Net Zero Innovation Portfolio Industrial Fuel Switching

Desktop Feasibility Study: Green Hydrogen in Steel Manufacture

Reference	BritishSteelRD_82
Issue no.	1
Date	30/11/2022
Classification	Public
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1. Executive Summary

This Green Hydrogen in Steel Manufacture (GHiS) feasibility study has investigated a first step to decarbonisation of the steel industry through use of hydrogen (H_2), manufactured from green sources, as a replacement for natural gas (NG). This work brought together powerful collaborators in British Steel (BSL) as a steel manufacturer, EDF R&D UK Centre as a developer of hydrogen solutions with EDF Group Companies (Hynamics and EDF Renewables)(EDF), and the unrivalled research capability of both the Materials Processing Institute (MPI) and University College London (UCL).

The object of this feasibility study is to develop a reliable cost estimate and engineering timescale to implement the demonstrator phase of the hydrogen conversion of BSL's Teesside Beam Mill (TBM) reheat furnace. The full estimated gross cost associated with demonstrator programme, including capital, labour and material costs, is estimated at £7.21million and the commissioning date is foreseen as April 2024. The experience, data and knowledge gained from this demonstrator phase will inform the full conversion of the TBM furnace and other furnaces within BSL and the UK steel industry as well as other energy intensive industries.

The high-level vision of the proposal is for EDF to use renewable resources to power green hydrogen production through electrolysis, and final use of the green hydrogen in BSL's reheat furnace at TBM. We believe that this collaboration, along with the support from Danieli Centro Combustion (DCC), provides a uniquely qualified team to 'firm-up' the costs not only for a future demonstration phase, but for wider adoption where decarbonisation of heat/reheat furnaces is required.

Steel is one of the core pillars of today's society and, as one of the most important engineering and construction materials, it is present in many aspects of our lives. However, the industry now needs to cope with pressure to reduce its carbon footprint from both environmental and economic perspectives.

Currently the steel industry is among the three biggest producers of carbon dioxide, with emissions being produced by a limited number of locations; steel plants are therefore good candidates for decarbonisation. BSL's efforts to decarbonise the business are already underway, with a variety of projects being implemented to improve environmental performance. This work looks to provide a realistic introduction path to hydrogen decarbonisation of steelmaking through a substantial volume of natural gas fuel switch to hydrogen. Hydrogen fuel switching of reheat furnaces directly aligns with two of the four "Glasgow COP26 Breakthroughs" and will have direct scalability to other reheat furnaces within BSL, the steel industry worldwide, and indeed other industries where similar furnace technology exists.

BSL's TBM currently operates a 100% natural gas fired continuous reheat furnace for the reheating of steel semi-finished products to temperatures of approximately 1300°C so that they may be hot rolled into sections and beams for the construction industry. Within the reheat furnace, heat is transferred to the stock by conduction and convection of the hot gases in the furnace to the surface of the steel and from radiation of heat from the walls of the furnace.

Although an apparently simple process, the need to reheat the steel to temperatures of about 1300°C with heat evenly distributed through the product makes the process both very energy intensive and a challenge to control efficiently. Consistency in the reheated product is vital to achieving the correct product dimensions and the temperature at each stage of the process affects the grain structure and metallurgy of the finished product giving it the desired final properties. The most cost-effective approach to decarbonising the steel reheat process is through a retrofit strategy for current reheat furnace assets, to allow hydrogen fuel switching.

Fuel switching to a green hydrogen fuel entails a great deal of process investigation (burner technology, combustion modelling, heat distribution, refractory lining impact, new sensor technology, possible furnace conversion and system integration), and product implications, (variations in scale build up, uniformity of heat transfer, and effect on metallurgical properties).

Through effectively managing the process integration of the fuel switching, the quality of the product should remain unchanged. The feasibility study has reviewed the technical maturity and economic viability of using alkaline, proton exchange membrane (PEM) or solid oxide electrolyser cell (SOEC) derived hydrogen vs blue or grey, and the impact on the product business model and GHG footprint. The possibility of utilising the valuable 'waste' heat from the reheat furnace, has been considered, as this could increase the efficiency of onsite SOEC hydrogen production by c.20%.

Currently the furnace exhaust temperature varies from 600 to 800°C in normal operation with a recuperator utilising this exhaust to preheat furnace combustion air to just below 500°C using a recuperator (heat exchanger). Although not considered as part of the demonstrator phase, as part of a fully converted or new reheat furnace, the 'waste' heat could be utilised to improve the efficiency of an SOEC electrolyser solution for hydrogen production.

This feasibility study has assessed the technological and economic aspects of switching from natural gas heating for the reheat furnace to the use of green hydrogen supplied by EDF in the UK.

As far as we are aware, the switch to burners capable of 100% hydrogen as a fuel in a walking beam reheat furnace is innovative and has not been demonstrated at scale. This innovation is reflected in a starting estimated TRL of around 5. Having said that, the constituent individual technologies encompassed within this proposal (alkaline or PEM electrolyser technology, burner technology, advanced modelling, fluid dynamics) have a higher TRL resulting in a project that is infinitely feasible if support for the study and demonstration are awarded. For example, the burner technology for 0-100% hydrogen is commercially available from DCC who have supported this study.

Building on the outcomes of the feasibility study outlined above, we propose that following the demonstration phase, hydrogen production facilities will be established on the Teesside steel manufacturing site adjacent to TBM. An electrolyser-based technology resulting in green hydrogen from renewable electricity resources has been benchmarked against alternative blue hydrogen options. Additionally, the demonstration will also lean on the results of the feasibility study to address the retrofit alterations required to the reheat furnace and production methodology that will be encountered during a fuel switch. We are well aware of the variations in the combustion characteristics of hydrogen versus natural gas, and we are fully expecting that burner technology, heat uniformity, product alterations and furnace reliability will all have to be addressed in the demonstration phase.

Through the effective research outlined in the feasibility and demonstration programme of work, the initial TRL of 5 can be raised to a TRL of 7; furthermore, knowledge of the lifetime costs of the fuel switch from both a CAPEX and OPEX perspective will be improved throughout both phases.

Conversion costs were unknown, in part due to uncertainty around which components would need to be either adapted or replaced. The feasibility study has identified the "battery limits" of the necessary conversion, impact on life of components (and hence ongoing replacement CAPEX), and the potential ongoing operational costs to run at 100% hydrogen.

For reheating product for rolling at TBM, the average thermal energy consumption is of the order of 1.8 GJ/tonne, which equates to 45.6m³ of natural gas usage. Each cubic meter of natural gas burnt is assumed to release 2.02kg of CO_2 at the point of combustion. The demonstrator would only be changing Zones 5 and 6 to be capable of hydrogen firing, which is only 25% of the CO_2 emissions; however, if successful the demonstrator would be a necessary step towards full decarbonisation of this reheat furnace as well as others in BSL's portfolio and would provide experience to other high energy using industries.

Key in the future adoption of hydrogen as a fuel switching agent is the creation of an industrial demand. BSL is a member of the East Coast Cluster and Zero Carbon Humber, both of whom have well developed plans for hydrogen networks. These developing networks will ensure a long-term improvement in cost and consistency of supply of hydrogen.

With the collaborators we have assembled in this consortium, we feel that all of the technical challenges can be addressed. Commercially the advantage of the proposed work is multifaceted. Firstly, as outlined above, the work initiates an industrial demand for hydrogen which will create demand pull for investment decisions by suppliers. Secondly, the use of hydrogen will paint the landscape for a wider decarbonisation of the steel sector possibly through hydrogen DRI.

Finally, as steel is a crucial input into the renewables, nuclear and transport sectors, the imperative of decarbonisation of the steel sector is key for the implementation of the UK's 2050 Net Zero targets.

2. Contents

3. Introduction

The project brings together BSL and EDF to assess the feasibility of introducing “green” hydrogen into the UK steel manufacturing process. EDF has carried out a techno-economic assessment of the methodology and practicality of delivery green hydrogen for fuel switching into the steel manufacturing process, and BSL has assessed the technical implications of the fuel switch on both product and process.

Together the partners have carried out an assessment of the economic viability and environmental impact of switching from natural gas to hydrogen in defined aspects of steel manufacture.

MPI, with support from UCL, has aided the assessment of the product and process viability for BSL.

As an energy intensive industry with hard to abate emissions, the steel industry offers the potential for large CO_2 emission savings through fuel switching from natural gas to hydrogen.

3.1. Report Structure

The report follows the Work Package Structure laid out in the NZIP IFS GHiS application document and follows, where practical, the agreed work package structure. The Chapters are titled as below:

- Current and Proposed Furnace Design (WP2)
- Product Impact Assessment (WP3)
- Hydrogen Supply and Energy Demand for Demonstrator (WP4)
- Environmental, Social, Health and Safety (WP5)
- Business Model (WP6)
- Demonstrator Design; Phase 2 Delivery Plan (WP7)
- Dissemination Plan (WP8)

Each Chapter is an independent document, with references to other Chapters where appropriate. The Chapters have however been brought together in a structure that is intended to assist the reader in understanding the technical challenges and provide an insight into the planning and research undertaken by the collaborating parties to develop a workable plan for delivery.

4. Current and Proposed Furnace Design (WP2)

The process at TBM takes semi-finished cast steel 'feedstock', in the form of steel slabs or blooms, which are currently produced and transported by rail from the Scunthorpe steelworks located 120 km south of TBM. The feedstock is first raised to a production temperature of around 1,300°C in a reheat furnace before being mechanically reduced in cross sectional area and elongated to form steel beams which are then cut to length for commercial sale.

This project deals with the process of reheating the slabs or blooms which is undertaken in what is currently a natural gas fired furnace.

4.1. Outline of Current Furnace Design

The furnace in use at TBM is capable of heating the feedstock at a rate of up to 220 tonnes/hour. The furnace is referred to as a Walking Beam Furnace (WBF) the title of which describes how the stock is transported through the approximately 44m long furnace.

The stock, in the form of steel slabs or blooms, are supported on rows of water-cooled pipes, often referred to as beams. These beams run longitudinally along the furnace. A mechanical mechanism lifts some of the rows of beams, above the nominal stock level and then transports them up to 500mm before lowering them back down to the fixed beams.

This method of transport gives the furnace its name of "Walking Beam Furnace". As the stock is supported above the hearth, this allows the stock to be heated from both above and below.

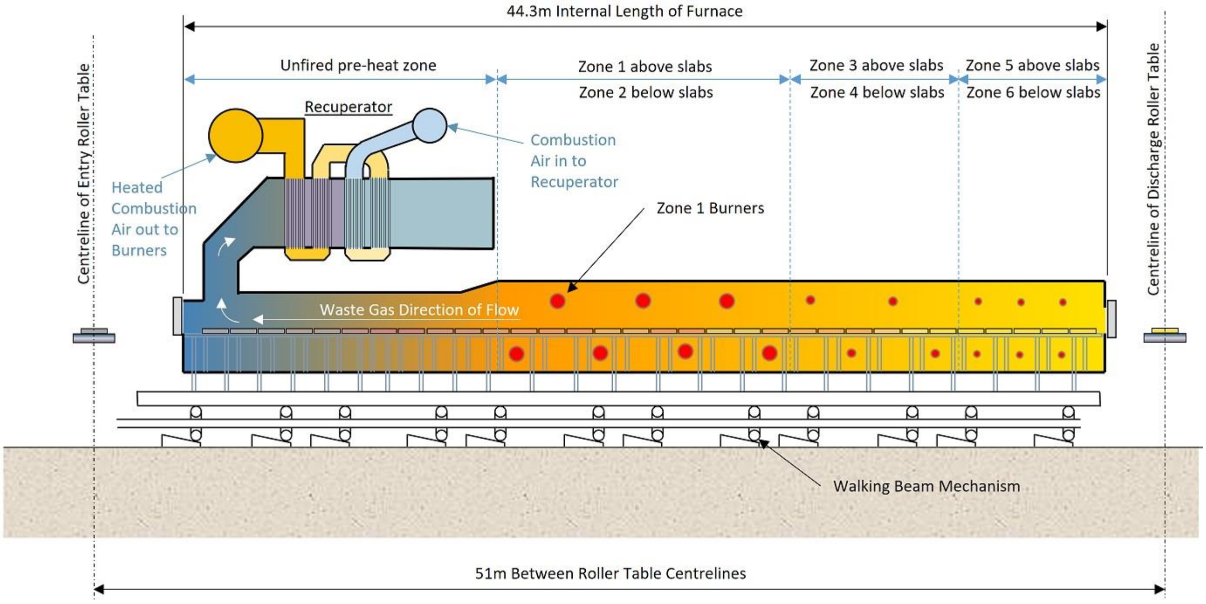


Figure 1 - Schematic Layout of the TBM Furnace

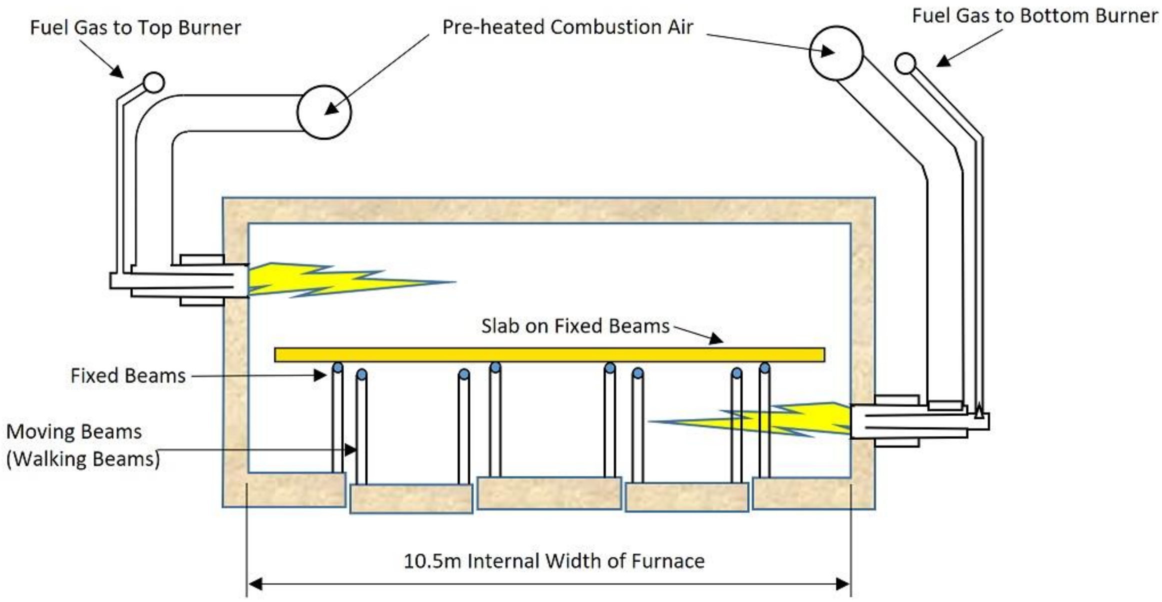


Figure 2 - Schematic Cross Section of Furnace

There are 6 fired zones in the furnace with a total of 34 burners of varying sizes. The larger burners are in the earlier zones, with smaller burners later in the furnace. The size of the slabs or blooms which are being heated vary, but a typical 'average size' would be approximately 1,200mm wide, 225mm thick and 9,500mm long and would weigh approximately 20 tonnes. At a high production rate of 200 tonnes/hour the slab would be resident in the furnace for nearly 3½ hours.

Cold slabs are charged in the west side and 'walked' through the furnace with a small gap of around 100 mm between them.

Waste gas from the furnace is removed at the charge end and the first burner is approximately 15m from the entrance, therefore as the material is transported through this unfired zone, it is preheated by the waste gas. The first heating zone it meets are zones 1 and 2, (zone 1 is above the stock, and zone 2 is underneath), this is the area where the surface temperature is raised rapidly.

Zones 3 and 4 are the next heating zones, this area continues heating the stock as the increased surface temperature conducts towards the centre. Zones 5 and 6 are referred to as the 'soaking zones'. Within these zones the surface temperature is not intended to be increased. It is an area of the furnace that allows time for the heat to fully conduct equally through the stock.

The furnace was designed to be capable of burning natural gas, fuel oil and coke oven gas (COG). COG is no longer available to the furnace as it is a gas produced as a by-product within an integrated steelworks and since the closure of Teesside Steelworks this has not been an available option. Fuel oil is not available either, its prohibitive cost has meant that the equipment, such as oil tanks and pumps, required for this fuel have now been decommissioned.

Air for mixing with the fuel is pushed into the combustion system by very large combustion air fans which first force the air through a 'bundle type heat recuperator'. The preheated air is then piped to each burner. Fuel is also piped to the burner and mixed with the combustion air as it leaves the burner and enters the furnace where the mixture is ignited by the high atmospheric temperatures.

The combustion products pass through the furnace towards the 'cold' charge end and then up through the furnace chimney, via the recuperator.

4.2. Current Furnace Operation

The furnace is nominally rated at 45MW, although it often runs much higher than this. The volumes of gas routed to each zone will vary considerably dependent upon the products being produced and hence the size of the bloom or slab, the speed of operation and if the production process is delayed or has recently restarted after a delay.

Table 1 below shows average consumption figures by zone for a 12-month period in 2021 to 2022. The following **Table *2*** shows the flow rates required when producing at high productivity rates and represents several hours of data recorded consecutively.

Average Fuel Use 2021/22					
Zone	**Burners Qty**	**Average Annual Use (GJ/hr)**	**Power Use (MW)**	**% Flow by Zone**	**% Flow by Zone Pairs**
1	6	17.04	4.73	13%	34%
2	6	29.57	8.21	22%	
3	5	10.33	2.87	8%	41%
4	5	44.70	12.42	33%	
5	6	8.83	2.45	7%	25%
6	6	24.63	6.84	18%	
Totals =		**135.10**	37.53	100%	100%

Table 1 - Average Annual Fuel Consumption by Zone

Peak Fuel Use 22nd April 2022					
Zone	**Burners Qty**	**Peak Use (GJ/hr)**	**Power Use (MW)**	**% Flow by Zone**	**% Flow by Zone pairs**
1	6	55.75	15.49	22%	51%
2	6	74.22	20.62	29%	
3	5	24.91	6.92	10%	34%
4	5	62.18	17.27	24%	
5	6	10.80	3.00	4%	15%
6	6	26.93	7.48	11%	
Totals =		**254.78**	**70.77**	**100%**	**100%**

Table 2 - Peak Fuel Consumption by Zone

Energy input into the furnace is controlled by regulating the flow of fuel and combustion air into the furnace. With natural gas as the fuel, the air to fuel ratio is controlled to 10:1 so as to ensure a slightly oxygen rich mix of combustion gasses, it is an important safety issue to always ensure that there is never excess fuel in the furnace.

Flow of fuel and air to each zone is controlled by valves in both the gas and air lines. A burner management system (proportional-integral-derivative (PID) controller) for each zone controls the flows to maintain the zone at the desired temperature set point. The zone temperature set point is provided by a supervisory control system (referred to as a Level 2 system) which models the temperature of each bloom or slab within the furnace and calculates the appropriate furnace temperature required to meet the production requirements.

In essence the Level 2 system will aim to increase the slab or bloom temperature to the required value as it travels through the furnace. The slab temperature is shown indicatively on the heating curves shown in **Figure *3*** below.

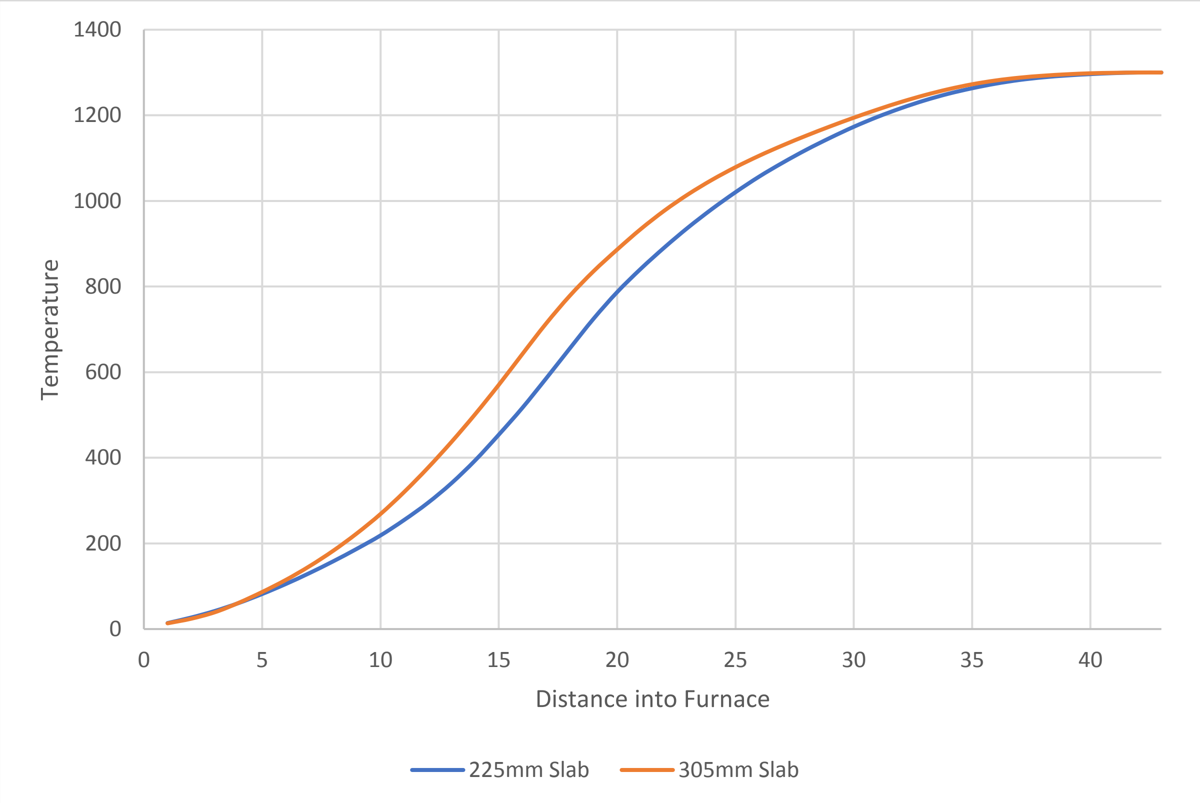


Figure 3 – Indicative Heating Curves for 225 and 305mm Thick Slabs

4.3. Low Carbon Options

As described above, the current methodology for heating steel is achieved by raising the temperature of the steel within an enclosed furnace, heated by the combustion of natural gas. Using hydrogen to directly replace natural gas as a combustion fuel is the simplest solution, but if the hydrogen is to be sourced by electrolysis so as to be Carbon neutral, then consideration should be given to heating directly by electricity.

Induction heating has been used in the steel industry for raising the temperature of steel to high enough temperatures to roll, unfortunately this technology has only ever been successfully implemented on smaller cross-sectional areas of steel than those heated at TBM and with steel that is already at an elevated temperature.

Additionally, the cross-sectional areas and profiles of the steels heated at TBM vary considerably and as the induction coils used for heating steel require a close proximity to the surface to operate efficiently, this is not practical to achieve this with the multitude of steel profiles.

Other electrical heating methods such as radiant or plasma heating have not yet been developed to a sufficient technical level, to be of use in this application.

There is also a developing requirement for Hydrogen to be used in the steel industry as a zero-carbon reductant as well as a fuel gas; this makes the development of bulk hydrogen production a necessity for decarbonising the steel industry going forward. This subject is discussed further in Section 6.8. The use of hydrogen as a heating fuel has therefore been chosen for this project.

4.4. Aim of Demonstrator Trial

The aim of undertaking this project is to move closer to the objective of completely displacing natural gas as the fuel supply for the reheating of steel slabs and blooms at TBM with that of hydrogen. This project will replace the current natural gas burners on Zones 5 and 6 with dual fuel natural gas and hydrogen burners and will include all the necessary pipework and burner changes and any necessary control system upgrades and replacements.

4.4.1. Oxygen Enrichment vs Atmospheric Air

As discussed in ***Paragraph 4.4.4*** the potential for generating unacceptably high levels of NO_x emissions as a result of the higher flame temperatures associated with hydrogen fuels is real. Discussions with potential suppliers however, highlighted that in their opinion, NO_x levels could be adequately controlled by the use of burners incorporating so called ‘flameless technology’. The purpose of this demonstrator trial is to verify the capability of burning hydrogen in a reheat furnace and to quantify the effects on products and the equipment. The added complexity and cost associated with Oxygen enrichment, particularly to the high levels required would be unnecessary for this purpose.

Oxygen enrichment would have other benefits which should at least be considered. By firing the furnace with a significantly lower volume of nitrogen gas in the combustion air will increase the furnace efficiency. The reduction in the volume of flue gasses should reduce the heat loss through the stack.

Retro-fitting a high level of oxygen enrichment will however change the balance of the furnace gasses and would be a major unknown in the operation of the furnace; therefore, it has been discounted for this Phase 2 demonstrator trial.

4.4.2. Scale of Demonstrator Trial

It is considered that the scale of the trial has to be large enough to prove that hydrogen technology can be applied to a full reheating furnace. It is envisaged that a single burner trial, in laboratory conditions, will be able to prove the capability of the burner to provide heat across the full width of the furnace, at guaranteed NO_x levels, but will be insufficient to prove the burner and control systems within an operational environment and single burner trials on the furnace itself will also be unable to prove the capability of the burner system. The hydrogen fired burner trial must meet all of TBM’s operational requirements and address the questions regarding the effects upon furnace operations raised.

For the above reasons a trial which involves at least one zone was considered the minimum required to prove the technology; Zones 5 and 6 have been selected for the demonstrator and the reasons these two zones were selected are as follows:

- The high temperatures of these zones will provide more robust information and data on the effects of burning hydrogen in the furnace
- The lower fuel requirements for these smaller burners (approximately 25% of total flow) will be a benefit if the planned electrolyser is not yet fully commissioned at the start of the trial
- Smaller burners will make equipment for burning either hydrogen or natural gas easier to install and also make it practical to apply hydrogen burners to both top and bottom zones
- The location of these zones at the discharge end of the furnace will permit waste gasses to travel through all zones and hence provide more data on any detrimental effects to refractories and to the feedstock
- The smaller thermal input of these zones will require less investment in equipment at this stage

4.4.3. Technical Differences between Natural Gas and Hydrogen Firing

The energy density by mass of hydrogen is significantly higher than that of natural gas; unfortunately, the energy density by volume is very much lower. Natural gas is a fuel which predominantly consists of methane (CH_4), so for simplicity, the comparison of energy densities in **Table *3*** below are for those of pure methane, rather than natural gas.

	Hydrogen	Methane
Energy Density by Mass (MJ/kg)	141.9	53.6
Energy Density by Volume (MJ/L)	0.012	0.036

Table 3 - Energy Density Comparison

The lower energy per unit volume of hydrogen means that approximately 3 times the volume of hydrogen is required when compared to methane to get the same amount of energy. As a result, therefore, either an increase in pressure of the fuel supply or an increase in the volumetric flow of hydrogen will be required.

The molecular size of a hydrogen molecule is significantly less than that of a methane molecule, therefore leaks are much more likely, requiring much greater care and attention to seals, gaskets and valves.

The flame speed of hydrogen is significantly higher than that of methane (approx. 250 cm/sec for hydrogen as opposed to 35 cm/sec for methane) making burner design crucial to ensure heating across the entire width of the furnace.

Finally, the flame temperature of hydrogen is higher than that of methane (2,200°C as opposed to 1,970°C). This increase in flame temperature will result in higher thermal NO_x emissions for hydrogen than for methane. This could result in the non-CO_2 emissions from hydrogen becoming unacceptable, without other measures such as innovative burner design, or even a high level of oxygen enrichment of the combustion air.

4.4.4. Control of NO_x Emissions

As previously discussed, the higher flame temperature of hydrogen as it is combusted in air, will result in a higher level of NO_x than is currently experienced with natural gas. Oxygen enrichment has been considered, however high levels would be required as sufficient Nitrogen has to be displaced from the combustion air to minimise the evolution of Thermal NO_x. This solution would be technically difficult due to the change in combustion air and waste gas volumes as well as the additional control and safety issues. The additional cost and energy requirements to supply oxygen to the furnace would of course also be high.

Discussions with proposed equipment suppliers have raised the possibility that levels of Thermal NO_x can be reduced by the use of 'Flameless Combustion Technology'. The aim of this burner design is to eliminate any stable flame front which is where the highest combustion temperatures are experienced and hence the point where thermal NO_x is predominantly generated. It is this combustion with an unstable flame front which results in lower thermal NO_x production.

4.4.5. Burner Design

As well as meeting the environmental requirements for the production of NO_x, the proposed burners would have to meet the technical requirements of the furnace to heat steel homogeneously by projecting heat across the full width of the furnace. Stable production must be maintained and hence it will also be a requirement of the burners to be able to fire either hydrogen or natural gas. Indeed, it is being considered that the burners may be able to provide the function of burning fuel over the full range from 100% natural gas to 100% hydrogen and any ratio in between.

It is envisaged that the replacement burners will be located where the current burners are, in the sidewall of the furnace at points above and below the stock level, in the same position. Separate modelling work has been undertaken by MPI and UCL and is discussed further (See ***Section 5.2***).

DCC have specified a flameless burner design which is currently in operation in a 'side wall fired' furnace of even larger design than TBM's furnace. As part of the Phase 2 procurement, due diligence will be performed on this burner design and any additional testing that may be deemed necessary will be considered at that time.

4.5. Testing Requirements of Phase 2 Demonstrator

To understand the ramifications of firing hydrogen within a steel reheating furnace and the suitability of converting the entire furnace to hydrogen firing, it is essential that a series of tests be undertaken to identify the benefits and drawbacks of the technology. These tests in some cases will involve taking benchmark measurements before the demonstrator trial modifications are undertaken. The tests will include the following:

- Slab temperature measurements.
- Monitoring of emissions
- Product quality tests
- Scale accretion on slabs
- Refractory inspections
- Recuperator inspection and performance
- General safety analysis

4.5.1. Slab Temperature Measurements

After reheating and discharge from the furnace, surface temperature measurements can be taken using optical pyrometers. These do not however give a full picture of the bulk temperature of the slab, nor do they give any feedback as to the temperature evolution during the reheat process. For process control purposes the bulk temperature and the temperature evolution during heating is all modelled within the Level 2 process control computer.

To calibrate the Level 2 system, particularly after a change in operating conditions such as changing the fuel type, it is best practice to send a test slab through the furnace which has been equipped with strategically placed thermocouples embedded within the steel. Data is logged on recorders which are held in thermally insulated boxes to protect the electronic equipment during heating.

It is envisaged that a thermocoupled slab trial will be undertaken before the burner changes are undertaken and then repeated when zones 5 and 6 are fired on hydrogen. This will provide data on the thermal transfer from the hydrogen flame and will also serve as calibration data for the Level 2 model.

4.5.2. Monitoring of Emissions

The current Environmental Agency requirements for the monitoring of stack emissions as stipulated in the site environmental permit currently require annual extractive monitoring of the flue gasses. It would be the intention for Phase 2 that a continuous monitoring approach would be used to record stack emissions which will gather data before the Phase 2 equipment is installed. After installation, data can then be gathered to monitor the performance of the burners with respect to emissions, particularly of NO_x, so that the emissions for a fully hydrogen fired furnace can be extrapolated from the data.

The methodology to be used in determining the effect of the change to hydrogen firing are discussed in more detail in ***Section 7.3.***

4.5.3. Product Quality Checks

It is envisaged that the change of combustion product gasses within the furnace atmosphere, at the elevated temperatures of the furnace, may well result in metallurgical changes to the feedstock, which may transfer to the finished product. There is a theoretical risk of hydrogen pick up within the steel whilst being heated in the presence of hydrogen, if this was the case then it can result in hydrogen cracking within specific products and steel qualities. Although this risk is believed to be small as there should be no free hydrogen in the furnace, the consequences of hydrogen pickup are so great, that testing for it is deemed prudent.

To quantify this risk, as well as the theoretical study already undertaken and described later in ***Section 5.4***, BSL will undertake product tests before the change on selected thick flange products, with levels of hydrogen around 5ppm and sulphur levels less than 0.015%. Once the products are rolled they will be stored for at least 14 days after which ultrasonic tests will be undertaken to detect any subsurface cracking which is indicative of hydrogen induced cracking.

During the demonstrator trial where zones 5 and 6 are fired with hydrogen, the same product will be rolled with steel of the same analysis and the test repeated. This should provide evidence as to if Hydrogen pick up has increased during the hydrogen firing process.

4.5.4. Scale Accretion

The influence of the combustion fuel on the formation of scale (Iron Oxides) on steel being heated within the reheat furnace are discussed in detail in ***Section 5.3***. In order to test and understand empirically the effect of the fuel change, a steel slab will be shot blasted and then weighed before being passed through the furnace with the new burners firing on natural gas. After removal and cooling the slab will be weighed again to directly measure the losses due to scale formation. The same trial will then be undertaken with a second slab of identical size and chemical composition, but with Zones 5 and 6 fired on 100% hydrogen. This will give a direct comparison of how the scale formation is affected by the change in fuel of the two zones which represent the highest temperatures of the slab whilst in the furnace.

4.5.5. Refractory Inspection and Performance

The response of the furnace insulation refractories to a change in waste gas composition has been discussed with refractory suppliers. The suppliers state that there is no evidence from furnaces burning hydrogen at the elevated temperatures used at BSL, therefore investigations into refractory performance during the demonstrator trial are deemed important. It is envisaged that the routine refractory inspections, supported by the refractory supplier, will be undertaken during furnace shutdown periods. The ability to inspect refractories during operation is limited to monitoring casing temperatures (an increase in the outside casing temperature is indicative of a refractory issue). These routine checks will continue and during the next furnace shutdown following the demonstrator trials, an internal refractory inspection, supported by the supplier, will be repeated.

In addition to these demonstrator tests, MPI will also be doing, in parallel, some independent accelerated laboratory based refractory testing.

4.5.6. Recuperator Inspections

As with the refractory inspections, the routine visual inspections of the recuperator, during furnace shutdowns, will continue both before and after the demonstrator trial. These will be supported by the continual monitoring of the existing thermocouple readings from the equipment.

Flow rates and waste gas volumes are however expected to be influenced by the fuel change, and the process control changes that result from these flow rate changes will be recorded both before and during the trial to gain a better understanding of the consequences of the fuel change.

Monitoring and understanding the gas flow rates through the recuperator during the demonstrator trial, will be invaluable to informing the design for a full furnace conversion.

4.5.7. General Health Safety and Environmental Analysis

The regulatory requirements associated with the burning of hydrogen will determine the minimum level of testing and inspection associated with the Phase 2 demonstrator trial. The scope and detailed requirements will be determined as part of the full Hazard and Operability (HAZOP) analysis which will form part of the Phase 2 implementation (see ***Section 7.2*****).**

General health, safety and environmental requirements will be controlled throughout the installation of the equipment and trial programme through the established BSL Management of Work process.

All equipment designed, manufactured, tested, installed and commissioned shall comply with UK Legislation and shall be in accordance with all relevant British, European and International Standards that are applicable and including those that are specifically listed below. The standards shall be the latest issue, including all parts, revisions and addenda current at the date of contract.

Applicable standards and regulations are listed in the HAZOP analysis.

5. Product Impact Assessment (WP3)

5.1. Introduction

The iron and steel industries account for approx. 7-8% of global CO_2 emissions. An area of high energy use is the reheating process of steel, where natural gas is the primary source of energy. The use of fossil fuels for heating contributes significantly to the emissions. The replacement of natural gas with an alternate source of energy that has a low or zero carbon emissions tariff is highly desirable to achieve carbon neutrality.

TBM have approached MPI to assist TBM develop a strategy to investigate the conversion from natural gas to hydrogen as a fuel.

5.1.1. Conversion Options

TBM have decided to follow the option of conversion to hydrogen for use in reheat furnaces. Initial investigation to a full conversion to hydrogen presented several engineering concerns as a first step.

- Hydrogen requirements.
- Changes to infrastructure.
- Changes to furnace design.
- Capacity of hydrogen burners to replace those in Zone 1 and 2.

Table *4* shows the energy values of the burners fitted to the furnace in each zone.

Zone	Qty	Burner ratings MWh
1	6	6.46
2	6	6.46
3	5	2.22
4	5	4.00
5	6	0.92
6	6	1.55

Table 4 – Burners in Zone and Rating

5.1.2. Initial Trial

An initial trail was selected as an option for a trial conversion to take forward into Phase 2 of the replacement of burners in zones 5 and 6, **Figure *4*** to flameless hydrogen combustion. From **Table *4*** it can be seen the burners in Zones 5 and 6 are the lowest energy and by extension, power ratings. To accompany this they are the smallest, physically. The location of these burners, at the end of the process are also logistically easier to convert as access is easier achieve the conversion.

As these are the lowest energy rating burners in the furnace, the conversion to current hydrogen technology offers the optimum location for trialling fuel conversion.

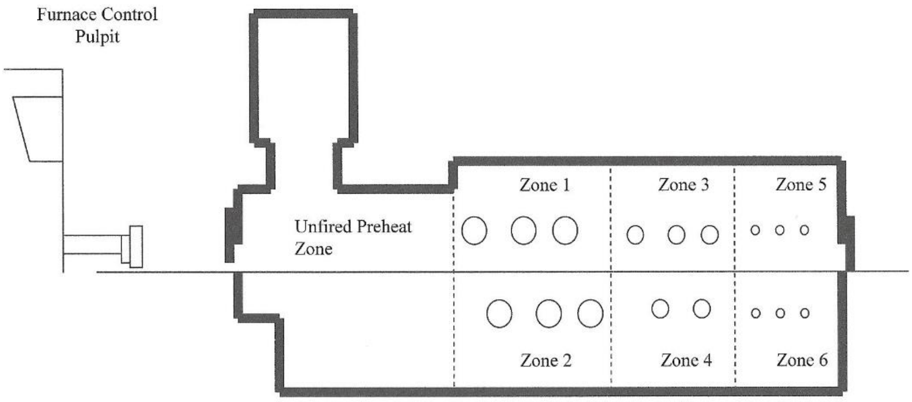


Figure 4 - Zonal Layout of the TBM Furnace

For energy values for the furnace, current data was used for continuous operation and taken as a mean for conversion. It should be noted on start up or during turn-down segments, the energy requirements will be significantly different. Higher during start up and lower during turn down.

The mean energy usage within the furnace was 45 MWh. From **Table *4***, using the total burner rating, Zones 5 and 6 account for 13.6% of the energy ratings. During operations Zone 5 and 6 burners account for 25% of the operational energy.

The equations for the basic fuel usage show that the output from natural gas and air result in carbon dioxide, water vapour and nitrogen (some oxides of nitrogen are also produced). For hydrogen combustion in air the resultant gases are water vapour and nitrogen (with some oxides of nitrogen). In the equations shown, oxides of nitrogen are not shown, and methane is use as a surrogate for natural gas (96% of natural gas is methane).

$$CH_4 + 2[O_2 + 3.76N_2] \rightarrow CO_2 + 2H_2O + 7.52N_2$$

$$2H_2 + [O_2 + 3.76N_2] \rightarrow 2H_2O + 3.76N_2$$

On a mass fuel basis (using 45MWh as the mean) the following fuels are required for the conversion. **Table *5*** shows the breakdown of the gases by mass.

Fuel and oxidant (kg)	Natural Gas (kg)	Hydrogen (kg)	Air $[O_2 + 3.76N_2]$ (kg)
NG + air	3951	N/A	7902
NG + H_2 + air	3161	270	6592
H_2 + air	N/A	1080	540

Table 5 - Masses of Fuel and Oxidant at 45MWHr

5.2. Modelling the Conversion to Hydrogen

To convert to hydrogen, the furnace will operate in a different manner compared to the current natural gas mode. To understand the operating parameters under a change in fuel strategy, modelling can be used to predict the effects in the changing atmosphere within the furnace brought about by the change in fuel.

A mathematical modelling approach of industrial furnaces has been developed based on the Hottel's zonal method of radiation analysis. In the zone method, the furnace enclosure is split into a number of gas and surface zones **Figure *5***, taking into account radiation interchange between all surface and volume zones, the enthalpy transport and source terms associated with the flow of combustion products and their heat release due to combustion. Energy balances are formulated for each zone, and these can then be solved sequentially over a series of time steps to yield the transient furnace performance including the stock temperature distributions. Zone models have modest computational requirements and have been successfully used to simulate the transient behaviour of a full-scale walking beam reheating furnace at TBM.

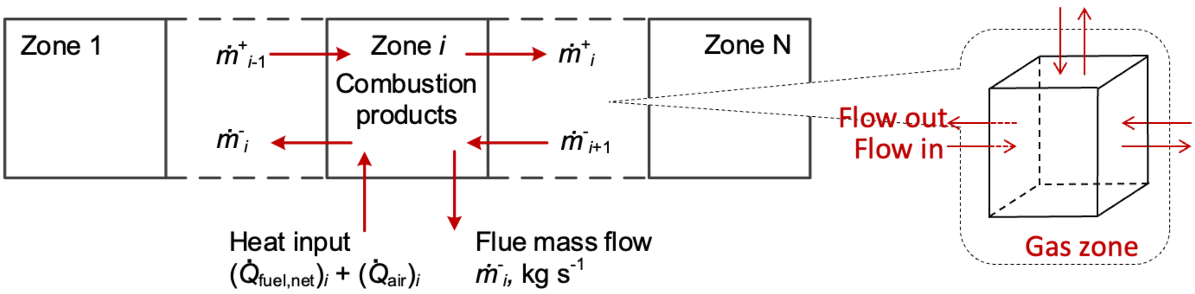


Figure 5 - Flow Field Specification for the Zone Model

The TBM furnace studied has an effective length of 45.35 m and width of 10.5 m. The furnace height varies between 2.96 m and 4.28 m along the length of the furnace, ***Figure 6***. In total 34 burners are installed within 6 control zones which fire natural gas.

Based on the mode of the furnace in current operation it was assumed the furnace contained 32 slabs of steel grade S355, each of a size 9500x1270x225mm and weighing approx. 21t. The gap between each slab was 100mm.

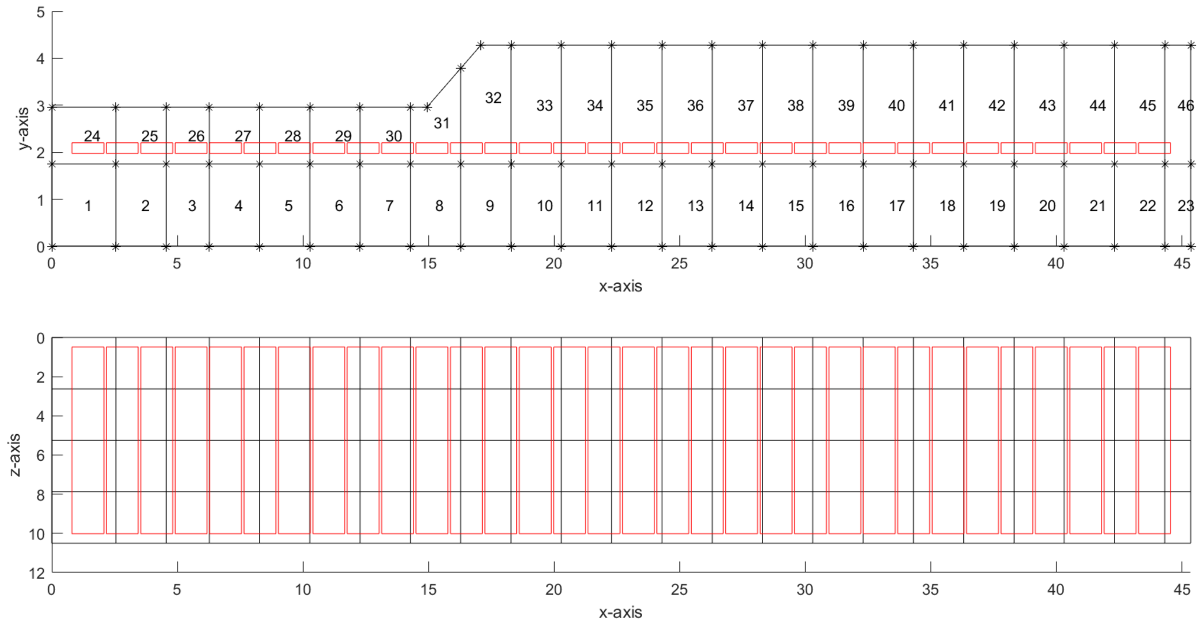


Figure 6 - Outline of the Furnace and Zoning Arrangement in XY – (Upper) and XZ – (Lower) Plane

Modelling Outputs

From the modelling of the furnace inputs, outputs, losses and energy to infrastructures were evaluated based on the base model, air and natural gas and two test cases: air with hydrogen and air with natural gas in zones 1-4 and hydrogen in zones 5-6. For all of the modelling modes, the following key in **Table *6*** applies.

Symbol	Value
Qf	fuel energy input
Qa	preheated air energy input
Qobs	energy transferred to steel obstacles
Qe	energy in exhaust gases as they leave the furnace
Qwc	energy transferred to the furnace water cooling
Ql	energy losses to furnace walls
Ec	combustion efficiency, 1 + (Qa/Qf) - (Qe/Qf) as a percentage
Ef	furnace efficiency, Qobs/Qf as a percentage; SEC, specific energy consumption, GJ/tonne

Table 6 - Key for Modelling Outputs

The energy balance can be calculated using the equation:

$$\text{Energy balance} = (\text{Energy input} - \text{Energy output})/\text{Energy input}$$

5.2.1. Air/Natural Gas

The furnace mode of air and natural gas as a fuel is the standard mode of operation. **Table *7*** shows the energy audit output from the model using fuel inputs as denoted in **Table *5***.

		Inputs		Outputs				Performance		
	Units	**Qf**	**Qa**	**Qobs**	**Qe**	**Qwc**	**Q1**	**Ec, %**	**Ef, %**	**SEC, GJ/t**
Model	**MW**	59.373	13.745	30.139	27.047	11.521	4.435	-	-	-
Energy balance	**%Hf**	81.202	18.798	41.221	36.992	15.756	6.066	77.594	50.763	1.239

Table 7 - Air/Natural Gas Data from Model

Using the heat to slab, the temperature of the slab can be calculated. During the final part of heating in the soak zone the slabs will achieve the temperatures shown in **Table *8***.

	Left	Right	Bottom	Top
Soak zone (°C)	1268.213	1252.965	1295.019	1306.531

Table 8 - Temperatures of Slab in Final Section of Soak Zone

5.2.2. Air/Hydrogen

Using the energy input data to calculate the fuel inputs, the following output data in **Table *9*** was modelled based on replacing all of the energy value of natural gas with hydrogen.

		Inputs		Outputs				Performance		
	Units	**Qf**	**Qa**	**Qobs**	**Qe**	**Qwc**	**Q1**	**Ec, %**	**Ef, %**	**SEC, GJ/t**
Model	**MW**	49.824	4.039	30.595	7.694	11.111	4.494	-	-	-
Energy balance	**%Hf**	92.502	7.498	56.803	14.284	20.629	8.343	92.664	61.408	0.913

Table 9 - Air/Hydrogen Data from Model

Using the heat to slab, the temperature of the slab can be calculated. During the final part of heating in the soak zone the slabs will achieve the temperatures shown in **Table *10***.

	Left	Right	Bottom	Top
Soak zone (°C)	1273.175	1255.755	1298.336	1310.422

Table 10 - Temperatures of Slab in Final Section of Soak Zone

5.2.3. Air/Natural Gas/Hydrogen

The potential for a blended approach, using natural gas is zones 1-4 and hydrogen in zones 5-6 revealed the data outputs in **Table *11***.

		Inputs		Outputs				Performance		
	Units	Qf	Qa	Qobs	Qe	Qwc	Q1	Ec, %	Ef, %	SEC, GJ/t
Model	**MW**	58.185	12.624	30.147	24.823	11.466	4.398	-	-	-
Energy balance	**%Hf**	82.172	17.828	42.575	35.056	16.193	6.212	79.034	51.813	1.200

Table 11 – Air/Natural Gas/Hydrogen Data from Model

Using the heat to slab, the temperature of the slab can be calculated. During the final part of heating in the soak zone the slabs will achieve the temperatures shown in **Table *12***

	Left	Right	Bottom	Top
Soak zone (°C)	1270.929	1254.496	1295.836	1309.249

Table 12 - Temperatures of Slab in Final Section of Soak Zone

5.2.4. Results from Modelling

- Across all three fuel systems, it can be seen there is a disparity in temperatures between left and right and top and bottom.
- The change between left and right is due to the number of burners on either side, with the left side of the furnace having an extra burner.
- The difference between top and bottom being through thermal distribution due to effluent gas production.
- The highest temperatures achieved on all of the sections of the slab are reached when using air/hydrogen mix for the whole furnace, with the blended fuel of air/natural gas and hydrogen reaching similar temperatures on the slab sections.
- From the energy conversions in **Table *7*** to **Table *12*** it can be seen as the percentage of hydrogen increases so does the efficiency of energy conversion to heat energy in the slab. This can lead to the conclusion that converting to air hydrogen fuel will increase efficiency of fuel energy conversion.

5.3. Oxide Formation

To establish the changes to mill scale formation a model was built using a thermodynamics program. Mill scale can be a significant loss to the steel industry with losses in the region of 3-5% dependant on the steel and process. Repeated heating can lead to increased mill scale.

The chemical analysis of steel on a wt% is required to model the scale formation. Table 7 shows the chemical composition of S355 grade steel, commonly used in TBM.

Grade	C	Si	Mn	P	S	Fe	Total
355	0.13	0.20	0.14	0.015	0.015	99.50	100

Table 13 – S355 Steel Chemical Composition

The mass of steel and the walk rate (3.2 hrs for the slab dimensions shown in section 2) through the furnace was used in conjunction with the fuel data shown in **Table *5*** to calculate the atmospheric conditions within the furnace over the three regimes tested. **Table *14*** highlights these conditions experienced per tonne of steel. Methane has been used as an analogous fuel for natural gas. Natural gas is made of 96% methane with more than 3% composed of other hydrocarbons that produce the same values of emissions as methane.

Fuel	CO_2,	H_2O	N_2	Tot
Air+H_2+CH_4	1.505	1.634	11.803	14.942
Air+H_2	0.000	0.514	0.967	1.481
Air+CH_4	1.881	3.763	14.148	19.792

Table 14 – Gas Weight Based on 100 T Steel, T/100 T Steel (Equivalent to Kg / 100 Kg-Steel or G / 100 G-Steel)

5.3.1. Oxides from Air and Natural Gas

The scenario of current operations was used as a baseline within the model to emulate current conditions in the furnace. The data from the model can then be used as a comparator for the new simulated conditions.

Figure *7* shows the output from the model, the combined metal oxide formation from all of the constituent parts of S355 steel.

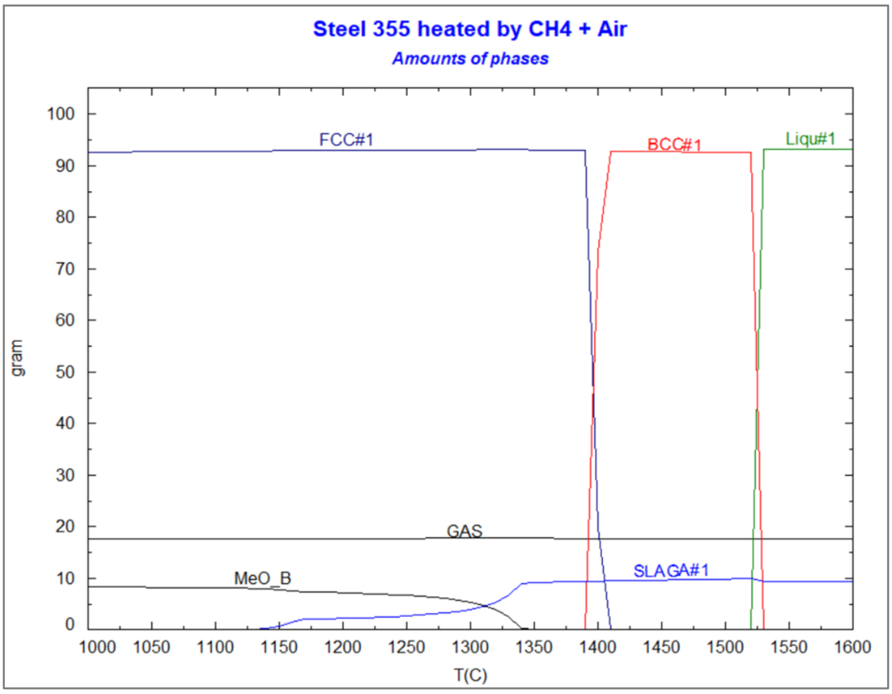


Figure 7 - Graphical Representation of the Phases of Steel over Temperature, with the Oxide Formation Stages

The gas atmosphere/100g of metal are shown in **Table *15***. **Table *16*** shows a breakdown of the oxides of metals as a percentage mass and the total mass in the final column.

H_2	H_2O	CO	CO_2	N_2	Total	Weight, g
15.621	11.596	5.45	1.53	65.79	99.99	17.664

Table 15 – Gas Atmospheres Felt over 100g of Steel

	SiO_2	FeO	Fe_2O_3	MnO	Mn_2O_3	MnS	FeS	P_2O_5	SiS_2	Total	Wght (g)
Slag#1	16.212	74.298	4.888	3.195	0.004	0.032	0.748	0.362	0.205	99.739	2.618
Oxides of Metal_B	-	87.742	10.806	1.441	0.010	-	-	-	-	99.999	6.580

Table 16 - % Oxide Formations under Air and Natural Gas Conditions

5.3.2. Oxides from Air with Hydrogen

The second scenario was for air with hydrogen as a fuel supply for compete fuel conversion in the furnace to hydrogen. **Figure *8*** shows the results of the model.

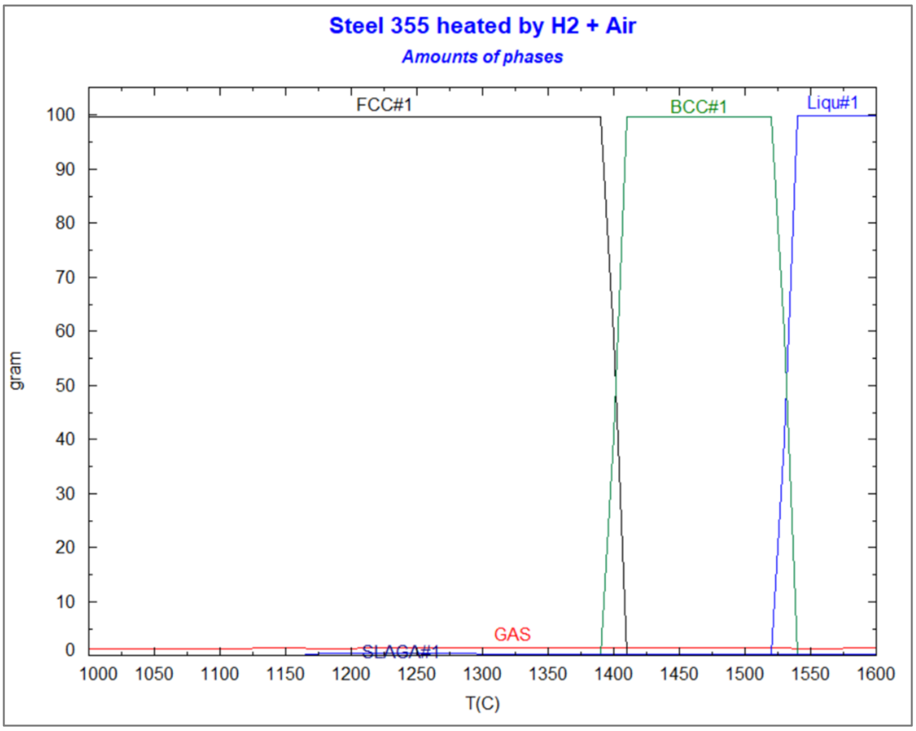


Figure 8 - S355 Heated in an Air and Hydrogen Fuel Strategy

Table *17* shows the gas environment experienced in the furnace. **Table *20*** shows the slag formation characteristics. The Oxides of metal values are too low to be calculated within this model.

H_2	H_2O	CO	CO_2	N_2	Total	Weight, g
36.6	2.65	13.12	0.36	47.19	99.92	1.318

Table 17 – Gas Atmospheres Felt Across the Steel with Air and Hydrogen

SiO_2	FeO	Fe_2O_3	MnO	Mn_2O_3	MnS	FeS	P_2O_5	SiS_2	Total	Slag (g)
40.99	13.92	0.018	42.62	0.004	0.965	0.314	9.50E-05	1.16	99.991	0.318

Table 18 - % Masses of Slag Formation under Air Hydrogen Fuel Strategy

5.3.3. Oxides with Air and Natural Gas (zones 1-4) and Hydrogen (zones 5-6)

The third strategy is for zones 1-4 on air/natural gas and zones 5-6 on air hydrogen. **Figure *9*** show the output of the model under this scenario.

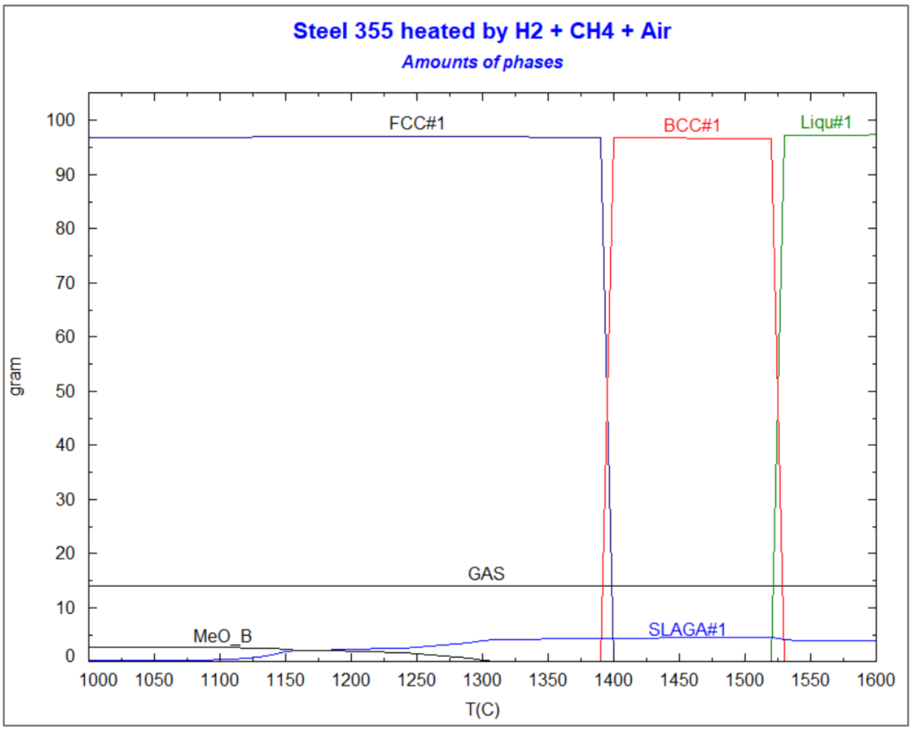


Figure 9 - S355 in a Blended Atmosphere of Air (Natural Gas/Hydrogen)

Table *19* highlights the atmospheric conditions in the furnace. **Table *20*** shows the slag and Oxides of metal mass balances produced on the steel under these conditions.

H_2	H_2O	CO	CO_2	N_2	Total	Weight, g
9.39	6.89	6.33	1.76	75.63	100.00	13.999

Table 19 – Gas Atmospheres Felt over 100g of Steel

	SiO_2	FeO	Fe_2O_3	MnO	Mn_2O_3	MnS	FeS	P_2O_5	SiS_2	Total	Wght (g)
Slag#1	16.072	72.345	4.6364	5.367	0.007	0.057	0.771	0.472	0.215	99.942	2.639
Oxides of Metal_B	-	87.004	10.463	2.516	0.017	-	-	-	-	100.00	1.424

Table 20 - % Oxide Formations under Air and Natural Gas Conditions

5.3.4. Results of Oxide Modelling

From the figures and the tables provided, it can be seen the model prediction is for a reduction in the mill scale formation with hydrogen. As the percentage of hydrogen increases, so the mill scale formation decreases. The exact breakdown of each of the metals within the scale is not shown in this data, however there is potential to calculate this through.

	$H_2 + CH_4$ + Air	H_2 + Air	CH_4 + Air
Steel	96.880	99.551	92.930
Gas	13.999	1.318	17.664
Slag	2.639	0.318	2.618
Oxides of metal	1.424	0	6.580
Slag + Oxides of metal	**4.063**	**0.318**	**9.198**
Steel oxidised, %	**3.12**	**0.45**	**7.07**

Table 21 – Oxide Product Percentages by Fuel

5.4. Metallurgical Modelling in Hydrogen Enriched Furnace Conditions

The presence of hydrogen in steel, even at ppm levels, is a significant concern in the steel industry due to the risk of hydrogen damage in service. These concerns increase for higher strength steels and as the thickness of the product increases. The industry has developed a range of hydrogen removal processes including complex liquid stage degassing processes and solid-state treatments. Often, a number of these dehydrogenation treatments are performed in sequence on the same product, as hydrogen is of such concern. This is the case for heavier section products rolled through TBM. The feedstock will undergo vacuum degassing prior to casting, slow product cooling and sometimes an additional furnace reheat and slow cooling cycle to remove hydrogen from the feedstock to ensure the finished product levels as low as 0.5 ppm. Due to the geometry of sections, rolled product hydrogen removal is not feasible.

With the plan to decarbonise steel production and fuel switch from natural gas to hydrogen gas reheating there is a concern that hydrogen deliberately introduced into the furnace atmosphere could result in hydrogen adsorption/absorption into the steel during reheating. This would in turn increase the risk of raising the product hydrogen content above the typical “safe” level.

To provide a theoretic assessment of the risk, a hydrogen modelling activity has been carried out to compare the effects of the current 100% natural gas reheating process (with practically no hydrogen gas) with furnace environments with increasing levels of hydrogen gas, using Sievert’s Law of hydrogen solubility in steel, Fick’s Law of diffusion and Dalton’s Law of partial pressures to model the hydrogen/steel interactions.

The hydrogen solubility in steel at temperatures experienced during a typical slab/bloom reheating cycle was calculated using Sievert’s Law. **Figure *10*** shows that at normal reheating temperatures the maximum solubility of hydrogen in steel is significantly higher than after the preceding dehydrogenation treats applied. This information shows that hydrogen could be absorbed by the steel during reheating given the right thermodynamic conditions and supports the need for detailed assessment and extreme caution.

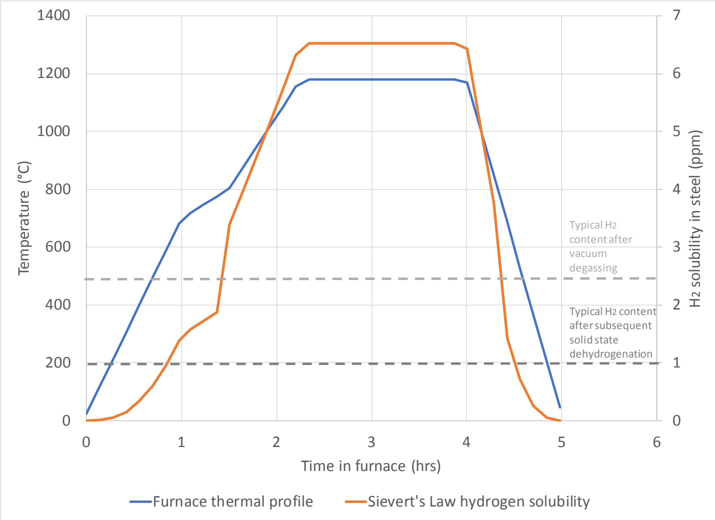
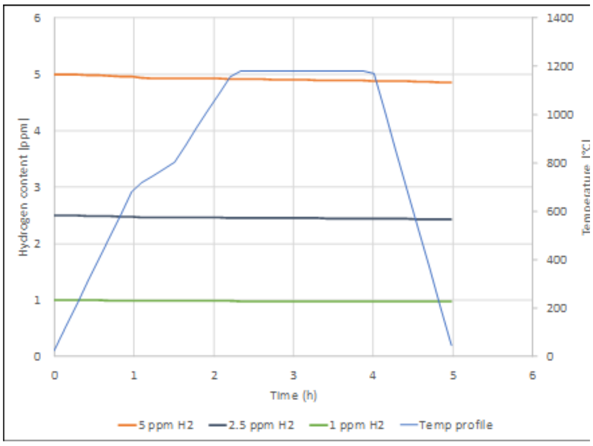


Figure 10 - Comparison of a Typical Thermal Profile of TBM Furnace with Hydrogen Solubility in Steel

Fick's law was used to model hydrogen diffusion through steel during a reheating thermal cycle. ***Figure 11*** shows how hydrogen content of steel stock with three different initial hydrogen contents would change during the reheating cycle for the current hydrogen free natural gas fired atmosphere. In all case the hydrogen content of the stock is predicted to decrease slightly during the reheating process as hydrogen diffuses out of the stock. ***Figure 12*** shows a similar plot but with a 100% hydrogen gas atmosphere. In this case, the steel hydrogen content is predicted to rise during the reheating process as hydrogen would be absorbed into the steel rather than diffusing out. For steel stock with a lower starting hydrogen content the modelled uptake rate is higher, giving rise to a greater absolute increase and far higher percentage hydrogen increase. In these cases it would be possible for a steel with a nominally safe hydrogen content to be made "unsafe" by reheating, and the risk levels increase with extended reheating times as might occur under delay conditions.



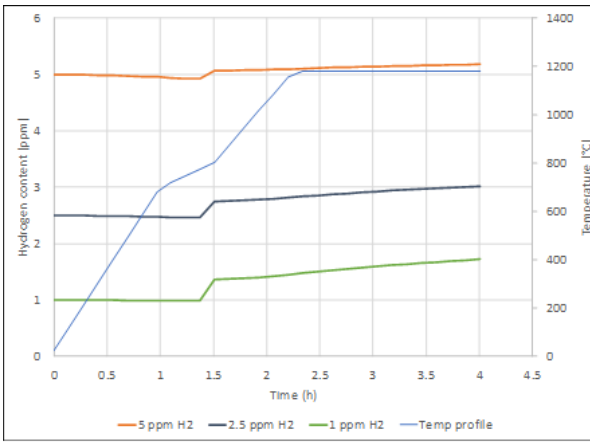


Figure 11 - Hydrogen Free Atmosphere **Figure 12 - 100% Hydrogen Atmosphere**

The long-term aspiration for the TBM furnace is to be able to use 100% hydrogen as the fuel source although initially the fuels used are more likely to be a mixture of natural gas and hydrogen mixed with air and/or oxygen and this would certainly be true in the case of changing the burners within specific zones only.

Four cases with varying amounts of hydrogen gas in the fuel mixture were considered using Dalton's Law

1. 100% natural gas and air
2. 80% natural gas/20% hydrogen and air
3. 60% natural gas/40% hydrogen and air
4. 100% hydrogen and oxygen

The calculations showed that for the first 3 cases the hydrogen partial pressure in the furnace atmosphere would be less than 10% increasing to 66% for case 4. ***Figure 13*** shows the predicted effect of varying the hydrogen partial pressure in the furnace on hydrogen solubility in steel as modelled using Sievert's Law.

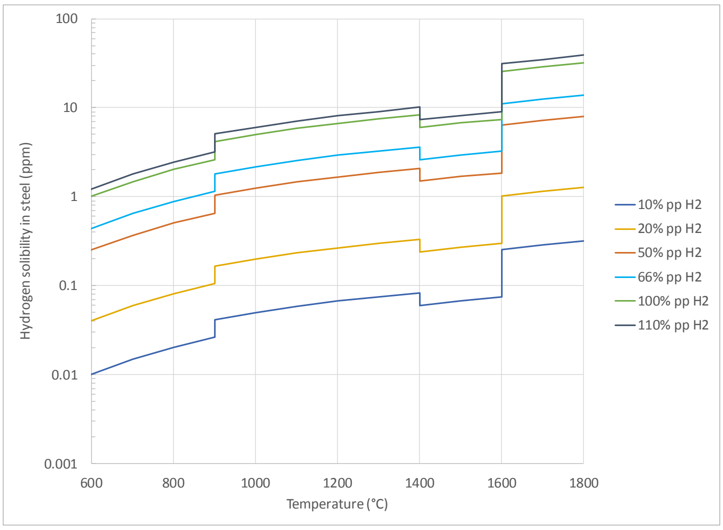


Figure 13 - Effect of Hydrogen Gas Partial Pressures on Hydrogen Solubility in Iron

The plot shows that for low partial pressures (10%), the hydrogen solubility in steel at the reheating temperature is less than 0.1 ppm. This solubility is below the level obtained after dehydrogenation treatments of the feedstock and there would be no driving force for hydrogen in the furnace gas atmosphere to enter the steel. For high partial pressures (≥ 66%) there could be a driving force for hydrogen to enter the steel as solubility limits can be above 3ppm and the feedstock for critical product applications would be expected to have been dehydrogenated to less than this hydrogen level.

These model-based predictions are, however, using a hydrogen partial pressure that assumes the hydrogen in the furnace is there as hydrogen either through lack of combustion or through thermal disassociation of the combustion product back to the constituent gases

$$2H_2 + O_2 \leftrightarrow 2H_2O$$

While the efficiency of dissociating water vapour is outside the scope of this work, it is likely to be significantly lower, perhaps less than 1% of the total volume of water vapour in the furnace. As such the partial pressure of hydrogen in a correctly operating furnace is never likely to approach the lower bound 10% case shown in **Figure *13***.

5.5. Conclusions to Product Impact Assessment

For large scale industry to achieve significant carbon emissions, a change to operating processes and procedures are required. The steel industry uses large quantities of fossil fuels as reactants, reductants and as fuels and account for 7-8% of all global CO_2 emissions.

TBM are addressing these issues by exploring the use of hydrogen as a fuel in the energy intensive process of reheating steels for onward processing. The use of hydrogen as a fuel would eliminate the carbon emissions from this part of the steel industry.

To facilitate this change TBM have commissioned MPI to evaluate the issue of hydrogen within the furnace. After extensive evaluation, an initial trial has been proposed to convert zones 5 and 6 to flameless burners whilst maintaining zones 1-4 as natural gas. On a mean energy usage, zones 5 and 6 account for 25% of the total energy usage.

Modelling of the fuel strategy showed that a conversion to hydrogen in zones 5 and 6 increased energy efficiencies and heat to slab was also improved compared to the natural gas strategy, whilst a full conversion to hydrogen revealed a greater improvement in efficiency and heat to product.

Modelling of hydrogen enrichment in furnace conditions indicates that while the maximum hydrogen solubility of the steel may be above current safe levels for section steel feedstock that has been obtained after vacuum degassing and solid-state dehydrogenation treatments, there is little risk of increased hydrogen induced cracking due to hydrogen uptake in the product. This low absorption probability is due to the low diffusivity of hydrogen in austenite and the low expected partial pressure of hydrogen gas in the furnace atmosphere. The steel hydrogen level is not predicted to increase significantly during reheating unless the furnace were to have an unburnt hydrogen gas rich atmosphere. An operating regime with a furnace full of unburnt hydrogen would pose a significant explosion risk and should never be allowed to occur.

Modelling of the mill scale formation highlighted that a change to a fuel strategy of hydrogen also revealed lowering of mill scale formation significantly. These results are based on the atmospheres present in the furnace using the energy values in current operations. The values of oxides of metal formation from this model are based on a first run of a new model, and there may be some variations to these values. The model does show a reduction in oxides of metal, however this needs corroboration with empirical data. Empirical data can be taken from a facility with a hydrogen test furnace where refractories and metal products can be tested and examined under controlled conditions.

The conversion to hydrogen is a positive strategy to reduce carbon emissions from this process. The results indicate the conversion to hydrogen in zones 5-6 will improve efficiency and heat to slab and will offer a method of reducing carbon emissions. The full conversion to hydrogen will eliminate carbon emissions. The conversion to hydrogen may lead to a small increase in thermal NO_X, however without data on the burner selection this cannot be attested to. A conversion to oxy/hydrogen combustion would eliminate the production of NO_X from air fed nitrogen.

6. Hydrogen Supply and Energy Demand for Demonstrator (WP4)

6.1. Introduction

6.1.1. Hydrogen in Teesside

The Tees Valley region has hundreds of years of established infrastructure and expertise in advanced manufacturing and engineering, offshore oil and gas, logistics and chemicals and process industries[1]. This offers a great opportunity for fuel switching to hydrogen and is a key factor in the projects in the region for blue and green hydrogen production. A key consideration in conversion to hydrogen will be proving technical, commercial and consumer cases with relevant industries. The large potential volume of demand in the region will support reduced capital investment cost per kilogram of hydrogen through larger scale facilities spreading the costs between multiple end users.

6.1.2. Electrolytic Hydrogen in Teesside

The use of local renewable energy to produce hydrogen for the steel industry in Teesside offers key opportunities in terms of purity, resilience and deployment timescales. Electrolytic hydrogen can be produced at very high purity (99.999%) and is not reliant on imported natural gas which is experiencing supply risks associated with conflict in Ukraine. The plans for electrolytic hydrogen will be completed by 2025 and offer an opportunity to utilise hydrogen earlier in the region. The economic assessment will consider a comparison between blue and electrolytic hydrogen, with both offering specific advantages in the region.

Purity of hydrogen is particularly relevant for developing a business case for capital expenditure on a hydrogen production facility with a range of end users. Fuel cells used in larger hydrogen vehicles where electrification is more challenging require high purity which is an expensive additional step for blue hydrogen production. The purity requirements for BSL are not as demanding considering historic use of works gases with a range of impurities, but for the producer the ability to easily supply transportation and power generation (via fuel cell) technologies supports a scaling business case in the region.

6.1.3. CCUS-enabled Hydrogen in Teesside

BP are developing a project in Teesside for steam methane reforming with carbon capture to form an East Coast cluster for hydrogen distribution. This is planned to start up in 2027 with 1GW of blue hydrogen production. The carbon captured from the project would be stored in the Endurance aquifer in the Southern North Sea. This has storage capacity of 450Mt. With 1GW of hydrogen production and a typical 95% load factor (8322 hours per year)[2] this equates to 8322 GWh of hydrogen per year. Carbon captured per year at a standard rate (232.9kgCO_2 per MWh (Higher Heating Value (HHV))) would be 1.938Mt per year of storage or 0.4% of the endurance aquifer storage capacity each year[3].

[1] "Tees Valley Combined Authority," [Online]. Available: https://teesvalley-ca.gov.uk/business/key-sectors/. [Accessed 12 08 2022].
[2] E. a. I. S. Department for Business, "Hydrogen Production Costs 2021," [Online]. Available: https://www.gov.uk/government/publications/hydrogen-production-costs-2021. [Accessed 2022 08 05].
[3]https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1079825/NS051-SS-REP-000-00010-Storage_Development_Plan.pdf.

6.1.4. Furnace Operation and Demand

The demonstration facility will be supplied with hydrogen during the trial to substitute for natural gas. The furnace zones are controlled to set temperatures for a given product mix and the demand for gas is driven by the rate of heat transfer to steel blooms and slabs within the furnace. This creates a requirement for a consistent hydrogen demand during typical rolling campaigns, although there will be some variation between product types and as a result of mill delays up and down stream of the furnace. Any limits on gas supply will create delays and lost revenue for the mill. The hydrogen supply must therefore ensure continuity during testing campaigns for consistent heating of the product and prevent any impact on rolling schedules for steel products.

To reduce risks to production schedules the burner configuration will be determined to allow operation on both natural gas and hydrogen. A change from natural gas to hydrogen within the supply can occur quickly with the burner design selected for demonstration. Typical rolling campaigns are for eight hours and are followed by a “roll change” when the rolling stands are swapped to produce a product with alternative dimensions or characteristics. This indirectly affects the furnace as steel cannot keep being heated and sent down the line while this occurs. A key factor to consider in the testing programme will be how quickly hydrogen can be brought online and the furnace conditions stabilised from a natural gas operating mode without creating a process delay.

The hydrogen supply expected during a test is a large demand of around 8.9MW of hydrogen (32 GJ/hour). The plans for hydrogen supply from the Tees Green Hydrogen project could be limited to 5-50 MW for BSL and other off takers of hydrogen in the region and therefore storage will be required to support the additional capacity. Oxygen supply will not be included within the demonstration but could be developed in future to optimise burner performance. The testing campaign length is therefore a key factor in Phase 2 and the start-up rates for hydrogen production and storage capacity will need to reflect the constraints.

6.2. Objectives for Demonstration Project

The plan for the demonstration project will be assessed against objectives relating to technical, commercial, safety, environmental and quality impact of the proposed solution. The role of the demonstration is to validate the proposed technology and determine the best pathway to scale the solution. For the furnace operation the key requirements are technical and safety factors, while for the supply the questions are more linked to commercial and operational requirements as hydrogen supply from electrolysis is a proven, but currently expensive technology. The demonstration will offer an opportunity to understand the full impact of a solution and how the hydrogen supply can meet the demands of a hot rolling mill.

The testing programme developed will be key to ensure effective learning from the project for future scaling and minimise risk to operations at BSL. Supplying hydrogen at a constant rate is expected from a supplier and should match the continuous operations at TBM. The trial approach incorporating small duration trials and switching between fuels will be tested thoroughly. The objectives reflect the requirements of the solution and the test plan must validate these requirements.

The following objectives will be assessed for proposed design to understand performance against key criteria (**Table *22***).

Objective	Assessment Criteria
Low-cost hydrogen option	The cost of hydrogen should be equivalent to historical stable natural gas prices, or a counterfactual energy price that allows the steel producer to operate competitively in international markets.
Purity of hydrogen achieved	Hydrogen purity should meet the requirements for combustion defined in Hy4Heat programme[4]
Low carbon hydrogen solution	The solution must meet the low carbon hydrogen standard threshold for carbon content.
Local economy impact	Support local jobs and the environment through the Demonstration
Available hydrogen supply	The hydrogen supply must meet the requirement for the mill fuel switching for a minimum of 8 hours.
Resilience of supply	Ensure continuity of supply and no lost production time associated with fuel switching
Safety	The solution must ensure safety standards are met and operation takes place in a safe manner, particularly switching between fuels.
Environment	Ensure emissions minimised in hydrogen production

Table 22 - Assessment Criteria for Business Case of Hydrogen Supply

6.3. Hydrogen Supply Concept

6.3.1. Trial Hydrogen Supply Design

Hydrogen from suppliers will require several tube trailers of hydrogen to provide enough energy for each test. If tests required can be carried out in an eight-hour shift, then eight 235kg tube trailers will provide enough for the 1800kg of hydrogen required. The coordination of testing will therefore need to be managed around available hydrogen and the production schedule of BSL. This route of hydrogen supply requires additional considerations of site transport logistics, lay down areas and safety associated with increased onsite storage (COMAH, DSEAR)

A larger number of tube trailers will be required during peak demand for heating from the furnace. The figures quoted in this section refer to average historical demand and around one tube trailer every two hours. During peak demand there could be a requirement for one trailer per hour and the higher limits will need to be confirmed in more detail during the demonstration phase.

[4] https://static1.squarespace.com/static/5b8eae345cfd799896a803f4/t/5e58ebfc9df53f4eb31f7cf8/1582885917781/WP2+Report+final.pdf.

6.3.2. Demonstration Role for Electrolytic Hydrogen Supply

The role of the demonstration facility is to prove the technical, commercial and safety impact of hydrogen conversion and act as a feasibility validation for 100% hydrogen conversion technology. The technical requirements for supplying hydrogen will be developed through the demonstration and support the longer-term hydrogen delivery to BSL. The operational requirements for supply including ramping rates, continuity and demand will support the development of ongoing commercial relationships for BSL with low carbon hydrogen supply. This will determine the technical and business model analysis during the demonstration phase of the project.

6.3.3. Long Term Electrolytic Hydrogen Supply Design Post-Trial

A 5-50 MW PEM electrolyser design will be used which produces hydrogen at 30 bar pressure for BSL and other local hydrogen demand. This may create a requirement for additional storage on the electrolyser site to maintain continuous supply. The hydrogen will be supplied via a hydrogen pipe that reduces pressure to ~ 300mBar required for the hydrogen burners at the mill location. The proposal is for full conversion of zones 5 and 6 which would simulate an effective and impactful conversion to hydrogen that could be extended in future work to the full furnace. As the operation of furnace zones on pure hydrogen is novel this will have to be tested and therefore burners that can switch between hydrogen and natural gas have been selected.

The switching between natural gas and hydrogen will require safety control measures for BSL as the gas supply is switched and this may have an impact on the operation of the electrolyser. The demand for hydrogen will ramp up quickly to minimise production delays during the switch and the hydrogen supply will need to be able to respond quickly. PEM electrolysers are capable of meeting steep demand increases, by responding within seconds to minutes. During the demonstration hydrogen tube trailers will be used with a pressure reducing station to BSL requirements.

6.3.4. Heat Recovery Consideration for Demonstrator

Heat recovery is a significant opportunity for hydrogen production linked to the steel industry but for the demonstrator the additional engineering work for the heat exchanger associated with the stack and recuperator of the furnace are outside of the scope of the project. Hydrogen clusters with solid oxide electrolysers utilising waste heat to increase efficiency and reduce operating costs per kg of hydrogen will form part of the scaled business case. However, the key objective of the project is to prove the fuel switching capability and the additional risk from an innovative electrolyser technology and furnace modifications would create challenges for the project beyond the industrial fuel switching objectives.

6.4. Costs

6.4.1. Demonstration Hydrogen Costs

The cost of hydrogen supply for trials is estimated at £605k over a three-month period. Typical hydrogen costs of £24/kg or £2/Nm^3 (at 1 bar, 15°C) would indicate a cost of £43.2k for a shift with 1800 kg of hydrogen. The equivalent for natural gas is the quarterly industrial price BEIS to June 2022 (140p/therm) is £2.7/kg, or £10/kg for 600p/therm. Assuming 5% of the time allocated to trialling in a 90-day period this would be ~14 shifts of testing. The high cost of hydrogen will be a limiting factor on the extent of trials possible within the demonstration time period. The furnace may also need to operate at higher flow rates, and it is assumed this figure is an average over multiple trials rather than a maximum level.

If trials were limited to say, 50 hours at an average consumption of 2,800 Nm^3/hour at £2/Nm^3, then the total hydrogen cost would be £280k. The equivalent energy supplied from Natural Gas at £100/MWHr would be £52.4k

6.4.2. Estimated Hydrogen Costs Post Trial

The Tees Green Hydrogen project is applying for strand 3 of the Net Zero Hydrogen Fund which will define the potential government support and price for BSL to purchase hydrogen. The hydrogen produced for the TBM will be sold at the standard strike price for associated production costs. The cost of production is being developed as part of the Tees Green Hydrogen bid but an indication can be found for estimated electrolytic hydrogen production costs from the BEIS production cost modelling (**Figure *14***).

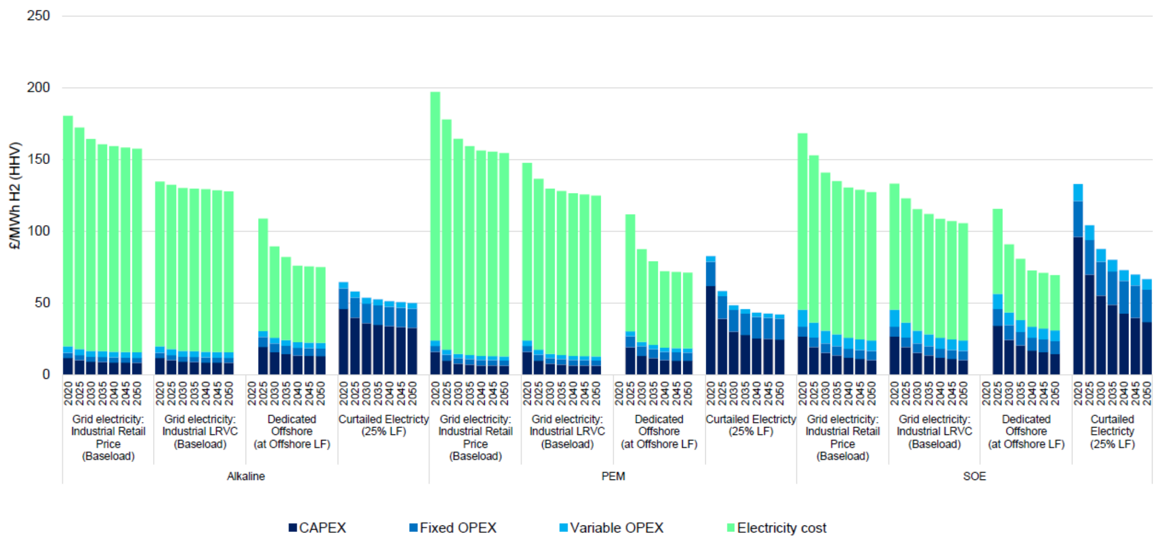


Figure 14 - LCOH estimates for electrolysis technologies, connected to different electricity sources, commissioning from 2020 to 2050, £/MWh Hydrogen (HHV) from BEIS Production costs 2021[20]

6.5. Demonstration Role for Electrolytic Hydrogen Supply

The role of the demonstration facility is to prove the technical, commercial and safety impact of hydrogen conversion and act as a feasibility validation for 100% hydrogen conversion technology. The technical requirements for supplying hydrogen will be developed through the demonstration and support the longer-term hydrogen delivery to BSL. The operational requirements for supply including ramping rates, continuity and demand will support the development of ongoing commercial relationships for BSL with low carbon hydrogen supply. This will determine the technical and business model analysis during the demonstration phase of the project.

6.6. Objectives Review

The demonstrator design is intended to prove the concept for electrolytic hydrogen production and highlight feasibility and revenue available if the solution is scaled. Considering the potential revenue available within existing and forecasted future steel markets, the solution will need to reduce costs by an order of magnitude to be cost effective at commercial scale, which could be achievable with optimisation and scale of the design.

Objective	Demonstrator	Commercial scale
Low-cost hydrogen option	Hydrogen cost will be typical for a small commodity volume.	Tees Green Hydrogen project planned with hydrogen business model to offer low-cost hydrogen supply for individual zones or full furnace with scaling plans
Purity of hydrogen achieved	Hydrogen purity will match existing supply chains for EDF nuclear plants of 99.95% during the trial. This is much higher purity than is required from a combustion application	Hydrogen purity will reach 99.999% post-trial with Tees Green Hydrogen electrolytic supply
Low carbon hydrogen solution	Hydrogen supply commercially dependent on availability from green or grey supply routes.	Tees Green Hydrogen project post-trial will provide low carbon hydrogen to the site.
Local economy impact	Supports long term skill development in hydrogen technologies and enables long term future for TBM	Project contributes to wider hydrogen economy in Teesside region and skill development through supporting business case for hydrogen production in the region
Available hydrogen supply	Suppliers engaged for timelines required and recognition of time constraints from Tees Green Hydrogen supply.	Tees Green Hydrogen Project will be online from 2025 and on the completion of the trial with current timelines.
Resilience of supply	Gas burners selected which can switch between 100% hydrogen and natural gas supply reducing risk.	Reliability of electrolysers is high, and burner design will reduce risk of lost hydrogen supply.
Safety	Supply will meet requirements for an industrial site	Design and testing procedures will ensure safety at TBM from hydrogen supply.
Environment	Environment impact will be minimised within engineering design.	Lower upstream emissions from hydrogen electrolysis provided after demonstration completed.

Table 23 - Operating Parameters for Demonstrator

6.6.1. Economic Assessment

The Phase 2 plan demonstrates the potential economic value of low carbon hydrogen switching if the government support reduces the cost of hydrogen to the equivalent (or less than) the natural gas price. The cost of hydrogen for the trials will be dependent on the methodology for strike price and reference price.

Electrolytic hydrogen production costs are projected to reduce due to the following factors:

1. Economies of scale: Reducing capital costs with a larger demand increases cost effectiveness of solution
2. Efficiency improvement of electrolysers
3. Solid oxide electrolyser technology: incorporating waste heat (industry) or generation heat (nuclear)
4. Reduction in maintenance costs with technology development

6.6.2. Operational and Technical

The trial solution selected offers the opportunities to switch quickly between natural gas and hydrogen allowing full hydrogen combustion cases to be tested while mitigating a risk from supply constraints associated with truck trailer deliveries. The solution will demonstrate the ability to switch to hydrogen fuel with the plan after the demonstration is completed to link to low carbon hydrogen supply that is being developed by EDF at a very suitable location. This provides the key requirements for technical performance, while providing resilience and a long-term plan to decarbonise within the region.

6.6.3. Scaling Potential

Scaling the solution will be very valuable as it will help to reduce the hydrogen supply costs and ensure a low carbon fuel switch for BSL. The first stage is to demonstrate hydrogen combustion in such a way that the concept could be proven for a full-scale hydrogen furnace to align with BSL capital plans for the future. The current furnace configuration is designed for natural gas so switching zones five and six provides representative data for a full switch without the capital cost of a full furnace redesign. The Tees Green Hydrogen project is also planning to scale with increasing demand. The project therefore demonstrates a route to scaling low carbon hydrogen locally and a prototype for other furnaces in the UK in the steel industry as well as glass and cement.

6.7. Conclusions – Hydrogen Supply

The solution could be cost competitive at scale with the right support and market signals and the demonstrator will prove the capability of supply and switching of the furnace. The hydrogen business model should ensure a cost competitive solution if costs are equivalent to natural gas, but the impact of high natural gas prices will need to be assessed to ensure this is fairly represented in the scheme. The technical requirements for pressure, flow and purity are achieved with hydrogen supply and the risk associated with Tees Green Hydrogen timelines is addressed through alternative suppliers. This project will demonstrate the requirement for hydrogen supply, operational conditions and provide a clear framework for an ongoing commercial solution post-trial.

The feasibility study has demonstrated how hydrogen switching can take place within the TBM furnace but the model of hydrogen supply will need to transition to a larger local facility to improve cost-effectiveness beyond the trial. The hydrogen truck trailer supply will be expensive and is not really suited to the large volume continuous operations of industry although it can provide effective data on the switching process. The combination of hydrogen supply and hydrogen demand are required in tandem and a key learning is that funding streams should reflect this to ensure the full value chain is developed for hydrogen projects.

6.7.1. Future Cost Competitiveness

The hydrogen cost forecasts are significantly lower with local low carbon hydrogen than during the demonstration phase of the trial. The hydrogen supply cost is around £24/kg while hydrogen cost models indicate figures below £5/kg for typical electrolytic hydrogen production. The role of the demonstration is to support the journey to decarbonisation for BSL and the TBM furnace. Converting the burners to hydrogen ready will reduce the barriers to deploying large scale hydrogen switching in the region. The larger cost for demonstration with commercial hydrogen prices via truck trailer should not be considered representative of the lower supply costs with a continuous supply linked to renewable piped electrolytic hydrogen supply.

6.7.2. Further Cost Reduction and Revenue Growth

The conversion at BSL is significant and will show the technology can be scaled for future furnace designs with 100% hydrogen production. The costs will also be far lower with piped hydrogen supply than road transport tube trailers. The scope to increase hydrogen supply is substantial with multiple hot rolling furnaces across the UK in the steel industry and considering the large demand when converting only 20-30% of natural gas to hydrogen. This feasibility study has demonstrated that with a confirmed hydrogen demand and technology in place for hydrogen switching the low carbon hydrogen supply can be increased significantly to enable fuel switching to low carbon alternatives within the steel industry.

6.8. Assessment of Wider Impact

…for Steel Industry (and Glass or Ceramics) of Modification to Hydrogen and Oxygen Enrichment

6.8.1. Heat Decarbonisation

There is significant overlap in heat decarbonisation assumptions and market development

The transition during the 2020's-30's away from natural gas reheating for product rolling and forming is anticipated throughout the steel and metals sector as it is for kiln operators in comparable energy intensive industries. In common with the glass and ceramics sectors the options for decarbonisation of these high temperature long dwell time processes are increased electrification or net-zero combustion gas, with the target in the gas option of 100% (green) hydrogen as the end point, although it could also be blended or used alongside renewable bio-carbons with carbon capture[5] as is being trialled for cement. With this in mind, many steel processors are undertaking feasibility studies and decarbonisation road mapping exercises to inform their capital replacement, refit or refurbishment plans, and original equipment manufacturers (OEMs) are increasing the energy ratings/fuel compatibilities and performance controls of their offerings to the market.

Because of the associated issues of upgrading national grids and creating the right seed conditions for industrial decarbonisation hubs to grow, the evolution toward net-zero industrial process heat is

[5] UK: Heidelberg Cement Produces Cement With Climate-Neutral Fuel Mix Using

a shared journey and there are therefore significant areas of opportunity for collaboration between foundation industries, with (oxy) hydrogen combustion overlaps in technical, regulatory, skills, and market signalling[6] [7]. Clearly there are many other overlaps in carbon-cutting which fall outside the remit of this work package such as electrification fuel switches, redesign, scrap/cullet quality and recovery rates, alternative materials or new circularity, industrial symbiosis and carbon capture.

6.8.2. Electrification as Driver

<u>Electrification likely to have increased take-up and electricity be the predominant energy vector</u>

Neither option (electrification or hydrogen fuel switching) is without cost, and all kiln operators, regardless of industry sector, are analysing or forming their best assessment of a dynamic context in which they have to weigh up factors including:

- Cost of upgrades to plant and site infrastructure to support any fuel switch
- Uncertainty over future energy costs
- Eligibility for state / regional support for capex or energy price subsidies
- Likelihood of being near to a hydrogen gas network (for larger users) or affordable
- Dependable merchant supply. Supply issues inherent as world green hydrogen supply capacity grows from a tiny baseline of below 1% of the market.
- The trade-offs between familiarity and dispatchability of gas, vs different operating strategies for electrical operation. This both in terms of operator competence and reproducibility of products, and physical properties of heat-treated products. Finely tuned thermal gradients across the components are more critical in ceramics processing (in general) than in metals due to the higher risk of thermal failure
- Capital lifetimes and relining/refit schedules, electrical network capacity, regulatory compliance in safety as well as CO_2 and NO_x emissions. Particularly for plants situated near housing
- Customer pressure to decarbonise and quantify their scope 1 and 2 emissions reductions

It does appear at this early stage in the journey that the majority of heating in whichever sector will transition to direct electrical (radiant and plasma for all, microwave in some specific cases, resistive for metals and glass, or inductive for metals) with hydrogen playing a significant supporting role as a high temperature radiant heat source. The higher cost per kWh of electricity is offset by factors such as its greater efficiency in use, smaller heat losses through exhaust stacks because of lower air flows, and efficiency of energy transfer for inductive heating of uniform profiles. However, each heat treatment process has its own specific needs and no single technology has the complete solution.

6.8.3. Oxygen Firing Early Take-up

<u>Oxy firing likely to increase take-up ahead of hydrogen</u>

This feasibility study considered oxy-hydrogen firing as an option for demonstration - oxy-gas firing is well known in the field and expected to become standard for higher temperature combustion, to reduce NO_x emissions. The adoption of oxy-firing in kiln practice, which according to suppliers has been sporadic over the past 25 years due to low gas prices, is only likely to continue in the 2020's and 30's as efficiency and emissions improvements are demanded, and likely to accelerate once

[6] British Glass - Net Zero Strategy.pdf (britglass.org.uk)
[7] Net Zero Steel - A Vision for the Future of UK Steel Production | Make UK

local electrolytic oxygen supply expands as part of the green hydrogen boom, provided the cost of capturing and delivering it is economic oxygen (and oxy-burner) suppliers already point at the technical, operational and emissions benefits of their technology for steel, glass and ceramics, including extending the working life of kilns by providing a higher temperature heating boost to the maintain upper range of heating capability[8]. This is an area where kiln operators in glass, ceramics and steel will have much in common. As they will on some questions of limiting or preventing surface (re) oxidation – critical for some building and ceramics products in terms of colouration, and for steels in terms of scale build-up. Regulation needs to develop to support hydrogen roll-out.

Another area in common is in informing the future regulation and development of ISO or British Standards for hydrogen as a widespread combustion gas; including pipe standards, fittings, flue, vent and fugitive emission detection, inspection regimes, and regulation of increased transport and storage on site for customers not connected to a hydrogen gas grid.

At this early phase of an emerging national industrial hydrogen demand, most UK demonstrators are applying petrochemical or aerospace standards for hydrogen safety, transport and storage and so far only a handful have been using 100% hydrogen, preferring to reassess the kind of 20-40% hydrogen blends with methane which are similar in behaviour to the Town Gas / COG in common use in the mid-20th century before the last major national fuel switching transition to North Sea fossil gas.

Availability of components is a significant problem for demonstration schemes too - caution from suppliers in guaranteeing ‘hydrogen ready’ versions of established kit, or hydrogen-specific parts (valves, seals, pressure regulation etc) is also adding to the long lead times, higher prices and enhanced pressure testing regimes, which are necessary, but which would be streamlined with a standardised approvals regime.

It is worth commenting that some of the gas equipment suppliers engaged in trials and demonstrations across different industries are identifying such market gaps and seeking to fill them through product and materials innovation, and that communication between the ceramics, glass and metals sectors is accelerating their opportunities to do so.

6.8.4. Initial Hydrogen Demand

Delivered Hydrogen is not yet enough to meet demand, and is bulky

A significant issue highlighted by all 100% hydrogen switching trials during Innovate UK/KTN feedback events has been the sheer volume of gas required to substitute for natural gas, particularly apparent when it has to be delivered by successive tankers. This is adding to the experience of gas suppliers and informing their logistical plans for 2023 onward, but for 2022-23 they are lagging behind demand by 12-18 months in terms of capacity to supply and replace compressed ‘merchant’ hydrogen. Whilst behind the scenes there is a degree of cross-cover between established suppliers, the sudden and rapid expansion of demand will make for a volatile market for reliable merchant hydrogen supply (including tankers) at least until 2025 when planned electrolytic capacity comes online and new tanker fleets are delivered.

Any new UK customer for hydrogen faces 12 months or more lead time, longer if on site electrolysers are required, and there is growing awareness of the unprecedented scale-up required to grow and support a green hydrogen sector, along with the as-yet unpublished Hydrogen Support Mechanism and other elements of a subsidy framework. This unavailability factor improves the case for electrification or efficiency improvements to existing combustion and heat recovery.

[8] https://www.researchgate.net/figure/Carbon-emission-for-unit-process-of-Chinas-ISI-in-2018-BF-BOF-route_fig5_359094048

6.8.5. Locality of Supply

Proximity to supply rather than locally competing demand is likely to be the biggest influence on uptake

Geographical influence is always strong for energy intensive processes and despite its potential to be generated anywhere there is electricity and water, hydrogen supply in the UK will still grow from established hubs such as NE and NW England. The location of potential competitors is down to historical access to energy and raw materials and is unlikely to change. Metals is the only sector where it is standard to make an unfinished product in one part of the country and ship it cold to another to reheat and form, but even then, the investment required to relocate a low-margin business such as rolling plate or rebar would dwarf the gains from being closer to a low carbon energy source for most businesses.

The only area of the UK where there is significant proximity between steel and glass making is Yorkshire, where a critical mass of high energy demand may be enough to support a rapid regional expansion of electrolytic hydrogen (and oxygen) capacity, even if it is further from the offshore wind capacity of the North Sea. The catalytic effect of Glass Futures' Brinsworth demonstration furnace in the Don Valley, to de-mystify and introduce alternative heating fuel options, and its proximity to large scale electrolyser manufacture, is an exemplar of cross-sector relevant hydrogen demonstration having the effect of creating momentum for local partnerships, i.e. cross-sector action to de-risk technology has a comparable effect to supply-side advantages of areas such as Teesside in stimulating the emergence of a regional hydrogen economy.

6.8.6. Hydrogen for Ironmaking

Synergy between hydrogen for heat and hydrogen for iron making

Steel is one of the few sectors where green hydrogen as a decarbonised chemical reductant in the primary production process has a greater significance to its potential impact as a heating fuel. This is because it displaces coal/coke and energy intensive sintered feedstock for the blast furnace route. The embodied energy/CO_2 of finished steel products can be up 70% attributable to the initial iron and steel-making processes, with the remainder split between subsequent heating and mechanical energy to form it into semi-finished and finished products, and transportation4. Heating for hot rolling is a significant component of the overall energy footprint but only represents typically 10% of the total embodied energy (dependent on the origin of the steel and the rolling process). BSL also estimates that transportation emissions for domestic steel supply are half or less those of imported steel[9].

Decarbonising the primary ironmaking route by hydrogen reduction can cut specific CO_2 emissions by at least 1.5 tonnes CO_2 per tonne of liquid steel. The other most significant sector where this applies is in fertiliser or ammonia manufacture where green hydrogen feedstock for the Haber-Bosch process can displace fossil-fuel derived hydrogen and offer a 3-fold reduction in CO_2 per tonne[10]. Since ammonia/fertiliser production is a major activity on Teesside, where there is capacity to supply up to half of the national market, and the main market for the grey hydrogen currently produced here, there is significant impact on the fertiliser sector from decarbonising hydrogen (by green supply or by CCUS if this can be proved to work economically at scale).

A similar Mtpa magnitude of carbon saving is on offer if a new source of hydrogen direct reduced iron (H_2-DRI) were to displace coal/coke blast furnace steel: this route has demonstrated <0.2 tonnes

[9] https://britishsteel.co.uk/who-we-are/sustainability/

[10] https://pubs.acs.org/doi/pdf/10.1021/acsenergylett.2c01615 (page 4, GHG paragraph)

CO_2 per tonne liquid steel vs 1.7-2.5 tonnes per tonne in the conventional BF-BOF route i.e., >90% savings (potentially zero CO_2, dependant on the embodied CO_2 in the electrical power source for hydrogen generation and subsequent steel melting).

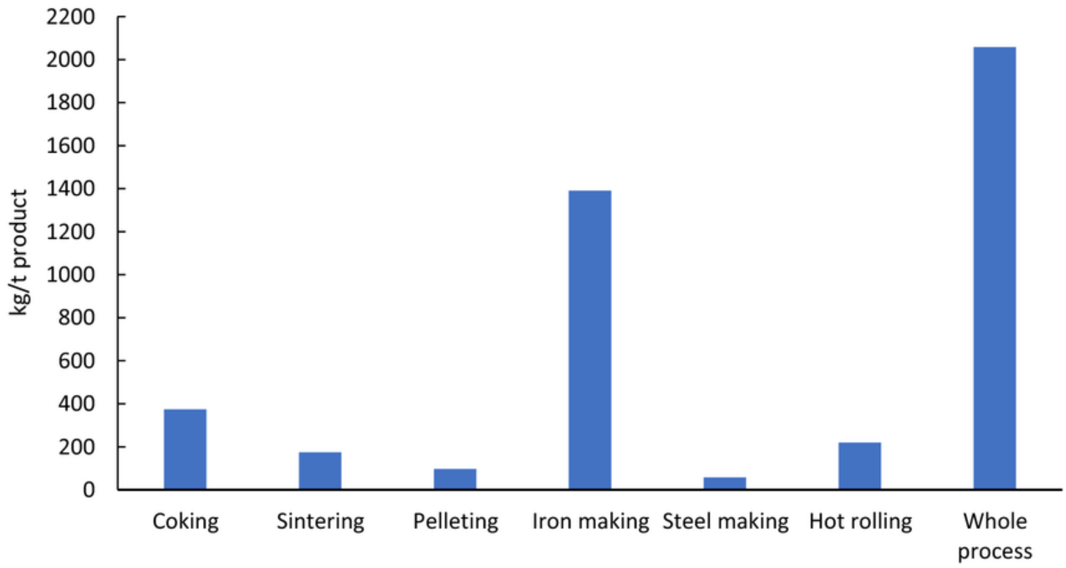


Figure 15 - Carbon Emission for Unit Process of China's ISI in 2018 (BF-BOF Route)[11]

Although Teesside ceased production of primary iron and semi-finished steel in 2016 with the closure of the Redcar Blast furnace, BOS steelmaking and continuous casting lines, the BSL TBM remained in operation to reheat and roll slab made in Scunthorpe. A future scenario with gigawatts of industrial hydrogen and green energy demand could see 'net zero' or 'fossil free' steel slab produced from the hydrogen-electric route, eminently feasible on Teesside due to availability of green energy, existing hydrogen economy, steelmaking skills and remaining infrastructure such as the deep dock of the former ore terminal, and brownfield land on the former steelworks.

With this in mind as a potential development the first steps towards integrating green hydrogen production close to the steel mill which this project has addressed represents a hugely significant strategic UK 'first': commercial steel processing integrated with green hydrogen, enabling actors on both sides to gain knowhow, operational experience, and build the skills base that helps underpin the move toward 'green steel' and keep options open for the future.

The conversion to hydrogen has a significant implication for foundation industries and with the advancement of green hydrogen, a full cycle across the fuel production and usage will lead to a significant reduction in emissions across all foundation industries.

[11] https://pubs.acs.org/doi/pdf/10.1021/acsenergylett.2c01615 (page 4, GHG paragraph)

7. Environmental, Social, Health and Safety (WP5)

7.1. Introduction

The introduction of hydrogen as a fuel with TBM is a major change in the process operating parameters and as such demands that the HSE procedures for implementing Plant Modification and Changes are followed. A key element of these procedures is the implementation of a HAZOP study is undertaken.

The HSE guidance indicates that the various stages of this process are:

1. Identify major hazards and check for availability of key hazard data
2. Coarse HAZOP using flowsheet and block diagram
3. Full HAZOP on frozen P&ID
4. Check that all intended actions have been implemented, including hardware and software
5. Pre-commissioning check including statutory requirement
6. Safety audit after a few months' operation

For the purposes of this study, only items 1 and 2 can be undertaken at this early stage of the project. This Chapter of the report describes these first steps which have been undertaken and BSL's plan going forward, to implement the use of hydrogen as a fuel in a safe and secure manner.

7.2. HAZOP Analysis TBM

BSL has undertaken a HAZOP analysis following the HSE recommendations and the current version is shown in Appendix 1. The HAZOP analysis is a live document and will be reviewed and the relevant stages complete as the project progresses. The stages of the BSL HAZOP process are as follows:

Hazard Study 1

Performed during the project feasibility study, it takes input from early stage inherent SHE studies and identifies the basic hazards of the materials involved and of the operation. HS1 establishes safety, health and environmental criteria and ensures the necessary contacts with functional groups and external authorities.

Hazard Study 2

Performed at the project definition stage, using prompt diagrams to stimulate creative thinking to identify significant hazards. Inherent SHE principles continue to be applied where possible and practicable, or assessment may be used to determine appropriate design features, including the identification of trip/alarm systems.

Hazard Study 3

Performed at the end of the project design stage, using fully developed P&IDs or equipment layout designs (ELDs) to identify hazards and operability problems, using guidewords to stimulate creative thinking about possible deviations and their effects.

Hazard Study 4

Performed at the end of the construction stage and before introducing process materials, this checks that the equipment and procedures are as designed and as required by the previous hazard studies.

Hazard Study 5

Performed at the end of the construction stage and before introducing process materials, this is a check that the project meets company and legislative requirements.

Hazard Study 6

Performed 3 to 6 months after beneficial production is established, this study checks that previous hazard studies have been completed where required and that early operation is consistent with the design intent and with assumptions.

7.3. Air Quality Emissions

Currently the furnace emissions are sampled as prescribed in the site environmental permit, as defined in table S3.1 (***Table 24***) of the permit which is reproduced below.

Table S3.1 Point source emissions to air – emission limits and monitoring requirements						
Emission point ref. & location	**Source**	**Parameter**	**Limit (including unit)**	**Reference period**	**Monitoring frequency**	**Monitoring standard or method**
A32 as shown on site plan in Schedule 7	Beam Mill reheat furnace	Oxides of nitrogen monoxide and nitrogen dioxide (expressed as nitrogen dioxide)	550 mg/m³	Periodic	Annual	BS EN 14792 or TGN M22 (Extractive Sampling and FTIR Analyser)

Table 24 – Site Environmental Permit Furnace Emission Monitoring Requirements (EPRVP3606BL)

It is understood from previous monitoring that the NO_x levels emitted are not static, and do change depending on a number of variables such as; rolling rate, feedstock and general furnace conditions. It will therefore be required to carry out extended periods of monitoring to give benchmark emissions levels in order to determine.

As discussed in ***Paragraph 4.5.2*** the following methodology will be used to monitor the effect of the furnace burner and fuel changes:

1. The furnace in its current configuration (with existing burners and firing on natural gas)
2. The furnace with the replacement burners in situ (firing on natural gas)
3. The furnace when under trial hydrogen firing conditions

It is considered that only with monitoring data available for the aforementioned periods will it be possible to determine the effect of Hydrogen firing on NO_x levels within the furnace.

7.4. Assessment of Upstream Hydrogen Emissions and Natural Gas Counterfactual

7.4.1. Low Carbon Hydrogen Supply Emissions

Converting from natural gas supply to hydrogen supply will drastically reduce the Scope 1 carbon emissions from the TBM and provide options for upstream emission reduction (Scope 2 and 3) depending on the hydrogen production route. BEIS have developed a methodology for assessment of carbon emissions (**Figure *16***) which considers these upstream emissions. Projects must demonstrate $20gCO_2e/MJ_{LHV}$ ($85gCO_2e/kWh_{HHV}$) to comply with this new standard. Depending on the low carbon hydrogen technology the raw material acquisition and operation of the hydrogen plant associated with Scope 2 and 3.

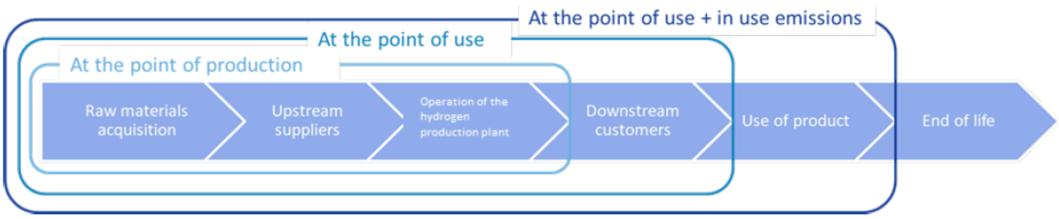


Figure 16 - System Boundary for BEIS Low Carbon Hydrogen Standard[12] ("Point of production")

7.4.1.1. Electrolytic Hydrogen

The largest source of carbon emissions from electrolytic hydrogen production is the upstream emissions associated with electricity (only scope 1 for the LCHS). UK Climate Change Committee highlights that in a decarbonised grid for the future the emissions would be $11\text{-}14gCO_2/ kWh_{HHV}$ ($3.1\text{-}3.9\ gCO_2/MJ_{HHV}$)[17]. An electrolyser linked to solar and wind generation locally will achieve these lower carbon intensities and is the plan after the demonstration phase is completed at the TBM. The development of electrolyser technology such as Solid Oxides will enable a reduction in electricity demand by increasing the tonnage of hydrogen produced per kWh of electricity and utilisation of waste industrial heat.

7.4.1.2. Blue Hydrogen

The production of hydrogen from methane reforming and carbon capture ("blue hydrogen") emits some carbon during capture processing and upstream in the natural gas production route. Forecasts

[12] E. &. I. S. Department for Business, "UK Low Carbon Hydrogen Standard," [Online]. Available: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1092809/low-carbon-hydrogen-standard-guidance-v2.1.pdf. [Accessed 05 08 2022].

for carbon capture rates are in the 90-95% range of carbon from natural gas in the production of hydrogen, but no existing CCS facility has yet achieved this. The current conversion efficiency is 65% but there is potential to increase this further to 85%. The carbon dioxide emitted during the production process could reduce from 285gCO_2/ kWhHHV (79.2 gCO_2/MJ_{HHV}) to 11-25 gCO_2/kWh (3.1-6.9 gCO_2/MJ_{HHV}) in 2050.

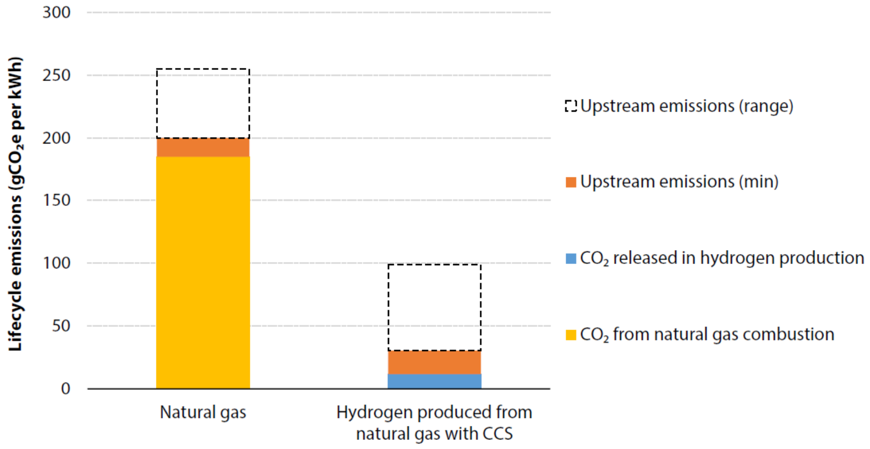


Figure 17 - Emissions from hydrogen production from natural gas with CCS (UK Climate Change Committee)[13]

7.4.1.3. BECCS Hydrogen

Biomass gasification is not currently deployed so efficiencies of 46-60% are suggested with further validation required[14] and in theory could be a negative emission technology. The biomass feedstock assessment must consider land and water footprint upstream and the availability of sustainable feedstock is a key consideration. Future Energy Scenarios[15] consider a smaller volume of hydrogen from biological sources due to constraints on sustainable supply sources and increase costs of gasification and gas cleaning in comparison with natural gas steam methane reforming technology. These scenarios also recommend using limited bioenergy supply where it can be most effective in reducing carbon emissions, such as in buildings and aviation fuels.

7.4.1.4. Grey Hydrogen

Currently the majority of hydrogen production in the UK is from Steam Methane Reforming (SMR) without carbon capture which has high carbon dioxide emissions. Grey hydrogen may play a role in transitioning to low carbon hydrogen and during the trial the approach is to find a suitable hydrogen supplier which may not be low carbon. Green hydrogen may not be available within the timescales required (as is the case in this trial), but the longer-term plan post-trial is to transition to low carbon supply. Combustion of grey hydrogen will produce more emissions than burning natural gas

[13] C. C. Committee, “Hydrogen in a low carbon economy,” 11 2018. [Online]. Available: https://www.theccc.org.uk/wp-content/uploads/2018/11/Hydrogen-in-a-low-carbon-economy.pdf. [Accessed 28 10 2022].
[14] C. C. Committee, “Hydrogen in a low carbon economy,” 11 2018. [Online]. Available: https://www.theccc.org.uk/wp-content/uploads/2018/11/Hydrogen-in-a-low-carbon-economy.pdf. [Accessed 28 10 2022].
[15] N. G. ESO, “Future Grid Energy Scenarios,” 2021.

7.4.2. Natural Gas Emissions

Natural gas emissions are a significant carbon dioxide emission within the steel industry for hot rolling and a range of high temperature process heating applications across the production route. Hydrogen has a significant potential for decarbonisation of the steel industry in the ironmaking, steelmaking and hot rolling processes. Hot rolling mills are often the location where a lot of emissions occur from either natural gas or works gases from other integrated steel production routes. Conversion to Electric Arc Furnaces to reduce carbon emissions from ironmaking as suggested by BSL[16] will create a shortage of works gases available for rolling mills and a demand for increased natural gas.

7.4.3. Comparison of Natural Gas and Hydrogen Supply

As can be seen in the graph below (**Figure *18***) from the UKCCC the natural gas emission range is lower than current gas reforming and grid connected electricity electrolysis. For the steel industry to decarbonise a low carbon source is required and both blue and electrolytic hydrogen offer the ability to operate below 20gCO_2/kWh (85 gCO_2e/kWh$_{HHV}$) of hydrogen and radically reduce the carbon emissions of the equivalent natural gas application. It is also important to highlight that without carbon capture; steam methane reforming has higher emissions than natural gas itself and its role as a transition fuel should be limited in time until alternative low Carbon capacity is available as planned for this trial approach.

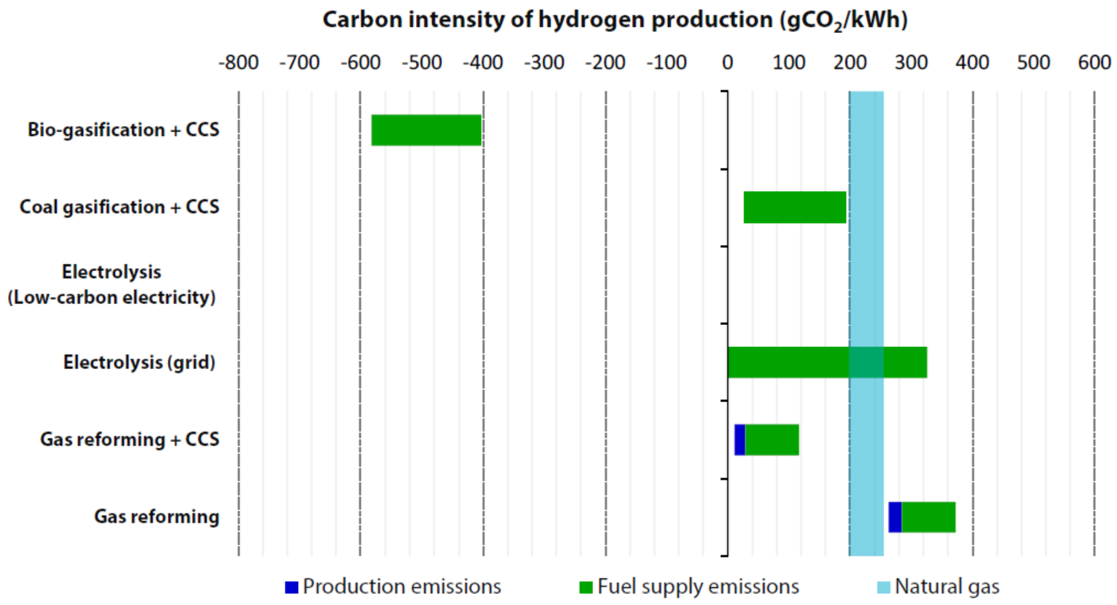


Figure 18 - Comparison of Carbon Intensity of Different Hydrogen Production Routes (UK Climate Change Committee)[17]

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[16] https://agmetalminer.com/2022/01/28/british-steel-moving-to-eaf-production-to-meet-carbon-emissions-targets/. [Accessed 09 11 2022].

[17] C. C. Committee, "Hydrogen in a low carbon economy," 11 2018. [Online]. Available: https://www.theccc.org.uk/wp-content/uploads/2018/11/Hydrogen-in-a-low-carbon-economy.pdf. [Accessed 28 10 2022].

7.4.3.1. Units of Comparison – Steel Production

The standard comparison of carbon emissions is the tCO_2 per kg of steel and these are used as standard benchmarks within the industry. The hot rolling processes offer an opportunity to reduce CO_2 emission by 5% for blast furnace steel and much higher levels for electric arc furnace steel which will increasingly decarbonise as the grid decarbonises. The hydrogen content of the steel semi-finished products will have an impact on selling low carbon products. Developing hydrogen technologies have potential to support Direct Reduced Iron technologies through increased efficiencies and lower capital cost per unit. Conversion of hot rolling to hydrogen will make a significant impact on tCO_2 per kg of steel and enable further reductions in other steel making processes through developed supply chains.

7.4.3.2. Teesside Beam Mill Potential Carbon Dioxide Emission Reduction

A full conversion to hydrogen offers a potential to reduce TBM's carbon dioxide emissions significantly, (this is discussed in detail within ***Section 7.5***). The potential reduction in carbon dioxide from this technology is significant, considering the BSL alone have three other UK hot rolling furnaces to develop similar technology.

7.4.4. Conclusions on Emission Impact of Conversion to Hydrogen

Converting to hydrogen fuel instead of natural gas or coal-based fuels offers great opportunity to reduce the global warming impact of the steel industry sites. To ensure the overall system impact is correct the hydrogen supply must be low carbon and this project has clear plans to support the development of a Tees Green Hydrogen supply post-trial that would ensure this was achieved. SMR and carbon capture of natural gas (or the less developed bioenergy sources) offers an opportunity to remove carbon from the energy system while using natural gas. Large volumes of hydrogen supply on site are vital to the expansion of industrial fuel switching within the steel industry and other energy intensive industries such as cement and glass. This project enables scaling of fuel switching technology across the UK and expertise beyond to dramatically reduce on site and upstream industrial emissions in an energy intensive industry.

7.5. GHG Emissions Before and After Conversions

7.5.1. TBM and Emissions Trading Scheme

TBM holds a greenhouse gas permit under The Greenhouse Gas Emissions Trading Scheme Order 2020. This authorises the regulated activities set out in the permit to be carried out at the installation and includes a number of conditions which we must comply with, including the monitoring and reporting of emissions, the surrender of allowances and notification requirements.

Highly exposed sectors are placed on the carbon leakage list and receive allowances equivalent to 100% of the relevant benchmark. TBM receives free allocations under the heat benchmark and the fuel benchmark.

<u>Heat benchmark</u>

- Inputs, outputs and corresponding emissions not covered by a product benchmark sub-installation relating to the production of measurable heat consumed within the installation's boundaries. Measurable heat means a net heat flow transported through pipelines or ducts using a heat transfer medium, such as steam, hot air, water for which a heat meter is or could be installed.

Fuel benchmark

- Inputs, outputs and corresponding emissions not covered by a product benchmark sub-installation relating to the production of non-measurable heat by fuel combustion consumed for the production of products.

The amount of free allocation received is calculated based a historical activity level from 2014 and 2018 and benchmark values[18] (no. allowances per TJ) and is provided inTable ***22***, whilst a full breakdown of emissions in 2021 is provided in ***Table 26.***

Benchmark	Allowances/TJ	Historical Activity Level	Allowances
Heat Benchmark	47.3	62.3 TJ	2,946
Fuel Benchmark	42.6	1,054.6 TJ	44,924
Total			**47,870**

Table 25 - Historical Benchmark

On a rolling 2-year basis the activity level is assessed and if there is a change of +/- 15% against the historical activity level there is a corresponding increase or decrease in free allocation. Following a breach of this +/- 15% limit, a narrower reassessment range of +/- 5% is applied thereafter.

The primary use of fuels on TBM is for the walking beam re-heat furnace which comprises of 6 zones of burners, which fire on natural gas.

There are also two steam boilers which primarily fire on natural gas, although have a gas oil backup option.

Propane and gas oil are also used on site for a number of activities including heating.

[18] EUR-Lex - 32021R0447 - EN - EUR-Lex (europa.eu)

2021										
Benchmark	Combustion Unit	Fuel	Activity	Units	NCV	Units	Energy Input (TJ)	Energy (TJ)	Emission Factor	tCO_2
	Total Furnace Input	Nat Gas	35,438,405	m³ @15C	36.40	MJ/m³ @ 15C		1290.1		
Fuel	Reheating	Nat Gas	34,403,000	m³ @15C	36.40	MJ/m³ @ 15C		1252.4	57.43	71924.48
Fuel	Misc Equip	Gas Oil	23	T	42.57	GJ/t		1.0	74.94	73.72
Fuel	Misc LPG	LPG	181	T	45.94	GJ/t		8.3	63.88	531.48
Heat	Misc Heating	Gas Oil	13	T	42.57	GJ/t	0.6	0.4	74.94	42.84
Heat	New Steam Boilers	Nat Gas	1,035,405	m³ @15C	36.40	MJ/m³ @ 15C	37.7	33.9	57.43	2164.66
Heat	Furnace Steam	Nat Gas						22.74	63.81	1451.10

Table 26 - Emissions Breakdown for 2021

The **Figure *19*** chart attempts to model the impact on emissions and allocation of free allowances in the event that hydrogen replaces natural gas according to the following schedule:

- Zones 5 & 6 at the beginning of year 0,
- Zones 3 & 4 at the beginning of year 3, and
- Zones 1 & 2 at the beginning of year 6.

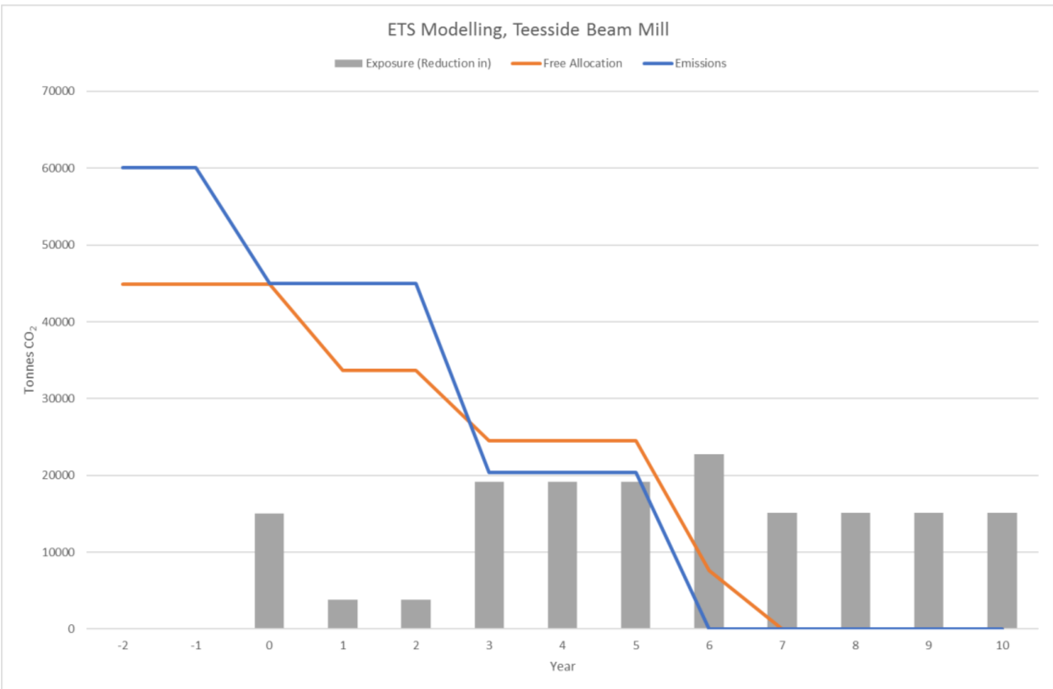

Figure 19 - Chart Representing Allocation vs Emissions

Assuming a static activity level and no change in fuel benchmark, the fuel switching strategy outlined here should reduce TBMs carbon exposure by circa 163,000 tCO_2 over a ten-year period.

However, it can be expected that there will be a reduction in the fuel benchmark from 2026, reducing free allocations available to installation operators and therefore increasing carbon exposure if no mitigating actions, such as fuel switching are taken.

Operators' commercial assessment of the viability of fuel switching to hydrogen will of course be influenced by the price of hydrogen. Unless this is pegged at or very close to the price of the fuel it is substituting the investment case will be eroded potentially to the point where operators may choose to shutter current operations rather make the required investments.

7.6. Supply Impact Assessment of Hydrogen Chain

7.6.1. Hydrogen Jobs Created During Phase 2

The project will purchase hydrogen from local suppliers in the UK and support development of local hydrogen supply as costs are connected to the distance of travel required. Air Liquide and BOC have both been approached for details on hydrogen supply in the region. This will support a developing ecosystem for hydrogen supply within the UK and the opportunity to develop skills for these applications. We are considering the option from hydrogen suppliers of a pressure reducing station and developing these solutions engaging directly with a large hydrogen user will offer opportunities to develop products that can be scaled across the UK and beyond.

7.6.2. Supplier and Contractor Opportunities

The hydrogen supply chain in the UK is being developed to support projects using hydrogen to transition away from fossil fuels. Hydrogen suppliers plan to expand their operations to supply an increasing demand for hydrogen across the UK and EDF plan to supply hydrogen locally from an electrolyser within hundreds of metres from the site. This will create additional employment opportunities for the construction and operation of hydrogen production facilities and distribution and supply business expansion across the region through guaranteeing a large off taker to support the initial investment.

7.6.3. Training and Development

Developing hydrogen supply in the region will provide an opportunity for the local population to develop skills and expertise that can support the local economy and wider technology development across the UK. The requirements of hydrogen supply in a hot rolling furnace have been developed within the project between MPI, BSL, UCL, EDF and OEMs. Using hydrogen will create new opportunities to learn about how it can be applied to the steel industry and ensure the workforce are prepared for the low carbon transition in energy intensive industries. This will support existing work from EDF, MPI and BSL in the region who have a track record of developing skills and expertise in the energy and manufacturing sectors.

7.6.4. Manufacturing Expertise

BSL and the Metals Processing Institute have experience developing expertise in high skill industries for manufacturing and this will be developed with increased hydrogen conversion. The learning from the feasibility study has already supported a greater understanding of conversion to hydrogen and the process impact in a hot rolling furnace. This is vital to support long term low carbon jobs in the manufacturing sector and these skills will be developed further with a demonstration facility. The skills developed will support wider projects in the Tees region but also expertise across the UK steel industry.

7.6.5. Benefits to Tees Green Hydrogen Project being Developed in the Region

EDF are developing a project to produce low carbon hydrogen linked to solar and wind assets in the region. The development of this project will enable hydrogen fuel switching to TBM that can demonstrate a route to 100% decarbonisation. That project was estimated to generate £10-20million GVA and £2-3million for the local region as well as creating 100-200 jobs of which 20% would be in the local region. Demonstrating the technology will enable scaling of that project as BSL would be a significant off taker already before extension of the technology to full furnace capital plans.

Process and energy have been identified as key growth areas for the Teesside region by the Tees Valley Combined Authority and this project supports the wider ecosystem for hydrogen in the region. The Redcar and Cleveland community at the location of the proposed electrolyser have a high GVA for energy sector in the region and high carbon dioxide emissions per capita. The cluster concept offers the opportunity to support power, transport and heating decarbonisation within the region as a larger volume of demand will enable a larger scale and lower cost solution for the region. This project offers a significant impact on both of these by creating jobs in the hydrogen economy for supply to BSL while reducing carbon dioxide emission for a ~40MW natural gas demand and long-term capital planning for replacement to 100% fuel switching in the future.

7.7. Social Impact Assessment – TBM

7.7.1. The Impact of Steel Production as a Foundation Industry in the UK Economy

The UK Steel manufacturing sector employs 32,000 people. The average wages of steel industry employees around 18% above national average and around 28% higher than the regional average. The supply chains for the UK industry supports employment directly for a further 52,000 people.

£2billion is directly contributed towards the UK economy by the industry with £1.5billion being positively contributed to the UK trade deficit. TBM directly exporting well over £100million of products every year with planned growth in this area.[19]

Teesside beam mills products are predominantly structural steels supplied to the UK construction industry. This production facility supplying 400,000 tonnes per year - over 60% of the UK requirement for large structural beams and columns. These products are essential constituent of a competitive and effective UK construction supply chains in all forms of transport; warehousing; high rise; general office and residential building applications. This makes TBM a key strategic asset for the UK construction industry.

BSL employs around 4500 direct employees, Teesside operations with around 540 people directly. Over 40% of Teesside operations employees having served manufacturing or engineering apprenticeships. National and International distribution from the site via heavy goods hauliers and local Tees River ports adding directly to local supply chain employment.

[19] UK Steel Net Zero Steel July 2022 : Make UK

The sustainability of employment at TBM heavily relies on the successful decarbonisation of BSL supply chains as a whole – BSL has published a Low Carbon Roadmap[20] identifying the 3 key steps as Introduction of CCUS for raw iron production, electrification of steelmaking processes and switch to hydrogen reheating in the mills. The assets of BSL production are such that a target of 82% overall emissions Type 1 and 2 - 8% of overall reduction of emissions are associated with reheating furnace process in rolling mills. Without progressing this decarbonisation plan and alternative fuel sourcing the viability of Teesside operations as a whole would be called in to question.

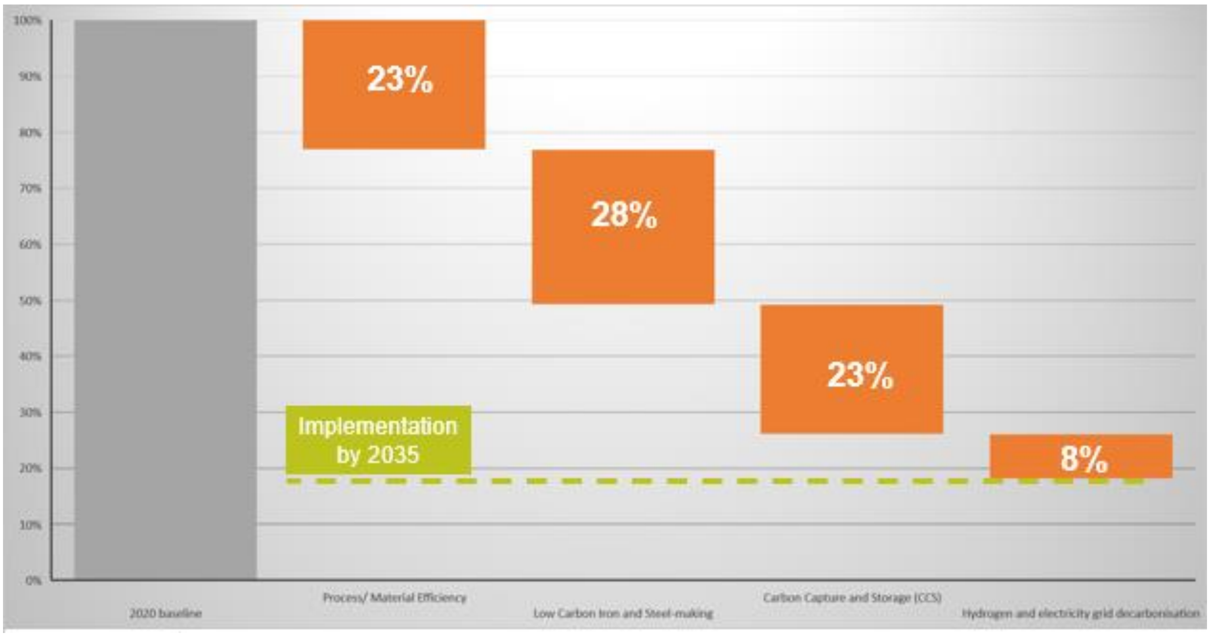

Figure 20 - BSL Decarbonisation Roadmap – Emissions Reduction Targets

7.7.2. Teesside Employment Opportunities

Teesside employment is weighted towards heavy industry a legacy of the iron steel and chemical industries dominance as drivers for growth of the area throughout last century. Even though the percentage of people remains above the national average in these industries significant reductions have occurred – the closure of Iron and steelmaking facilities being the single biggest change in 2013-2018 period.

[20] https://britishsteel.co.uk/who-we-are/sustainability/low-carbon-roadmap/

Industry Sector	Tees Valley Jobs (2018)	Change (2013-2018)	% Change (2013-2018)	% Change Nationally (2013-2018)	Location Quotient
Chemical and Process	5,361	-2,822	-35%	9%	2.2
Raw Materials and Agriculture	6,255	-275	-4%	7%	1.8
Advanced Manufacturing	18,055	3,235	22%	8%	1.5
Clean Energy Low Carbon	8,215	1,327	19%	13%	1.4
Healthcare	35,978	-4,143	-10%	10%	1.3
Other Public Services	49,386	1,355	3%	2%	1.1
Other Private Services	38,786	-643	-2%	4%	1.1
Logistics	19,399	4,022	26%	10%	1.0
Construction	12,844	-1,058	-8%	20%	0.9
Other Manufacturing	9,742	1,861	24%	7%	0.9
Creative, Culture and Leisure	30,228	804	3%	12%	0.8
Professional and Business Services	32,238	4,792	18%	14%	0.7
Digital	6,455	1,415	28%	27%	0.7
Biologics	143	-68	-32%	3%	0.2

Table 27 - Tees Valley Employment by Industry

Note: The location quotient measures the concentration of jobs. Location quotients greater than 1 indicate a higher concentration of jobs in an industry sector than the national average.[21]

The Tees Valley can be defined as a functional economic area with close to 9 in 10 local jobs filled by Tees Valley residents and similarly close to 9 in 10 local residents employed within Tees Valley i.e., relatively small and balanced levels of in and out-commuting.

The Chemical and Process, and Construction sectors rely on further education and apprenticeship provision to feed a large proportion of its workforce, in particular process, plant and machine operatives and skilled trades.

The technician and graduate engineer opportunities created by developing new technology applications in the steel industry will have a high likelihood of impacting with the local workforce. These technologies will require sustainable skills development as part of the broader low carbon technologies being developed in the area.[22]

7.7.3. Training and Development

The development of this technological application in Steel production is directly aligned Tees valley stated employment strategy objectives given the nature of Teesside operations and the fact that 90% of new employees enter the work force via Manufacturing or Engineering Apprenticeships or are degree level qualified individuals. More specifically all individuals working in the area of furnace activities are taken through these routes to employment with upskilling on use of alternative fuels of circa 35 current employees required. Development of a long-term fuel conversion solution will lead to a direct employment of a project team – scope and scale of team dependent on findings of the Phase 2 demonstrator project.

Tees Valley employment strategy stated objectives include: Increase the number of Tees Valley residents with higher level skills, whilst ensuring a parallel supply of higher-level jobs. Increase the number of Tees Valley residents with intermediate level skills. Reduce the number of Tees Valley

[21] TVCA Net Zero Strategy (2020)
[22] Local Skills Report – Tees Valley Combine Authority – March 2021

residents with no qualifications Increase apprenticeship starts, particularly in Tees Valley priority sectors.

Tees Valley occupational clusters - alignment analysis indicates gaps in demand for clusters including hydrocarbons and metal work Skills shortage with vacancies high within the Transport and Storage sector – due to current and future growth in demand. These cluster requirements have direct alignment to UK Steel manufacturers stated decarbonisation strategies.[23]

[23] Local Skills Report – Tees Valley – March 2021

8. Business Model (WP6)

8.1. Introduction

8.1.1. Full Hydrogen Conversion Impact on Steel Carbon Dioxide

The low carbon hydrogen standard in the UK is linked to incentives for hydrogen production from low carbon routes when this can be shown to be below $20gCO_2e/MJ_{LHV}$ [24] which will support decarbonisation of more challenging sectors. The UK government is supporting a range of schemes such as the Net Zero Hydrogen Fund for capital and development expenditure and the Hydrogen Business Model for operational costs for hydrogen to incentivise uptake versus counterfactuals. At present the steel industry uses natural gas as a heating fuel for processes at high temperatures above 1000°C. Electrification is challenging, whereas hydrogen combustion offers a suitable alternative to achieve net zero. Hydrogen with an equivalent cost to historical stable natural gas prices, or a counterfactual energy price that allows the steel producer to operate competitively in international markets would resolve the financial disincentive that is currently in place. Additionally, current initiatives to decouple wholesale electricity prices from gas prices could support the business model; as details are unclear these are not yet considered in this report.

8.1.2. CCUS-enabled and Electrolytic Forecasts for Industry UK

Hydrogen that meets the requirements of the Low Carbon Hydrogen Standard (LCHS) in the UK can be produced from water via electrolysis or through Steam Methane Reforming with carbon capture from natural gas or biological sources. The forecasts for hydrogen production will include a range of solutions suited to different applications and locations. Hydrogen production from low carbon electricity will therefore be compared with alternative technologies to determine the costs, environmental impact and timescales for deployment of the demonstration project.

The goal of achieving net zero carbon emissions will require a substantial increase in low carbon hydrogen production. The National Grid Future Energy Scenarios to 2050[25] include a significant increase in hydrogen production from electrolysis for the three scenarios that achieve net zero. This can be in the form of grid connected electrolysis or direct wire connections to nuclear or renewables. The demonstration in this trial will show hydrogen production through electrolysis linked to renewable electricity (wind and solar) in the region. This aligns with plans to increase offshore wind production in the UK to 50GW by 2030[26] and ambitions for hydrogen production in the UK.

The production of hydrogen from Steam Methane Reforming with Carbon Capture and Storage (CCS) ("blue hydrogen") plays a significant role in achieving net zero under 2 of 3 National Grid Future Energy Scenario projections[17]. Within the UK there are a range of planned "blue hydrogen" production solutions linked to industrial hubs in strategic locations. However, CCS projects with sustained capture rates at the levels required for the LCHS (c.+80% capture rate) have currently not been demonstrated, and further development is needed such as commercial scale Autothermal Reformer technology (ATR) + CCS.

[24] E. &. I. S. Department for Business, "UK Low Carbon Hydrogen Standard," [Online]. Available: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1092809/low-carbon-hydrogen-standard-guidance-v2.1.pdf. [Accessed 05 08 2022].
[25] N. G. ESO, "Future Energy Scenarios," National Grid ESO, 2021.
[26] D. f. I. Trade, "Offshore Wind," [Online]. Available: https://www.great.gov.uk/international/content/investment/sectors/offshore-wind/. [Accessed 05 08 2022].

The National Grid Future Energy Scenarios have been developed for four scenarios. The forecast hydrogen production (**Table *28***) and framework for scenarios (**Figure *21***) are shown:

	Consumer Transformation	**System Transformation**	**Leading the Way**	**Steady Progression**
Methane reformation with CCUS	34	332	0	50
Networked electrolysis	103	78	178	2
Imports	0	0	43	0
Non-networked electrolysis	0	0	69	0
BECCS	0	43	8	0
Nuclear electrolysis	12	23	0	0
Total	**149**	**475**	**297**	**52**

Table 28 - National Grid Future Energy Scenario Forecast for Hydrogen Supply in 2050 (TWh)

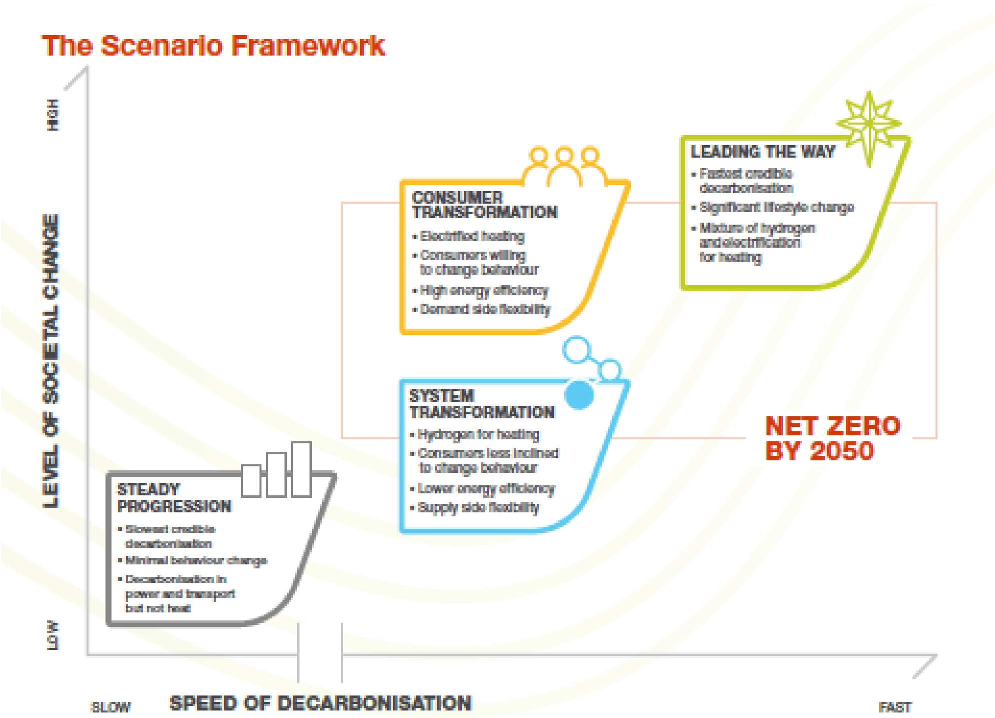

Figure 21 - National Grid Future Energy Scenario framework

8.1.3. Hydrogen Supply Cost Overview

Models for the cost of hydrogen supply have been developed for two different low carbon routes of production, electrolytic and gas reformation with carbon capture and storage. The improving performance and scale of these technologies will be considered using BEIS 2021 hydrogen production cost projections for electricity, gas and carbon prices. After the completion of the trial the current plan is for hydrogen to be supplied from an electrolysis plant, linked to low carbon electricity from offshore wind and solar energy. The electrolytic hydrogen scenario will therefore consider a similar case in 2040.

The demand for hydrogen from BSL is relatively consistent for the majority of the year so the load factor of hydrogen production should be as high as possible to maintain continuity of supply. The hydrogen demand would be steady for 6 days a week with a reduction in demand during a down day (when the furnace operates at lower temperature). A loss of gas risks a production stop which is very expensive to an industry with large-fixed costs spread over hours of operation. Similarly, hydrogen production facilities aim to maintain high load factors to maximise output and reduce investment cost per unit delivered.

8.1.3.1. Electrolytic Hydrogen

Electrolytic production offers a great opportunity to reduce the future costs of hydrogen due to the potential growth of low-cost renewable and nuclear energy in comparison with high and volatile gas prices. A challenge for electrolytic hydrogen is that renewable generation has a significantly lower load factor and will need to be supplemented by grid electricity to maintain 24/7 operation. This would not be the case if the technology was coupled with nuclear plants. Optimistic forward-looking scenarios combine low renewable cost with low grid costs.

Current electrolytic hydrogen production costs are high, driven by high CAPEX and electricity market price, but as the technology matures, scales and low carbon generation is increased it will become increasingly cost competitive. The cost of production is largely related to the electricity price and the second largest impact are the capital costs. As has been seen with offshore wind, as the technology scales the cost per unit can dramatically reduce. Technology developments will also offer opportunity to increase efficiency of hydrogen production above the current performance of PEM and Alkaline technology.

8.1.3.2. Methane Reforming & Carbon Capture

Methane reformation is the current dominant method of hydrogen production, with significant associated carbon emissions. The future of this technology relies on process developments to improve efficiency and align better with capturing carbon for transport and storage. Current trials of capturing carbon achieve c.60% capture rate, whereas 95%+ should be targeted for a net zero future. Further CAPEX and OPEX cost reductions are limited due to the maturity of the steam reforming technology. Promising technologies such as Autothermal reforming (ATR) with Gas Heated Reformers and Sorption Enhancement align better with capturing carbon from the process and could improve process efficiency and achieve these high capture rates, although they are not yet commercially proven.

The carbon capture element reduces process efficiency by c.10% vs the traditional method of producing hydrogen from fossil fuels. The carbon capture storage is key to the deployment of this technology and although the modelled price of hydrogen from this method would indicate a simple solution the deployment of large-scale carbon capture in the UK is yet to be deployed.

8.1.3.3. Modelling Assumptions

To understand the relative economic merits of the different production routes and timelines, a high-level economic assessment has been undertaken. Key assumptions relate to CAPEX, OPEX, electricity price scenarios and gas price scenarios. Key assumptions and sources are presented in **Table *29***. System costs have been excluded from this analysis. Presented Levelized Cost of Hydrogen (LCOH) are production costs, not market prices and as such are likely lower than sold prices.

Variable	Value (all costs in £2021)			Source
Renewable Factors	2025	2030	2040	
Solar PV Load Factor	11%	11%	11%	BEIS Electricity Costs 2020 + EDF Modelling (2025 LCOE based on CfD AR4)
Solar PV LCOE/MWh	£53	£45	£37.5	
Offshore Load Factor	51%	57%	63%	
Offshore LCOE/MWh	£43	£40	£35	
Estimated Hybrid PV + Offshore Load Factor	50%	52%	55%	-
Hydrogen Production CAPEX, OPEX, Life, Construction etc.				BEIS H_2 Production Costs 2021
Prices (/MWh, /therm, /tonne)				
Today Grid	£359.1			BEIS 2021 EEP ExtHigh FFP
10yr Historical Grid	£52.5			
2025 High Grid	£115.5			
2030 Low Grid	£40.9			BEIS 2021 EEP FFP Low
2040 Low Grid	£59.0			
2040 Natural Gas	64p			BEIS 2019 EEP
2023 Forward Curve	300p			Market Price
June 2022 Industrial Gas Price	140p			BEIS Quarterly Stats
Carbon Price	£100			Expectation by 2030
Carbon T&S	£10.9			Uniper

Table 29 – Economic Modelling Assumptions

8.1.3.4. Analysis

Multiple scenarios have been run to capture the range of potential hydrogen costs in the near term and the future cost reductions under certain price projections. **Figure 22** presents the cost stacks for each production route, comparing the different technologies.

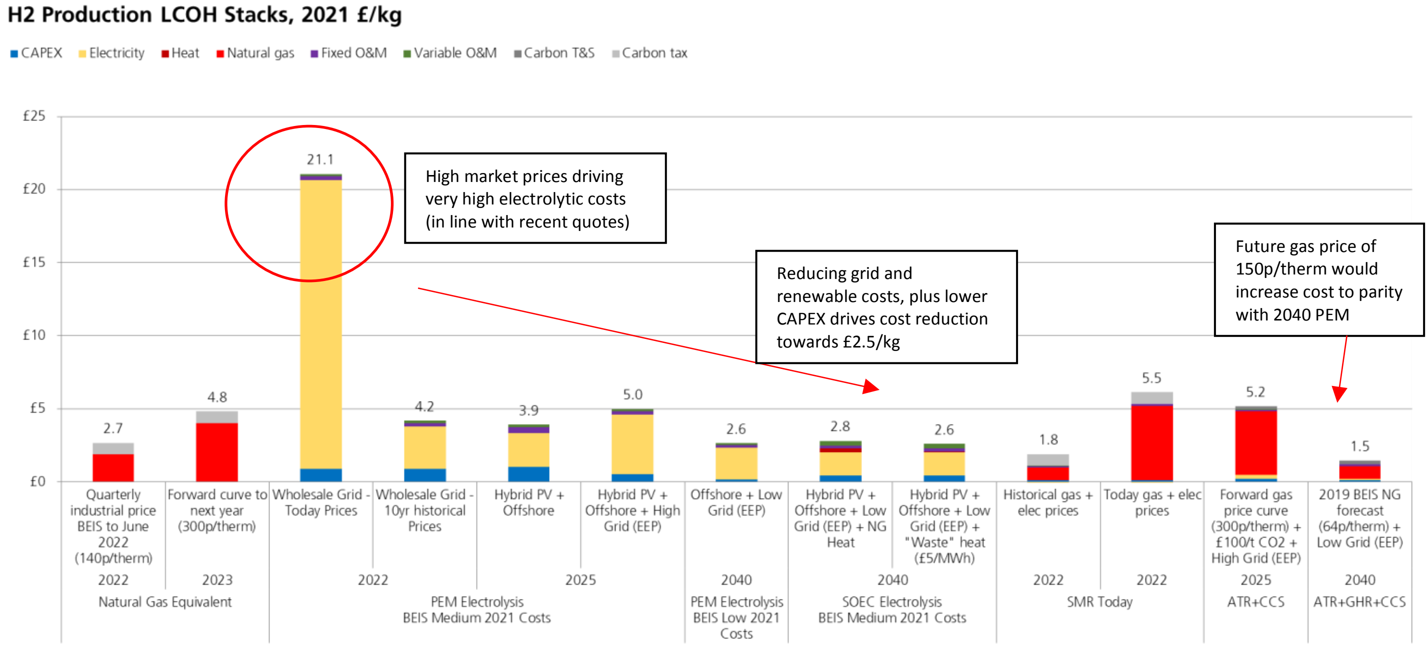

Figure 22 – Hydrogen Production LCOH Cost Stacks

Costs today for electrolytic and gas reformed hydrogen are significantly higher than projections due to the prevailing market dynamics. These prices are forecast to continue into the mid-2020s, having a significant impact on the blue hydrogen route, as domestic gas prices are exposed to global market forces. Electrolytic projects that have private wire connections to renewables, become cost competitive with blue hydrogen in this time period. Given contracts for difference auctions are ongoing and achieved strike prices are in the £40/MWh region, these electrolytic LCOH values are likely achievable in the near term but rely on continued investments in scaling electrolysis production capacity to reduce capital costs.

Under BEIS low-cost scenario for PEM, by 2040 £2.6/kg could be achievable, dependent on electricity price secured. If an ATR+GHR+CCS project were successful and captured +95% of the emitted carbon, this route would be cheaper than the 2040 PEM scenario at a price of 150p/therm. Higher carbon taxation could impact this further and there are uncertainties around the transport and storage costs associated with capturing carbon that could negatively impact project economics. However, blue hydrogen looks a promising technology for upscaling the industry and delivering near term emissions reduction.

There is also potential for SOEC to develop in this time frame, which is particularly interesting for the steel industry as waste heat is available to generate steam needed to improve its efficiency. EDF are investigating the potential for heat from nuclear generation to support this technology and the optimum location for heat supply could be developed with this technology between production and hydrogen use. As shown in the graph, SOEC under mid-range BEIS cost assumptions could achieve parity with PEM electrolysis in 2040, but the technology is sensitive to variable OPEX and the price paid for “waste” heat. As soon as there is a market for this heat, it becomes a priced commodity. There are also technological advancements needed to extend the stack life and reduce variable OPEX.

BEIS projected hydrogen production costs suggest that as electrolytic technology matures and scales, capital costs reduce, and the electricity and operating costs become a larger factor. Based on these assumptions, the overall cost to the hydrogen customer will reduce and further improve their business case for using hydrogen (alongside carbon taxation and premium price for sustainable products). The Industrial Fuel Switching project will support these goals by creating a hydrogen ready off taker for low carbon hydrogen provided in the Teesside region after the demonstration phase is completed.

8.1.3.5. Comparison and Sensitivity

The alternative cost models indicate that although hydrogen is a more expensive fuel the costs of production will reduce significantly as technology matures. Electrolytic hydrogen has a significant opportunity to reduce in cost with improved technology and links to lower cost low carbon generation are developed. A challenge for electrolytic hydrogen is the lower load factor of renewable energy that offers the potential for significantly lower prices, while steam methane reforming is very dependent on the natural gas price, carbon price and supply chain. All low carbon hydrogen technologies will improve as they expand. The concept of electrolytic hydrogen for this trial supports a long-term price goal and in the short term will be supported by the hydrogen business model that will help to create an equivalent price to natural gas.

As shown above, there are significant cost implications for currently produced hydrogen due to volatile and expensive energy markets. Certainty in electricity price, CAPEX support and sold price support would all help to alleviate the current situation and help to develop a pipeline of electrolytic projects. **Figure 23** demonstrates what could be achieved through coupling Contract for Difference (CfD) AR4[27] projects with Hydrogen Business Model and Net Zero Hydrogen Fund support, reducing required hurdle rate. One key issue that cannot be alleviated through policy alone is increasing material and labour costs, which is driving up cost per kW to install the technology.

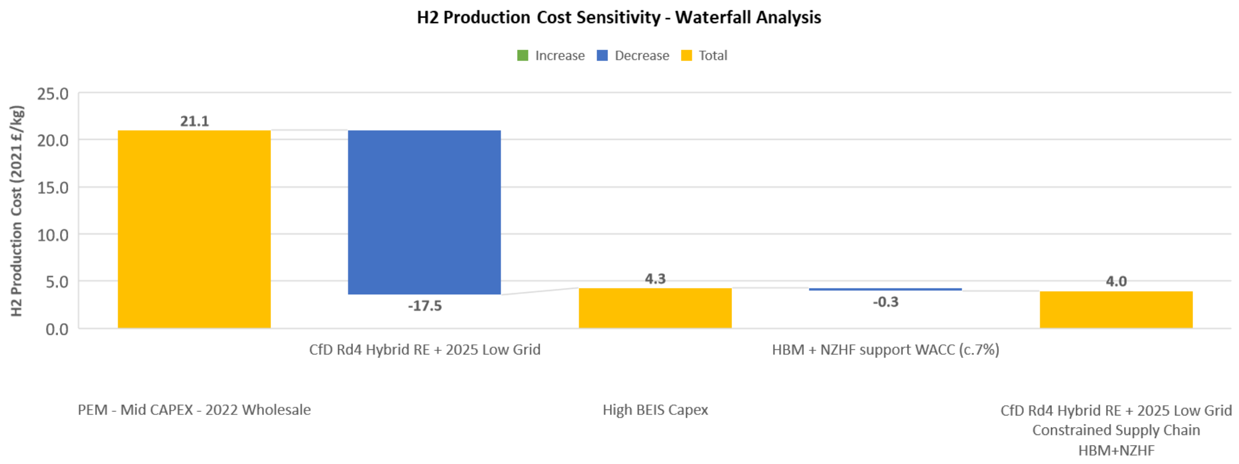

Figure 23 – Hydrogen Production LCOH Waterfall Analysis – Near Term Electrolysis (Excludes system costs and value creation)

[27] https://www.gov.uk/government/collections/contracts-for-difference-cfd-allocation-round-4

8.2. Revenue

8.2.1. Fuel Supply Chain Carbon Emissions Steel

A direct impact of reducing carbon emissions and switching from natural gas to blue or electrolytic hydrogen is the ability to reduce the carbon credits required and either increase revenue or reduce costs depending on the yearly allocation available. Industrial users can reduce costs for carbon credits for emissions through validated low carbon hydrogen. The following carbon contents are defined by the World Steel Association[28].

- 19.8tCO_2/t H_2 (Grey)
- 1.8tCO_2/t H_2 (Blue)
- 0tCO_2/t H_2 (Green))

Producing hydrogen from electrolysis of water has significant carbon benefits over other forms of production (**Figure *24***), as seen from the global warming potential from production, manufacturing and decommissioning of various conversion technologies (Wulf & Kaltschmitt, 2018). Electrolytic hydrogen can support system energy balancing and decarbonisation by producing more during peak energy production and less during constrained time periods. As can be seen the carbon emissions may not match the expectation from the World Steel Association.

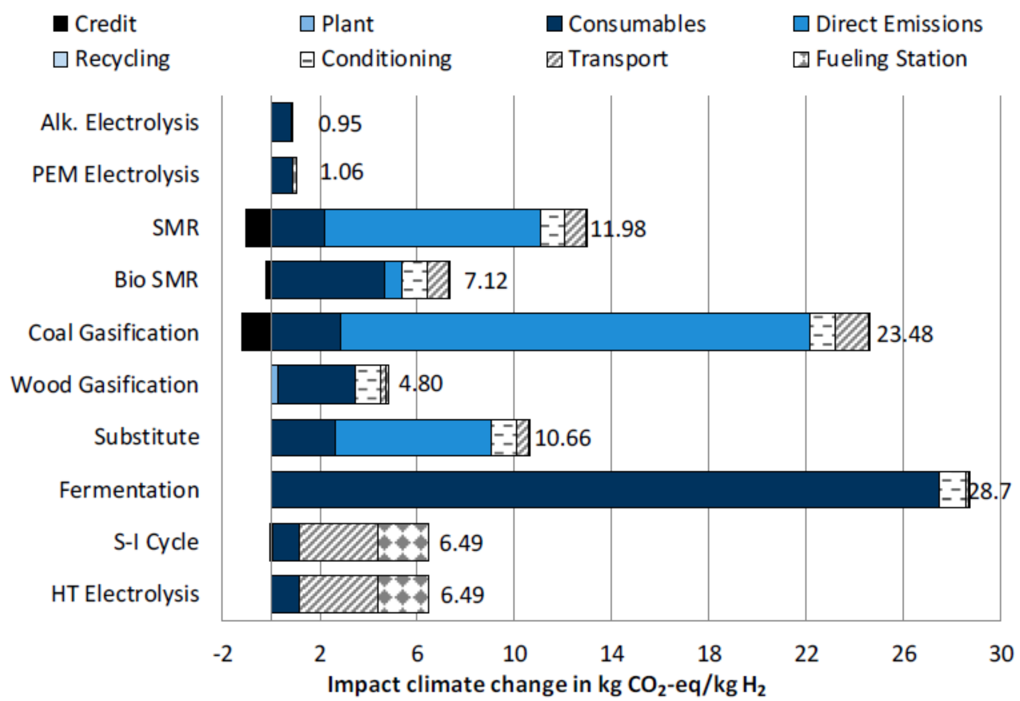

Figure 24 - Carbon Emissions from Different Hydrogen Production Routes

[28] W. S. Association, "World Steel Association," [Online]. Available: https://worldsteel.org/wp-content/uploads/CO2-data-collection-user-guide-version-10.pdf. [Accessed 06 09 2022].

8.2.2. Low Carbon Hydrogen Product Value

The value of hydrogen conversion for the steel industry has many factors beyond the price per unit as it offers a route to decarbonisation that can enable a green steel product for steel customers. As customers expect companies to report their carbon emissions it is important to demonstrate clear routes to reduce carbon for general customers and government procurement requirements. The requirement for low carbon products will increase with international competition and it is vital to maintain market share, increase revenues and reduce carbon credit costs through switching to lower carbon fuels such as hydrogen.

The producers of electrolytic hydrogen from low carbon electricity also have potential secondary value they can offer through resilience and flexibility. The local energy supply can reduce the risk to gas supplies from instability in specific regions and support the local economy. The ability to store hydrogen and release from storage depending on price for electricity generation or hydrogen consumption also offers opportunities to gain additional future revenues for electricity and hydrogen suppliers. At present the hydrogen supply needs to expand for these secondary benefits to become more prominent but the potential is there with large hydrogen storage forecast and the need to decarbonise electrical dispatch capacity currently met with gas peaking plants.

8.2.3. Low Carbon Hydrogen Funding

The UK government has launched the Net Zero Hydrogen fund to support capital and development expenditure on low carbon hydrogen projects in the UK. The Net Zero Hydrogen Fund is worth up to £240 million and includes four strands:

- Strand 1: DEVEX (development expenditure) for FEED studies and post FEED costs
- Strand 2: CAPEX (capital expenditure) for projects that do not require revenue support through the hydrogen business model
- Strand 3: CAPEX for non-CCUS enabled projects that also require revenue support through the hydrogen business model
- Strand 4: CAPEX for CCUS-enabled projects that require revenue support through the hydrogen business model

The hydrogen business model will be designed to support the difference for hydrogen costs between the cost of production (‘strike price’) and the market value of hydrogen (‘reference price). The intention of this scheme is to reduce the disincentive currently experienced for companies such as BSL when selecting between hydrogen and natural gas for combustion or other processes. A graphical demonstration of the scheme is shown below (***Figure 25***)

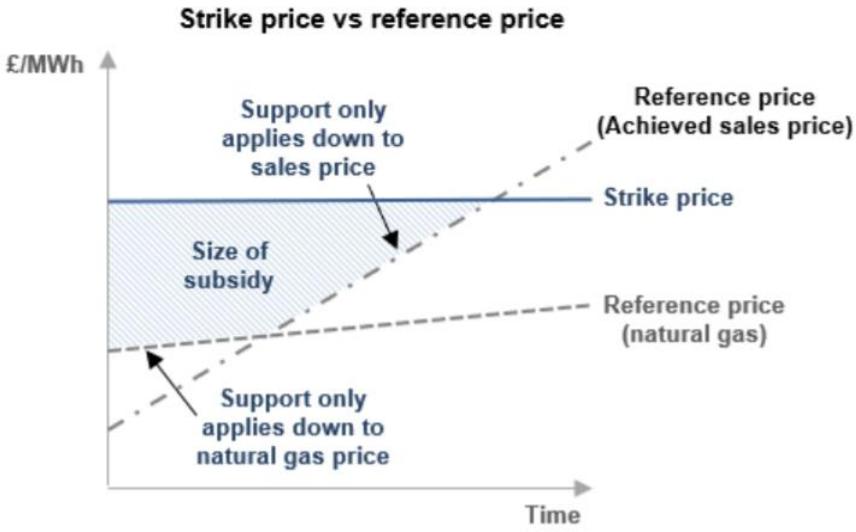

Figure 25 - Graph to Summarise the Funding Available from the Hydrogen Business Model

In principle the hydrogen business model scheme will provide effective support for low carbon hydrogen production and to provide a mechanism by which industrial users can switch from hydrogen to natural gas without exposing themselves to an increase in fuel costs. The scheme should operate well in most anticipated scenarios of future gas and electricity prices.

One potential issue with the scheme has arisen due to the record extreme high natural gas prices which have been experienced in the market this year. As illustrated above (***Figure 25***), the scheme is designed not to provide support below a floor price based on natural gas prices. This arrangement would work well in times of the "normal" gas prices but the extreme prices of the past year illustrate the potential for the natural gas price to exceed the hydrogen strike price in the scheme contract (**Figure *26***) – at which point the scheme would offer no subsidy to the hydrogen producer. While it might be argued that a subsidy is un-necessary at this point, as low carbon hydrogen could be acquired as or more cheaply than natural gas, in reality there is likely to be a price limit at which an industrial user would be unwilling to commit to purchase either low carbon hydrogen or natural gas in a long-term contract.

This creates a potential risk for the electrolytic hydrogen producer that they are unable to sell their hydrogen, particularly if they are also unable to fix all of their input electricity costs on a long-term basis, also bearing in mind that with electricity prices linked heavily to gas prices, periods of extreme high gas prices tend to correlate with very high electricity prices. One way to address this risk would be to index the hydrogen strike price in some way or to some extent to electricity or gas prices. It is proposed that "blue" hydrogen producers will benefit from indexation linked to natural gas prices – however it is currently proposed by BEIS that electrolytic hydrogen strike prices are only linked to a generalised consumer price index. Another approach might be to include some clauses in the contract to address this relatively unlikely but potentially difficult scenario.

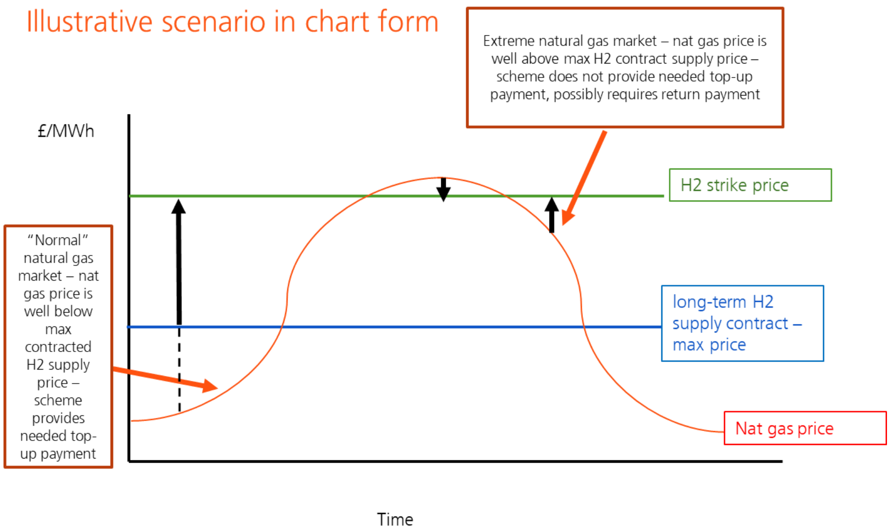

Figure 26 - Illustrative Scenario for Electrolytic Hydrogen Supply with the Hydrogen Business Model

8.3. Green Steel Market

8.3.1. UK Market Share

The UK structural section market in 2021 was 1.2m tonnes, of which BSL obtained a market share of 54%. Market size is expected to fall to 1m tonnes in 2022 and BSL forecasting its share to remain consistent at 56%. Forecasts for 2023 vary, with Eurofer suggesting 0.6% growth[29], whilst a recent CPA forecast suggested a 3.9% contraction[30] based on current economic conditions.

It is difficult to assess the size of the UK market for Green Steel. The majority of BSL's competition in the UK originates from European producers whose steel is from the EAF route who can offer the customer a low embodied carbon product. Anecdotally there is growing interest from clients and fabricators in low carbon products, and whist not yet wide-spread, buyers are increasingly specifying EAF produced steel or making sourcing decisions based on carbon intensity.

There are anecdotal reports that some end users are willing to pay a premium for a low embodied carbon buildings. However, this does not appear to be translating into higher prices for low embodied steel products at this time.

8.3.2. International Steel Trading and Green Market Share

Steel customers are increasingly requiring carbon reporting and performance from suppliers and this creates an incentive for low carbon steel and a risk to market share. Government procurement within the UK is already linked to decarbonisation plans for 2050 and this is key for strategic projects involving steel and cement. Industrial customers expect increased reporting on carbon intensity and

[29] https://www.eurofer.eu/assets/publications/economic-market-outlook/economic-and-steel-market-outlook-2022-2023-fourth-quarter/EUROFER_ECONOMIC_REPORT_Q4_2022-23_final.pdf
[30] https://www.constructionproducts.org.uk/news-media-events/news/2022/november/cpa-autumn-forecast-2022/]

may pay premiums for low carbon options. Company requirements for carbon reporting will increase demand for low carbon freight from road, rail, maritime and aviation industries and steel is a factor in carbon emissions in all these sectors. Furthermore, access to finance at competitive rates increasingly comes with stringent Environmental, Social and Governance (ESG) requirements.

The international nature of the steel market creates challenges and opportunities for decarbonisation. Effective international standards for carbon reporting are required as the switch to lower carbon options will increase costs for energy to steel producers with a challenging market.

8.4. Cost

8.4.1. Furnace Operational Costs Impact

The output of modelling described in ***Sections 5.2 and 5.3*** suggests that the substitution of natural gas with hydrogen should reduce operational costs through higher energy efficiency and yield (reduced scale) respectively. These shall be assessed during the demonstration phase, as shall the impact on maintenance costs. The maintenance costs on a hydrogen system, which is more complex than the current system should still be similar to the current gas supply system once a piped supply is in place after the completion of the trial.

During the trial maintenance costs will be higher with connection and disconnection of tube trailers and the additional pressure reduction station to maintain alongside the existing system. The requirement for resilient supply will require a hydrogen and natural gas system to be maintained. In the long-term capital plans a one hundred percent hydrogen furnace should have similar operating costs as long as lifetimes of components are similar which will be validated during the demonstration.

Maintenance effects on refractories and the recuperator and waste gas system, whether positive or negative, will also be evaluated during the trial.

8.4.2. Hydrogen Operational Cost

The commercial challenge for low carbon hydrogen is that the cost per unit of energy is currently higher than natural gas, given the most common production route is from natural gas without carbon capture. The role of this project is to consider a suitable business model for low carbon hydrogen supply which can support decarbonisation of the hot rolling process for the steel industry. There is a clear intention to decarbonise the steel industry in the UK and this project will assess the economic factors as well as technical and operational.

The cost of hydrogen production relates to ongoing operational costs, capital costs and development costs needed for scaling low carbon technologies. Government funding for the Net Zero Hydrogen Fund and Hydrogen Business Model will support projects to produce low carbon hydrogen. The cost of hydrogen is therefore a combination of the cost of supply and the subsidy support provided through the hydrogen business model.

8.4.3. Electrolytic Hydrogen Capital Cost

The investment cost for hydrogen is projected to reduce with time and scale of production. The Industrial Fuel Switching project is designed to prove the concept is feasible and pave the way for hydrogen uptake within hard to abate industries. The large amount of heat and chemical energy required in industry offer a great opportunity for rapid decarbonisation, but technologies need to be proven to ensure operational, technical, quality and safety requirements are met for the consumer of hydrogen. Forecast capital costs are expected to reduce for electrolytic hydrogen (**Figure *27***) as the technology matures and scale increases.

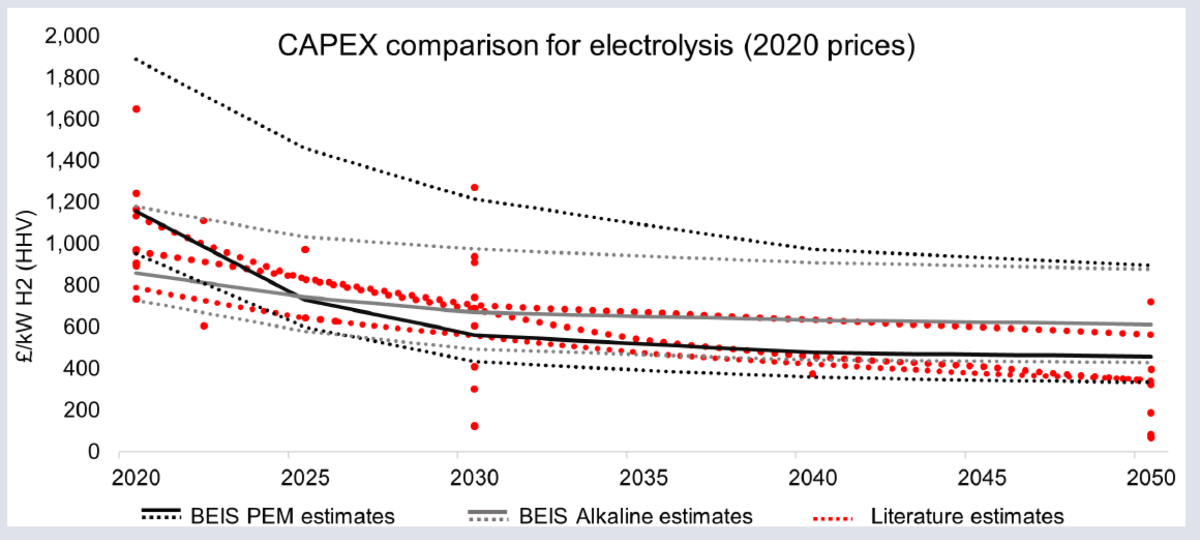

Figure 27 - Capex Forecast for Electrolysis of Hydrogen[31]

8.4.4. Capital Cost of Furnace Modifications

The technical requirements associated with upgrading the furnace to undertake the Phase 2 demonstrator trial are described in more detail later in this report (***Section 9.5***). The budget price for installation is £7.51million.

8.5. Wider Supply Chain Impact: Cost and Emissions

8.5.1. Cost impact

The supply of hydrogen to the steel industry offers great opportunities to increase the scale of hydrogen production and support the development of low carbon clusters. A key requirement of a hydrogen production project is off takers with hydrogen demand locally. This project has shown how TBM would support hydrogen production in the region and reduce the cost by enabling larger hydrogen facilities to be built to meet that demand. Converting two zones is equivalent to ~10 MW of hydrogen, but converting the full furnace is ~50 MW of demand which would increase the scale of electrolytic hydrogen production by 5 with an associated reduction in cost per unit.

8.5.2. Emissions

Developing an increased hydrogen demand will support the reduction of emissions in the production of hydrogen by supporting the business case for deploying electrolytic and "blue hydrogen" projects that can produce the scale needed in this industry. The transition role of grey hydrogen will no longer be required once the technology is validated and piped hydrogen supply solution from low carbon sources can demonstrate their business case. This will enable a significant reduction in

[31] [Online]. Available: https://tradingeconomics.com/commodity/uk-natural-gas. [Accessed 09 11 2022].

carbon emissions upstream in the hydrogen supply chain and ensure an effective transition to net zero. The carbon credit costs for industrial users will also create an incentive for low carbon hydrogen so that carbon emission trading can validate the lower requirement for these credits for industrial users.

8.5.3. Resilience of Supply

The cost of lost production to industries such as steel, cement and glass is high and therefore hydrogen production must be reliable and ensure continuity of supply. Hydrogen production from grid connected electrolysis and steam methane reforming with carbon capture can both theoretically operate at a load factor of 95% in a "baseload" configuration[32] . Hydrogen storage capacity can be included with either solution to prevent lost production during maintenance.

The production of hydrogen with local renewable energy provides a sustainable long-term solution for clusters of industrial energy demand. The economic value to the local region will be significant through supporting a wider hydrogen economy through fuel switching and increasing low-carbon electricity demand. Developing a solution to provide hydrogen to multiple end users will ensure a cost-effective installation and operating model suited to maintain the economic benefits of local industry.

8.6. Business Model Assessment

The long-term business model for industrial fuel switching with low carbon hydrogen production will offer greater cost savings for an integrated hydrogen supply and revenue through increased scale and technical innovation. The conversion of a reheating furnace to 100% hydrogen would increase the scale of production for hydrogen to 50MW and reduce the cost of hydrogen per unit. This could be extended further by combination with other carbon intensive processes for iron and steel making process on integrated sites in the UK and internationally. Innovation in hydrogen production technologies would also allow a reduction in operating costs and electricity demand.

Hydrogen from electrolysis offers secondary benefits to a scaled solution within the steel industry through market optimisation and heat recovery. SOEC is a technology that can incorporate waste heat to increase efficiency and is well matched to the steel industry. The ability to optimise production based on market pricing and storage capacity could develop further with a wide range of end users with varying demand alongside steel production. This would contribute to a lower overall hydrogen cost to consumers and is considered by the government in a "curtailed electricity scenario" when generation exceeds supply[20].

8.7. CO_2 Life Cycle Analysis Contribution

For reheating product for rolling at TBM, the average thermal energy consumption is of the order of 1.8 GJ/tonne, which equates to 45.6m^3 of natural gas usage. Each cubic meter of natural gas burnt is assumed to release 2.02kg of CO_2 at the point of combustion (UK Gov GHG Conversion Factors 2022) however, there is additional assumed CO_2 release based on well to tank energy usage equivalent to a further 0.34kg CO_2/m^3 of gas. Thus for 1.8GJ of combustion energy there is an assumed release of 107.6kg CO_2 for the steel reheating process within the TBM furnace. For 500,000t of annual production this equates to 54,000t of CO_2 emission.

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[32] E. a. I. S. Department for Business, "Hydrogen Production Costs 2021," [Online]. Available: https://www.gov.uk/government/publications/hydrogen-production-costs-2021. [Accessed 2022 08 05].

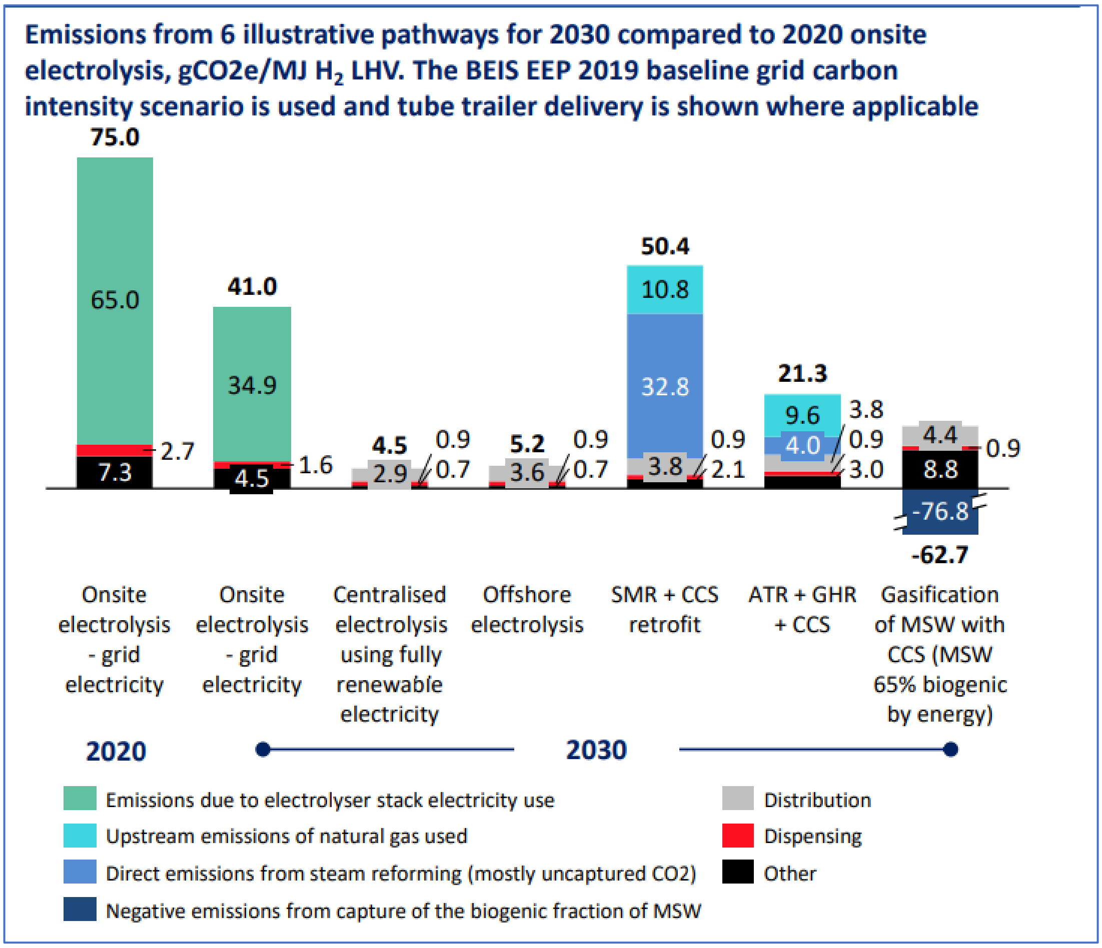

Figure 28 - Well to Tank CO_2 emission levels for differing future Hydrogen production technologies. (Element Energy, Zemo Partnership Accelerating Transport to Zero Emission, August 2021).

Although the burning of Hydrogen to release thermal energy can be considered a zero point of use emission process. This does not take into account the energy used in the Well to Tank production process. The Element Energy, Zemo Partnership project report from 2021 examined a number of differing scenarios for Hydrogen production. From this work 2 of the scenarios have been used to demonstrate potential CO_2 reduction at TBM by hydrogen fuel switching.

- The 1st scenario is using grid electricity for on-site electrolysis with the assumed 2030 grid renewable proportion, this assumes each MJ of hydrogen consumed is responsible for 41.0kg of CO_2 emission.
- The 2nd scenario assumes 100% renewable electricity is used for Hydrogen production in which case the CO_2 emission is very much reduced to 4.5kg/MJ.

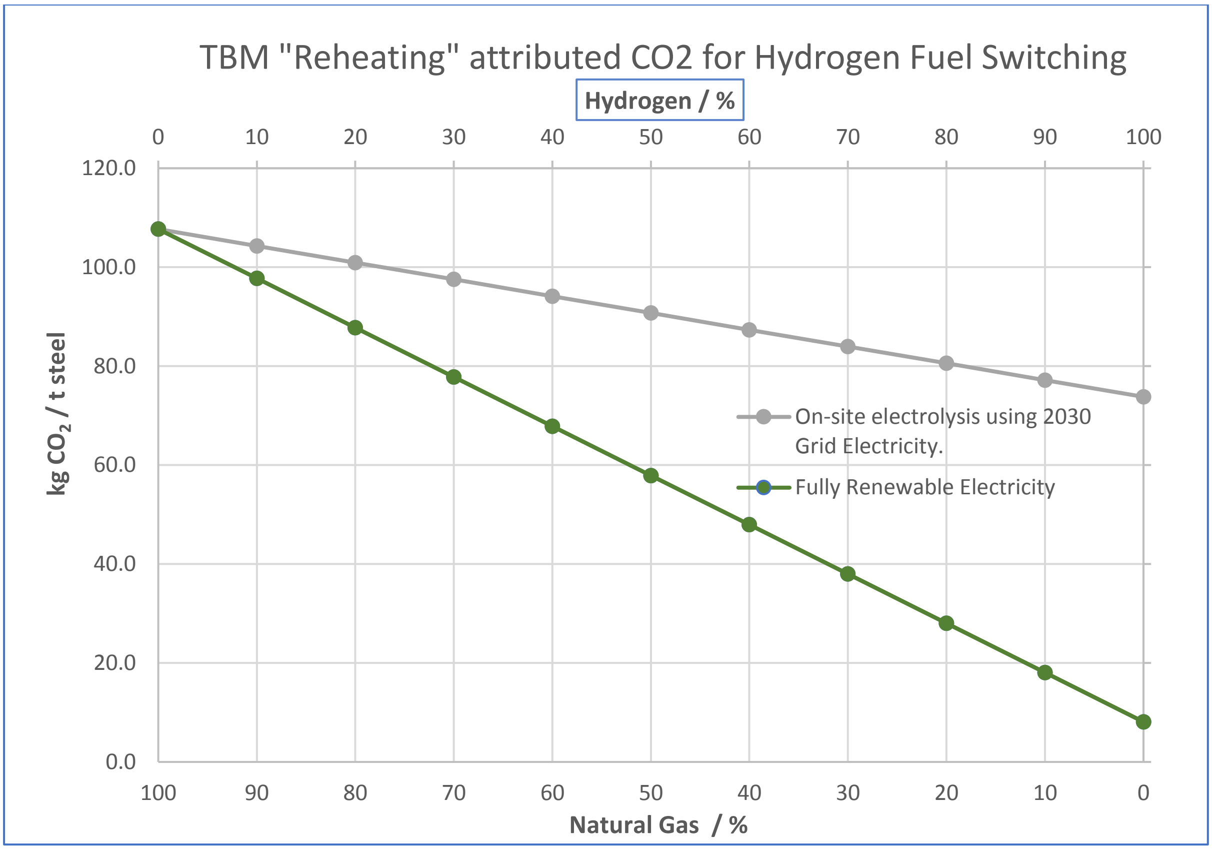

Figure 29 - Reheating fuel related CO_2 emission for natural gas and effects of switching from natural gas to hydrogen produced via different scenario electrolysis routes.

Assuming like for like energy utilisation within the reheating furnace switching to 100% hydrogen electrolysed using grid electricity can reduce CO_2 emissions by 31.5%, reducing overall emissions by 17kt. In the scenario where the furnace is fully converted to hydrogen fuel and hydrogen is generated by electrolysis using only green electricity, the emitted CO_2 drops to 8.1kg per tonne of reheated steel. This scenario provides for a CO_2 emissions reduction of over 92%, saving 50kt of emitted CO_2.

These numbers are based on like for like energy utilisation. However, the modelling work for UCL indicates that hydrogen provides a more efficient reheating process, with less air being heated and taking energy from the furnace as it is released through the chimney. The predicted efficiency gains could reduce the required MJ of thermal energy requirement by as much as 20 to 30%. This potential improvement in efficiency provides for further CO_2 reduction potential, with significant benefits in the early-stage development when renewable electricity produced hydrogen may suffer restricted availability.

8.8. Conclusions to Long Term Hydrogen Business Case

8.8.1. Economic Assessment

The cost of converting the furnace to be hydrogen ready is significant but the larger cost of ongoing price of fuel is more important in the long run for the cost-effective operation of the furnace at TBM. The long-term forecasts for hydrogen supply costs indicate a price of £60-130-60 per MWh_{HHV} of electrolytic hydrogen from renewable energy + grid, while natural gas is currently selling at £3 and reached peaks of £6.40 a therm[33] (£100-£200 per MWh) in 2022 and would incur an additional carbon tax cost of c£20/MWh at £100/tCO_2. At present electricity prices are strongly linked to natural gas, but low carbon generation offers a great opportunity to reduce costs.

8.8.2. Operational and Technical

The operational performance with hydrogen should be similar to that with natural gas but this needs to be fully validated with a demonstration project. The requirement for constant hydrogen supply can be met through low carbon generation of electrolytic hydrogen or steam methane reforming with carbon capture technology. The demonstration trial will validate performance on a smaller scale of demand. A one hundred percent conversion to hydrogen would fundamentally change the operating parameters of the furnace and it may require a new furnace design solution. A key factor that would need to be addressed for full conversion is carbon content and resilience of supply as electricity for electrolytic hydrogen from renewable sources currently has a low load factor and will require additional input from grid electricity or low carbon nuclear generation to meet 24/7 operational requirements at BSL.

8.8.3. Scaling Potential

The scaling potential for the technology can be achieved by incorporating the technology into capital plans for hot-rolling furnaces once it has been validated at scale through trials. The option for burners which can burn either hydrogen or natural gas also offers a method to de-risk capital investment if hydrogen supply was constrained in future or prices were not competitive with natural gas, though this would introduce additional operational cost due to carbon emission exposure. The scale of natural gas demand from the steel industry offers a large potential for scaling hydrogen across the UK and beyond and will support the business model for increasing supply through offering a reliable, consistent demand for hydrogen all year. As the technology scales the cost of hydrogen and the conversion costs per facility will reduce to improve the business case for both the supply and demand for low carbon hydrogen in the steel industry.

[33] https://tradingeconomics.com/commodity/uk-natural-gas. [Accessed 09 11 2022].

9. Demonstrator Design; Phase 2 Delivery Plan (WP7)

9.1. Introduction

The aim of this chapter of the report is to present the technological requirements of the equipment which will be required to convert a section of the current TBM furnace from natural gas to hydrogen gas as its fuel supply it will then go on to describe the technical requirements of the equipment and the drivers which led to the proposed technological solutions laid out here.

The chapter will go on to describe fuel control strategy and the proposed modifications required to the existing systems; the fuel supply requirements such as flows and pressures for hydrogen.

Funding requirements for design, equipment supply and the likely supply chain partners, as well as risk assessments for the project will also be discussed.

9.2. Funding Requirements

The full estimated gross cost associated with demonstrator programme, including capital, labour and material costs, is estimated at £7.21million. It should be noted that this value excludes any assessment of post-demonstrator residual values of equipment or materials.

9.3. Project Partners

The Supply Chain Partner for this project has been identified as EDF. EDF have made a major contribution to this report and have worked together with BSL to identify the way forward for a smooth implementation of the hydrogen supply for the Phase 2 design.

Theoretical and analytical input has been provided by the technical partners MPI and UCL for this report, using theoretical modelling techniques. Support will be ongoing with measurement, data analysis and further modelling during the demonstrator phase to validate current assumptions and to further understand process product and equipment impacts.

For technical support to the implementation of the project several suppliers were approached; however, DCC an Italy based supplier to the steel industry, had the most significant references for trials with hydrogen burners and the implementation of low NO_x burners. With their breadth of experience with steel rolling mill reheat furnaces, they were by far the most qualified company to assist with implementation of the demonstrator phase.

Additional resource and expertise may be procured to assist in specialist areas, specifically ATEX and DSEAR compliance studies.

9.4. Technical Drivers for Design of Trial

The reason for undertaking this project is to move closer to the aim of completely displacing the carbon-based fossil fuel natural gas as the fuel supply for the reheating of steel slabs and blooms at TBM with that of hydrogen. This project will replace the current natural gas burners on Zones 5 and 6 with dual fuel natural gas and hydrogen burners and will include all the necessary pipework and burner changes and any necessary control system upgrades and replacements. The reasons for selecting zones 5 and 6 for this demonstration trial and the aims of the demonstrator trial are discussed in more detail within ***Section 4.3***

Upon commissioning of the upgrade of the two furnace zones, data can be collected (***Section 4.5***) which will inform the design requirements for a complete hydrogen fired furnace, whether by upgrading the existing furnace or by installation of a replacement furnace.

9.4.1. Technical Differences between Natural and Hydrogen Firing

The lower energy per unit volume of hydrogen means that approximately 3 times the volume of hydrogen is required when compared to methane to get the same amount of energy (***See Paragraph 4.4.3***). As a result, therefore, either an increase in pressure of the fuel supply or an increase in the volumetric flow of hydrogen will be required.

The molecular size of a hydrogen molecule is significantly less than that of a methane molecule, therefore leaks are much more likely, requiring much greater care and attention to seals, gaskets and valves.

The flame speed of hydrogen is significantly higher than that of methane (approx. 250 cm/sec for hydrogen as opposed to 35 cm/sec for methane) making burner design crucial to ensure heating across the entire width of the furnace.

Finally, the flame temperature of hydrogen is higher than that of methane (2,200°C as opposed to 1,970°C). This increase in flame temperature will result in higher thermal NO_x emissions for hydrogen than for methane. This could result in the non-CO_2 emissions from hydrogen becoming unacceptable, without other measures such as innovative burner design, or even a high level of oxygen enrichment of the combustion air.

9.4.2. Implications of Hydrogen Fuel

For the reasons outlined above, adherence to ATEX and DSEAR regulations will be central to the design process for the equipment and control philosophy on this project. The detailed engineering design will include an appraisal of the implications of using hydrogen on the existing furnace and how this can be achieved within the regulations. Upgrading of some of the current electrical systems, not associated with the hydrogen supply, may be deemed necessary after the study has taken place. This topic is covered in more detail elsewhere within this report (***Section 7.2***).

9.4.3. Hydrogen Level in Fuel

The aim of the Phase 2 demonstrator trial is to replace natural gas with 100% hydrogen firing. It should however be noted that mixing hydrogen with natural gas can give some benefits on CO_2 reduction with fewer technical issues than pure hydrogen; however, the benefits are not linear. Theory suggests that with a 50% mix of hydrogen and natural gas, then the levels of CO_2 are still 80% of those of pure natural gas.

The burner design and control system, which is envisaged, has the capability of burning a mix of natural gas and hydrogen in any percentage from zero to 100%; however, the Phase 2 demonstrator trial aims to use 100% hydrogen and will only consider stepping back from this if the technological challenges become too great. The technological challenges could include: a reliable hydrogen supply, excessive NO_x production or issues with flame profile/temperature which have a detrimental effect on product quality.

9.4.4. Hydrogen Supply

The requirements for hydrogen have being discussed in detail with the partner company EDF. The discussions have included the handover of data by BSL to EDF of historic fuel usage on the furnace, by zone, permitting the total amount of energy currently consumed to be used as a guide to the ongoing hydrogen requirements for zones 5 and 6.

As described previously, the hydrogen supplied by EDF for the demonstrator trial is likely not to be guaranteed or consistent, so the requirement to have flexibility to burn either hydrogen or natural gas is essential to guarantee continuity of production output for BSL.

Pressures at which the hydrogen will be required to be delivered to the furnace will be around 600mbar and the design is aimed to meet a peak demand of 4,500 Nm^3/hr although average usage is estimated to be around 33GJ/hr (**Table *1***) which is the equivalent of 2,800 Nm^3/hr of hydrogen.

Details of EDF's plans to deliver hydrogen to the furnace are discussed in more detail in ***Chapter 6***.

9.5. Scope of Supply for Demonstrator

The preliminary design and scope of supply has been defined with DCC, who have proposed burner designs as well as P&ID for the project.

9.5.1. Process Hardware

Hydrogen will be supplied by EDF to the site boundary at a higher pressure than will be required at the burners. A pressure reduction station will be required at the reheat furnace before hydrogen is piped to zones 5 and 6 through new dedicated hydrogen pipework. Local to the zones, before branching to individual burners hydrogen will be mixed with natural gas in the required proportions. The aim is to be 100% hydrogen fired; however, supply or possibly technical issues may result in firing only on natural gas or a diluted mix of hydrogen to the furnace. New pipework, valves and controllers will be necessary for all pipework which will be carrying hydrogen or a hydrogen/natural gas mix.

Replacement burners will be installed, replacing the current natural gas burners. The burner design will have been tested and their capability proven before installation. (***See Section 4.3***). The design of burners will use 'flameless technology' (***See Paragraph 4.4.5***) and the burner control system will use 'pulse firing' technology which will use all the burners on full output unless a reduction in zone temperature is called for. Then it will switch one or more burners off for periods of time, cycling the duty burners systematically. This way for example, if there are 6 burners in the zone and 67% flow is required, 4 burners will be on and 2 will be off. This way the burners are either operating at full flow at their most efficient in terms of output and emissions, or off completely.

Replacement of burners and much, if not all of the pipework installation, will have to be undertaken during a planned furnace shutdown. Typically, TBM stops production for a 2-week period twice per year (usually in September and December) so that major maintenance tasks can be undertaken safely. All the on-furnace installations will be carefully planned and undertaken during this period. Burner installation and refractory repairs require access to the furnace interior which can only be undertaken once the furnace has been cooled and these must be completed early, so the refractories have sufficient time to dry out before the furnace is re-ignited. This will significantly reduce the available time for this work.

9.5.2. Control Systems

The current furnace is fitted with valves and a control system which regulates the fuel and combustion air supply to each furnace zone independently. The required zone temperatures are controlled by PID controllers for each zone. The zone temperature set point is provided by a Level 2 supervisory control system which models the temperature of each bloom or slab within the furnace and calculates the appropriate furnace temperature required to meet the production requirements.

The existing Level 2 set point control will be unchanged; however, new controllers and valve systems will be required for zones 5 and 6, not only to regulate the control of fuel to the burners, but also to regulate the mix of hydrogen and natural gas.

The system is designed to operate seamlessly with the current control system.

9.6. Project Timeline

The timescale to undertake the project from commencement is 11 months from placement of orders, the critical path is the supply of equipment by the main OEM and aligning the activities with a planned shutdown of the rolling mill.

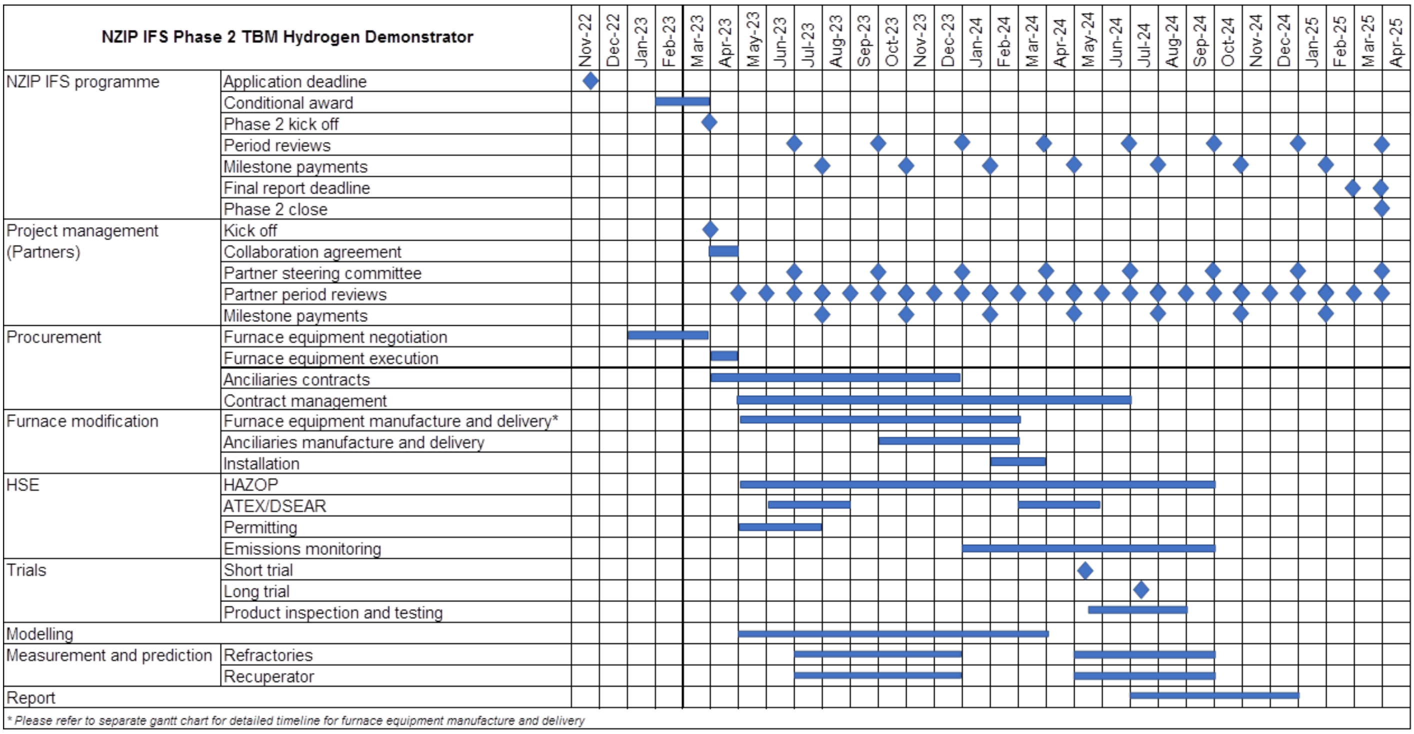

Table 30 - Project Time Schedule

9.7. Risk Assessment

A full risk assessment of the project will form part of the detailed design study as part of the demonstrator. A preliminary risk assessment undertaken has been prepared and is shown in Appendix 2

10. Dissemination Plan (WP8)

Fuel switching in the form outlined in this report will predominantly be of interest to the energy intensive industries. BSL and MPI, through their involvement with UK Steel, SUSTAIN and the TFI Network+, are ideally placed to carry out this dissemination. BSL and MPI sit on the UK Steel R&D Steering Committee which encompasses all the UK steel manufacturers. SUSTAIN offers a wider audience for dissemination, representing not just all UK steel manufacturers, through a research collaboration, but also supply chain companies and OEM equipment suppliers for the steel industry. Beyond steel, the TFI Network+ allows the dissemination of the fuel switching to the other energy intensive industries, including glass, ceramics, metals, paper, cement, and bulk chemicals, which account for 10% of the UK's total CO_2 emissions.

As a member of Zero Carbon Humber, BSL also has a close relationship with the East Coast Cluster, and through that forum all of the UK clusters, allowing swift dissemination through both the cluster Communication Committee, and the Cluster Plans. BSL is a member of the Steering Committee of Zero Carbon Humber and the Humber Industrial Cluster Plan.

The project partners plan to have an end of project dissemination day for BEIS at a Teesside location (TBM or MPI) where all partners will attend. In addition to the above, BSL, EDF, MPI, and UCL all have well developed and respected Communication Teams that will offer excellent dissemination through trade journals, local and national press, and a variety of social media options. Integrated communications strategies will ensure information and key messages are disseminated to targeted audiences delivering relevant content on the appropriate channels in a timely fashion. Channels include, but are not limited to, face to face meetings, online meetings/webinars (Webex and Teams), events, digital publications, letters and emails. These are also supported through articles and documents published on our websites and supporting posts and messaging on our 3 main social media platforms – LinkedIn, Twitter and Facebook.

11. Discussion and Conclusions

Decarbonising the steel industry is a significant economic and technical challenge. This feasibility study has investigated a first step through the use of hydrogen, manufactured from green sources, as a replacement for natural gas in a reheat furnace, specifically the reheat furnace at BSL's TBM. Collaborating on the Study were BSL as a steel manufacturer, EDF as a developer of hydrogen solutions, and the research capabilities of both the MPI and UCL. Additionally, DCC has brought their experience with reheat furnace design as well as recent innovations with the application of Hydrogen burners.

Modelling work has found that hydrogen switching could increase overall furnace efficiencies from 50% to 61%, whilst also increasing yield by reducing losses to scale formation significantly.

The product and emissions risks associated with burning hydrogen are hydrogen pick up and NO_x formation respectively, these have been examined during this feasibility study. In both cases the work undertaken suggests minimal risk, though burner design will be key to managing NO_x within acceptable levels, and the design and function of these burners will be crucial to the success of the trial.

These and other technical challenges will need to be reviewed under a test programme, and the study therefore proposes the installation of hydrogen burners in a section of TBM's furnace. The demonstrator will provide invaluable data in assisting BSL and the broader UK steel industry meet the challenge of decarbonisation. As an energy intensive industry with hard to abate emissions, the steel industry offers the potential for large CO_2 emission savings through fuel switching from natural gas to hydrogen.

A full conversion of TBM's furnace to hydrogen could reduce its direct CO_2 emissions by 94% or 71,000 tonnes based on 2021 emissions data. However, the choice hydrogen production route will be key to delivering reduction the full supply chain emissions with hydrogen produced from an electrolyser powered by renewable electricity delivering some of the lowest Scope 2 and 3 emissions numbers.

The study has found potential obstacles for hydrogen uptake in potential imbalances in supply and demand, and in the cost of hydrogen. Implementation of support measures such as the Hydrogen Business Model will be key to delivering hydrogen at a price that competes with other, existing, fuels. Until a mature and reliable supply of hydrogen at volume is secured the Technology Readiness Level development associated with any subsequent demonstrator would be limited to a move from TRL 5 to TRL 7.

Alternative heating strategies were considered, but the physical constraints and levels of technical development made the burning of hydrogen the only practical solution for this application.

This feasibility study is intended to provide the reader with an understanding of the technical challenges and provide an insight into the planning and research undertaken by the collaborating parties to develop a workable plan for delivery. The aims also include the development of a reliable cost estimate and engineering timescale to implement the demonstrator phase of the hydrogen conversion of the TBM reheat furnace. The full estimated gross cost associated with demonstrator programme, including capital, labour and material costs, is estimated at £7.21million and the commissioning date is foreseen as April 2024.

12. Appendices

12.1. Appendix 1 – TBM HAZOP

12.2. Appendix 2 – Risk Register