduction shaft, , assuming solar PV is the only power source, the required electricity storage capacity would be more than 2,3 TWh (and cost EUR 400 billion). BESS can therefore be used as a support to other measures but it won't solve the issue in a meaningful and cost competitive way.

Another approach would be to ensure overcapacity of RES over the electrolyser power, to increase the electrolyser capacity factor. At the gigawatt scale, which is what is needed for the steel industry, this approach would however be difficult to implement, as the over-contracted amounts of RES would also have to be measured in gigawatts to make any meaningful impact.

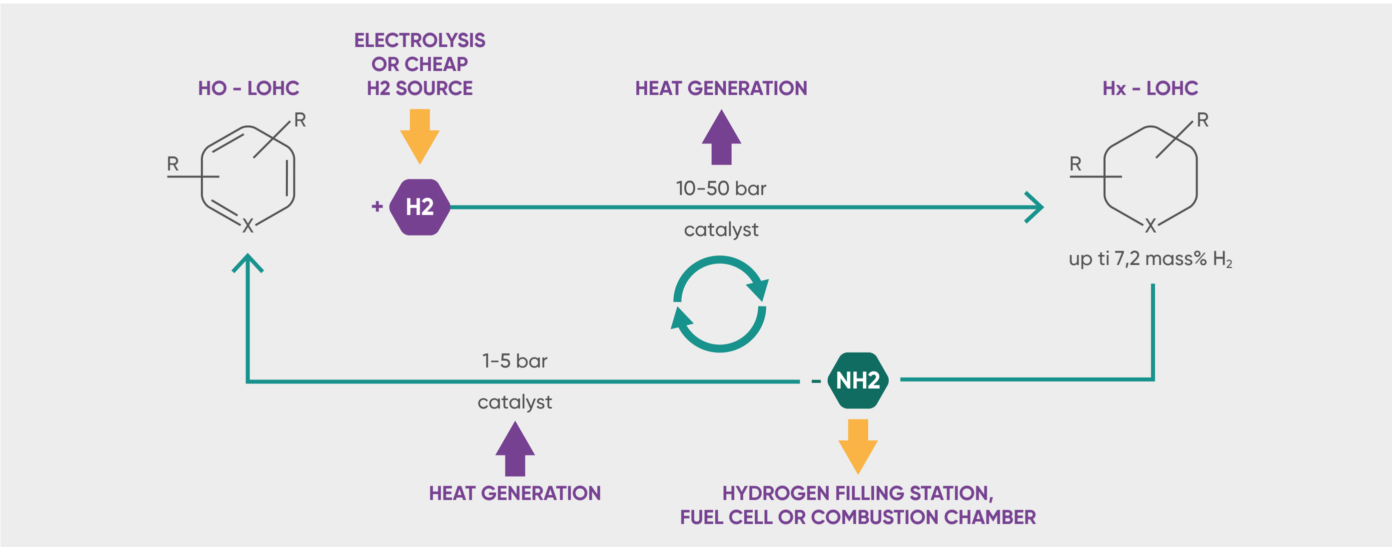
Filling the gaps with generation from existing renewables (especially steady flow hydropower) might also not be an option due to the risk that the RES additionality requirement in the RED II would be extended to cover also hydrogen used in industry.

Large scale, local, hydrogen storage in an aboveground tank, would also be problematic in this case. As calculated in the previous chapter, in order to be fully reliant on solar PV as a power source, one would need a significant amount of storage – well beyond what is possible using aboveground compressed hydrogen storage (not to mention costs, which would exceed EUR 30 billion).

A potential solution might be to use liquid organic hydrogen carriers (LOHC) for local hydrogen storage. As LOHC hydrogenation releases heat and dehydrogenation requires heat, there are some potential synergies to be gained with the integration of a LOHC system in an industrial environment, where industrial waste heat could be used for the dehydrogenation process.

As a recent study has shown, using an example of cement plants, integration of the LOHC system into a cement plant allows for optimized utilization of waste heat. The exhaust heat from the cement plant can increase the efficiency of the storage system. The effectiveness of the LOHC system can be elevated by 12 percentage points. The electricity costs of the cement plant can be significantly reduced by adding a LOHC storage system.[56] There is no reason similar benefits could not be realised in a steel plant.

Figure 43: SCHEMATIC VIEW ON HYDROGEN STORAGE USING THE LOHC SYSTEM.
Source: P. PREUSTER, C. PAPP, P. WASSERSCHEID, LIQUID ORGANIC HYDROGEN CARRIERS (LOHCS): TOWARD A HYDROGEN-FREE HYDROGEN ECONOMY, 2016, ACCOUNTS OF CHEMICAL RESEARCH, 50(1), 74–85.



56 / C. Krieger, K. Müller, W. Arlt, Coupling of a Liquid Organic Hydrogen Carrier System with Industrial Heat, Chemical Engineering & Technology, Volume 39, Issue 8, August, 2016, Pages 1570-1574.

While the size of the required storage system would remain a challenge, it would at least theoretically be possible, as standard 100 000 m3 vertical oil storage tanks could be used to store LOHC.

Besides the required size of storage, another problem with onsite management of RES variability would be that it would require scaling up the size of the electrolysis system. If one would want to be able to produce hydrogen for storage at times where there is oversupply of RES power, additional electrolysis capacity would have to be provided. This would not only lead to higher CAPEX but will also exacerbate the second big challenge when it comes to using grid-connected local electrolysis for steel, namely – grid capacity constraints.

In order to supply a constant stream of hydrogen for a 4 Mt steel plant, the minimum size of the electrolyser would be 1,2 GW. Adding to that the power demand for the EAF and other electricity uses in the H2-DRI-EAF setup, the total power demand would be around 1,6 GW. It is highly unlikely that there are many steel plants in Europe where the grid operator is capable of supplying this amount of additional power without significant grid upgrades.

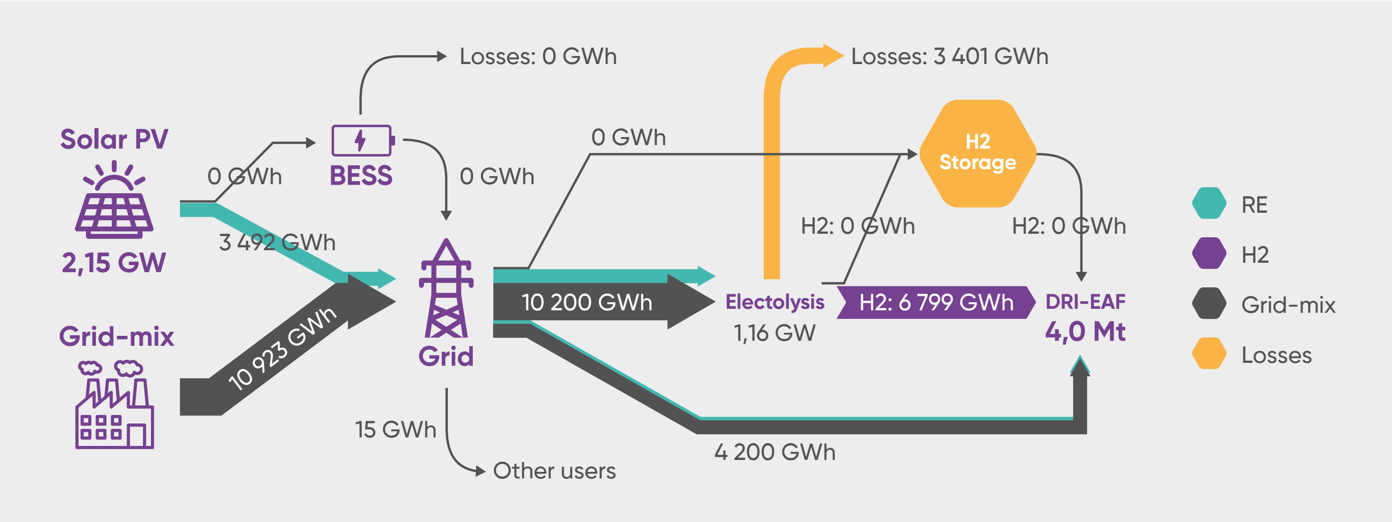
This would be challenging enough for an H2-DRI-EAF plant, with the electrolyser operating at baseload. If, however, the RED II/III would impose strict temporal correlation requirements for renewable hydrogen production, thus demanding the electrolysis plant to operate in load-following mode, the required grid connection capacity would grow even further. For solar PV it would be 4,5-5,0 GW.

Of course, both storage and grid capacity problems are exacerbated in the analysed example because of the reliance on solar PV only, which has a limited capacity factor. Using a mix of various renewable sources, preferably with negatively correlated generation profiles – e.g. solar PV and onshore wind, would alleviate the problem to a degree. But it would not eliminate it. Even if through a combination of measures, like optimizing the mix of renewables, over-contracting RES and some battery storage, it would be possible to increase the overall RES capacity factor to 6 000 full load hours equivalent, the required grid connection would still be around 2,2 GW for an H2-DRI-EAF plant with an annual production capacity of 4 Mt of crude steel. To fully decarbonise the largest steel plant in Europe – the Thyssenkrupp plant in Duisburg, would require 6,6 GW of power supply.

In the transition period, this could be managed by gradual conversion from BF-BOF to H2-DRI-EAF, one blast furnace at a time, to ease the growth of the required power. A mix of hydrogen and natural gas could also be used in the reduction shaft to decrease the reliance on renewable hydrogen. Another alternative might be to use "blue" hydrogen instead (or next to) renewable hydrogen. Hydrogen produced in a natural gas-fired autothermal reforming (ATR) plant with CCS promises a 95% CO2 emission reduction, with the added advantage of steady hydrogen flow. A similar effect could be achieved using zero-emission nuclear power to supply the electrolysers.

All things considered, however, it is highly unlikely that an H2-DRI-EAF plant, based on renewable hydrogen, could

Figure 44: SOLAR PV BASED, GRID-CONNECTED H2-DRI-EAF SETUP - OPTION 1.
Source: HYDROGEN EUROPE.



ever operate without some degree of reliance on grid-mix electricity. A combination of measures, like small local buffer H2 storage, BESS and overcapacity of RES or electrolyser might be employed to reduce the use of grid electricity but it is difficult to see how it could be eliminated entirely.

For this reason, we envisage 5 potential options for a green steel project with a grid-connected central electrolysis, relying on solar PV for hydrogen production.

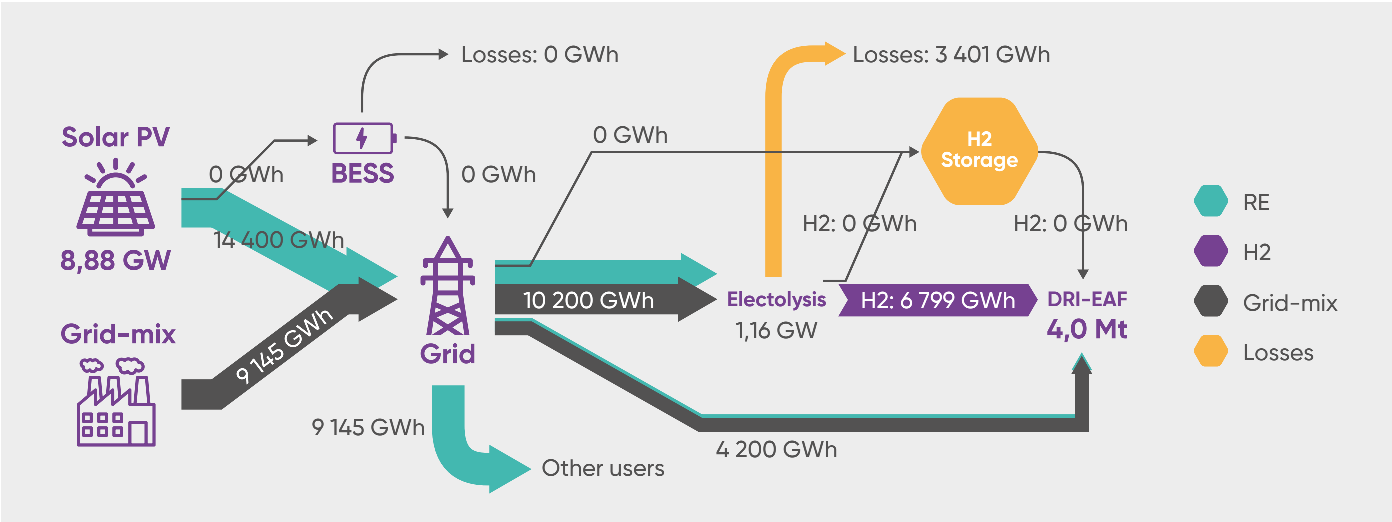
Option 1 would be to dimension the solar PV plant so that at the maximum output level it would generate enough electricity to cover 100% power demand of the water electrolysis installation.

Thus, the entire solar PV output would be used by the electrolysers with no need to export any generation to the grid. The electrolyser would be operated at full load for the entire year to ensure a constant flow of hydrogen to the reduction shaft. Any electricity demand, which could not be covered by the solar PV generation would be just taken from the power grid. No electricity storage or hydrogen storage would be needed in this case (outside of a small operational buffer tank).

Continuing with the Romania example (assuming solar PV utilization of around 1 600 full load hours) to ensure no export of electricity to the grid is needed, the maximum size of the solar PV farm(s) would be around 2,1 GW, delivering around 3,5 TWh of renewable electricity to the H2-DRI-EAF plant. Renewable energy supply would have to be complemented by almost 11 TWh of grid-based electricity, meaning that renewable energy would constitute just shy of a quarter of the total energy consumption. Taking only hydrogen production into account, the RES share using this approach would be 29%.

As a result, even though there would no direct CO2 emissions, the final crude steel product could not be considered renewable, as there would be significant indirect emissions related to grid electricity supply. In all but two EU countries, the net GHG emission balance would be positive with the average EU-27 benefit of 1,27 tCO2/tCS. Only in Poland and Estonia, would this approach lead to an increase of GHG emissions – and even there the overall balance would be close to zero.

Figure 45: SOLAR PV BASED, GRID-CONNECTED H2-DRI-EAF SETUP - OPTION 2.
Source: HYDROGEN EUROPE.



Furthermore, if the revision of the RED II directive, proposed in the Fit-for-55 legislative package (i.e. RED III), would be adopted as per the European Commission's proposal, i.e. requiring that by 2030 at least 50% of hydrogen consumed for industrial uses, should be of renewable origin, Option 1 would fail to meet the requirement.

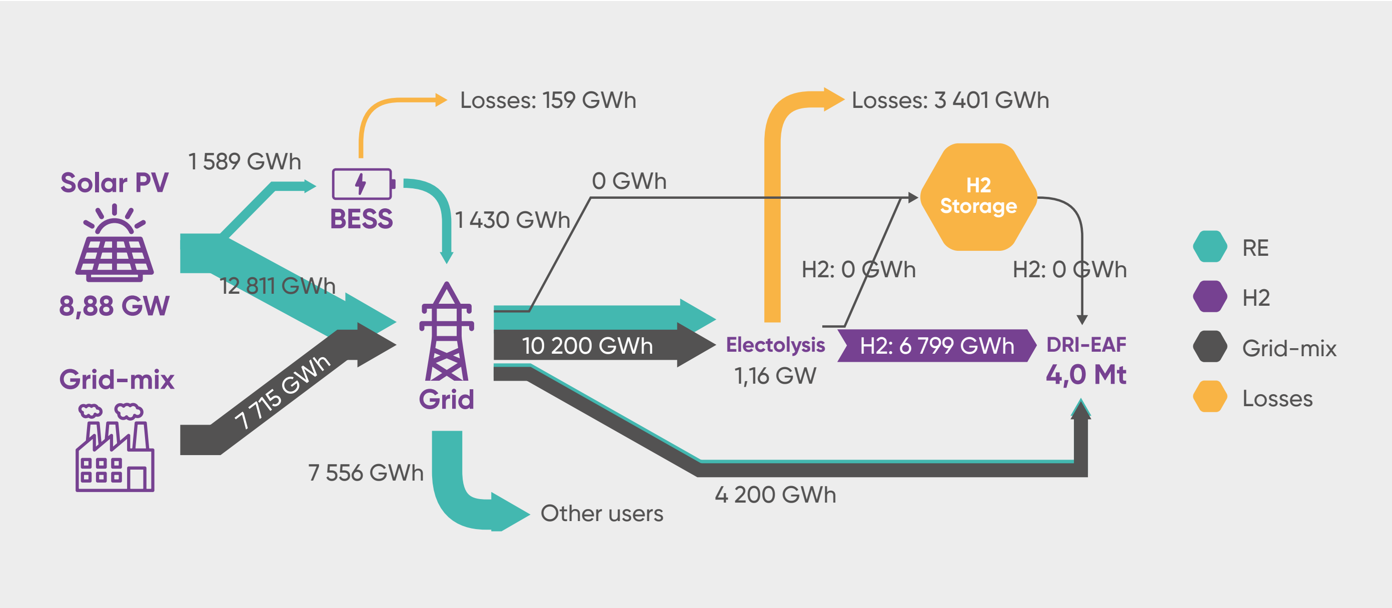
Option 2 would be to dimension the solar PV plant so that the total amount of renewable electricity it would generate on an annual basis would be equal to that of the total electricity demand of the H2-DRI-EAF plant (around 14,4 TWh/y for a plant with a CS production capacity of 4 Mtpa).

The electrolyser would be operated at full load for the entire year to ensure a constant flow of hydrogen to the reduction shaft. Any electricity demand, which could not be covered by the solar PV generation would be just taken from the power grid. No electricity storage or hydrogen storage would be needed in this case (outside of a small operational buffer tank).

Producing such an amount of renewable energy, with the assumed solar PV capacity factor would require close to 9 GW of new solar PV assets. Still – due to the absence of energy production at night and solar irradiation seasonal variability, only around 36% of energy output could be used "directly". Thus, around 9,1 TWh would still need to be exported to the grid and a corresponding amount drawn from the grid at other times to keep the electrolyser running at full load. Excluding electricity used for EAF, renewable share in hydrogen production would be around 38% - still a long way out from the 50% RED III target.

Assuming there is no curtailment of the excess solar PV generation, and the entire excess output could be exported to the grid, the carbon footprint of the produced steel should still be considered to be zero. In fact, it could even be negative, considering that the electricity drawn from the grid would be mostly at night, i.e. when there is a high concentration of renewable wind energy in the power system, and energy export to the grid would take place during the day, when there is a higher chance it would

Figure 46: SOLAR PV BASED, GRID-CONNECTED H2-DRI-EAF SETUP - OPTION 3.
Source: HYDROGEN EUROPE.



replace fossil-based power generation. **However, if it is not possible to claim the energy taken from the grid as renewable via a guarantee of origin system, due to, e.g. a strict regulatory requirement for temporal correlation of renewable energy production and use, hence it's difficult to see this as an attractive option for investors.**

Option 3 – would be to extend the previous approach and add BESS to the setup, in order to store and shift some of the excess RES power generation to a time where there is not enough of it and thus reduce the need for using grid-mix electricity.

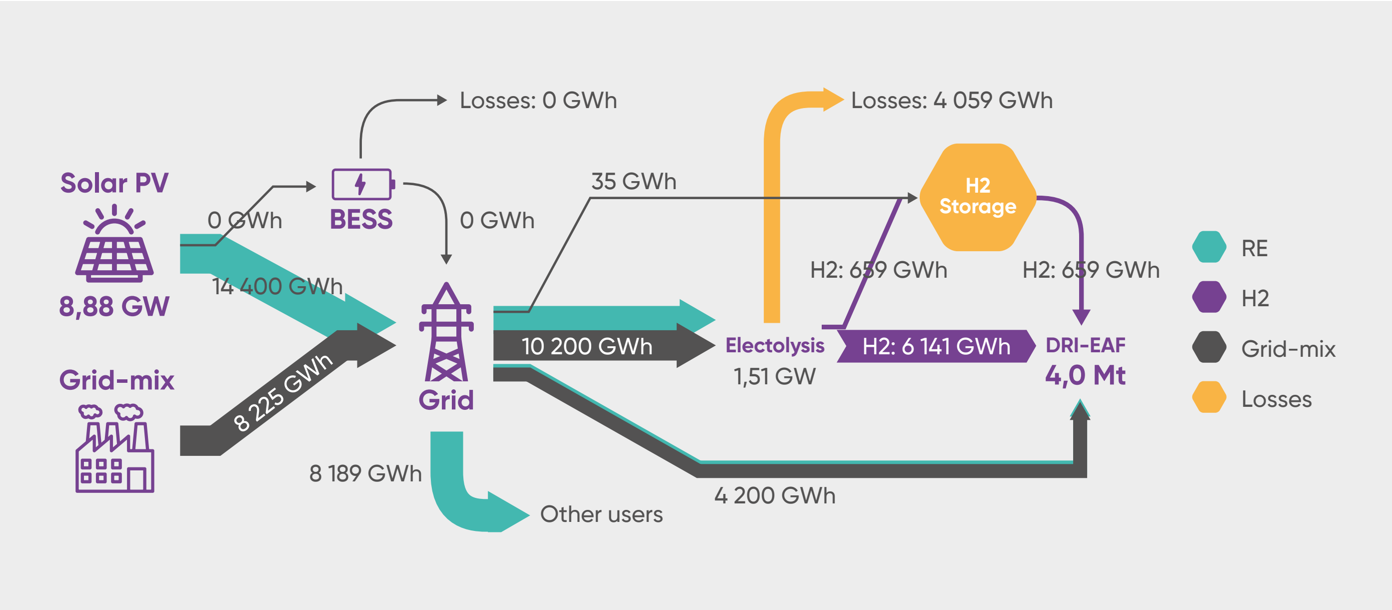
The electrolyser would still operate at full load, but now could be supplied with renewable electricity fulfilling a strict temporal correlation criteria, both directly and from the energy stored in a battery.

Assuming the BESS would be dimensioned so that it could provide enough energy for up to 4 hours of full load operation of the electrolyser, the total system size would have to equal 4,66 GWh. Assuming specific CAPEX for BESS of around 170 EUR/kWh and 40 EUR/kW[57], total additional investments would amount to EUR 1,6 billion.

This added investment would lead to a reduction in grid sourced electricity consumption by around 1,4 TWh/y at an additional levelized cost of around 116 EUR for each MWh of electricity drawn from the BESS. As a result of added renewable energy consumption, the total RE share in hydrogen production would rise above the 50% threshold and would reach 52%.

57 / Based on Lazard's levelized cost of storage version v.7.0.

Figure 47: SOLAR PV BASED, GRID-CONNECTED H2-DRI-EAF SETUP - OPTION 4.
Source: HYDROGEN EUROPE.



Option 4 – would be to replace the BESS with hydrogen storage on site.

Assuming that the electrolyser would be scaled up by 30% compared to the base scenario, hydrogen tanks with a total maximum capacity of around 100 tonnes would be needed to store hydrogen produced at times where the electrolyser output would exceed the DR process continuous hydrogen demand. Total hydrogen storage turnover would be around 20 ktpa (~10%).

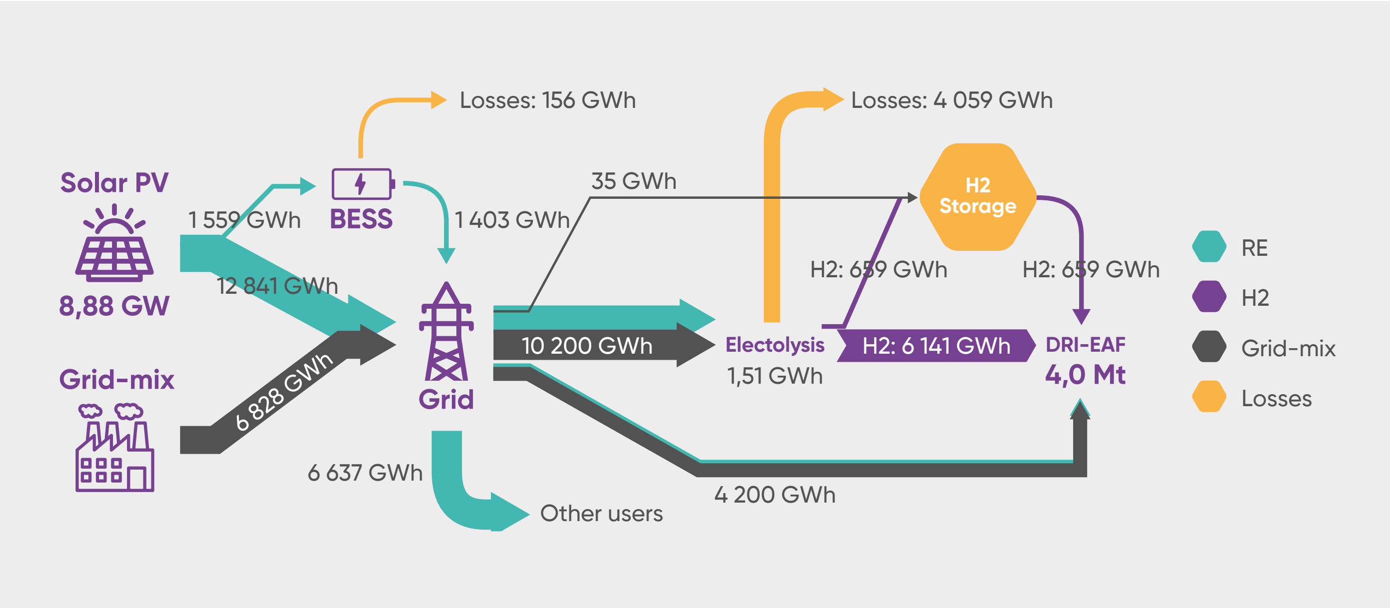
While the total amount of grid-mix electricity, which would have to be used is higher than in the BESS scenario (option 3), by around 0,6 TWh, the additional costs of Option 4 would be considerably lower. Including both extra expenses for 30% electrolyser oversizing as well as the above ground storage system capable of storing up to 100 tonnes of compressed hydrogen, total additional CAPEX would be around EUR 0,5 billion. The RE share in hydrogen production be roughly 48%, so not enough to clear the 50% threshold but high enough to suggest it would be possible with small tweaks to the setup.

Option 5 – would be to include both BESS and hydrogen storage on site.

The additional CAPEX in this case would be over EUR 2 billion compared to the base case, but it would allow the reduce the amount of grid-mix electricity used by 2,3 TWh. Using EU-27 average carbon intensity of electricity generation, this approach would increase the annual CO2 benefit, directly attributable to steel production, by around 1 Mt of CO2 per year. The RE share in hydrogen production would be almost 62%. It's also the only option where over 50% of electricity used by the entire H2-DRI-EAF plant would be renewable.

At the same time, from the overall system point of view, if all excess RES generation could be successfully exported to the grid, without resulting in any RES curtailment or grid congestion issues, the additional GHG benefits of this approach would be questionable.

Figure 48: SOLAR PV BASED, GRID-CONNECTED H2-DRI-EAF SETUP - OPTION 5.
Source: HYDROGEN EUROPE.



The following table summarizes all the analysed options.

Table 8: COMPARISON OF 5 ANALYSED OPTIONS FOR GRID-CONNECTED ELECTROLYSIS.
Source: HYDROGEN EUROPE. NOTE: 1 - EXCLUDING RES ,2 - BASED ON AVERAGE CARBON INTENSITY OF ELECTRICITY MIX FOR THE EU-27.

Parameter	Unit	Option 1	Option 2	Option 3	Option 4	Option 5
RES Power	GW	2,15	8,88	8,88	8,88	8,88
Electrolysis	GW	1,16	1,16	1,16	1,51	1,51
BESS capacity	MWh	-	-	4 658	-	4 658
H2 storage	t	-	-	-	100	100
H2-DRI-EAF CAPEX	EUR bn	2,94	2,94	2,94	3,30	3,30
Additional CAPEX for the storage system[1]	EUR bn	-	-	1,56	0,16	1,72
RES share in the H2 production	%	29	39	52	48	62
Grid-mix energy use	GWh	10 923	9 145	7 715	8 225	6 828
GHG footprint[2]	tCO2/tCS	0,63	0,53	0,44	0,47	0,38

Results and conclusions

Based on the above analysis and the same two prices scenarios, as previously, for each of the options, we have estimated the total crude steel production costs. The results have been summarized in the graphs below.

Figure 49: CRUDE STEEL PRODUCTION COSTS FROM GRID - CONNECTED ELECTROLYSIS, COMPARED TO THE BF-BOF ROUTE.
Source: HYDROGEN EUROPE. NOTE: * DC RES – SCENARIO WITH DIRECT CONNECTION TO RENEWABLES AND DELIVERY OF HYDROGEN VIA PIPELINE (AS DESCRIBED IN THE PREVIOUS CHAPTER).

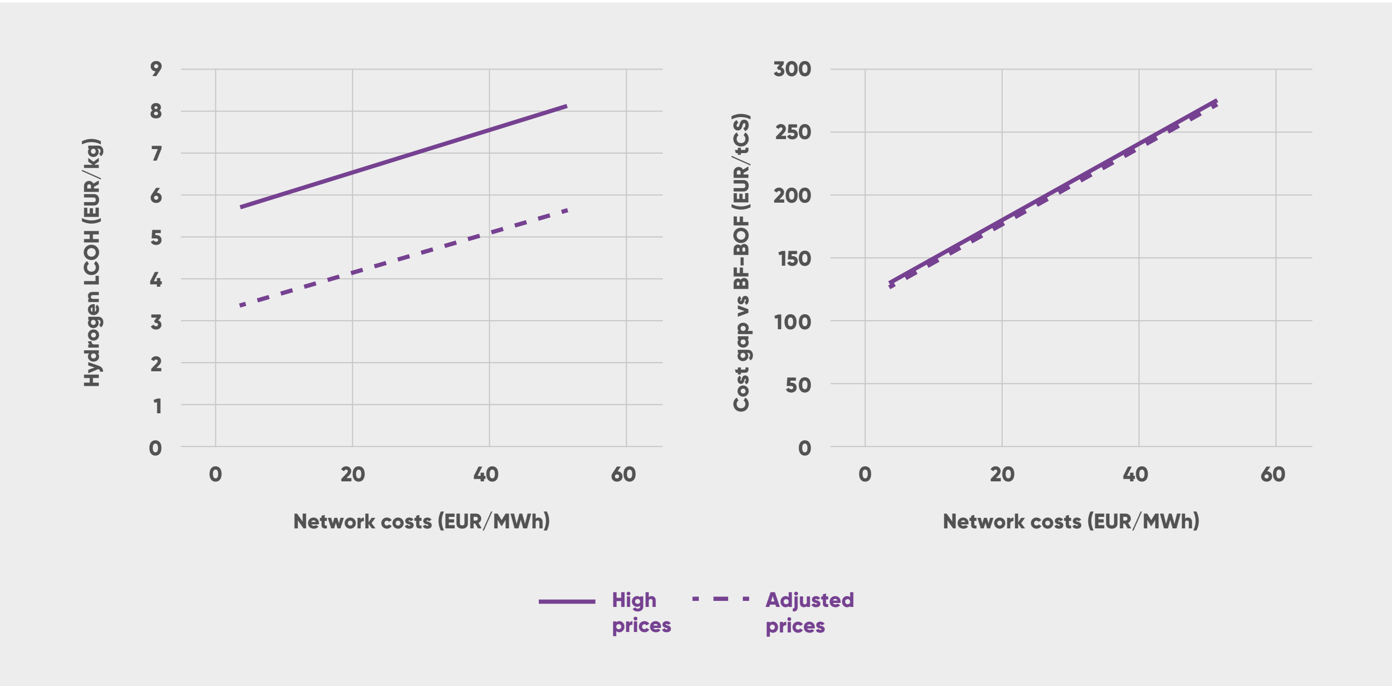
Generally, the cost analysis shows that the grid-connected, on-site electrolysis approach can be cost competitive with the approach of producing hydrogen near RE sources and delivery of hydrogen via pipeline (as described in the previous chapter). As this approach relies more on grid electricity than the other (where grid-mix electricity was only used for EAF), this approach is especially attractive in the case of "adjusted prices" – i.e. in a world with relatively low wholesale electricity prices. With current high electricity prices, this approach is not cost competitive anymore.

There are however several caveats one should keep in mind when assessing the viability of these two options, which go beyond a simple cost comparison, and which are just as important.

First, all analysed grid connected options besides option 1, would require significant overcapacity of installed renewable power, which results in excess renewable generation in a TWh order of magnitude, which would have to be sold on the spot day-ahead market. As already described, its challenging for multiple reasons and might not always be possible. On the other hand, option 1, which does not have this problem, doesn't allow to pass the 50% RE share in hydrogen production, required by the RED III. With the direct connected electrolysis setup neither of these problems exist, as there is no RE overcapacity required and hydrogen used for steelmaking is 100% renewable.

Secondly, cost competitiveness of the grid-connected electrolysis case is, unsurprisingly, strongly correlated to the electricity grid fees and taxes. In the analysis above it was assumed those costs to be 20 EUR/MWh. While that is possible in some EU Member States, it is not possible in all of them. In some EU Member States with the added environmental taxes, capacity taxes, the total network costs are around 30 EUR/MWh or even 40 EUR/MWh. As in this approach all electricity used for hydrogen production goes through the grid, this has significant impact on hydrogen production costs and, consequently, on crude steel production costs. The following graph shows the hydrogen production costs and cost gap vs the BF-BOF route depending on network costs. It's clear that grid-connected electrolysis can only be a viable option, with low network costs.

Figure 50: SENSITIVITY OF HYDROGEN PRODUCTION COSTS AND COST GAP VS THE BF-BOF ROUTE, TO THE CHANGE IN NETWORKS COSTS IN GRID-CONNECTED ELECTROLYSIS SCENARIO.
Source: HYDROGEN EUROPE.
Note: ABOVE GRAPH BASED ON OPTION 3.



On the other hand, grid-connected electrolysis would offer additional potential benefits (and revenue opportunities) from ancillary services provided to the electricity grid operator. As mentioned, the only part of the system, that is designed to run in continuous mode is the reduction shaft. The electric arc furnace is a batch process (approximately 2 h per batch) and the electrolyser is built of many single units, which allows for flexible operation. The amount of scrap charged to the EAF can also be adjusted allowing for flexibility in total electricity use. Hydrogen storage enables to decouple the electrolyser from the rest of the process and can act as a buffer so that the reduction shaft can still operate continuously. By installing additional electrolyser capacity, excess stored hydrogen can then be used in times of high electricity prices or alternatively sold or even re-converted to electricity in fuel cells[58].

In the analysed example of a 4 Mtpa steel plant, which for the continuous operation would need 1,2 GW of electrolysis, if the electrolyser is dimensioned 30% larger than required, an instantaneous negative reserve power of 360 MW could be provided when electricity prices are low or when there is a risk of renewable power curtailment (at nights). This would result in a storage flow of 7,2 tonnes of hydrogen per hour. Hydrogen from storage then opens the possibility to offer positive reserve power by reducing the electrolyser load when electricity prices are high. An option for positive reserve power on the day-ahead spot market is a flexible EAF operation, which is already practised today. If the EAF is used as a positive reserve (shut down), the HBI produced in the shaft can be stored or directly sold to customers. Finally, adjusting the scrap share of the EAF charge leads to significant changes in electricity consumption. A switch from pure DRI to pure scrap operation would free up 1,3 GW, if both the electrolyser and the shaft are shut down[59].

Using the previously mentioned Belgian capacity market example, this could improve the green steel cost competitiveness by 3-10 EUR/tCS just from capacity reserve with additional revenues possible from active frequency regulation.

It should be noted however that most of the additional costs of options 3 to 5 could be avoided if the regulatory framework would allow for some flexibility regarding the temporal correlation between RES generation and its use for hydrogen production.

As has been shown, if the requirement is the ability to prove that the renewable energy was generated within an hour of the time of its consumption for hydrogen production in order to prove that this hydrogen is renewable, due to the continuous operation of the reduction shaft, just contracting renewable energy to cover peak electrolyser load is not enough to surpass the 50% RE share threshold. Not even contracting a PPA for almost 9 GW of solar power, producing an equivalent amount of energy - on an annual basis - to match the entire H2-DRI-EAF consumption, would be enough.

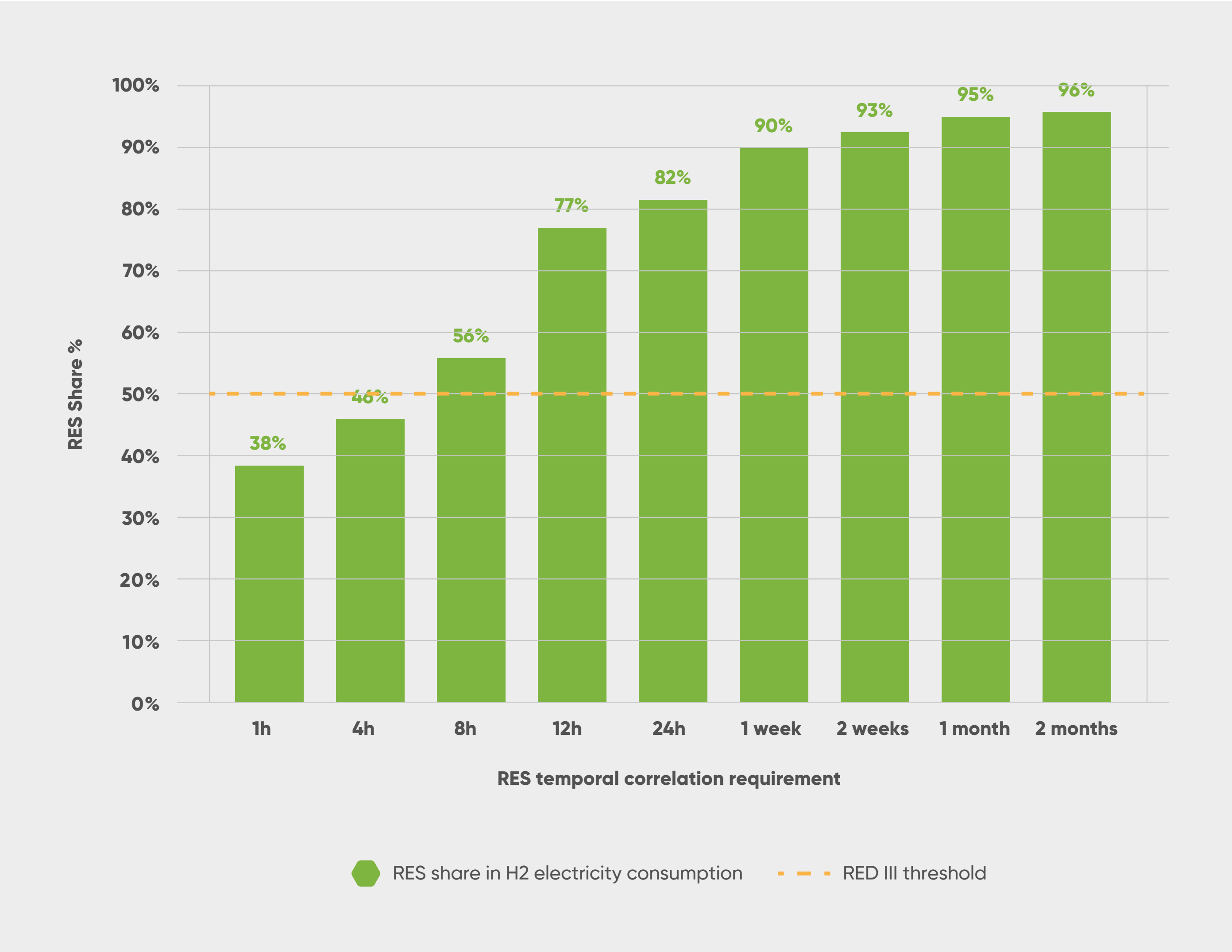
Additional measures would be needed – either in the form of BESS or oversizing the electrolyser coupled with hydrogen storage (or both at the same time). This would however entail significant additional capital investment, inflating the total CAPEX by up to 50% for battery storage. Even though, in some circumstances, especially with persisting high energy prices, investing in energy storage might be a sound decision, the extra capital needed will surely slow down deployment.

If the temporal correlation requirements would be eased off, to allow 8h balancing of renewable energy production with its consumption for hydrogen production, this would allow to reach the 50% threshold even without any storage. 24h balancing would allow to increase RE share in hydrogen production to over 80% without storage.

This could not only help avoiding significant capital expenditures for the steel industry, but would also create an incentive for the industry to engage in RES deployment, rather than focus on storage solutions.

58 / V. Vogl, M. Åhman, L. J. Nilsson, Assessment of hydrogen direct reduction for fossil-free steelmaking, Journal of Cleaner Production, 2018.
59 / Text adopted after V. Vogl, M. Åhman, L. J. Nilsson, Assessment of hydrogen direct reduction for fossil-free steelmaking, Journal of Cleaner Production, 2018.

Figure 51: RE SHARE IN HYDROGEN PRODUCTION IN VARIOUS ALLOWABLE RENEWABLE ENERGY BALANCING PERIODS, NO STORAGE INCLUDED.
Source: HYDROGEN EUROPE.



Although this example is based on solar PV, one can expect similar assumptions whilst sourcing renewable electricity from onshore and offshore wind. In the case of wind-based technologies, where periods of limited production usually last for longer than the day/night cycle of solar PV, in order for projects based on those technologies to benefit in the same way as solar, the balancing period would have to be stretched to 1 week or even 1 month.

09 Summary and conclusions

The purpose of this analysis was to assess the viability of using solar energy (and renewable energy in general) for the decarbonisation of steel manufacturing and to identify the boundary conditions for this approach to become economically feasible. The analysis specifically focused on hydrogen-based direct reduction of iron ore coupled with an electric arc furnace (H2-DRI-EAF), by comparing the levelized cost of steel with the BF-BOF benchmark.

The importance of tackling the GHG emissions from the steel sector is obvious as it is responsible for around 4% of the GHG emissions in Europe. At the same time, the sector generates around 2,6 million jobs making it an important part of the EU economy, which demands careful consideration about what is the cost-optimal pathway for decarbonisation.

Depending on the system's energy efficiency, the BF-BOF route usually has a carbon footprint between 1,6 to 2,0 tonnes of CO2 per tonne of crude steel produced with the EU average being around 1,9 tonnes of CO2 per tonne of steel.

While direct emissions in the H2-DRI-EAF route are reduced almost to zero, the final carbon footprint of this approach would rely on the carbon intensity of electricity used – both for hydrogen production as well as to operate the electric arc furnace. Considering the amount of electricity consumption, for the process to be beneficial from the point of view of net GHG emissions, the maximum carbon intensity of electricity used **cannot exceed 513 gCO2 per kWh.** This means that careful consideration should be given to the source of electricity used.

If the H2-DRI-EAF process is based on renewable electricity significant GHG emission savings could be obtained. However, in order to use exclusively renewable energy, several key challenges would have to be addressed.

The first one is cost. With an estimated current hydrogen delivery price (including production, transportation and storage) of 5,3 EUR/kg, both in the 'High prices' and in the 'Adjusted prices' scenario total green steel production costs are higher than the BF-BOF benchmark, with the difference being 126 EUR and 203 EUR per tonne of crude steel respectively. **For a typical ICE passenger car, this would translate to an added cost of 100 – 170 EUR per vehicle.**

According to our estimates, in order for the project to achieve break-even, the hydrogen delivery price would have to be below 3,0 EUR/kg - in the 'high prices' scenario and below 1,5 EUR/kg - in the 'adjusted prices' scenario. **The estimated CO2 break-even price is 140 EUR/t for both price scenarios.**

It should be noted however that these estimations are a reflection of the current electrolyser and solar PV costs. It is expected that a further decrease of the solar PV technology costs, coupled with a reduction in electrolyser CAPEX, resulting from scaling-up and automation of the manufacturing process, should lead to a significant fall in renewable hydrogen production costs in the coming decade. Electrolyser CAPEX alone, are expected to fall by around ¾ compared to current levels – enough to enable renewable hydrogen production costs with low-cost renewable energy, to reach 1,5 USD/kg by 2025[60]. If the green hydrogen production costs fall down as predicted, by 2025-2030 it should be possible to eliminate the cost gap between entirely – even in a scenario with low fossil fuel prices.

In the meantime however, if the end consumers are not willing to pay a green premium for a fossil-free steel, a significant financial support would needed.

The second big challenge is the scale. The total capacity of all installed BF-BOF plants in the EU is around 103 Mt of hot metal per year. Switching all of those plants to hydrogen-based DRI/EAF could potentially save up to 196 Mt of GHG emissions per year but in order to do so would require up to 5,3 Mt of renewable hydrogen and up to 370 TWh of additional renewable electricity generation (including EAF electricity consumption).

Converting just a single steel plant with a capacity of 4 Mt of crude steel per year (EU average) would require: 1,2-1,3 GW

60 / https://www.rechargenews.com/transition/nel-to-slash-cost-of-electrolysers-by-75-with-green-hydrogen-at-same-price-as-fossil-h2-by-2025/2-1-949219

of electrolysis running at full load, 3,3 billion EUR of capital investment (including 1,2 billion EUR for electrolysis) and between 10,2 to 21,7 ha of land for the electrolysis plant (and additional area for new renewable power deployment). If variable renewable electricity is used and the electrolyser cannot be operated at constant full load, the challenge becomes even bigger. When using exclusively solar PV for hydrogen production, the required electrolysis power would grow to around 4,5-5,0 GW, driving up the required CAPEX to almost 7 billion EUR for a single plant of average capacity.

Multiplied by the number of plants across the EU, the sector will need to access both debt and equity finance (in large amounts) to accompany the public support. Coupled with the existing cost gap, raising the necessary funds will be extremely challenging – especially in light of the foreseen free allowances phase out.

The third big challenge is the necessity to provide constant supply of hydrogen to the reduction shaft. When hydrogen production is based entirely on variable renewable energy, like solar PV or onshore/offshore wind, significant amount of operational storage is needed. While underground hydrogen storage in salt caverns offers a cost-effective solution, underground salt formations are not uniformly available across the whole EU. Furthermore multiple salt caverns might be needed for a single steel plant.

Finally, securing access to a sufficient amount low-cost renewables will also be a challenge – especially in northern part of Europe.

While imports of renewable hydrogen are most likely inevitable for some EU countries, because of low hydrogen break even price, the steel sector will remain a challenging market for imported hydrogen. Although business case can be improved by using waste heat for dehydrogenation or direct use of ammonia in the DRP. Decoupling direct reduction from EAF using renewable briquetted iron as the “hydrogen carrier” to deliver renewable energy to EAF units in the EU is also an option.

Another possibility, for areas with shortage of renewable resources, is to produce hydrogen in situ, with electricity delivered through the power grid. In this case however, ensuring steady supply of hydrogen remains a challenge, as available storage options are expensive.

As a result, if the final version of the RED III would include a very strict (1h) temporal correlation requirement for renewable hydrogen production, it would create a significant obstacle the deployment of DRI-EAF based on renewable hydrogen.

On the other hand allowing 24h balancing of renewable energy production with its consumption for hydrogen production, would allow to increase RE share in hydrogen production to over 80% without any additional storage - significantly reducing capital demands and thus increasing economic attractiveness of green hydrogen use in the steel sector.

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Wuppertal Institut für Klima, Umwelt, Energie.


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