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Renewables pull and strategic push – What drives hydrogen-based steel relocation?

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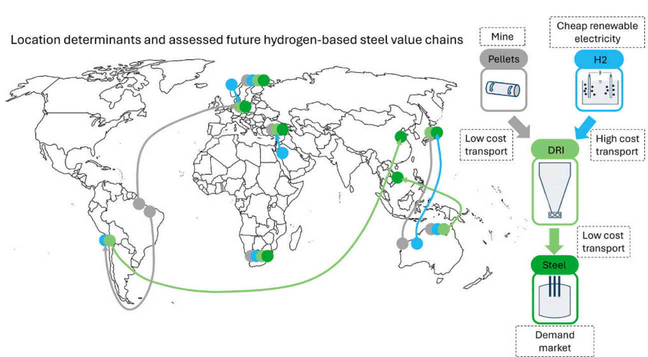
HIGHLIGHTS

- Assessment of renewables pull and strategic push factors for hydrogen steel relocation.
- Hydrogen steel's cost varies across value chains similarity to conventional steel.
- Renewables pull effect is sensitive to assumptions and weaker than previously found.
- Modest policy interventions lowering cost of hydrogen and capital influence results.
- Both strategic push and renewables pull is necessary to accelerate the transition.

GRAPHICAL ABSTRACT



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ABSTRACT

Hydrogen-based steelmaking using green hydrogen can achieve above 95 % CO_2 emission reductions. Low-cost renewable electricity is a prerequisite and research has found that access to renewable energy resources could pull energy-intensive industry to new locations, the "renewables pull"-effect. However, previous studies on hydrogen-based steel differ on key assumptions and analyse a wide range of energy costs (10–105 EUR/MWh) making conclusions hard to compare. In this paper we assess techno-economic and strategic drivers for and against such a pull-effect by calculating the levelized cost of green hydrogen-based steel across five archetypical new value chain configurations. We find that the strength of the pull-effect is sensitive to assumptions and that the cost of hydrogen-based steel vary across geographies and value chain configurations to a similar degree as conventional steel. Other geographically varying factors such as labour costs can be as important for relocation, and introducing globally varying cost of capital moderates the effect. The renewables pull effect can enable faster access to low-cost renewables, and export of green iron ore is an important option to consider. However, it is not clear how strong a driver the pull-effect will actually be compared to other factors and polices implemented for strategic reasons. A modest "strategic push", implemented through various subsidies, such as lowering the cost of hydrogen or capital, will reduce the pull-effect. In addition, focusing on the renewables pull effect as enabling condition risk slowing innovation and upscaling by 2030 in line with climate goals which is currently initiated in higher cost regions.

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1. Introduction

Steel production contributes 7–8 % of global CO_2 emissions with most emissions stemming from the reduction of iron ore [1]. To reach long-term climate goals, the sector need to rapidly scale up technologies that reduce emissions sharply [2]. The hydrogen-direct reduction-electric arc furnace route (H-DRI-EAF) is emerging as a promising combination of technologies, that is available globally by 2030 [3,4], and with industrial support demonstrated by a growing list of companies working one large scale H-DRI-EAF projects [5]. Since the first techno-economic assessment of H-DRI-EAF based steel [4], a range of studies have evaluated integrated steel plants using H-DRI-EAF further establishing the emission reduction potential from production in countries such as Norway [6], Japan [7], and the Middle East [8], including a first global assessment by Devlin et al. [9]. Generally, the literature focus on the cost-competitiveness compared to fossil steel production with the European context receiving most attention [6,10–14].

However, reducing emission with H-DRI-EAF technology has implications beyond integrated plants. Conventional steel is typically produced in large integrated steel mills due to the strong cost and energy benefits with integrated production, e.g., through the use of off-gases from coke production and blast furnaces, often in downstream rolling processes. A second defining feature is the location of natural resource endowments of iron ore and coking coal, combined with low-cost seaborne bulk transport of these commodities. Low complexity of the main materials used in steel making, together with global standardisation and low-cost transport, has unlocked steel production geographically from mining. Iron ore is today the third largest traded commodity by volume and second by value, only surpassed by fossil fuels [15,16].

The total cost of emerging low carbon hydrogen-based steel made in the H-DRI-EAF route will instead be dependent on access to low-cost renewable electricity. As low-cost renewables are more commonly found in, e.g., parts of the Global South [17], this becomes a key new determinant for the location of steel value chains [9,10,13,14,18,19]. Referred to as the "renewables pull" effect [10,18] this could either lead to relocation of integrated plant, or part of the value chain exporting green iron as Hot Briquetted Iron (HBI). Such a separation the energy intensive parts of the steel value chain from final steel production has recently been argued to be an important enabler of decarbonisation of the global steel system, as several major traditional steel industry locations (e.g., in Europe) are struggling to access sufficient low-cost clean energy [9,11,18]. If H-DRI-EAF steel becomes the new technology of choice, the pace of the transition to low carbon steel will thus be influenced both by how fast technology can be proven in large scale demonstration plants, and by the new conditions in the value chain. And the strength of the renewables pull effect will depend on techno-economic conditions and how these compares across value chains [10,18].

A new research field is thus emerging that analyses the potential new steel value chain configurations and the renewables pull effect on individual value chains such as Australia to Japan [7], and imports to Europe [10,13,14,18]. For example, Verpoort et al. [10] and Egerer et al. [14] have carried out analyses of value chains from the point of high-cost, import dependent regions such as Germany, and others have focused on the export opportunity for countries such in the global south such as Australia [19] and South Africa [20]. The recent global study by Devlin et al. [9] also called for more work on HBI-trade. This is important, not least in East Asia, as iron ore trade with China is a defining feature of global steel value chains and few studies consider this value chain. Recently published results also confirms that HBI trade can enable a faster transition to low-carbon steel at regional level, but also comes with several new challenges related to both geopolitics and the economics of building large new industries for HBI export [21].

We would here like to emphasise that conclusions on future value chain reconfigurations need to also consider what changes can materialize within the time determined by global climate goals, and that there is limited attention in the literature on strategic geoeconomic rationales for maintaining domestic production. Critically, while previous studies have explored individual and regional H-DRI-EAF value chains and compared some techno-economic factors globally, results show high uncertainty. No study to date reviews all drivers for and against integration and relocation, and transparently compare assumptions on energy, transport and other costs across differently set up value chains. We aim to address this gap, and do not focus on addressing the competitiveness of H-DRI-EAF steel compared to conventional per se, or how to optimally locate production. Instead, we aim to systematically explore what the comparative advantages of differently configured value chains are, considering both techno-economic factors, and strategic factors.

In this study, we therefore first review the literature to specify the key economic and strategic variables that can pull and push H-DRI-EAF-based steel making in value chains using green hydrogen. Secondly, we select and calculate the Levelized Cost of Steel (LCOS) for a range of scenarios defined by five archetypical H-DRI-EAF steel value chain configurations using green hydrogen. These reflects some of the most important trade flows today as well as flows that can be expected to grow in importance during the 2030s driving new investments, and costs of integrated plants at high and low-cost locations. Both existing large steel-producing countries, as well as emerging markets are purposefully selected in visualise the archetypical value chains. For the comparisons with integrated plants cases are chosen to be representative of the highest cost (Sweden) and lowest cost (South Africa) according to the first global comparing integrated plants [9], both for which there are also dedicated studies in the literature [12,20]. We limit our assessment to focus on the main energy intensive process steps, and throughout our analysis, we focus on the three locational determinants of iron ore mines, renewable energy access, and demand markets. Finaly, we assess the strength of "strategic push", by evaluating the influence of subsides to hydrogen or capital cost as part of an industrial policy to maintain production capacity in existing locations. The overarching goal is to use a consistent set of transparent assumptions across possible value chain configurations to answer the following questions:

- How large difference in LCOS can emerge for different configurations of H-DRI-EAF based steel value chains?
- And how sensitive are conclusions on the renewables pull effect to varying assumptions on key techno-economic variables and other strategic considerations?

We aim to assess the importance of the renewables pull effect in accelerating the decarbonization of steel to reach climate targets. Our focus is therefore on the near-term defined as 2030, as low carbon steel initiatives across the world must start in the first half of 2030 to put the global steel sector on a transition trajectory towards zero emissions in line with climate targets [2].

2. Methods

We first reviewed assumptions made in the recent literature of decarbonization of steel in general, and analysis of H-DRI-EAF steel in particular, focusing on conditions and factors that influence how H-DRI-EAF steel production can scale up by 2030, the renewables pull effect and what factors that are important due to large uncertainties. In line with earlier research on H-DRI-EAF, the successful completion of pilot plants and tangible progress on the first large scale plant, we assume that technological risk is manageable and that continued progress in the innovation system will enable upscaling in the 2030s [3,5,22]. With a short time-horizon for the study, we avoid strong assumptions on technological development well into the future.

After identifying key assumptions and parameters, we used bottom-up techno-economic modelling to determine difference in LCOS across a set of scenarios defined by archetypical value chain configurations in illustrative case studies. Five archetypical value chains were established by first analysing all possible configurations of the manufacturing processes (See Appendix F). The case studies were selected purposefully to explore costs and to reflect the most important steel value chains today based on iron ore production and export statistics, steel production data, as well as potential low-cost green hydrogen production regions and trade flows. For example, cases using integrated plants were not selected to be representative of average cost, but high and low cost endpoints according to existing literature (See Appendix B and E). Our method did not consider the optimal placement of production facilities, nor did we limit the analysis by political feasibility of any emerging value chains, such as import of HBI instead of Iron ore to China. H-DRI-EAF steel production with green hydrogen and 0 % scrap was modelled using 2030 project installation year. This timeframe is chosen as the aim of the paper is to illustrate the potential impact of H-DRI-EAF technology on steel value chain, if projects are scaled up in time to start phasing out blast furnaces in line with climate goals [2].

2.1. Modelling the hydrogen steelmaking system

The system model and its boundaries are outlined in Fig. 1. Our model, implemented in Python in the Jupyter Notebook Environment, draws on the approaches developed by [4,6] (see Appendix F). At the core, the model describes the production of green hydrogen through electrolysers, the reduction of iron ore using DRI shaft furnaces, and the production of molten steel using EAFs (See Fig. 1.). We choose to model the H-DRI-EAF process both due to existing models and research, as well as the technological readiness with the completed HYBRIT pilot plant, but other hydrogen-based steel making methods are possible such as fluidised bed [23]. As our model analyses the most important implications of the change to H-DRI-EAF on value chains, we purposefully do not include upstream processing and beneficiation of iron ore (assumed to always take place at the mine), nor downstream casting and rolling as these will be similar across all configurations (see Appendix A).

As our model is designed to analyse how process location and integration influence LCOS, we model three sets of system configurations: full system integration, systems where the electrolyser is separated, and systems where the EAF is separated (See Fig. C1, C2, Appendix C). For all cases, we assume a steel plant production capacity of 2.5 Mt./year [4] which is also the size of the first commercial plant being built in Sweden [5]. Mass and energy balances are calculated for the system as a basis for cost calculations, focusing on the basic chemical reactions according to [4]. Specific heat and enthalpies, are estimated according to [6], and assumptions on key parameters for electrolysis and steel making such efficiency, hydrogen demand, metallisation rates are kept the same across cases and in general follow [4] (See Appendix C).

In some of the alternative system configurations additional energy is required (Fig. C1, C2, Appendix C). When the electrolyser is separate, the water circuit is open, which requires additional heating of inlet water from our assumed 25 °C reference temperature to the electrolyser operating temperature [4,6]. At the same time, the open circuit allows more heat to be recovered in the condenser by cooling the exhaust water stream down to the reference temperature. In configurations where the EAF is separate, the hot metallic DRI shaft output stream is assumed to be compressed into HBI, which is cooled, stored and transported to the EAF. This requires a small additional energy for compression and additional heating to compensate the iron cooling from 650 °C [24] to our 25 °C.

2.2. Economic assumptions

The LCOS is calculated as the annualised cost of the steel plant through Eq. (1). The cost components studied are selected based on the review and results of this (see **Table 1**) and focus on how costs related energy, transport and labour costs, vary across the different value chain configurations and cases in our study (see Appendix D).

$$LCOS = C_{CAPEX}*ACC + C_{res.} + C_{energy} + C_{labour} + C_{transp.} + C_{other.} \tag{1}$$

Where C_{CAPEX} refers to the total capital investments and ACC is the annuity factor. C_{energy} and C_{labour} represent energy and labour costs respectively. $C_{other.}$ comprise operations and maintenance (O&M) costs and revenues generated by O_2 sales, $C_{res.}$ comprise costs of iron ore pellets, lime fluxes, graphite electrodes and alloys. Lastly, $C_{transp.}$ include the costs for transporting iron ore pellets, HBI and H_2. The annuity factor is calculated using eq. (2).

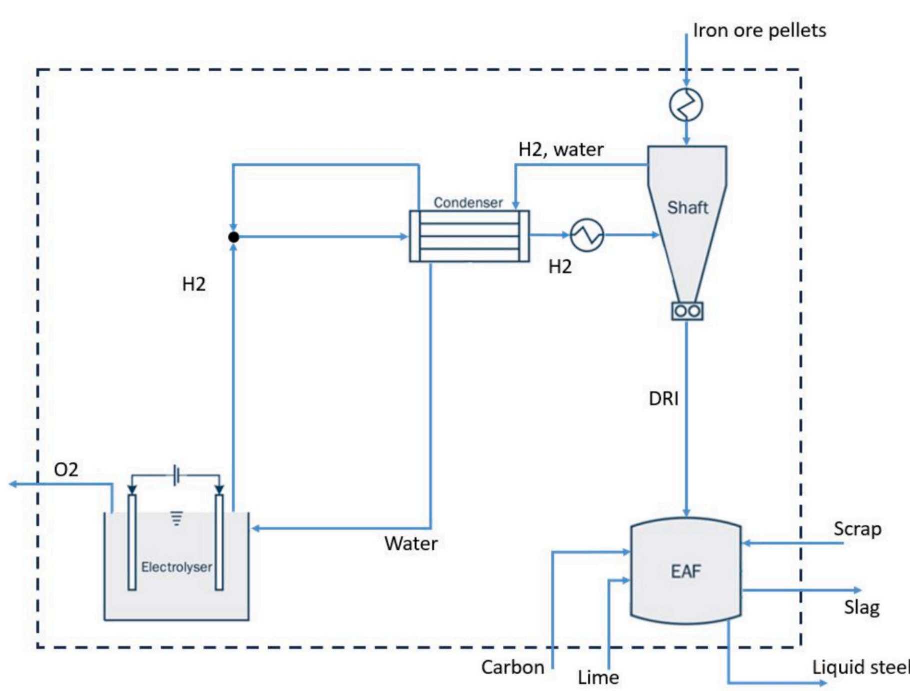

Fig. 1. System boundaries and schematic of the integrated H-DR process. Adapted from ref. [4].

Table 1
Key drivers for and barriers against reconfiguration of the steel value chain in terms of costs showing range of assumptions in literature and how this informs our modelling assumptions.

Techno-economic driver	Assumptions on costs in the literature	Analysis and how this informs our adapted modelling assumptions
Renewable energy costs	Gielen et al. [19]:€22/MWh, assumption for future grid scale renewables. Lopez et al. [13]: €10–36/MWh based on baseload renewable energy estimates. Devlin et al. [9]: €14–43/MWh based on bottom-up modelling of island mode renewables. Fan and Friedman [25]: €49–74/MWh, industrial prices. Verpoort et al. [10]: €15–105/MWh	Very large differences. Some studies use long-term future renewable energy costs at large scale (LCOE), some include firming cost or assume baseload costs from hybrid solar and wind energy in island mode while other use assumptions based on "current market prices" for industrial users. Our assumption is based on based load renewables varying between €44–83/MWh for low to high-cost regions (See, Table D3, Appendix D).
Hydrogen transport costs	Lopez et al. [13]: Very high impact of Liquid Hydrogen (LH2) shipping cost adding 1.5–2.9 times the production cost of hydrogen depending on case and time horizon. Verpoort et al. [10]: assume LH_2 transport cost that roughly doubles hydrogen cost adding €1.7–2.2/kg LH2. Devlin and Yang [7]: Transport is a minor contributor at only average 5 % of total costs across cases but with much higher total costs making comparisons hard.	Varying granularity and system boundaries for analysis using literature values, e.g. ref. [10], or detailed bottom-up techno economic modelling of hydrogen carriers and pipelines, e.g., ref. [13]. High variability and we us average values from a review of the wider literature on hydrogen transport at €3.4/kg LH2 (see Appendix D, Transport cost).
Labour costs	Generally lower resolution in the literature, but labour costs are important, e.g., between 4 and 21 % of the total production costs of steel in 2050 depending on country of production in Devlin et al. [9]. High labour costs generally disadvantage advanced economies, where e.g., labour costs in Australia at €115/t steel offset the country from being the 3rd lowest cost producer to the 11th.	Limited analysis in the literature with simplistic assumptions using average wage with premium of 30 % and the same labour productivity of 2 h/kW installed electrolysers, 0.22 h/t DRI, and 0.49 h/t steel for the EAF across economies. We choose to vary labour cost based on data on steel worker wages, employer contributions and overhead costs.
Energy use and integration benefits	Vogl et al. [4]: 3.5 MWh/t Liquid Steel (LS), for reduction using pellets, idealised conditions with high potential for waste heat recovery, both PEM and alkaline electrolysers. Bhaskar et al. [6]: 4.25 MWh/t LS, assumption for pellet reduction, alkaline electrolysers, electrical heating needs and efficiencies. Lopez et al. [13]: 5–6 MWh/t crude steel, assumptions for fines reduction. Verpoort et al. [10]: 3.7 MWh/t LS using 0.43 MWh/t from natural gas to raise carbon content and 0.16 MWh/t to reheat HBI Devlin and Yang [7]: 4.9–7.6 MWh/t crude steel.	Technical analyses differ with varying assumptions on waste heat recovery, choice of reduction process, electrolyser technologies and efficiencies, electrical heater efficiencies, and assumptions on natural gas use to achieve the right carbon content. E.g., Devlin and Yang [7] find larger benefits but this stem from a wider system boundary (hydrogen transported to fuel EAF). All studies exclude rolling and processing to finished steel products, but some variation due to assumptions on unit of analysis being liquid steel or crude (cast) steel. Our model is based on Vogl et al. [4] and Bhaskar et al. [6].
Varying cost of capital	Lopez et al. [13] and Devlin et al. [9] use 7 % and 8 % across all cases. For comparison of individual value chains Devlin and Yang [7] use 7 % in both locations, both Australia and Japan being OECD countries. Verpoort et al. [10] and Trollip [20] use a higher 8 % rate in the renewable energy rich region with higher risk compared to 5 % and 6 % respectively for the importing country in studies of the renewables pull effect. Similarity, Samadi et al. [18] use 7.15 % vs 4.88 % comparing DRI production only.	Unclear how large factor WACC is compared to the renewables pull effect, no study including a range of cases that vary WACC across regions, or explore the effect of higher WACC on steelmaking. We choose to vary WACC of conventional steel plants in low (5 %) and high capital cost regions (8 %), in line with historical averages [26] and Verpoort et al. [10], and add an additional 2 %-points for the elevated risk of new technology. Finaly, we use WACC for renewable energy according to analysis by IRENA [27].

$$ACC = \frac{r}{1-(1+r)^{-n}} \tag{2}$$

Where r refers to the interest rate and n represents the lifetime of the steel plant. The CAPEX is estimated for the main plant components: the electrolyser, shaft furnace and EAF [4,6]. We explore the effect of varying interest rate according to the review (see **Table 1**). We model energy costs based on cost-optimized levelized costs of baseload electricity from hybrid PV-wind systems, assessed on a global scale [17]. We thus use comparable estimates across cases in that we have the same source across cases. We also adjust the electricity cost estimates for each study location based on the Weighted Average Cost of Capital (WACC) conditions for renewable energy [27] and the economic status of the locations, scaling the original costs as suggested by [17] (see Appendix D, Energy costs). Remaining assumptions on cost related to CAPEX, resources, O&M and O_2 are based on [4] and detailed in Appendix C (see Table C1). Notably, these are assumed to be the same across cases as we focus on variations on transport, energy, labour costs, and cost of capital, and this is a limitation of our study.

For liquid H_2 transport (LH2) shipping costs, we reviewed the literature and used average results on cost as a function of distance (€/kg/km) identified from a range of recent studies (See Table C2). We use average values as studies showed a wide range of costs for components related to liquefaction of hydrogen, port and storage costs [28]. To reduce this uncertainty, we also choose to base hydrogen transport on floating storage and regasification (similar to how LNG infrastructure is often built out today), rather than more costly on shore storage [29]. The generally low technical maturity of LH2 shipping and this infrastructure setup needs to be considered when interpreting results. Finally, for hydrogen transport via on- and offshore pipelines we use data from [30] and average specific investment costs for newly constructed hydrogen pipelines (See Appendix D, Transport cost).

We base labour costs on [9], modelling regional hourly rates for steelworkers, together with labour intensities of the major process steps in our model: the electrolyser, DRI shaft furnace and EAF. This allows analysing regionally varying labour costs and cross-country value chains. However, hourly steelworker rates were estimated by scaling 2020 data on gross national income [31], with data on wages in the iron and steel sector [32] and employer contributions, retrieved from [33], for each country providing more detailed results. We assumed a uniform overhead cost rate of 25 % [34]. The electrolyser labour intensity is based on [9], while assumptions for the DRI shaft furnace and EAF are derived from empirical data [35] (See Appendix D, Labour cost).

Finally, we assess the LCOS sensitivity by comparing across cases, as well as varying three variables across cases: interest rates, energy costs and labour costs. For interest rates, we assume equal WACC conditions of 5 % across all cases instead of varying WACC, in line with [4]. This reflects an assumption of a few global actors making similar investments worldwide, facing comparable risks regardless of location. For energy costs, we test rates 40 % below 2030 estimates of levelized cost of baseload electricity by [17], which align with [9] and more optimistic 2050 estimates in [17]. For labour costs, we use cost that does not vary based on our method, but instead standardize the steelworker wage-to-national average wage ratio at 1.3 and replace uniform overhead costs with variable rates using personal income tax [36] as a proxy, making results comparable to Devlin et al. [9].

3. Results: Cost assumptions and illustrative cases

3.1. The key determinants of H-DRI steel value chain configurations

Our review reveals that conclusions on LCOS vary strongly across the literature. Devlin et al. [9] modelled islanded renewable electricity supply and found that LCOS of fully integrated H-DRI-EAF in 2030, 2040 and 2050 would reach an interval of €457–830/t with a mean estimate from €534–654/t – a similar cost interval of BF-BOF steel in 2021 (we use currency conversions to EUR according to year of publication from here on). Fan and Friedman [25] found H-DRI-EAF LCOS at €659/t in the US, and argue that this is double compared to BF-BOF and that CCS would be a less costly option assuming lower baseline cost of conventional steel. Recently, both Egerer et al. [14] and Verpoort et al. [10] find even higher costs in Germany at €1260/t and €930/t in 2030 and 2040 respectively, while Toktarova et al. [12] find significantly lower costs at €300–320/t by 2050 for northern EU.

Reviewing the above literature we identify five main techno-economic components that can drive such large differences in LCOS and therefore affect how steel value chains can be reconfigured: 1) *Cost of renewable energy and hydrogen production*, 2) *Cost of transport*, 3) *Cost of Labour*, 4) *Energy use and integration benefits* including assumptions on process design, and 5) *Differences in weighted cost of capital (WACC)*. The literature also discusses policy interventions that can act as a driver or barrier for relocation. We identify two main rationales for a "strategic push" via subsidies: *Maintaining and protecting existing a domestic steel industry*, and *Increasing domestic value added by moving up the value chain* producing steel. The relative importance of strategic push policies has not been evaluated extensively in the literature as they are hard to quantify. Below we provide some qualitative analysis and review of research to date, and we later quantify effects of policy support exemplified by state guarantees lowering WACC and subsidies for green hydrogen production.

1) The cost of renewable electricity can strongly alter the comparative advantages of H-DRI-EAF steelmaking. Early findings estimate that electricity makes up 25–35 % of total production costs pending on electricity price under ideal conditions [4,9]. However, with higher electricity costs, the share can be 40–50 % [9,10], and conversely much lower, at 15–20 % [12]. Table 1 shows that the literature has assumed electricity costs ranging from ca €10–105/MWh across different geographies and time horizons, a full order of magnitude. A core assumption yielding low LCOS is that electricity is available at optimized future production costs in grids, e.g., Toktarova et al. [12], or Devlin et al. [9], modelling "islanded" electricity cost (i.e., not grid-connected) and not at short-term market price, e.g., Fan and Friedman [25]. Assumptions thus vary greatly on how renewable electricity carries the cost of its intermittency. For levelized cost of electricity (LCOE), assumptions that grid connected renewables are added to a well-designed power system that can accommodate large quantities of new renewable electricity avoids the need for major additional firming. This is reasonable for some regions such as Scandinavia, but other regions will have much higher grid-related costs. For power systems in island mode, assumptions on system design and modelling approaches greatly influence LCOS. In conclusion, future electricity costs can vary widely and are dependent on local power system contexts including regulatory regimes.

2) Cost of transporting hydrogen, iron ore and HBI. Both iron ore and HBI transport is very cost efficient, using the same types of large bulk carriers with modest or no modifications needed for HBI, and assumptions have limited impact on relocation. For hydrogen transport, on the other hand, there are large uncertainties on both liquefaction and transport [28,37]. Some studies compare different value chain configurations, including both HBI and hydrogen imports to Europe from Morocco and Chile [13] and from Australia to Japan [7]. The European study by Lopez et al. [13] find LCOS to vary between €380–545/t across configurations with HBI trade most cost efficient. Notably, comparing the LCOS of integrated domestic production in Germany, Finland or Spain to a value chain based on importing hydrogen from Chile or Morocco or HBI from Morocco are all within ca 20 % of LCOS [13]. Verpoort et al. [10] recently found the corresponding difference for Germany importing HBI from a region with €40/MWh lower energy costs to be 13 %, with larger differences for import of semi-finished steel. Devlin and Yang [7] find much larger differences but exported hydrogen for the EAF elevates cost, and others find even smaller differences [14]. In summary, hydrogen transport cost assumptions are very uncertain and the impact on LCOS is inconclusive. HBI transport appear cost effective, and more research on how this impact value chains is needed [9].

3) The cost of labour differs between regions and can drive relocation. Assumptions on labour costs vary in the literature, ranging between €53/t steel representing 8–15 % of the total production costs [4], to €16/t steel, making up 3 % of the total production costs [6]. Other studies do not address differences [10,13]. Two recent studies show that labour cost differences can have a large impact and prompt relocation to energy rich regions in some cases [7,9]. However, these studies make general assumptions that steelworker wages are 30 % above the national average wages, and that the labour productivity is consistent globally. Consulting UNIDO data [32] on salaries in the iron and steel sector and comparing it to gross national incomes we find no such relationship across countries (see Appendix D, Labour cost). Rather, steelworker wages in advanced economies are close to, or below the national average (e.g., about 80 % of the average wage in Sweden), but in developing countries, they surpass significantly the national average (e.g., recently ranging between 160 %–200 % percent of the average wage in Brazil). A review of the available data on the number of workers per ton steel further shows significant variations across plants and countries, and newer plants can in general be expected to use state-of-the-art technology that is less labour intensive. Apart from costs, the availability of skilled labour may also play a role for industrial relocation [10].

4) Energy use and integration benefits. For the traditional BF-BOF route there are clear energy benefits of co-locating the different parts of the value chain. For H-DRI-EAF facilities, the advantages of integration are not as obvious due to lower temperatures and less off-gases. Examples of heat integration for the H-DRI-EAF are charging hot DRI from the shaft furnace to the EAF and thermal energy recovery of the shaft furnace exhaust gases to heat the hydrogen feedstock. The assumptions made on technologies used (e.g., shaft or fluidized bed), their efficiencies and heat integration options, determine the energy needs which influence the renewables pull effect. The difference in energy use is quite large comparing more idealised systems such as Vogl et al. [4] at 3.48 MWh/t liquid steel to much less energy efficient processes assumed in Lopez et al. [13], who estimate the energy use to be 5–6 MWh/t for crude steel based on fluidised bed reactors instead of iron ore pellet-fed shaft furnace. Apart from process assumptions, the unit of analysis being liquid steel or crude steel from continuous casting or semi-finished products likely also influences energy needs and costs, but system boundaries and assumptions made are often opaque.

5) Weighted average cost of capital (WACC). For studies comparing costs across a range of locations, the norm in existing studies is to use a fixed WACC (or interest rate, studies use different terms), focusing the analysis on the impact of low cost renewables [9,13]. Several studies of individual value chains do model higher WACC in locations rich in renewable energy but with higher capital costs, relative to countries within OECD [10,18,20]. Assumptions on WACC in individual studies of H-DRI-EAF vary more, from low, representative of a mature system at 5 % in Vogl et al. [4] and Toktarova et al. [12], to twice as high at 10 %, capturing higher initial risks such as Bhaskar et al. [6] (Table 1). Despite this large difference, assumptions on WACC for the H-DRI-EAF plant specifically appear to have a rather small effect on total costs, as energy costs dominate over cost for the steel plant. But renewable energy production in turn is capital intensive, and renewable energy costs again therefore critically depend on WACC assumptions. All in all, WACC assumptions could moderate the renewables pull effect significantly, as renewable rich regions on average have higher risk and therefore WACC, and needs to be studied more.

Strategic push and policy interventions. For existing producers, closing industries are associated with high economic and social impacts including both direct costs for scrapping technology and conducting environmental cleanups, but also harder to quantify costs related to labour, such as pensions, retraining, or social costs associated with closures of major sources of employment and taxes [38,39]. Steel is also used in a large variety of downstream sectors, such as the automotive and construction sector, and another rationale for protecting the industry can be to secure supply chains and to avoid supply shortages driving inflation and to minimise imports [40]. A country with a downstream industry such as automotive or shipbuilding, may prefer to support a domestic steel industry over importing steel and be exposed to potential supply shocks. Domestic access to steel is also a concern for hard security, with mining and minerals increasingly highlighted for its derivate value for defence [41]. A transition to domestically-produced hydrogen can also reduce fossil fuel imports.

Countries with rich renewable energy endowments and existing, or to be developed iron ore exports, may regard the transition to H-DRI as an opportunity to move up the value chain and capture a larger share of the total value added. Exporting HBI for this reason is the explicit motivation for some studies [19,20]. Lopez et al. [13] also discuss that if the EU opts to import HBI instead of raw materials this can achieve both lower cost and development of the Global South. But there are also similar strategic rationales for developing steel production domestically as for the protection of existing steel industries; positive externalities such as the provision of new relatively well-paid jobs for the non-college educated, and again, the supply of steel for downstream industries such as construction, military, shipbuilding and automotive [41,42].

Conclusions on how to evaluate policy interventions quantitatively depend on range of political and regulatory factors. For current steel producing regions such as the EU, policy support include direct subsidies for domestic green steel demand or supply to enable the low carbon transition [43,44], support for green H_2 production including through facilities such as the European Hydrogen bank, or more subtle support such as credit guarantees, used to lower the capital cost for the elevated risk of first-of-a-kind-plants [45]. Modelled cost differences in steel value chains are sometimes discussed explicitly as the support necessary to preserve domestic steel production. Verpoort et al. [10] for example conclude that some €80/t LS subsidies are needed in Germany. Policy measures to support the development in exporting regions is less discussed, but again domestic steel industries can be developed or protected through a variety of policies, such as offering subsides to electricity or green hydrogen or direct support for pilot and demonstration plants [46]. In addition, carbon and energy policy can be designed in a way to protect domestic industries via various tax exemptions and trade policies. We conclude that given current policy incentives, an analysis of the impact of a) credit guarantees lowering WACC for the riskier H-DRI-EAF steel to the level of mature technology, and b) direct support for hydrogen production can illustrate the impact of policy interventions.

The review shows large variations in assumptions, with potentially significant impact on the conclusions that can be drawn on the strength of the renewables pull effect, and no study includes examples of all possible value chain configurations, enabling comparison across configurations.

3.2. *Five cases to illustrate potential value chain configurations*

We find that there are five plausible archetypical configurations through which a low carbon H-DRI-EAF value chain can be organized in (see Appendix B and E). These configurations were identified by combining the location determinants iron ore mines, renewable energy, and demand markets, and the four process-stages in the H-DRI-EAF value chain (See Fig. 1.). Selecting production sites to evaluate the renewables pull effect evidently offers a multitude of plausible cases and combinations, and in contrast to the existing literature, our analysis does not aim to identify optimal solutions for each archetypical configurations, nor identify the lowest cost region. Instead, the aim is to have a purposeful sample of cases that illustrates all the possible configurations through representative cases of possible low carbon steel value chains in 2030 and our selection and rational is presented in Fig. 2.

Energy cost assumptions are key and we choose to draw on the work of Fasihi and Breyer [17] and their findings on 2030 baseload electricity costs of hybrid PV-wind power plants globally. This makes energy costs across locations comparable and so that cost differences are driven by the potential for low-cost renewables given the resources rather than differences in assumptions on costs for firming the intermittency of renewable energy. Our adjustments of WACC conditions are further motivated by the review, highlighting the importance of WACC assumptions on both the steel making assets and as influencing energy cost. We find that energy costs vary from €44–83/MWh across regions (See, Table D3, Appendix D). Notably, this makes our assumptions more conservative than studies that assume lower renewable energy costs for 2050. In addition, we pay special attention to cost assumptions for integrated plants in Sweden where both the first pilot plant (Hybrit) and large-scale commercial H-DRI-EAF plant (Stegra) are located. The first large scale projects being built in northern Sweden has been able to sign long-term Power Purchase Agreements (PPAs) based on expansion of wind power with no or few extra cost added for balancing due to an already strong power system. We therefore include a low-cost case in Sweden at €64/MWh complementing the high cost €79/MWh based on ref. [17]. This assumption is also closer to recent power prices and long-term Swedish forecasts (see Appendix D).

Across these value chain configurations, low-carbon LCOS ranges from €480–700/t liquid steel (Fig. 3). Costs are higher than conventional BF-BOF steel but fall within the cost-range of global BF-BOF-based steel (Fig. 4d). Our results are thus broadly comparable with the average costs across previous studies of H-DRI-EAF. Notably, variations across cases are similar in magnitude to differences observed for conventional steel across regions around the world (Fig. 4d). For example, in 2019, a year with low production costs, LCOS varied between ca €400–600/t for BF-BOF hot rolled coil, and in 2021, when energy costs and raw material costs escalated, costs rose to between €550–800/t. When value-chain disruptions impacted the global trade in 2021 and 2022, the spread in prices for hot rolled steel were even larger. However, it is important to note that actual cost-competitiveness in both the short and longer term, depend on CO_2 prices realized through existing policy such as the EU ETS and the development of similar trading systems in, e.g. China, which we do not include in Fig. 4d.

As suggested in the literature, relocating steel production to regions with renewable energy endowments can lower LCOS. The largest differences emerge when comparing the highest energy cost (Case 5a) and the lowest (Case 5c) amounting to €110/t steel (22 % difference). However, assuming lower renewable electricity cost of €64/MWh representative of the higher end of recent and forecasted electricity prices in northern Sweden (Case 5b) moderates the renewables pull effect significantly to 14 %. Case 5a and 5b are thus somewhat higher and

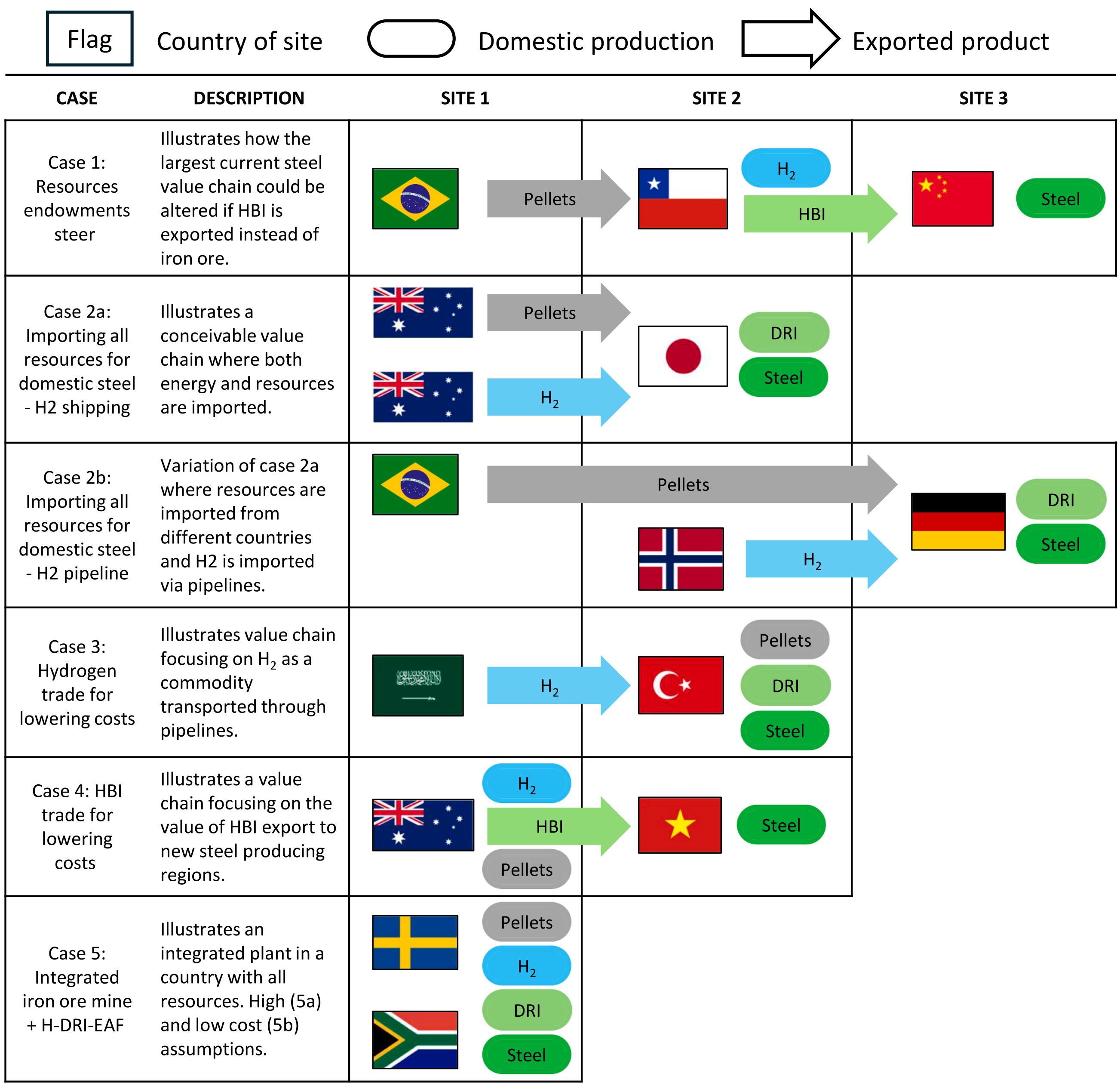

Fig. 2. Country case selection for the five identified archetypical value chain configurations and short descriptions of what reconfiguration each case illustrates.

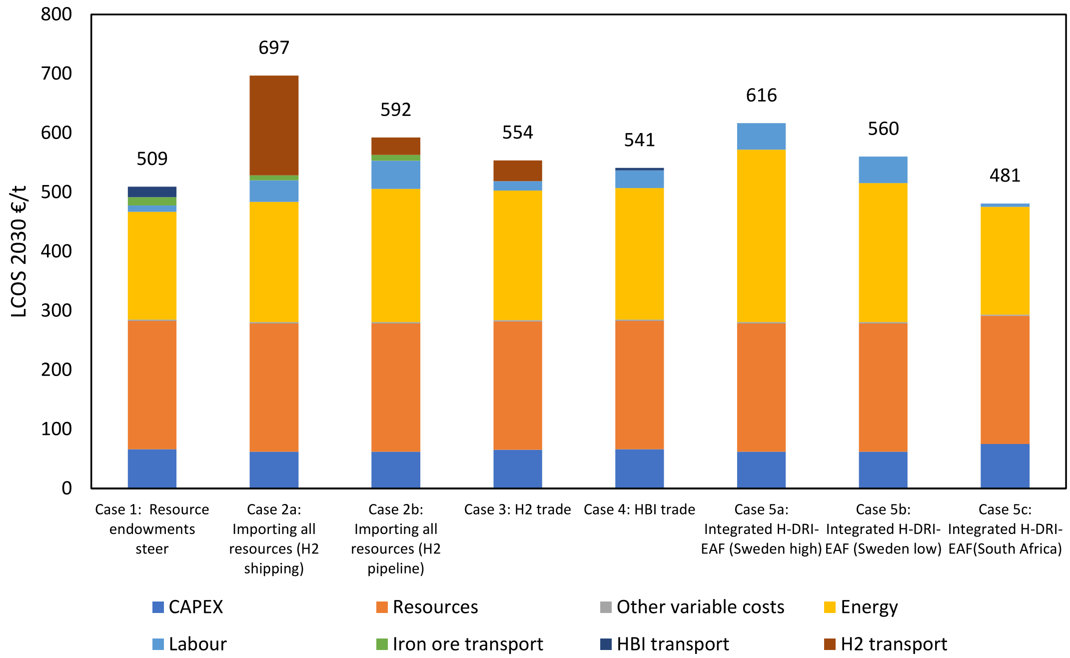

Fig. 3. LCOS for liquid steel across our five archetypical value chain configurations in 2030. CAPEX comprises the costs of the electrolyser, DRI shaft furnace and the EAF, but not CAPEX for renewable energy. Other variable costs include both O&M costs and the potential revenues from O_2 sales at €15/t.

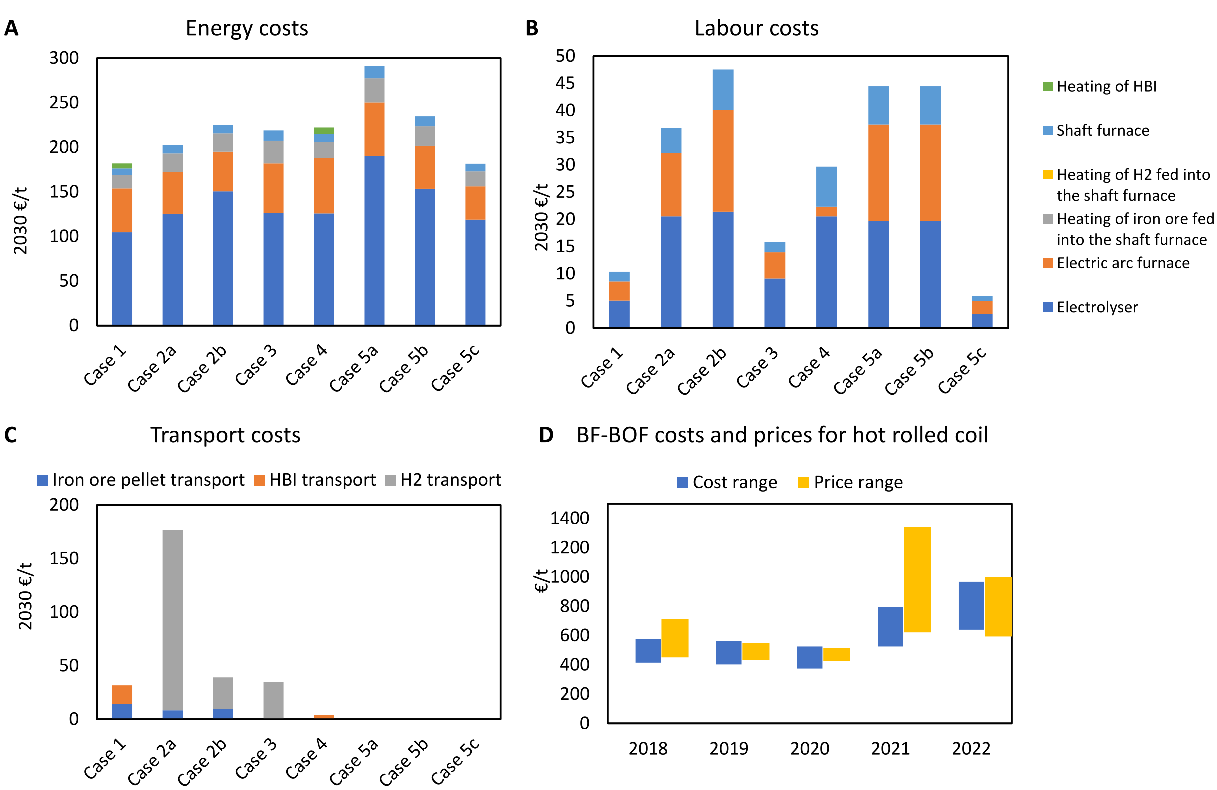

Fig. 4. Modelled cost in 2030 for Energy (a), Labour (b), and Transport (c), and the global spread of costs and prices of BF-BOF based hot rolled coil in the recent past (d).

lower respectively, than Lopez et al. [13] who found Spanish LCOS 17 % lower than those of Finland in 2030, or Verpoort et al. [10] with average generic differences between a renewable rich regions and Germany in 2030 of 18 %.

While assumptions on renewable energy cost are key and variations in energy costs is the most important factor, we find that except for the high-cost assumption in Case 5a that deviate from projected electricity costs in Sweden, LCOS differences arising from differences in renewable energy fall within a range of only €53/t. With more optimistic energy cost assumptions across all cases, this difference falls to €45/t (again excluding Case 5a) (See Fig. 6). Notably, labour cost variations reach a maximum of €42/t (see also Fig. E2, Appendix E). As seen in Fig. 3, labour costs share vary significantly, ranging from only 1 % of the LCOS in Case 5c (with the lowest overall LCOS), to up 8 % of the LCOS in Case

2b and 5b. Our results suggest value chain relocations to lower energy cost regions and countries with relatively low steelworker rates, such as in Case 5c (South Africa), Case 1 (Brazil, Chile, China), and Case 3 (Türkiye and Saudi Arabia). The difference between labour and energy costs are comparable across several cases but labour cost differences can surpass those of energy costs (i.e., Case 2a with Case 3, Fig. 4a, b). These differences, however, do not account for other location factors, such as skilled labour availability, that may offset lower costs [10,18].

Comparing with the existing literature, Devlin et al. [9] show higher LCOS and larger variations, likely related to methodological differences for, e.g., labour costs, as well as oversizing electrolysers driving higher labour need, as they model islanded energy systems. Nonetheless, our results might underestimate such differences. Applying the same approach as Devlin et al. [9] to estimate steelworker rates results in greater LCOS variations, with labour cost differences reaching up to €54/t steel. While we model these costs with higher granularity than earlier studies, more research is needed on how labour costs interact with the renewables pull effect.

With regards to transport, we find that long-distance sea transport in Case 2a add €168/t steel, equivalent to ca €3.4/kg LH2. This is a very significant impact on relative costs higher than all other cost differences (see Fig. E2, Appendix E) but the outlook is highly uncertain. The cost is dominated by the cost of the carrier and infrastructure. We base cost on a review of a range of studies considering large scale 160,000 m^3 LH2 carriers that includes hydrogen boiloff, and average estimated costs of carriers are rather consistent. But all datapoints are theoretical as no large-scale hydrogen transport has been built. Liquefaction and terminal costs are more uncertain and using more optimistic assumptions from the literature based on large scale liquefaction and large-scale export and import terminals, representing higher economics of scale, LH_2 transport could become as low as €2/kg LH2 or even lower. This potentially halves the transport cost and would thus make Case 2a much more viable (see Appendix D, Transport cost). Lower transport cost for hydrogen can also be realized through pipelines which costs has lower uncertainty (Case 2b and 3). All in all, variation in hydrogen transport cost becomes a factor comparable in size to difference in variation in labour and energy costs, or much higher in the case of hydrogen shipping (Fig. 4b).

Transport costs of iron ore and HBI are always small compared to overall difference LCOS in line with most of the existing literature [7,10,13] and can therefore be seen as both a key enabler of relocation, or conversely as only marginally driving large changes compared to today's value chains. That is, since transport of iron ore is and will be cheap also in the future, there is in principle no economic reason to co-locate iron ore resources with renewable energy for the H-DRI-EAF process, which is the focus of many studies to date (such as ref. [9]). The rational for integration is rather strategic, to maintain or establish domestic steel production or value added [19,20]. Disaggregating the value chain transporting iron ore to a region with low-cost renewable energy determining the location DRI plant and electrolysis and exporting HBI (Case 1) is indeed emerging as a low-cost option.

In general, the value chain configurations that separate production across multiple sites have costs that fall in the cost range of integrated H-DRI-EAF plants. For energy use specifically, individual studies in the literature show significant differences (see Table 1), but using same technology assumptions across our cases, we find small cost savings from integration. The most notable factor comes from charging hot DRI to the EAF directly, eliminating the energy need for HBI briquetting and heating at 0.1 MWh/t steel. This corresponds only to around 2 % of total energy consumption in Case 1 and 4. We might thus underestimate integration benefits, which all else equal would strengthen the case for integration (Case 5) over relocation of iron ore reduction combined with HBI exports (Case 1 and 4).

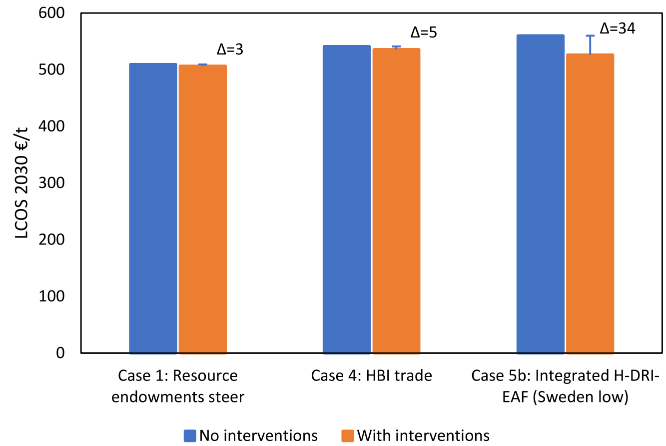

Fig. 5. Evaluation of policy interventions in 2030. In case 5b, the modelled hydrogen production subsidies amount to €26/t and state guarantees to €8/t.

To evaluate policy interventions, we quantify the impact of hydrogen production subsidies and credit guarantees. While the American climate policy package the *Inflation Reduction Act* (IRA) includes subsidies for hydrogen production of up to €2.9/kg ($3/kg) hydrogen, the first European Hydrogen Bank auctions resulted in much lower support at €0.37–0.48/kg [47], and we choose to evaluate a conservative €0.5/kg subsidy. To quantify lower cost of capital through state backed credit guarantees, we lower WACC by 2 percentage points, removing the elevated WACC assumed for first-of-a-kind plants (See **Table 1**). Both these interventions are applied to Case 5b to illustrate interventions to protect existing industries. State guarantees are further applied to Australia in Case 4, motivated by an ambition to move up the value chain in countries of high fiscal capacity and where energy costs are low. The capacity to make such interventions are unevenly distributed globally. We also lower WACC in China in Case 1, assuming it can introduce similar guarantees, while keeping higher WACC in Chile and Brazil, reflecting lower fiscal capacity for such measures. With these policy interventions, we find that lowering WACC has a smaller impact on the LCOS than hydrogen production subsidies (see Fig. 5.), particularly when WACC reductions are limited to certain parts of the value chain. Our assumed hydrogen production subsidies reduce the LCOS of Case 5b below that of Cases 3 and 4 but remains about €20/t higher than Case 1 with the interventions. However, this gap could easily be closed with more ambitious subsidies, e.g., line with the €4/kg announced by France, the €2.9/kg in the IRA, or AUD 2/kg proposed in Australia (see Appendix E, Fig. E2). In other words, even rather modest interventions compared to proposed policy alter cost-competitiveness, and reflects a rather sensitive relationship between natural endowments and industrial policy in the low-carbon steel transition. We also find that applying consistent WACC levels across all cases increases LCOS variations (reducing cost further in low-cost regions), again highlighting the sensitivity of LCOS and the renewables pull effect to key assumptions (see Fig. 6).

4. Discussion

Our results indicate that the renewables pull effect is weaker for steel

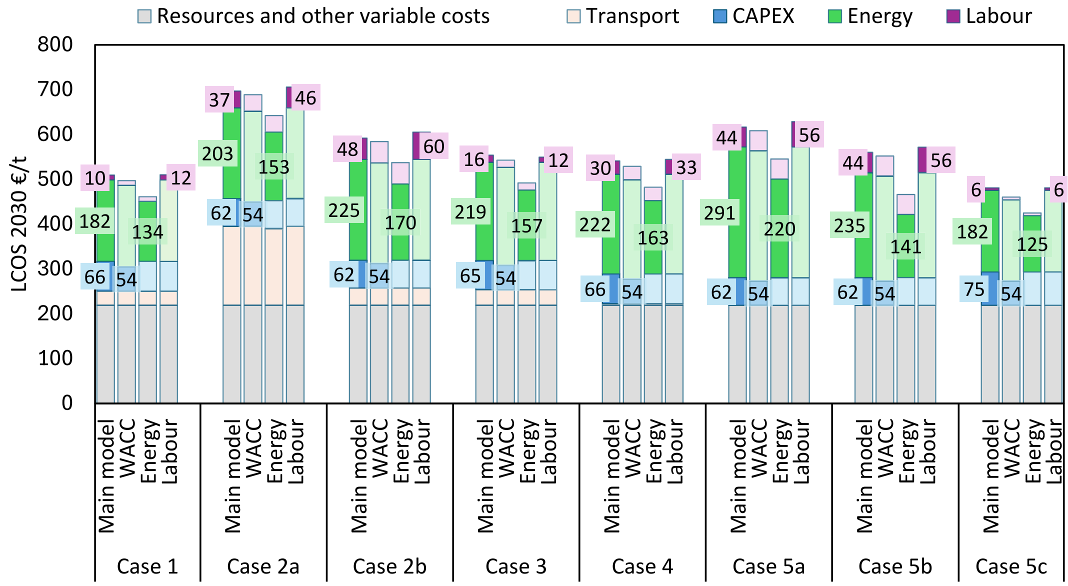

Fig. 6. Sensitivity analysis of the modelled cases with varying WACC conditions, energy costs and labour costs. Results are compared to LCOS under default parameters ("Main model"). The numbered boxes are used to show cost variations resulting from testing LCOS sensitivity to WACC, energy and labour variables.

than previously argued. Previous research has already shown that the renewables pull effect is stronger for commodities such as e-fuels, urea, and ethylene, where energy is even larger share compared to steel [10,48]. Our analysis shows that conclusions on the renewable-pull effect are sensitive to assumptions of the cost of energy, labour, and hydrogen transport, as well as subsidies. For example, recent literature on H-DRI-EAF assume Sweden to be a highest cost region [9], but forecasts and historical electricity prices in northern Sweden show lower-costs, which significantly influence results. Longer term electricity costs could lead to much lower LCOS in Sweden and northern Europe [12]. Our analysis show that existing studies differ not only on key costs assumptions and LCOS, but methods used and system boundaries.

There are also significant factors counteracting the renewables pull-effect. Most studies do not include differences in WACC which further countervails the effect for key locations. In addition, anticipated cost reductions of wind, solar, batteries and hydrogen stemming from economies of scale and improvements in global innovations systems, will benefit all geographies. When we use optimistic energy costs proportionally across cases all else equal, this indeed make other cost more important, something that is not generally recognised in the current renewables pull-literature. How strong this effect is, and if country specific technology innovations and lower CAPEX cost for general infrastructure (e.g., in China), outweigh this effect is an important future research question.

Both other studies and ours show that difference in labour costs can be as important as energy costs for relocation [9], but more granular analysis beyond our methods and the current literature is clearly needed. This includes both better data on labour intensity, more detailed comparisons of labour costs vs capital costs with higher degrees of automation following advancements in digitalisation that can be applied when new greenfield steel plants are built, and the bargaining power of labour. If this leads to greater relative importance of cost of operations should be considered in future research.

It should be highlighted that there are limitations to our results. First, we do not aim to conclude on the feasibility of changes to each value-chain, or political realism by 2030. Our aim was to select a set of value chains to assess how large difference can emerge. But this approach by necessity does not cover all important flows, and larger cost differences could appear had other cases been selected, or particularly important cases had been modelled in higher detail. For example, China accounts for more than half of the global production of steel and our analysis does not consider that DRI and EAF equipment cost could vary due to due to differences in domestic industrial scale or capacity. An additional improvement would be to model up and down processing explicitly. Future research should further such detailed characteristics of steel production in different countries and key regions.

However, we believe that our analysis spans the full range of high and low costs cases, and in general show that wile techno-economic analysis is important, it is also insufficient for explaining how value chains may be reconfigured [49,50]. Using 15 EUR/MWh lower cost assumption for energy in Sweden combined with modest subsidies on hydrogen production and cost of capital through credit guarantees resulting in 34 €/t subsidy make modelled cost on par with our value chain where we have let resource endowment steer. Policy makes thus has tangible options to influence decision on retaining domestic production for strategic reasons. It is also important to recognise that the global competitiveness of hydrogen-based steel vs conventional steel is inherently linked to environmental policy in general, such as emission trading systems, and if these expand to new locations such as China. However, such analysis and modelling of the impact of climate policy on the competitiveness of hydrogen-based steel vis-a-vis conventional steel across geographies is beyond the scope of this paper.

In general, our results show point at an important discussion of the risk that uncertain modelling assumptions drive conclusions on threshold effects beyond which a new value chain will dominate. Importantly, we find that using common assumptions, the largest variation in LCOS across the H-DRI-EAF value chain configurations is not greater than global price and production cost differences for fossil steel production sites across the world. Steel and iron-ore are highly strategic resources, with steel being produced in all major countries and economies, and traded globally with varying quality, prices, and cost structures. Domestic demand and labour costs have historically been key drivers of relocation of steel industry, and we argue that these factors will remain important during, and after a transition to low-carbon steel. Geopolitical tensions resulting in trade barriers such as tariffs and a generally more fragmented global economy is also increasing the relevance of a strategic push for hydrogen-based steel implemented through various subsidies, combining energy, climate, and security concerns. However, applying methods that instead focus on optimising for low costs, could identify opportunities differently configured H-DRI-EAF value-chains, and such analysis need to be considered in concert with our results.

5. Conclusions

A low carbon steel transition will be accelerated by better access to low-cost renewable energy, and our research confirms earlier research arguing that trade of HBI is an important low-cost option that can be on par with the best locations for fully integrated plats. We also show that mining clearly needs not be combined with renewable energy production and the DRI shaft, as iron ore transport is very efficient. Future research should therefore develop more fine-grained models including global transport of both iron ore and HBI.

Investment in new or refurbished BF-BOF steelmaking must cease during the 2030s in order to avoid worsened carbon-lock in and to meet global climate goals [2] and our findings indicate that this transition does not necessarily lead to relocation. That is, policymakers' room for manoeuvre is not confined by energy costs. Both climate policy and industrial policy are now clearly linked to geopolitical competition including rising tariffs and leadership on decarbonisation technology [51]. If the new wave of green industrial policy such as IRA in the United States and the corresponding hydrogen production support in the EU and Australia are implemented, this will strongly impacts costs [44], and according to our results, even rather modest support can be comparable to energy cost differences and thus be a strategic driver against relocation.

Finally, we note that countries and regions such as the EU which currently spearheads the transition [5], also generally have higher production costs for both conventional and low-carbon steel. Emphasising the renewables pull effect when global cost differences are uncertain and multifaceted risks postponing large-scale investments and support for domestic steel decarbonisation, in turn delaying the transition. H-DRI-EAF likely remains more costly than BF-BOF steel by 2030, but cost differentials are not too large for a range of factors, including strategically motivated interventions, to tip the scale towards a globally accelerated transition to a low-carbon steel industry in both higher and lower energy cost regions. Hence, to deliver on the Paris Agreement, policymakers should act to accelerate the decarbonisation of steelmaking across both existing and new steelmaking sites, rather than wait for the renewables-pull effect.

CRediT authorship contribution statement

Björn Nykvist: Writing – review & editing, Writing – original draft, Visualization, Software, Methodology, Formal analysis, Conceptualization. **Jindan Gong:** Writing – review & editing, Writing – original draft, Visualization, Software, Methodology, Formal analysis, Conceptualization. **Jonas Algers:** Writing – review & editing, Writing – original draft, Formal analysis, Conceptualization. **Max Åhman:** Writing – review & editing, Writing – original draft, Methodology, Funding acquisition, Formal analysis, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. System boundary and limitations

A.1. Technology choice

This study focuses on hydrogen based direct reduction of iron ore (H-DRI) combined with Electric Arc Furnaces (EAF). While some analysis find the H-DRI-EAF route to be much more expensive than Carbon Capture and Storage (CCS) applied to the conventional Blast Furnace (BF) – Basic Oxygen Furnace (BOF) route, e.g., ref. [25] the industry responses past five years show a growing list of companies working on H-DRI projects and CCS and bioenergy display much less industrial taction [5,52]. We therefore focus on H-DRI-EAF as the emerging leading technology to decarbonise steel. Our focus is on primary steel production, and we thus assume that the EAF use no scrap.

The industrial reasons for choosing H-DRI are several. The technology is commercialised for natural gas based direct reduction and thus has relatively low technological risk. At the same time, changing the core steel making process unlocks innovation potentials compared to the mature blast furnace technology. In addition, CCS added to steel plants inherently adds cost [46]. The global energy system transitions to renewable energy, hydrogen technology can play a significant role in several applications where it is hard or impossible to directly electrify [53]. But more importantly, using hydrogen from renewable electricity unlocks multiple well-known pathways of technological learning and economy of scale in renewable energy, as well as energy storage and electrolysers [53–56]. As these components are critical to the H-DRI-EAF value chain, these trends are expected to reduce the cost of the H-DRI-EAF process over time [9,13] and since low cost hydrogen is potentially located in other locations than coking coal, this technological shift could impact the global steel value chain.

A.2. Iron ore quality

The main technical barrier to H-DRI is often stressed to be iron ore quality. If direct reduced iron in the form of sponge iron or briquetted to HBI is fed directly to EAFs this requires high quality iron ore with low gangue levels and a total Fe content of >67 % [9,57]. Both additional beneficiation before reduction and alternative routes that combine the H-DRI process with melting and thus easier removal of slag, by adding a new dedicated melting unit and/or repurposing existing basic oxygen furnaces, are viable options to enable use of lower quality iron ores [57]. Modelling this cost in detail is beyond the scope of the paper, and we instead assume generally higher cost of high Fe content DRI pellets. We thus assume iron ore for 62 % content to cost €88/t representing a long term global average of ca USD 100/t,[1] and we assume a €35/t premium for beneficiation and/or processing in line with the average beneficiation cost of low grade iron ore to DRI of 67 % Fe content of USD 40/t as modelled by [9].[2] This gives a total of €123/t for

[1] https://tradingeconomics.com/commodity/iron-ore

[2] We assume a currency exchange rate of $1.1422/€ throughout the study, corresponding to the 2020 year's exchange rate, unless data in $ is reported for a specific year.

processed iron ore.

A.3. Palletization and integration

There is a potential for energy savings by integrating the iron ore pelletizing process (such as in the Metso grate kiln system) with the DRI shaft.[3] The pelletizing processes consist of three stages: a grate – where iron ore is dried and pre-heated, a kiln – where the iron ore is processed to hardened pellets, and a cooler – where the iron ore pellets are cooled down to temperatures manageable for downstream processes. These stages have different operating temperatures, allowing for heat recovery between the stages. The kiln operates at temperatures of 1200–1340 °C. Feeding the high temperature iron ore pellets directly from the kiln to the DRI shaft, moving the cooling to a later stage, could eliminate the need for additional energy to pre-heat the iron ore pellets before the DRI shaft. In our model, this additional heating need amounts to around 0.34 MWh/t. As the iron ore processing lies outside the system boundaries in this model, the potential energy savings are not explored in this study which is a limitation. However, the energy integration benefit is lower than 10 % of the total energy demand and would thus only influence energy related results marginally.

Appendix B. Approach to selecting value chain cases

To select what value chains to assess we first considered all theoretically possible configurations based on three strong location determinants: iron ore mine location, demand market location and locations with cheap renewable electricity. We then selected the configurations that are conceptually distinct and plausible. That is, configurations that illustrate how the determinants of the location of the process stages can be combined, but we ruled out cases that are clearly impractical, thus speaking against a certain configuration. For example, since the DRI-shaft by necessity have process stages both upstream (iron ore mine and hydrogen production) and downstream (EAF), it is always rational to co-locate the DRI-shaft with one or more process stages to avoid unnecessary transport (See Appendix F).

We then assessed plausible locations to situate our selected configurations based on iron ore production and export statistics, steel production data, potential green hydrogen trade flows, and our identified H-DRI-EAF value chain determinants. The country selection for the cases further reflects a combination of resource availability, trade potentials, and proximity considerations.

In Case 1: Resource endowments steer, we model iron ore flows from Brazil to China, the largest 2019 trade route, with Chile included as a potential green hydrogen exporter due to its proximity to Brazil. In Case 2a: Importing all resources (LH2 shipping), Australia and Japan represent the largest 2019 iron ore exporter and second-largest importer, respectively, with Australia also being a potential green hydrogen exporter. This value chain configuration is also motivated by existing research, e.g. by ref. [7]. For Case 2b: Importing all resources (H_2 pipeline), we choose Germany, one of the top 10 steel producers in 2019, for its offshore pipeline connections to Norway, a potential green hydrogen exporter. Brazil is chosen as Germany's largest iron ore supplier in 2019. In Case 3: H_2 trade, Türkiye represents a major steel producer, nearly self-sufficient in iron ore. We pair it with green hydrogen imports from Saudi Arabia via onshore pipelines. For similar reasons as in Case 2a, Australia is modelled as an HBI exporter to Vietnam, a rapidly growing steelmaking region in Case 4: HBI trade. Case 5: Integrated H-DRI-EAF is divided into three sub-cases, exploring Sweden as a leader in H-DRI-EAF steelmaking under high (5a) and low (5b) electricity price scenarios, and South Africa (5c) as a region with all necessary natural resources for H-DRI-EAF steel production and its low renewable energy cost and high renewables pull potential. Further methodological details and the rational for country selection are provided in Appendix F.

We focus on specific sites within the selected countries to model illustrative trade routes specific to each case, and to select regionally relevant baseload electricity costs. We select key locations for trade routes by identifying seaports near EAF facilities and resource sites while considering proximity and trade relevance. Shipping distances are calculated via the Searoutes API, and pipeline distances are derived from planned projects and estimated using Google Maps. Specific sites for Cases 5a, 5b, 5c are selected based on where H-DRI-EAF plants are being developed and on resource sites. See Table D1, Appendix D, for a detailed list of sites in our model.

Appendix C. Supplementary methods

C.1. Technical assumptions for modelling steelmaking

As Vogl et al. [4] we only consider the basic chemical processes taking place according to eqs. (3, (4, and (5.

$$H_2O \rightarrow H_2 + {}^1\!/\!_2 O_2 \tag{3}$$

$$Fe_2O_3 + 3H_2 \rightarrow 2Fe + 2H_2O_{(g)} \tag{4}$$

$$Fe_2O_3 + H_2 \rightarrow 2FeO + H_2O_{(g)} \tag{5}$$

Thus, we exclude details such as of slag formation and minor material flows related the iron ore pellet impurities from our analysis. We assume that all elements, but steel are discharged from the EAF with the slag [4]. Reference conditions assume operations at 25 °C under atmospheric pressure. Specific heat and enthalpies of the mass flows are determined using the Shomate equation, see Eq. (6), following Bhaskar et al. [6].

$$H^{\circ} - H^{\circ}_{298.15} = A \times t + \frac{B \times t^2}{2} + \frac{C \times t^3}{3} + \frac{D \times t^4}{4} - \frac{E}{t} + F - H \tag{6}$$

Where:

- t is the temperature in Kelvin
- A, B, C, D, E, F and H are substance-specific coefficients retrieved from the NIST webbook [58]

We only consider the heat capacities of the main components of respective flows.

[3] https://www.metso.com/portfolio/grate-kiln-system/

For the electrolyser, our assumptions on capital expenditures (CAPEX), a 70 °C operating temperature and a 72 % efficiency, allow for both alkaline and proton exchange membrane (PEM) technologies to be explored [4]. We model H_2 supply at 50 % above stoichiometric requirements and assume that 60 % of the O_2 byproduct is sold for revenue, per ref. [4]. In the iron making process, iron ore pellets with 67 % iron content are reduced in the DRI shaft furnace, assuming a 94 % metallization rate and an operating temperature at 800 °C [4]. We assume market prices for high quality iron ore pellets to be €123/t which include a premium for DRI grade pellets (see Appendix A). Pellets are assumed to be preheated to the furnace operating temperature using an electric heater with 85 % efficiency [6]. The output stream of iron, wüstite (FeO) and impurities is assumed to leave the furnace at 650 °C [24] while recycled excess H_2 and water reagents are assumed to be released as exhaust gases at 800 °C [4]. Additionally, the shaft furnace requires 80 kWh/t steel for auxiliary power [6].

Our model includes a condenser unit to recover heat from the shaft furnace exhaust gas stream and use it to preheat the furnace's inlet H_2 stream with an 75 % efficiency [4]. The H2 and water exhaust gases are assumed to enter the condenser at 800 °C, where they are separated and cooled to 70 °C [4]. When modelling a fully integrated system, the water is recirculated to the electrolyser, while the H_2 exhaust stream is redirected to the feed stream entering the condenser unit and continuing to the shaft furnace (See Fig. 1). Additional energy for preheating the H_2 inlet stream to the operating temperature is provided by an electric heater with the same efficiency as mentioned above. Any excess recovered heat is assumed to offset the shaft furnace's requirements.

When modelling fully integrated steelmaking, the EAF is charged with the hot stream of metallic iron, wüstite (FeO) and impurities together with carbon, lime fluxes and alloys to produce molten steel. Slag is formed with lime fluxes at a consumption rate of 50 kg/t steel, and the EAF alloy and graphite consumption are assumed to be 11 kg/t steel and 2 kg/t steel, respectively [4]. Lastly, we model the EAF specific energy consumption to be 752 kWh/t steel at a 0 % scrap charge, according to ref. [4].

C.2. Steel production process under disintegrated value chain configurations

C.2.1. Cost assumptions for parameters common across cases

All parameters and data originally in USD ($) were converted to EUR (€) using annual average exchange rates provided by the European Central Bank (ECB)[4] for the respective year of the $ data. When the year of the $ data was unspecified, the average 2020 exchange rate of $1.1422/€ was applied. Additionally, values from other years were adjusted to 2020 € using the ECB's Harmonized Index of Consumer Prices.[5]

Table C1
Cost assumptions, based on Vogl, Åhman, and Nilsson (2018), with the exception of the costs for iron ore pellets that include a premium for DR grade pellets.

CAPEX electrolyser	585	€/kW installed capacity
CAPEX shaft furnace	230	€/t capacity
CAPEX EAF	184	€/t capacity
O&M costs	3	% of CAPEX
Iron ore pellets	123	€/t
Selling price of O_2	60.8	€/t O_2
Lime fluxes	90	€/t lime flux
Graphite electrodes	4000	€/t graphite electrode
Alloys	1.777	€/t alloy
Lifetime DRI shaft and EAF	20	years
Lifetime electrolyser	10	years

C.3. Transport costs

C.3.1. Iron ore pellets and HBI shipping costs

Recent cost estimates and assumption used in the literature for bulk shipping cost of iron ore pellets and HBI vary substantially. For example, Verpoort et al. [10] find cost in 2016 to be as low as €2.5/t but also discusses recent costs as high as €40/t, in the end choosing €10/t for their analysis of costs in 2040. The high-end cost is consistent with recent high cost for transport between Brazil and China for large scale Capesized cariers of 180,000 DWT of €34/t,[6] but market cost for iron ore transport is sensitive to current conditions including fuel costs and economic activity, and short-term shortages. In general, costs depend on transport distance, as well as assumed ship size. The largest bulk freight carriers used for iron ore transport operated by Vale are the Valemax 400,000 DWT carriers with reported cost of as low as €15/t from Brazil to China,[7] but for shorted trips cost can be significantly higher. As a compromise, we select reported higher end values of €34/t for long distance large scale transport between Brazil and China of 10,000 nm, and using a speed of 14.5 nm/h [7] resulting in a cost of or €0.55 /t/day. While HBI transport is today done using smaller carriers and, e.g., Devlin and Yang therefore consider two different sizes [7] we use the same estimate for both iron ore and HBI transport cost as we consider large scale transport and the same bulk carriers can be used for both.

C.3.2. Hydrogen pipeline costs

Our modelled costs for hydrogen transport through pipelines are based on assessments of 2030 costs by [30] and calculated according to eq. (8).

$$C_{P,H2} = \left(CAPEX_{P,H2} + OPEX_{P,H2}\right) \times D_{o,d} \tag{7}$$

[4] https://www.ecb.europa.eu/stats/policy_and_exchange_rates/euro_reference_exchange_rates/html/eurofxref-graph-usd.en.html
[5] https://www.ecb.europa.eu/stats/macroeconomic_and_sectoral/hicp/html/index.en.html
[6] Original value: $43/t in 2021. https://lloydslist.com/LL1138354/Capesize-daily-rates-leap-to-almost-75000
[7] Original value: $18 /t in 2018. https://www.lloydslist.com/LL1125415/Vale-forecasts-60-cent-freight-advantage

Where:

- $C_{P,H2}$ denotes the onshore transport costs of hydrogen through pipelines
- $CAPEX_{P,H2}$ denotes the capital costs of onshore hydrogen pipelines
- $OPEX_{P,H2}$ refers to the operational costs of onshore pipeline transport of hydrogen, assumed as €0.0775/tH_2/km [30].
- $D_{o,d}$ refers to the onshore transport distance between origin *o*, and destination *d*.

Transport costs through offshore pipelines are estimated as 1.96 times the costs of using onshore pipelines [30].
The capital costs for onshore hydrogen pipeline are calculated based on specific investment costs, according to eq. (8).

$$CAPEX_{P,H2} = \frac{SIC_{P,H2}}{\kappa} \times a \tag{8}$$

Where:

- $SIC_{P,H2}$ refers to the specific investment costs of hydrogen pipelines, assumed to be the average of the low and high costs of new constructions at €2.14/tH_2/y/km [30].
- The annual pipeline utilization rate, κ, is set at 75 % according to [30].
- a denotes the annuity factor and is calculated according to eq. 5 in main text), assuming a lifetime of 55 years and an interest rate of 8 % [30].

C.3.3. Hydrogen Liquefaction costs

Al Ghafri et al. [28] offers a recent review of hydrogen liquefaction which we base cost assumptions on. Liquefaction cost can be divided into a) energy costs, and b) non-energy cost related capital and other operational costs. We use a simple model of these two categories of cost based on Al Ghafri et al. [28] as shown in Table C2. The largest liquefaction facilities are today at ca 30 tons per day (TPD) capacity which is much too small for the steel value chain considered in our analysis of a 2.5 Mt./y steel plant that requires the order of 500 TPD. Our outlook is also for the first large-scale value chains in the near-term future. Concurrently, we use average values of large-scale studies of 500 TPD or more, and assessed as cost for the 2030 time horizon, summarized in Table C2. below.

Table C2
Liquefaction cost and specific energy consumption data for large scale hydrogen liquefaction in 2030.

Study name in Al Ghafri et al. (2022)	Liquefaction NON- energy costs [€/kg H_2]	SEC [kWh/kg H_2]
APERC	0.19	6.4
Teichnmann et al.	0.33	7.0
Ishimoto et al.	1.02	6.5
KHI	0.60	11
Average	0.53	*7.7*

Calculating liquefaction costs this way yields the following model:

$$C_{liq.} = C_{NEliq.} + SEC \times C_{el.} \tag{9}$$

Where:

- $C_{liq.}$ is the liquefaction cost in €/kg
- $C_{NEliq.}$ is average CAPEX and OPEX cost not related to energy €0.53/kg H_2
- $SEC = 7.7$ kWh/kg H_2 is the average specific energy requirement for liquefication
- and $C_{el.}$ is the electricity cost in €/kWh

C.3.4. Hydrogen transport costs

Liquid hydrogen transport costs for large scale value chains have been modelled in a range of studies. However, comparisons are hard to make due to different assumptions on harbour costs, in particular varying assumptions on need for storage at loading port, and storage and regasification equipment at receiving port [28]. Here we review studies that a) are large scale and evaluate tankers at 160000 m3 or more (on par with today's LNG carriers), and b) clearly state that the study is a bottom-up techno economic model that separate out carrier specific costs from other costs Table C3. Note that all these studies focus on large to very scale value chains in terms of daily demand of LH2 (200 tpd to 10,000 tpd). We include all these as there is no significant relationship between costs/km and daily demand in this range, and this independence is to be expected also above a certain size, as the economies of scale for transport of liquid hydrogen primarily relate to the carrier itself.

A simple linear regression setting the intercept to zero has the best model fit, see Fig. C3. This is a reasonable model assuming that almost all costs are linear with distance, except for boil-off at a constant %-age, and small portion of cost idle loading and unloading. All in all, transport costs are dependent on distance.

$$C_{carrier} = 4.29 \times 10^{-5} \times l \tag{10}$$

Where:

- $C_{carrier}$ is the transport cost related to the carrier in €$kg^{-1}H_2$ and
- l is the transport length in km, one way

Table C3
Data on LH2 carrier transport costs.

Study	Transport distance [km]	Size of Carrier [m3]	Daily demand value chain [tpd]	Carrier Cost [€/kg LH2]
Ahluwalia et al. [59]	5915	180,000	1564	0.25
Ahluwalia et al. (2021)	7769	180,000	1188	0.32
Ahluwalia et al. (2021)	10,868	180,000	1311	0.43
Ahluwalia et al. (2021)	16,887	180,000	1405	0.66
Johnston et al. [60]	19,801	160,000	208	1.00
Johnston et al. (2022)	8213	160,000	463	0.43
Al-Breiki Bicer. (2020)	12,000	160,000	752	0.34
Al-Breiki Bicer. (2020)	9700	160,000	752	0.29
Al-Breiki Bicer. (2020)	2400	160,000	752	0.08
Ishimoto et al. (2020)	23,407	172,000	378	1.17
Raab et al. [61]	9125	160,000	226	0.41
Hampp et al., [37]	13,056	157,778	9862	0.64
Kamiya et al. [62]	9000	160,000	618	0.22
Wijayanta etl al. [63]	9000	160,000	822	0.33
ERIA [64]	9000	160,000	770	0.22

C.4. Other transport costs: Loading and receiving ports and regasification

Large scale hydrogen onshore storage is falls within a wide range of cost €0.29 to €3.1/kg for short term daily storage, and longer-term storage is far more expensive [65]. Some of the recent literature on LH2 value chains shows that storage at ports can be even more expensive than the transport itself in [63,66]. Here we note that modern LNG value chains often use floating storage and offloading units (FSO) and floating storage and regasification units (FSRU) as these often have lower costs [29]. The existing LH2 literature does not consider this option but given that cryogenic shipping and handling of LH2 in the literature is modelled based of LNG value chains all other regards, it is reasonable to expect that a similar setup is beneficial for LH2 transport. The added benefit is that we can avoid using highly uncertain LH2 storage costs as these estimates vary significantly in the literature (e.g., see sources in ref. [28]).

We thus model storage at loading port costs based on deploying floating stationary carriers. That is, a carrier is always docked at the loading and spends their time there acting as storage. Similarly, at the receiving port, we model the value chain based on a FSRU, i.e., a regasification unit of the same size as the transport carriers transporting LH2. FSRU has extra equipment and costs more than a transport carrier but are otherwise equal and it is possible to convert carriers to FSRU. We modelled the cost of a LH2 FSRU based on the extra CAPEX cost for LNG FSRU compared to LNG carriers applied to the full carrier cost (see data sources in Table C4). The average "FSRU-factor" is 1.56, i.e., we model a LH2 FSRU unit as 56 % more expensive compared to a LH2. This could be optimistic or pessimistic depending on OPEX cost differences, but it is a reasonable assumption that they scale similarly.

Table C4
FSRU additional cost above tanker cost.

LNG FSRU cost	LNG Carrier cost	FSRU-factor	Source
m USD (2022) 332	m USD (2022) 250	1.33	https://lngprime.com/asia/excelerate-to-splash-about-332-million-on-fsru-order-in-south-korea/63086/
m USD (2022) 300	m USD (2022) 175	1.71	https://crsreports.congress.gov/product/pdf/IN/IN11956
m USD (2013) 325	m USD (2013) 200		https://pdf.usaid.gov/pdf_docs/PA00KWB5.pdf
		1.63	
Average FSRU-factor:		1.56	

To estimate cost of a stationary LH2 carrier, that in turn is used to model FSRU and FSO costs, we observe that fuel costs as a share of total carrier transport costs have been assessed to be in the range of 20 % [67], to 40 % [59], with others in between, such as [60] at 30 %. That is, the energy for propulsion is a key component, and very across studies due to a range of assumptions, with a similar variance in the cost breakdown as LNG carriers [68]. The key assumptions that can influence energy costs are bunker fuel cost, voyage speed and the type and efficiency of marine propulsion system, including whether boil gases are used for propulsion or liquified again to avoid degradation of the carried load. It is outside the scope of this study to do detailed modelling of this, and we thus make simplified assumptions modelling energy costs being 30 % of total carrier costs and linear with distance.

Finally, we assume an average speed of 18 kn (32.85 km/h) for the carriers as the literature reviewed typically use assumptions between the 16–20 kn. For example, Hampp et al. [37] assumes 20 kn, Johnston et al. [60] 18 kn, Al-Breiki, Briecer [67] 20 kn, Ichimoto et al. [66] 16kn, Raj et al. [69] for LNG 20kn. With this data, the daily cost of operating a carrier sans energy for propulsion can be calculated as:

$$C_{carrier\ p.d.} = 0.7 \times 4.29 \times 10^{-5}\left[\frac{EUR}{kgkm}\right] \times 32.85\left[\frac{km}{h}\right] \times 24\left[\frac{h}{d}\right] \times \mathrm{d} = 0.024 \times \mathrm{d}\left[\frac{EUR}{kg}\right] \tag{11}$$

And we now use this to model loading port storage costs as LH2 FSO and LH2 FSRU costs per day as:

$$C_{loading\ p.} = C_{carrier\ p.d.} \tag{12}$$

$$C_{recieving\ p.} = C_{carrier\ p.d.} \times FSRU\_factor \tag{13}$$

The final costs of transport now depend on how large scale the value chain is. The larger, the shorter time LH2 spend stored in the FSO and FSRU, before being moved to a carrier, and onward from the receiving port respectively. Our base assumption is a value chain of 500 TPD LH2, or 9700 m3 LH2. Hence a FSO of 160,000 is filled in 24 days. Together with one day of loading and unloading time between, to, or from FSO and FSRU [66] the total cost of storage at loading and receiving ports can thus be calculated.

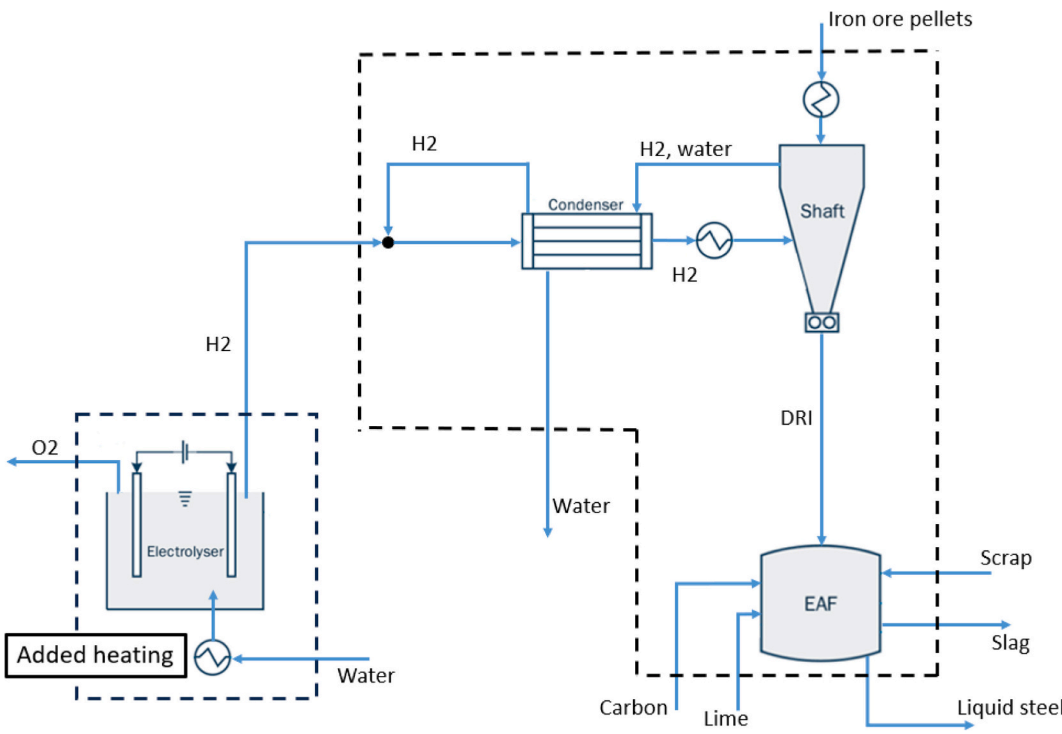

Fig. C1. System boundaries of the techno-economic model of value chain configurations where the electrolyser is located separately (Cases 2a, 2b, and 3), adapted from ref. [4].

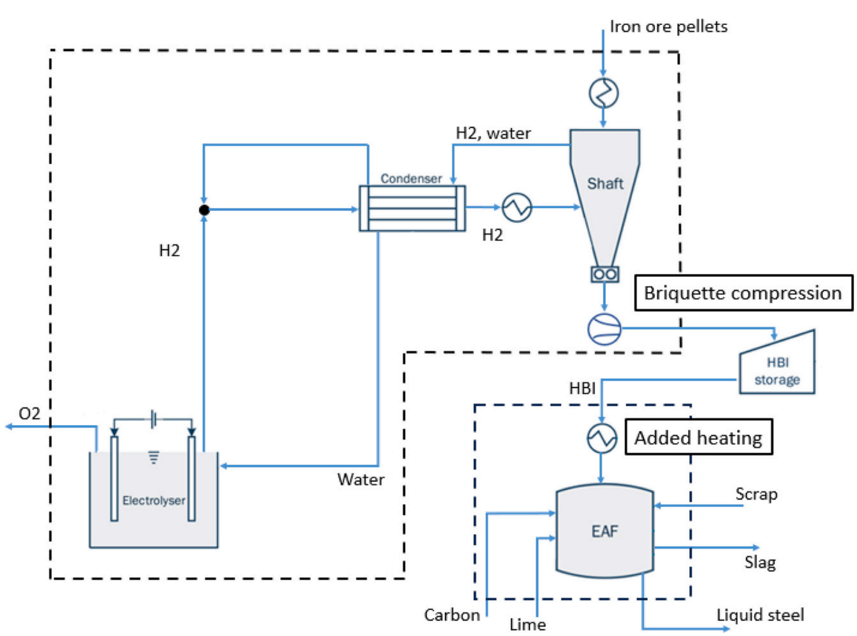

Fig. C2. System boundaries of the techno-economic model of value chain configurations where the EAF is located separately (Cases 1, 4), adapted from ref. [4].

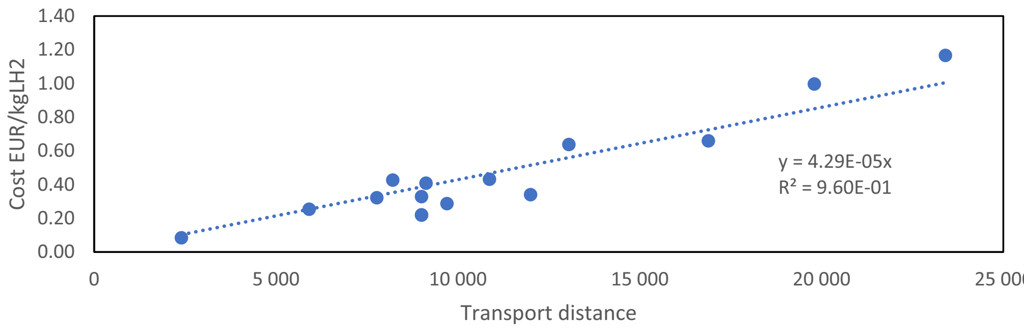

Fig. C3. LH2 carrier cost as function of distance in reviewed studies.

Appendix D. Case specific input parameters

D.1. Transport Cost

To model transport costs, we use illustrative examples of trade routes for each case, see Table D1. To estimate transport distances for shipping, we first identify seaports located near EAF steelmaking facilities in them demand market countries for each case. For case 1, we then select seaports in Brazil and Chile located near key resource sites: one of Brazil's largest iron ore mines in the Pará region [70], and a cost-competitive green hydrogen production site in Chile's Atacama Desert [13,71]. The same port in Brazil is selected in case 2b from which iron ore pellets are assumed to be shipped to Port of Rotterdam, the closest port to an H-DRI-EAF plant under construction in Duisburg, Germany [35]. For case 2a, port Hedland is chosen based on the work of Devlin and Yang [7]. In case 4, Port Darwin is chosen for its iron ore trade relationship with one of the largest Vietnamese steel producers [72]. For case 3, Neom is identified as a hydrogen transport origin point due to significant project investments [73] while Zonguldak, Türkiye is selected as the destination, hosting an EAF facility [35]. Lastly, for offshore pipelines in case 2b, the origin and destinations points, along with the hydrogen transport distance, are based on a previously planned green H_2 pipeline project [74].

Assumptions on maritime shipping distances are based on Searoutes routing API [75]. The H_2 transport distance via onshore pipelines is estimated using Google Maps. The quantities of each transported commodity are estimated through the corresponding mass flows and the reference plants' rated capacities.

Table D1
Assumptions on transport distances, modes of transport, and distances for each case and transported commodity.

	Port of origin	Destination port	Mode of transport	Commodity	Distance
Case 1: Resource endowments steer	Ponta de Madeira, Brazil	Port Antofagasta, Chile	Shipping	Iron ore pellets	6013 nm
	Port Antofagasta, Chile	Port Qingdao, China	Shipping	HBI	10,138 nm
Case 2a: Importing all resources (LH2 shipping)	Port Hedland, Australia	Port Osaka, Japan	Shipping	Iron ore pellets	3456 nm
	Port Hedland, Australia	Port Osaka, Japan	Shipping	LH2	3456 nm
Case 2b: Importing all resources (LH2 pipeline)	Ponta de Madeira, Brazil	Port of Rotterdam, Netherlands	Shipping	Iron ore pellets	4126 nm
	Vestland, Norway	Wilhemshaven, Germany	Offshore pipeline	H_2	937 km
Case 3: Hydrogen trade	Neom, Saudi Arabia	Zonguldak, Türkiye	Onshore pipeline	H_2	2200 km
Case 4: HBI trade	Port Darwin, Australia	Port Hoa Phat Dung Quat, Vietnam	Shipping	HBI	2437 nm

D.2. Energy costs

Energy costs are derived from Fasihi and Breyer's [17] estimates for baseload electricity costs from on-site, large-scale hybrid photovoltaic (PV)-wind systems across global regions. Specifically, we use their 2030 estimates for the levelized cost of baseload electricity in the locations listed in Table D1. For case 5a in Sweden, we use estimates for Norrbotten, where the world's first large scale H-DRI-EAF plant is built by Stegra [76]. We also use a lower electricity costs estimate for Norrbotten in case 5b, to reflect Power Purchase Agreements (PPA) [77]. We use what we believe is a conservative estimate of €64 /MWh based on signed by Stegra (formely H2GS). Notably, the current longer term price forecast by Swedish transmission system operator (TSO) Svenska Kraftnät that models a price of €40–63.5 /MWh in 2035 [78]. Electricity costs in South Africa, case 5c, are estimated for the Northern Cape province, home to two major suppliers of high-grade iron ore products [79].

Cost estimates from Fasihi and Breyer [17] are nominally based on a 7 % weighted average cost of capital (WACC) globally, but as is to be expected, cost vary depending on WACC assumptions in a linear manner as is shown in Fig. D1. To account for varying costs of capital across OECD and non-OECD countries, we thus adjust the estimated levelized costs of baseload electricity using this linear relationship (Table D2). Our WACC assumptions for the two groups are based on first calculating average local WACC conditions for solar PV and onshore wind from [27] for each country in our assessment and then calculating the average for countries within the OECD and non-OECD categories, respectively. The original cost estimates and costs under changing WACC assumptions for the levelized cost of baseload electricity are shown in Table D3.

Table D2
Levelized cost of baseload electricity for Germany and Kenya in 2030 under varying WACC conditions, data from [17, Fig. 30].

WACC	Germany		Kenya	
	WACC cost factor [#]	Levelized cost of baseload electricity [€/MWh]	WACC cost factor [#]	Levelized cost of baseload electricity [€/MWh]
3 %	0.73	48.5	–	–
5 %	0.87	57.5	–	–
7 %	1	66	1	43.75
10 %	–	–	1.23	53.75
15 %	–	–	1.63	71.25

Table D3
Original cost estimates, based on Fasihi and Breyer [17] in €/MWh and the local WACC levels for renewable energy. The final assumptions consider local WACC conditions of 4 % in OECD countries and 5 % in non-OECD countries.

Country	Location	Original cost estimates for levelized costs of baseload electricity [€/MWh]	Country- and technology specific WACC [%]		Assumed levelized cost of baseload electricity [€/MWh]
Reference		[17]	[27]		
			Solar PV	Onshore wind	
Australia	Darwin	66	2.90 %	2.9 %	52
Australia	Pilbara	65			52
Brazil	Pará	77	6.30 %	4.9 %	67
Chile	Atacama	55	3.50 %	4.5 %	44
China	Shandong	75	2.50 %	2.5 %	65
Germany	North Rhine-Westphalia	75	1.30 %	1.3 %	60
Japan	Osaka	78	2.30 %	4.7 %	62
Norway	Vestland	78	4.50 %	4.5 %	62
Saudi Arabia	Neom	60	6.20 %	6.2 %	52
South Africa	Northern Cape Province	57	5.20 %	6.6 %	50
Sweden (high cost)	Norrbotten	100	3.20 %	3.5 %	79
Sweden (low cost)	Norrbotten	–			64
Türkiye	Zonguldak	93	7.50 %	7.5 %	74
Vietnam	Quang Ngai	95	6.00 %	5.1 %	83

Our assumed energy costs are generally higher than those reported by Devlin et al. [9], whose modelled levelized cost of electricity (LCOE) ranges between €22–63/MWh for 2030. However, the variation in LCOE across countries follows a similar pattern. Chile, South Africa and Australia have the lowest LCOE, Brazil and China fall in the middle, and Turkey and Sweden highest LCOE among the countries. It is important to note, though, that not all countries in our study are included in their analysis. Differences in the LCOE range can be explained by the fact that Devlin et al. [9] model islanded supply of renewable energy, whereas we base our assumptions on results from large-scale baseload generation by Fasihi and Breyer [17].

D.3. Labour costs

Drawing from the rational of Devlin et al. [9], we model labour costs C_{labour} using assumptions on local steelworker wages and employer contributions, along with uniform overhead cost rates and labour intensities for the key process steps in our model: the electrolyser, DRI shaft and EAF, as follows:

$$C_{labour} = SR_m \times (LI_{Elect.} + LI_{SF} + LI_{EAF}) \tag{14}$$

Where:

- SR denotes the hourly steelworker rate in country m
- $LI_{Elect.}$, LI_{SF}, and LI_{EAF} denotes the labour intensities of the electrolyser, DRI shaft furnace and EAF, specified in Table D5.

Per capita steelworker wages for each country are estimated using 2020 data on wages and employment in the basic iron and steel sector. For countries with outdated data, the most recent available figures on steelworker wages and employment are used. These data are combined with gross national income (GNI) per capita for the corresponding year, along with employer contribution rates to calculate the average wage ratio between the steel industry and GNI, Eqs. (15) and (16). All data and calculated wage ratios are presented in Table D4. Due to lacking data on wages and employment in the South African basic iron and steel sector, we estimate the wage ratio by averaging the ratios from all other countries.

$$SWavg_{m,a} = \frac{W_{m,a}}{E_{m,a}} \times (1 + EC_m) \tag{15}$$

$$WR_m = \frac{SW_{avg_{m,a}}}{GNI_{m,a}} \tag{16}$$

Where:

- $SWavg_{m,a}$ denotes the average steelworker wage in country m, year a
- $W_{m,a}$ denotes wages and salaries in basic iron and steel
- $E_{m,a}$ denotes number of employees in basic iron and steel
- EC denotes employer contributions.
- WR_m denotes the average wage ratio between steelworker wages and national averages
- $GNI_{m,a}$ refers to the gross national income.

The final assumptions on hourly steelworker rates were calculated as:

$$SR_m = \frac{(GNI_{m,2020} \times WR_m) \times (1 + OH)}{2080} \tag{17}$$

Where:

- $GNI_{m,2020}$ denotes the 2020 gross national income for respective country
- OH denotes the uniform overhead cost rates at 25 %, based on [34], and
- 2080 are the assumed number of working hours in a year.

The hourly steel worker rates, denoted by SR_m, are shown in Table D4.

Table D4
Data on regional steelworker wages, employment and GNI, and the calculated wage ratios and hourly steelworker rates.

	Year	Wages and salaries	Employees	GNI corresponding year	Employer contributions	Wage ratio	2020 GNI	Hourly steel-worker rate
Reference	Basic iron and steel sector [32]			[31]	Retrieved from	[–]	[31]	[–]
Unit	[–]	[m€/year]	[#]	[€/capita/year]	[%]	[–]	[€/capita]	[€/capita/h]
Australia	2020	933	17,876	46,953	19.50 %	1.33	46,953	37.5
Brazil	2020	1461	132,036	6925	30.50 %	2.08	6925	8.7
Chile	2016	93	5948	11,922	2.40 %	1.35	11,399	9.2
China	2016	20,055	2,733,631	7283	28.20 %	1.29	9210	7.1
Germany	2020	65 30	125,387	41,998	21.15 %	1.5	41,998	37.1
Japan	2014	10,835	294,603	38,533	15.09 %	1.1	35,782	23.6
Norway	2020	109	1919	68,823	14.10 %	0.95	68,823	39.1
Saudi Arabia	2018	665	26,818	19,611	11.75 %	1.41	19,637	16.7
Sweden	2020	1115	24,461	47,995	31.42 %	1.25	47,995	36.0
Türkiye	2020	1128	85,089	8020	22.50 %	2.03	8020	9.8
Vietnam	2020	419	84,571	3020	21.50 %	1.99	3020	3.6
South Africa	–	–	–	–	–	1.48	5349	4.8

https://taxsummaries.pwc.com/
Our assumed labour intensities stem from Devlin et al. [9] together with empirical data from the Global Energy Monitor's Steel Plant Tracker (GSPT) data-set. These are presented in Table D5.

Table D5
Labour intensities of the major H-DRI-EAF process steps.

	Value	Unit	Reference
Electrolyser	2	[h/kW installed electrolyser]	[9]
Shaft furnace	0.18	[h/tDRI]	[35]
EAF	0.49	[h/t steel]	[35], (personal communication)

The shaft furnace labour intensities were derived by empirical observations from the GEM's Steel Plant Tracker dataset, where six steel plants were filtered out using the filters described in Table D6.

Table D6
Filters applied to the GEM Steel Plant Tracker dataset.

	Shaft furnace labour intensity filter	EAF labour intensity filter
Main production equipment	DRI	EAF
Start-up year	2010 or later	2010 or later
Workforce data entry	$\neq$ n/a	$\neq$ n/a

We then selected the plants where it was clear that the workforce data was data on the direct jobs generated by the plant, arriving at five plants with transparent workforce data. Assuming the same number of hours in a working year, of 2080 h/y, we calculated the number of working hours associated with each plant. The shaft furnace labour intensity for plant i was then calculated as:

$$LI_{SF,i} = \frac{WF_i \times Wh}{NC_i \times DRI_{req.}} \tag{18}$$

Where:

- WF_i denotes the size of the workforce in plant i,
- Wh denotes the number of working hours in a year, assumed to be 2080 h/y [9]
- $DRI_{req.}$ refers to the required tonne DRI to produce one tonne of molten steel.
- NC_i denotes the nominal capacity of shaft furnace represents annual nominal capacity of the plant's shaft furnace.

Applying a similar rational for deriving the EAF labour intensity results in a list of 20 plants with transparent workforce data, filtered in accordance with Table D6. Based on this list, an empirically derived labour intensity lands on 1.91 h/t steel. While these plants show EAF as their main production equipment, their operations involve other processes as well, such as rolling and casting mills. To limit our estimation to the EAF unit, we assume that the EAF labour input corresponds to 43 % of the total labour input for EAF, casting and hot rolling processes [80], leaving our empirically derived EAF labour intensity at 0.82 h/t steel. Consulting a technical expert, however, reveals that the labour input, limited to the EAF only, rather lies in the order of 0.16 h/t steel for efficient mills (personal communication). Averaging these values results in our assumed EAF labour intensity of 0.49 h/t steel, in line with [9].

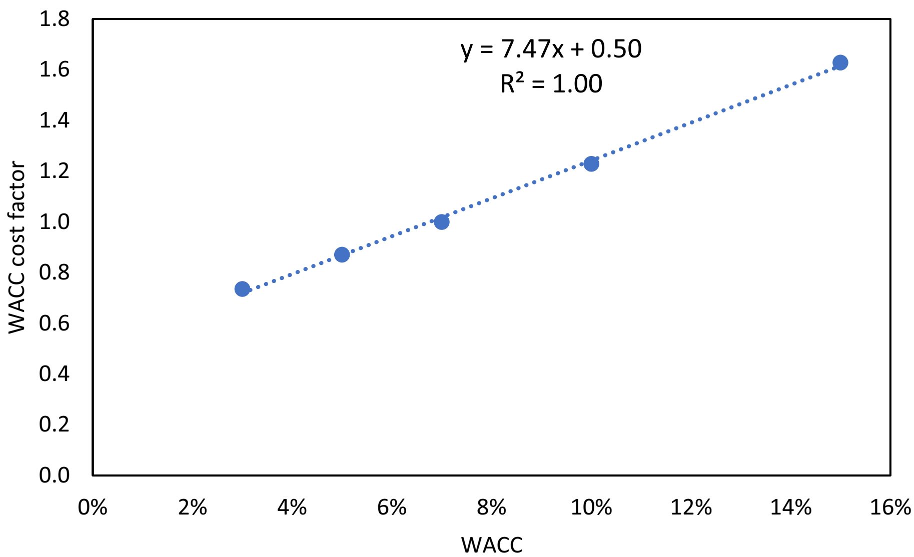

Fig. D1. WACC cost factor indicating how the levelized costs of baseload electricity vary, as a function of WACC, based on ref. [8., Fig. 30].

Appendix E. Additional results

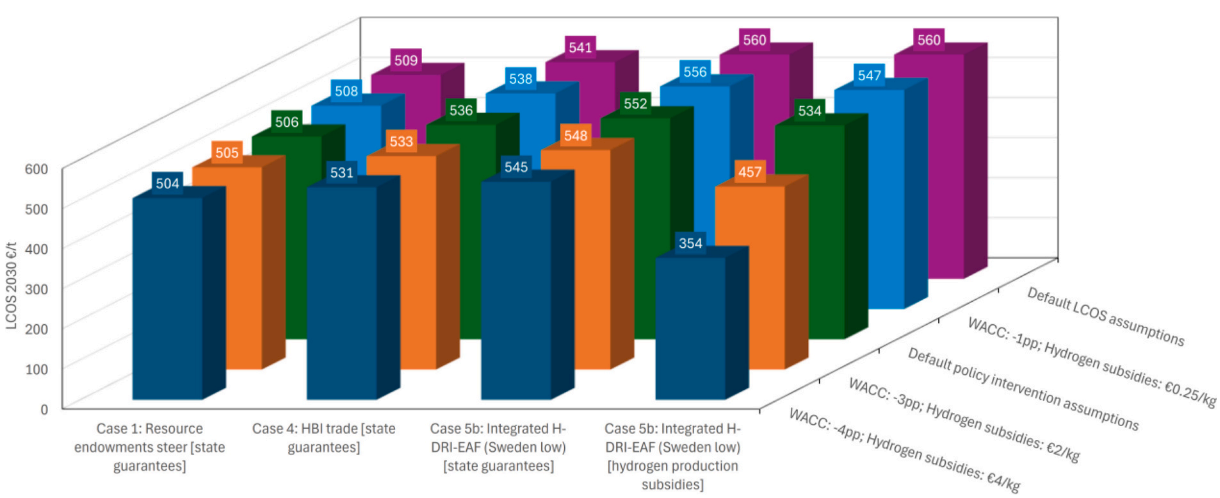

Fig. E1. Heatmap showing differences in each component of LCOS comparing all cases with the Case 5c, the lowest cost case of integrated production in South-Africa.

Fig. E2. Sensitivity in LCOS comparing both default parameters, policy interventions according to main text, and higher interventions representing impact of even stronger strategic interventions in Case 1, 4, and 5b.

Appendix F. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.apenergy.2025.126189.

Data availability

Data, methods, and assumptions are available in the Appendixes, Supplementary Information, and the python code made available through GitHub https://github.com/ji-gong/Circular-And-Sustainable-steel-Transitions.

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