Energy system requirements of fossil-free steelmaking using hydrogen direct reduction

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ARTICLE INFO

ABSTRACT

The iron and steel industry is one of the world's largest industrial emitters of greenhouse gases. One promising option for decarbonising the industry is hydrogen direct reduction of iron (H-DR) with electric arc furnace (EAF) steelmaking, powered by zero carbon electricity. However, to date, little attention has been given to the energy system requirements of adopting such a highly energy-intensive process. This study integrates a newly developed long-term energy system planning tool, with a thermodynamic process model of H-DR/EAF steelmaking developed by Vogl et al. (2018), to assess the optimal combination of generation and storage technologies needed to provide a reliable supply of electricity and hydrogen. The modelling tools can be applied to any country or region and their use is demonstrated here by application to the UK iron and steel industry as a case study. It is found that the optimal energy system comprises 1.3 GW of electrolysers, 3 GW of wind power, 2.5 GW of solar, 60 MW of combined cycle gas with carbon capture, 600 GWh/600 MW of hydrogen storage, and 30 GWh/130 MW of compressed air energy storage. The hydrogen storage requirements of the industry can be significantly reduced by maintaining some dispatchable generation, for example from 600 GWh with no restriction on dispatchable generation to 140 GWh if 20% of electricity demand is met using dispatchable generation. The marginal abatement costs of a switch to hydrogen-based steelmaking are projected to be less than carbon price forecasts within 5–10 years.

1. Introduction

Iron and steel is the industrial sector with the highest level of greenhouse gas emissions, accounting for approximately 7% of global CO_2 emissions (Philibert, 2017). Over 1.8 billion tonnes of steel are manufactured worldwide every year, the bulk of which is produced using the traditional blast furnace-basic oxygen steelmaking (BF-BOS) approach (World Steel Association., 2020). The industry is heavily reliant upon coal to produce coke as a reducing agent in blast furnaces and to provide heat and electricity, and as such around 1.8 tonnes of CO_2 are released per tonne of steel produced (World Steel Association., 2019).

Increasing numbers of countries and regions around the world are committed to heavy reductions in greenhouse gas emissions by 2050, with 2019 seeing the United Kingdom, France, New Zealand and Denmark all enshrine net zero emissions targets in law, and the EU agree a bloc deal for net zero which was subsequently presented to the UN (Darby, 2019). Within the iron and steel industry, the European division

of the world's largest steel producer, ArcelorMittal, recently announced its intention to be carbon neutral by 2050 (ArcelorMittal, 2020). Investment decisions in the industry are long-lasting, as a result of high capital costs and long (e.g., 25-year) blast furnace campaigns. Consequently, 2050 is only one investment cycle away, and new low carbon technologies must reach the market by 2030 to avoid "locking-in" CO_2 emissions (IEA. Clean Energy Innovation. 2020) for two to three decades to come.

There is a range of possible approaches to decarbonising the iron and steel industry, varying in their technological maturity and greenhouse gas abatement potential. The main options are: substitution of coal and coke with biomass in blast furnaces and basic oxygen furnaces (Mandova et al., 2018, 2019; Tanzer et al., 2020); direct reduction of iron using natural gas, biogas, or hydrogen (Vogl et al., 2018; Andersson et al., 2020); carbon capture, utilisation, and storage (CCUS) (Tanzer et al., 2020); increased electrification and use of low carbon electricity generation (Luh et al., 2020); increased steel reuse and recycling (Dunant et al., 2018); and implementation of other energy efficiency improvements such as the HIsarna process (Quader et al., 2016) and

Nomenclature

b	Biomass + CCUS power
c	Storage charge power
d	Storage discharge power
E	Installed energy storage capacity
e	Curtailed renewable energy
g	CCGT + CCUS power
i	Electricity storage technology index
j	Hydrogen storage technology index
k	Time step
L	Storage technology lifetime in years
l	Load
n	Nuclear power
P	Installed storage charge/discharge power capacity
s	Solar power; number of time steps in analysis period
s_{ref}	Reference solar time series
T_y	Length of analysis period in years
t	Time step
tLS	Tonne of liquid steel
w	Wind power
w_{ref}	Reference wind time series
x	Energy in storage
α	Capital cost of electricity generation per unit generation capacity
γ	Cost of storage power capacity
η_c	Storage charge efficiency
η_d	Storage discharge efficiency
λ	Operating cost of electricity generation per unit electricity generated
φ	Installed generation power capacity
ω	Cost of energy storage capacity
BECCS	Bioenergy with carbon capture and storage
BEIS	UK Government Department for Business, Energy and Industrial Strategy
BF	Blast furnace
BOS	Basic oxygen steelmaking
CAES	Compressed air energy storage
CCGT	Combined cycle gas turbine
CCUS	Carbon capture, utilisation, and storage
CfD	Contract for difference
DR	Direct reduction (of iron)
DRI	Direct reduced iron
EAF	Electric arc furnace
ETS	Emissions trading scheme
HBI	Hot briquetted iron
H-DR	Hydrogen direct reduction (of iron)
LCOE	Levelised cost of energy/electricity
LS	Liquid steel
PV	Solar photovoltaic power

blast furnace top gas recycling (van der Stel et al., 2012). Of these options, only those involving bioenergy, CCUS, hydrogen, or electrification could achieve zero or near-zero net greenhouse gas emissions.

When considering whether biomass should be encouraged in iron and steel manufacturing, governments must assess the available biomass resource and competing demands for this resource from other sectors, such as power generation. In the 2020 edition of their annual energy pathways report, Great Britain's electricity system operator calculated that the most efficient use of GB's limited biomass supply will be to produce negative emissions in the power sector, with industrial use of biomass likely to be limited to the cement sector (National Grid ESO, 2020). The technical potential of biomass substitution in blast furnaces is dependent on its physical properties, and even the most appealing options (such as charcoal produced using slow pyrolysis) could only be used for partial substitution (Mandova et al., 2018; Fick et al., 2014), offsetting up to 57% of the CO_2 emissions occurring on site (Norgate et al., 2012). Others have highlighted the uncertainty around whether biomass can truly contribute towards meeting the targets of the Paris agreement, considering the time taken for replanted trees and crops to absorb the CO_2 emitted during combustion (MacDonald and Moore, 2020). However, recent research has shown that aggressive use of biomass and CCUS in steelmaking could potentially provide net negative lifecycle emissions, effectively resulting in carbon negative steel (Tanzer et al., 2020).

Aside from biomass, one of the most attractive options to radically decarbonise the iron and steel industry is hydrogen direct reduction of iron (H-DR) using shaft furnaces (similar to the MIDREX process for producing direct reduced iron, or DRI, with natural gas) (Vogl et al., 2018; Pei et al., 2020), with iron then converted to steel in electric arc furnaces (EAFs) or induction furnaces supplied with zero carbon electricity from renewables or nuclear power. Within the H-DR process, hydrogen acts as the main reductant, converting iron ore to metallic iron and water. This can be contrasted with the traditional BF route, in which carbon is the main reductant, forming liquid hot metal saturated in carbon and carbon dioxide. There are then further carbon emissions from BOS, in which oxygen is injected into the liquid metal to oxidise carbon by the carbon boil reaction (C + ½ O_2 → CO), so as to lower the carbon content of the liquid metal to those desired for steels. Direct reduction with natural gas (the MIDREX process) is already widely used in parts of the world where natural gas is in abundance.

Use of hydrogen as a reducing agent has been under consideration since the early days of DRI in the 1970s (Tsay et al., 1976; Astier et al., 1982), however it has seen little attention until recently due to the maturity of BF-BOS and historically low or non-existent carbon prices. H-DR/EAF steelmaking is now being seriously considered in Sweden as the only realistic option for the country to achieve its legally binding target of carbon neutrality by 2045 (Vogl et al., 2018; Kushnir et al., 2020). Since 2016, SSAB, LKAB and Vattenfall have been working together on the HYBRIT initiative (Hydrogen Breakthrough Ironmaking Technology), which aims to replace coal with hydrogen in the steelmaking process (Pei et al., 2020). Construction of a pilot H-DR plant in Luleå was completed in 2020 (Reuters, 2020), and the replacement of fossil oil with bio-oil at iron ore pellet plants is already being trialled in Malmberget (reVattenfall team t, 2020).

This recent interest in H-DR comes at a time when there is increasing focus on the potential use of hydrogen as an energy vector in difficult-to-decarbonise sectors of the economy (Abdin et al., 2020), such as heavy transport (Apostolou and Xydis, 2019), space heating (Quarton and Samsatli, 2020; Boait and Greenough, 2019), and industry. National Grid ESO recently announced that hydrogen will be required for the UK to reach net zero carbon emissions by 2050 (National Grid ESO, 2020), and it features heavily in the UK Government's recently-published ten point plan to achieve net zero (Government. The Ten Po, 2020).

Clean hydrogen is classed as either 'green' when produced using low carbon electricity, or 'blue' when produced using methane reforming with CCUS. 2020 saw several significant announcements regarding green hydrogen. In Spain, Iberdrola announced that it will build a 100 MW solar PV plant featuring a 20 MWh lithium-ion battery storage system and a 20 MW electrolyser producing hydrogen for a fertiliser manufacturing facility (Lee, 2020). When operational in 2021, this will be the world's largest green hydrogen plant. In the Netherlands, Shell and Eneco won a subsidy-free auction for a 759 MW offshore wind farm, with a 200 MW electrolyser expected alongside for one of Shell's refineries (Parnell, 2020). This will be part of a hub with 3–4 GW of

wind-powered green hydrogen production. Outside Europe, Air Products signed an agreement with ACWA Power and NEOM to build a $5 billion green hydrogen-based ammonia production facility in Saudi Arabia (Air Products, 2020). This will integrate 4 GW of wind and solar power to produce 590 tonnes of hydrogen per day and is expected to be operational in 2025. The ammonia will be transported globally and dissociated into hydrogen for use in buses and trucks.

The surge of interest in green hydrogen is partly a result of considerable reductions in the cost of electrolysers and renewable electricity (Glenk and Reichelstein, 2019). From analysis of recent contracts for difference (CfD) auctions in Europe, it has been shown that offshore wind projects are effectively already subsidy-free in Germany and the Netherlands, and it appears likely that in 2019 the UK will have auctioned the world's first negative-subsidy offshore wind farm (Jansen et al., 2020). This implies that several offshore wind projects could expect to earn less money under the CfD-awarded contracts than under wholesale market terms alone and likely signals the end of CfDs for offshore wind in mature markets.

While there have been recent developments of H-DR technologies (Guo et al., 2015) and process models for H-DR/EAF primary steelmaking (Vogl et al., 2018; Ranzani da Costa et al., 2013), little attention has been given to the wider energy system impacts of its adoption. A recent investigation of Sweden's future energy system found that very little additional flexibility will be required to meet 2050 climate targets as a consequence of the significant hydropower capacity which is already in place (Kan et al., 2020). However, that study did not consider requirements for hydrogen, and many other countries, such as the UK, do not have such rich hydropower resources.

This study seeks to improve the understanding of the energy system requirements of a switch to H-DR/EAF steelmaking. The methods presented are applicable to any country and their application is demonstrated through a case study on Great Britain. An energy system planning tool has been developed, based on linear programming and time-series analysis of historical weather data, and is integrated with Vogl et al.'s

(Vogl et al., 2018) thermodynamic process model of H-DR/EAF steelmaking, as presented in Section 2. In Section 3, the energy demands of H-DR/EAF steelmaking are investigated, and the optimal combination of energy generation, storage, and conversion technologies is found for a range of possible future scenarios. Marginal abatement costs of a switch to H-DR/EAF steelmaking are calculated and compared with carbon price projections, and the system costs are investigated. Finally, our conclusions are presented in Section 4.

2. Methods

To determine the costs and emissions associated with H-DR/EAF steelmaking, and the combinations of energy system technologies that can provide a firm supply of electricity and hydrogen, a newly developed energy system cost optimisation tool is integrated with an existing thermodynamic process model.

2.1. Hydrogen direct reduction and electric arc furnaces

To determine the resource consumption of H-DR/EAF steelmaking, we implement a thermodynamic process model recently developed by Vogl et al. (2018). As shown in the flow diagram of Fig. 1, the system comprises an electrolyser for splitting hydrogen from water, a shaft furnace for direct reduction of iron using hydrogen as the reducing agent, and an electric arc furnace for converting DRI and scrap into steel. The model uses mass and energy balances to determine the flows of hydrogen, oxygen, water, iron ore, sponge iron, scrap, carbon, lime, and slag, for a given liquid steel (LS) output and scrap charge, along with the requirements for electricity to run the electrolyser, shaft furnace, electric arc furnace, and heating systems (e.g., pre-heating of iron ore, hydrogen, and briquetted iron). For full details of the thermodynamic process model, the reader is directed to the paper by Vogl et al. (2018).

Selected operating parameters of the H-DR/EAF system are given in Table 1. These are mostly taken from ref. (Vogl et al., 2018). EAF specific
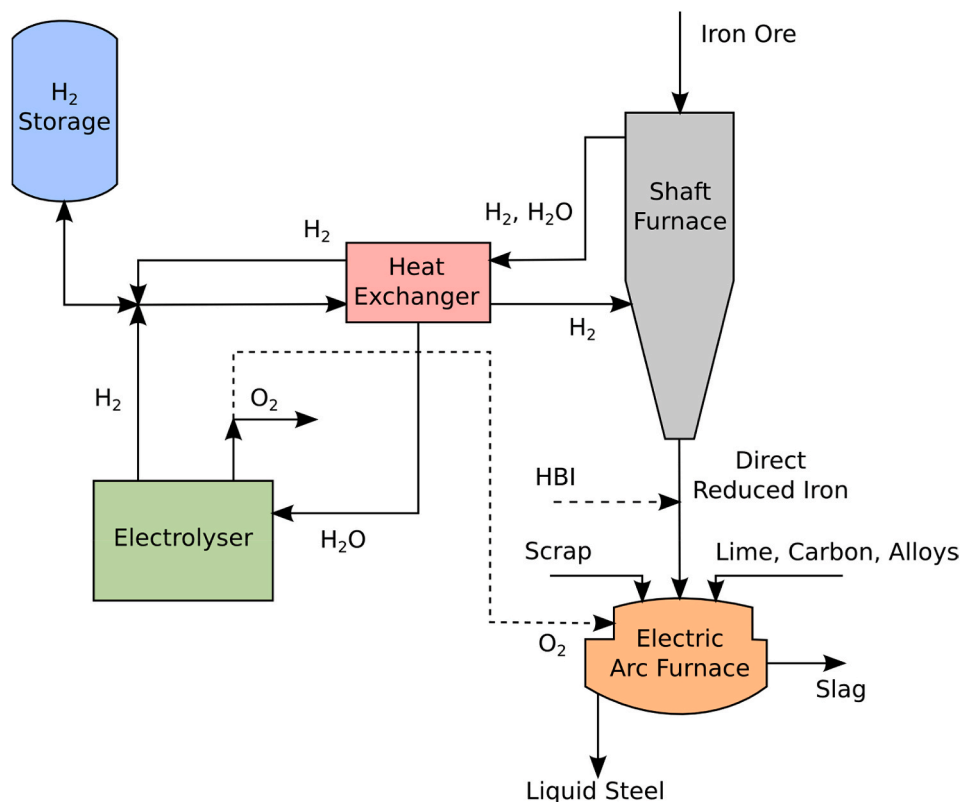

Fig. 1. Process flow diagram for H-DR/EAF steelmaking. Adapted from ref. (Vogl et al., 2018).

Table 1
Operating parameters for the H-DR steelmaking model.

Parameter	Value	Refs.
Electrolyser efficiency, η_{el}	72%	Vogl et al. (2018)
Heat exchanger efficiency, η_{hxu}	75%	Vogl et al. (2018)
Electrolyser operating temperature, T_{el}	70 °C	Vogl et al. (2018)
Shaft furnace operating temperature, T_{dr}	800 °C	Vogl et al. (2018)
Metallisation achieved in shaft furnace, α	94%	Vogl et al. (2018)
EAF specific energy consumption on 100% scrap charge	425 kWh/tLS	Heat Treat Consortium. El (2020)

energy consumption has been updated using the value for EAFs with oxy-fuel burners, which could make use of the oxygen by-product from water electrolysis (requiring less than 10% of the by-product).

In this work we assume that the EAF is charged with hot DRI directly from the shaft furnace. Hot DRI charging has been in use at a small number of natural gas DRI steelworks since 1998, and has higher energy efficiency than cold charging as well as reduced tap-to-tap time (ENERGIRON, 2020).

Steelworks are typically run at full output to maximise plant utilisation and return on investment. However, flexibility in H-DR/EAF steelmaking arises at a few points. Firstly, while DRI/EAF plants are designed for a specific ratio of scrap to DRI, the EAF scrap charge can be increased up to 100%. This typically occurs if the DR shaft furnace is shut down (such as for maintenance), allowing the plant to continue steel production. However, the product options from steel produced using 100% scrap are limited; wire rod, flat products, and thin strip require very pure iron and good scrap quality, and so charges for such products tend to contain low levels of scrap (Cavaliere, 2019). Having a relatively high design scrap charge (e.g., 50%) allows the capacity of the shaft furnace to be reduced. Such an approach might make sense economically if the plant is powered by renewable energy, as high scrap charges could be used to reduce electricity consumption at times when renewables output is low, with products such as rebar being produced at such times, then lower scrap charges could be used to produce flat products and wire rod at times when renewables output is high.

We do not investigate in detail the options for demand response through modifying scrap charges in this work, as it would require a detailed understanding of the value of individual steel products and the changing demand for those products that is too granular for our intent of determining overall energy system impact. Instead, a simple analysis of the benefits of demand response is included. Aside from this, we assume that all flexibility must be provided in the energy system through dispatchable generation, renewables curtailment, and energy storage. It is anticipated that our approaches could be extended in future to examine demand response in more detail.

Another source of flexibility in H-DR/EAF steelmaking is storage of DRI. It is not feasible to store DRI in its raw "sponge iron" form, as oxidation and self-heating/combustion can occur, but it can be compacted at around 650 °C into briquettes known as hot briquetted iron (HBI), for ease of handling, shipping, and storage. In this work we assume that DRI passes directly from the DR shaft furnace to the EAF, maximising energy efficiency in the steelmaking process, however we recognise that HBI storage could potentially be used to reduce requirements for dispatchable energy, enabling greater use of renewables. Again, we anticipate that HBI storage could be integrated into future versions of the model.

2.2. Energy system planning

To determine the lowest possible cost of meeting the energy requirements of a switch to H-DR/EAF steelmaking, an energy system planning tool has been developed. This uses time series analysis based on historical wind and solar capacity factors, with linear programming

used to determine the lowest-cost combination of electricity generation technologies, electricity-hydrogen conversion technologies (electrolysers and hydrogen expansion turbines), and energy storage technologies. Low carbon dispatchable generation technologies are included in the form of combined cycle gas turbines with carbon capture, utilisation, and storage (CCGT + CCUS) and biomass + CCUS (also known as bioenergy with carbon capture and storage, or BECCS). We recognise that the time taken for a BECCS facility to reach carbon neutrality depends upon a wide range of factors (Fajardy and Mac Dowell, 2017), and researchers have questioned if biomass can truly contribute towards meeting the targets of the Paris agreement and the UK's goal of reducing greenhouse gas emissions to net zero by 2050 (MacDonald and Moore, 2020). Nuclear power is included on the basis that it can only provide a constant output.

An overview of the arrangement of the energy system model is shown in Fig. 2. Arrows are used to show the possible power flows. The model includes the main electricity generation technologies expected to be present in future electricity systems: wind, solar, nuclear, CCGT + post-combustion CCUS, and biomass + post-combustion CCUS (w, s, n, g, b, respectively). Electricity can be converted to hydrogen using water electrolysis (f_{eh}), and hydrogen can be converted to electricity using hydrogen expansion turbines (f_{he}). Multiple energy storage systems can be present, comprising both electricity storage and hydrogen storage technologies, indexed by i and j respectively. Storage charging is denoted by c and discharging is denoted by d. In the analysis presented here, a single electricity storage technology (underground compressed air energy storage, or CAES) and a single hydrogen storage technology (underground salt cavern storage) are included. Renewables generation can be curtailed (e).

The model accounts for conversion efficiencies for transfer of energy into and out of storage and between electricity and hydrogen. Each generation technology has an associated power capacity. Power capacities are also associated with the electricity-hydrogen conversion technologies. Each energy storage technology has an associated charge/
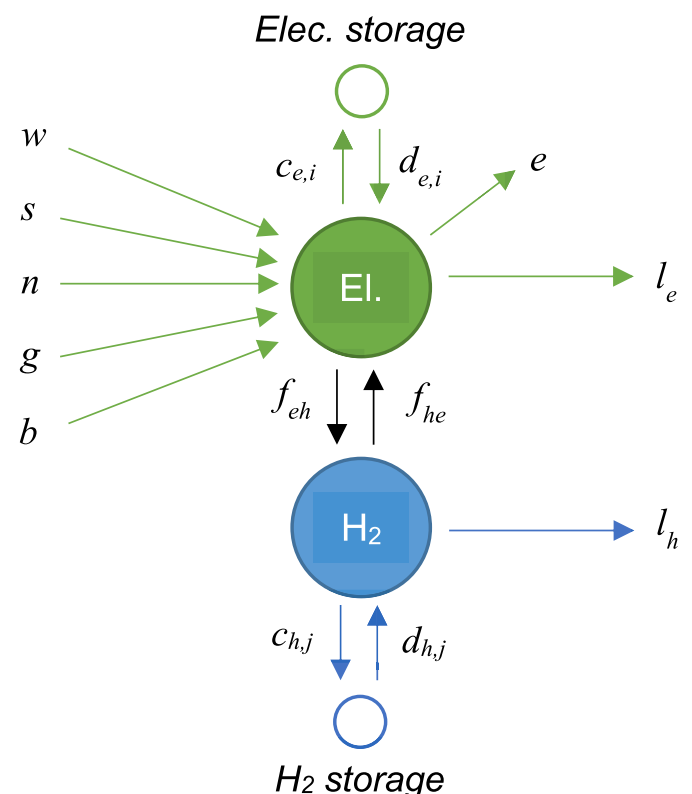

Fig. 2. Energy flows in the energy system optimisation model.

discharge power capacity and energy storage capacity. The demands for electricity and hydrogen as calculated using the thermodynamic process model are given by l_e and l_h. It should be noted that l_e does not include electrolyser demand as this is accounted for by f_{eh}.

The linear programming tool finds the lowest cost combination of generation, storage, and electricity-hydrogen conversion technologies that could provide a firm supply of low- or zero-carbon electricity and hydrogen for H-DR/EAF steelmaking. For the power generation technologies, capacity costs and operating costs are accounted for. For the energy storage technologies, costs are included for energy storage capacity and power capacity. Capacity costs are also included for electrolysers and hydrogen expansion turbines. Constraints on the net CO_2 emissions of the energy system are not included here (with residual emissions arising from CCGT + CCUS generation), however they could be easily added using inequality constraints, in order to specify a maximum carbon intensity of the manufactured steel. In any case, CCGT + CCUS capacities are small in the optimum energy system due to high costs.

Many long-term energy system planning tools (such as UK TIMES and OSeMOSYS) split the full analysis period into shorter periods representing multiple years and allow plant to be built or decommissioned in each period, requiring a mixed integer programming approach. As an example, UK TIMES can be run for time horizons out to 2100 and largely uses five-year periods, each represented by four seasons, each of which is represented by a typical day of four time-slices (Daly and Fais, 2014). To include both electricity and hydrogen in our model while accounting for the inter-month variability in renewables availability and ensuring that runtimes remain reasonable, our model is formulated so that generation and storage capacities remain constant throughout the analysis period. To gain an understanding of the likely effect of energy technology cost reductions, the model is run using generation and electrolyser cost projections for five-year intervals between 2025 and 2040. Further information on the time-slice approach used in our model is given in Section 2.3.

Constraints are used to ensure that the electricity and hydrogen demands calculated using the process model outlined in Section 2.1 are met in each time interval using the installed generation and storage. Our approach makes the assumption of perfect foresight of renewables output, and so the results provide a lower limit on the amount of flexibility (i.e., storage or dispatchable generation capacity) required. The wind and solar generation time series are formed by scaling up historical wind and solar capacity factors for the region of interest (see Section 2.3). Constraints are used to ensure that nuclear provides a constant output, reflecting the fact that nuclear generation is used to provide baseload power due to its relatively high minimum stable output, long cold-start time, and high start-up cost (Staffell and Green, 2012, 2016).

The optimisation problem is linear and solved using IBM ILOG CPLEX 12.10 through the CPLEX Connector for MATLAB.

The optimisation problem is laid out below.

$$l_h + \frac{f_{he}}{\eta_{he}} - f_{eh}\eta_{eh} + \sum_j \left(c_{h,j} - d_{h,j}\right) = 0 \tag{3}$$

$$c_{e,i}, d_{e,i}, E_{e,i}, P_{e,i}, c_{h,j}, d_{h,j}, E_{h,j}, P_{h,j}, x_{i,0}, x_{j,0} \geq 0 \; \forall \, i,j \tag{4}$$

$$e, w, s, n, g, b, \varphi, P_{eh}, P_{he} \geq 0 \tag{5}$$

$$c_{e,i}, d_{e,i} \leq P_{e,i} \; \forall \, i \tag{6}$$

$$c_{h,j}, d_{h,j} \leq P_{h,j} \; \forall \, j \tag{7}$$

$$g \leq \varphi_g \tag{8}$$

$$b \leq \varphi_b \tag{9}$$

$$f_{eh} \leq P_{eh} \tag{10}$$

$$f_{he} \leq P_{he} \tag{11}$$

$$e \leq w + s \tag{12}$$

$$0 \leq x_{i,0} + \sum_{k=1}^{t} \left(c_{i,k}\eta_{c,i} - d_{i,k} / \eta_{d,i}\right)\Delta t \leq E_i \; \forall \, i,t \tag{13}$$

$$0 \leq x_{j,0} + \sum_{k=1}^{t} \left(c_{j,k}\eta_{c,j} - d_{j,k} / \eta_{d,j}\right)\Delta t \leq E_j \; \forall \, j,t \tag{14}$$

$$x_{i,0} \leq E_i \; \forall \, i \tag{15}$$

$$x_{j,0} \leq E_j \; \forall \, j \tag{16}$$

$$\sum_{k=1}^{s} \left(c_{i,k}\eta_{c,i} - d_{i,k} / \eta_{d,i}\right)\Delta t = 0 \; \forall \, i \tag{17}$$

$$\sum_{k=1}^{s} \left(c_{j,k}\eta_{c,j} - d_{j,k} / \eta_{d,j}\right)\Delta t = 0 \; \forall \, j \tag{18}$$

$$w = \varphi_w w_{ref} \tag{19}$$

$$s = \varphi_s s_{ref} \tag{20}$$

$$n = \varphi_n \mathbf{1} \tag{21}$$

α_w, α_s, α_n, α_g, and α_b represent the capital costs of wind, solar, nuclear, CCGT + CCUS, and biomass + CCUS power; φ and λ represent the installed capacities and operating costs of the electricity generation technologies; α_{eh} and α_{he} are the capital costs of electrolysers and hydrogen expansion turbines, and P_{eh} and P_{he} are the installed capacities; $\omega_{e,i}$ and $\omega_{h,j}$ are the costs of electricity storage capacity and hydrogen

$$\min_{e,c,d,E,P,\varphi,g,b,x} \alpha_w\varphi_w + \alpha_s\varphi_s + \alpha_n\varphi_n + \alpha_g\varphi_g + \alpha_b\varphi_b + \left(\lambda_w\sum w + \lambda_s\sum s + \lambda_n\sum n + \lambda_g\sum g + \lambda_b\sum b\right)\Delta t + \alpha_{eh}P_{eh} + \alpha_{he}P_{he}$$

$$+ T_y\left(\sum_i \omega_{e,i}E_{e,i} / L_{e,i} + \sum_i \gamma_{e,i}P_{e,i} / L_{e,i} + \sum_j \omega_{h,j}E_{h,j} / L_{h,j} + \sum_j \gamma_{h,j}P_{h,j} / L_{h,j}\right) \tag{1}$$

subject to

$$l_e - w - s - n - g - b + e + f_{eh} - f_{he} + \sum_i \left(c_{e,i} - d_{e,i}\right) = 0 \tag{2}$$

storage capacity; $\gamma_{e,i}$ and $\gamma_{h,j}$ are the costs of charge/discharge power capacity for electricity and hydrogen storage; $E_{e,i}$ and $E_{h,j}$ are the energy storage capacities of the electricity and hydrogen storage; $P_{e,i}$ and $P_{h,j}$ are the charge/discharge power capacities of the electricity and hydrogen storage; T_y is the length of the analysis period in years; $L_{e,i}$ and $L_{h,j}$ are the lifetimes of the electricity and hydrogen storage technologies in years;

$x_{i,0}$ and $x_{j,0}$ are the energy in storage types i and j at the start of the analysis period; Δt is the length of the time interval associated with each entry in the time series l, w, s, n, g, b, e, c, d, and f; and w_{ref} and s_{ref} are time series of wind and solar capacity factors.

The equality constraints of equations (2) and (3) ensure that, at each time interval, electricity and hydrogen loads are met using the installed generation and storage. The inequality constraints of equations (4) and (5) are positivity constraints on all decision variables. The inequality constraints of equations (6)–(11) ensure that power capacity constraints are met for storage charge, storage discharge, gas and biomass generation, and electrolyser and hydrogen expansion turbine. The inequality constraints of equation (12) ensure that curtailment never exceeds the combined output of wind and solar. The inequality constraints of equations (13) and (14) ensure that energy storage capacity constraints are met. Equations (15) and (16) ensure that the energy in storage at the start of the analysis period is within the energy storage capacity constraints, and equations (17) and (18) ensure that, for each energy storage system, the states of charge at the start and end of the analysis period are equal. Equations (19)–(21) show how w, s, and n are formed by scaling up reference wind, solar, and nuclear time series, where historical wind and solar capacity factors are used as w_{ref} and s_{ref}. In equation (21), **1** is a vector of ones, ensuring that nuclear power provides a constant output.

Since a linear programming approach is used, all terms in the objective function are linear functions of the decision variables, with the inherent assumptions that unit capital and operating costs are independent of a technology's installed capacity and utilisation. In reality, however, fixed costs can be shared over more units of output, thus tending to lower unit costs at high levels of deployment and utilisation. To account for this it would be necessary to introduce nonlinear terms and use nonlinear programming techniques, potentially increasing runtime considerably. By not including the sharing of fixed costs, our approach is quite conservative, and we believe that identifying the appropriate parameters to represent fixed costs could become quite arbitrary.

2.3. Data

To ensure that the results are representative, the energy system optimisation is performed using 20 years of historical wind and solar capacity factors (for the years 2000–2019). These were determined using reanalysis (Staffell and Pfenninger, 2016; Pfenninger and Staffell, 2016) and are freely available for specific locations or as national-level averages at 1-h resolution at www.renewables.ninja (Pfenninger and Staffell, 2020). Using these data has the advantage that they provide the full renewables availability, whereas actual generation data would be affected by curtailment and the fact that renewables capacities and capabilities have changed markedly in the last 20 years. We use Great Britain as a case study in this work and intend to be forward looking, therefore values for wind are based on Great Britain's long-term future wind fleet. Values for solar are based on the distribution and characteristics of Great Britain's existing solar PV fleet; the future solar fleet is not planned out to the same extent as the wind fleet, and so capacity factor data are only available for the existing fleet.

After each time series has been synthesised at 1-h resolution, we then aggregate the data by "time-slice" for use in the energy system optimisation, to ensure that computational time remains reasonable. We adopt a similar time-slice approach to that used in the UK TIMES model (Daly and Fais, 2014), but consider each month of the year rather than only four seasons. We use four time-slices to represent each month, separating the 24-h day into night (00:00–07:00), day (07:00–17:00), evening peak (17:00–20:00), and late evening (20:00–00:00) periods. As a consequence, each year of data is represented with 48 time-slices. Using time-slices in this way ensures that the diurnal effects of solar resource are taken into account. The data used in this analysis are summarised in Table 2, with further details given in the rest of this section and in the

Table 2
Summary of the data used in the analysis.

Data Stream	Details	Sources
Hydrogen and electricity demands	Constant demands assuming steady steel production.	Calculated using thermodynamic process model developed by Vogl et al. (Vogl et al., 2018)
Wind and solar capacity factors	One-hour resolution data for the UK's existing solar fleet and long-term future wind fleet, developed using reanalysis. Data used for 2000–2019 inclusive, aggregated to four time-slices per month.	http://www.renewables.ninja (Pfenninger and Staffell, 2020)
Electricity generation costs/ parameters	Projections of CapEx, OpEx, net CO$_2$ intensities, and lifetimes for onshore wind, large-scale solar, CCGT + CCUS, and biomass + CCUS, for the years 2025, 2030, 2035, and 2040. LCOE for nuclear. Fuel costs for each year from 2020 to 2039 inclusive.	UK Government's Department for Business, Energy and Industrial Strategy (BEIS) (Department for Business, 2020a; Department for Business, 2020b; Ray and Ferguson, 2018)
Energy storage costs/ parameters	CapEx for cavern-based hydrogen storage and compressed air energy storage per unit storage capacity and per unit charge/discharge power capacity. Lifetimes and charge/discharge efficiencies.	(Vogl et al., 2018; nnovation landsca, 2019; Lord et al., 2014; Barbour et al., 2015; Locatelli et al., 2015; Nikolaidis and Poullikkas, 2018)
Electricity/ hydrogen conversion costs/ parameters	CapEx, efficiencies, and lifetimes for electrolysers and hydrogen expansion turbines.	(Vogl et al., 2018; Department for Business, 2020a; Schmidt et al., 2017a; Taibi et al., 2020; Gandolfi et al., 2020; Steward et al., 2009)
Carbon prices	Low, central, and high projections of traded carbon prices for each year from 2020 to 2039 inclusive.	BEIS (Department for Business, 2019)

Supplementary Material.

The average annual capacity factors from the reanalysis data are shown in Fig. 3 over 40 years, from which the annual variability of wind power is particularly notable, with its annual capacity factor ranging from 34% in 2010 up to 44% in 1986. The coefficient of variation is 5.5% for wind and 2.3% for PV. We recognise that renewables variation could be taken into account using a stochastic approach such as Monte Carlo simulation, with renewables capacity factors synthesised using Markov Chains. However, correctly accounting for the diurnal and seasonal changes in solar output in a Markov Chain would require implementation of a solar position algorithm (Bright et al., 2015). It was deemed that this would not carry sufficient benefit in answering our research questions to justify the effort.

It is assumed that the steelworks' electricity and hydrogen demands are constant, on the basis that manufacturers tend to run plant at full power to make full use of manufacturing capacity. The need to maximise asset utilisation and efficiency in this way has been elicited in discussions with several senior figures from within the steel industry. It should be noted that energy storage requirements could be reduced by oversizing steel production capacity and modifying production rates according to renewables availability, in which case storage of materials (e. g., HBI or steel products) would be required. It is anticipated that the trade-offs between energy storage and material storage will be investigated in future work.

Cost projections for low-carbon electricity generation technologies have recently been published by the UK Government's Department for Business, Energy and Industrial Strategy (BEIS) for the years 2025, 2030,
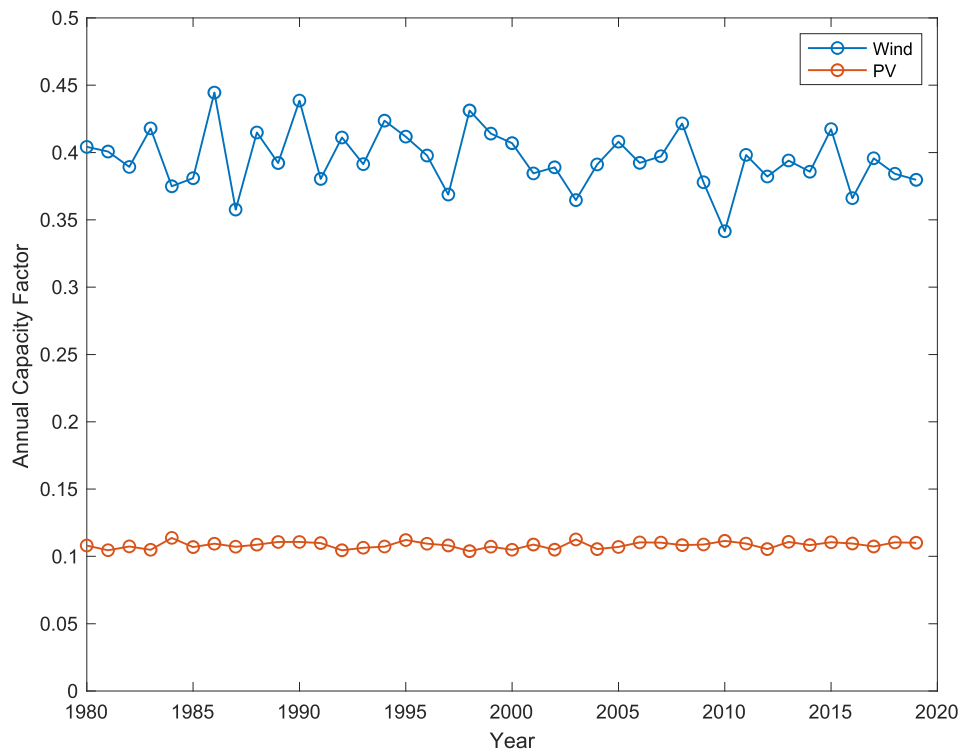
Fig. 3. Annual capacity factors for wind and solar energy for Great Britain from 1980 to 2019, based on existing solar PV capacity and the long-term future wind fleet. Data from renewables.ninja (Pfenninger and Staffell, 2020).

Table 3
Key parameters of the electricity generation technologies included in the model. 2025 cost projections shown, projections for later years given in the Supplementary Material.

	Net CO$_2$ Intensity (gCO$_2$/kWh)	Lifetime (years)	Discounted Capacity Cost (£/MW)	Variable Cost[a](£/MWh)	Refs.
Onshore Wind	0	25	1,531,000	6	Department for Business (2020a)
Solar PV	0	35	617,000	0	Department for Business (2020a)
Nuclear[b]	0	35	0	60	Department for Business (2020a)
CCGT + CCUS (post-combustion)	34.3	25	2,149,000	5	(Department for Business, 2020a; Ray and Ferguson, 2018)
Biomass + CCUS (post-combustion)	−1318.5	25	6,236,000	4	(Department for Business, 2020a; Ray and Ferguson, 2018)

[a] Variable cost does not include fuel or carbon costs.

[b] Nuclear LCOE of £60/MWh used.

Table 4
Key parameters of the energy storage technologies.

	Charging Efficiency	Discharging Efficiency	Lifetime (years)	Energy Capacity Cost (£/kWh)	Power Capacity Cost (£/kW)
Underground H$_2$ Storage	72% (Vogl et al., 2018)	62.5%[a] (nnovation landsca, 2019)	30	0.67 (Lord et al., 2014)	See Table 5
Underground CAES	83.67% (Barbour et al., 2015)	83.67% (Barbour et al., 2015)	30 (Nikolaidis and Poullikkas, 2018)	2.50 (Locatelli et al., 2015; Nikolaidis and Poullikkas, 2018)	300 (Locatelli et al., 2015)

[a] Hydrogen charging and discharging efficiencies are those of electrolyser and hydrogen expansion turbine, respectively.

2035, and 2040 (Department for Business, 2020a). These were constructed by BEIS following a period of evidence gathering and are based on learning rates and economies of scale. Key parameters of the electricity generation technologies included in the model are shown in Table 3, those of the energy storage technologies are shown in Table 4, and electricity-hydrogen conversion parameters are shown in Table 5.

Electrolyser cost reductions out to 2040 have been estimated based on the projections of Schmidt et al. (2017b). These reduce costs to £506/kW in 2025, £439/kW in 2030, £371/kW in 2035, and £338/kW in 2040, roughly in line with projections made elsewhere (Taibi et al., 2020). Full details of the projected capacity costs for electricity generation technologies and electrolysers are given in the Supplementary Material.

Table 5

Key parameters of the electricity-hydrogen conversion technologies. 2020 electrolyser costs shown, projections for later years given in the Supplementary Material.

	Lifetime (years)	Cost (£/kW)
Electrolyser	10 (Vogl et al., 2018; Schmidt et al., 2017a)	540 (in 2020) (Vogl et al., 2018; Taibi et al., 2020)
Hydrogen Expansion Turbine	30 (Gandolfi et al., 2020)	800 (Department for Business, 2020a; Gandolfi et al., 2020; Steward et al., 2009)

Projected fuel costs for gas and biomass are taken from recently published reports by BEIS (Department for Business, 2020b; Ray and Ferguson, 2018) (with fuel efficiencies of 30% and 47% used for biomass + CCUS and CCGT + CCUS, respectively (Department for Business, 2020a)), and carbon prices are taken from the Treasury Green Book supplementary appraisal guidance also published by BEIS (Department for Business, 2019). These values are included in the Supplementary Material, along with other costs and parameters from the thermodynamic process model. Central estimates are used in the analysis unless stated otherwise. All costs are discounted to the start of the 20-year analysis period using a discount factor of 5%.

3. Results and discussion

In this section we use the thermodynamic process model and energy system optimisation tool presented above to calculate the energy requirements of H-DR/EAF primary steelmaking, the energy generation and storage capacities of the lowest-cost energy system to meet these requirements if the UK steel industry was switched to H-DR/EAF, and the expected future costs of producing steel using this approach.

3.1. Energy demands of H-DR/EAF steelmaking

The energy consumption and mass flows in H-DR/EAF steelmaking have been determined using the thermodynamic process model for a range of EAF scrap charges, as shown in Fig. 4. The strong relationship between energy demand and scrap use is clear; total energy demand when operating on 100% scrap (450 kWh per tonne of liquid steel, or tLS) is 87% lower than when operating on 100% DRI (3.43 MWh/tLS), with electrolysis accounting for two-thirds of total energy demand when operating on 100% DRI. As such, scrap utilisation will be key to reducing electrolyser capacity and electricity demand in H-DR/EAF steelmaking, however the product options for steel produced using high levels of scrap are limited and heavily dependent upon scrap quality.

With a 50% scrap charge, hydrogen demand is 25.2 kgH$_2$/tLS. To convert the 7.2 MtLS/yr UK steel industry to the H-DR/EAF approach at

Table 6

Optimal combination of generation and storage technologies to meet the energy demands of a complete switch to H-DR/EAF steelmaking in the UK. Based on near-term (2025) electricity generation technology costs.

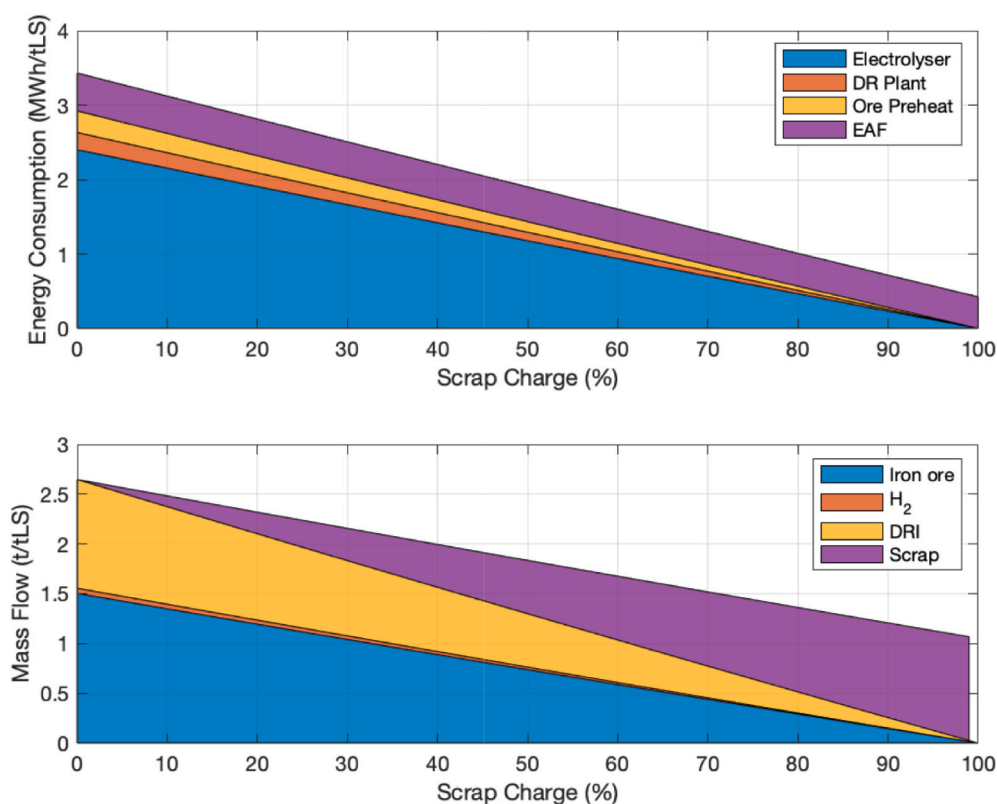|	Scrap Charge		
	0%	25%	50%
Steel Production (MtLS/yr)	7.2	7.2	7.2
Hydrogen Demand (GW)	1.42	1.06	0.70
Non-H$_2$ Electricity Demand (GW)	0.51	0.47	0.43
Wind Capacity (GW)	5.25	4.09	2.96
Solar Capacity (GW)	4.42	3.45	2.49
Nuclear Capacity (GW)	0.00	0.00	0.00
CCGT/Biomass + CCUS Capacity (GW)	0.11	0.08	0.06
H$_2$ Storage Energy Capacity (GWh)	1067	832	600
H$_2$ Storage Power Capacity (GW)	1.08	0.83	0.61
CAES Energy Capacity (GWh)	56	44	32
CAES Power Capacity (GW)	0.22	0.18	0.13
Electrolysis Capacity (GW)	2.48	1.86	1.25
H$_2$ Expansion Turbine Capacity (GW)	0	0	0

Fig. 4. Energy demands and resource flows in H-DR/EAF steelmaking for a range of scrap charges.

this level of scrap utilisation would require a hydrogen production rate of 181,720 tH$_2$/yr, equivalent to 697 MW. This is very similar to the rate of hydrogen production required to convert the city of Leeds (population of 793,139 in 2019 (Leeds Observatory, 2021)) to hydrogen heating, of 732 MW (Leeds City Gate, 2016).

If H-DR/EAF steelmaking was pursued as a means of decarbonising the UK steel industry, it is possible that DRI would be imported as HBI from countries and regions with iron ore reserves and low electricity costs, for use in UK-based EAFs. The within-UK energy demands for this scenario are the non-electrolyser demands plus an additional energy demand for HBI preheating of up to 160 kWh/tLS.

3.2. Energy system requirements

The lowest cost combination of generation and storage technologies to meet the energy demands of a full switch to fossil-free H-DR/EAF steelmaking in the UK is shown in Table 6 for three different levels of EAF scrap charge, and the optimal storage operation over a 20-year period is shown in Fig. 5. All results presented in this subsection are based on estimates of electricity generation costs in 2025 and fuel/carbon prices from 2020 to 2039, and so present a near-term view of the optimum energy system.

From Table 6, the strong negative relationship between scrap charge and energy system requirements is again clear. The levelised cost of energy (LCOE) from nuclear power is higher than the combined LCOE from renewables and storage and so the optimal combination of energy technologies does not include nuclear power, even though it is naturally suited to providing a steady supply of electricity.

The inter-seasonal and inter-annual operation of hydrogen storage is evident from Fig. 5. In the case of 50% scrap charge (which is used in the rest of the paper), with the optimal combination of storage capacities it would take around 41 days to fully discharge the hydrogen storage from 100% state of charge, and 10 days to fully discharge the CAES.

In this case, 80% of demand is met from wind, 19% is met from solar, and 1% is met from CCGT + CCUS. Renewables curtailment is equal to 2.3% of the available supply. The optimal wind and solar power

capacities are significant, equating to around 12% and 19% of the UK's total installed wind and solar capacities in mid-2020 (24.1 GW (renewable UK, 2020) and 13.4 GW (Department for Business E, 2020)), respectively. In reality, considering the land-use requirements of solar power in particular, it is likely that large offshore wind farms would be the most appealing option in areas with suitable bathymetry.

While we are focusing on green hydrogen here (produced using water electrolysis powered by low carbon electricity), blue hydrogen (produced using natural gas reforming with CCUS) has also been proposed as a low cost means of providing low carbon hydrogen. The largest existing steam methane reforming plant has a capacity equivalent to 338 MW (Leeds City Gate, 2016). This would be capable of providing the hydrogen required for a steel production rate of 3.5 MtLS/yr (roughly equal to the output of the large integrated steelworks at Port Talbot in South Wales, for example).

The hydrogen storage capacities required for a range of wind and solar penetrations are shown in Fig. 6, along with the levelised cost of electricity to run the electrolysers, DRI furnaces, and EAFs. The hydrogen storage capacity curve is not completely smooth because only one dataset of renewables capacity factors is used (though this covers an extended period of 20 years) and because the cost of energy is quite insensitive to total storage capacity, due to its low costs. The curve flattens at high levels of energy from solar as dispatchable generation starts to become a cost-effective way of dealing with the loss of supply every night. It should be noted that the minimum LCOE happens to be almost exactly the £46.60/MWh that the UK steel industry currently pays for electricity (Aaskov, 2021).

Evidently the cost of electricity is minimised at a high wind penetration of around 80% as a result of wind power's much higher load factor than solar. The minimum hydrogen storage capacity of 334 GWh (equating to a specific storage capacity of 46 kWh/tLS/yr) is found at a wind penetration of 60%. This is just over half of the cost optimal hydrogen storage capacity of 600 GWh (83 kWh/tLS/yr), found at a wind penetration of 80%. Storage capacity and cost of energy are minimised at relatively high levels of supply from wind because wind power is available day and night, unlike solar. There is a small degree of
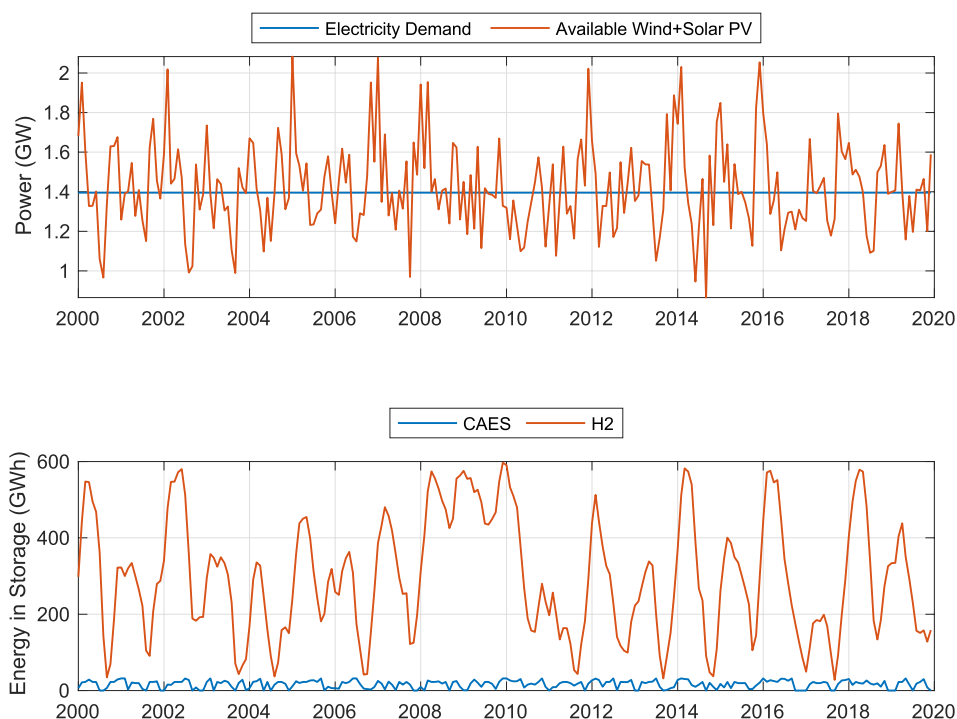

Fig. 5. Optimal energy system operation to provide the UK iron and steel industry with firm electricity and hydrogen in a complete switch to H-DR/EAF steelmaking, with 50% scrap charge. Values shown are monthly averages of the time-slice values.
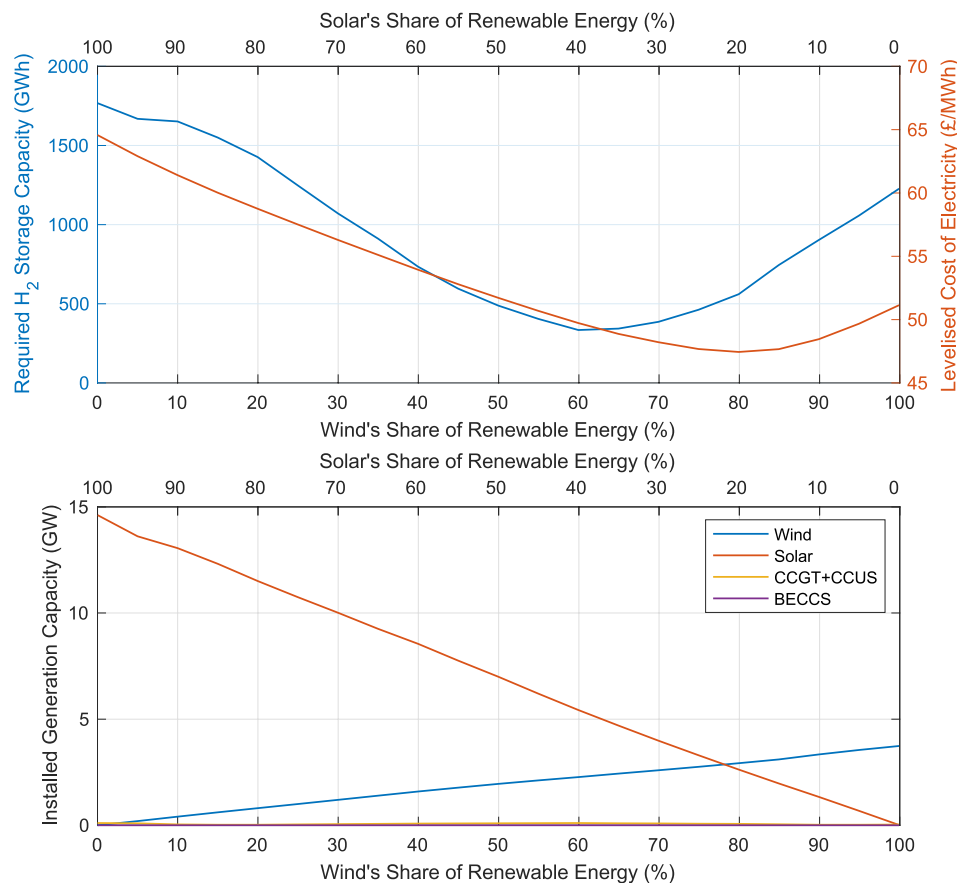
Fig. 6. (a) Hydrogen storage capacity required to switch current UK steelmaking output (7.2 MtLS/yr) to H-DR/EAF powered by renewable electricity with 50% scrap charge, and corresponding levelised cost of energy (electricity and hydrogen), at various penetrations of wind and solar power. (b) Optimal combinations of electricity generation capacity at the same penetrations of wind and solar power.

complementarity between wind and solar in Great Britain as irradiance is weakly anticorrelated with wind speed throughout the year (Bett and Thornton, 2016), and hence, as is apparent in Fig. 6(a), the minimum value of required hydrogen storage capacity is away from the ends (i.e., 0% or 100% wind or solar). The storage capacity requirement is more than doubled if the share of supply from wind is 100% rather than 80%.

There is currently one underground hydrogen storage site in the UK, at Teesside, where hydrogen is stored in three relatively small salt caverns at a depth of 350–450 m and with a total volume of 210,000 m^3 (Caglayan et al., 2020; Crotogino et al., 2010). These were constructed in 1971–72 and are still in operation today (Donadei et al., 2016). The UK's technical potential for onshore salt cavern storage of hydrogen is estimated to be in excess of 1000 TWh, with particularly high energy densities available in the East Yorkshire salt field (Caglayan et al., 2020). Other European countries with good onshore salt cavern storage potential within 50 km of the coast (for brine disposal) include Germany, Denmark, Portugal, and Spain (Caglayan et al., 2020). The UK's current natural gas storage capacity is in the region of 27 TWh, comprising 14 TWh of medium-term gas storage capacity and 13 TWh of LNG capacity (Wilson, 2019).

To reduce the energy storage requirements of hydrogen-based steelmaking it is possible to leverage other flexibility options, such as dispatchable generation and demand response. As shown in Fig. 7, maintaining a supply of dispatchable generation (e.g., from a source such as biomass or natural gas with CCUS) considerably reduces the energy storage requirements of the steel industry in a switch to H-DR/ EAF primary steelmaking. By way of example, if 20% of electricity supply is provided with dispatchable generation, it would be theoretically possible to match supply and demand using 143 GWh of hydrogen

storage, less than half the lowest capacity in the cost-optimal system configuration. The imperfect capture rates of CCUS would mean residual CO_2 emissions if CCGT + CCUS was used, though BECCS could provide CO_2 removal and the steel industry could potentially use this as a means to offset CO_2 emissions from other sectors or its own historical emissions, depending upon future government policy. In any case, some reserve of dispatchable generation will likely be necessary to deal with extreme weather events, when wind and solar resources are low for an extended period.

The optimal combination of generation and storage capacities for a steel production level of 1 MtLS/yr are shown in Fig. 8 against HBI import level, based on UK wind and solar resources and a 50% scrap charge. The capacity of CCGT + CCUS remains relatively small at all levels of HBI import, with cavern storage of hydrogen and compressed air providing more cost-effective load balancing. Nuclear capacity is zero at all levels of HBI import because of its relatively high cost.

Total generation and storage requirements are reduced by over 50% if all DRI is imported rather than produced natively, however cross-border carbon regulation would be necessary to ensure that the carbon intensity of imported DRI is low. At high levels of DRI import, hydrogen requirements are reduced and hence hydrogen storage becomes less attractive than CAES for balancing renewables supply with the steel industry's energy demands, due to hydrogen's relatively low turnaround efficiency when used for electricity-in/electricity-out storage.

3.3. Cost analysis

The levelised costs of the optimal energy system for H-DR/EAF
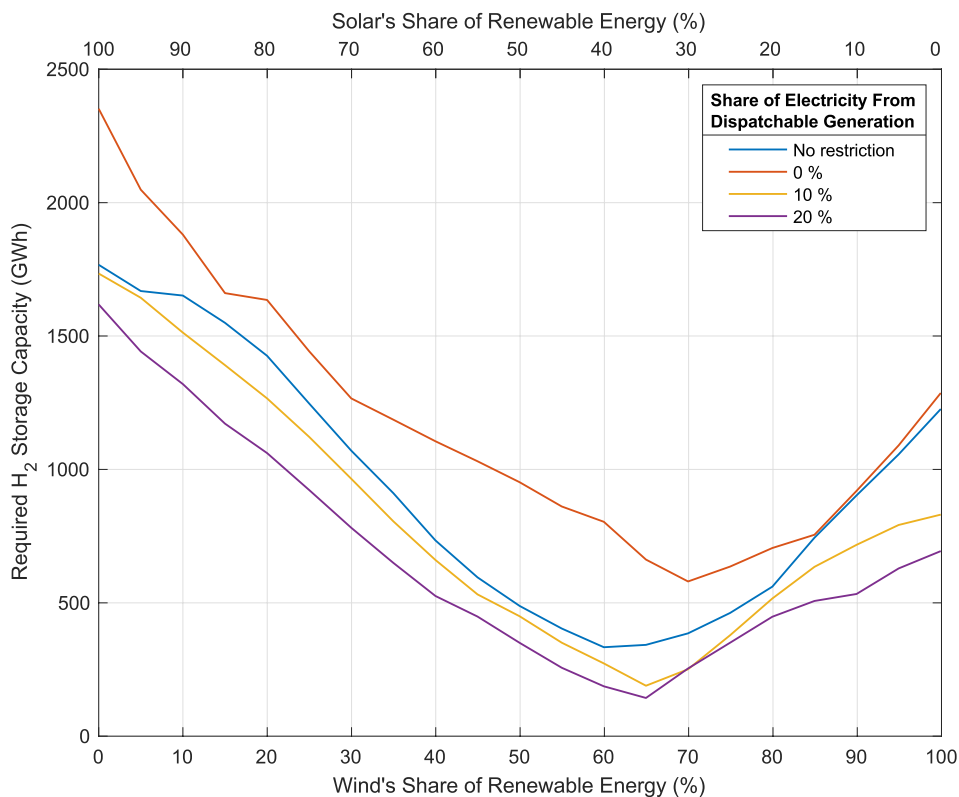
Fig. 7. Required storage capacity to meet the energy requirements of a complete switch to H-DR/EAF steelmaking in the UK against wind and solar's share of renewable generation, with 50% scrap charge and for several different shares of electricity from dispatchable generation.
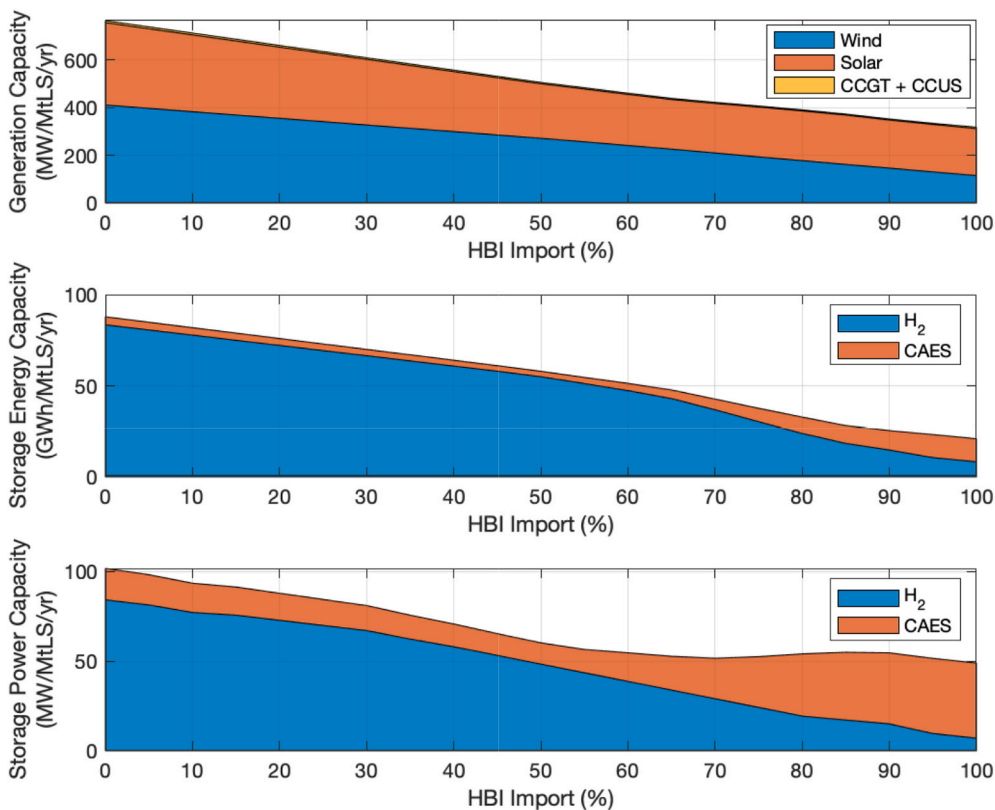

Fig. 8. Optimal capacities of electricity generation and energy storage technologies for H-DR/EAF steelmaking, against HBI import level, for 50% scrap charge and based on UK wind and solar resources.
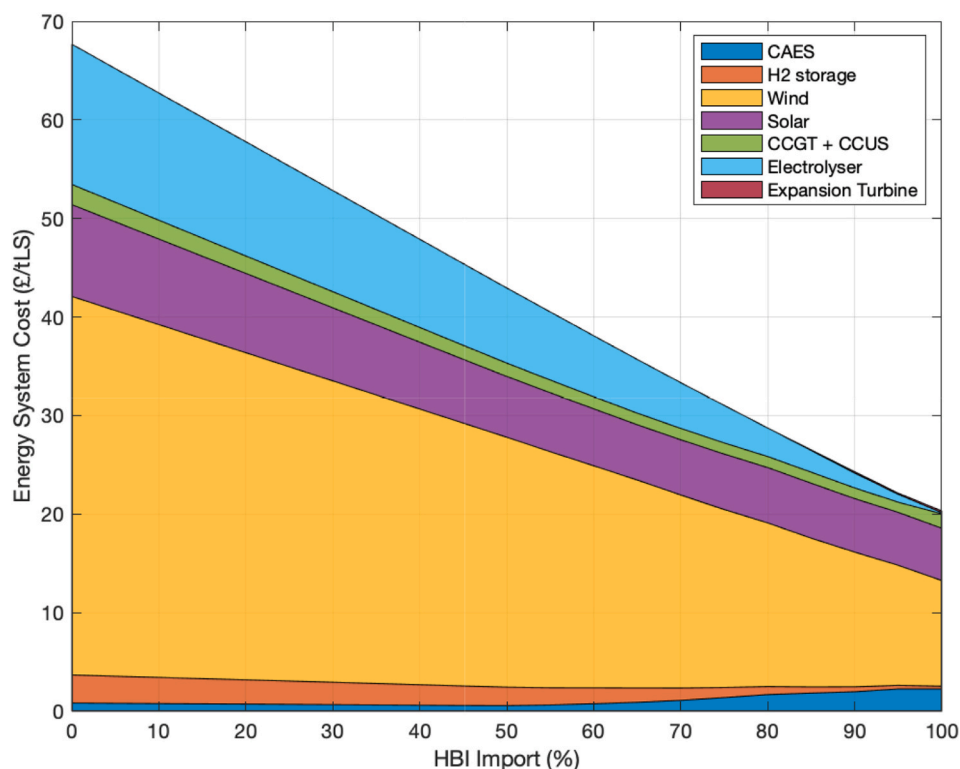
Fig. 9. Capital cost breakdown of optimal energy system to power H-DR/EAF steelmaking with 50% scrap charge. Based on UK wind and solar resources and assuming hot feed of non-imported DRI to EAFs.

steelmaking are broken down by technology in Fig. 9. Wind power accounts for over half of the energy system costs at all levels of HBI import, with electrolysers and solar power making up most of the remaining costs. With no HBI import, the total energy system cost is £68/tLS. If the entire 7.2 MtLS/yr UK primary steel industry were converted to the H-DR/EAF technology, the annualised energy system cost would be £487m. Total energy system cost reduces to £20/tLS if all HBI is imported, or £146m annually in the UK. The total cost of energy storage capacity remains at £2-£4/tLS at all levels of HBI import.

It must be noted that this analysis does not include legacy costs resulting from government policy, which are known to distort the UK electricity market (Helm, 2017). Socialising the legacy costs has been proposed, though in any case many of them are for time-limited contracts that are due to expire in the mid-2020s (Helm, 2019).

Fig. 10 shows a breakdown of the energy and resource requirements if the entire UK primary steelmaking capacity (7.2 MtLS/yr) was based on hydrogen DRI and EAFs at 50% scrap charge, along with costs per ton of liquid steel. In this case, the UK scrap consumption for a full conversion to EAF steelmaking would be approximately 4 Mt/yr. This is around half of the UK's ferrous scrap exports in 2019 (8.1 Mt/yr) (World Steel Association., 2020).

Marginal abatement costs for H-DR/EAF steelmaking are shown in Fig. 11 along with recent UK Government carbon price projections (Department for Business, 2019). Marginal abatement costs in 2025 range from £23/tCO$_2$ for greenfield sites up to £38/tCO$_2$ when considering blast furnace relining, reducing to £21-£37/tCO$_2$ by 2030 and £17-£32/tCO$_2$ by 2040. According to this analysis, if the steel industry paid the full cost of its carbon emissions (i.e., if emissions trading scheme (ETS) free allowances did not exist), H-DR/EAF steelmaking powered with green hydrogen would be cost-competitive with blast furnace relining in the UK by 2030 at the latest and potentially by the mid-2020s if central cost estimates prove to be accurate. If brownfield or greenfield sites are considered, cost competitiveness would be expected even sooner. With rising carbon prices in future, it is expected that by

2040 the traded price of carbon in the UK will be 2–14 times the marginal abatement cost of H-DR/EAF steelmaking.

Greater clarity over the future of ETS free allowances and carbon prices would allow the steel industry to plan for the future with greater confidence, stimulating investment in decarbonisation. The competitiveness of UK industry could be improved through reforms to industrial electricity prices, which are some of the highest in Europe. This is a consequence of several factors affecting the UK, including relatively lower levels of cross-border electricity trading, reduced support for long-term contracts, and the way that network and policy costs are recovered evenly across all consumers whereas other countries recover proportionately more from domestic and commercial consumers (Grubb and Drummond, 2018). As the cost of greenhouse gas emissions increases in the UK, a carbon border adjustment mechanism will be crucial to maintain the competitiveness of UK industry and ensure that carbon leakage does not occur.

H-DR/EAF steelmaking can potentially be a lower cost option than bioenergy with carbon capture and storage, with recent projections of CO$_2$ avoidance costs for the deployment of bio-CCS in the UK steel industry being in excess of £80/tCO$_2$ (Mandova et al., 2019). Hydrogen direct reduction also has the added benefit of not having the carbon absorption lag of bioenergy or requiring the deployment of carbon capture and storage infrastructure. However, as shown in this paper, the energy requirements of hydrogen-based steelmaking are significant. Bio-CCS also has the potential to provide carbon dioxide removal, unlike green hydrogen derived using renewables.

3.4. Limitations and future work

The results presented in this section are based on analysis which includes a number of assumptions and simplifications in order to make the problem tractable. The key limitations are listed here along with their likely impact on the accuracy of the results and suggestions for how these effects might be account for in future. It is hoped that this will
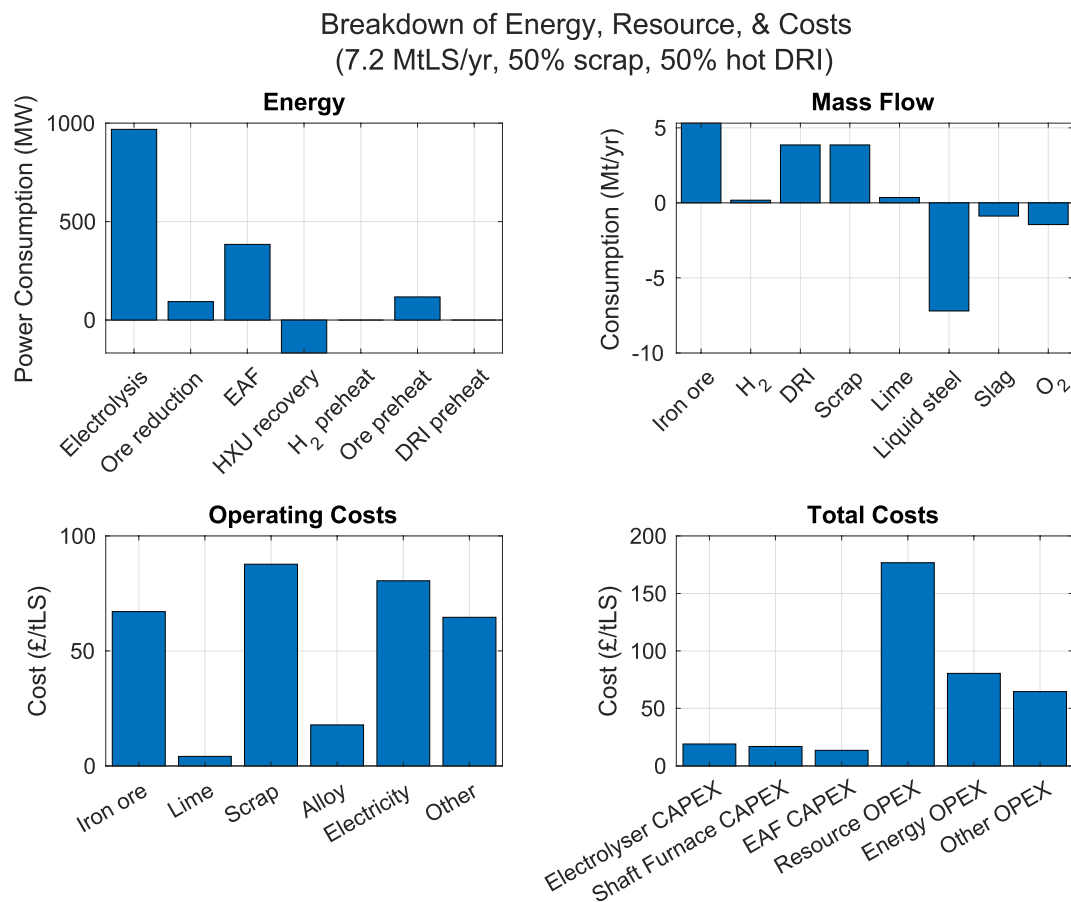
Breakdown of Energy, Resource, & Costs
(7.2 MtLS/yr, 50% scrap, 50% hot DRI)

Fig. 10. Energy, resource, and cost breakdown if UK steel production was provided entirely using H-DR/EAF, with 50% scrap charge.

guide future research in this area.

- **Steel industry in isolation.** Our analysis determined the energy system requirements, and associated costs, for the iron and steel industry in isolation, rather than considering how it might fit into the wider energy system. As such, the energy system costs shown here provide an upper limit, considering that the steel industry could act in isolation if lower costs could not be achieved by integrating with the rest of the energy system (e.g., by absorbing renewable energy that would otherwise be curtailed at off-peak times). The wider energy system could be considered by adding components to the time series of electricity and hydrogen demands.
- **Dataset size.** The analysis is based on 20 years of historic wind and solar capacity factors for the UK. While we believe that this is a sufficiently long period that bulk energy storage becomes necessary to deal with the varying renewables availability between seasons and years, we recognise that future weather events may be more extreme. Markov chains could be developed based on historic wind and solar reanalysis data and used to generate time series of renewables capacity factors for use in a Monte Carlo approach.
- **Data resolution.** While the wind and solar capacity factors that we used are based on reanalysis performed using 1-h resolution data, we aggregated the hourly-resolution time series into time-slices (four per month), as explained in Section 2.3. This was performed to ensure that the runtime of the linear programming solver is not excessively long, while preserving several of the key characteristics of renewables availabilities (such as diurnal solar variation and seasonal wind and solar variation). However, by aggregating the data into time-slices, the higher resolution variation is lost. It can be expected that higher resolution data would tend to increase the energy storage requirements above those determined here. However,

since energy storage costs comprise a relatively small component of the energy system cost (and an even smaller component of the total cost of steel production), the total costs would not be increased significantly.

Previous energy system studies have conducted long-run energy system optimisation while accounting for high temporal resolution variation in supply and demand by "soft-linking" energy system planning tools and power system models (Zeyringer et al., 2018). A long-duration energy system planning tool is used with time-slices to determine the lowest cost combination of energy system technologies, then flexibility requirements (such as storage capacities and demand response) are fine-tuned using higher resolution data.

- **Perfect foresight.** By using historic data and an optimisation approach that considers all of the data simultaneously, we have inherently assumed that the energy storage is operated based on perfect foresight of 20 years of wind and solar availabilities. This could be avoided in future work through several different approaches, such as introducing artificial uncertainty, adopting forecasting approaches, and using stochastic receding horizon analysis for the storage scheduling.
- **Materials storage.** In our analysis, we have assumed that all of the energy balancing is conducted using energy storage. However, the output of a H-DR/EAF steelworks could be uncoupled from renewables availability to some extent by storing HBI or finished steel. This approach could be included in the linear programming formulation if the analyst has an understanding of the costs of materials storage.
- **Varying scrap charge.** Another source of energy flexibility in hydrogen-based steelmaking is the option to vary the scrap charge in the EAF and accordingly vary the output of the DR furnace feeding
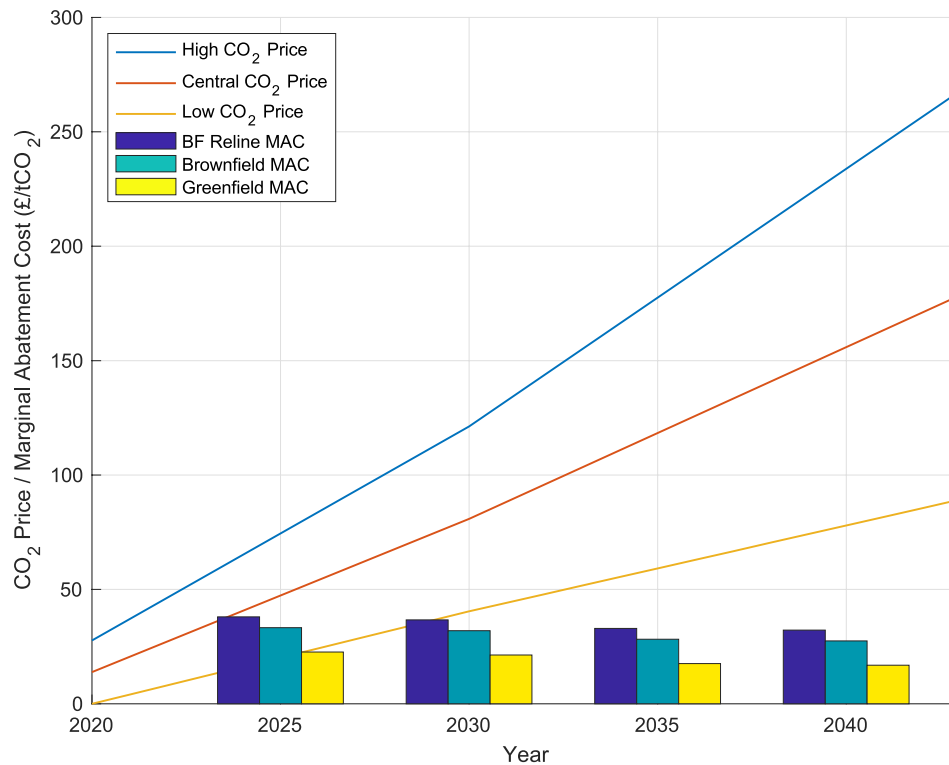
Fig. 11. CO_2 price projections and marginal abatement costs for H-DR/EAF steelmaking in the UK, with 50% scrap charge.

the EAF. EAF melting is a batch process with tap-to-tap times typically less than an hour, and so the scrap charge in each melt could be varied according to electricity price (driven by renewables availability). Again, this could be included in the linear programming formulation, though it must be considered that scrap metal can introduce contaminants that affect steel quality.

- **Experience rates and economies of scale.** The optimisation problem uses unit costs for the energy technologies that are independent of the scale of deployment or utilisation. In reality, long run costs are reduced through economies of scale and through experience. Future analyses could account for the latter by including learning curves (Schmidt et al., 2017b), however this would introduce nonlinearities to the objective function.

4. Conclusions

Hydrogen direct reduction of iron ore is seen as one of the key technologies to radically decarbonise steel production. However, while it is known to be highly energy-intensive, the energy system requirements and costs have not previously been considered in detail. In this study, we have addressed this gap in the knowledge through a case study on the United Kingdom, although the methods employed are applicable to any country. A previously published thermodynamic process model of H-DR/EAF steelmaking has been integrated with a new long-term energy system planning tool that has been developed and applied with recent projections of technology costs, carbon prices, and fuel prices.

Our key findings can be summarised as follows:

- Fossil-free steelmaking in the UK based on hydrogen direct reduction and electric arc furnaces is expected to be cost-competitive with blast furnace – basic oxygen steelmaking within 5–10 years, while having near-zero CO_2 emissions.
- For an annual production rate of one million tonnes of liquid steel, there is a steady hydrogen demand of 100–200 MW (depending upon

the level of scrap utilisation) and 60–70 MW of additional electricity demand.
- For the same annual production rate and assuming a 50% scrap charge, the optimum energy system largely comprises 415 MW of wind power capacity, 350 MW of solar, 180 MW of electrolyser capacity, and 80 GWh of cavern-based hydrogen storage.

The energy demands of the H-DR/EAF approach are highly dependent on the level of scrap in the electric arc furnace charge. Assuming an average scrap charge of 50%, it has been found that a complete switch to H-DR/EAF steelmaking in the UK, with its annual steel production of 7.2 MtLS, would require a steady supply of around 700 MW of hydrogen (20.7 tH_2/hr, or 182,000 tH_2/yr) and 430 MW of additional electricity on top of that required for electrolytic hydrogen production.

Using the energy system model with recent cost estimates for low-carbon energy system technologies and 20 years of wind and solar data, the optimal energy system to meet these demands has been found. With a 50% scrap charge to the electric arc furnaces, the optimal energy system would comprise 3 GW of wind power, 2.5 GW of solar power, 60 MW of combined cycle gas power with carbon capture, 1.3 GW of electrolysers, 600 GWh/600 MW of hydrogen storage, and 30 GWh/130 MW of compressed air energy storage. These capacities are significant, and long-term government support will be vital if the steel industry is to successfully transition to the H-DR/EAF steelmaking approach.

Energy system costs for a self-sufficient UK steel industry operating on H-DR/EAF with a 50% scrap charge are estimated to be around £68/tLS. Over half of these costs are for wind power, with electrolysers and solar power comprising the bulk of the remaining costs. It is possible that it will prove financially advantageous to import direct reduced iron from iron-rich countries, in which case the energy system costs to the UK could be reduced to around £20/tLS.

The marginal abatement costs of H-DR/EAF steelmaking range between £23-£38/tCO_2, and based on recent projections of traded carbon prices, these will be lower than the cost of carbon by 2030 at the latest, but potentially as soon as the early- or mid-2020s. These costs are also

lower than recent estimates of the cost of decarbonising steel production through deployment of bio-CCS. However, the values will be affected by legacy costs for electricity generation and free allowances to the iron and steel industry in the UK emissions trading scheme, and the effects of these must be investigated in more detail in future work.

Given the finding in the present work that primary steelmaking based on hydrogen direct reduction and electric arc furnaces can be made competitive with blast furnace – basic oxygen steelmaking, we recommend that the UK Government provide support for technology demonstrators of this combination in the UK context, potentially considering developments such as integrated high temperature electrolysis. On top of this, we make several further recommendations to the UK Government to drive forward decarbonisation of the UK steel industry: 1) address the policy and network costs that adversely affect industrial electricity prices and put the UK iron and steel industry at a disadvantage to international competition; 2) provide clarity over the future of free allowances to energy-intensive industry in the UK emissions trading scheme (given that they effectively lower the cost of carbon emissions to heavy industry); and 3) develop and introduce cross-border carbon regulation for iron and steel products to ensure the competitiveness of UK industry and prevent carbon leakage.

CRediT authorship contribution statement

Andrew J. Pimm: Conceptualization, Methodology, Software, Validation, Data curation, Writing – original draft, Visualization, Project administration. **Tim T. Cockerill:** Conceptualization, Methodology, Supervision, Funding acquisition. **William F. Gale:** Conceptualization, Methodology, Writing – review & editing, Supervision, Project administration, Funding acquisition.

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.

Acknowledgments

All data generated in this study are included either in the paper or the supplementary data that accompanies this.

Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.jclepro.2021.127665. It is also available from University of Leeds at https://doi.org/10.5518/997.

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