

IS GREEN STEEL WITHIN REACH IN INDIA?

Green DRI Economics, Policy Drivers and Site Feasibility in

Andhra Pradesh

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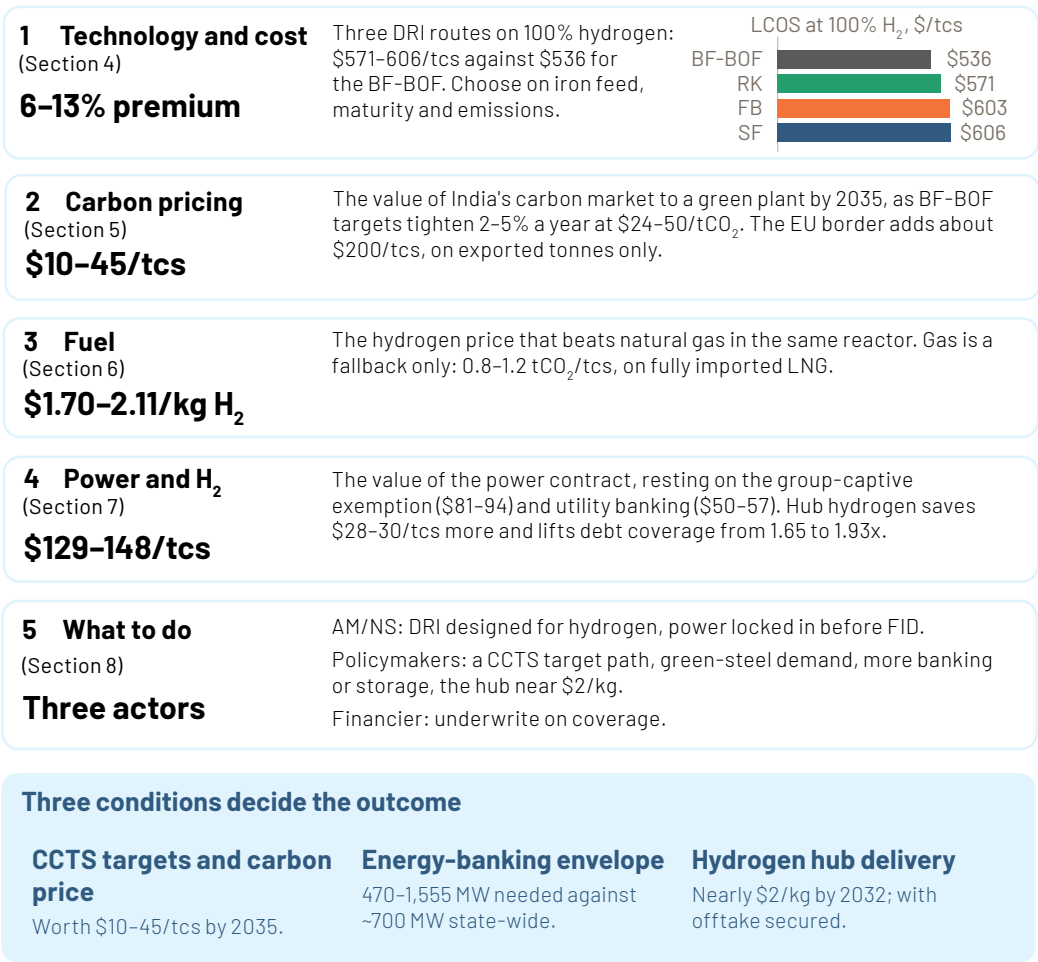
Cover image: **Concept illustration only.** AI-generated visualisation of a potential green steel development in Andhra Pradesh, created using OpenAI ChatGPT. The image is intended for illustrative purposes and does not represent a final facility design.

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THE REPORT AT A GLANCE

Phase 2 at Rajayyapeta: 9.6 Mtpa of new primary capacity, hydrogen-ready DRI routes against the coal-based BF-BOF, commissioning in 2033.



LCOS in 2025 USD per tonne of crude steel.

Figure ES. The report at a glance: the five steps of the analysis with the number that carries each, and the three conditions outside the plant fence that decide the outcome.

EXECUTIVE SUMMARY

India's next wave of steel capacity is being planned now, creating a critical opportunity to determine whether new production locks in conventional, carbon-intensive steelmaking or moves towards a competitive green-steel pathway. This report prices one real decision inside India: the route for Phase 2 of ArcelorMittal Nippon Steel's greenfield complex at Rajayyapeta, Andhra Pradesh, representing roughly 9.6 Mtpa of new primary steel capacity expected to be decided around 2030 and commissioned in 2033.

Using a plant-level model based on the site's actual ore, power, and policy position, this report compares three direct reduced iron (DRI) routes—shaft furnace on high-grade pellet, fluidised bed on low-grade fines, and rotary kiln on low-grade fines—against a coal-based blast furnace–basic oxygen furnace (BF–BOF) incumbent across fuel configurations from natural gas to 100% green hydrogen.

This report is structured around five key analytical questions. Section 2 reviews the three direct-reduction technology pathways and their respective ore requirements. Section 3 outlines the scope, analytical boundary, and underlying cost methodology. Section 4 evaluates the levelised cost of green steel across the technology options and examines the role of raw-material quality. Section 5 assesses the impact of domestic carbon pricing under the CCTS and external trade measures under the EU CBAM. Section 6 evaluates the operational and cost implications of utilising natural gas as a transitional fuel versus pure hydrogen. Section 7 examines power contracting, energy banking, and hydrogen procurement options in Andhra Pradesh. Finally, Section 8 synthesises the core conclusions, delivers stakeholder recommendations, and presents a decision calendar for project execution.

KEY FINDINGS & DECISION DRIVERS:

- **Modest Green Premium and Technology Convergence:** At 100% hydrogen, green steel costs 6–13% more than BF–BOF (\$571–606/tcs vs \$536/tcs; ₹49,800–52,800 vs ₹46,700).^{*} With cost differences among green routes within \$35/tcs (₹3,100/tcs), reactor selection depends on iron-feed security, technological maturity, and emissions rather than headline cost alone. The shaft furnace remains the cleanest and most commercially mature option, whereas fines routes eliminate pelletisation premiums by utilising low-grade ore.
- **Domestic Carbon Market Impact:** Under India's Carbon Credit Trading Scheme (CCTS), a 5% annual target tightening on high emitters at \$50/tCO₂ (₹4,400/tCO₂) yields \$25–45/tcs (₹2,200–4,000/tcs) in value to green plants from 2030–2035, closing the rotary kiln's green premium at commissioning and bridging most of the shaft furnace gap by 2035.
- **EU Border Pressure for Exports:** For European exports, the EU CBAM provides a \$179–209/tcs (₹15,600–18,200/tcs) landed-cost advantage over Indian BF–BOF steel by 2033 commissioning. However, because exports represent only 3–5% of Indian output and EU import quotas do not differentiate green steel, domestic policy and demand remain the primary drivers.
- **Hydrogen as Strategic Plan, Natural Gas as Fallback:** Green hydrogen outcompetes natural gas in the reactor once delivered at \$1.70–2.11/kg (₹148–184/kg). While natural gas provides a lower-cost initial operating option (\$531–553/tcs; ₹46,300–48,200/tcs), it emits 0.8–1.2 tCO₂/tcs and exposes the facility to volatile LNG imports. Facilities should be designed for hydrogen from inception, treating gas strictly as transitional insurance.
- **Procurement and Power Structuring:** Power contracting structures influence levelised costs by up to

\$129–148/tcs (₹11,200–12,900/tcs). Securing group-captive status saves \$81–94/tcs (₹7,100–8,200/tcs) via surcharge exemptions, while utility energy banking provides an additional \$50–57/tcs (₹4,400–5,000/tcs) benefit.

- **Hub Hydrogen Procurement:** Purchasing green hydrogen from a regional hub (such as Pudimadaka at \$2/kg; ₹174/kg) reduces steel production costs by \$28–30/tcs (₹2,400–2,600/kg) compared to on-site generation, removes \$1.2 billion (≈₹10,500 crore) in electrolyser capital from the project balance sheet, and improves project cashflows.

ACTIONABLE RECOMMENDATIONS:

- **For AM/NS India:** Commit Phase 2 to fuel-flexible DRI technology (e.g. shaft furnace) designed for hydrogen from day one; legally and meter-wise separate Phase 2 as an independent CBAM installation to prevent emissions blending with Phase 1 BF-BOF capacity; lock in group-captive renewable power equity and utility banking before Final Investment Decision (FID); and protect the captive feed cost base using Bailadila ore slurry links.
- **For Policymakers:** Publish a clear, long-term CCTS reduction trajectory; create market demand by linking public procurement to Green Steel Taxonomy star ratings; expand industrial green-energy banking envelopes; accelerate the Pudimadaka hydrogen hub; and establish accredited domestic CBAM verification infrastructure.
- **For Financiers:** Evaluate transition climate risks, long-term balance-sheet exposure, and cash-flow stability over base levelised production costs. Financiers should explicitly require Phase 2 to adopt a green DRI route rather than a conventional BF-BOF pathway to ensure capital resilience and mitigate financial vulnerability under tightening carbon regulations. Prioritise group-captive power structures and external hydrogen procurement from regional hubs to optimise debt capacity and project bankability.

Note: Rupee figures are converted at ₹87.16 per US dollar. All costs are in 2025 prices. All figures above \$10 are rounded to the nearest ₹100

1. INTRODUCTION AND OBJECTIVES

1.1 CONTEXT: INDIA'S STEEL DECARBONISATION CHALLENGE

India is the world's second-largest crude steel producer, with roughly 200 million tonnes per annum (Mtpa) of installed capacity and the world's largest producer of sponge iron (direct reduced iron), at about 56 Mt in FY2024–25.¹ In addition, India stands out as the sole major steel market experiencing simultaneous growth in demand and production capacity. With per-capita finished-steel consumption currently at 108 kg—just half of the 215 kg global average—the National Steel Policy aims for 300 Mtpa in capacity and 158 kg per-capita consumption by 2030–31. Reflecting this growth trajectory, India accounts for 42% of global steelmaking capacity currently under development, representing 357 Mtpa, a pipeline triple the size of China's.^{1,2} Because most of this capacity is yet to be built, the decisive question for reducing the Indian steel sector's emissions is not how to retrofit the existing fleet but which technology the new capacity adopts.

Beyond the industrial implications, the stakes are critical for national resilience. The IPCC Sixth Assessment Report highlights India's heightened vulnerability to climate change, particularly regarding heat stress, water scarcity, and threats to agricultural systems and coastal infrastructure. Consequently, the decarbonisation trajectory of India's highest-emitting heavy industry directly impacts both its trade competitiveness and its broader exposure to climate risks.³

India's steel sector currently operates on a highly carbon-intensive baseline, averaging 2.54 tonnes of CO₂ per tonne of crude steel (tCO₂/tcs; 2023–24) against a global average of all routes at 1.91 tCO₂/tcs, exceeding the global average by 33%, with the industry accounting for 10–12% of overall national CO₂ emissions.⁴ Primary steel production in India is heavily dependent on coal-reliant methods. Together, the blast furnace–basic oxygen furnace (BF–BOF) pathway and the coal-based direct reduction with electric arc or induction furnace (C–DRI–EAF/IF) route generate approximately 74% of the country's crude steel, operating with an intensity of around 2.2 to 3.1 tCO₂/tcs.^{1,4} This carbon-intensive production pathway is clearly evident in the project pipeline for future additions: 93% of India's planned ironmaking expansion remains reliant on coal, and the country accounts for over 60% of all BF–BOF capacity currently under development worldwide.^{5,6} These operational life cycles represent long-term commitments: with standard 40-year spans, facilities constructed during this decade will continue generating emissions into the 2060s. Furthermore, blast furnaces rely on imported coal, with India sourcing over 85% of its metallurgical coal internationally; thus, each additional coal-reliant facility reinforces this reliance throughout its operational lifespan. Because merely 5% of proposed ironmaking capacity has commenced construction, the opportunity to reorient future ironmaking infrastructure remains substantially available.⁷ Nevertheless, it narrows with every project that moves to construction.

Direct reduced iron (DRI) provides a scalable, lower-carbon alternative for primary steelmaking. By extracting oxygen from solid iron ore rather than smelting it with coke, DRI produces reduced iron that can subsequently be melted into crude steel. The process can utilise reducing gases, such as natural gas, pure hydrogen, or varying blends, or solid coal as reductants. Gas-based DRI is among the most promising pathways for decarbonising the steel industry. Throughout this report, gas-based means reduction by any such gas, as distinct from coal-based DRI. Run entirely on natural gas, gas-based DRI already emits half the CO₂ of the coal-based BF–BOF, because it eliminates metallurgical coke; using green hydrogen the emissions fall further still. Currently, three reactor families can reduce iron ore in this way, and this report compares all three: the vertical shaft furnace, fed with

pelletised ore, and the fluidised bed and rotary kiln, both fed directly with iron ore fines (Section 2 describes each in detail, including how far each is from commercial scale).

Non-gas reduction pathways, alongside nascent technologies like plasma smelting and electrolytic reduction, fall outside the scope of this study. Similarly, carbon capture, utilisation, and storage (CCUS) applications for DRI or BF-BOF routes are excluded: commercial-scale precedents remain limited to a single operational facility, no commercial blast furnace currently captures its diluted steel off-gases, and the requisite CO₂ transport and storage infrastructure is not present on India's eastern seaboard. Coal-gasification syngas DRI (as at JSPL Angul), though prominent in current Indian planning, reduces with gas made from coal and carries coal-scale emissions without capture; it too is outside the green scope. Furthermore, it does not suggest that any single technology provides a universal solution for the entire Indian steel industry. Decarbonisation across India's current steelmaking fleet will expectedly rely on a combination of technical pathways—including oxygen enrichment and heat-balance optimisations in blast furnaces, fuel substitution, scrap-reliant electric arc furnaces, and ultimately, molten ore electrolysis. Instead, the focus here is more specific: defining the optimal route for constructing a new 9.6 Mtpa primary steel plant committed around 2030 with a projected 40-year operational life.

DRI is experiencing rapid global expansion, with 169 Mtpa currently in operation. While shaft furnace technology—the most mature approach—dominates current production, DRI still accounts for only 10% of global ironmaking. Nevertheless, its capacity has expanded by 15% annually over the last five years, significantly outpacing blast furnaces at 2.4%. DRI now represents 43% of the global ironmaking development pipeline, positioning it to reach approximately 284 Mtpa by 2030. What DRI is not, yet, is green: 98% of operating capacity runs on fossil reductants (of which 83% natural gas and 17% coal) and only 2% (4 Mtpa) uses green hydrogen as primary reductant.⁴ It is worth highlighting that coal-fired rotary kilns make up the majority of India's current DRI capacity. These kilns generate an average of 2.7–3.1 tCO₂/tcs, making them significantly more carbon-intensive than standard blast furnaces, which produce 2.2–2.6 tCO₂/tcs.⁴ This report focuses specifically on the gas-based adaptation of the rotary kiln rather than the existing coal-fired incumbent.

Several features make DRI a natural fit for India, and gas-based DRI is seen as a leading candidate for new green Indian capacity.⁸ As mentioned, the country has operated DRI at scale for decades, albeit in its coal-based rotary-kiln form and EAFs and IFs already produce more than half of its crude steel.¹ Scrap, the other EAF/IF feedstock, is structurally scarce in India, making DRI the main future source of green steel.⁹ India's resource base also favours the switch: India is largely self-sufficient in iron ore, consuming 77% of the 289 Mtpa it mines, while importing more than 85% of the metallurgical coal it uses.^{1,4} Coal-fired rotary kilns stand out as an exception because they utilise domestic non-coking coal. Consequently, the rationale for replacing them centres on mitigating carbon emissions and addressing the severe local air pollution around sponge-iron clusters, rather than reducing import reliance. Regardless of the driving factor, the solution remains identical: substitute the reductant. Transitioning from coal-fired to gas-based furnaces allows India to leverage its extensive DRI operational experience as a strategic asset for decarbonisation.

A major advantage of DRI is its inherent fuel flexibility. Unlike a blast furnace, whose emissions profile is largely locked in by its hardware, a DRI reactor's carbon footprint is determined by its fuel input. The same family of reactors can process natural gas, hydrogen, or any combination of the two, accommodating higher hydrogen shares through modifications to burners and gas-handling systems rather than requiring entirely new equipment. When hydrogen is generated via electrolysis using renewable power, it introduces zero fossil carbon into

the process. As a result, a facility does not need to lock in its hydrogen mix at project inception; the existing equipment can incrementally scale up hydrogen use as availability improves and costs decrease. Furthermore, hydrogen-based DRI is actively featured on India's policy agenda, albeit currently at the pilot stage. Through the National Green Hydrogen Mission, the Ministry of Steel is backing pilot initiatives that produce DRI using 100% hydrogen in shaft furnaces, alongside trials that inject hydrogen into operational natural-gas DRI shafts and blast furnace units.^{1, 10} These are pilot-scale; the commercial-scale evidence is accumulating in Sweden, where the HYBRIT pilot has made DRI on 100% hydrogen since 2021 and Stegra is building the first commercial hydrogen-DRI plant, even as several conversions elsewhere in Europe have been paused on cost.^{11, 12, 13}

A tightening set of market signals and regulatory policies is accelerating the transition of new production capacity toward lower-carbon pathways. On the domestic front, the Green Steel Taxonomy (2024) specifies a plant-level threshold of 2.2 tCO₂e/tonne of finished steel to qualify as "green," featuring a star-rating system for deeper reductions that caps five-star eligibility at or below 1.6 tCO₂e/t. Although this designation currently functions as a labeling framework without direct fiscal support, it is anticipated to serve as a key anchor for green steel procurement; the Carbon Credit Trading Scheme (CCTS; 2023) is developing a national carbon market now spanning nine sectors including iron and steel; and the National Green Hydrogen Mission (2023) underwrites the hydrogen supply side.^{10, 14, 15} Externally, the European Union (EU)'s Carbon Border Adjustment Mechanism (CBAM) entered its definitive phase on 1 Jan 2026, with the first certificates surrendered in 2027; with roughly a third of India's steel exports bound for Europe, the rating agency ICRA estimates a profit erosion of US\$60–165 per tonne on Indian steel exports to EU between 2026 and 2034.^{16, 17} The prominent point is that domestic and international policy are beginning to both favour new low-carbon primary capacity, and that the technology choice for India's new plants is being made now.

1.2 A REAL ANCHOR: THE AM/NS ANDHRA PRADESH GREENFIELD

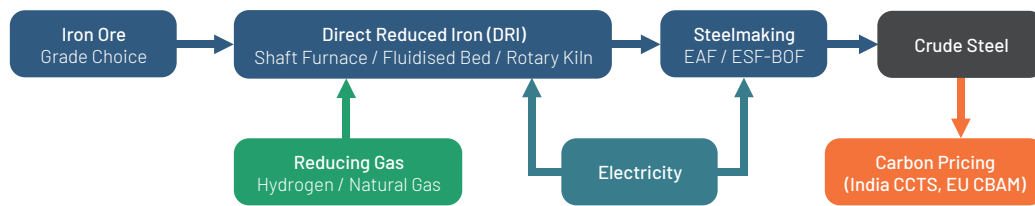
A prime example of these large-scale decisions is currently taking shape along the coast of Andhra Pradesh. This report bases its financial assessment on a real-world project: the greenfield steel complex being developed by ArcelorMittal Nippon Steel India (AM/NS India) in Rajayyapeta, Anaparthi district, Andhra Pradesh. Envisioned for an overall capacity of 17.8 Mtpa across two distinct phases, the initiative represents an estimated total expenditure of ₹1.35 lakh crore (approximately US\$16 billion). Throughout this document, this project is designated as the AM/NS Rajayyapeta greenfield. Construction has begun: land acquisition started in 2025, the foundation stone was laid in March 2026, and Phase 1 (8.2 Mtpa, about ₹70,000 crore) targets first steel in early 2029. Phase 1's technology is already fixed, and it is conventional: the environmental clearance specifies a coke-oven-sinter-BF-BOF configuration.¹⁸ The open decision is Phase 2, which roughly doubles the site to its full capacity and whose route has not been specified. While no date for that decision has been announced, this report adopts 2030 as a decision year to be consistent with the 2033 commissioning the company has stated for Phase 2, and models the green-iron configurations Phase 2 could pursue at 2030 costs, on the site's real ore-supply, power and policy position.

Decarbonisation is not an afterthought for this project; it is central to both its owner's corporate strategy and statutory obligations. Under the terms of its environmental clearance, the Phase 1 facility must steadily lower its emissions intensity to 1.8 tCO₂/tcs, while adhering to any tighter benchmarks introduced under upcoming national green steel frameworks. Meanwhile, AM/NS India is well positioned among domestic producers to lead the transition to primary green steel. With approximately 9 Mtpa of operating crude capacity, the company's

emissions intensity stands at around 2.27 tCO₂e/tcs under the latest CCTS benchmarks—nearly 10% lower than the national average. This advantage stems from its reliance on a natural gas-based DRI fleet, ~26% renewable power integration, and expanded scrap utilisation. Furthermore, it became the first integrated steelmaker to earn certification under the Ministry of Steel's Green Steel Taxonomy, receiving a 4-star rating for hot-rolled products and a 3-star rating for cold-rolled products.¹⁹ AM/NS has committed to cutting CO₂ intensity 20% by 2030 against a 2021 baseline on a path to net zero by 2050, and frames the Andhra Pradesh complex as the bridge between that 2030 target and the 2050 ambition: a next-generation hub designed to take on future technologies, green hydrogen among them.²⁰

The Rajayyapeta site itself, on the Bay of Bengal coast in Anakapalli district, south-west of Visakhapatnam, reinforces the case. AM/NS is developing a captive port at D.L. Puram to keep raw-material and export logistics in-house, and iron ore can reach the site by slurry pipeline from National Mineral Development Corporation's Bailadila mines in Chhattisgarh, securing low-cost, reliable feed.^{21, 22} The site also sits inside Andhra Pradesh's emerging green-industrial ecosystem: the state has scaled renewable capacity from 1.3 GW in 2014 to 9.5 GW in 2024, is building the Pudimadaka green-hydrogen hub near Visakhapatnam, amounting to 20 GW of dedicated renewables targeting ~1,500 tonnes of green hydrogen per day; expected to be finalised by 2032, and offers clean-energy incentives under its Integrated Clean Energy Policy.^{23, 24}

Analysing a real site is critical because each candidate route imposes distinct operational requirements, demanding varying ore qualities, distinct volumes of power and hydrogen, and specific downstream processing units. Green ironmaking encompasses several structural configurations: the DRI reactor can utilise a pellet-fed shaft furnace, or rely on a fluidised bed or rotary kiln charged directly with ore fines. Delivering its product straight to an EAF, the shaft furnace requires DR-grade pellets, containing approximately 67% Fe with gangue content under ~2%, in contrast to BF-grade pellets, which typically offer 63–65% Fe and tolerate higher gangue levels. DR-grade iron ore is scarce in India and priced at a premium, so the shaft furnace's case rests on securing low-cost supply. The fines-based routes sidestep the pellet constraint by using abundant low-grade domestic ore, at the price of an extra smelting step downstream: their higher-gangue iron is melted in an electric smelting furnace (ESF) into hot metal (pig iron), which a converter then refines into steel. The same principle lets a shaft furnace run on cheaper BF-grade pellet, sending its DRI to a smelter rather than to an EAF.²⁵ The economics of green steel turn equally on carbon-price exposure, on whether the reducing gas starts as natural gas or hydrogen, and on how the plant procures electricity and hydrogen under Andhra Pradesh's specific policies. This analysis therefore takes these factors in turn, organised around five decision-relevant questions (Figure 1.1). The first four examine the economics at a 2030 snapshot and the fifth runs that snapshot forward in time.



1	The green premium and the route choice What green steel costs by route, and vs BF-BOF	Section 4
2	Carbon-price pressure India's carbon market (CCTS) first, then the EU's CBAM, as both tighten	Section 5
3	The fuel choice: hydrogen and natural gas Cost, emissions, and risks as the hydrogen blend changes	Section 6
4	Power and hydrogen procurement How to source power, and whether to make or buy hydrogen	Section 7
5	The time dimension How the answers evolve as carbon rises and hydrogen costs fall	Section 5 to 7

Figure 1.1 The five decision-relevant questions, mapped against the value chain and the report sections that answer them.

2. TECHNICAL REVIEW: THE THREE DIRECT-REDUCTION TECHNOLOGY PATHWAYS

DRI production technologies strip oxygen from iron ore in the solid state, and the resulting metallic iron is then melted into crude steel. India's existing sponge-iron kilns do this with coal; the three DRI routes examined here (shaft furnace, fluidised bed, rotary kiln) use reducing gas (natural gas, hydrogen, or a blend) to avoid the high carbon emissions of coal. The three routes differ chiefly in the reactor and, critically, in the grade of iron ore they require. This drives the trade-off shown in Table 2.1: the fines routes save on the iron-feed line but consume more of others (more ore mass, more electricity, more hydrogen, and carbon that must be added at the smelter), because they carry the ore's gangue into an ESF, an additional smelting vessel that plays the role of the blast-furnace hearth (Section 2.4). All figures are converted at ₹87.16 to the U.S. dollar, the 2025 average rate used throughout.

Consumable	Unit	Shaft furnace	Fluidised bed	Rotary kiln
Iron feed – mass	t/tcs (wet) ²⁶	1.31	1.99	1.99
Iron feed – grade ²⁷	%Fe	67 (pellet)	58 (fines)	58 (fines)
Iron feed – unit price	\$/t	138	59	59
Iron feed – cost ²⁸	\$/tcs	181	117	117
Electricity (steel only)	kWh/tcs	1,322	1,644	1,487
Of which DRI	kWh/tcs ²⁹	649	990	810
Of which steelmaking	kWh/tcs	674	654	677
Hydrogen (if 100%)	kg/tcs	53.7	60.8	59.4
Electricity for electrolysis	kWh/tcs	2,753	3,114	3,046
Natural Gas (if 100%)	MMBtu/tcs	8.8	11.6	11.1
Flux (burnt limestone)	t/tcs	0.034	0.120	0.120
Electrode ³⁰	t/tcs	0.0020	0.0013	0.0014
Oxygen	Nm ³ /tcs	50	81	81
Carburising carbon	t/tcs	–	0.052	0.058

Table 2.1 Physical consumables per tonne of crude steel. Hydrogen, electrolysis power and natural gas are each shown for the pure-fuel case; the routes are examined across the full range in Section 6. The hydrogen, reduction-stage power and natural-gas intensities are technical inputs from the reactor literature and expert review; the per-tonne-of-steel quantities are computed from the ore and reactor mass balance. Electricity rows are for the 100%-hydrogen configuration; on natural gas the kiln and the reformer duties are gas-fired instead. The shaft-furnace column reflects its EAF metallic charge of 0.93 tDRI plus 0.15 tScrap per tonne of steel, while fines routes charge no scrap. Appendix A carries the full input set.

2.1 SHAFT FURNACE DRI: THE MATURE, PELLET-BASED ROUTE

The shaft furnace is the dominant commercial DRI technology, with more than 80 plants worldwide and substantial Indian operating experience. India's gas-based, shaft furnace DRI capacity is about 12.3 Mtpa, concentrated in three plants: AM/NS Hazira (6.8 Mtpa), JSPL Angul (1.8 Mtpa, on syngas from coal gasification) and JSW Dolvi (1.6 Mtpa).^{31, 32, 33} Mechanically the reactor is simple: pellets descend through a refractory-lined shaft against an ascending reducing gas at 800–950 °C, reduced in the upper zone and cooled or carburised below. Two technology designs dominate: Midrex, which reforms natural gas in an external reformer, and Energiron/HYL, which reforms in situ at higher pressure and tolerates the higher hydrogen fractions more readily. Both accept high hydrogen shares: 100% hydrogen operation has been demonstrated at pilot scale, and the first commercial-scale 100% hydrogen units are under construction in Sweden.

Its principal current constraint is that it requires high-grade, iron-ore pellets, around 67% iron, with gangue under about 2%, because its DRI is charged directly to an EAF. Reduction removes oxygen, not gangue: whatever silica and alumina enter with the pellet leave in the DRI, and an EAF can only remove them by fluxing and melting them into slag, at the cost of lime, electricity, refractory wear and iron yield. Beyond roughly 3–4% gangue, that penalty becomes prohibitive, which is what sets the specification: the reactor itself tolerates leaner burden, and the specification comes from the pellet form the shaft needs plus what the EAF can afford. As competing virgin iron tightens, higher-gangue DRI may find buyers at a discount, but the penalty logic stands. In the Indian context, where much domestic ore is low-grade, this means either buying premium DR-grade pellet or upgrading low-grade ore through beneficiation and pelletising. At this site, however, the constraint is softened. AM/NS's slurry-pipeline link to the high-grade Bailadila ore, among India's highest-grade hematite, gives access to feed that can be upgraded to DR-grade without the deep beneficiation that typical 58% Fe domestic ore would demand. This in-house pellet position can give the route an important cost advantage. The reduced iron is melted in an EAF; the model assumes the shaft furnace can be turned down to 50% of capacity, ramping at up to 5% an hour.

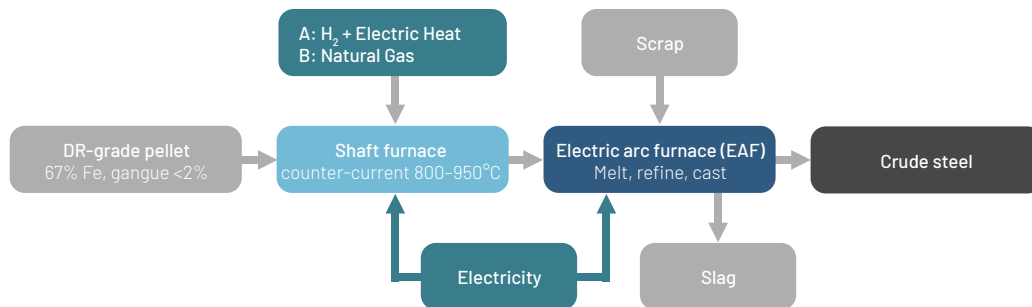


Figure 2.1 Shaft furnace DRI route

2.2 FLUIDISED BED DRI: FINES-BASED, PILOT-SCALE

Fluidised-bed DRI reduces fine iron ore directly in a fluidised bed, without first agglomerating it into pellets. This could be an important advantage in India's ore market, and at this site: it can use low-grade ore fines (around 58% iron) directly, side-stepping the cost of beneficiation and pelletising. The reactor is a cascade of fluidised

beds in series, counter-current to the gas: fines are suspended in the rising reducing gas and pass stepwise from hematite to magnetite to wüstite to metallic iron, at roughly 400 °C, 650 °C and 700 °C.³⁴ Dispensing with the packed bed is what allows fine feed, but it introduces the failure mode that has dogged the attempts: as metallisation rises, the iron particles become sticky and agglomerate, defluidising the bed. Circored in Trinidad (0.5 Mt/y of hot briquetted iron (HBI)) fought sticking and plugging through its ramp-up, ran above nameplate capacity once fixed in 2001, but was idled later again; it was restarted in 2004 but is now closed.³⁵ The two FINMET plants, at Port Hedland and Puerto Ordaz (2.0 and 2.2 Mtpa targets, from 1999), hit ore sticking from the start and never consistently reached design output.³⁶ A fluidised bed also needs far more gas in circulation than it consumes, of order 2.5 times the stoichiometric hydrogen requirement, to hold the equilibrium toward metallic iron; hence large reactors, heavy recycle duty and the highest reduction-stage power demand of the three routes. Against that history, POSCO's FINEX plants at Pohang show fluidised-bed pre-reduction of fines running commercially at 1.5–2.0 Mtpa, though coal-based and coupled to a melter-gasifier rather than to hydrogen.³⁷ The reduced fines are melted in an ESF and refined in a BOF, the configuration POSCO's HyREX programme has adopted.³⁸ The technology is at pilot / pre-commercial scale (technology readiness level, TRL, 4–5): references include the 1999 Circored plant, and current pilot programs HYFOR (Primetals, Austria) and HyREX (POSCO, Korea).^{39, 40} It is also the least flexible of the three, which mandates operational output maintained between 70% and 100% of nameplate capacity and ramping at a maximum of 10% an hour. And as a pilot-stage technology, its capital cost carries a wide uncertainty band in the coming decade.

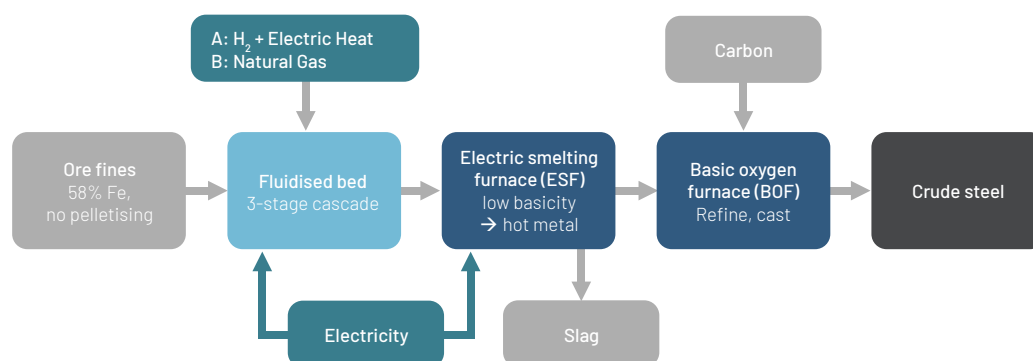


Figure 2.2 Fluidised Bed DRI route

2.3 ROTARY KILN DRI: FINES/LUMP-BASED, EARLY-COMMERCIAL

In India today, coal-based rotary-kiln direct reduction is extensively deployed within the sponge-iron industry. Over 300 of these plants run on domestic non-coking coal containing 35–45% ash, yielding approximately 85% of the nation's total DRI.¹ Adopting hydrogen in a rotary kiln retains the established mechanical baseline; an inclined, rotating cylinder with solids tumbling counter-current to the gas flow. However, internal combustion is swapped for electric-resistance heating, keeping the reducing gas free from combustion byproducts so it can be recycled efficiently. Conversely, when fuelled by natural gas, the kiln relies on traditional firing to supply both process heat and reduction, as resistance heating elements struggle to attain the higher operating temperatures needed. This thermal penalty translates to an estimated 60% firing efficiency for the rotary kiln, compared to 80% for a shaft furnace. A key operational advantage of rotary kilns is their ability to process ore fines or lump directly, eliminating the need for pelletisation.⁴¹ The technology currently sits at an early-commercial stage (TRL 7–8).

Its flagship benchmark is Hylron's Oshivela facility in Namibia; its 15,000 t/year green-hydrogen rotary kiln has been in operation since March 2025, with an additional 185,000 t/year under construction to achieve a total site capacity of 200,000 t/year.⁴² Like the fluidised bed, the reduced product is melted in an ESF and refined in a BOF. Its electrically heated kiln draws the least power of the three at the reduction stage, using 650 kWh per tonne of DRI at 100% hydrogen, against 700 for the shaft furnace and 800 for the fluidised bed. This is because the kiln is heated electrically rather than by burning part of the gas, so no excess preheated gas is needed as a heat carrier. It also provides superior operational flexibility, achieving turndown to 40% of output capacity and ramping up to 20% per hour. Its case therefore rests on cost as much as on iron-feed flexibility and Indian operating familiarity. Two things currently hold the readiness back: 1) accretion (ring build-up on the kiln wall), a documented failure mode of coal kilns; hydrogen kilns run cooler and Oshivela has not reported it, but long-campaign evidence is thin; 2) unit size: Indian coal-based kilns run at 50–900 tonnes a day and Oshivela's first module is smaller still, whereas shaft furnaces can supply 1 Mtpa and above, so a 9.6 Mtpa plant implies a large number of parallel kilns rather than a handful of shaft furnaces. Modularity is also why the route turns down so well and can be staged against the build-out of renewable and hydrogen supply, but scaling many units is a different proposition from scaling one.

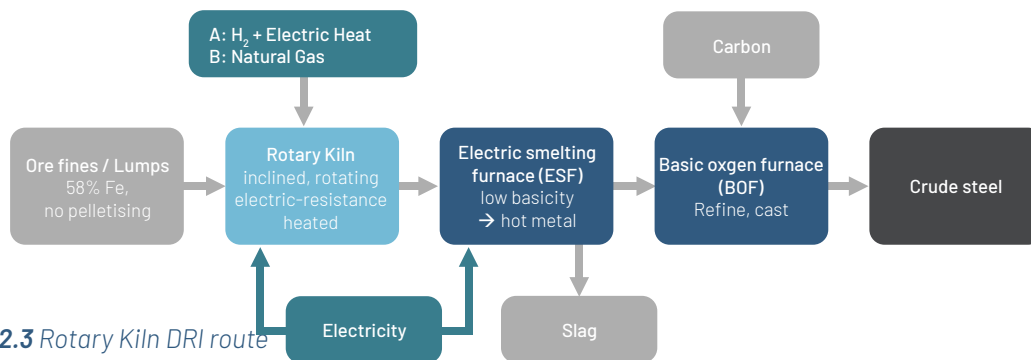


Figure 2.3 Rotary Kiln DRI route

2.4 THE DOWNSTREAM CONSEQUENCE: EAF AGAINST SMELTER-PLUS-CONVERTER

The choice of DRI reactor decides the remaining steelmaking process as well, and this is where most of the cost difference in Table 2.1 actually sits. DRI made from DR-grade pellet is clean enough to charge straight to an EAF, which melts and primary refines in one vessel. DRI made from 58% Fe fines is not: it carries roughly 19% gangue, and an EAF would require additional fluxing and melting. The fines routes therefore melt in an ESF, which behaves much like the hearth of a blast furnace. It runs at low basicity, takes the gangue off as slag, delivers hot metal as pig iron, still carrying carbon, silicon and phosphorus, and then refines that hot metal in a BOF. This extra ESF vessel is the price of the cheaper feed, though not purely a cost: it keeps the conventional BOF step unchanged, mirroring the blast-furnace pattern, allows extended refining, and is less sensitive to nitrogen pick-up than an EAF route. However, it increases consumption of lime, oxygen, and carburising carbon, leading to a post-reduction energy demand of 654–677 kWh/tcs that rivals the 674 kWh/tcs needed by a shaft furnace–EAF route. When combined with the higher energy needs of rotary or fluidised bed reduction stages, overall process energy requirements scale up significantly.

While electric smelting furnaces are well-established in adjacent applications like ferroalloy and ilmenite processing, none have operated at commercial steel-plant scale yet. Consequently, demonstrating ESF technology for DRI service remains a key readiness threshold that both ore-fines routes must overcome. In Indian practice, small coal-based kiln DRI is often melted in induction furnaces instead. That configuration does not scale to a 9.6 Mtpa plant, so this report models only the two melting configurations a plant of this size would use: an EAF for the low-gangue DRI of the shaft furnace, and an ESF followed by a BOF for the high-gangue DRI of the fines routes.

3. SCOPE, ASSUMPTIONS AND COST METHODOLOGY

This section outlines the analytical scope, baseline assumptions, and the core methodology used to determine the production costs and carbon emissions associated with steelmaking. This study solves the plant at a scale of 9.6 Mtpa of crude steel, as an estimate of the capacity of the AM/NS Rajayyapeta greenfield plant Phase 2, but the cost of steel is computed per tonne.⁴³

3.1 HOW THE COST AND EMISSIONS OF STEEL ARE CALCULATED

The central metric is the Levelised Cost of Steel (LCOS): the break-even selling price, in U.S. dollars per tonne of crude steel (\$/tcs), that recovers all capital and operating costs over each asset's economic life, including the iron- and steelmaking plants and the cost of obtaining materials, fuels, and energy (electricity, hydrogen, or natural gas, etc.).

For cases that build their own power or hydrogen, an hourly optimisation model sizes and dispatches the renewable, electrolyser, battery and hydrogen-storage assets at least cost subject to an emission-intensity limit.⁴⁴ The DRI reactors' turndown and ramp limits and how they interact with variable renewable supply are also modelled. Cases that instead buy power or hydrogen take the contracted price directly. Carbon credits, a revenue or a charge, and the subsidies described below are netted from the LCOS.⁴⁵

Emissions are accounted cradle-to-gate: the plant's direct process emissions (Scope 1) and purchased-electricity emissions (Scope 2), plus the embedded (Scope 3) emissions of purchased materials. Fuel supply chains are outside this boundary: the natural-gas count the combustion of the gas but not the liquefaction, shipping and methane leakage behind imported LNG, and the BF-BOF comparator likewise excludes coal-mine methane. In this report, this cradle-to-gate intensity is the default basis for reporting steel sector emissions and for the emission-intensity cap; the CCTS and the EU CBAM count narrower statutory boundaries, and this analysis prices each instrument on its own boundary.

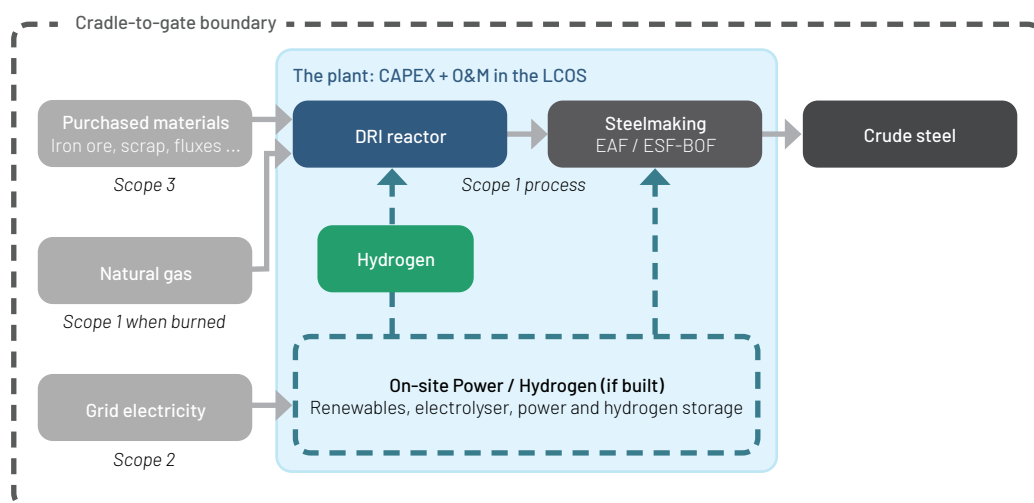


Figure 3.1 System boundary used for cost and emissions accounting. The LCOS finances everything inside the plant panel and pays the price of every purchased flow crossing it; emission intensity counts the plant's Scope 1 and 2 plus the embedded Scope 3 of purchased materials.

3.2 KEY COST AND TECHNICAL ASSUMPTIONS

Table 2.1 sets out the physical consumables per tonne of crude steel; the table below sets out the price, finance and policy assumptions of the study. Two physical inputs are worth stating here because they differ by route: a) Hydrogen consumption scales with the oxygen actually removed per tonne of DRI rather than with DRI mass, so the gangue-bearing fines DRI needs less per tonne than DR-grade pellet DRI: 58 kg/tDRI for the shaft furnace against 49.1 for the fluidised bed and 47.7 for the rotary kiln; b) Reduction-stage electricity at 100% hydrogen is 700, 800 and 650 kWh/tDRI respectively, and delivered natural gas in the all-gas case is 9.5, 9.3 and 8.8 MMBtu/tDRI.⁴⁶

Input	Central value	Note
Plant modelled	9.6 Mtpa at 85% capacity factor	AM/NS Rajayyapeta greenfield Phase 2
Investment Year	2030	Year of the Phase-2 decision; inputs take their 2030 values, purchased commodities escalating at 2%/yr in real terms from their 2025 reference
Weighted Average Cost of Capital (WACC)	10% nominal	Standard Indian project benchmark; each asset is amortised over its own economic life (Appendix A.4)
DR-grade pellet (shaft-furnace)	\$138/t	BF-grade domestic PELLEX ⁴⁷ price (\$114 in 2025, Fe 63%), escalated to \$126 for 2030, plus a 10% DR-grade premium
Low-grade ore fines (fluidised bed / rotary kiln)	\$59/t	Indian low-grade hematite (58% Fe); IBM average sale price ex-mine plus grinding, \$53.5 in 2025, escalated to 2030
Natural gas	\$13/MMBtu	Delivered R-LNG \$11.7/MMBtu in 2025, escalated to 2030

Input	Central value	Note
Power	\$0.044/kWh all-in	The base case sources renewable electricity through a group-captive structure: the consumer holds an equity stake ($\geq 26\%$) in the generator, which exempts it from the cross-subsidy surcharge under the Electricity Rules 2005. The contracted portfolio is a shaped solar-and-wind hybrid taken as generated and firmed by monthly banking with the DISCOM rather than by storage. The delivered cost is $\approx \$0.044/\text{kWh}$.
Hydrogen	On-site generation	The base case produces hydrogen on-site by alkaline electrolysis, sized and dispatched by hourly optimisation alongside the power system, within each reactor's turndown and ramp limits. It draws a 25% capital subsidy and the SIGHT production subsidy.
- Electrolyser	\$394/kW with 25% of CAPEX subsidy	Alkaline electrolyser installed cost (including balance of plant and EPC) \$525/kW in 2030, 25% CAPEX subsidy applied under AP Integrated Clean Energy Policy ¹⁸
- Hydrogen production subsidy	\$0.5/kg H_2 (years 1-3)	The Strategic Interventions for Green Hydrogen program (SIGHT) under the National Green Hydrogen Mission (NGHM) ¹⁰ provides a declining ₹50/40/30 per kg over the first three production years
Domestic carbon price	\$0/tCO ₂	The base case prices no carbon.

Table 3.1 Input of the base case.

3.3 THE DECISION SPACE: THE BASE CASE AND WHAT WE TEST AGAINST IT

The analysis is built around the base configuration described in Table 3.1; each major choice is then tested against the following alternatives.

Decision lever	Central case	Alternatives tested	Section
DRI route	Shaft furnace (DR-pellet → DRI → EAF)	Fluidised bed, rotary kiln (low-grade fines → DRI → ESF → BOF)	Section 4
DR-grade pellet price	\$138/t	\$126 (BF-grade floor) → \$184 (imported DR-grade)	Section 4
Carbon price	\$0/tCO ₂	India domestic CCTS; EU CBAM; rising trajectory	Section 5
CCTS reduction targets	n/a	Targets on the BF-BOF fleet tightening 2% or 5% a year; carbon price \$24-50/tCO ₂	Section 5
Fuel / reductant	100% green hydrogen	100% natural gas → blends → 100% hydrogen	Section 4 & 6
Power procurement	Group-captive renewables (shaped hybrid, banked)	Third-party open access, shaped open access with/without DISCOM banking, on-site captive	Section 7
Hydrogen supply	On-site electrolysis	Purchase from hub	Section 7

Table 3.2 The decision space: the base case and the alternatives tested against it.

4. THE GREEN PREMIUM AND TECHNOLOGY CHOICE

This section answers the first decision question: what steel costs to make via the three DRI routes in the base case, before any carbon price or credit. We find that at 100% hydrogen, green DRI steel costs about 6–13% more than steel from a BF-BOF. On cost, the rotary kiln is the cheapest route across the fuel range, about \$35/tcs below the shaft furnace at 100% hydrogen; the fluidised bed sits about \$3/tcs below the shaft furnace. The shaft furnace retains an advantage in emissions and technology maturity, while the rotary kiln leads on cost through its tolerance of low-grade ore and its independence from the DR-grade pellet market.

4.1 THE COST OF GREEN STEEL BY ROUTE AND FUEL

Compared on a common basis at 100% hydrogen, the rotary kiln is the cheapest route (\$571/tcs against the shaft furnace's \$606; Figure 4.1) while the fluidised bed costs \$603, giving green premiums over the BF-BOF incumbent (\$536/tcs) of 6%, 13% and 13% respectively.⁴⁸ The fines routes (rotary kiln and fluidised bed) reach that position from a large head start, most of which is given away. Reducing low-grade ore directly without beneficiation and pelletisation saves \$64/tcs on the ore itself, though only \$58/tcs once the rest of the reduction stage's operating cost is counted. However, a significant portion of this advantage is offset downstream: the smelting stage requires about 35% more reduced iron, along with supplementary energy demands for both the ESF and BOF. The rotary kiln retains about three-fifths of its initial cost lead, whereas the fluidised bed keeps only a few dollars of it. These estimates include India's hydrogen support: the Strategic Interventions for Green Hydrogen Transition (SIGHT) production incentive and the state electrolyser capital subsidy, which contribute a \$16–18/tcs credit at 100% hydrogen.⁴⁹ Without it the routes costs \$588–622/tcs, a premium of 10–16% (rotary kiln \$588, fluidised bed \$621, shaft furnace \$622). However, the support is not assured for a plant of this size: SIGHT has not been extended to steel offtake, the electrolyser schemes are tendered in limited tranches, and the state capital subsidy is capped state-wide (Appendix B). This cost ordering holds across the fuel range, but the margins narrow when using natural gas. Here, the rotary kiln makes steel for about \$531/tcs, slightly below the greenfield BF-BOF, while the shaft furnace is at \$553 and the fluidised bed, at \$554, is effectively level with it. Using natural gas, the fines-based routes consume roughly 30% more fuel than the shaft furnace because gas consumption is tied to DRI volume and the downstream smelter demands about 35% more DRI per tonne of crude steel. When transitioning to hydrogen, the fuel fulfills only the chemical reduction requirements, leading to near-stoichiometric hydrogen consumption across all DRI reactor types. Shifting from 100% natural gas to 100% hydrogen transfers process heating to electricity, eliminating \$144–151/tcs of gas expenditure in the fines routes compared to \$114/tcs in the shaft furnace. However, because the required hydrogen and heating electricity are also incurred per tonne of DRI, these input intensities make the fines routes about 11–13% more expensive per tonne of steel for these components. As the hydrogen proportion increases, these combined factors expand the shaft furnace's cost disadvantage relative to the rotary kiln and erase its margin over the fluidised bed.

Between the two fines routes, the fluidised bed's premium over the rotary kiln is about \$33/tcs at 100% hydrogen, and it divides into two parts. The first is capital: its reactor costs \$400 per tonne of annual DRI capacity against the kiln's \$300, worth about \$19/tcs once annualised; both figures are early-stage estimates and carry wide uncertainty.⁵⁰ The second is reduction-stage power: the fluidised bed draws 800 kWh/tDRI against the kiln's 650, because it must hold far more gas in circulation than it consumes to keep the reduction equilibrium moving toward metallic iron, and that gas has to be reheated and recompressed for recycle. On an as-generated renewable

portfolio the difference is amplified, because the extra load must be built and firmed rather than simply bought. Flexibility works in the same direction but second-order. All three reactors run to nameplate availability, but their turndowns are different. The kiln follows the generation profile down to 40% of capacity and back at 20% an hour, holding temperature through low-generation hours, while the fluidised bed holds above 70% and moves at only 10%/hr, so it draws more grid power when the renewable portfolio falls short, increasing both emissions and cost. Using natural gas, the fuel is delivered on demand and heat is not electric, so the cost difference between the two fines routes is mostly the capital difference.

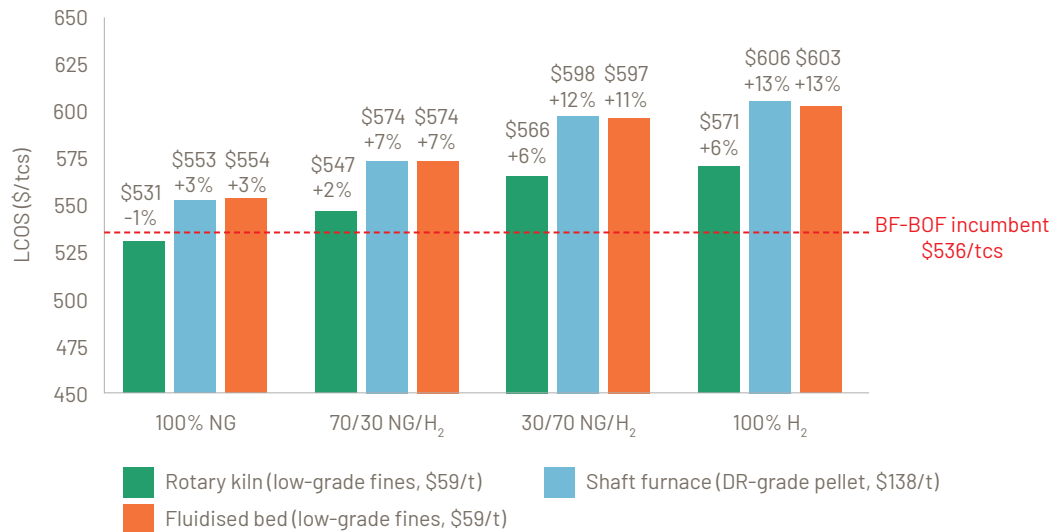


Figure 4.1 LCOS by route and fuel without carbon credit. Labels show LCOS and premium relative to the BF-BOF (\$536/tcs).

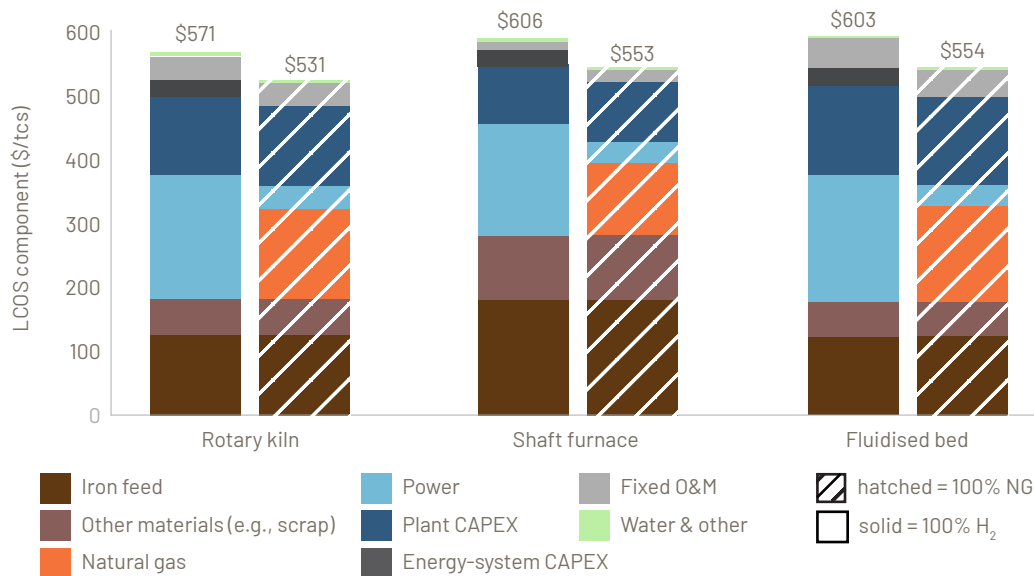


Figure 4.2 Cost decomposition at 100% hydrogen (solid) and 100% natural gas (hatched).

4.2 THE IRON-FEED ADVANTAGE AND THE PELLET CONDITION

The structural appeal of the fines routes is that the technologies tolerate low-grade ore, avoiding the beneficiation and pelletisation premium that DR-grade pellet embodies (\$117/tcs vs. \$181/tcs; see Table 2.1). Rahbari et al. (2025) find this advantage decisive in Australia, where expensive high-grade pellets make the fluidised bed the economic route to green steel from low-grade ore.³⁴ The ore saving matters in this case too, but as the fines routes need to give back much of their saving on iron feed to the smelting process, the price difference between the DR-grade pellet and low-grade fines becomes decisive.

As shown in Figure 4.3, holding the fines price constant, the rotary kiln undercuts the shaft furnace at any DR-grade pellet price above \$111/t, and the fluidised bed above \$136/t. Our \$138/t for DR-grade pellet is the domestic BF-grade price plus a conservative 10% premium, sitting at the lower end of the \$12–17/t range reported for DR-grade over BF-grade pellet, reflecting AM/NS's ore slurry pipeline access and captive pellet position.⁵¹ Even so, both fines routes remain cheaper, the rotary kiln clearly and the fluidised bed by about \$3/tcs. Therefore, any widening of the DR premium benefits the fines routes. At the imported DR-pellet price (~\$184/t) the shaft furnace rises to about \$666/tcs, with both fines routes clearly cheaper.

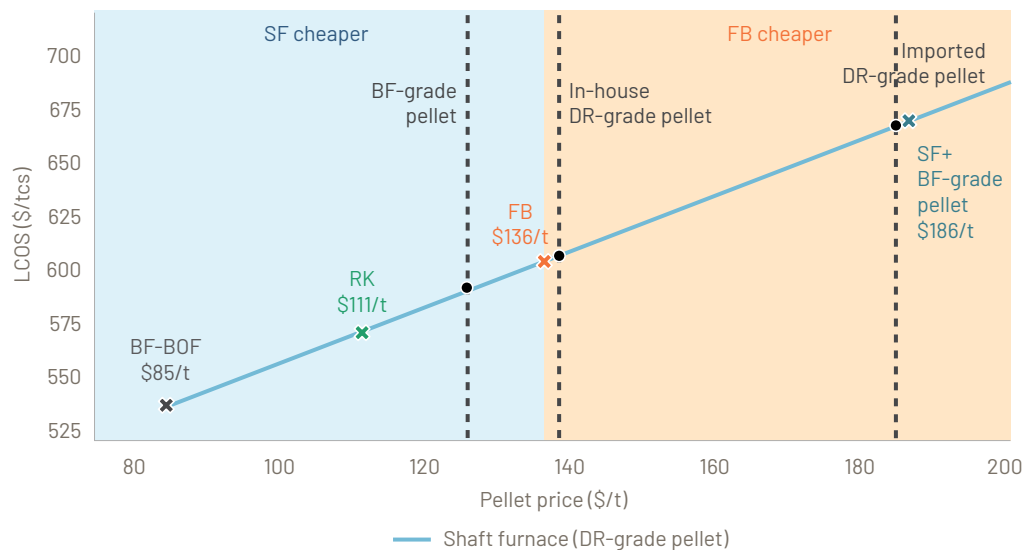


Figure 4.3 Shaft furnace LCOS (blue line) versus pellet price, at 100% hydrogen. Crosses mark the break-even pellet price against the other routes (green: 100% hydrogen rotary kiln; orange: 100% hydrogen fluidised bed; purple: 100% hydrogen shaft furnace with BF-grade-pellet and smelter; red: BF-BOF). Dashed lines mark reference pellet prices. SF: shaft furnace; FB: fluidised bed; RK: rotary kiln; BF-BOF: blast furnace and basic oxygen furnace.

India's pellet industry is large with national pellet capacity reaching about 164 Mtpa in FY2024–25, up from 148 Mtpa the previous year as domestic capacity expanded.¹ The bulk is BF-grade and the BF-grade products are mostly consumed by India's coal-based DRI units. True DR-grade pellets (~67% Fe, gangue under ~2%) are scarce: most domestic ore is hematite from Odisha, Jharkhand and Chhattisgarh, much of it needing substantial beneficiation to reach DR-grade. Transportation and storage challenges for iron ore concentrate and pellet, and a volatile pellet market, compound the problem.⁴ That scarcity also carries a price globally: on the seaborne (Brazil/Atlantic)

market, DR-grade pellet premiums have run at roughly \$45–60/t over the 65% Fe index,⁵² and are expected to widen if DRI capacity additions outpace DR-pellet supply.

AM/NS is one of the largest pellet producers in India, with about 20 Mtpa of pelletisation capacity: 12 Mtpa at Paradeep, the largest single-location pelletising complex in the country, and 8 Mtpa at Visakhapatnam. Its Visakhapatnam pellet plant is being expanded to 12 Mtpa with a new travelling-grate pelletising line (operational ~2027) that can produce both BF-grade and DR-grade pellets.⁵³ AM/NS Rajayyapeta greenfield's Phase 1 also includes a 14 Mtpa captive pellet plant at the site itself. The main advantage of the AM/NS in-house pellet plant is that it is fed with high-grade Bailadila ore through the slurry pipeline; unlike the typical low-grade Indian iron ore, the Fe content of the Bailadila ore runs as high as 64–69% Fe, making it a good fit for supplying the DR-grade pellet needed by the shaft furnace route.²¹ However, how much DR-grade pellet these captive pellet plants can actually deliver, and at what cost, remains an important open question.

Alternatively, should low-cost DR-grade pellets remain unavailable, could the facility circumvent this limitation by substituting cheaper, more abundant BF-grade pellets? Because BF-grade pellets contain ~10% gangue, feeding high-gangue DRI directly into an EAF is unfavourable; doing so imposes operational constraints past a certain threshold and requires extra lime, electricity, and iron-yield losses to melt and flux away the gangue. Like the fines route, the high-gangue DRI needs an ESF and BOF downstream to remove the gangue as slag. We test this configuration (shaft furnace DRI-ESF-BOF on BF-grade pellet at \$126/t) and derive an LCOS of \$669/tcs at 100% hydrogen, the most expensive configuration examined, because the pellet discount is outweighed by the extra pellet and hydrogen required and the smelter's capital and power. The comparison is, however, sensitive to the DR-grade premium. If domestic premiums widened toward seaborne levels (e.g., the imported DR-grade price of ~\$184/t), the gap would narrow to about \$3/tcs; the BF-pellet configuration draws level with the standard shaft-furnace-EAF route only if DR-grade pellet reaches about \$186/t (Figure 4.3).

4.3 EMISSIONS AND MATURITY

Eliminating metallurgical coke through direct reduction allows every evaluated pathway to achieve emissions well below those of the traditional BF-BOF route (Figure 4.4). Operating entirely on natural gas, emission intensities range from 0.81 tCO₂/tcs for the shaft furnace to 1.21–1.22 tCO₂/tcs for the fines-based pathways. These levels represent a 53–69% decrease compared to the BF-BOF benchmark of 2.6 tCO₂/tcs, comfortably placing all options within the top 5-star rating (≤ 1.6 tCO₂/tcs) defined by the Indian Green Steel Taxonomy. The BF-BOF benchmark of 2.6 tCO₂/tcs and \$536/tcs is for a coke-oven, sinter-plant, BF-BOF configuration (i.e., the one for Phase 1) that is used in the UC Berkeley 2026 study.⁵⁴ The emission of 2.6 tCO₂/tcs is on the high side for a furnace built new but this does not qualitatively change any result of this study.⁵⁵

As the proportion of hydrogen increases, overall emissions decline steadily. Under a 100% hydrogen operating scenario, emissions for the three direct-reduction pathways range from 0.29 to 0.57 tCO₂/tcs. Across this spectrum, the shaft furnace-EAF route demonstrates a clear performance benefit, achieving an intensity of 0.29 tCO₂/tcs, beneath the IEA near-zero benchmark of 0.4 tCO₂/tcs, whereas the fines-based pathways remain higher at 0.55–0.57 tCO₂/tcs. This emissions discrepancy is primarily driven by downstream processing at the smelter. To complete the reduction process and achieve necessary carburization of the hydrogen-reduced iron (producing hot metal at ~3.5% C), carbon must be introduced. The oxidation of this added carbon inside the ESF and BOF generates an additional burden of ~0.20 tCO₂/tcs, an operational requirement avoided by the

shaft furnace-EAF configuration.⁵⁶ A secondary factor is the greater electrical consumption of the fines routes, which incurs grid-related emissions whenever renewable contract generation is insufficient to cover demand. Conversely, in the upstream supply chain, the shaft furnace exhibits higher embedded emissions because iron ore pelletisation involves more induration carbon than the raw ore fines used by competing routes.

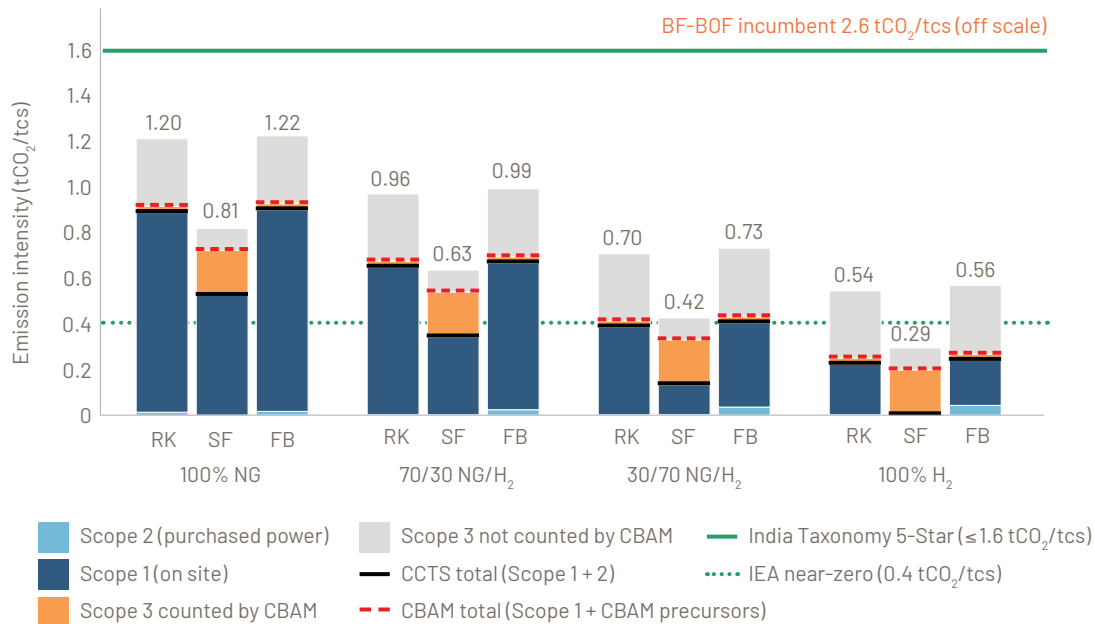


Figure 4.4 Emission intensity by route and fuel mix. This section only discusses cradle-to-gate (Scope 1+2+3) emission intensity; the CCTS and CBAM boundaries are discussed in Section 5.

Note that the natural-gas cases here count the combustion of the gas but not its supply chain. Incremental gas for the site would be regasified liquefied natural gas (LNG; Section 6.3), and liquefaction, shipping, regasification and methane leakage along that chain adds about 13–18 kgCO₂e/MMBtu on a 100-year GWP basis, adding about 0.14 tCO₂e/tcs for the shaft furnace on 100% natural gas and about 0.2 tCO₂e/tcs on the fines routes; these additional emissions doubles on the 20-year GWP metric.⁵⁷ The coking-coal mine methane behind the BF-BOF is uncounted in the same way and would raise the incumbent BF-BOF emissions of 2.6 tCO₂/tcs by a comparable amount. On a lifecycle basis the gas routes remain roughly 45–65% below the incumbent, but the gap against the hydrogen routes are larger.

On the other hand, we assume a static emission footprint for the BF-BOF route, as a conventional blast furnace. Hydrogen injection, heat-balance optimisation and oxygen enrichment are technologies the steel industry is currently exploring to cut the technology's emissions without changing the route.^{58, 59} However, this does not change the advantage of DRI over BF-BOF on emission: 1) The deep emissions cuts in these technologies are largely test-furnace results; commercial injection without CCUS cuts a blast furnace's own emission by 10–20%; 2) Hydrogen goes further in a DRI than in a blast furnace: Under simulated operating conditions, injection into a blast furnace needs about 2.1–2.8 kgH₂/tcs of each 1% cut in CO₂, against about 0.7 kgH₂/tcs when hydrogen DRI replaces blast-furnace iron. Even 29–34 kg of injected hydrogen per tonne cuts emissions by only 21–26%. The same electrolyzers and renewable power therefore do 3–4 times the work in a DRI; 3) a decarbonised furnace

remains a coke asset: even at the 43% test-furnace result, a BF-BOF with hydrogen injection would emit about 1.3–1.5 tCO₂/tcs despite Scope 2, a gap of more than 1.0 tCO₂/tcs against the hydrogen-shaft-furnace route. For a greenfield plant committed for forty years, the decarbonising blast furnace is a lower ceiling reached with more hydrogen, not an alternative to the route choice.

The three pathways vary significantly in terms of technological maturity. The shaft furnace represents a fully commercialised route (technology readiness level 9 on natural gas), backed by extensive operational experience in India. Beyond the country's existing 12.3 Mtpa natural gas shaft furnace capacity, the Ministry of Steel has backed pilot projects operating on 100% hydrogen while the first commercial-scale 100% hydrogen plants are under construction in Sweden. Conversely, although India boasts the world's largest rotary kiln capacity, its current infrastructure is entirely coal-fired.¹ While the mechanical and operating familiarity may transfer, the gas-based adaptation of a kiln sits at early-commercial scale and unit size is its limit: the only hydrogen rotary kiln in operation, Hylron's Oshivela plant in Namibia, makes 15,000 t of DRI a year, and India's largest coal-fired kilns are about 0.2 Mtpa each, so a 9.6 Mtpa Phase 2 would need on the order of fifty such modules. The kiln's modularity is therefore also its scale problem, which is why this report treats it as the fines-route option to develop rather than the reactor to build Phase 2 on. The fluidised bed has neither advantage: it is at pilot scale, with no Indian operating base at all.⁶⁰

The terms of choice are therefore: at 100% hydrogen the rotary kiln is the cheapest route, the fluidised bed sits marginally below the shaft furnace, and the shaft furnace is the cleanest and the most technologically mature. What the fines routes offer is freedom from DR-pellet supply, at a clear cost benefit especially for the rotary kiln, together with wider operating flexibility and, for the kiln, modular scaling, in exchange for higher emissions and less mature reactors. As the DR-grade pellet price sits well above the rotary-kiln break-even, the case for the shaft furnace would normally be made on carbon and delivery risk, however the in-house AM/NS pellet plant can produce DR-grade pellets from the high grade ore slurry at likely very low cost. Between the two fines routes themselves, the choice would turn on reactor capital and near-term maturity, on both of which the rotary kiln currently has the advantage, given its lower capital cost and India's operating experience with kilns.

4.4 WHAT WOULD CHANGE THE RANKING?

Given the narrow cost differentials among the pathways, even incremental shifts in key variables can alter their relative economic ranking. A sensitivity analysis of the primary operational and market drivers demonstrates the conditions required to pivot the competitive balance.

Lever	Effect on the shaft-furnace vs fines-route balance	Likelihood
DR-grade pellet price drops	Below \$111/t (\$136/t) the shaft furnace undercuts the rotary kiln (fluidised bed)	Plausible; depends on the captive-pellet cost and iron ore quality. The fluidised bed cost sits very close to the shaft furnace, so which of the two leads depends on the ore price substantially.
Carbon price rises	Favours the shaft furnace (it is cleaner)	Likely over time
Fluidised bed / rotary kiln / smelter CAPEX falls	The fines routes are at pilot/early-commercial stage; a fall in CAPEX would deepen the fines routes' advantage, and may change the position between fluidised bed and rotary kiln.	Plausible as the technology matures
Power + electrolyser costs fall	Relatively favours the fines routes (they are more electricity-intensive and consume more hydrogen)	Realistic but slow
Fines route charge higher-grade fines	Running the rotary kiln or fluidised bed on higher-grade fines cuts smelting duty and other consumables at the cost of dearer iron feed; trades the same way as the pellet-price lever and narrows the shaft furnace's emission advantage.	Plausible where beneficiated concentrate is available.

Table 4.1 Conditions that would shift the balance between the shaft furnace and the fines routes.

5. CARBON PRICE: INDIA'S DOMESTIC MARKET AND THE EU CARBON BORDER

Whilst the previous section evaluated plant competitiveness relative to BF-BOF strictly on production costs, this section analyses the complementary lever for closing the green premium: imposing a cost on carbon emissions, which bears hardest on carbon intensive technologies. We examine two key regulatory frameworks affecting the facility: domestically, India's Carbon Credit Trading Scheme (CCTS), and internationally, the EU's Carbon Border Adjustment Mechanism (CBAM). Under the CCTS each plant is measured against a reduction target set from its own baseline, so what the carbon price is worth to a green plant depends on how fast the targets on the BF-BOF fleet tighten. At an indicative \$24/tCO₂ in 2030, targets tightening 2% a year are worth about \$5/tcs to a green plant in 2030 and \$10 by 2035; at \$50/tCO₂ with targets tightening 5% a year the value reaches \$25 and \$45, enough to close the rotary kiln's premium as Phase 2 commissions.⁶¹ However, the current CCTS design offers a greenfield green plant little direct incentive; a common emission intensity threshold, if the scheme evolves towards one, would reward green plants directly. The EU border adds a second and larger signal, but only for the small share of total Indian output that is exported to Europe.

5.1 WHAT EACH INSTRUMENT COUNTS

The emissions reported in Section 4 are cradle-to-gate throughout (Scope 1, Scope 2, and the embedded Scope 3 of purchased materials). However, CCTS and CBAM count different emissions. The CCTS obligation is set at unit level and counts Scope 1 plus Scope 2, so how the plant procures power feeds straight into its compliance position.¹⁵ The CBAM works the other way: for iron and steel it charges the direct emissions of each production step plus the embedded emissions of precursor goods but excludes the indirect emissions from purchased electricity. Because electricity sits outside the boundary for CBAM, renewable power earns no credit at the border, and green hydrogen is indistinguishable from grid-electrolysis hydrogen in a CBAM declaration.⁶² Under CBAM the shaft furnace carries the induration emissions of its purchased pellet, which is a CBAM precursor, while the fines routes carry nothing for their ore but pay instead for the flux and injected carbon that remove gangue in the smelter, which are direct emissions on site. The two effects significantly narrow the shaft furnace's emissions advantage: 0.196 against 0.247 tCO₂/tcs, where the cradle-to-gate figures are 0.292 against 0.540. The CCTS boundary cuts the other way. It counts no precursor emissions at all, so the shaft furnace's pellet drops out entirely and its domestic intensity falls to almost nothing, while the fines routes still carry the flux and injected carbon that remove gangue, because those are burned on site.

5.2 INDIA'S DOMESTIC CARBON MARKET

The Indian CCTS establishes a national carbon market in support of the country's updated nationally determined contribution (NDC) of a 47% cut in emission intensity below 2005 levels by 2035, on the way to net zero by 2070.⁶³ It works through two mechanisms: a compliance mechanism, which sets emission-intensity targets for energy-intensive units and issues tradable Carbon Credit Certificates (CCCs) to those that beat their target while requiring those that miss it to buy and surrender certificates; and a separate voluntary crediting mechanism, open only to non-covered entities. The steel sector was added in 2025, and its targets remain in draft: quantified unit-level targets were proposed in June 2025 and reissued as a revised draft in June 2026, but have not yet been finally

notified. The drafts set targets at the individual-unit level, from each plant's own baseline, continuing the approach of the Perform, Achieve and Trade (PAT) energy-efficiency scheme: for example, AM/NS's Hazira plant (baseline 2.2701 tCO₂e/t) must reach 2.1696 tCO₂e/t, a reduction of 4.4% over FY2025–26 and FY2026–27.^{1, 64}

The June 2026 revised draft sets cuts of a few per cent (a 2–3% cut in 2025–26 rising to 4–6% by 2026–27), and early credit prices are expected at around ₹800–900/tCO₂ (\$9–10/tCO₂) near-term.⁶⁵ This rewards efficiency improvement within the BF–BOF fleet but offers a greenfield DRI plant, whose own baseline would presumably sit near its already-low intensity, essentially nothing. New greenfield plants are outside the compliance mechanism until they are fully operational and have the 2–3 years of production data needed to set a unit-specific baseline, so Phase 2 would not enter before 2035, and the target it would receive is not yet defined. We therefore count neither a credit nor an obligation for the green plant. What the scheme changes is the cost of the BF–BOF fleet it competes with: a BF–BOF that does not cut its intensity must buy certificates for its shortfall against a target that it tightens every cycle.

To evaluate this, the two settings that define the scheme's impact—the carbon price and the pace of reduction targets—are tested for the green routes (\$571–606/tcs at 0.00–0.24 tCO₂/tcs on the CCTS boundary) against the BF–BOF (\$536/tcs at 2.23 tCO₂/tcs). If the BF–BOF stays at its baseline intensity and its target sits a given percentage below that baseline, it buys certificates for that percentage of 2.23 tCO₂/tcs, while the green plant is counted as neither buying or selling. The carbon price that closes the premium is therefore the premium divided by that shortfall. At the 4–6% of the current draft it is out of reach, about \$630/tCO₂ for the shaft furnace and \$310 for the rotary kiln; at a cumulative 20% it falls to \$157 and \$78, and at 40% to \$79 and \$39. These are upper bounds on the scheme's effect, because a BF–BOF that can abate for less than the certificate price will do so. They also describe a BF–BOF whose baseline is already set: a blast furnace built new for Phase 2 would, like the green plant, enter the scheme only after its first years of operation, so in those years the scheme reaches Phase 2 through its competitors: it raises the costs of the existing BF–BOF producers that Phase 2's steel is sold against.

How fast the targets tighten is the critical lever. Accordingly, two trajectories from 2025 are examined: targets tightening 2% a year, roughly continuing the pace of the current draft, and 5% a year, representing a differentiated approach for the highest-emitting units with larger cuts required for plants further above the sector's overall trajectory. They reach cumulative cuts of 10% and 23% by 2030, 18% and 40% by 2035, and 26% and 54% by 2040. Figure 5.1 left prices at the indicative \$24/tCO₂ and at \$50/tCO₂. On the 2% path at \$24 the scheme is worth \$5/tcs to a green plant in 2030 and \$10 in 2035, a small part of the \$35–70 premium. On the 5% path at \$50 it is worth \$25 in 2030 and \$45 in 2035: the rotary kiln's premium closes around 2032–33, as Phase 2 commissions, and the shaft furnace's is two-thirds closed by 2035. A steeper path for the highest emitters, 7% a year, would close the shaft furnace's premium before 2040 at the same price. Carbon intensities are counted on the CCTS's own Scope 1+2 boundary.

The premium the scheme has to cover also depends on how much hydrogen the plant runs. The scheme's value does not change with the green plant's fuel, because it is the BF–BOF's certificate cost, but the premium rises with the hydrogen share: from \$17–18/tcs on 100% natural gas to \$67–70 at 100% hydrogen for the shaft furnace and the fluidised bed, and from just below zero to \$35 for the rotary kiln. At the \$45/tcs the 5% path delivers at \$50/tCO₂ in 2035, the rotary kiln is covered at every hydrogen share and the other two routes up to about 40% hydrogen; at the \$25 it delivers in 2030, the rotary kiln is covered up to about 60% hydrogen and the other two only near all-gas

operation; at the \$10 of the 2% path at \$24 in 2035, only the rotary kiln is covered, and only up to about a quarter hydrogen. At these levels the domestic carbon market supports hydrogen blends before it supports full hydrogen, so the last step to 100% hydrogen rests on the hydrogen price rather than on the carbon price.

Three further effects work in a green plant's favour and are not priced here. A carbon cost on the BF-BOF fleet lifts domestic steel prices, and a near-zero producer captures that increase without bearing the cost. And the Green Steel Taxonomy, which today is a label with no fiscal support attached, is expected to become the basis for green-steel demand, through public procurement and buyers' own commitments. That demand cannot yet be sized, but what the premium would be can be: a premium of \$35–70 per tonne of crude steel, a small fraction of the cost of the buildings, vehicles and equipment the steel goes into; a hydrogen-DRI would also earn the Taxonomy's highest rating. Finally, such a plant could also earn revenue in international carbon markets under Article 6 of the Paris Agreement, for example through the India–Japan Joint Crediting Mechanism.⁶⁶

To illustrate, under a benchmark aligned with the Green Steel Taxonomy's threshold of 2.2 tCO₂e/t, a hydrogen-DRI facility would earn \$47–53/tcs at an assumed carbon price of \$24/tCO₂, where a carbon price of \$18–34/tCO₂ fully offsets its green premium. If evaluated against the more stringent 5-star threshold of 1.6 tCO₂e/t, the facility would generate \$33–38/tcs, requiring a carbon price between \$25 and \$50/tCO₂ to cover the premium.⁶⁷ Under the current design the same result needs both \$50/tCO₂ and the faster target path. The level of a threshold and its path are for the scheme's designers; what matters for an investment decided around 2030 is that the direction is signalled early.

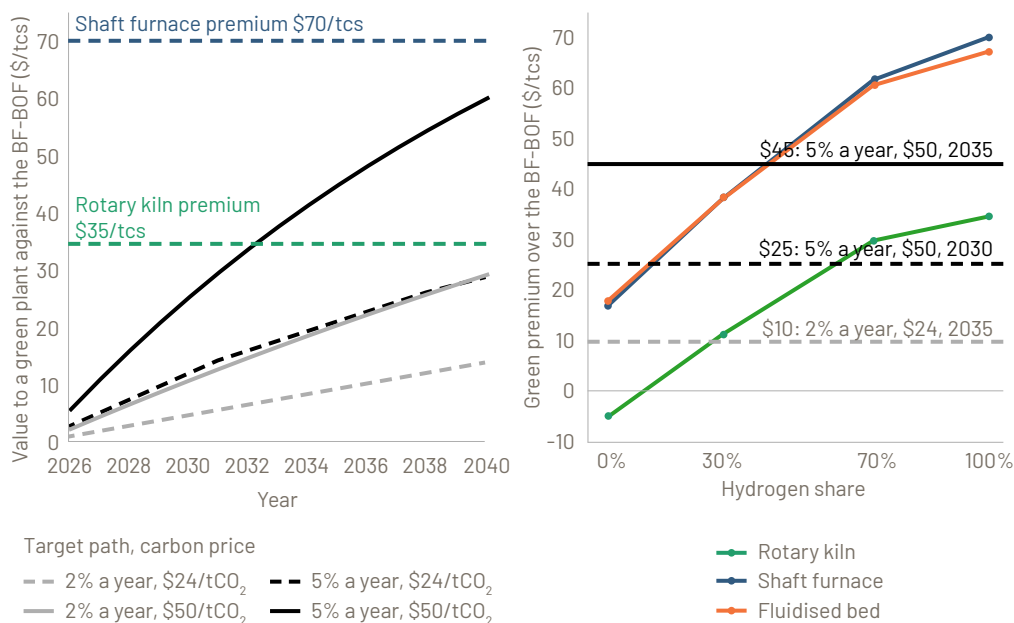


Figure 5.1 What the CCTS is worth to a green plant under plant-specific targets. Left: the value of the scheme to a green plant against the BF-BOF, on targets tightening 2% and 5% a year from 2025 at \$24 and \$50/tCO₂; dashed lines are the premiums of the rotary kiln (\$35/tcs) and the shaft furnace (\$70/tcs) at 100% hydrogen. **Right:** the green premium of each route by hydrogen share; horizontal lines are the value of the scheme on the 5% path at \$50/tCO₂ in 2030 and 2035 and on the 2% path at \$24 in 2035, and a route is covered where its premium lies below a line. The

BF-BOF is held at its baseline intensity, so the values are upper bounds. Carbon intensities are counted on the CCTS boundary (Figure 4.4).

5.3 EU CARBON BORDER PRESSURE: A SIGNAL FOR EXPORTS

The second carbon instrument is the EU's border adjustment. It is already in force, but it reaches only the steel India sells into Europe. Total exports are 3–5% of national output, and about 40% of them go to the EU. The CBAM exists to put an importer on the same footing as an EU producer. An EU producer receives free allowances up to a route-specific benchmark, and an importer's charge is reduced by a corresponding benchmark-based deduction per tonne of the imported good: the CBAM charge is the ETS price applied to whatever is emitted above that deduction. That shelter is being withdrawn gradually, from about 97.5% of the benchmark in 2026 to none by 2034.^{54,68} At the same time, as the CBAM's definitive phase began on 1 January 2026, importers of steel into the EU are paying for its embedded carbon at a price that tracks the EU ETS, currently about €80/tCO₂ (≈\$86⁶⁹; the Q2 2026 CBAM certificate price is €75.28/tCO₂⁷⁰) and reaching €125/tCO₂ (≈\$140) by 2034. The forward looking prices sit within the range of current market forecasts.⁷¹

For the steel that is exported, the exposure is concentrated in Europe. Four EU markets, Italy, Belgium, Spain and Poland, take nearly 40% of India's EU-bound steel exports, and on 2025 trade volumes India would face CBAM fees of roughly €0.4–0.8 billion a year when CBAM reaches full liability in 2034, because its steel is BF-heavy and it has carried no material domestic carbon price to offset the border charge.⁷² A green-DRI plant avoids most of that charge.

Year	Blast furnace route	Direct reduction route	Gap
2026	1.330	0.463	0.867
2028	1.228	0.428	0.800
2030	0.702	0.245	0.458
2032	0.361	0.126	0.236
2034	0.000	0.000	0.000

Table 5.1 Free-allocation shelter by route: CBAM benchmark of steel (BF-BOF: 1.364; DRI-EAF: 0.475 tCO₂e/tcs) × CBAM factor of year.⁷³

Evaluating the total cost of landing a tonne of steel in the EU illustrates this impact clearly as free allocations are phased out and carbon prices rise. For example, an Indian BF-BOF facility emitting 2.2 tCO₂/tcs would face additional carbon costs of \$75/t in 2026, \$169/t by 2030, and \$308/t by 2034. In contrast, a green facility emitting 0.196–0.247 tCO₂/tcs on the border boundary operates below the deduction threshold and pays no carbon adjustment fees until the early 2030s, with rotary kilns crossing the threshold in 2030 and the other direct reduction routes in 2031, prior to Phase 2 commissioning. Separating these escalators reveals that withdrawing free allocation with allowance prices held at \$86/tCO₂ increases the BF-BOF border charge to \$189/t by 2034, while allowing carbon prices to rise to \$140/tCO₂ under 2026 free allocation levels results in a \$121/t charge. Compounded together, these factors reach \$308/t, with the withdrawal of free allocation representing the larger driver. While actual cash costs may be lower as EU market prices adjust upward to reflect rising domestic producer compliance costs and tighter supply constraints, the net effect remains decisive: CBAM renders green

DRI from India substantially cheaper to land in Europe than BF-BOF steel.⁷⁴ By the target 2033 commissioning date, landing costs for shaft furnace steel sit \$180/tcs below the BF-BOF baseline, while rotary kiln steel achieves a \$209/tcs advantage, expanding to \$211/tcs and \$239/tcs respectively in 2034 once free allocations expire. Throughout this transition, the rotary kiln maintains its position as the lowest-cost route for EU delivery.

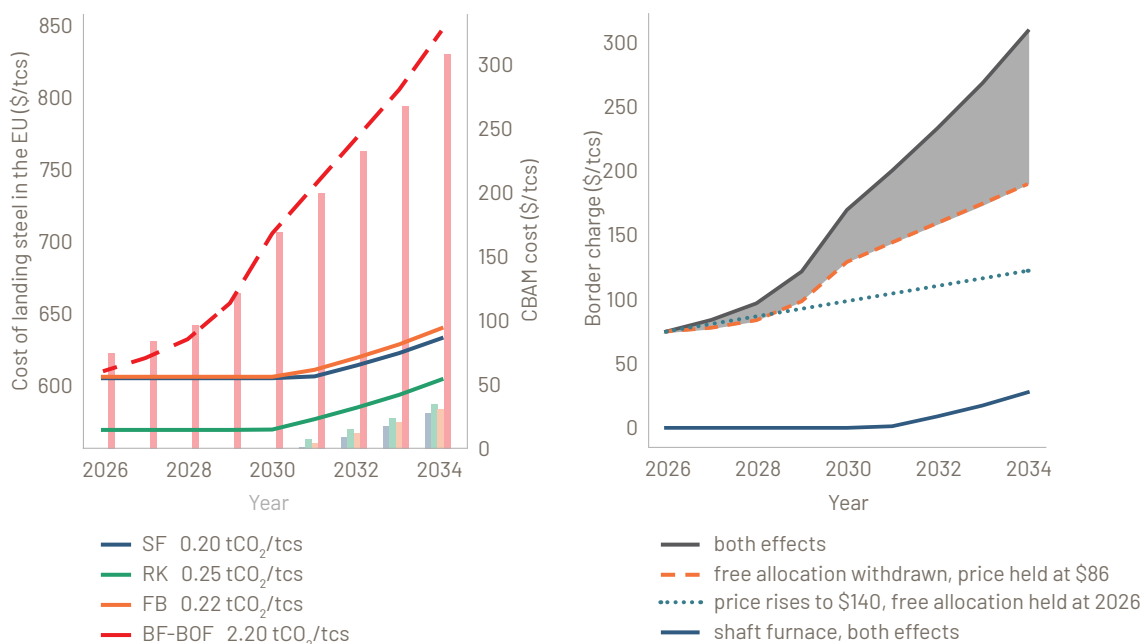


Figure 5.2 The border charge under CBAM. **Left:** The border charge of CBAM (bars, right axis) and landing a tonne of steel in the EU (production cost plus the border charge, left axis) as free allocation is withdrawn and the allowance price rises from \$86 to \$140/tCO₂. The charge is the allowance price applied to emissions above the free-allocation benchmark, which is route-specific (Table 5.1), so the green routes sit below their own deduction and pay nothing until 2031 (2030 for rotary kiln). **Right:** the same charge for the BF-BOF with each escalator held fixed in turn, separating the withdrawal of free allocation from the rising allowance price Carbon intensities are counted on the CBAM boundary (Figure 4.4).

However, it should be noted that the CBAM implementing rules require the declared emission intensity to be verified at installation level. An importer that cannot supply verified data is charged on a country-specific default value, set from the worst performers and carrying a mark-up that rises from 10% in 2026 to 30% from 2028. A greenfield installation producing steel by a single route can supply that data on clean metering to a verifier, which a brownfield site blending several routes cannot do as easily. The rules also require a weighted average intensity if the same goods are produced in one installation by more than one route.⁷⁵ Rajayyapeta would run Phase 1 BF capacity alongside Phase 2, and if both make the same product, the exported tonnes would carry a blended intensity of roughly 1.1 tCO₂/tcs, even though Phase 2 is green DRI. That would raise the 2034 border cost from \$27/t to roughly \$155/t and cut the advantage over BF-BOF by more than half. Avoiding that is a matter of how Phase 2 is drawn rather than of policy. Accrediting Indian verifiers and building installation-level measurement capacity is itself a policy task; without it, even clean capacity pays default-value charges. A related certification sits with the hydrogen itself.⁷⁶

Two qualifications keep the border in proportion. India exports only 3–5% of its steel output; about 2.4 Mt went to the EU in 2025, roughly 40% of exports and 8% of EU imports. From 1 July 2026 the EU replaced its steel safeguard with a tariff-rate quota of 18.3 Mt/yr, a 50% duty above it and a melt-and-pour origin rule, and the EU-India trade agreement gives India about 1.64 Mt of that quota.⁷⁷ None of this distinguishes clean from conventional steel, so a green plant competes for the same quota as every other exporter, including gas-based DRI producers in the Middle East with cheaper gas, and pays the CBAM on top. At the same time, quotas and the CBAM together restrict EU supply and are lifting EU steel prices, which is why the cash cost of the charge to an importer may be smaller than the headline. Consequently, while the EU border mechanism strengthens the rationale for green DRI, it cannot sustain the project on its own; the ultimate determinant will be the domestic market, which is where virtually all of the facility's steel output will be absorbed.

5.4 WILL THE PREMIUM ACTUALLY CLOSE AND WHEN?

Putting the two instruments together gives a two-speed answer to how durable the green premium really is.

- **For domestic sales, the premium narrows through the 2030s rather than closing at project start.** Near-term CCTS carbon prices of ~\$9–10/tCO₂, reaching an estimated \$24/tCO₂ by 2030, combined with the modest reduction mandates in current draft policy, provide only minimal financial benefit to a low-emission facility. However, if policy targets tighten by 5% annually and carbon prices approach \$50/tCO₂, the scheme's value rises to \$25/tcs by 2030 and \$45/tcs by 2035. This increase offsets the green premium for the rotary kiln pathway as Phase 2 opens, and bridges most of the cost gap for shaft furnaces by the late 2030s. Market demand for certified low-carbon steel could further reinforce this trend if the Green Steel Taxonomy becomes the standard for procurement.
- **For the share sold into the EU, the premium is already closed.** CBAM is in force and prices Indian BF-BOF steel on every tonne it emits above the free-allocation benchmark, so by the 2033 commissioning the hydrogen routes land \$179–209/tcs below it, widening to \$209–239 in 2034 as the free allowance disappears. This advantage applies only to steel sold into the EU, which is a small percentage of the market for India right now, and the EU's import quota caps the volume without giving cleaner steel any preference.

There is, however, an important feedback that argues for a faster-rising domestic price: every rupee India does not charge at home is, in effect, paid to the EU as CBAM revenue on its exports. That “keep the carbon revenue onshore” logic, sharpened by the EU-India trade negotiations now under way, creating upward pressure on the CCTS price over time.⁷⁸ The prudent planning assumption is therefore that the effective carbon price the plant faces rises through the 2030s as the domestic scheme tightens, with the border adding to it on exported tonnes. Two caveats temper the speed but not the direction: the CCTS price is politically sensitive and could be held low to protect industry, and the CBAM rules on whether a domestic carbon payment is creditable against the border charge are still being settled.

6. NATURAL GAS AS A FUEL: TECHNOLOGY FLEXIBILITY, PRICE, EMISSIONS AND SUPPLY

While DRI reactors possess the technical capability to operate on natural gas, hydrogen, or any combination of both, using natural gas offers a cost profile that closely mirrors a greenfield BF-BOF facility. Although a natural-gas initial phase may appear financially attractive, it does not constitute a near-zero carbon strategy. This route generates 0.8–1.2 tCO₂/tcs prior to accounting for methane emissions along the LNG supply chain. Furthermore, it relies on imported LNG at scale unprecedented in the Indian steel sector, volumes that would be impossible to absorb amid ongoing global supply constraints. The subsequent shift involves a subsequent transition to hydrogen that is neither simple nor without expense. This section therefore asks what hydrogen must cost to beat natural gas in the same reactor, and what a gas start would expose the plant to if hydrogen is late.

6.1 THE FUEL-FLEXIBLE REACTOR AND THE COST-EMISSIONS TRADE-OFF

The reactor is fuel-flexible: changing the natural-gas-hydrogen blend shifts burner and gas-handling duty stepwise but does not materially alter the economics, so this study treats the fuel range as near-linear. The shaft furnace makes steel for \$553/tcs at 100% natural gas, at a delivered gas price of \$13/MMBtu, about 3% above the BF-BOF, and emits 0.81 tCO₂/tcs. Raising the hydrogen share lowers emissions roughly linearly to 0.29 tCO₂/tcs at 100% hydrogen, but adds cost: the shaft furnace pays \$53/tcs to shed 0.52 tCO₂/tcs, reflecting the electrolyser and renewable power that hydrogen requires; the switch does not pay until a carbon price of \$102/tCO₂ even if every tonne of CO₂ it sheds were credited at that price. The fluidised bed and rotary kiln pay less, about \$49 and \$40/tcs respectively. They burn more gas per tonne of steel than the shaft furnace, around 11 MMBtu against 8.8 MMBtu, so the switch removes a larger gas bill while adding a similar cost across routes. Even so, the carbon price the switch needs is still \$76/tCO₂ for the fluidised bed and \$60/tCO₂ for the rotary kiln, far above anything the CCTS is projected to reach in the early 2030s. The case for raising the hydrogen share on domestic tonnes therefore rests on the hydrogen cost falling, not on the carbon price rising.

At the border the answer is different, because the CBAM charge is not linear in emissions. It falls only on what an installation emits above its free-allocation deduction, and the two fuel modes sit on opposite sides of that line: at the border boundary the 100% natural gas shaft furnace emits 0.72 tCO₂/tcs and pays, while the 100% hydrogen mode at 0.20 sits below the deduction and pays nothing. Switching therefore saves the whole of the natural gas charge, and that saving grows as free allocation is withdrawn from \$22/tcs in 2026 to \$53 in 2030 and \$73 by 2034 for the shaft furnace. Taking CBAM costs into account, hydrogen becomes the cheaper fuel to export from 2030 for the shaft furnace, 2029 for the fluidised bed and 2027 for the rotary kiln.

Because Phase 2 of the AM/NS Rajayyapeta plant commissions in 2033, the border will already reward hydrogen by the time the plant exists, so a natural-gas start is a hedge against hydrogen cost and hub readiness rather than a bet that carbon prices stay low. And because this holds only on exported tonnes, the date at which the plant should raise its hydrogen share depends on how much of its output goes to Europe. The higher the export share, the earlier the switch pays.

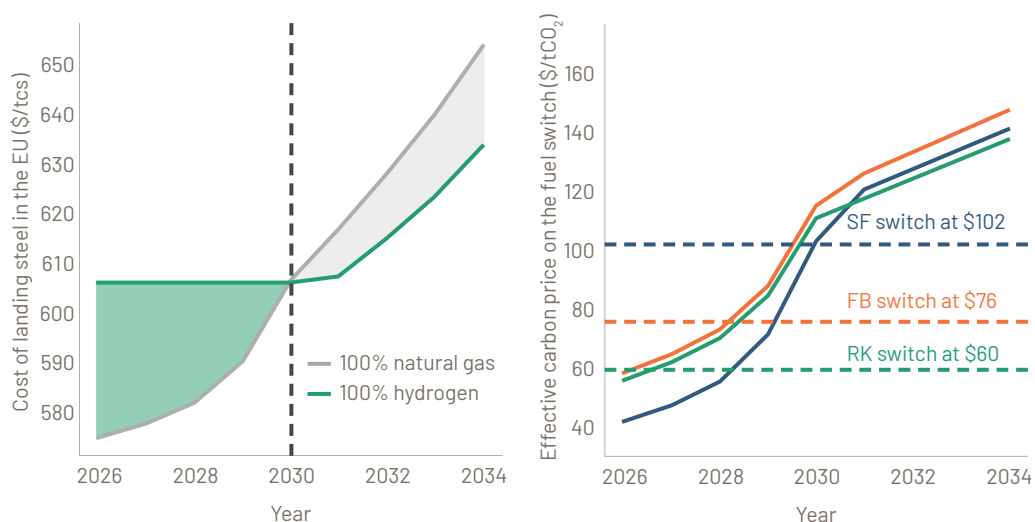


Figure 6.1 When the gas-to-hydrogen switch pays. **Left:** the cost of landing shaft-furnace steel in the EU on 100% natural gas and on 100% hydrogen, as free allocation is withdrawn and the allowance price rises. The natural gas mode sits above its free-allocation deduction and pays; the hydrogen mode sits below it and does not, so the two cross in 2030. **Right:** the same saving expressed as an effective carbon price on the fuel switch, against the flat threshold each route needs (dashed). Carbon intensities are counted on the CBAM boundary (Figure 4.4).

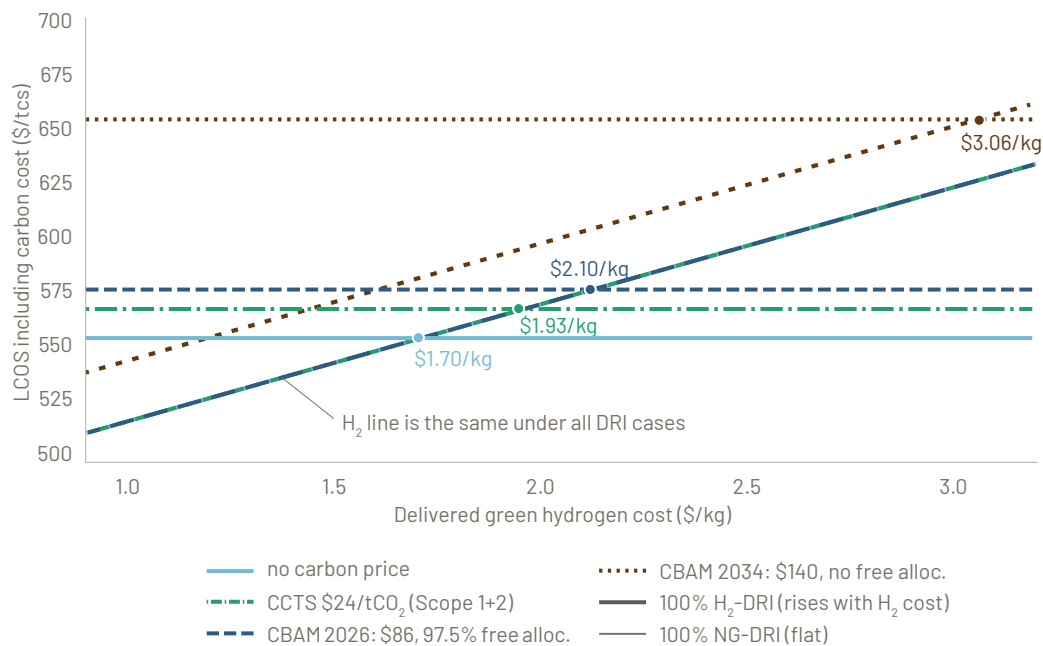
6.2 READING THE FUEL CHOICE IN HYDROGEN-COST TERMS

The switch can also be read in hydrogen-cost terms. Earlier analysis sets out the green premium against the BF-BOF; the question here is when hydrogen beats the plant's own natural-gas mode. The shaft furnace route uses about 54 kg of hydrogen per tonne of steel, so every \$1/kg fall in the green hydrogen price takes roughly \$54/tcs off the 100% hydrogen route. This study models on-site hydrogen at \$2.95/kg in 2030, or \$2.69/kg after subsidy, a price where a 100% hydrogen plant is still the more expensive option. It reaches parity with natural gas at \$1.70/kg with no carbon price. When a domestic carbon price applies and credits the plant for emissions abated after joining the CCTS, this breakeven rises by ~\$0.10/kg per \$10/tCO₂ increase, reaching \$1.93/kg under a baseline \$24/tCO₂ price.

At the EU border the threshold depends on when, not just on the allowance price, because the charge falls only on emissions above the free-allocation deduction. Through the late 2020s the 100% natural gas mode sits above that line and the 100% hydrogen mode below it, so the whole charge lands on gas. In 2026, at \$86/tCO₂ with 97.5% of the benchmark still granted free, the plant could pay \$2.11/kg for hydrogen and still be better off exporting hydrogen-made steel; by 2034, at \$140/tCO₂ with no free allocation, both modes pay and the threshold rises to \$3.06/kg. The value of switching therefore grows with the phase-out rather than arriving at once.

Two main factors help bridge the remaining cost gap. First, existing policy incentives, including the SIGHT production subsidy, worth about \$0.12/kg levelised and Andhra Pradesh's 25% electrolyser capital subsidy, provide an effective discount of roughly \$0.26/kg, reducing on-site hydrogen production costs from \$2.95/kg to \$2.69/kg. Second, technology costs are expected to decline as electrolyser and renewable energy markets mature through the 2030s. For facilities purchasing hydrogen, price reductions generally take effect at PPA renewal or

during stack replacement cycles, typically every 10 years, making long-term capital re-investment milestones around 2043 particularly critical. According to the Ministry of Steel's *Green Steel India* report, green hydrogen prices are projected to fall from ~\$5/kg in 2024–25 to \$1.5/kg in a base-case scenario, \$2.0/kg conservative, \$1.0/kg ambitious, by 2030–31.⁴ The base-case trajectory comfortably clears the domestic parity threshold of \$1.70/kg, while the conservative scenario achieves parity if carbon pricing applies. Furthermore, all projections meet the \$2.11/kg EU border parity benchmark, demonstrating that exports to European markets do not depend on aggressive hydrogen cost reductions.



6.3 WHAT A GAS START WOULD EXPOSE THE PLANT TO

The results modelled price natural gas at a fixed level (\$13/MMBtu), which cannot represent price volatility, contract structure or supply interruptions, so the risks of a natural-gas start are assessed here from what the plant would be exposed to: the gas bill's share of cost, the volume it would need, and the price history. The \$13/MMBtu reflects today's market: spot LNG landed in west India averaged about \$11.9/MMBtu in 2025, roughly \$13–14 after regasification, pipeline tariff and taxes, and new Henry-Hub-linked term contracts deliver at about \$13.⁷⁹ At that price the shaft furnace on natural gas costs about \$553/tcs, some \$17 above the BF-BOF, and would need delivered \$11.05/MMBtu to reach parity, which requires a cheaper delivered price than today's. The fluidised bed follows at \$554/tcs, needing \$11.43/MMBtu to reach parity, and the rotary kiln is already slightly below the BF-BOF, holding parity up to about \$13.4/MMBtu. Legacy crude-linked term supply at about \$8.8/MMBtu landed would clear all three, but no new steel buyer has secured it in India.² Spot exposure is harsher: delivered LNG exceeded \$20/MMBtu in 2021–22 and again in 2026 as the Middle East conflict pushed Asian spot prices above that level.^{80, 81} At \$20 a natural-gas plant produces at about \$615/tcs, which is above its own 100%-hydrogen cost. Two further caveats attach to a gas start. Neither CBAM, the CCTS, nor this study's emissions accounting counts the upstream methane of the LNG chain. And the start presumes regasification and pipeline capacity at the site, credible on the Krishna-Godavari basin corridor, with the gas-side equipment accepting underuse if the switch comes early.

For each \$1/MMBtu increase in natural gas, the hydrogen price at which the switch pays, from full natural gas to full hydrogen, rises about \$0.16/kg: from \$1.70/kg at \$13/MMBtu to \$1.87/kg at \$14/MMBtu with no carbon price. Once natural gas passes \$19/MMBtu, the \$2.7/kg hydrogen is already the cheaper fuel. The fines routes cross earlier, at \$17.2/MMBtu for the fluidised bed and \$16.6 for the rotary kiln, because they burn more natural gas per tonne of steel than the shaft furnace. Carbon pricing pulls all of these forward: under the 2034 CBAM regime the shaft furnace's crossover falls to \$10.73/MMBtu, below today's delivered price.

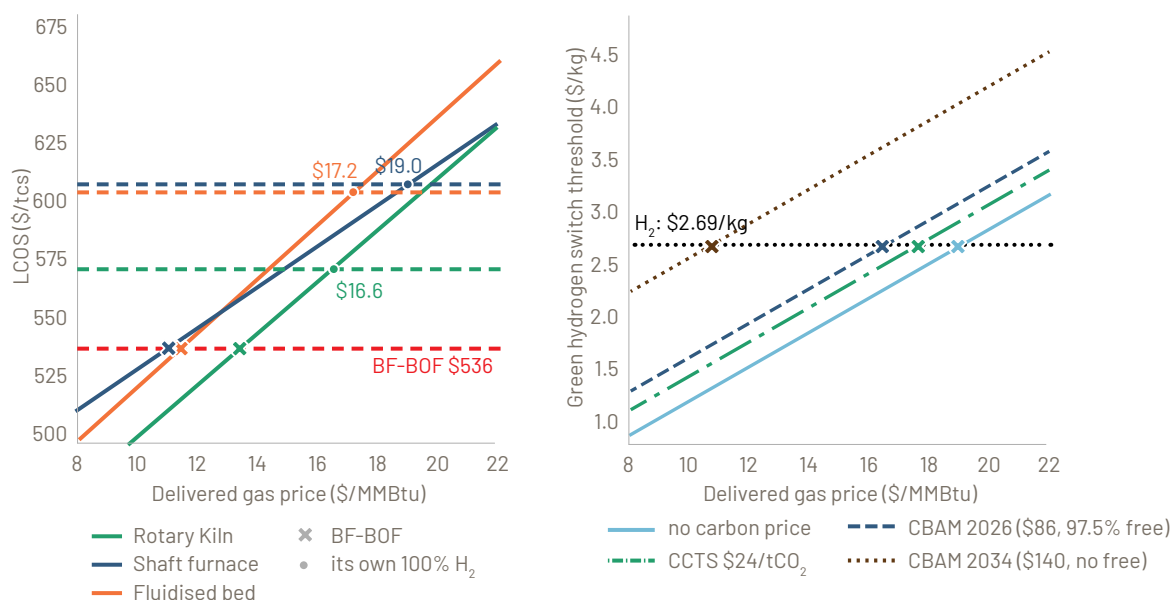


Figure 6.3 Gas-price sensitivity of the natural gas start. **Left:** Production cost against the gas price for 100% natural gas DRI routes. Dashed horizontals are the same route at 100% hydrogen; a cross marks where each route matches the BF-BOF, and a dot where it matches its own 100%-hydrogen cost. **Right:** The green-hydrogen price at which the shaft furnace's switch from 100% natural gas to 100% hydrogen pays, rising about \$0.16/kg for every \$1/MMBtu of gas, under each carbon-price scheme; crosses mark where each threshold reaches the plant's own subsidised hydrogen cost of \$2.69/kg.

Supply is the second exposure, and at the project's scale it is substantial. Run 100% on natural gas, the AM/NS Rajayyapeta Phase 2 project needs about 72 (shaft furnace) to 95 (fines route) million MMBtu a year, equal to around 3–4% of India's current gas consumption and 6–7% of its LNG imports.⁸² Domestic APM, Administered Price Mechanism, the legacy domestic-field gas sold at a government-set price, gas is allocated to city gas and fertiliser and is not available to steel, so this demand would be met with term and spot regasified LNG: imported, dollar-linked, and concentrated on Qatar, whose exports the 2026 Hormuz crisis halted outright, disrupting term deliveries as well as spot.⁸³ The precedent is direct. India's existing natural-gas DRI capacity, including AM/NS Hazira, has curtailed output during past LNG price spikes. AM/NS India's output fell about 13% year-on-year in 2022 during the war-driven LNG price surge, and the Sponge Iron Manufacturers Association notes that no greenfield natural-gas DRI plant has been built in India since 1994 for want of gas.^{84, 85} A natural gas start at this scale therefore needs a diversified term-supply strategy that no Indian steelmaker has yet secured.

7. POWER AND HYDROGEN PROCUREMENT IN ANDHRA PRADESH

Power and hydrogen together are about a third of the levelised cost of 100%-hydrogen steel, and are therefore decisive. Previous sections rest on buying renewable electricity as an as-generated wind-solar portfolio through a group-captive structure, firming it with the distribution utility's banking mechanism, and making hydrogen on-site. The power arrangement in particular is specific to Andhra Pradesh. This section compares the procurement options, first on cost and then on capital and bankability.

7.1 POWER: HOW TO SOURCE THE ELECTRICITY

Power is the largest single cost in producing green hydrogen and green steel, so how it is procured matters more than any other site decision. Three key questions must be answered. The first is related to structure: whether the plant contracts as an ordinary open-access consumer or holds enough equity in the generating vehicle to qualify as a group-captive user under India's Electricity Rules.⁸⁶ The second is the product: whether it buys firm round-the-clock (RTC) power, for which the developer carries the firming, or an as-generated portfolio it firms itself. The third, if it firms itself, is the firming mechanism: the utility's banking allowance or the grid. These three questions apply to any contracted portfolio, whether pure wind or a solar-wind-hydro mix. The table below sets the routes against all three, together with the alternative of building and owning the generation, which is subsequently discussed on its financing merits.

Route	Product / firming	Delivered power (\$/kWh)	LCOS (\$/tcs) SF / FB / RK	Emissions (tCO ₂ /tcs) SF / FB / RK
Group captive, shaped hybrid (base case)	As-generated, firming by monthly banking	0.044	606 / 603 / 571	0.29 / 0.56 / 0.54
Group captive, shaped hybrid, self-firmed	As-generated, no banking; grid fills the gaps	0.053	656 / 660 / 627	0.73 / 1.01 / 1.02
Group captive, firm RTC contract	Developer firms, priced into the tariff	0.064	683 / 691 / 656	0.29 / 0.51 / 0.54
Self-build, own generation	Own solar, wind and storage	0.048	653 / 656 / 622	0.49 / 0.82 / 0.77
Third-party open access, shaped	As-generated, banked; full surcharge	0.064	687 / 698 / 660	0.29 / 0.56 / 0.54
Third-party open access, unbanked	As-generated; grid fills the gaps	0.072	735 / 752 / 714	0.75 / 1.05 / 1.05

Table 7.1 Power-procurement routes at 100% hydrogen. All rows are full hourly solves on the same renewable portfolio.⁸⁷ Delivered power is the all-in cost of the electricity consumed, including contracted energy, wheeling, surcharges and any grid purchases, or, for the self-build its own annualised capital and operating cost. The delivered power cost is derived from the hourly optimisation model by 8,760-hour load matching; group captive + firm RTC contract is a flat tariff.⁸⁸

The three questions set the result. First, regarding the structure, claiming the group-captive exemption rather than contracting as an ordinary open-access consumer saves \$0.019 per kWh, which represents the cross-subsidy and additional surcharges, amounting to \$81 per tonne of crude steel or about \$660 million a year at this plant's output. The group-captive structure is set by the Electricity Rules of 2005, as amended in March 2026. Under these rules, the plant must hold at least 26% of the equity in the vehicle that owns the generation and consume at least 51% of what it generates. In return, it is exempt from the cross-subsidy and additional surcharges, though it still pays wheeling.⁸⁹ The 2026 amendment lets the 26% equity be held across a corporate group, suiting a joint venture whose parent owns the renewables arm, and confirms that energy routed through storage counts as captive consumption.

Second, regarding the product, buying as-generated power rather than a firm round-the-clock product is worth a further \$77 per tonne of crude steel. This is because a firm power purchase agreement at ₹5.06 per kWh costs 66% more than the solar option at ₹3.05 and 38% more than the wind option at ₹3.66, and because the plant can absorb part of an as-generated supply itself, leveraging the flexibility of the electrolyser and reactor along with hydrogen storage. The ranking remains consistent across all three direct reduced iron routes. The spread between the most expensive and cheapest options is \$129 per tonne of crude steel on the shaft furnace, and even larger on the fines routes in step with the extra electricity they require.

Third, the firming mechanism: banking is worth \$50/tcs. The same contract without it leans on the grid, which costs both money and emissions.

However, this analysis assumes banking is available without limit, priced only by the 8% charge deducted in kind, equivalent to \$5/tcs at this plant's volumes. A commercial open-access consumer in Andhra Pradesh today gets banking on monthly settlement, with 92% effective return and no carry-forward across months. Banking sits with the distribution utility under state-commission terms; there is no interstate analogue. Within a month the utility is, in effect, acting as a free battery of month-long duration. That is a generous regime but it is capped: the Andhra Pradesh Integrated Clean Energy Policy 2024 limits state-wide banking to 5% of total state peak demand, about 700 MW in fiscal 2025 and shared across all open-access consumers, while this AM/NS Rajayyapeta greenfield Phase 2 alone would bank an average of roughly 1.5 GW, twice the entire envelope.²³ This trend is also against future industrial electricity users: banking regimes across India are being tightened, with higher charges and shorter settlement windows, and distribution utilities under financial strain cannot be expected to absorb the swings of a load this size indefinitely. Although the Ministry of Power's Green Hydrogen Mission provides a renewable energy-banking mechanism for green-hydrogen production, the scale and charge rest with the state. Banking is not storage: the utility absorbs the user's surplus as it is injected and serves the withdrawal from whatever is generating then. What the plant buys is a standing call on the grid's balancing capacity, and extending that to this scale is a question about system balancing and transmission. How that call will be capped by 2030 is unclear; it depends on the balancing capacity the system has by then, including renewable and storage capacity built alongside it. The banked route is therefore the lowest-cost case, not the most secure one: whether the plant can rely on it should be settled with the utility and the regulator before the investment decision.

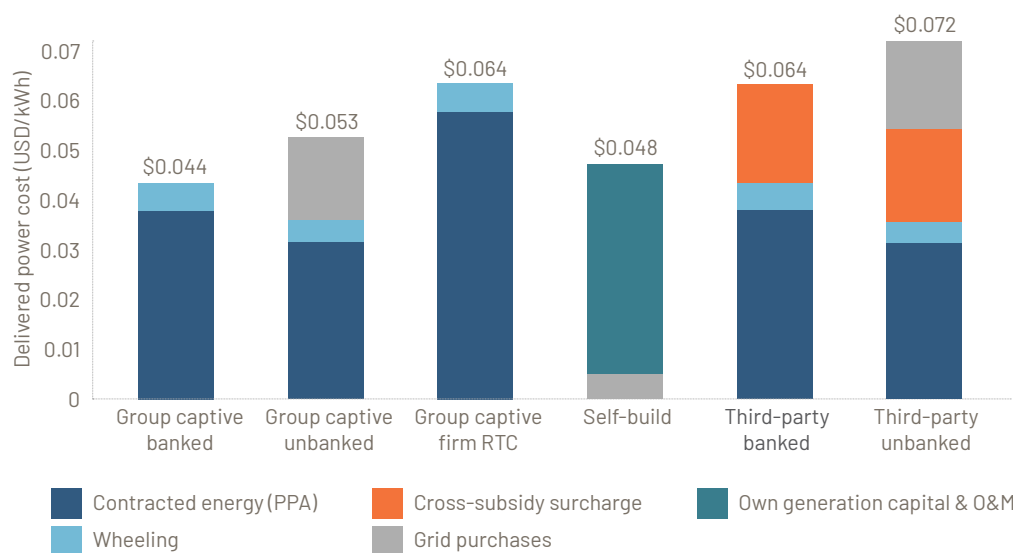


Figure 7.1 What the plant pays for a kilowatt-hour under each procurement route. Each bar stacks the components of the delivered price: the contracted energy itself, wheeling charges, the cross-subsidy, grid power, and, for the self-build, its own annualised generation capital and O&M. Totals match the delivered-power column of Table 7.1. The red block prices cross-subsidy surcharge, which appears only in the options without group-captive status; the grey block prices the purchase of grid power where the renewable portfolio falls short, in the options without banking

Behind every structure of electricity procurement stands a physical build, irrespective of who finances it or how. Scaled to this plant's RTC load of about 3.8 GW, firming it would take 15 GW of renewables plus storage, roughly \$10 billion of generation capital on some 45,000 acres, with a multi-year lead time. Wind is the binding constraint on site: the coastal plant site has almost none largely due to crippling low capacity factors, 12.5% capacity factor with a modern turbine, while the Rayalaseema belt around Anantapur reaches 28.1% and peaks in June to August. A credible portfolio therefore wheels wind roughly 600 km across the state, which costs nothing extra in wheeling terms, since the charge is state-wide, but does depend on transmission capacity the model does not represent. Locating part of the infrastructure portfolio out of state is also possible in principle: interstate transmission charges are waived for green-hydrogen production commissioned by the end of 2030 under Ministry of Power orders, but interstate wheeling would add transmission-allocation questions of its own, so the model keeps the infrastructure portfolio in-state.

7.2 WHAT THE COST RANKING HIDES: CAPITAL AND BANKABILITY

Ranking the electricity-sourcing methods on cost alone is of limited use for real-world business decisions. A levelised cost is blind to who owns the capital, and two routes a few dollars apart on cost can differ by billions on the plant's own balance sheet, and the option that looks strongest on earnings can be among the weakest on debt service. Rajayyapeta is unusual in having two parents, ArcelorMittal and Nippon Steel, able to fund from their balance sheets, as the \$5 billion package for Hazira led by the Japan Bank for International Cooperation (JBIC) showed.⁹⁰ The project-finance framing below shows which structure the parents would have to stand behind, and by how much.

	Group captive, banked	Group captive, self-firmed	Third-party open access, banked	Self-build, self-firmed
LCOS (\$/tcs)	606	656	687	653
EBITDA at \$650/tcs steel (\$ bn)	1.33	1.00	0.67	2.27
Debt raised (70% of capital) (\$ bn)	6.1	6.5	6.1	14.4
Minimum DSCR	1.65	1.23	0.92	1.25
Equity IRR	16%	8%	4%	10%
Capital on the plant's books (\$ bn)	8.8	9.3	8.8	20.6
of which generation and storage	—	0.1	—	10.7
Steel price needed for 1.3 x DSCR	\$611	\$659	\$692	\$662

Table 7.2 The main structures as a financing case for the 100% hydrogen plant with shaft furnace.⁹¹ Capital excludes the equity the group-captive structure requires in the generation vehicle (of order \$0.8 billion) which sits outside the plant and therefore outside these ratios. All rows are computed from the current cost set by the project-finance model, at 8.16 Mtpa of output (9.6 Mtpa nameplate at an 85% capacity factor). All columns make their hydrogen on site; the hub-purchase variant is priced in Section 7.3.

The central finding is that the self-build generates the most cash yet covers its debt less well than the group captive, banked base case; of the four structures, only this base case clears the 1.3× covenant of DSCR (the cash available each year divided by that year's debt payment, with lenders typically requiring at least 1.3×). Owning the generation means there is no power bill in the operating cost, so its EBITDA is \$2.27 billion against \$1.33 billion for the base case. But the capital behind that cash needs \$14.4 billion of debt against \$6.1 billion (at 70% of capital), so minimum DSCR falls from 1.65 to 1.25, and the equity return (IRR) falls from 16% to 10% alongside. Third-party open access pushes the minimum coverage lower still, to 0.92: it carries no more capital than the base case, but the \$81/tcs of surcharges cuts its cash flow roughly in half, and the debt payment does not shrink with it. The same asymmetry shows in what each route needs from the market: the base case holds 1.3 times coverage at a steel price of \$611/tcs, while the self-build needs \$662 and third-party open access \$692. If the steel price falls, the gap widens: at \$600/tcs steel the base case slips to 1.20 times, the self-build to 1.06 and open access to 0.38. The deeper lever is the cost of capital itself: structures that stabilise cash flow raise debt capacity and lower the return investors require, which affects the bankable steel price more than physical design choice. Hydrogen-linked projects of comparable ambition such as Stegra in Sweden and AM Green at Kakinada, have raised project debt on this pattern, anchored on offtake contracts and tranches of concessional finance.^{92, 93}

Set against those disadvantages, what the self-build buys is independence. It needs neither the surcharge exemption nor the banking allowance, and is independent of the regulator. This study counts no revenue for surplus generation; selling the roughly 2 TWh/yr it curtails at the Rs 360/MWh (≈\$4.3/MWh) surplus rate would recover only about \$1/tcs. Swapping the lithium-ion battery for cheaper, longer-lived 8-hour pumped hydro lets the near-zero variant hold 6.7 GWh rather than 4.3, yet moves the LCOS by less than \$1/tcs, because the residual shortfalls are longer than any daily-cycling store can bridge. Storage technology is not what distinguishes these options; the surcharge exemption is.

7.3 HYDROGEN: MAKE ON-SITE OR BUY FROM THE HUB

The second choice is whether to make hydrogen on site or buy it from the planned Pudimadaka hub near Visakhapatnam. On its group-captive power the plant makes hydrogen for about \$2.95/kg, or \$2.69 after subsidies. Buying instead at an assumed \$2.0/kg delivered, the conservative case from the Ministry of Steel, saves \$28/tcs and removes \$23/tcs of annualised capital. What the plant should also look at is the timing, because the hub is not expected to run until around 2032.²⁴ If the hub is running at commissioning, the case for buying from the hub is a ladder of thresholds: below about \$2.53/kg buying beats building an electrolyser; below \$1.54 it beats natural-gas DRI; below \$1.22 it beats the \$536/tcs BF-BOF outright. The Ministry of Steel's base-case scenario of \$1.5/kg of hydrogen by 2030–31 (a target) will clear the first two but not the third: it lands the hub route at \$551/tcs, which is still about \$15 above the BF-BOF and \$20 above the rotary kiln on gas.

The stronger argument for buying is financial. The electrolyser is roughly \$1.2 billion of the plant's capital, renewed on a 10-year cycle against the reactor's 40-year life.⁹⁴ Buying hydrogen takes overnight capital from \$8.8 to \$7.6 billion and debt from \$6.1 to \$5.3 billion, and at the \$2/kg delivered price the hydrogen bill is slightly smaller than the cost of making it. Every financing metric for the plant improves at once: minimum debt service coverage rate from 1.65 to 1.93 times, the equity return from 16% to 21%, and the steel price that holds 1.3 times cover from \$611 to \$590/tcs. On the plant's books the hub is a much more comfortably financed configuration.

Regarding how restrictive constructing an on-site electrolyser would be in the event of hub delays, the impact is minimal. With approximately \$0.42/kg of its total cost sunk into CAPEX post-construction, operations could continue until hub prices drop to around \$2.11/kg. Because electrolyser stacks account for roughly half the installation expenditure and require replacement after a decade, the initial re-investment phase, approximately 2043, provides an ideal window to transition methodologies; the longer-lasting balance of plant can be depreciated or retained for backup duties. Should the facility transition hydrogen sourcing to the hub, the plant can sell the 26% stake in the generation vehicle and reassign its contracts, or to contract the electrolyser's share of the portfolio in tranches as the hub's delivery becomes clear.

The governing constraint remains securing sufficient hydrogen volume from the hub, given that a 100% hydrogen Phase 2 operation demands nearly 1,200 tonnes daily, representing 80% of the hub's total projected output, much of which is already earmarked for derivatives like ammonia and methanol.⁹⁵ Purchasing hydrogen directly from the hub requires a formal offtake agreement incorporated into the hub's expansion plan, rather than relying on unallocated excess capacity. If the facility secures only a portion of its required supply, such as a 60% baseline allocation from the hub supplemented by 40% on-site hydrogen generation, the resulting production cost is \$590 per tonne of crude steel, placing it between the standalone hub and fully on-site hydrogen scenarios.

7.4 PUTTING IT TOGETHER: WHAT TO BUILD, AND WHAT IT RESTS ON

The two answers to what to build and what it rests on combine into a single structure: buy power as an as-generated wind-solar portfolio through a group-captive vehicle, firm it with the utility's banking mechanism, and buy hydrogen from the hub rather than making it. That combination costs \$578/tcs, about \$28 below the same plant making its own hydrogen and \$25 above natural-gas DRI, and it falls to \$551/tcs if the hub reaches the \$1.5/kg of the official base trajectory. On the rotary kiln the same combination lands at \$541/tcs even at the \$2/kg hub price, within \$5 of the BF-BOF.

One further condition binds Phase 2's configuration rather than its procurement: the blended CBAM intensity of Section 5.3, under which Phase 1's BF-BOF emissions would lift Phase 2's declared intensity, on 100% hydrogen DRI, from about 0.2 to 1.1 tCO₂/tcs, if the two are reported as one installation on the EU border boundary, and its 2034 CBAM cost from about \$27/t to roughly \$155/t. That single accounting outcome is worth more than every procurement decision in this section put together. Two configuration choices avoid it: keep Phase 2's steelmaking separately metered, permitted and reportable as an installation in its own right, and sell Phase 1's iron as pig iron under its own customs heading rather than converting it into the same finished product.

Procuring hydrogen externally also mitigates regulatory risk, albeit without eliminating it completely. Given that electrolyzers account for approximately 70% of total plant power consumption, off-taking hydrogen scales down the required renewable energy contract portfolio from nearly 17.6 GW to 5.4 GW. Consequently, annual energy cycled through utility banking drops from 13.6 TWh to 4.1 TWh, reducing the average banked load from 1,555 MW to roughly 470 MW. Even so, 470 MW is two-thirds of the state's 700 MW banking threshold, and a single consumer cannot expect to be allotted that share. Unless the threshold rises or grid-scale storage is supported, the plant falls back on the self-firmed contract, at the cost and emissions penalty set out below; the hub route makes the ask smaller, not small.

Nevertheless, external procurement does not resolve the fundamental intermittency challenge. Converting variable renewable power into a firm hydrogen supply remains necessary, shifting that operational burden to the centralised hub, which factors balancing costs into its delivered rate of \$2/kg. A dedicated hydrogen hub is better positioned to manage this variability, as it can maintain larger storage reserves and aggregate demand across multiple industrial off-takers with non-coincident load profiles. There is also a question of competence: AM/NS is a steelmaker, and building and operating gigawatt-scale electrolysis and renewables is not its core business; the hub places that task with a developer whose business it is.

None of these pathways is entirely free of risk. For instance, losing the energy-banking permission alone increases the self-firmed group-captive contract cost by \$50/tcs to cover grid-supplied shortfalls, while raising carbon emissions from 0.29 to 0.73 tCO₂/tcs. The hydrogen route is only as clean as the electricity behind it: made entirely on grid power, the shaft furnace route would emit about 2.2 tCO₂/tcs at the 2030 factor, no better than the BF-BOF, and grid-fed hydrogen starts to cut emissions only once the grid falls below about 0.57 kgCO₂/kWh, which the national trajectory reaches around 2028. The power contract is therefore the decisive site decision for emissions as well as for cost.⁹⁶ By contrast, the \$653 self-build option bypasses regulatory permissions entirely and costs no more than the self-firmed contract; however, it requires \$11.9 billion in additional capital and misses the 1.3-times minimum debt-service coverage covenant, at 1.25. As the grid decarbonises and lowers its price, however, the self-firmed/unbanked options that use grid electricity to fill the shortfalls also get cleaner and cheaper.

Should the hydrogen hub face deployment delays rather than a lost regulatory permission, fallback options remain straightforward: on-site electrolysis is available at \$606/tcs, while a natural gas configuration costs \$553/tcs, allowing the hydrogen blend to scale as hub capacity matures. These decisions together define a ladder of operational independence. Positioning the project at the lower-cost, higher-exposure end of this ladder ensures that the financial consequences of losing any single regulatory permission are evaluated in advance. Starting with natural gas represents the final safety net if both energy banking and the hydrogen hub become unavailable; while operating on gas shrinks power requirements from 3.8 GW to approximately 0.7 GW and nearly removes grid-banking dependencies, it incurs significant emissions and LNG market exposures. Consequently, the primary

recommended configuration relies on group-captive power coupled with banking and regional hub hydrogen (\$578/tcs, 1.93× debt cover), backed by on-site electrolysis under the same power agreement (\$606/tcs, 1.65×) as the initial alternative.

8. CONCLUSIONS

Green steel at Rajayyapeta is not blocked by technology. What decides Phase 2's viability sits largely outside the plant: the power-contracting structure, the state's energy-banking envelope, the pace of the CCTS reduction targets, the carbon price, and the delivery of the hydrogen hub each move the cost of steel several times more than the choice of DRI reactor. The overall findings, recommended actions for each stakeholder, and the chronological sequence of project decision milestones are detailed below.

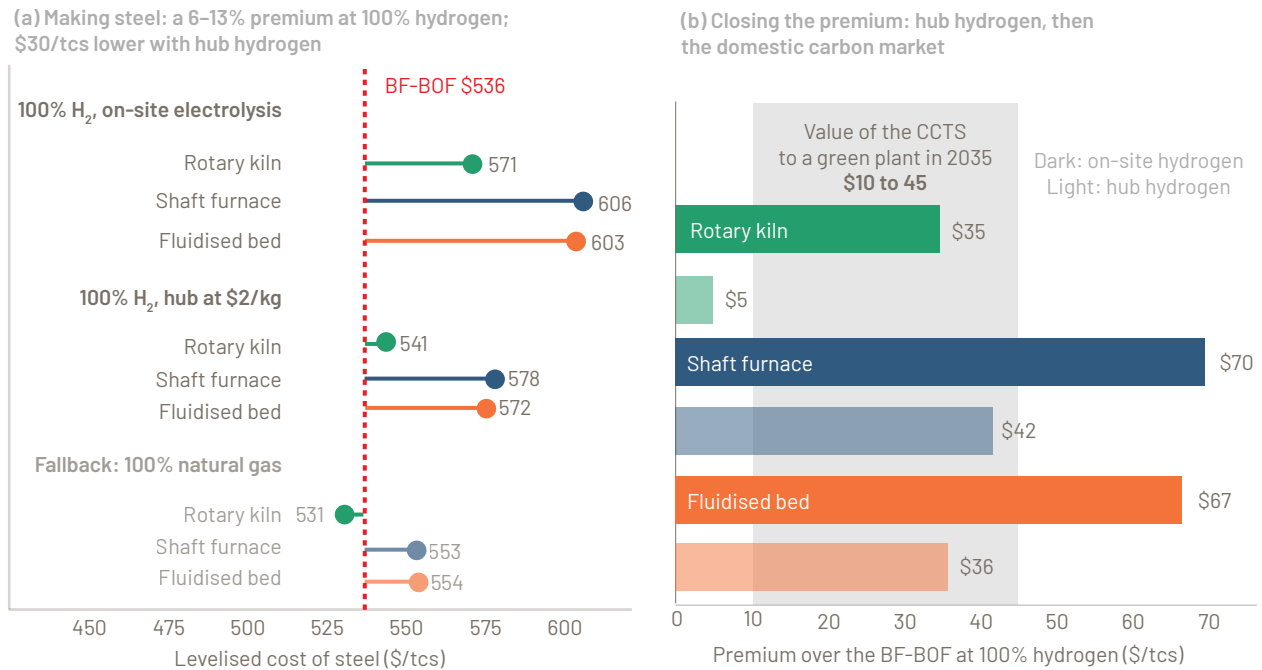


Figure 8.1 The report in one picture. (a) the levelised cost of making steel for each configuration against the greenfield BF-BOF (\$536/tcs), with natural gas shown as the fallback. (b) the premium of each route at 100% hydrogen, on on-site and on hub hydrogen, against the value of the CCTS to a green plant in 2035.

8.1 FINDINGS

- **The premium is modest and the routes have levelled.** At 100% hydrogen, green steel costs 6–13% more than the BF-BOF (\$571–606 against \$536). Within \$35/tcs of one another, the reactors are chosen on iron-feed security, maturity and emissions rather than headline cost: the shaft furnace is exposed to the pellet market and little else; the rotary kiln is its mirror image, cheap to feed and expensive to power.
- **The domestic carbon market works through the pace of its targets.** A greenfield plant sits outside the CCTS compliance mechanism in its first years and its eventual target is undefined, so no credit is counted for it; what the carbon price is worth to it is the certificates the BF-BOF fleet must buy as its targets tighten. At \$24/tCO₂ with targets tightening 2% a year that is \$5/tcs in 2030 and \$10 in 2035; at \$50 with targets tightening 5% a year it is \$25 and \$45, which closes the rotary kiln's premium as Phase 2 commissions and two-thirds of the shaft

furnace's by 2035. Demand for certified green steel under the Taxonomy, which carries no fiscal support today, and credits in international carbon markets could add to it. Although the current design of the CCTS offers limited direct incentive for financing greenfield clean capacity, this framework could evolve. Transitioning to a unified emission-intensity benchmark in the future, where facilities running below the threshold receive credits, would directly encourage such additions. For instance, at a benchmark of 1.6 tCO₂/tcs, a carbon price between \$25 and \$50/tCO₂ would offset the green premium.

- **The EU border helps, on exported tonnes only.** For steel sold into Europe the CBAM makes green steel cheaper to land than Indian BF-BOF steel, by \$179–209/tcs at the 2033 commissioning, and, from 2027–2030 depending on route, makes hydrogen rather than natural gas the cheaper fuel for tonnes exported to Europe. The green routes pay next to nothing at the border before the 2030s, while the BF-BOF's charge escalates from \$169/t in 2030 to \$308 by 2034. An incumbent that decarbonises narrows the emission gap but does not change the order: a blast furnace at the best test-furnace result reported, a 43% cut, would still pay \$175–205/t at the 2034 border against \$27 for the shaft furnace route (Section 4.3). But India exports 3–5% of its steel and the EU quota does not distinguish clean from conventional steel, so the border supports the case rather than carrying it.
- **Hydrogen is the plan; natural gas is only a fallback.** Hydrogen beats natural gas in the same reactor once it is delivered at \$1.70–2.11/kg, within reach of the official cost trajectory. A gas start would commission at \$531–553/tcs but at 0.8–1.2 tCO₂/tcs, more than twice the hydrogen routes' 0.3–0.6, and its exposure is severe: 100% imported LNG at 3–4% of national consumption, with supply and price moving together, and a later switch is only real if the hydrogen system has been planned, permitted and financed from the outset. Hydrogen belongs in the design from day one, gas is the insurance.
- **Procurement beats technology, and rests on concessions.** The power contract is worth up to \$129–148/tcs, several times the effect of the fuel choice, but the two settings that deliver it, the group-captive exemption (\$81–94) and energy banking with the distribution utility (\$50–57), are regulatory concessions whose continuation for a load of this size is not assured. Losing both costs more than any technology choice can recover. The cost ranking also hides the financing: of the power structures tested, only the base case with group-captive and banking clears a 1.3× debt-service covenant.
- **Buying hydrogen from the hub is the largest lever in the plant's own hands, if the hub delivers.** Net of the same power assumptions, it is \$28–30/tcs cheaper than making it, takes \$1.2 billion of the electrolyser capital off the balance sheet, cutting project debt from \$6.1 to \$5.3 billion, and lifts minimum debt coverage from 1.65 to 1.93 times. The rotary kiln with hub hydrogen lands at \$541/tcs, within \$5 of the BF-BOF.

Table 8.1 collects the levers by route, with who decides each. Section 8.3 orders the plant's own decisions by how hard each is to revisit.

Lever	Comparison	DRI route			Who decides it
		SF	FB	RK	
Base-case LCOS	at 100% hydrogen	606	603	571	—
Power-contracting structure	best to worst contracted route	129	148	144	Steelmaker and regulator
<i>group-captive exemption</i>	vs third-party open access	81	94	90	Central Electricity Rules
<i>as-generated vs firm RTC</i>	vs a developer-firmed product	77	88	86	Steelmaker
<i>banking allowance</i>	vs self-firming the same contract	50	57	56	State and distribution utility
<i>the same, buying hydrogen from the hub</i>	power exposure falls with the electrolyser load	42	51	47	Steelmaker
Domestic carbon price and reduction targets	value in 2035: \$24/tCO ₂ with targets tightening 2% a year, to \$50 with 5% a year	10-45	10-45	10-45	Policymaker
EU border charge (CBAM)	landed-cost advantage over the BF-BOF on exported tonnes at 2033	180	179	209	EU; already in force
Hydrogen price	per \$1/kg delivered	54	61	59	Market and hub
natural gas vs hydrogen	at 2030 costs	53	49	40	Steelmaker
Iron feed price	per 10%	18	12	12	Market and supply
Hydrogen support (SIGHT and state electrolyser subsidy)	vs no support	16	18	17	Central and state government

Table 8.1 What moves the number, by route. Each row is the change in that route's base-case levelised cost at 100% hydrogen, against the comparison stated. The rows are one-at-a-time sensitivities from a common base case and are not additive: the indented power rows are alternative contracting structures for the same renewable portfolio, and the power and hydrogen rows are alternatives to one another rather than additions. The CBAM row is a landed-cost advantage on exported tonnes rather than a change in levelised cost.

8.2 ACTIONABLE RECOMMENDATION FRAMEWORK

FOR AM/NS INDIA

Commit Phase 2 to a fuel-flexible DRI hardware now, with hydrogen designed from the start: The shaft furnace is the only DRI reactor proven at Phase 2 scale at the moment; it runs on any hydrogen share, so the plant can be designed for hydrogen from the start and hold natural gas as a fallback if hydrogen supply is late; 100% hydrogen DRI becomes the cheaper option once green hydrogen is delivered below \$1.70–2.11/kg. The rotary kiln's cost lead is a reason to pilot it at module scale on the site's fines. Repeating Phase 1's BF-BOF locks in a 40-year emissions profile that faces tightening CCTS targets at home and a CBAM charge of \$308/t by 2034 on any tonnes exported to Europe, and deepens exposure to imported coking coal. However, EU access is not assured for either: the new

EU steel quota regime applies regardless of carbon content, so the case for the DRI route has to rest on domestic competitiveness first.

Register Phase 2 as a separate CBAM installation: legal and metering separation prevents Phase 1's BF-BOF emissions from blending into Phase 2's declared intensity, since a single installation declares a weighted average.

Contract power through a group-captive structure and secure banking before the Final Investment Decision (FID): the 26% equity stake in the wind-solar vehicle unlocks the surcharge exemption, worth \$81-94/tcs, and the banking allowance, worth \$50-57/tcs, is the state's to grant; both would need to be in hand before capital commits.

Protect the feed cost base: the site's slurry link to the Bailadila mines and captive pelletising put in-house DR-grade pellet at about \$138/t; that supply, more than the reactor choice, keeps the shaft-furnace option alive if the merchant DR-grade premium widens.

FOR CENTRAL & STATE POLICYMAKERS

Publish a long-dated path for CCTS reduction targets, and signal how the scheme will treat new low-emission capacity: The CCTS incentivises green steel primarily by tightening targets on high-emitting plants. A 5% annual target reduction with carbon prices rising toward \$50/tCO₂ adds \$25-45/tcs in value to green plants from 2030-35, covering the rotary kiln's premium upon Phase 2 commissioning and closing most of the shaft furnace's gap by 2035. Announcing this trajectory before 2030 will ensure it is investable at the Phase 2 decision. Although the current framework offers minimal direct incentive for clean greenfield additions, evolving toward a unified emission-intensity benchmark with tradable credits below 1.6 tCO₂/tcs would yield \$33-38/tcs at \$24/tCO₂, while \$25-50/tCO₂ would offset the entire green premium.

Turn the Green Steel Taxonomy into demand: the Taxonomy carries no fiscal support today. Linking public procurement and large buyers' commitments to its star ratings would create a market for the \$35-70/tcs premium, a small fraction of the cost of the end products, without a budget line.

Expand state-level banking envelopes for heavy industry: The Andhra Pradesh Electricity Regulatory Commission should create dedicated industrial green-energy banking tiers beyond the 700 MW cap to accommodate large-scale industrial decarbonisation hubs.

Accelerate Pudumadaka green hydrogen hub delivery: Timely commissioning of state-backed hydrogen infrastructure by 2032 provides industrial buyers with affordable bulk fuel without forcing capital-intensive, on-site electrolyser builds. Include steel sector in tenders

Build CBAM verification capacity: Accredite Indian verifiers and support installation-level monitoring so that exporters can declare verified actual intensities rather than pay punitive default-value charges.

FOR INSTITUTIONAL FINANCIERS AND UNDERWRITERS

Rigorously Evaluate Financed Emissions and Climate Risk: JBIC alongside the Japanese private megabanks MUFG, SMBC, Mizuho, and SMTB, has established a strong precedent of underwriting low-cost, long-tenor overseas steel debt packages, including the \$5 billion co-financing facility for AM/NS India's Hazira expansion

and multi-billion-dollar overseas funding packages for Nippon Steel.⁹⁷ Japanese public and private loan providers would do well to incorporate formal financed emissions accounting such as aligning with the Partnership for Carbon Accounting Financials (PCAF) methodologies and sector-specific 2030 decarbonisation targets, and comprehensive climate risk evaluations into their due diligence. Financiers may wish to evaluate:

- **Transition & Regulatory Risk:** Accounting for how a conventional BF-BOF build risks owning uneconomic assets under tightening CCTS targets at home and, on exported tonnes, CBAM border charges escalating from \$169 per tonne in 2030 to \$308 by 2034 and tightening CCTS domestic compliance. Underwriting Phase 2 as a green DRI facility actively reduces the lenders' own Scope 3 financed emissions portfolio, whereas funding a BF-BOF expansion directly contradicts Net-Zero commitments.
- **Physical & Infrastructure Vulnerability:** Evaluating localised climate risks to raw material supply lines, grid stability, and coastal infrastructure at the Anakapalli site to ensure long-term debt servicing capability.

Evaluate Cash-Flows, Not LCOS: Lenders would be better served by prioritising cash flow stability and coverage covenants over base levelised production costs. Sourcing hydrogen externally from a hub yields superior bankability compared to self-build generation (minimum DSCR 1.93 against 1.25), even when LCOS figures appear close. Buying from the hub also lifts the equity IRR from 16% to 21% and lowers the bankable break-even steel price from \$611 to \$590/tcs.

8.3 THE DECISION CALENDAR

The choices above fall due at different times and bind to different degrees; Table 8.2 orders them by how hard each is to revisit.

- **The steelmaker:** decide in order of irreversibility. The reactor comes first and is cheap to get right: the DRI routes sit within \$35/tcs of one another and the reactor is fuel-flexible. The power structure and group-captive equity follow at FID; hydrogen make-or-buy waits for commissioning and reopens at the 2043 electrolyser re-spend. The banking allowance is not the plant's to decide, and must be secured before FID.
- **The investor:** underwrite coverage, not levelised cost. The steel price that holds 1.3 times cover is \$590/tcs buying hydrogen from the hub, \$611 making it on site, \$662 for the self-build and \$692 on third-party open access; buying hydrogen is a financing decision as much as a cost one.
- **The policymaker:** holds the largest levers, and they are regulatory settings rather than budget lines; their cost falls on cross-subsidy payers and the system's balancing capacity, not the exchequer. In order: the pace of CCTS reduction targets and the carbon price (\$10–45/tcs by 2035), the energy-banking envelope (about 700 MW state-wide against the 470–1,555 MW this one plant needs), the group-captive exemption, and a hub delivered near \$2/kg.

Four assumptions carry the most uncertainty in this report. Transmission for the 600 km wind wheel is not modelled; the banking envelope is the binding regulatory question; the DR-pellet premium rests on a supply that does not yet exist at this scale; and the purchased-commodity prices are 2025 market anchors carried forward at 2% a year real. None of them changes the shape of the answer, but may change the magnitude of the margins.

Decision	Taken	Reversible?	What it turns on
Reactor and route	FID	No; a 40-year asset	Sections 4 and 6: the fuel-flexible shaft furnace preserves the fuel choice at no cost
Power structure and group-captive equity	FID	At contract renewal	Section 7.1: worth \$129-148/tcs across the contracted routes
Banking allowance	Not for the plant to decide	Set by the state	Section 7.1: a state envelope of about 700 MW against roughly 470 MW needed even when hydrogen is bought
Hydrogen: make or buy	Commissioning	At the electrolyser re-spend, around 2043	Section 7.3: the hub is expected around 2032
Fuel share, gas to hydrogen	Continuous	Fully	Section 6: the delivered hydrogen price against the \$1.70/kg switch threshold

Table 8.2 The decision calendar, ordered by how hard each choice is to revisit. Dates are indicative for a plant commissioning in 2033.

One consideration belongs here even though it fits in no table. Capacity built this decade will still be running in the 2060s, in one of the countries most exposed to the climate change that steel emissions drive. The narrow premium this report finds means the commercial choice and the climate choice now largely coincide; that alignment, rather than any single subsidy, is the real opportunity of Phase 2.

APPENDICES

APPENDIX A. MODEL AND METHODOLOGY

The results in this report come from a cost-minimising linear program of the integrated plant. For each configuration (a process route, a fuel blend, a power-procurement mode and a hydrogen-supply mode), the model chooses the size of every energy asset (contracted or captive solar and wind, battery storage, electrolyser, and hydrogen storage) and its dispatch in every hour of a full year (8,760 hours; weather reference year 2019), so as to serve the steel plant's electricity, heat and hydrogen demand at minimum total annual cost. The plant is modelled at 9.6 Mtpa of crude steel nameplate at an 85% capacity factor. Because the program is linear in capacity, per-tonne results are scale-invariant.

The reported metric is the levelised cost of steel (LCOS, 2025 USD per tonne of crude steel): annualised capital (each asset's capex converted to an annuity at the WACC over its economic life) plus fixed O&M, purchased materials, fuel, labour, grid charges and policy payments or credits, divided by annual crude-steel output. Emissions are accounted cradle-to-gate: the plant's direct (Scope 1) and electricity (Scope 2) emissions plus the embedded (Scope 3) emissions of purchased inputs.

A.1 PROCESS ROUTES AND MASS-ENERGY BALANCES

Three route configurations are modelled: the shaft furnace feeding an electric arc furnace (SF-EAF), and the fluidised bed and rotary kiln each feeding an electric smelting furnace and basic oxygen furnace (FB-ESF-BOF, RK-ESF-BOF). A fourth variant (SF-ESF-BOF on BF-grade pellet) is examined in Section 4.2. Each stage is a fixed mass-energy balance; Table A.1 shows the stage balances and the metallurgical specifications. Metallisation at the DRI stage is route-specific; melting closes the remainder. In the hydrogen cases the DRI is carbon-free, so the ESF charges carburising carbon to close the residual iron oxide and include 3.5% C in the melt; on natural gas the shaft-furnace DRI instead carries about 1.5% carbon from the reformed gas. All ore fines are Indian low-grade hematite fines: 57.3% Fe on a dry basis (50.4% as received at 12% moisture), 5.3% SiO₂, 4.5% Al₂O₃, 2.0% other gangue and 6.0% loss on ignition.⁹⁸ The DR-grade pellet is 67% Fe with about 2.3% acid gangue. The fines routes charge as-received fines to a dryer integrated with the DRI reactor; the shaft-furnace route charges DR-grade pellet directly. Downstream, the shaft furnace feeds an EAF (85% DRI / 15% scrap metallic charge), while the fines routes carburise and smelt their DRI in an ESF and refine the hot metal in a BOF.

Each route runs across the fuel range: 100% natural gas, 30% and 70% hydrogen blends, and 100% hydrogen, with reductant demand interpolated linearly between the poles. On natural gas, the fuel supplies both reduction chemistry and process heat; on hydrogen, consumption is near-stoichiometric and the heating duty moves to the electricity bill, which is why the fines reactors' larger heat demand appears as gas on one end of the range and electricity on the other.

Stage (per unit)	Iron feed	H ₂ (kg) [100%]	NG (MMBtu) [100%]	Electricity, 100% H ₂ (kWh)	Other consumables	Output
Shaft furnace ⁹⁹ (tDRI)	1.41 t DR-pellet	58	9.5	700	—	DRI (94.7% Fe, 3.9% gangue)
Fluidised bed (tDRI)	1.61 t fines	49.1	9.3	800	—	DRI (81.2% Fe, 17% gangue)
Rotary kiln (tDRI)	1.60 t fines	47.7	8.8	650	—	DRI (81.8% Fe, 17% gangue)
EAF (tcs; 15% scrap)	0.926 tDRI + 0.15 t scrap	—	—	674 (600 base + 80/ tDRI)	flux 0.037 t/ tHBI; O ₂ 50 Nm ³ ; electrode 0.002 t	Crude steel (99.7% Fe, 0.2% C)
ESF (tHM)	1.17–1.18 tDRI	—	—	522 (RK) / 500 (FB)	flux 0.084 t; O ₂ 25 Nm ³ ; electrode 0.0013 (RK) / 0.00125 (FB) t; carburising C 0.0495 (FB) / 0.0557 (RK) t	Hot metal (96% Fe, 3.5% C, 0.4% Si)
BOF (tIs)	1.048 tHM	—	0.1	130	flux 0.031 t; O ₂ 55 Nm ³	Crude steel (99.7% Fe, 0.2% C)

Table A.1 Stage-level mass-energy coefficients, per tonne of stage product (tDRI, tcs, tHM, tIs). Electricity for the DRI stages is shown at 100% hydrogen; on natural gas only the auxiliary load remains. The per-tonne-of-crude-steel values of report Table 2.1 are these coefficients multiplied by the stage flows of Table A.1a; the two tables reconcile exactly.

Table A.1a lists the stages in each route and the realised flows per tonne of crude steel from the solved model at 100% hydrogen. The tonnage flows are identical across the fuel range; only the energy inputs change, and on natural gas the shaft-furnace DRI additionally carries about 1.5% carbon.

Route	Process chain	Iron feed (t/tcs)	DRI (t/tcs)	Hot metal (t/tcs)	H ₂ (kg/tcs)
SF-EAF	DR pellet → shaft furnace → EAF	1.31 pellet (67% Fe)	0.926	— (EAF)	53.7
FB-ESF-BOF	Fines → dryer → fluidised bed → ESF → BOF	1.99 wet fines (50.4% Fe)	1.238	1.048	60.8
RK-ESF-BOF	Fines → dryer → rotary kiln → ESF → BOF	1.99 wet fines (50.4% Fe)	1.246	1.048	59.4
SF(BF pellet)-ESF-BOF	BF pellet → shaft furnace → ESF → BOF	1.67 pellet (63% Fe)	1.208	1.048	64.5

Table A.1a Routes, stages and realised flows per tonne of crude steel (100% hydrogen).

Tables A.1b–d give the elemental balance of each chain in kilograms per 1,000 kg of dry ore fed. Oxygen is the oxygen bound to iron; LOI leaves at induration (pellet) or in the reactor off-gas (fines).

SF-EAF (100% H ₂)	Pellet	DRI	Crude steel
Fe (oxidised)	307.7	15.4	0
Fe (metallic)	0	292.3	303.1
O (bound to Fe)	132.2	4.4	0
SiO ₂	5.6	5.6	0
Al ₂ O ₃	4.8	4.8	0
Other gangue	2.4	2.4	0.3
LOI	6.6	0	0
H ₂ O	0	0	0
C	0	0	0.6
Total (kg)	459.2	324.8	304.0

Table A.1b Shaft-furnace chain, kg per 1,000 kg dry ore. EAF slag: 29.5 kg on this basis (CaO 38%, FeO 20%, SiO₂ 19%, Al₂O₃ 16%, MgO 7%). On natural gas the DRI additionally carries 9.0 kg C (≈1.5%), total 333.8 kg. The chain above excludes scrap; the plant EAF charge adds 15% scrap.

FB-ESF-BOF (100% H ₂)	Wet fines	Dried fines	DRI	Hot metal	Liquid steel
Fe (oxidised)	573.0	573.0	40.1	0	0
Fe (metallic)	0	0	532.9	573.0	568.1
O (bound to Fe)	246.2	246.2	11.5	0	0
SiO ₂ / Si	53.0	53.0	53.0	2.4 (as Si)	0
Al ₂ O ₃	45.0	45.0	45.0	0	0
Other gangue	22.8	22.8	22.8	0.6	0.6
LOI	60.0	60.0	0	0	0
H ₂ O	136.4	0	0	0	0
C	0	0	0	20.9	1.1
Total (kg)	1,136.4	1,000.0	705.3	596.9	569.8

Table A.1c Fluidised-bed chain, kg per 1,000 kg dry fines. The ESF removes the gangue as 167.7 kg of slag (CaO 31%, SiO₂ 29%, Al₂O₃ 27%, other 13%; basicity 1.1) and carburises the melt; the BOF blows the carbon back down to steel specification, producing 31.5 kg of slag (CaO 57%, FeO 20%, SiO₂ 16%, MgO 7%) and 46.1 kg of CO off-gas on this basis.

RK-ESF-BOF (100% H ₂)	Wet fines	Dried fines	DRI	Hot metal	Liquid steel
Fe (oxidised)	573.0	573.0	57.3	0	0
Fe (metallic)	0	0	515.7	573.0	568.1
O (bound to Fe)	246.2	246.2	16.4	0	0
SiO ₂ / Si	53.0	53.0	53.0	2.4 (as Si)	0
Al ₂ O ₃	45.0	45.0	45.0	0	0
Other gangue	22.8	22.8	22.8	0.6	0.6
LOI	60.0	60.0	0	0	0
H ₂ O	136.4	0	0	0	0
C	0	0	0	20.9	1.1
Total (kg)	1,136.4	1,000.0	710.2	596.9	569.8

Table A.1d Rotary-kiln chain, kg per 1,000 kg dry fines. Identical to the fluidised bed except at the DRI stage: 90% metallisation leaves the residual iron oxidised into the ESF, where melting completes the reduction. ESF and BOF slag and off-gas as in Table A.1c.

A.2 ENERGY SYSTEM AND PROCUREMENT MODES

Renewable supply uses hourly 2019 profiles from two sites: solar at the plant site (17.41° N, 82.72° E; PVGIS-ERA5, single-axis tracking) and onshore wind at Anantapur in the Rayalaseema belt (14.68° N, 77.60° E; NASA POWER 50 m winds extrapolated to a 132 m hub, V136-class turbine, 12% losses), consistent with the 600 km wind wheel described in Section 7.1. The energy technologies the model can build or contract are listed in Table A.2 at their 2030 costs; the electrolyser is an alkaline system at 51.2 kWh per kg of hydrogen (65% efficiency), with compression to storage at 2 kWh/kg.

Technology	Capex (2030)	Unit	Life (yr)	Fixed O&M (%/yr)
Utility-scale solar PV	516	USD/kW	30	1.5
Onshore wind	1,040	USD/kW	30	2.5
Alkaline electrolyser (system)	525	USD/kW	10	3.0
Li-ion battery (4-hour)	86	USD/kWh	15	3.0
H ₂ compressed-gas storage	394	USD/kg	25	2.0
DRI shaft furnace	345	USD/(tDRI/yr)	40	3.0
DRI rotary kiln	300	USD/(tDRI/yr)	40	3.0
DRI fluidised bed	400	USD/(tDRI/yr)	40	3.0
ESF (incl. casting)	337	USD/(tcs/yr)	40	3.0
ESF	388	USD/(tHM/yr)	40	5.0
BOF	72	USD/(t/yr)	40	3.0

Table A.2 Technology capital costs (2030), economic lives and O&M rates. Sources: solar and wind from expert consultation for Andhra Pradesh (2026, at the project exchange rate of ₹83.3/USD); electrolyser from anonymised Andhra Pradesh project data; battery at the IEEFA (2025) tender-implied level; DRI reactor capital consistent with the international literature, the rotary kiln at 0.87 of the shaft furnace.

Power-procurement modes differ in who owns the renewables and in the charges the electricity carries (Table A.3). The delivered PPA tariffs available locally in Andhra Pradesh are ₹5.06/kWh (\$0.058) for a firm RTC product, ₹3.05/kWh (\$0.035) for solar, and ₹3.66/kWh (\$0.042) for wind, sourced from discovered price from various auctions. Open-access energy pays a wheeling charge of ₹0.49/kWh (\$0.006) and, where applicable, a cross-subsidy surcharge (CCS) of ₹1.67/kWh (\$0.019) are added; group captive ($\geq 26\%$ equity) is exempt from the surcharge. The distribution companies (DISCOM) industrial tariff is ₹6.49/kWh (\$0.075). Renewable certificates are priced at \$15/MWh in 2030.

The DISCOM banking mechanism, where enabled, is modelled: monthly settlement, 92% in-kind return, no carry-forward across months and no buy-back of the residual. Portfolio caps on contracted capacity are solver guardrails scaled to the plant (not transmission limits); the binding constraints of interest are the prices and charges.

Structure	Energy price (\$/kWh)	Wheeling / CSS (\$/kWh)	Firming
Group captive, shaped hybrid + DISCOM banking	solar 0.037 / wind 0.044	0.0056 / exempt	monthly banking (92%)
Group captive, shaped hybrid, self-firmed	solar 0.037 / wind 0.044	0.0056 / exempt	grid fills the gaps
Group captive, firm RTC PPA	0.061	0.0056 / exempt	developer firms, in tariff
On-site captive (self-build)	build at cost	— / —	own storage + grid top-up
Third-party open access, shaped + banking	solar 0.037 / wind 0.044	0.0056 / ≈ 0.019	monthly banking (92%)
Third-party open access, unbanked	solar 0.037 / wind 0.044	0.0056 / ≈ 0.019	grid fills the gaps

Table A.3 Power-procurement mode inputs. These are the contracted tariffs and charges the model prices from; the delivered power costs of report Table 7.1 (\$0.044–0.072/kWh) are model outputs computed on top of them, including grid purchases and firming. Grid purchases carry the DISCOM tariff and the grid emission intensity; the Andhra Pradesh electricity-duty waiver for green-hydrogen loads is applied where in force. The grid emission intensity is a national projection on the CEA baseline (0.48 tCO₂/MWh in 2030, declining thereafter)

Hydrogen can be made on-site (the central case) or bought from the planned Pudimadaka hub at an assumed delivered \$2.0/kg. On-site production captures the SIGHT incentive, modelled as the notified three-year declining schedule (₹50/40/30 per kg), levelised to \$0.12/kg over the plant life.

A.3 EMISSIONS ACCOUNTING AND CARBON-PRICE APPLICATION

The report's default metric is cradle-to-gate intensity: on-site process emissions (Scope 1), purchased-electricity emissions (Scope 2), and the embedded emissions of purchased materials (Scope 3). Two statutory boundaries are priced on their own terms: India's Carbon Credit Trading Scheme counts Scope 1 plus Scope 2 at unit level, and the EU border adjustment counts direct emissions plus CBAM-listed precursors while excluding indirect emissions. The three are not nested. Every intensity is decomposed into four segments (Scope 2; Scope 1; Scope 3 counted by CBAM; other Scope 3) so that each boundary is a contiguous block of the same stack. Section 5 prices each boundary.

Domestic carbon pricing is applied on the CCTS boundary. Section 5.2 values the scheme as the certificates a BF-BOF held at its baseline intensity must buy, with no credit or obligation counted for the green plant, against a plant-specific target tightening 2% or 5% a year from 2025, at an indicative \$24/tCO₂ (there is no official CCTS price projection) and an illustrative \$50. The fuel-switch thresholds of Section 6 apply the carbon price to the difference in emissions between the two fuel modes of the same plant. Both are computed from the base-case solves; no separate carbon-price case is solved. The border charge is the EU allowance price applied to embedded emissions above the free-allocation deduction, computed as the route-based CBAM benchmark (1.364 tCO₂e/t for the blast-furnace route and 0.475 for the DRI route at the crude-steel boundary; Implementing Regulation (EU) 2025/2621 times the year's CBAM factor (97.5% in 2026 declining to nil from 2034; Directive 2003/87/EC, Article 10a(1a)). The allowance price is a linear path from \$86 per tonne in 2026 (about €80; the Q2 2026 certificate price is €75) to \$140 by 2034 (about €125), passing \$113 in 2030. The 2030 point is the European Commission's recommended projection parameter of €95 per allowance; the path lies between the post-July-2026 analyst range (€90–120 for 2030) and the earlier consensus of €126. Because the charge is linear in the allowance price above the deduction, a lower or higher path scales every border charge and landing advantage in Sections 5 and 6 in proportion without changing the ordering of the routes. The certificate price importers actually pay is the weighted average of EU ETS auction clearing prices, published quarterly in 2026 and weekly from 2027.

A.4 PRICES, FINANCE AND POLICY ARCHETYPES

Commodity prices are 2025 USD with real escalation to the 2030 target year (Table A.4); capex uses the 2030 vintage of Table A.2. The weighted average cost of capital is 10%, applied as a capital-recovery factor per asset life. Emission factors follow ResponsibleSteel/IPCC values; the Central Electricity Authority's national grid trajectory (0.48 tCO₂/MWh in 2030, 0.36 in 2035).

Input	Price (2025; USD/unit)	Real growth (%/yr)	Emission Factors (tCO ₂ /Unit)
DR-grade pellet, domestic	138/t (2030)	BF PELLEX 114 (2025) at 2%/yr + 10% DR-grade premium	0.14/t ¹⁰⁰
Low-grade fines (58% Fe)	59/t (2030)	—	0.035/t
Natural gas (delivered, industrial)	11.77/MMBtu	2 (=13.0 in 2030)	0.0592/MMBtu
Steel scrap	402/t	2	0
Burnt limestone	33.5/t	1	1.473/t
Graphite electrode	2,500/t	1	4.45/t
Ferroalloys	935/t	1	2.186/t
Carburising carbon (coal proxy)	189/t	2	3.667/t
Oxygen (captive ASU)	0.04/Nm ³	1	0.000426/Nm ³
Labor (fully loaded)	20/h	2	—

Table A.4 Commodity and input prices.

A.4.1 IRON-ORE AND PELLET PRICE DERIVATION

The BF-grade domestic pellet reference is USD125.87/t in 2030 (USD114 in 2025, carried forward at 2% a year real). The 2025 level is taken for consistency with the UC Berkeley (2026) India study that supplies the report's BF-BOF benchmark (\$536/tcs), and it sits at the low end of the current market: BigMint's PELLEX index (Fe 63%, DAP Raipur) stood at ₹10,050/t on 1 May 2026, with concluded deals at ₹9,600–10,200/t; at the project exchange rate of ₹83.3/USD, the USD114 anchor corresponds to about ₹9,500/t.¹⁰¹

The case charges the shaft furnace delivered DR-grade pellet (67% Fe) at USD138/t, a 10% (USD12.6/t) premium over the BF-grade reference. This is a conservative estimate of the cost of in-house pellet made from high-grade Bailadila-type fines, not a market price: published market premiums for DR-grade over BF-grade pellet are around USD30/t domestically and USD45–60/t on the seaborne market. Table A.4a builds the in-house cost from this study's own beneficiation and pelletisation coefficients under two ore feeds. Fed with NMDC Bacheli (Bailadila) fines—the supply chain AM/NS already operates into Visakhapatnam via slurry pipeline—the cost basis is about USD111/t, so the USD138 price covers the cost plus a margin of roughly USD27/t. Fed instead with typical low-grade Indian fines, the cost rises to about USD156/t, roughly where a purchased tonne at the domestic market premium would also land. The route ranking turns on which applies: the rotary kiln overtakes the shaft furnace at a delivered pellet price of about USD111/t (Section 4.2), so the shaft-furnace case rests on the Bailadila corridor delivering at the captive cost.¹⁰²

Component (2030 USD/t)	High-grade Bailadila fines (64% Fe)	Low-grade fines (58% Fe)
Fines price, delivered	59.00	59.09
Ore per tonne of concentrate (t)	1.16	1.91
Ore charge	68.62	112.86
Beneficiation: power (114 kWh at \$0.046)	5.28	5.28
Beneficiation: capital, O&M, labour	12.02	12.02
Concentrate (67% Fe), subtotal	85.92	130.16
Induration: NG (1.11 MMBtu at \$13)	14.44	14.44
Pelletising: power, capital, O&M, labour	10.90	10.90
DR-grade pellet, cost basis	~111	~156

Table A.4a Bottom-up cost of in-house DR-grade pellet (67% Fe) under two ore feeds, at the plant's delivered power price (\$0.044/kWh) and delivered gas price (\$13/MMBtu), with capital recovered at 10% over 25 years (beneficiation, \$62/t capacity) and 40 years (pelletising, \$43/t) at 85% utilisation. Fines prices: high-grade = NMDC Bacheli fines (64% Fe, FOR) at \$54/t plus \$5/t slurry transport to the plant; low-grade = Odisha 55–58% Fe fines at about ₹3,800/t plus USD10/t grinding.^{103, 104}

Policy settings enter through scenario archetypes (Table A.5). The base case books no carbon price but includes the SIGHT hydrogen incentive and the 25% electrolyser capital subsidy; a no-subsidy case strips all support to isolate the bare technology comparison. Carbon prices are applied to the solved cases analytically, each on its own emissions boundary (Appendix A.3).

Archetype	Carbon price (\$/tCO ₂)	SIGHT (\$/kg)	Electrolyser capex subsidy
BASE Central case	0	0.124	25%
BASE technology	0	0	0%

Table A.5 Scenario archetypes. Each archetype crosses the route, fuel-blend, power-mode and hydrogen-mode dimensions in the run matrix.

A.4.2 THE PROJECT-FINANCE LAYER

Financing metrics are computed from the same cost set: 70% of capital funded by debt at 7% real over 15 years, 25.17% corporate tax, 20-year straight-line depreciation, a four-year construction draw, and 40 years of operation with the electrolyser re-spent every 10 years and any battery every 15. Reported metrics are minimum and average debt-service coverage over the loan tenor, the equity internal rate of return, and the steel price at which coverage holds 1.3 times.

APPENDIX B. POLICY AND REGULATORY LANDSCAPE

Brief descriptions of every instrument the report relies on, with the role each plays in the analysis.

National Steel Policy, 2017 (Ministry of Steel). Targets 300 Mtpa of crude-steel capacity and 158 kg per-capita consumption by 2030–31. Frames the demand growth that makes new-capacity choices decisive (Section 1.1).

Green Steel Taxonomy, 2024 (Ministry of Steel). Defines green steel by emission intensity below 2.2 tCO₂e per tonne of finished steel, with star ratings below that: three stars at 2.0–2.2, four at 1.6–2.0 and five at or below 1.6. The five-star band is the one against which a natural-gas fallback is read (Sections 4.3). The Taxonomy is a label with no fiscal support attached today; it is expected to anchor demand for green steel through procurement, which the report treats qualitatively (Section 5.2).

Carbon Credit Trading Scheme, 2023 (CCTS). India's compliance carbon market. Steel entered in 2025; unit-level intensity targets remain in draft (June 2025, revised June 2026) and are set from each plant's own baseline. The report tests the carbon price (an indicative \$24 per tonne for 2030, and \$50) against reduction targets tightening 2% and 5% a year (Section 5.2). New greenfield plants enter the compliance mechanism only once they are fully operational and two to three years of production data allow a unit-specific baseline.

National Green Hydrogen Mission, 2023, and SIGHT. The hydrogen supply-side programme. The Strategic Interventions for Green Hydrogen Transition scheme pays a declining production incentive over the first three years (Rs 50/40/30 per kg), worth about \$0.12 per kg levelised in the model (Sections 3.2 and 6.2). The incentive is tendered in tranches and has not been extended to steel offtake; the base case assumes the plant secures it, and Section 4.1 reports the figures without it.

Electricity Rules, 2005, amended March 2026 (Ministry of Power). Define group-captive status: at least 26% equity in the generating vehicle and at least 51% offtake exempt the consumer from cross-subsidy and additional surcharges. The 2026 amendment lets the equity be held across a corporate group and confirms energy routed through storage counts as captive. Worth \$81–94 per tonne here (Section 7.1).

Andhra Pradesh Integrated Clean Energy Policy, 2024. The state framework for renewable procurement: monthly energy banking with a 92% effective return, a state-wide banking envelope of about 5% of peak demand (roughly 700 MW), and a 25% electrolyser capital subsidy, which is capped state-wide and may not cover a project of this scale full. The banking allowance is the analysis's binding regulatory dependency (Section 7.1).

Pudimadaka green-hydrogen hub. The planned hub near Visakhapatnam (about 20 GW of dedicated renewables, roughly 1,500 tonnes of hydrogen a day, full build-out expected by 2032). The report's make-or-buy analysis assumes delivery near \$2 per kg (Section 7.3).

EU Emissions Trading System (Directive 2003/87/EC). The allowance market whose price the border charge applies. Averages: EUR 83.6 per tonne in 2023, EUR 64.8 in 2024; the European Commission recommended parameter for Member State projections is EUR 95 per allowance in 2030, the anchor of the price path in Section 5.3. Article 10a(1a) sets the CBAM factor schedule for free-allocation phase-out (Section 5.3).

EU Carbon Border Adjustment Mechanism (Regulation (EU) 2023/956). Charges importers the allowance price on

embedded emissions above a free-allocation deduction; definitive phase began 1 January 2026, full liability from 2034. Covers direct emissions and listed precursors for iron and steel; indirect emissions are excluded (Sections 5.1 and 5.3).

Implementing Regulations (EU) 2025/2620 and 2025/2621. The 2620 regulation sets the free-allocation adjustment mechanics (deduction = CBAM benchmark times CBAM factor); the 2621 regulation sets the route-based benchmark values (1.364 blast furnace, 0.475 DRI, 0.066 scrap at the crude-steel boundary). A single installation making one product declares a weighted-average intensity, which is why Phase 2's registration matters (Sections 5.3 and 7.4).

APPENDIX C. SUPPLEMENTARY RESULTS

C.1 LEVELISED COST AND EMISSION INTENSITY BY ROUTE AND FUEL

Route	Hydrogen share	LCOS (\$/tcs)	Cradle-to-gate (tCO ₂ /tcs)	CCTS boundary (tCO ₂ /tcs)
Shaft furnace	0%	553	0.81	0.52
Shaft furnace	30%	574	0.63	0.34
Shaft furnace	70%	598	0.42	0.13
Shaft furnace	100%	606	0.29	0.00
Fluidised bed	0%	554	1.22	0.89
Fluidised bed	30%	574	0.99	0.66
Fluidised bed	70%	597	0.73	0.40
Fluidised bed	100%	603	0.56	0.24
Rotary kiln	0%	531	1.20	0.88
Rotary kiln	30%	547	0.96	0.64
Rotary kiln	70%	566	0.70	0.38
Rotary kiln	100%	571	0.54	0.22

BF-BOF comparator: \$536/tcs; 2.60 cradle-to-gate, 2.23 on the CCTS boundary, 2.20 on the border boundary.

C.2 BORDER CHARGE AND LANDED POSITION AT 100% HYDROGEN (EU CBAM)

Year	Deduction (DRI route)	SF charge (\$/t)	RK charge (\$/t)	BF-BOF charge (\$/t)
2026	0.463	0	0	75
2028	0.427	0	0	97
2030	0.245	0	1	169
2032	0.126	9	15	233
2033	0.067	17	24	268
2034	0.000	27	35	308

Charges are the allowance price applied to embedded emissions above the deduction.

APPENDIX D. ABBREVIATIONS

BF-BOF	blast furnace and basic oxygen furnace
BOF	basic oxygen furnace
CBAM	Carbon Border Adjustment Mechanism (EU)
CCTS	Carbon Credit Trading Scheme (India)
CN	Combined Nomenclature (EU customs codes)
DRI	direct reduced iron
DSCR	debt-service coverage ratio
EAF	electric arc furnace
ESF	electric smelting furnace
ETS	Emissions Trading System (EU)
FID	final investment decision
HBI	hot briquetted iron
LCOS	levelised cost of steel
NGHM	National Green Hydrogen Mission
RTC	round-the-clock (firm power product)
SEFA	specific embedded free allocation (CBAM deduction per tonne)
SIGHT	Strategic Interventions for Green Hydrogen Transition
tcs	tonne of crude steel
WACC	weighted average cost of capital

ENDNOTES

- 1 [https://steel.gov.in/sites/default/files/2026-04/Final%20Annual%20Report%202025-26%20\(English%20Version\).pdf](https://steel.gov.in/sites/default/files/2026-04/Final%20Annual%20Report%202025-26%20(English%20Version).pdf)
- 2 <https://steel.gov.in/national-steel-policy-nsp-2017>
- 3 IPCC AR6, Climate Change: Impacts, Adaptation and Vulnerability
- 4 https://steel.gov.in/sites/default/files/2025-11/GSI%20Report%20FINAL%20NEW_18092025_2.pdf
- 5 <https://worldsteel.org/wider-sustainability/sustainability-indicators/>
- 6 <https://globalenergymonitor.org/research/why-indias-build-now-decarbonize-later-approach-achieving-net-zero-steel-industry-will>
- 7 <https://iecc.gspp.berkeley.edu/resources/the-economic-case-for-green-steel/>
- 8 <https://www.pib.gov.in/PressReleasePage.aspx?PRID=2088827®=48&lang=2>
- 9 India is a net scrap importer, and projections from WorldSteel put scrap demand at 70-80 Mt once production reaches 250 Mt, well beyond domestic supply.
- 10 <https://mnre.gov.in/en/national-green-hydrogen-mission/>
- 11 <https://www.hybritdevelopment.se/en/category/press-en/>
- 12 <https://stegra.com/en/the-boden-plant>
- 13 <https://gmk.center/en/posts/major-pause-in-eu-steel-industry-decarbonization-projects/>
- 14 <https://steel.gov.in/sites/default/files/2025-03/Taxonomy%20Brochure.pdf>
- 15 <https://icapcarbonaction.com/en/ets/indian-carbon-credit-trading-scheme>
- 16 <https://www.icra.in/Rating/DownloadResearchSummaryReportViewer/5100>
- 17 The detailed policy and regulatory landscape is set out in Appendix B
- 18 https://www.amns.in/storage/statutory-documents/March2026/EC_8_2_MTPA_ISP_Rajayapetta.pdf
- 19 <https://www.amns.in/?press-release=amns-india-becomes-first-integrated-steel-producer-to-receive-green-steel-certification-from-ministry-of-steel-under-new-taxonomy>
- 20 <https://www.amns.in/storage/Reports/AMNS-Climate-Action-Report-2024.pdf>
- 21 <https://www.amazingap.com/2026/03/anakapalli-steel-plant-foundation-stone.html>
- 22 <https://www.bizzbuzz.news/national/andhrapradesh/after-green-nod-am-n-s-plant-gets-centres-ok-for-slurry-pipeline-from-odisha-chgarh-1376963>
- 23 <https://jmkresearch.com/wp-content/uploads/2024/10/AP-Policy.pdf>
- 24 <https://www.ngel.in/page/hydrogen-hub>
- 25 In principle any DRI can feed an EAF as part of the metallic charge; low gangue is preferred, and a scrap-rich charge can accept lower-quality DRI. The boundary is techno-economic rather than absolute: gangue brings excess slag formation and energy consumption. With scrap scarce in India and at this plant's scale, the smelter route is the practical configuration (Section 2.4).
- 26 Iron feed is wet tonnes as delivered, the basis on which Indian ore is traded, while the Fe grade is assayed dry; the fines carry about 12% free moisture.
- 27 The fines routes are priced on 58% Fe fines, the representative grade of India's abundant low-grade hematite; higher-grade fines are usable and shift cost from downstream smelting to the feed bill.
- 28 The iron-feed prices are market assessments (IBM/CEIC average sale price for fines, BigMint PELLEX for pellet, with the DR-grade premium cross-checked against Midrex)
- 29 Reduction-stage power is 700, 800 and 650 kWh per tonne of DRI respectively, converted here to a per-tonne-of-steel basis.
- 30 Graphite electrode consumption is scaled with the electrical energy of the melting vessel at 2.5 kg/MWh.
- 31 <https://www.gem.wiki/ArcelorMittalNipponSteelHaziraPlant>
- 32 <https://www.jsplgroup.com/coal-gas-for-dri-plant.php>
- 33 <https://www.midrex.com/press-release/jsw-steel-uses-cog-to-supplement-ng-for-dri-production/>
- 34 Rahbari et al. 2025: <https://doi.org/10.1016/j.crsus.2024.100301>
- 35 https://www.academia.edu/1237578/Circored_fine_ore_direct_reduction
- 36 https://vdeh.de/media/luengen_dri_ecic_2022.pdf
- 37 <https://www.sciencedirect.com/science/article/abs/pii/S0360544225033328>
- 38 <https://www.posco.co.kr/homepage/docs/eng7/jsp/hyrex/>
- 39 <https://www.primetals.com/en/portfolio/solutions/ironmaking/direct-reduction/hyor/>
- 40 <https://www.posco.co.kr/homepage/docs/eng7/jsp/hyrex/>
- 41 <https://www.teriin.org/research-paper/hydrogen-rotary-kilns-ironmaking-india>
- 42 <https://www.gem.wiki/HylronSteelNamibiaPlant>
- 43 The model is linear in plant capacity and didn't consider the economies of scale, so the results are valid as a comparison between routes at a common scale and should not be read as the cost of a materially larger or smaller plant.
- 44 The cap is 2.2 tCO₂/tcs, the Green Steel Taxonomy's green-eligibility threshold, and is slack for every green route (0.29-0.57 tCO₂/tcs).
- 45 The full methodology can be found in Appendices.
- 46 The central assumptions and inputs are summarised; the full set is in Appendix A.
- 47 PELLEX India is a domestic benchmark price index for iron ore pellets.
- 48 This is based on electricity through group-captive renewable power, hydrogen from on-site electrolysis, and no carbon price applied; the notified hydrogen support is included, as stated below.
- 49 Policy support: 25% subsidy on CAPEX of electrolyser and SIGHT production incentive of ₹50, 40 and 30 per kg in the first three years of operation.
- 50 Rotary kiln is expected to be cheaper given the low price of the coal-based rotary kiln in India.
- 51 Not a market price: \$138/t is the estimated cost of DR-grade pellet made in-house from high-grade Bailadila-type fines. The model's own beneficiation and pelletising coefficients put that cost near \$111/t (see Appendix A.4.1), so \$138 covers cost plus a margin of about \$27/t. Purchased DR-grade pellet might be dearer and seaborne premiums are usually \$45-60/t.
- 52 <https://labradorironore.com/news/labrador-iron-ore-royalty-corporation-results-fo-14812/>
- 53 https://www.danieli.com/en/news-media/news/arcelormittal-nippon-steel-india-selects-danieli-corus-new-pelletizing-plant_37_880.htm
- 54 <https://iecc.gspp.berkeley.edu/wp-content/uploads/2026/05/IECC-Economic-Case-for-Green-Steel-Production-in-India-Report-May26.pdf>
- 55 On a Scope 1+2 basis, best available technique is about 1.7-1.8 tCO₂/tcs, the average European integrated works and Nippon Steel run at 2.0-2.1, the worldsteel BF-BOF average is 2.3, and Tata Steel targets below 1.8 by 2030. Adding the 0.37 tCO₂/tcs of embedded Scope 3 that separates this report's 2.23 from its 2.6 puts them on the cradle-to-gate basis at about 2.1-2.2 for best available technique and 2.4-2.5 for current practice. A blast furnace commissioned around 2030 at current European or Japanese practice would therefore sit near 2.4-2.5 cradle-to-gate against the 2.6 used here.

56 <https://www.aist.org/getmedia/1f692aad-90e1-4d92-b591-6b97060144cf/Electric-Smelting-Furnace-based-Flowsheets.pdf#:~:text=We%20are%20delighted%20to%20bring,of%20a%20lower%20carbon%20intensity>

57 Life-cycle supply-chain (pre-combustion) intensities of traded gas average about 13 kgCO₂e/MMBtu on a GWP-100 basis. <https://www.nature.com/articles/s41467-020-14606-4>

58 Nippon Steel reports a 43% CO₂ reduction in a test furnace with heated hydrogen injection in 2024, and China Baowu's HyCROF trial a cut of more than 21% with 30% less solid fuel in 2023.

59 <https://transitionasia.org/hydrogen-in-iron-making-is-hydrogen-injection-in-a-blast-furnace-the-best-way-to-cut-emissions/>

60 Details are in Section 2.

61 No official projection of the CCTS price exists. \$24/tCO₂ is an indicative estimate for 2030 used in sector discussions, and \$50/tCO₂ is an illustrative higher level for a deep-decarbonisation case.

62 https://eur-lex.europa.eu/eli/reg_impl/2025/2620/oj

63 https://beeindia.gov.in/show_content.php?lang=1&level=1&ls_id=189&lid=294

64 <https://ddnews.gov.in/en/govt-drafts-emission-targets-for-over-460-industries-under-carbon-market-plan/>

65 <https://icapcarbonaction.com/en/news/compliance-obligations-under-indias-carbon-credit-trading-scheme-enter-force-seven-sectors>

66 <https://carboncredits.com/japan-india-jcm-article-6-carbon-credits/>

67 The range indicates the spread among rotary kiln, fluidised bed, and shaft furnace.

68 EU Directive 2003/87/EC, <https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A02003L0087-20240301#A1-1>

69 €1 = \$1.10 throughout this report

70 https://taxation-customs.ec.europa.eu/carbon-border-adjustment-mechanism/price-cbam-certificates_en#quarterly-prices-in-2026

71 Price path used throughout: \$86/tCO₂ in 2026 rising linearly to \$140 in 2034 (\$113 in 2030). The 2030 value corresponds to the European Commission's recommended projection parameter for Member State greenhouse-gas projections, €95 per allowance in 2030 (Commission guidance of April 2024). For comparison, the pre-review consensus of seven forecasters was €126 for 2030 (GMK Center, December 2025), and forecasts revised after the Commission's July 2026 ETS review proposal cluster at €90-120 for 2030 (ABN AMRO, Energy Aspects, MATERIA, Enerdata, July-August 2026). The CBAM certificate price is the weighted average of EU ETS auction clearing prices, so the two move together.

72 <https://www.outlookbusiness.com/magazine/eu-cbam-alerts-indian-steel-units-to-decarbonise>

73 The free allocation shelter is calculated by CBAM benchmark of the good x the year's CBAM factor. The adjustment formula and the benchmarks of the route-specific CBAM benchmarks follow Implementing Regulation (EU) 2025/2620, read at the crude-steel boundary (CN 7207 semi-finished, continuous cast): BF-BOF 1.364, DRI-EAF 0.475 tCO₂e/t; the CBAM factor is 97.5% in 2026 falling to 14% in 2033 and nil from 2034, following Directive 2003/87/EC; the cross-sectoral correction factor (≈1) is omitted.

74 <https://sandbag.be/wp-content/uploads/04.08.2026-Sandbag-CBAM-impact-on-India-updated.pdf>

75 https://eur-lex.europa.eu/eli/reg_impl/2025/2547/oj/eng

76 The EU governs hydrogen imported as renewable fuels and requires the electrolyser and its renewable supply to sit in the same bidding zone; India's nationally interconnected grid has not been recognised as one. CBAM declarations for steel do not require RFNBO compliance, but a hub built for exports will be designed to it, and any future EU low-carbon steel label may reference it. <https://www.argusmedia.com/pt/news-and-insights/latest-market-news/2874351-india-s-h2-sector-seeks-eu-bidding-zone-recognition>

77 Regulation (EU) 2026/1384

78 <https://www.ceew.in/blogs/how-india%E2%80%99s-final-emission-reduction-targets-can-shape-carbon-market-dynamics>

79 <https://www.argusmedia.com/en/news-and-insights/latest-market-news/2769530-viewpoint-indian-term-ling-to-make-2026-imports-pricier>

80 <https://www.bloomberg.com/news/articles/2022-03-04/asia-ling-price-surges-to-record-as-war-spurs-panic-over-supply>

81 <https://www.eia.gov/todayinenergy/detail.php?id=67604>

82 https://ppac.gov.in/uploads/rep_studies/1710505208_Snapshot-of-India's-Oil-and-Gas%20Data-February-2024.pdf

83 Policy Guidelines, Ministry of Petroleum and Natural Gas, India, <https://mopng.gov.in/en/natural-gas/policies-guidelines>

84 <https://www.linkedin.com/pulse/indias-sponge-iron-production-up-nominal-6-cy22-steelmint>

85 <https://www.spongeironindia.com/images/publications/May-2023.pdf>

86 <https://cea.nic.in/legal-affairs/electricity-rules-2005/?lang=en>

87 Hourly renewable portfolio assuming a single-axis tracking solar at the plant (average 20.8% capacity factor) and wind wheeled from the Anantapur belt (average 28.1%).

88 The delivered PPA tariffs available locally in Andhra Pradesh are ₹5.06/kWh (\$0.058) for a firm RTC product, ₹3.05/kWh (\$0.035) for solar, and ₹3.66/kWh (\$0.042) for wind, sourced from discovered price from various auctions. A wheeling charge of ₹0.49/kWh (\$0.006) and, where applicable, a cross-subsidy surcharge (CCS) of ₹1.67/kWh (\$0.019) are added. The distribution companies (DISCOM) industrial tariff is ₹6.49/kWh (\$0.075). Renewable certificates are priced at \$15/MWh in 2030.

89 <https://www.powermin.gov.in/static/uploads/2026/04/cbe6e10292387044a4b5ecb684198562.pdf>

90 <https://corporate.arcelormittal.com/media/news/regulatory-news/amns-luxembourg-holding-sa-signs-5-billion-loan-agreement-with-consortium-of-japanese-banks>

91 Real 2025 dollars, 70% gearing, 7% real interest over a 15-year tenor, 25.17% corporate tax, 20-year straight-line depreciation, a four-year construction draw and 40 years of operation, with the electrolyser re-spent every ten years and the battery every fifteen.

92 <https://stegra.com/news-and-stories/h2-green-steel-raises-more-than-4-billion-in-debt-financing-for-the-worlds-first-large-scale-green-steel-plant>

93 <https://ammoniaenergy.org/articles/am-green-production-nears-at-indias-first-renewable-ammonia-mega-project/>

94 This treatment is conservative: the 10 years for an electrolyser is a stack life, and replacing only the stack (roughly half the installed cost) while the balance of plant runs longer would trim the 100%-hydrogen LCOS by about \$4-5/tcs.

95 <https://www.hydrogenfuelnews.com/green-hydrogen-hub-at-pudimadaka-ntpcs-7-gw-vision-for-clean-ammonia-methanol-and-e-saf/8573295/>

96 Grid factor: the Central Electricity Authority's national trajectory reports 0.477 kgCO₂/kWh in 2030 falling to 0.36 by 2035; the CEA CO₂ Baseline Database puts the FY2024-25 weighted average at about 0.71 kgCO₂/kWh. The crossover is (BF-BOF intensity minus the route's non-electricity intensity) divided by the route's total electricity at 100% hydrogen including electrolysis, about 4.1 MWh/tcs for the shaft furnace: (2.60 - 0.29)/4.1 ≈ 0.57 kgCO₂/kWh cradle-to-gate and (2.23 - 0.00)/4.1 ≈ 0.55 on the CCTS boundary.

97 The Japan Bank for International Cooperation

98 <https://sesagoaironore.com/products/specification/ironore/>

99 Metallisation Rate: SF 96%, FB 93%, RK 90%.

100 Ore chain: mining, beneficiation, induration

101 <https://www.bigmint.co/insights/detail/india-pellex-declines-inr-350-t-3-5-t-as-producers-in-raipur-trim-offers-prices-may-drop-further-746382>

102 <https://www.futuremarketinsights.com/reports/iron-ore-pellet-market>

103 <https://www.nmdc.co.in/>

104 <https://www.ceicdata.com/en/india/iron-ore-average-sale-price/iron-ore-average-sale-price-fines-55-58-fe>

