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Working Paper

Ironing out the way for green steel financing a green hydrogen-based: Ironmaking plant in an emerging market

OIES Paper: CM, No. 10

Provided in Cooperation with:

The Oxford Institute for Energy Studies, Oxford

Suggested Citation: Muslemani, Hasan; Craen, Stephen; Butterworth, Paul; Duma, Daniel; Lambert, Martin (2024) : Ironing out the way for green steel financing a green hydrogen-based: Ironmaking plant in an emerging market, OIES Paper: CM, No. 10, ISBN 978-1-78467-257-7, The Oxford Institute for Energy Studies, Oxford

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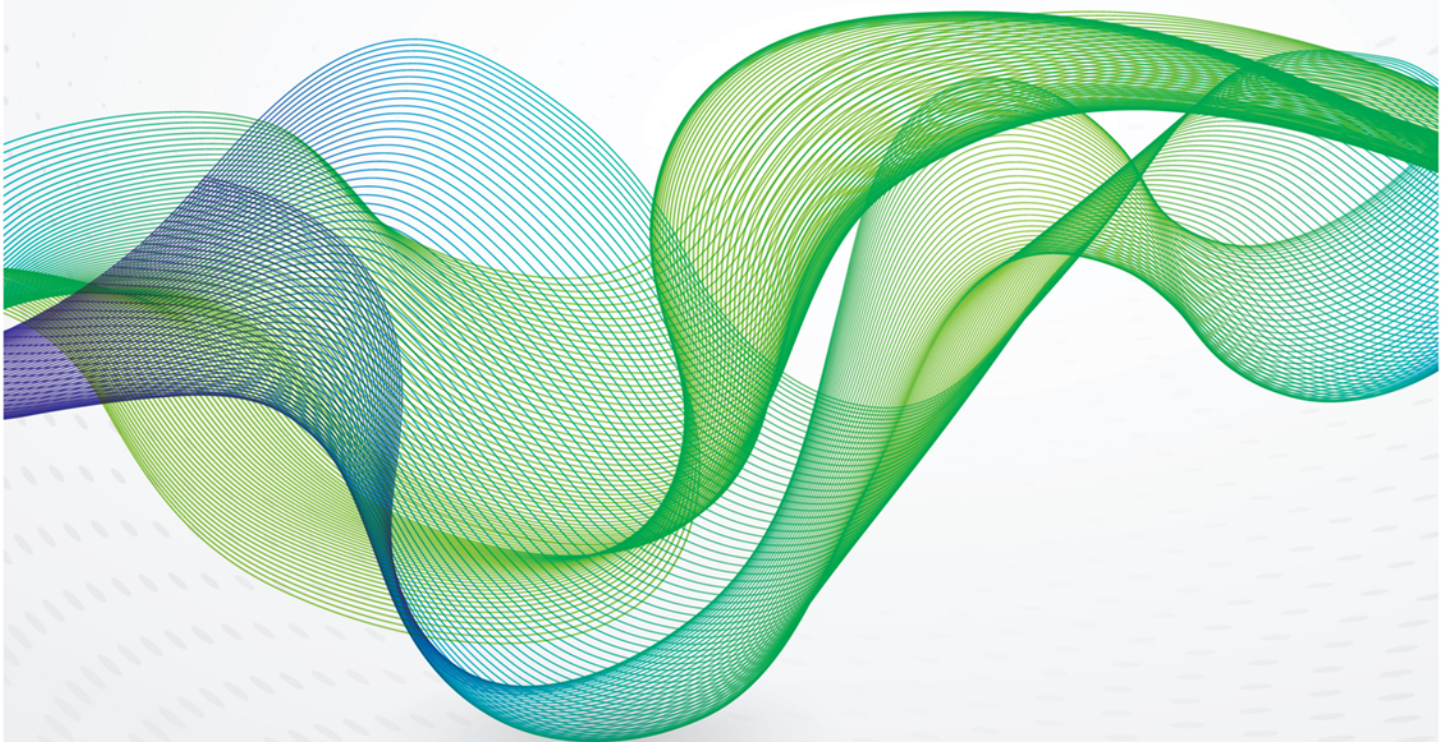
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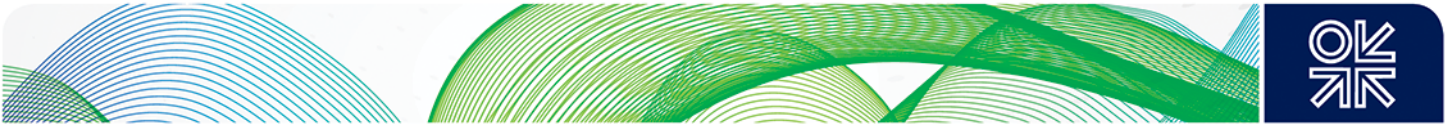
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November 2024

Ironing out the way for Green Steel

Financing a Green Hydrogen-based Ironmaking Plant in an Emerging Market





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ISBN 978-1-78467-257-7



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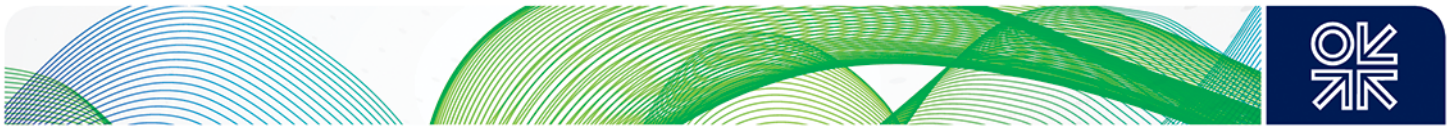


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Acknowledgements

The authors thank the Leadership Group for Industry Transition (LeadIt) and the Stockholm Environment Institute (SEI) for the opportunity to present preliminary findings of this research at workshops held at COP28 in Dubai and virtually, and similarly Stegra (formerly H2GreenSteel) for feedback on the technical analysis conducted in this study. The authors also appreciate Paulo Carvalho for his insights and review of the article.



Executive Summary

The iron/steel industry is one of the highest emitting sectors, contributing 7-9% of overall global emissions. As population and economic growth will demand more steel as a key building block of society, the need to decarbonize the sector is critical. To that extent, a range of breakthrough low-carbon technologies has emerged that can offer radical emission reductions, including carbon capture and storage and hydrogen-based solutions. Particularly, *green* hydrogen-based production has the potential to reduce the carbon footprint of steel to effectively zero.

Ironmaking is the most emissions-intensive stage in the overall steelmaking process, as it traditionally relies on coal/coke to reduce iron ore in blast furnaces. Substituting fossil reductants with green hydrogen to directly reduce iron (through the DRI method) can decarbonize ironmaking. As such, this study aims to design and evaluate the financial feasibility of an archetype green hydrogen-based ironmaking project in a developing country, for export of the green product into developed markets.¹

Technical and market challenges which may face the project are assessed and potential solutions suggested. Different project commercial structures and debt/equity requirements are also appraised. The study estimates that the project will incur capital costs in the range of 9 billion USD with levelized cost of delivered green hot briquetted iron (HBI) estimated at 690 USD/tonne – representing a premium of around 100% over the 'grey' alternative. This corresponds to levelized costs of green hydrogen production of 4.84 USD/kg and clean electricity of 45.5 USD/MWh.

Financing such an unprecedented, world-scale project would be a challenge but is not impossible. Key requirements include a robust commercial structure with long-term contracts that essentially fix the green premium for the product and lock in supply of the specialised iron ore required and support from the governments of both the host and offtaker's countries. Carbon pricing, along with protective trade measures such as carbon border adjustments, will be critical to ensure economic viability over the long run. Access to low-cost, long-term agency financing will also be key to the project's success while a suite of mechanisms also exists to leverage public support in the host and offtaker's countries.

Beyond the financial analysis itself, this work has wider industry implications. Historically, iron- and steelmaking plants have been geographically co-located, largely because blast furnaces produce hot metal and the ability to supply the hot metal directly to a basic oxygen furnace (BOF) or electric arc furnace (EAF) without having to cool it for transportation (then reheating it in another location) offers significantly greater energy efficiency. However, since the direct reduced ironmaking process reduces iron ore to HBI in a solid phase, this energy synergy becomes less important.

As there is no technical requirement to integrate iron- and steelmaking when using DRI/HBI, industry investors will seek to locate new plants in the lowest-cost locations. Thus, ironmaking plants are expected to be located in regions of lowest-cost renewable electricity (after full firming), and steel plants, whilst might also be co-located to utilise the low-cost power, can instead be located in end markets. This allows for the usage of existing EAF capacity and local expertise to make more specialised steels or to exploit end-customer proximity to better manage inventory and product quality, as well as commercial, technical, product development and relationship issues with those customers.

Further in the future, if/when the steel market is dominated by green steel products and green ironmaking becomes intrinsically profitable, it is likely that iron ore-producing countries which also have abundant renewable electricity resources will seek to capture the value added by building their own green ironmaking plants and exporting green HBI.

¹ Initially, a full, integrated steel plant was considered but was rejected on the grounds of cost, avoidance of stranded steel plants in developed countries and operational reasons.



1. Introduction

In responding to climate change, one of the most serious threats facing humankind today, recent measures have aimed to decarbonise different parts of society, in particular energy generation and industrial production. This has culminated in international climate agreements, such as the 2015 Paris Agreement, which set out ambitious global emission reduction targets while industries followed suit in taking climate action.

The steel sector is one such industry. Steelmaking is the second highest industrial emitting sector – only second to cement – contributing around 25% of industrial CO₂ emissions² and 7-9% of overall global emissions³. As an essential (and literal) building block of society, steel demand is expected to grow significantly in the coming decades⁴, owing to its direct relationship to population and economic growth. Yet, from an emissions standpoint and unless urgently addressed, the sector alone is on track to consume 50% of the total remaining carbon budget needed for a 1.5°C scenario by 2050.⁵ As such, the need to decarbonise steelmaking cannot be stressed enough.

A range of options have traditionally existed to reduce the carbon footprint of steel production, including fuel switching, energy efficiency improvements, reducing overall output and adopting less energy-intensive production routes.⁶ However, these measures fall short from achieving the radical emission reductions required, where the role of novel breakthrough low-carbon technologies becomes key. Broadly, these technologies can be categorised into: i) carbon-based, where CO₂ emissions are eliminated from the steelmaking process using carbon capture and storage (CCS) technology: this is especially the case where traditional blast furnaces are used to reduce iron ore using coke/coal, ii) hydrogen-based, where hydrogen (H₂) substitutes coal or natural gas to directly reduce iron ore (the direct reduced ironmaking method, or DRI), and iii) electron-based, where iron ore is reduced using electricity (electrolysis).⁷

Of these solutions, H₂-based steelmaking is widely considered as one of the most promising decarbonisation solutions, offering the potential to reduce the carbon footprint of production effectively to zero when hydrogen made using renewable energy ('green hydrogen') is used to reduce iron ore to 'green iron', which can then be charged into electric arc furnaces that too can be powered with clean electricity to produce 'green steel' (the H₂-DRI-EAF process). Indeed, according to the Green Steel Tracker⁸, H₂-based solutions underpin the majority of existing and announced green steel projects globally, with much lower penetration from CCS- and electrolysis-based steelmaking.

In essence, switching into H₂-based production also means that the ironmaking process no longer needs to be necessarily co-located with rich fossil fuel resources – as has historically been the case in China for instance. In a world where cleaner iron is produced using green hydrogen, access to abundant

² International Energy Agency (IEA) (2020). Iron and Steel Technology Roadmap. Towards More Sustainable Steelmaking.

³ World Steel Association (2020). Climate change and the production of iron and steel. <https://worldsteel.org/climate-action/climate-change-and-the-production-of-iron-and-steel/>

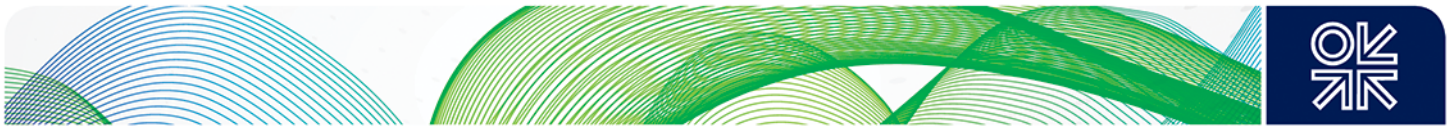
⁴ Global steel demand is expected to grow from 1.8 million tons in 2020 to around 2 million tons in 2030, according to analysis by Bronk & Company available at: https://brnk-company.com/wp-content/uploads/2023/01/BC_Newssupply_012_en.pdf

⁵ Rocky Mountains Institute (RMI) (2019). The Next Industrial Revolution. <https://rmi.org/insight/the-next-industrial-revolution/>

⁶ Quader, M. A., Ahmed, S., Ghazilla, R. A. R., Ahmed, S., & Dahari, M. (2015). A comprehensive review on energy efficient CO₂ breakthrough technologies for sustainable green iron and steel manufacturing. *Renewable and Sustainable Energy Reviews*, 50, 594-614.

⁷ Muslemanni, H. (2023). Stainless Green: Considerations for making green steel using CCS and H₂ solutions. Oxford Institute for Energy Studies, Paper CM03, Oxford, UK.

⁸ Leadership Group for Industry Transition (LeadIt) (2024). Green Steel Tracker. <https://www.industrytransition.org/green-steel-tracker/>



renewable energy and iron ore supplies become limiting factors. This opens up the possibility of producing green iron in regions where those resources co-exist, for its eventual use domestically and/or export into overseas markets in the form of hot-briquetted iron (HBI),⁹ where steel can then be produced.

However promising, unless finance to build and operate green ironmaking facilities can be accessed and markets for the green products are established, including clear market signals that demand for the premium green product exists and that customers are willing to pay a premium, green iron/steel projects may not materialise – regardless of choice of decarbonisation technology. Financing such a project is the central theme that this study aims to investigate.

In particular, this work has four objectives. First, an archetype green iron (DRI/HBI) export project is designed and presented, including justification of scale assumptions, technology adopted, project configuration and capital costs, to subsequently evaluate the levelized cost of green HBI delivered (Section 2). Second, we assess technical and market challenges which may face such a project and suggest potential solutions, including in relation to the supply of clean electricity and raw materials to market exposure and the possibility of absorbing the green premium (Section 3). Mechanisms to leverage public support in the host and importing countries are also highlighted (Section 4). Third, possible project commercial structures are assessed, including identifying key agreements which will be needed in place to make the project financeable (Section 5). Lastly, we discuss debt and equity requirements of the project, including objectives of the initial sponsors and the challenge of financing such a world-scale project, with the potential to secure public money (Sections 6-8).

2. The Archetype Project

2.1 Description

For illustrative purposes, an archetypal green iron export project (the “Archetype”) is considered. Key requirements for developing the project were that it should be:

- i. located in a developing country with world-class, low-cost renewable energy resources;
- ii. of world-scale capacity to offer best economies of scale and a globally competitive levelized cost;
- iii. based on ‘green’ hydrogen produced via electrolysis (as opposed to ‘blue’ hydrogen produced from natural gas with carbon capture and storage)¹⁰, and
- iv. to the extent possible, using proven technology with a track record of use at scale.

The project was developed to meet the above criteria while adopting cost and technical estimates provided by CRU.¹¹ As the Archetype is intended to be used for illustrative purposes only, it was modelled at a relatively high level albeit with sufficient detail to be able to draw conclusions relevant to financing. Following several iterations, the configuration of the archetype project, including the selected DRI plant, hydrogen plant, power supply and storage facilities is depicted in Figure 1, with technical details relevant to each component provided in Table 1.

⁹ HBI is a more stable and less reactive form of DRI, making it easy to transport, handle and store.

¹⁰ The Archetype considered only green hydrogen (vs blue) as it offers a much greater scope for emissions reduction. A recent study (Bennett, A., & Serrenho, A. C. (2024). A systematic comparison of the energy and emissions intensity of hydrogen production pathways in the United Kingdom. *International Journal of Hydrogen Energy*, 89, 364-374) estimates that, once upstream emissions are included, emissions from blue hydrogen production represent only a modest reduction compared to direct use of natural gas. Green hydrogen, on the other hand, offers much higher reductions and alignment with climate targets.

¹¹ For more information, refer to the Appendix or contact the authorship team.

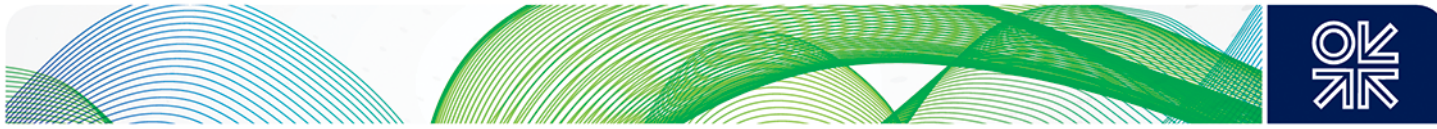


Figure 1: Illustration of the Archetype Project

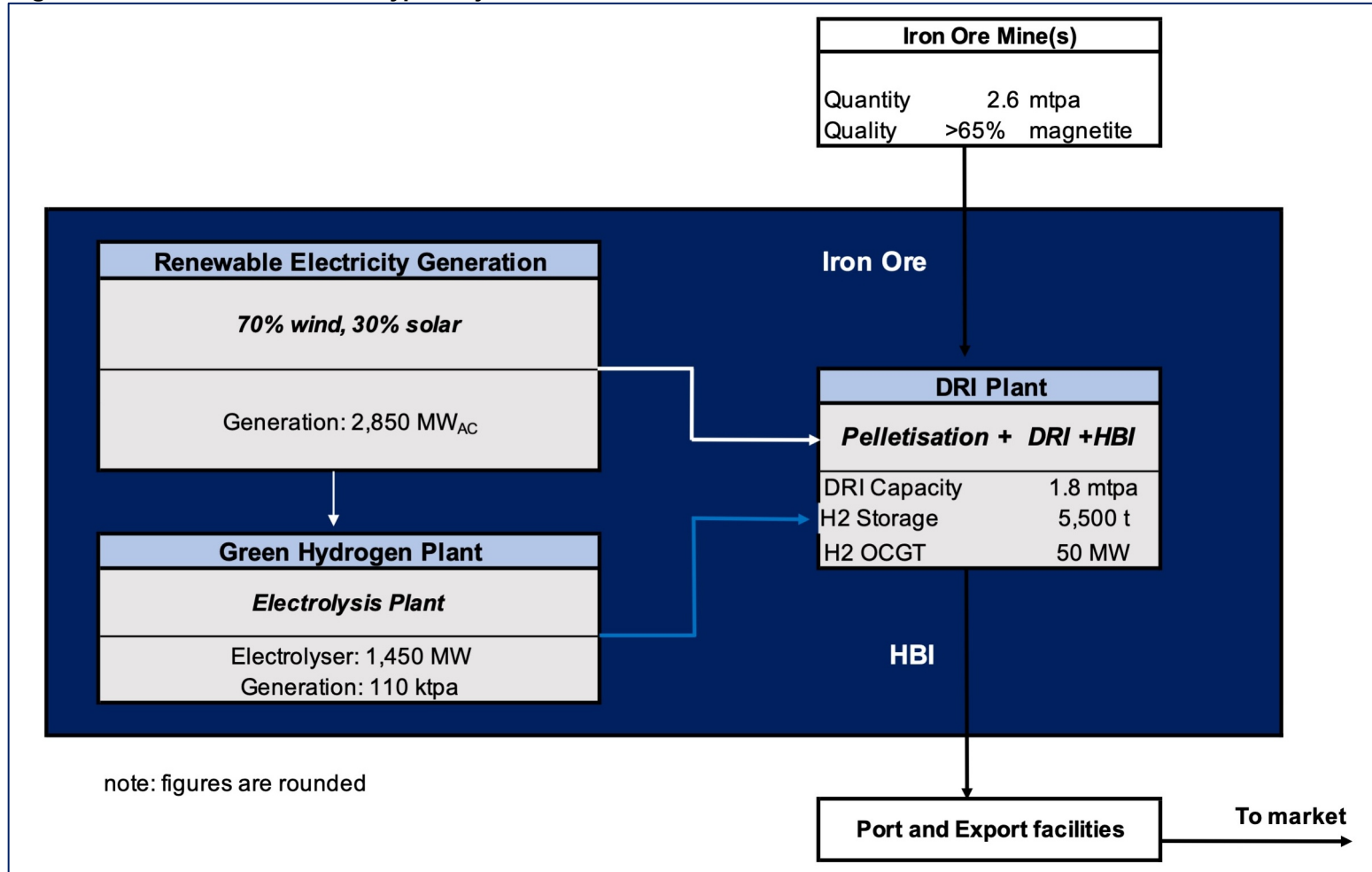
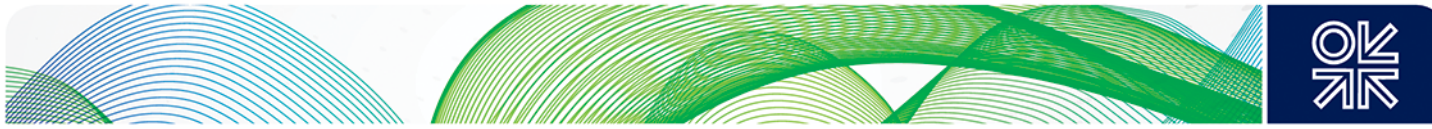




Table 1: Description of the different components of the Archetype Project

Component of the Archetype Project	Description	Notes
DRI plant	<p>A 1.8 mtpa DRI plant comprising:</p> <ul style="list-style-type: none"> - Pelletization plant, - DRI furnace, and - Hot briquetted iron (HBI) plant. 	<p>This is considered to be world-scale. Slightly larger Midrex DRI furnaces have been built and operated but 1.8 mtpa was chosen as it is believed to offer the necessary level of economies of scale.</p>
	<p>The DRI plant includes sufficient hydrogen storage for feedstock and fuel for power generation for up to 18 days operation. The total requirement, 5,500 tonnes, would be stored in above ground, steel storage tanks.</p>	<p>18 days storage was estimated to be the level of storage required to maintain continuous operation of the plant both as feedstock and fuel for power generation (albeit with some seasonal variation depending on the solar/wind resource).</p>
	<p>The DRI plant includes a 15 minute fast-start battery and an 50MW open cycle hydrogen-fired gas turbine to generate electricity for up to 18 days in periods when power is not available from the dedicated wind and solar farms.</p>	<p>Lined Rock Cavern (LRC) storage was considered, but rejected, given its limited track record to date. We understand that the HYBRIT project¹² plans to use LRC technology. If successful, we would expect future green steel projects to use it too, where salt caverns are not available, on grounds of cost.</p>
		<p>Hydrogen storage and a hydrogen-fired open-cycle gas turbine (OCGT) was chosen vs a LiO battery given that hydrogen storage is about 10% of the cost of electricity storage compared to a LiO battery on a MWh basis (based on CRU's unit cost estimates for hydrogen and LiO battery storage).</p>

¹² <https://www.hybritdevelopment.se/en/hybrit-a-unique-underground-fossil-free-hydrogen-gas-storage-facility-is-being-inaugurated-in-lulea/>



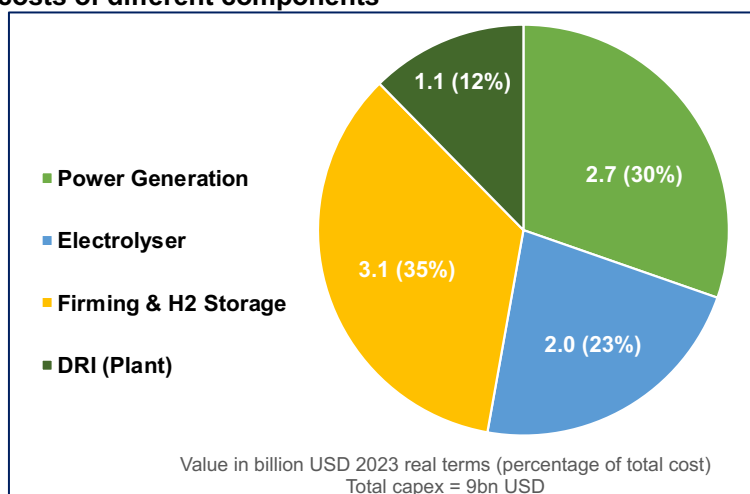
Hydrogen plant	A 1,450 MW electrolyser capable of producing the 110 ktpa green hydrogen required by the DRI plant.	<p>The hydrogen plant was sized to produce the requirements of the DRI plant while operating on an intermittent basis, following the generation of the solar and wind farms (assuming the electrolyser is fully flexible and can track renewable energy generation). Again, this is because the cost of storing hydrogen is much lower than electricity.</p> <p>A pressurised <i>alkaline</i> electrolyser was assumed on the grounds of technical readiness, cost, and ability to ramp up and down given the intermittent nature of the electricity supply.</p>
Wind and solar farms	A combination of wind and solar farms (in the ratio of 70% wind to 30% solar) with an aggregate capacity of 2,850 MW_{ac}	<p>The 70:30 ratio was estimated as a typical ratio to optimize the generation profile but would need to be optimized to the local resource conditions. Additional capacity was included to compensate for the inefficiency of making hydrogen to be used subsequently for power generation.</p>
Storage, loading and port facilities	Not part of the Archetype.	<p>The Archetype would also require facilities to import and store iron ore and other raw materials as well as to store and export HBI. These were not included as part of the Archetype which was assumed to be located at a port with such pre-existing facilities.</p>

2.2 Capital costs

The capital cost of the Archetype project was estimated at \$9 billion USD in 2023 real terms. Certain components of the project, especially the electrolyzers, wind turbines and solar panels, are expected to fall in cost by 2030 and this is reflected in the estimate.

It is worth noting that the DRI plant itself only represents 12% of the capital cost. The rest comprises: power generation (30%), hydrogen-making (23%) and firming the intermittent power generation with hydrogen storage and a modest hydrogen-fired OCGT (35%) (Figure 2). The latter makes up the largest component of overall capital costs. With capital costs of battery storage almost 10x as expensive as hydrogen storage¹³, strong emphasis was placed on minimizing storage, especially batteries, while seeking to ensure reliable, continuous operation of the DRI/HBI plant. It is evident that the inclusion of an EAF, in necessarily continuous operation, would substantially increase the need for storage of electricity in some form and hence the cost.

Figure 2: Capital costs of different components



2.3 Levelized costs

The Archetype's levelized cost of the electricity, hydrogen and total HBI, in RT 2023 were each calculated (see Appendix for more details):

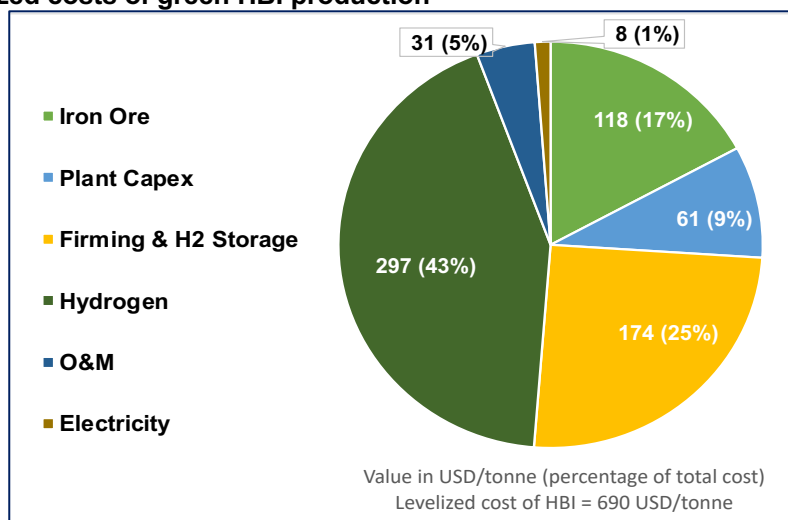
- Levelized cost of electricity (LCOE) excluding storage costs was estimated at \$45.5/MWh;
- Resulting levelized cost of green hydrogen at \$4.84/kg; and
- Levelized cost of green HBI, which includes all costs including electricity and hydrogen storage, was \$690/tonne.

The components of the levelized cost of HBI are shown in Figure 3. This clearly illustrates the relatively small component of the cost represented by the traditional DRI plant itself and the major role of the cost of producing green hydrogen from intermittent renewable sources.¹⁴

¹³ Based on CRU's unit cost estimates for hydrogen storage and LiO battery storage.

¹⁴ Note that the electricity cost shown here is only that required directly by the DRI plant – the bulk of the power cost is subsumed in the cost of the hydrogen.

Figure 3: Levelized costs of green HBI production



Note: electricity cost is that required to run the plant, not to produce hydrogen, which is included in the firming & H₂ storage cost estimate.

2.4 Other considerations

2.4.1 Choice of HBI vs integrated steel plant

The Archetype project considered in this study is HBI-only. While a fully integrated steel plant was initially considered and analyzed, it was dismissed due to:

- i. High capital cost, estimated to be more than \$20 billion USD, which would make financing highly challenging. The additional cost was largely driven by the power storage requirements for the EAF;
- ii. Additional complexity of construction and operation;
- iii. Potential problems associated with dealing with product quality issues when remote from the buyers; and
- iv. The fact that many buyers would likely have their own existing EAFs but would need to replace their blast furnaces in any event to achieve decarbonisation.

Moreover, construction of a (green) HBI-only plant would decarbonise the major source of emissions in the steelmaking process since the blast furnace is typically responsible for over 60% of overall emissions.¹⁵ Keeping the higher value-added steelmaking component in the buyer's home country might also be more politically appealing to the buyer's countries' governments which would be critical given the support that will be required of them.

2.4.2 Choice of renewable resource

While existing, low-cost hydropower would be ideal to support the Archetype project (as is the case for Stegra – formerly H₂GreenSteel), it is not considered here as it is a resource that is limited to specific regions. Instead, a combination of wind and solar (70:30) was selected to provide the broadest applicability of the concept. That said, if a country were able to offer an existing hydro plant to reliably firm new wind and solar generation, this could offer a substantial cost saving.

¹⁵ https://setis.ec.europa.eu/system/files/2021-02/jrc119415_iron_and_steel_decarbonisation_brief.pdf



2.4.3 Minimum regret for the future

It is expected that significant technological advances will be made in the lifetime of the plant. These could include reduction in electricity storage costs, new electrolysis technologies and increased electrolyser efficiency, amongst others. It is important to seek to design the plant in such a way as to minimise obsolescence risk. It is also likely that the project will expand to become a green power/hydrogen hub in the host country e.g. supplying green hydrogen to domestic and export markets. The project would preferably be designed to accommodate these changes, to the extent possible, and as far as implications on capital costs are not prohibitive.

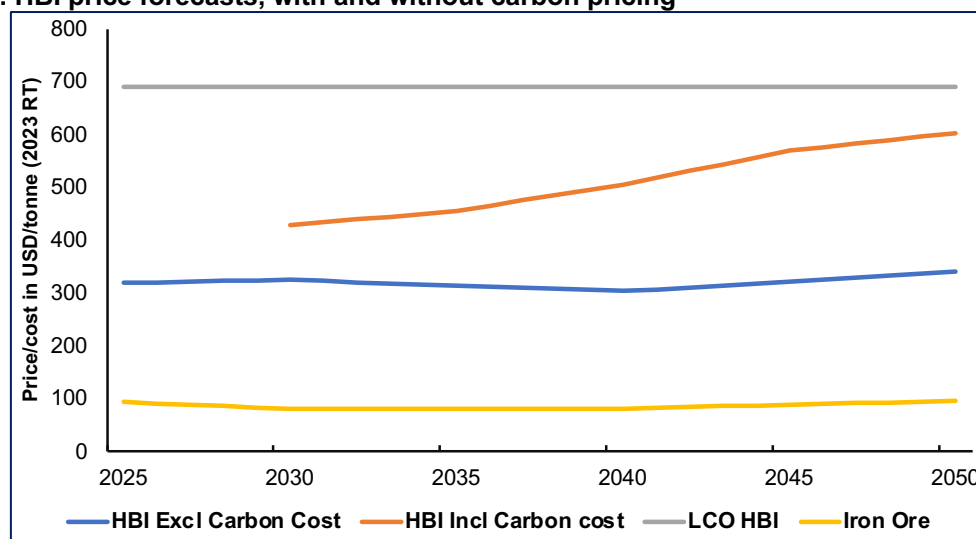
3. Challenges and potential solutions

In this study, several technical, commercial, economic and financial challenges to the project's development were identified. These are presented below together with some potential solutions.

3.1 Premium for the green product

As noted earlier, the LCOE (before firming) of \$45.5/MWh leading to a levelized cost of green hydrogen (before storage) of \$4.84/kg is expected to be globally competitive compared with other wind/solar-powered projects on a gross basis (i.e. before any local government support schemes), given that the site would be selected, among other reasons, for intensity of wind and solar resources. However, the Archetype project is unlikely to benefit – directly at least – from the subsidies and tax reliefs available in, for example, the US (the Inflation Reduction Act) or Europe (the Net-Zero Industry Act).

Figure 4: HBI price forecasts, with and without carbon pricing

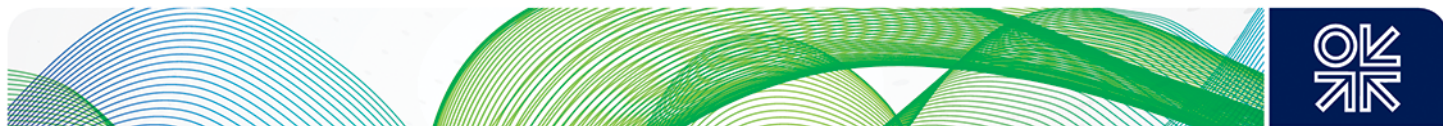


Source: CRU (2023)¹⁶

The calculated levelized cost of green HBI of \$690/tonne represents a premium of more than 100% over the current price for 'grey' HBI. Current carbon pricing forecasts e.g. in Europe, do not provide confidence that carbon pricing alone will be sufficient to allow the Archetype to compete with the 'grey' product over the long term. This will present a major challenge to both equity and debt financing.

Indeed, uncertainty surrounding the future pricing of a green product, the market for which is primarily driven by the need to reduce carbon emissions, is common to a number of sectors such as low-carbon power generation (e.g. nuclear, solar and wind). In the electricity sector, this has generally been addressed by mechanisms that offer the seller a fixed price for an extended period of time either directly

¹⁶ CRU (2023). CRU Steel Long Term Market Outlook 2023.



as a feed-in tariff or as a contract for difference (with a strike price set against a widely-traded market price). This has proved successful in terms of attracting investment to those sectors.¹⁷

However, green steel/HBI differs from power in two respects. First, at least in the case of the Archetype, the product is produced in a different jurisdiction; and second, unlike renewable power, HBI has significant feedstock costs, notably iron ore (and power, if purchased from a third party). The uncertainty around the green premium could therefore be addressed by a long-term offtake contract that, in effect, fixes the premium for a sufficiently-long period to support financing. The details of such a contract are addressed in more detail in Section 4.

Imperative to note here that this merely transfers the risk to the offtaker/buyer who may or may not be able to pass it on directly to their customers, depending on the impact of the premium on the cost of final products in which the steel is used (e.g. automobiles) and the willingness of customers to pay for that premium.¹⁸ To support the widespread adoption of green steel, government support is expected to be necessary and the forms it could take are addressed in more detail in Section 5.

3.2 Iron ore supply

While blast furnaces can accept a relatively wide range of grades of iron ore, DRI used in an EAF needs to be produced using ores with an iron content greater than 66%.¹⁹ Such ore quality is not widely available and represents only about 4% of global seaborne trade.²⁰ This is set to increase as ores suitable for DRI furnaces attract an increasing premium price and mining companies invest in beneficiation facilities at their mine sites to achieve this grade. However, not all ores can be readily beneficiated to the necessary quality. Furthermore, iron ore trade is mostly limited to four major players: Vale, Rio Tinto, BHP and FMG.²¹ Thus, some investors will have real concerns about the ongoing availability of iron ore for the Archetype project.

Unless the Archetype was located at or is close to a mine site (for instance, with the mining company as a shareholder), investors will look for long-term, fixed-volume contracts for the supply of a suitable grade of iron ore. Given the very specific requirements of DRI, at present this is expected to be a requirement for investors and lenders. It may also be of value to the mining company to support investment in a new beneficiation plant.

3.3 Electricity supply

A reliable long-term, low-cost supply of electricity is critical to the success of the project. Given its location in a developing country, which is not expected to have substantial renewable power generation capacity, it was assumed that the project would have dedicated power generation facilities. These could either be owned by the same company as the HBI project, or by a third party and contracted on a long-term fixed-price basis, to provide the required security of supply.

In a developed country, a project would likely seek to have a grid connection to increase its security of supply. This would have to be considered on a case-by-case basis depending on the robustness of the grid and whether connection might expose the project to greater risk than not. Self-contained – or ‘island’ – operation has therefore been assumed in this study.

¹⁷ Ason, A. & Dal Poz, J. (2024). Contracts for Difference: The Instrument of choice for the energy transition. Oxford Institute for Energy Studies, OIES Paper ET34. Oxford, UK.

¹⁸ For more details on the willingness of the automakers to pay for green steel, refer to Muslemani, H. et al. (2022). Steeling the race: ‘Green steel’ as the new clean material in the automotive sector. Oxford Institute for Energy Studies, Paper ET09, Oxford, UK.

¹⁹ Midrex (2022). The iron ore challenge for direct reduction on road to carbon-neutral steelmaking. Available at: <https://www.midrex.com/tech-article/the-iron-ore-challenge-for-direct-reduction-on-road-to-carbon-neutral-steelmaking/>

²⁰ <https://www.nature.com/articles/s41467-023-38123-2>

²¹ <https://www.fool.com.au/2024/09/12/why-the-iron-ore-price-could-have-further-to-fall/>



3.4 Technology

Ideally, the Archetype would rely on fully-proven technology with all equipment having demonstrated a satisfactory track record on a similar scale in similar service. DRI furnaces do have a good track record of operation at this scale using hydrogen, albeit more often produced by reforming natural gas. Areas where the track record may be more limited include operation of a large-scale electrolyser on an intermittent basis; operation of a large wind and solar farm on an 'island' basis, and operation of 100% hydrogen-fired gas turbines.

Unproven technology should be avoided where other more mature, cost-effective alternatives exist. However, it would not be surprising for a project such as the Archetype to have to use some technologies for which experience is limited or has been at a different scale or service. While investors will certainly look for guarantees and warranties by OEMs (original equipment manufacturers), in such cases, the role and commitment of the sponsors will likely be critical. Specifically, sponsors should have both the expertise to resolve any teething problems that could arise and the financial capability to fund required changes.

3.5 Market exposure

In addition to the magnitude of the green premium noted previously, the Archetype project is exposed to the margin between the price of a specialised grade of iron ore and that of HBI. The long-term margins between iron ore, HBI and steel should be relatively stable, trending to the cost of building a new plant, yet the short-to-medium term margins vary significantly depending on the utilisation of the current fleet of iron- and steelmaking facilities. While equity and debt investors have accepted such risk in the past, it has reduced the achievable level of debt, and hence increased the levelized cost.

Therefore, it would be desirable for the project developer to allocate this risk to buyers in the offtake agreement provided they can manage the volatility – which should be easier for them given it is a smaller component of the price of their end-products.

4. Commercial model and risk allocation

The overall project, from power generation to offtake of HBI, is exposed to a range of risks, some of which were described among the challenges to the Archetype in Section 3. The risk profile of the project company (the entity which will raise the equity and debt, own the overall project, and be a party to the project agreements) can be mitigated by a combination of:

- Government support both in the host country (developing economy) and the destination markets (assumed to be in developed economies such as in Europe, USA and Japan); (see Section 5)
- Allocation of risks among the project parties by the project agreements (including insurance); and
- Further allocation of risks between debt and equity (including the project company's ultimate shareholders) through the financing agreements (see Sections 7 & 8).

This section describes options for ownership and commercial structure of the project and key project agreements. While such a world-scale green iron plant is unprecedented in Emerging Markets and Developing Economies (EMDE), we here seek to draw on relevant precedents from other similar-scale investments in other sectors. In particular, we consider key risks and how these might be allocated to the various parties through the project agreements in order to minimize the overall risk profile and maximize "bankability".

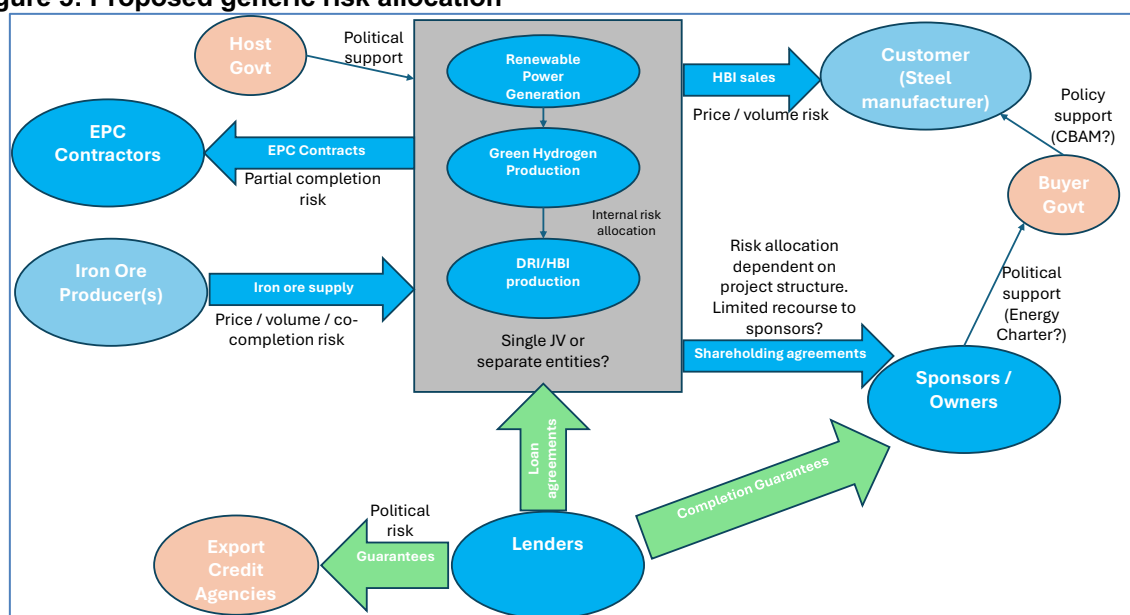
Note that in a previous OIES paper on financing of a green ammonia plant²², reference was similarly made to precedents from financing similar large scale infrastructure projects in LNG²³ or offshore wind²⁴. Those precedents are also valid here, together with adapting previous practice in the iron and steel industry.

4.1 Project ownership and commercial structure

As described in the outline of the Archetype in Section 2, the scope of the project is envisaged to include renewable power generation, green hydrogen production and production of DRI and ultimately HBI for export. Product flows into the project are assumed to be, principally, a supply of appropriate iron ore, while product flow out of the project is assumed to be HBI to be shipped to a steel producer outside the host country. As such, revenue to the project company will be from sales of HBI, which is assumed will be processed into finished steel products by the customer.

Figure 5 shows a generic risk allocation following the general principle that a commercial structure should allocate risks to the entity best able to manage each risk. This principle has worked well, for instance, in the LNG and power generation markets, but will require some adaptation to established practices in the iron and steel industry. Within these broad principles, there are different ways in which the overall project could be structured, and there are potential advantages and disadvantages of the different structures as discussed in the following sub-sections.

Figure 5: Proposed generic risk allocation



Source: Authors' analysis

4.1.1 Integrated ownership model

Under this model, it is assumed that renewable power generation, hydrogen production and the DRI/HBI plant are all in the ownership of a single project company (i.e., grey box in Figure 5), whereby there is no sale and purchase of electricity or hydrogen by project company. This is especially applicable where the project is in a remote location, and the plant is the sole (or most significant) consumer of renewable power, and the green hydrogen is exclusively used in the DRI process. On the other hand, the total investment (again, estimated at \$9bn) will pose a very significant financing challenge so it may prove

²² Craen, S. (2023). Financing a world scale hydrogen export project. Oxford Institute for Energy Studies, Paper ET21, Oxford, UK.

²³ <https://www.oxfordenergy.org/publications/lng-finance-will-lenders-accommodate-the-changing-environment/>

²⁴ https://wfo-global.org/wp-content/uploads/2022/09/WFO_FinancingOffshoreWind_2022.pdf



easier to finance smaller project components separately. In this context, it should be noted that the market capitalisation of large steel companies (e.g. 2nd ranked JSW is \$25bn)²⁵ is significantly smaller than many energy companies (e.g. 10th ranked BP is \$100bn)²⁶.

One advantage of the integrated model is that it reduces the need for separate agreements between the individual project components and hence the need to ensure full consistency between each of those agreements. In any case, it is likely that lenders will consider the end-to-end supply chain when assessing project risk. It is assumed that the iron ore will be supplied from a mine developed and operated separately, but there could also be merit in considering the mine owner as a co-investor in the project company.

4.1.2 Segregated ownership model

In this case, rather than a single project company, there would be 3 separate entities (i.e., the 3 blue ovals inside the grey box in Figure 5). This may be preferable where the plant is located in an existing or developing industrial cluster and where there are likely to be multiple customers for renewable power as well as multiple customers for green hydrogen. The advantage here is that with multiple offtakers, the power company and green hydrogen company will be able to lower their risk, and hence potentially cost of capital, by selling to a diverse customer group. It would also result in the amount of financing for each component being smaller, and so more manageable in the market, than with one integrated project company.

On the other hand, the segregated model will require more – and more complex – commercial agreements between each of the entities. In particular, it will be important that such agreements are structured so as to provide confidence in security of supply and to ensure that pricing is consistent along the chain to avoid margins of one entity being “squeezed in the middle”. For example, in the event of a constraint in green hydrogen production, either on account of technical issues or lack of renewable power, the DRI plant will require confidence that it will receive as much green hydrogen as possible, ideally in priority over other potential customers for the product.

Within the segregated model, there are two potential alternative structures: a) the “buy/sell” model, where, for example, the hydrogen company buys electricity and sells hydrogen to the DRI plant, or b) the “tolling” model where the DRI company buys the electrons and pays the hydrogen company to convert the energy into hydrogen. The choice of “buy/sell” or “tolling” is also likely to depend on specific project circumstances and the risk appetite of the sponsors and lenders involved.

4.2 Key project agreements

This section sets out the key agreements that the project company (or companies in the case of the segregated model) will need to enter with third parties or sponsors in order to implement the project (the ‘project agreements’). Note that these do not include agreements with lenders which comprise the finance agreements. The key project agreements are divided into those that govern the construction or pre-completion phase and those that govern the post-completion phase. Completion is the point in time when the project has been constructed and has passed various performance tests in accordance with its specification for a period of time such that there is no reason to expect that it will not continue to perform in accordance with the forecasts made in the financial model at the time of final investment decision (FID). Completion is an important project finance concept, usually defined in detail by a series of tests. This section is only intended to cover the key agreements that may have features specific to a DRI export project. The project will, in practice, have many project agreements, some of which will span both the construction and operational phases of the project (such as land leases). However, these are common to many infrastructure projects and are not expected to be significantly different for a DRI export project.

²⁵ <https://companiesmarketcap.com/steel-industry/largest-companies-by-market-cap/>

²⁶ <https://companiesmarketcap.com/energy/largest-companies-by-market-cap/>



4.2.1 Pre-completion phase

A large-scale project such as the Archetype would generally be constructed by a number of contractors under Engineering Procurement and Construction (EPC) contracts. Precedents such as LNG and offshore wind projects comprise very different components: upstream gas developments and cryogenic gas plants in the case of LNG, and wind turbines, offshore structures, and subsea cables in the case of offshore wind. As a result, it has not typically been practical to have a single EPC contractor build the entire project under a single lump sum contract, and thus ‘wrapping’ the whole project risk.

Given the complexity of the Archetype DRI plant, with renewable electricity generation, electrolytic hydrogen production and storage and iron ore handling and DRI, it is assumed that no single EPC contractor would be able or prepared to “wrap” the whole project at a reasonable cost. Construction will likely be carried out under a number of separate EPC contracts. These contracts will likely be managed on behalf of the project companies/sponsors by a project management organisation and/or “owner’s engineer”. It will be important to ensure good co-ordination between the multiple EPC contracts in order to minimise the risk of completion of one part of the chain while another part is significantly delayed.

4.2.2 Post-completion (operational) phase

HBI Offtake

The key agreements which will provide the revenue stream to underpin the whole project will be the arrangements for offtake of HBI. In the LNG industry, for example, it had been traditional for such a mega project to be underpinned by a long-term (typically 20-year) take-or-pay offtake agreement with several large utilities as highly creditworthy customers. In the iron and steel industry, such long-term contracts have not been common, so it is likely that the project will need to rely on a diverse range of shorter-term contracts. Indeed, it has been reported that Stegra (formerly H₂GreenSteel) has signed contracts of more than 5-7 years for the majority of its output.²⁷ Since green HBI will need to be sold at a premium to lower cost “grey” HBI, the customers in turn are likely to be relying on government support mechanisms (for example the EU carbon border adjustment mechanism (CBAM) or the EU Emissions Trading Systems, EU-ETS) to justify a premium price for the product.

Iron Ore purchase

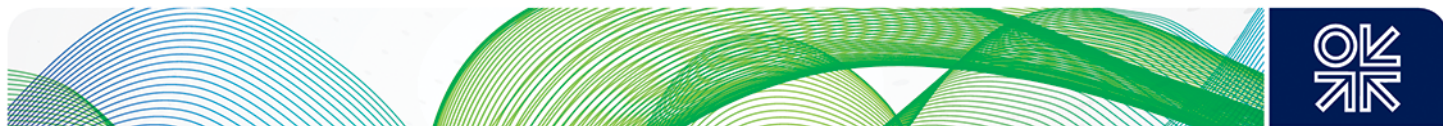
As noted in the ‘challenges’ Section 3.2, a reliable supply of appropriate quality iron ore will be essential for reliable operation of the DRI plant. This is particularly challenging given the specific iron ore quality requirements for a DRI plant compared with a traditional blast furnace. Ideally, the project will have long-term iron ore purchase contracts from several suitable mines, in order to provide security of supply and diversify risk. While long-term (5-10 year) volume contracts are common in the industry, prices may be negotiated annually or quarterly.²⁸ Bankability of the project will require contracts of a term greater than that of debt (e.g. 18+ years). A particular challenge in this case will be to have confidence that the price of iron ore will be sufficiently stable to protect the margin between iron ore purchase and HBI offtake.

Intra-project agreements

While the HBI offtake and iron ore supply provide the key external agreements, it will also be important that (in the segregated model) the agreements between the individual project entities (power generation, hydrogen and DRI) are suitably structured with risks allocated appropriately. This will be particularly challenging where there are multiple offtakers for power and hydrogen where each customer is likely to see themselves as requiring priority supply. Establishing a portfolio of customers, some of whom can provide flexibility to balance the overall system, will likely be a key success factor.

²⁷ <https://www.h2greensteel.com/latestnews/h2-green-steel-has-pre-sold-over-15-million-tonnes-of-green-steel-to-customers>

²⁸ See for example agreement between BHP and Baosteel from 2008: <https://www.bhp.com/news/media-centre/releases/2008/01/bhp-billiton-and-baosteel-sign-long-term-iron-ore-supply-agreement>



5. Policy support

As described in Section 4, a project of this complexity and size will require strong commitments from the host country, the importing country, and multilateral bodies promoting green industries. Adequate policies and assurances will need to be in place for investors to be willing to deploy capital to the project.

5.1 Host country

The host government should credibly assure investors that the clean energy generated through the project will not be diverted to other uses. This can be accomplished by making the renewable energy plant captive – i.e. not connected to the national grid. This eliminates diversion risk, although admittedly also loses potential advantages of grid connection. Other contractual arrangements to ensure priority of renewable energy to the plant ahead of any other uses can be designed. As is typical for project finance structures with foreign investment in hard currency, certain investor protections need to be adopted by the host government. These include permission to hold offshore hard currency accounts and to make debt service and distribution payments offshore, needed to provide comfort to lenders that debt service in hard currency will be prioritized and protected from any currency conversion issues that the host country may experience.

To aid project economics, the host government could also offer waivers for certain import duties and taxes for equipment that will most likely be sourced abroad. A common example is importing duties for PV panels which can add a significant cost to the project. Finally, the host country must be a signatory to the investment treaties²⁹ relevant to the particular case (depending on the jurisdictions of the project sponsor(s) and lender(s)). These treaties set out the rules of dispute settlement with the host country, for instances when all other negotiations fail. They also serve as assurance for foreign investors that any significant dispute will be handled on neutral terms.

5.2 Importing country(ies)

Given the project size, offtakers are most likely going to be from OECD countries.

5.2.1 Absorbing the green premium

The role of the importing country's government is fundamental in making such a green industrial project possible. In the absence of strong policy signals, the demand for green steel at significantly higher prices would be unlikely to materialize. Carbon pricing would be the most systematic way of incentivizing producers to incorporate the external costs of emitting greenhouse gases (GHGs) into their production costs and pass them, at least in part, to end consumers. According to the World Bank's Carbon Pricing Dashboard³⁰, there are currently 73 carbon pricing initiatives around the world (some are sub-national jurisdictions such as in California). However, at an average of 23\$/tCO₂ in 2024,³¹ the global average price is much lower than the 75 \$/tCO₂ which reported to be required by 2030 to stay in line with the Paris Agreement targets.³²

The most significant carbon pricing scheme is the EU-ETS, which covers emitters in industrial and energy generation installations (and other sectors). Starting from 2026, the EU will gradually phase out the free allocation of emissions allowances to industrial installations at risk of carbon leakage, exposing them fully to the carbon price. To protect them from competition from jurisdictions that do not have a carbon price, the EU is launching its Carbon Border Adjustment Mechanism (see Box below), which may have a positive influence on green industrial investments in countries benefitting from abundant renewable resources.

Another way to ensure the sustainability of the appetite for absorbing the green premium is through carbon contracts for differences (CCfD). In Germany, for example, CCfDs are seen as a way to create

²⁹ <https://icsid.worldbank.org/node/20271>

³⁰ <https://carbonpricingdashboard.worldbank.org/>

³¹ <https://www.visualcapitalist.com/sp/visualized-the-price-of-carbon-around-the-world-in-2024/>

³² <https://www.imf.org/en/Blogs/Articles/2022/07/21/blog-more-countries-are-pricing-carbon-but-emissions-are-still-too-cheap>



certainty for the carbon price over a certain period of time.³³ For example, a manufacturer in the automotive industry committing to purchase hydrogen-based green steel on the assumption of a certain (high) carbon price in the future would be compensated by the government should that price decrease below a certain level.

CBAM is the EU's policy to prevent carbon leakage, by taxing the embedded emissions of certain goods, including iron and steel, imported into the EU. Embedded emissions are defined as direct emissions from the production of goods plus indirect emissions from the generation of electricity consumed in the production process. The CBAM will be gradually phased in as the free allocation of ETS emissions allowances to EU installations is phased out. This phase-out (and concurrent phase-in) starts in 2026 with 2.5% of allowances and is completed in 2034 when 100% of allowances will be auctioned. To be allowed into the EU market, importers of the respective goods into the EU will need to purchase CBAM certificates in proportion to their embedded emissions. The price of CBAM certificates will be based on weekly averages of EU-ETS certificates – which are forecasted to be well above 100 euros per ton after 2025.

Considering that integrated route crude steel has an emissions intensity between 1.8 and 4 tCO₂/t, at the forecasted price of €250 per EUA in 2034*, CBAM would add between €450-1000 in carbon costs per ton of steel (for reference, the price of steel in 2024 was around 600 €/ton).

The implications of CBAM for an export-oriented green steel plant in a developing country are likely to be positive. The exported good would have a significant advantage over EU and non-EU competitors with higher embedded emissions. Provided that the green premium would be absorbed by customers, CBAM would only act in favor of green steel in developing countries.

Moreover, the CBAM regulation specifies that the EU will provide technical assistance and funding to developing countries particularly EMDEs in applying the CBAM which, together with other development partner initiatives, can spur the growth of green industrial projects in the Global South.

* based on analysis by Redshaw Advisors

5.2.2 Balancing the effect of domestic industrial policy

OECD countries, including the USA and European Union Member States, have been experiencing a revival of state-led industrial policy. The Inflation Reduction Act in the US and the Net Zero Industry Act in the EU are both relevant examples of industrial policy, with a role for subsidies aiming to boost local manufacturing of equipment and deployment of technologies for the energy transition.

It is difficult to establish the net effect of such initiatives on green industrial investments in developing countries with much lower fiscal space to fund industrial policy. On one hand, the competition is clearly on uneven terms, and the US and EU will be comparatively more attractive for investments in green industries, taking advantage of subsidies, lower cost of capital, and better infrastructure. On the other hand, by kick-starting technology adoption, for example in green hydrogen, the US and EU could create new markets and contribute to economies of scale and learning, driving down costs over the medium term, making such technologies available in other countries as well (as was the case with PV panels).

In any scenario, OECD countries may strive to help lower-income countries avoid a fossil-based development path. They should ensure that their own industrial policy does not price poorer countries out by creating a level playing field for investments in both countries or, at the very minimum, providing lenders with explicit assurance of their support for projects in developing countries.

³³ <https://www.bmwk-energiawende.de/EWD/Redaktion/EN/Newsletter/2020/11/Meldung/direkt-account.html>



5.2.3 Support through DFIs/MDBs/ECAs

The project could be supported significantly by various interventions and instruments offered through organizations funded mostly by OECD countries, such as Multilateral Development Banks (MDB), Development Finance Institutions (DFI), and Export Credit Agencies (ECA). The cost of capital in many lower-income countries is much higher than in OECD countries, reflecting the country risk premium. Blended finance interventions would be able to reduce it which, for capital-intensive projects where financing costs are significant, could make a difference in becoming viable. The full range of blended finance instruments could be relevant for a project of this profile, including from technical assistance, project preparation grants and viability gap funding, to concessional lending, and guarantees, such as partial credit guarantees and political risk insurance.³⁴

Technical assistance involves experienced specialists from DFIs or MDBs assisting the host government in setting up the legal and regulatory framework, as well as contract templates, based on international best practices. International Finance Corporation (IFC) and many other DFIs offer such services. Project preparation grants can be extended to project sponsors to cover the significant costs of structuring a project. Sponsors may be hesitant to cover such costs, which may never be recovered, should the project not materialize. For example, the Green Climate Fund³⁵ offers a project preparation facility.

Viability gap grants are meant to cover the shortfall in project economics that prevent it from reaching a certain target return, required by investors. The Private Infrastructure Development Group (PIDG)³⁶, among others, offers such services. Concessional lending simply means extending credit at below-market interest rates. Many DFIs, benefitting from their high credit rating, can borrow at advantageous interest rates, and pass them on, even if risk-adjusted, on concessional rates and longer tenors than the market. An example of concessional lending in the industrial sector is the Mozal aluminum project in Mozambique. ECAs, IFC and other DFIs offered a total of USD 830 million to the project.³⁷

Guarantees are of many types and are frequently used in infrastructure and industrial investment project finance. Some of the most common are partial risk and partial credit guarantees. They both represent promises to cover part of debt service of a project by a third party, most often a DFI, should some pre-defined risks materialize (for example, the government not honoring their obligations). The African Development Bank (AfDB)³⁸ and other MDBs and DFIs offer such guarantees.

Another widespread guarantee instrument is offered by the Multilateral Investment Guarantee Agency (MIGA) - the political risk insurance arm of the World Bank Group (WBG).³⁹ MIGA sells insurance policies to equity investors for up to 15 years covering four types of non-commercial risks: 1) currency transfer and convertibility; 2) breach of contract; 3) expropriation; and 4) war and civil disturbance. Other organizations, including private ones, offer similar services.

Note that as the project is focused on exports, the currency mismatch prevalent in the renewable energy sector would not be applicable.

³⁴ Refer to Table 2 in section 7.2.2.

³⁵ <https://www.greenclimate.fund/projects/ppf>

³⁶ <https://www.pidg.org/our-business/our-companies/pidg-ta>

³⁷ https://people.duke.edu/~charvey/Teaching/BA491_2000/Mozal.pdf

³⁸ <https://www.afdb.org/en/projects-and-operations/financial-products/african-development-fund/guarantees>

³⁹ <https://www.miga.org/what-we-do>

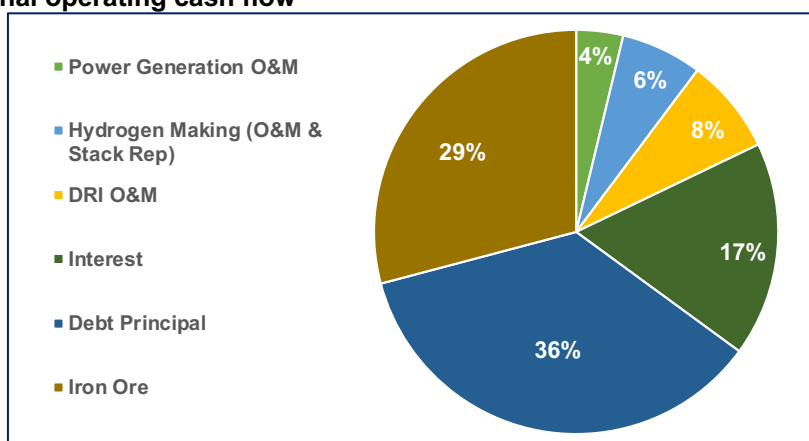
6. Financing

6.1 Cost of capital

For any renewable project, the cost of capital, including both debt and equity, is a significant component of the cash cost.⁴⁰ For the Archetype project, the cost of iron ore is a significant component of the cash cost. However, since all HBI plants will have to pay a similar price for iron ore, the margin cash cost (i.e. the total cash cost less the cost of iron ore) is most relevant for the Archetype project, reflecting best the green premium vs other HBI plants using coal or natural gas.

Figure 6 shows the relative contribution of the cost of servicing debt and equity to the total margin cash cost of produced HBI for the Archetype. Servicing debt and equity comprise 53% of the total cash outgoing with operating costs amounting to only 18%. Debt service has been split into principal and interest and the dividends have been allocated between the return of equity capital (with no return) and the return on equity (% p.a.) to allow for comparison. The variable components, being interest and return on equity, are the components the project should seek to minimise and represent (slightly more than) the total operating cost.

Figure 6: Marginal operating cash flow



6.2 Sponsors' financing objectives

The initial sponsors of the project will wish to form an investor group that has the financial and technical capability to execute the project, has the support of the host government and may include both offtakers and contractors to ensure alignment of all the project stakeholders. They will wish to maximise debt, throughout the project life, to in turn maximise their returns consistent with a competitive lowest cost of delivered HBI. The debt financing objectives are addressed in more detail in 6.3 below. They will also wish to minimise contingent liabilities associated with the project, such as completion support or other post-completion obligations but consistent with obtaining the best debt terms. Lastly, Initial Sponsors, especially the host government, will have an eye to the future of the project which could range from expansion of the HBI plant to forming the core of a future "Hydrogen Hub" supplying a number of both domestic and export-oriented green hydrogen industries.

6.3 Debt financing objectives

According to the capital asset pricing model, the cost of capital is a function of the perceived riskiness of a project compared to the average market risk. The perceived riskiness, and hence cost of capital, of the project company can be minimised by efficient allocation of the various risks among the project

⁴⁰ Refer to Craen, S. (2023). Financing a world scale hydrogen export project. Oxford Institute for Energy Studies, Paper ET21, Oxford, UK.



parties who are best placed to manage them. This would develop a robust, ‘bankable’ risk allocation structure that allows the level of debt to be maximised.

Debt is not only cheaper than equity but, in most jurisdictions, is also tax-deductible making the after-tax cost significantly lower. Thus, the cost of capital can be reduced by increasing leverage (the percentage of debt in the capital structure) at the start of the project and seeking to maintain as high a level of debt as possible throughout the life of the project to reduce repayment obligations. This can be done either by maximising the initial term of the debt, spreading repayments over a longer period of time or planning to re-finance the debt periodically to increase leverage and maturity. In developing countries, refinancing is more challenging as debt markets tend to be more volatile, reducing confidence that refinancing can be achieved when it is required, and most agency lenders are not permitted to refinance under their charters.

It is also important to enhance liquidity, to ensure as many lenders as possible are able and willing to lend to the project, not only to ensure that there will be sufficient lenders available to fulfill the finance plan but to create a competitive environment to lessen lenders’ interest margins.

6.4 Key financing challenges

Assuming that the project has a robust, bankable commercial structure as noted earlier, the key challenge will be that of the scale of the financing required for such a world-scale project. A secondary challenge, depending on the desire of the host country to own a stake in the project and its credit strength, will be that of funding the host government’s stake.

6.4.1 Scale

Achieving world scale will be critical to the success of the project as to be able to deliver the low cost of delivered HBI required to make the project globally competitive and justify locating the plant offshore from the offtaker or mine. Assuming a total funding requirement of \$13bn (\$11bn capital cost plus pre-completion financing costs), and a debt:equity ratio in the range of 60-70% dependent on the terms of the commercial arrangements, the project will require: \$8-9bn debt and \$4-5bn equity. This is a substantial financing requirement in the context of a project in a developing country that uses relatively new technology and relies on significant economic support from its offtakers and their respective governments.

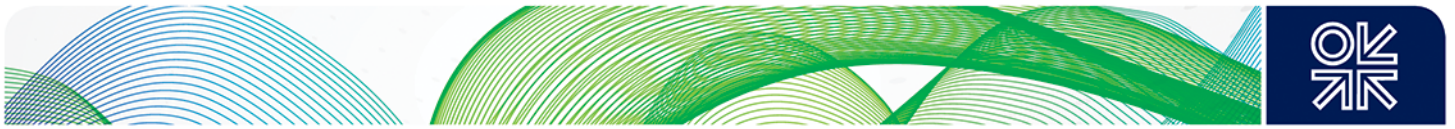
To put this in context, in 2022, Stegra (formerly H2GreenSteel) raised €3.3bn senior debt and €1.5bn equity for its DRI/steel project located in Sweden, with a wide range of equity investors and understood to be based on a number of medium term (up to 7 year) offtake contracts for 60-70% of the capacity. Similarly, in 2023, Neom Green Hydrogen Co. raised \$6.1bn senior debt for its green hydrogen/ammonia project in Saudi Arabia. The equity raising was supported by PIF (the KSA investment fund) and the project was based on a 30-year offtake agreement with Air Products.⁴¹ Neither project has raised as much as the Archetype would require. However, Mozambique LNG, in 2020, raised \$14.9bn senior debt for a \$20bn LNG project led by Total and supported by long-term offtake contracts with creditworthy Asian buyers.⁴² This gives some confidence that, for a project with strong sponsorship and offtake and a robust commercial structure, this level of funding can be raised provided lenders do not feel materially exposed to new technology risk.

6.4.2 Host government funding

For such a major infrastructure project, it is likely that the host government will wish to take a material shareholding in the project, directly or through a state-owned company. This is likely to be beneficial for the project in terms of alignment of interest but, depending on the financial strength of the host country,

⁴¹ <https://www.pfie.com/story/4193120/neoms-green-hydrogen-epoch-008rtjzqrm>

⁴² <https://www.nsenenergybusiness.com/news/total-14-9bn-financing-mozambique-lng/>



may present problems in terms of: i) raising the government share of the equity and ii) the acceptability of the government credit, for example, completion support.

7. Debt

In Craen (2023)⁴³, there was an extensive description of the theory and practice of debt finance for a green ammonia “Archetype” export project. To avoid repetition, sections of that paper are referred to here where relevant. It is useful to note, however, the key differences between the two Archetypes.

- **Scale:** the green ammonia project's total project capital cost was \$2.1bn whereas the green iron Archetype capital cost is estimated at \$9bn. The issue of market capacity, which was of limited concern for the green ammonia project, is a material issue for green steel.
- **Market:** there is a very limited international trade in hydrogen, let alone green ammonia, and while there is an established market for “grey” ammonia, green ammonia would be looking to penetrate a much wider market, e.g. for power generation, which does not currently exist. In contrast, there is currently a deep market for both HBI and steel products. This study's Archetype's green HBI product would be competing directly with an established market for “grey” HBI. Thus, green steel investors can be reasonably confident that they can sell HBI into the market at the expiry of the original offtake contracts, albeit with uncertainty on the green premium.
- **Pricing:** The green ammonia project does not need to purchase any material feedstock and thus was likened to offshore wind, and the recommended pricing would be an essentially fixed price, at least until costs and carbon pricing have reached the point that no further government support is required to promote investment. The green ironmaking Archetype project must purchase iron ore in a widely traded market, which is a material component of its operating cost. The recommended HBI pricing is on a cost-of-service basis (with a fixed component for operating costs and cost of capital but a pass-through of the actual cost of iron ore).

7.1 Project vs corporate finance

A project carried out by a joint venture of more than one sponsor can be structured either: i) in such a way that each partner is responsible for raising its individual share of the project funding (this can be done with an unincorporated joint venture (UJV) or a limited liability partnership (LLP) or unit trust), or ii) where the sponsors incorporate a special purpose company (SPC) to own the project assets and have the responsibility for raising debt for the project in a single financing with limited financial recourse to the sponsors ('project financing').

In this paper it is assumed that the Archetype project would use project financing as this is the more common structure in Emerging Markets and Developing Economies (EMDEs) where a satisfactory legal framework for UJVs or LLPs may not exist, and where the host government has some ownership in the project and such a joint financing provides all parties with greater confidence that the full debt requirement will be raised on time.

Note that while corporate finance is normally considered “cheaper” than project finance, project sponsors may be able raise debt at a lower cost. The project has a cost of capital that is determined by its own risk profile and if sponsors choose to fund it at a lower cost, that would in effect be a subsidy. However, setting up a project finance will cost more and be slower, due to the greater level of due diligence and documentation that is required.

⁴³ Craen, S. (2023). Financing a world-scale hydrogen export project. Oxford Institute for Energy Studies, Paper ET21, Oxford, UK.

7.2 Debt objectives and how to achieve them

As noted in Section 6.3, the key objectives of the debt financing are:

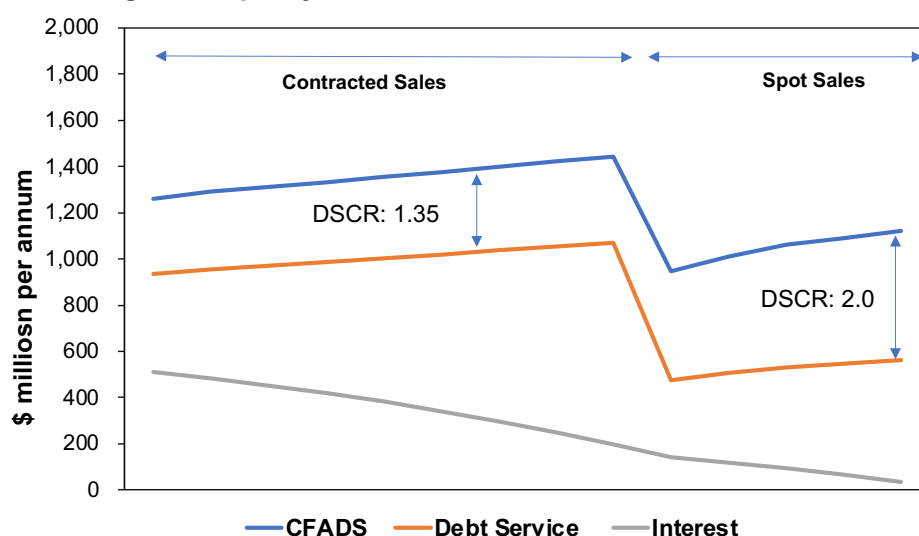
1. To increase leverage by
 - a) Maximising initial level of debt; and
 - b) Minimising annual repayments
2. To reduce the cost of debt; and
3. Maximise the sponsors' flexibility (e.g. to manage the project or the financing)

7.2.1 Maximising project debt capacity

The first step to increase leverage is to maximise the project debt capacity, that is the amount of debt that the project can service and repay. Lenders assess the initial debt capacity of a project by applying debt service cover ratios (DSCRs) to the forecast cash flow available for debt service (CFADS) as illustrated in Figure 7.

The loan maturity date is set to provide a 'tail' period of at least two years prior to the maturity of the offtake contract to accommodate delays or interruptions. Lenders then determine the 'cushion' or Debt Service Cover Ratio (DSCR) they require to ensure that debt service can be maintained, in all reasonable downside scenarios, to repay the debt by maturity. Typical DSCRs for an integrated steel project range from 1.3 for a "cost of service" project with no material price exposure to 2.0 for a merchant project with full exposure to iron ore and steel prices.

Figure 7: Assessing debt capacity



Thus, the initial debt capacity of the project would be determined by the degree to which the project is exposed to commodity prices, the market premium for a green product and the term of the offtake contract (assuming it is sheltering the project from those risks). These will be defined by the risk allocation as discussed in Section 4.

The other key factor in determining project debt capacity is the term of the debt: the longer the term, the lower the required repayment in any year and the greater the debt capacity. In countries with access to deep, liquid, well-developed bank markets, projects could consider using medium-term debt (of 5-7 years) where the bulk of the debt is refinanced at maturity, rather than being fully repaid in its term. If lenders are confident that refinancing will be available on reasonable terms, they can consider



repayment with an effective profile of up to 20 years. However, in EMDEs, lenders are unlikely to have the necessary confidence that a loan could be refinanced when required and so maximising project debt capacity, both initially and throughout the life of the project, will require achieving the longest-term debt available from the outset.

Based on the assumptions set out in the Appendix, the Archetype is estimated to have a project debt capacity of \$8-9 billion.

7.2.2 Maximising market capacity

Also, as previously highlighted, \$8-9 billion is a substantial amount of debt to raise for a project with relatively new technology in an EMDE. Table 2 summarises the principal categories of lenders that should be considered for such a project. For more detail on these lenders and their requirements, refer to Baker & Benoit (2022).⁴⁴

Table 2: Potential project lenders and their requirements

Lender	Capacity (USD billion)	Term (years)	Key Features
Concessional Lender	Up to 1	Up to 20	Offers below market pricing
Export Credit Agencies	Up to 5	Up to 16	Linked to procurement
MDBs	0.25 – 0.5	Up to 20	Focused on developing countries
DFIs	up to 1	Up to 16	Focused on developing countries
Commercial Banks*	Up to 2	7 to 20	Flexible
Sub-total	Up to 9.5		
Project Bonds	Up to 2	Up to 20	Require credit rating

* This capacity refers to the capacity to lend in addition to amounts guaranteed by export credit or other agencies.

The capacity for each lender group is the author's estimate and will vary in practice depending on the specific host country, the lenders' policies at the time and global market conditions. Project bonds have been shown as a separate category given their limited application to date for projects in EMDEs but should still be considered as the market for project bonds continues to mature rapidly.

In conclusion, with a maximum capacity below \$10 billion, there is a real possibility that the financing could be limited by market capacity (rather than project debt capacity). This means that particular care will need to be taken in development of the project to ensure that the specific requirements of each group of lenders are met. In particular, the procurement programme would need to be managed to ensure that goods and services are procured from countries whose export credit agencies are prepared, and have the capacity, to lend to or provide credit support. Development banks will also have specific requirements to ensure that their development and ESG goals will be met – and again it will be necessary to ensure that processes and reporting are developed to meet their needs.

Given the size of the debt requirement, the Archetype will probably have limited flexibility to prioritise its sources of debt. However, to the extent that there is any, priority should be given to export credit agencies due to the longer term that they offer as well as the incentive they give commercial banks both to lend and to offer longer loan terms than they would ordinarily to the host country.

⁴⁴ Baker, R., & Benoit, P. (2022). How Project Finance Can Advance the Clean Energy Transition in Developing Countries. Oxford Institute for Energy Studies, Paper ET17, Oxford, UK.



7.2.3 Getting the best terms

Typically, the best loan terms, both pricing and flexibility, are achieved by ensuring that the market capacity is greater than the debt requirement for the project to create competitive tension amongst the lenders. However, for the Archetype, it is unlikely that there will be substantial over-capacity as noted above. The key to getting the best terms will therefore be in the execution, using experienced financial and legal advisers to identify all potential lenders in advance, understand their requirements and tailor the project appropriately.

Another option, where some of the sponsors have the financial capacity and appetite to do so, is for those sponsors to act as senior lenders to their own project, matching the terms of the other lenders. This reduces the demand on the market, allowing for greater competition and better terms. It also provides further confidence to third-party lenders to see a major sponsor lending alongside them.

7.2.4 Other features

Sponsor Completion Guarantees

The potential need for sponsor completion guarantees was explored in Craen (2023). For the green ammonia export project, it was concluded that such guarantees would not be an absolute requirement of lenders but might be offered by larger sponsors to avoid potential delays caused by the greater complexity required in the absence of such guarantees. For a green steel project, with relatively new hydrogen DRI technology (vs well established ammonia synthesis) as well as a much larger scale, it is more likely that completion guarantees will be required. It will be important to ensure that any such guarantees are structured in such a way as to give the sponsors adequate time to allow for possible delays and rectify any teething problems that could arise.

Political Risk Insurance

Political risk insurance is generally available from a number of government agencies on a long-term basis and could be considered to increase the commercial banks' appetite to lend at the required term.

Segregated Financing

As considered in Section 4, and discussed further in Section 8, it may be beneficial to structure the project in two companies with different sponsors: i) power and green hydrogen production and ii) an HBI plant. For the purpose of debt, given that both projects would be reliant on a single source of revenue (HBI sales), debt capacity will be maximised if the project is considered as a single project. This would be achieved by establishing a single multi-source debt facility to fund both projects and ensuring that: all revenues are paid into a single project account; all operating costs are paid as a priority from this account and that debt service, for the single debt facility, would be paid before any distribution to either of the green hydrogen or HBI companies. Allocation of cash between the two sub-projects would be negotiated between the sponsors to reflect the terms of the green hydrogen supply agreement, including any agreed damages for non-performance. However, the sub-project companies would not be permitted to take action against one another without the approval of the lenders.

8. Equity

It is estimated that the Archetype will require \$4-5 billion of equity plus a contingent liability of \$ 8-9 billion assuming completion guarantees are required/offered. The scale of this requirement is such that, for the early projects at least, a small group of financially strong industry players are expected to be required. These initial sponsors would work with the host government, offtakers and the offtakers' respective governments to define the project technically, commercially and financially, including government support mechanisms. Once well-defined, the initial sponsors might look to introduce further equity investors, or project partners ahead of FID. Such project partners would likely be drawn from parties with an existing stake in the project such as the offtakers, OEMs and EPC contractors. Their involvement would be welcomed by lenders as it would provide a greater alignment of interest among the project parties. Some banks (e.g. IFC) might also be interested in taking a minor equity interest in the project.



The initial sponsors would need to bring expertise in the relevant sectors for the project (renewable power generation, hydrogen manufacture by electrolysis and HBI-making with hydrogen). However, while the project will need multiple sponsors to share the substantial financial burden, they will be required to share risks of which they have limited experience (e.g. steel industry risks for a company whose expertise is power generation or hydrogen-making risks for a steel company). It is not considered practical to completely segregate these risks even by creating two separate sub-project companies responsible for green hydrogen and HBI respectively, as to do so would require substantial long-term obligations: either take-or-pay for green hydrogen supply or damages for failure to supply for the HBI company. These obligations would also need to be supported at the sponsor level since neither can operate without the other.

Therefore, an alternative to a simple single project company with all initial sponsors as shareholders is proposed, under which there would be two sub-project companies, one to make green hydrogen and supply it to a separate HBI company under a long-term agreement. The sub-project companies would each be owned and operated by the sponsor(s) with the relevant experience. While lenders would treat the two sub-project companies as a single project, with full access to their joint cash flow, the two sponsor groups would receive distributions according to their capital contributions, adjusted if necessary to account for any penalties under the green hydrogen supply agreement.

9. Conclusions

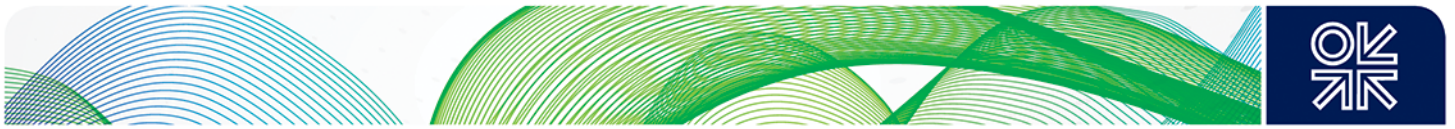
This study has examined the challenges and opportunities to financing an archetype green hydrogen-based DRI/HBI plant in a developing country for export into developed markets, offering real benefits to host and offtaking countries. At an estimated capital cost of 9 billion USD – including for power generation, DRI plant, hydrogen-making, and firming intermittent power generation with hydrogen storage and a modest hydrogen-fired OCGT – finance would be a challenge but is not impossible.

Considering the size of capital investment, low-cost, long-term financing will be critical to the project's success. This is especially the case as the levelized cost of green HBI production is estimated at 690 USD/tonne, representing a premium of around 100% over traditional, 'grey' HBI. Carbon pricing under Emissions Trading Systems remains unlikely to reach the levels required to support such a project on its own, where more targeted support mechanisms can provide fixed prices for extended periods of time and in turn help attract investment. These may include feed-in tariffs or contracts for difference which have proven instrumental in financing other green projects (e.g. renewables).

This should be complemented by a robust commercial structure and support from the host and offtaker's governments, industry sponsors and potentially development banks, including entering into long-term offtake agreements that can help minimise financial risks and create revenue certainty for early projects. Similarly, introducing carbon border adjustments (CBAM) in offtaking countries/regions ensures that (green) imports are at an advantage compared to domestic 'grey' production. Moreover, government intervention through public procurement, setting standards for what defines 'green iron' and 'green steel', and potentially mandating the use of green iron for steelmaking, can create demand for the green product.

As long as hydrogen DRI requires support from one or a group of governments, the choice of project location will be driven by those governments (and which plants they are prepared to support). This may be influenced by looking to use lowest-cost energy to reduce the support required but will also be driven by employment in their own country and other considerations. Note that if/when green hydrogen and storage costs have reduced and/or enough of the market has carbon pricing/sectorial quotas, a traded market in green DRI/HBI might exist which would not require specific project support – likely by 2040 or beyond.

While this analysis focused on appraising success factors for a green HBI project, this work has wider industry implications. Historically, iron- and steelmaking plants have been geographically co-located, largely because blast furnaces produce hot metal and the ability to supply the hot metal directly to a basic oxygen or electric arc furnace without having to cool it for transportation (then reheating it in



another location) offers significantly greater energy efficiency. However, since the DRI process reduces iron ore to HBI in a solid phase, this energy synergy becomes less important.

As there is no technical requirement to integrate iron- and steelmaking when using DRI/HBI, industry investors will seek to locate new plants in the lowest-cost locations. Thus, ironmaking (HBI) plants are expected to be located in regions of lowest-cost renewable electricity (after full firming), and steel plants, whilst might also be located there to utilise the low-cost power, can instead be located in end markets. This allows for the usage of existing EAF capacity and local expertise to make more specialised steels or to exploit end-customer proximity to better manage inventory and product quality, as well as commercial, technical, product development and relationship issues with those customers.

It is also expected that once green HBI-making becomes a profitable practice in its own right (i.e. no project subsidies are required), principal countries supplying iron ore (e.g. Australia and Brazil) which also have good renewable energy resources might preferentially move to capture the value added of selling green HBI vs iron ore. Such a fundamental change in the competitive landscape of an industry is not unprecedented, as a similar shift was witnessed in the petrochemicals industry where production over the past decades moved away from industrialised (consumer) markets to be located closer to the lowest-cost source of feedstocks.

Appendix

Illustrative debt and equity economics for the Archetype Project

A simplified financial model was developed to illustrate the economics of the Archetype project in terms of return on debt and equity and the impact of the term of debt and the offtake contract.⁴⁵

The modelling has been done on a pre-tax basis and the cost of capital reflects the pre-tax cost of debt (rather than post-tax) for consistency.⁴⁶

1.1 Assumptions

The detailed assumptions used in the Model are summarised in the following sections.

1.1.1 Technical assumptions

Table 1A: Technical assumptions

Plant Component	Capacity		Capital Cost (millions) 2030 prices, in real terms base year 2023
DRI Plant:	1.832	million tonnes p.a.	1,100
Hydrogen fired power plant	50	MW	43
LiO (short term) battery	50/15	MW/minutes	18
Hydrogen Storage	18/5,500	Days/tonnes	3,050
Total			4,215
Hydrogen plant (incl electrolyser)	112	ktpa	2,050
	1,450	MW (peak)	
Renewable Power generation (70% wind; 30% solar)	2,850	GW _{AC}	2,725
TOTAL			9,000

⁴⁵ Mezzanine debt or preferred equity have not been considered for the Archetype given its location in a developing country where there is less appetite for this type of capital. However, it should be considered, perhaps after completion, depending on the capital markets' liquidity for the specific location.

⁴⁶ Although this is perhaps a simplification, it is not an uncommon approach where the project is owned by a 'tax transparent' vehicle and tax is managed at the shareholder level.



1.1.2 Commercial Assumptions

The Base Case offtake is assumed to be a 10-year contract (from commencement of deliveries “COD”) for 100% of the capacity of the plant on a cost-of-service basis: with a pass through of the cost of iron ore and a fixed price for the cost of conversion to HBI with payment on a capacity basis i.e. irrespective of whether the offtaker actually offtakes product. After the term of the contract, CRU’s HBI price forecast (including carbon costs) was applied.

1.1.3 Economic assumptions

The cost of capital used is 9.0% p.a. This is higher than the figure used in the Hydrogen Export Finance paper (Jan 2023) of 6.88% p.a. reflecting both an increase in interest rates of 1.5% p.a. and equity market premium since then. It also reflects a more subjective premium to reflect the additional risks posed by the complexity and scale of the green steel Archetype.

1.2 Levelized costs

The Model first uses the assumptions to calculate the levelized cost of: electricity, hydrogen and DRI in real terms (RT 2023). These are summarised in Table 2A.

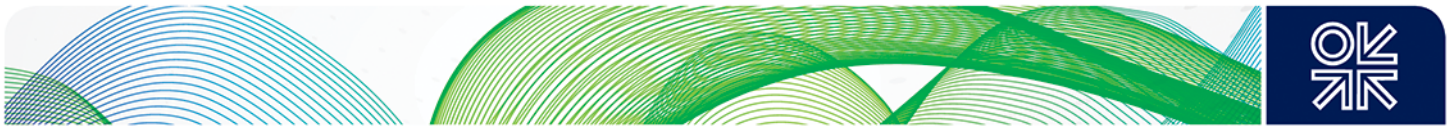
Table 2A: Levelized costs

Electricity		Hydrogen		DRI	
USD/MWh		USD/kg		USD/tonne	
Capex	41.3	Capex	1.86	Iron Ore	118
Opex	4.1	Electricity	2.56		
Total	45.5	Opex	0.28	Capex (DRI Plant)	61
		Stack Replacement	0.13	Firming	174
Firming Cost	47.2	Total	4.84	Hydrogen	297
Total (firmed)	92.7			Opex	39
				Total Processing	571
				Total DRI	690

In our modelling, the cost of “firming” the intermittent generation to supply the 24/7 supply required by the DRI plant was allocated to the DRI plant. This was to allow the levelized costs of electricity and hydrogen to be readily compared with other costs quoted in the literature, which are generally generation following. If the firming costs were, instead, to be allocated to the electricity cost, this would increase from \$45.5 to \$92.7 per MWh. While the DRI plant will always require some amount of hydrogen storage and battery capacity to ensure continuous operation, this would be substantially less with a firm electricity supply (such as from a hydroelectric plant). It would also allow significant further cost savings e.g. the electrolyser could be sized 23% smaller if it were able to operate 24/7.

1.3 Debt and equity economics

The levelized cost is the fixed, real terms price of HBI, assuming the CRU iron ore price forecast that yields the defined return on capital of 9.0%. This essentially reflects a 20-year cost plus offtake contract.



A Base Case was established using the assumptions above and including a 10-year cost-of-service offtake contract with, effectively, a fixed HBI price (in real terms 2023). Since the CRU forecast price is lower than the levelized cost of HBI calculated, the contracted HBI price was increased to maintain the project return on capital at the required rate of 9.0% p.a. A financing with an average term of 15 years from the final investment decision (“FID”) was modelled and the debt level estimated using a DSCR of 1.35 for contracted revenues and 2.0 for spot sales.

Sensitivity cases were run to assess the sensitivity to changes in the length of the offtake contract and the term of the debt financing. For each case, the adjustment to the contracted HBI price to maintain the 9.0% WACC, the amount of senior debt and equity and the equity return. The sensitivity case assumptions are set out as:

- | | |
|--------|--|
| Case 1 | Examines the impact of a shorter-term offtake contract: 7 years from COD |
| Case 2 | Examines the impact of a longer-term offtake contract: 15 years from COD |
| Case 3 | Examines the impact of a life-of-project offtake contract: 20 years from COD |
| Case 4 | Examines the impact of a shorter debt term: 12 years from FID |
| Case 5 | Examines the impact of a longer debt term: 18 years from FID |
| Case 6 | Examines the impact of a longer offtake contract term (15 years from COD) together with a longer debt term: 18 years from FID. |

The results of the analysis are summarised in Table 3A.

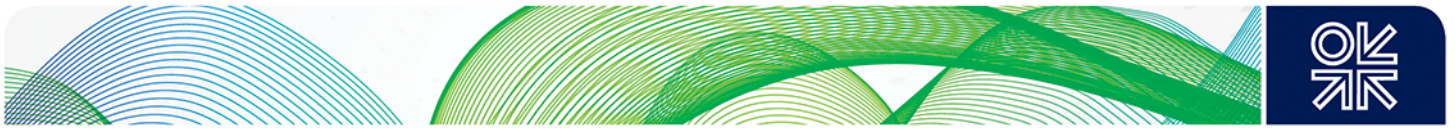
Table 3A: Sensitivity analyses to length of offtake contracts and term of debt financing

Archetype Project	Units	LCO(HBI) Case	Base Case	C1	C2	C3	C4	C5	C6
Assumptions									
:	(% p.a.)	9.0%							
Required cost of capital	(MOD) (USD/mt RT23)	CRU (including Carbon Costs)							
HBI price (spot)	(% p.a.)	6.50%							
Cost of debt (all-in)									
Offtake contract term	(years)		10	7	15	20	10	10	15
Loan Term	(years)		15	15	15	15	12	18	18
Results:									
HBI price (contracted) (req'd to achieve WACC)	(USD/mt RT23)	690	745	814	704	690	745	745	690
Debt		7,285	7,133	7,122	7,133	7,285	6,564	6,905	7,706
Equity		3,835	3,944	3,955	3,944	3,818	4,471	4,155	3,413
Total		11,120	11,077	11,077	11,077	11,103	11,034	11,060	11,120
DER:		65.5%	64.4%	64.3%	64.4%	65.5	59.5%	62.4%	69.3%
Return on equity	(% p.a.)	10.8%	10.9%	10.6%	10.9%	10.8%	10.3%	11.6%	12.4%

1.4 Conclusions

HBI Contract Price

In each case the HBI contract price was adjusted to yield a 9.0% p.a. WACC. This is a simplified assumption as, in theory, the WACC should reduce as the project risk is removed by increasing the term of the contracted period. However, many industry investors have a hurdle rate they wish to achieve on



any investment in a sector and this analysis was thought to be useful to indicate the likely relationship between the price and term of the offtake contract. Since the CRU forecast of the price of green HBI is lower than the LCO(HBI) calculated for the project, for a shorter term, the fixed price has to be higher to compensate for the lower price in the tail period. Thus, the Base Case price is 745 \$/mt – 8% higher than the LCO(HBI) due to the assumed 10-year term. This rises to an 18% premium with a 7-year tenor and reverts to the LCO(HBI) when the price is fixed for the 20-year economic life of the project.

Project Cost and Debt and Equity Levels

The total project cost, including interest and fees on debt, is broadly \$11 billion across the cases and the debt:equity ratio is approximately 65% for a debt term of 15 years. This leads to a debt requirement of \$7-7.5 billion and equity of \$3.5-4 billion. The debt level and return on equity remain broadly constant (10.6-10.9% p.a.) for the 15-year debt term, because the HBI price adjusted to maintain a constant WACC.

Debt Finance

The project economics support a reasonable level of debt for a project of this kind – 65%. The level of debt, \$7-7.5 billion, while substantial is expected to be achievable as discussed in Section 7.

The debt:equity ratio and return on equity vary with the term of the debt, illustrating the value of seeking the longest-term debt. For a project that relies heavily on ECA and other institutional financing, there is very limited scope to re-finance with those lenders, so an extension beyond the assumed term of 15 years would rely on refinancing in either the commercial bank or bond markets. This might be practical in the later years of the project where the debt level has been reduced and the host country's economy may have improved giving it better access to international capital markets.

Equity

The level of equity for a project of this kind (\$3.5-4 billion) is substantial and is most likely to be achievable from a joint venture of financially strong industry partners rather than the equity capital markets.

The value of firmed electricity supply

The Archetype is based on the assumption of using a combination of solar and wind generation in a low-cost location given the difficulty of identifying locations that could offer fully firmed (e.g. hydroelectric) generation. The levelized cost analysis identifies that the cost of firming the solar and wind generation with an estimated load factor of 30.5% amounts to 47 \$/MWh. A fully firmed electricity supply would also permit a significant reduction in the size of the electrolyser and a move to more reliable continuous operation.