



Green electricity direct connection in China's steel industry

Policies, economics, and stakeholder incentives

September 2026

RESEARCH
PAPER



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ABOUT EARTH & LIFE SYMBIO

Earth & Life Symbio (E&L) is a Singapore-headquartered organisation working across Asia and partnering globally to advance low-carbon industrial growth, energy transition and nature-positive development. Our mission is to catalyse the transition towards a thriving, climate-resilient world where low-carbon industrial growth, energy transition and nature-positive development advance together. E&L brings together and activates the ecosystem across Asia's manufacturing economies and energy sectors - aligning policy, capital, industry, science and civil society to turn climate and nature ambitions into coordinated action and scalable real-economy impact. Our work spans corporate engagement, investor dialogue, policy-aligned research, and on-the-ground study tours, with a strong emphasis on hard-to-abate industries, biodiversity risk, and nature-positive finance.

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Preface

The global energy transition is reshaping the economics of steelmaking. China's steel industry remains heavily dependent on coal-based blast-furnace-basic-oxygen-furnace (BF-BOF) production, while scrap-based electric-arc furnaces (EAFs) depend on large and increasingly variable electricity purchases. As renewable generation expands, steelmakers face a practical question: when can green electricity direct connection lower production costs and emissions without shifting unmanageable balancing and network costs to the grid?

Earth & Life Symbio (E&L) launched the "Energy and Hard-to-Abate Industrial Transition" research series to examine how changes in the power system reshape energy-intensive manufacturing. The series links climate policy, electricity-market design, industrial competitiveness, and corporate investment decisions, focusing on the interaction between power-system change and industrial transition.

This report is the output from the series. It focuses on green electricity direct connection in China's steel industry, examining the implications for steelmakers' electricity costs, green-electricity procurement, and decarbonisation pathways. It assesses the policy and commercial arrangements needed to match renewable supply with industrial load, combining policy analysis, an hourly techno-economic model, and stakeholder perspectives.

The report is intended for policymakers, steelmakers, renewable developers, grid companies, investors, and other stakeholders assessing green electricity direct-connection projects. Its central finding is conditional: green electricity direct connection can improve the economics of selected steel projects, but the result depends on renewable-resource quality, the hourly load profile, storage, grid connection, tariff treatment, and settlement risk.



Executive summary

The Paris Agreement's 1.5°C temperature goal and the net-zero ambitions adopted by a growing number of countries and regions set the wider policy context. For standalone scrap-based EAFs, however, green electricity direct connection is primarily an electricity-cost question. China's steel industry remains a priority for industrial-emissions control, while renewable capacity continues to expand and the ability to absorb wind and solar output varies by region and time of day. Document 650, issued by the National Development and Reform Commission (NDRC) and the National Energy Administration (NEA) in May 2025, established China's first national framework for green electricity direct connection. It promotes local consumption through dedicated generation-load matching while retaining requirements for system security and fair cost sharing. The report therefore asks when direct connection can lower steelmakers' electricity costs and support decarbonisation, and when higher green-electricity shares, storage needs, tariff treatment, or balancing exposure make the project more expensive.

The analysis combines policy review, scenario design, quantitative economic assessment, and stakeholder analysis. It uses an hourly techno-economic model covering all 8760 hours of the year to assess self-built direct-connection projects in six cities spanning China's wind and solar resource regions and steel-production belts. The central scenarios test green-electricity shares of 30%, 50%, 70%, 90%, and 100% off-grid. BF-BOF steelmaking and hydrogen-based direct reduced iron (H₂-DRI) are discussed to establish mechanism boundaries; their outcomes are not extrapolated from the EAF model.

Key findings

1. Reducing electricity costs is the main reason steel companies consider green electricity direct connection, while the marginal benefits of lower carbon costs and broader market access remain limited. At BF-BOF plants, directly connected renewable power can serve part of the plant load, displace captive generation and free by-product gas for other uses. The switch becomes attractive only when the incremental value of the freed gas exceeds the revenue from captive generation and the avoided-allowance benefit at prevailing carbon prices covers the green-electricity premium. Stand-alone EAF companies are not yet subject to compliance

obligations for China ETS allowances, so direct connection offers limited additional value for carbon compliance. Electricity-related indirect emissions are also not currently included in the accounting deductions for certificates under the European Union (EU) Carbon Border Adjustment Mechanism (CBAM). Under current policy and market conditions, reducing electricity costs is therefore the primary consideration for steel companies pursuing green electricity direct connection.

- 2. Green electricity direct connection does not automatically reduce costs. Its economics depend on the user's load profile, average load factor, backup-capacity requirement, green-electricity penetration, and the regional average electricity-market trading price.** Increasing the self-supply share of green electricity can reduce grid imports and, in turn, some system operation and grid-loss charges. But that marginal substitution benefit may diminish when the levelised cost of green electricity exceeds the local market price. Savings in transmission and distribution charges depend mainly on the difference between the company's actual load factor and the regional grid's average load factor. Any uncovered electricity deficit is exposed to spot-market price volatility, so project feasibility depends heavily on the user's ability to forecast renewable generation and electricity demand and coordinate operations.
- 3. In the scenarios modelled, the energy cost of green electricity rises as its share increases.** The unit cost of self-consumed green electricity reaches its minimum at around a 30% green-electricity share and rises thereafter. Across the report's 30%/50%/70%/90% scenario set, the full-cost levelised cost of electricity (LCOE) for self-consumed green electricity is lowest at approximately 30%; higher shares require more generation capacity and longer-duration storage.
- 4. Under this report's strict 100% reliability assumption, fully off-grid projects are not commercially competitive.** Leaving the grid requires substantial storage and generation redundancy to cover periods of low wind and solar output. This conclusion does not replace an engineering reliability assessment incorporating multi-year weather data, equipment availability, N-1 security checks, maintenance, and backup arrangements. The required renewable capacity and storage produce very poor economics.

5. When companies can forecast renewable power accurately, optimise storage dispatch, and respond on the demand side, the economics of green electricity direct connection improve significantly. High-quality renewable-output forecasts and flexible load adjustment can reduce dependence on public-grid connection capacity and related connection costs. They also bring load and generation profiles into closer alignment, materially improving project returns.

6. Green electricity direct-connection projects that satisfy implementation requirements are scarce in practice because of limited resources and competing market interests. Steel plants generally have few wind and solar resources available for development on or near their sites.

At the same time, most high-quality renewable sites are already committed to existing arrangements for proxy power purchases or contracts for difference. In low-price regions, renewable developers have little financial incentive to invest in direct-connection projects. In high-price regions, generators are less willing to make concessions and generally prefer the more predictable settlement offered by contracts for difference or integrated generation-and-sales models. That leaves steel companies with less room to negotiate direct connection.



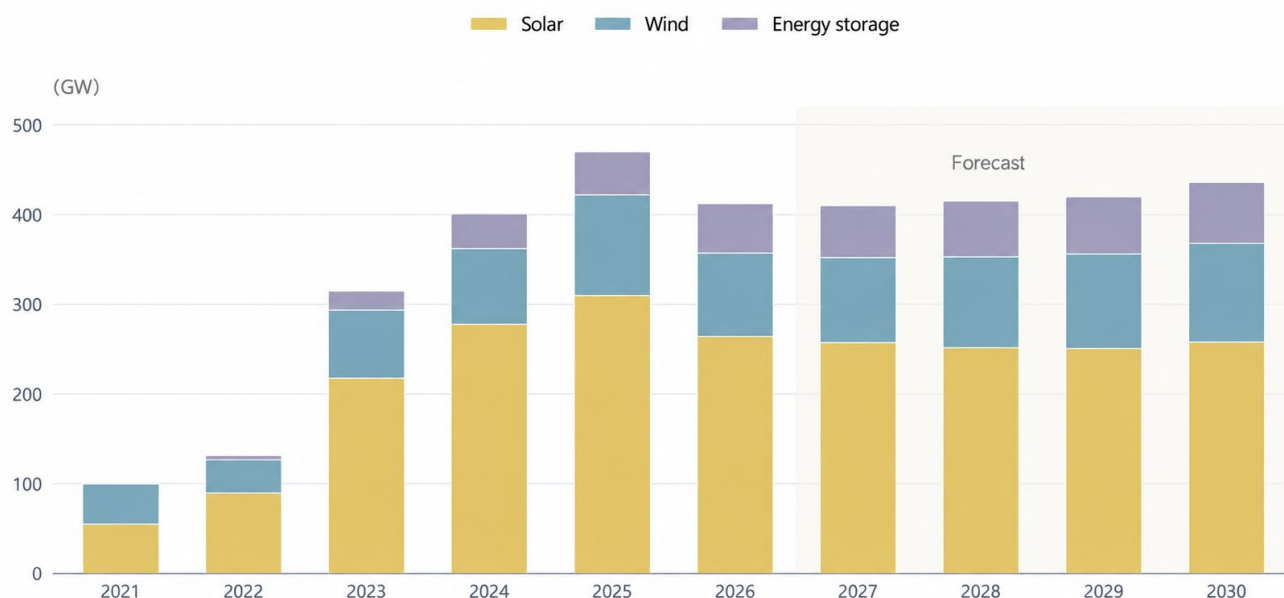
Scale, markets, and steel

In response to the growing urgency of climate change, China has committed to reducing net greenhouse-gas emissions by 7% to 10% below their peak level by 2035. China's nationally determined contribution (NDC) targets include wind and solar installed generation capacity of more than 3.6 TW, and a non-fossil share of approximately 30% of energy consumption. These updated climate targets will reshape the energy system and drive continued expansion of wind and solar capacity.¹

China's deployment of wind, solar, and other renewable energy has outpaced its planned

milestones. By the end of 2024, China had 520.7 GW of wind capacity and 886.7 GW of solar photovoltaics (PV) capacity, or approximately 1.41 TW combined, exceeding the 2030 climate-action target ahead of schedule. In 2025, renewable power became the main driver of capacity growth. Renewable capacity additions reached 452 GW, accounting for 83% of all new capacity, and total renewable capacity reached 2.34 TW, approximately 60% of national installed capacity. Wind capacity reached 640 GW and solar PV capacity 1.20 TW, or 1.84 TW combined, surpassing thermal-power capacity. Renewable generation reached 3,990 TWh, up 15% year on year and accounting for approximately 38% of total generation.^{2,3}

Figure 1. Annual additions to solar, wind and energy storage capacity in China: Historical data and forecasts



Source: BloombergNEF; National Energy Administration; Earth & Life Symbio. Note: Data for 2025–2030 are BNEF forecasts as of December 2025; figures are expressed on an alternating-current (AC) basis.

Installed capacity is not the same as usable electricity that matches demand over time. The distinction is visible in both absorption rates and equivalent full-load hours. In 2024, the national average wind absorption rate was 95.9% and the solar PV absorption rate was 96.8%; average equivalent full-load hours were 2127 for wind (down 107 hours year on year) and 1211 for solar PV (down 81 hours). The China Electricity Council attributed the decline in hours to weaker wind and solar resource conditions and lower absorption rates amid mounting renewable-absorption pressure in some regions. In 2025, wind absorption was 94% and solar PV absorption was 95%, while capacity additions accelerated during the year. National averages indicate strong overall absorption, but they do not demonstrate

economically effective use for a specific generation-load project. That depends on the project's hourly resource profile, local load, export capability, network constraints, storage, curtailment, and settlement rules. Some areas of northwest and southwest China still recorded wind and solar curtailment rates above 10%. Tibet recorded a solar curtailment rate of 35.1% and a wind curtailment rate of 31.4%; Qinghai recorded 16.6% solar curtailment, Xinjiang 13.7%, and Gansu 10.4%.⁴

Market-based trading mechanisms evolved in parallel. China's early large-scale renewable-energy expansion relied mainly on policy instruments such as administratively set tariffs, central-government subsidies, guaranteed offtake, and renewable-consumption quotas. This did not mean that market

trading was entirely absent; rather, industrial users lacked standardised, regulated channels for procuring customised green-electricity products with clear environmental-attribute traceability and defined physical delivery profiles. In 2019, the grid-parity framework for wind and solar advanced subsidy-free deployment while retaining a two-track transition between subsidised projects and competitively determined tariffs. The turning point came in September 2021, when the NDRC and NEA formally launched the first green-electricity trading pilot. The first batch attracted 259 participants from 17 provinces and completed transactions totalling 7.935 TWh. This marked a formal shift toward integrating electricity value with environmental attributes and gradually bringing green-electricity products into the integrated national electricity market.^{5,6}

Market mechanisms have become substantially deeper, but they remain layered. In 2025, market-based electricity transactions reached 6,600 TWh, or 64% of total electricity consumption; market-based transactions for renewable electricity reached 1,350 TWh, or 60% of total renewable generation. Environmental-attribute trading also expanded rapidly. As policies such as mandatory green-electricity-consumption assessments for energy-intensive industries took effect, annual green-certificate trading exceeded 800 million certificates. Green certificates converted from green-electricity transactions and stand-alone environmental-attribute certificates have different cross-provincial and intra-provincial features. As renewable-energy market reforms advance, the traditional guaranteed-offtake system is being adjusted, and more renewable generation is entering spot and medium- and long-term market bidding. The temporal and spatial differences in electricity value are therefore becoming more pronounced. In China, a green certificate is the sole certificate for the environmental attributes of 1 MWh of qualified renewable energy. Once issuance, transfer, and cancellation procedures are complete, it can support a compliance claim for renewable-energy consumption. The certificate itself does not prove that the buyer received stable, local, or hourly matched physical renewable electricity. In the new phase of full renewable-energy market participation and highly volatile spot prices, balancing the price risk of high market exposure with the need for real-time matching of physical green electricity has become a central

consideration in corporate green-electricity procurement.^{7,8}

This distinction helps clarify the commercial challenge facing some energy-intensive users. A user may purchase green certificates through national or cross-provincial markets but still be unable to secure enough locally deliverable green electricity for a specific facility or production schedule because of location, contract structure, delivery profile, network capacity, or provincial rules. This creates a gap between the price of environmental attributes and the value of green electricity associated with physical delivery, timing, and location.

Under sector-specific policies, including the Implementation Plan for Carbon Peaking in the Steel Industry and the Guiding Opinions on Promoting High-Quality Development of the Steel Industry, China has set quantitative targets to raise EAF steel output to more than 15% of crude-steel output by 2025 and aim for 20% by 2030, while recycling and utilising 300 Mt of scrap steel. The Notice on Renewable-Energy Electricity Consumption Responsibility Weights and Related Matters also places steel and other energy-intensive industries within a dedicated assessment framework and sets minimum renewable-energy consumption shares for key energy users in each province.

Deep decarbonisation in steel depends heavily on electrification, especially a shift to EAF-based short-process steelmaking. EAF steel currently accounts for only approximately 10% of China's steel output. Relative to the policy targets of 15% in 2025 and 20% in 2030, there is substantial room for growth and substitution. Traditional BF-BOF producers therefore face a fundamental restructuring of their energy systems. For EAF steelmakers, electricity is the second-largest cost item after scrap, accounting for more than 20%–30% of total costs. As steel companies face pressure from domestic renewable-consumption assessments and the international CBAM, the key question is whether green electricity direct connection can combine deep decarbonisation with lower electricity costs.

Chapter 1

Direct connection and its rules

The emergence of green electricity direct connection signals a new stage in China's power transition. The initial challenge was to build renewable capacity; the current challenge is to match that capacity with demand without eroding its economic value, because curtailment turns abundant midday output into waste. For energy-intensive industries, this shift raises a more direct question: can direct connection to renewable generation reduce electricity costs while supporting decarbonization. Steel, particularly EAF steelmaking, is the key sector for testing that proposition.

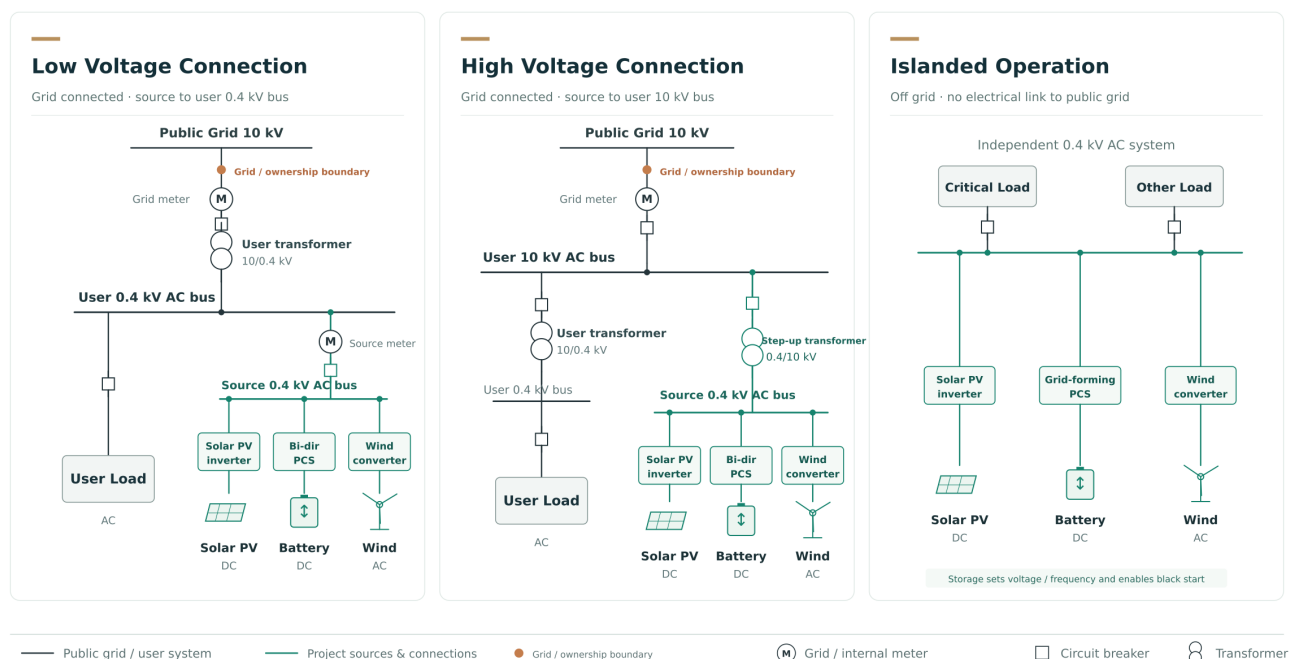
1.1 What direct connection is and what it is not

Green electricity direct connection supplies renewable electricity from wind, solar, biomass, or other renewable sources to one or more power users over a dedicated line instead of injecting that output directly into the public grid. The arrangement provides physical traceability for the electricity supplied.

A grid-connected project remains dependent on approved arrangements for connection, dispatch, protection, metering, and settlement and should not be described as electrically or institutionally independent of the grid. Off-grid projects operate independently of the public grid. Conventional green-electricity trading and Chinese green certificates (GECs) provide environmental attributes, consumption claims, and settlement instruments; they do not constitute physical direct connection.

Green electricity direct connection can create value for both the power system and industry. On the power-system side, it opens an additional generation-load channel for local consumption of renewable output in areas or periods where renewable absorption is constrained. On the industrial side, subject to appropriate metering, green-certificate retirement, product-carbon-footprint assessment, and downstream recognition rules, it can give energy-intensive companies a high-credibility route to procure green electricity. Steel, as a representative energy-intensive, hard-to-abate sector, sits at the intersection of these two needs.

Figure 2. Grid-connected project types



1.2 Document 650 (May 2025): The national framework

The NDRC and NEA jointly issued the Notice on Matters Concerning the Orderly Promotion of Green Electricity Direct Connection in May 2025 (发改能源〔2025〕650号, hereinafter “Document 650”), establishing the first national policy framework for green electricity direct connection. Three design choices in the document laid the foundation for subsequent policy evolution.

First, it clarified who is responsible for developing and owning a project. In principle, the load-side enterprise is the project's responsible entity. Investment is open to all types of market participants, explicitly including private enterprises, while grid companies may not invest in projects. The document also exempts eligible renewable generation within direct-connection projects from the electricity-supply licensing requirement. The relationship between this exemption and the power-supply business area, dispatch, and safety responsibilities must be confirmed for each project.

Secondly, it set the consumption boundaries that shape project design. Document 650 requires annual self-generated and self-consumed electricity to be at least 60% of available generation and to supply at least 30% of total electricity consumption. It also requires the load-side green-electricity share to increase over time and reach at least 35% before 2030. Provincial authorities must set an upper limit on electricity delivered to the public grid, in principle no more than 20% of available generation. The export limit is a provincial cap; it does not create a general right to export electricity.

Third, it established the accounting basis for attributing renewable-electricity consumption claims, subject to the applicable rules on registration, metering, data verification, and certificate issuance. Self-consumed electricity should not be assumed to qualify automatically for freely tradable green certificates. Where the relevant green-certificate rules apply, projects must complete the prescribed registration and data procedures; the form, transferability, and cancellation of certificates depend on the rules applicable to the project and its electricity flows.⁹

Document 650 is an enabling framework, not an operating manual. It delegates key details—including project approval, line planning, grid-connection arrangements, and recognition of renewable-energy

utilisation—to provincial authorities and project-specific procedures. Some provincial governments have already issued implementation documents and pilot schemes, but policy status, technical feasibility, and commercial conditions differ substantially across jurisdictions.

1.3 Document 1192 (October 2025): Paying for remaining grid services

If Document 650 addressed whether a project could be built, Document 1192 addresses how a project that remains connected to the grid should pay for the grid services it continues to use. Its core principle is fair cost sharing: projects may avoid costs demonstrably associated with electricity they do not obtain from the public grid, but they must still bear applicable transmission and distribution tariffs, system operation charges, government funds, surcharges, and reliability-related charges.

Document 1192 introduces a capacity-based transmission and distribution tariff that links the charge to the capacity connected to the public grid, not to the project's generation. The formula has two components: the capacity (demand) charge under current policy, plus (the regulated electricity tariff at the relevant voltage level $\times$ the provincial average load factor $\times$ 730 $\times$ the capacity connected to the public grid).

Document 1192 is intended to improve how transmission and distribution costs are allocated as new forms of electricity use expand, including green electricity direct connection and distributed generation consumed nearby. As integrated generation-network-load-storage projects, distributed generation, and direct-connection users become more common, the public grid must continue to guarantee supply while recovering the associated costs. Some users draw less electricity from the grid but still rely on reserved capacity, voltage support, and emergency backstop service. The grid must therefore keep capacity available and configure assets in line with contracted capacity and system-security standards. These fixed costs do not disappear when users consume less electricity. If the allocation method remains unchanged, the shortfall will ultimately be shifted to other users.

More specifically, transmission and distribution tariffs are set under the “permitted costs plus reasonable returns” principle. Each regulatory period establishes a relatively fixed level of permitted revenue, which is recovered from users through capacity and energy tariffs. The capacity tariff primarily covers depreciation

of the grid's fixed assets and returns on investment; the energy tariff primarily covers operation and maintenance, line losses, and other costs. Under the current allocation mechanism, the capacity tariff is based on the transformer capacity registered by the user or its maximum demand, while the energy tariff is based on actual electricity imported from the grid. As the user's self-generation-and-consumption ratio rises and grid imports decline, its energy charge falls, creating a reduction in the energy charge. If changes in distributed-generation output or load characteristics cause actual maximum demand to fall below registered transformer capacity, or if the user optimises billing through contracted maximum demand or actual maximum demand, the capacity charge's billing base falls below the supply capacity the grid has reserved for the user, creating a reduction in the capacity-charge base. Together, these reductions leave the grid's current-period transmission and distribution revenue below the approved recoverable level, creating a revenue variance.

Under current regulatory rules, the transmission and distribution revenue variance is carried forward for coordinated settlement in the next regulatory period. Although grid companies can ultimately recover their costs, this arrangement creates an inequity in cost allocation. The shortfall in the current period is not borne directly by the entities that caused it; instead, it is apportioned among all users in the next period under the existing allocation rules. For industrial and commercial users that continue to connect to the public grid through conventional arrangements and pay transmission and distribution charges as usual, this effectively creates a new cross-subsidy: some users' costs of occupying system capacity are shifted to users that do not receive the corresponding service. Document 1192 is intended to correct this mismatch between rights and responsibilities, not simply to raise the energy costs of projects that consume electricity locally.

Accordingly, the charging mechanism in Document 1192 follows a policy logic similar to the system-reserve charge for captive power plants: it makes the grid-reliability costs associated with self-generated and self-consumed electricity explicit and measurable and assigns them to users that benefit from public-grid reserve services. In the short term, this directly closes the transmission and distribution fee-recovery gap. In the long term, it helps shift the allocation basis for transmission and distribution tariffs from primarily connection capacity and grid imports toward "occupied grid capacity." The allocation basis must

reflect users' actual use of public-grid resources more accurately to avoid cost shifting when users "use less of the grid and pay less, while system responsibilities remain unchanged." This allows all market participants to support development of the new power system on a fair cost-sharing basis.

1.4 Document 688 (May 2026): From one-to-one to one-to-many

Jointly issued by the NDRC and NEA in May 2026, the Notice on Matters Concerning the Orderly Promotion of Multi-User Green Electricity Direct Connection Development (发改能源〔2026〕688号) expands the green electricity direct connection model from one user to multiple users sharing a project. The notice provides an institutional basis for multi-user projects, but operational details still need to be standardised, including hourly traceability, responsibility for metering and data submission, allocation of responsibilities among users, and transparent approval procedures.

Document 688 stipulates that both grid-connected and off-grid projects must pay government funds and surcharges, consistent with Document 650's "fair and reasonable social responsibility" principle. Multi-user models may improve load matching but also complicate allocation and settlement among users. No unified national rules yet govern grid access, dispatch, settlement, and renewable-energy consumption accounting for cross-provincial projects, so such projects should be treated as pilot-stage, case-by-case arrangements.

Multi-user projects turn a shared load into an independent project with clearly defined primary responsibility and settlement boundaries. Document 688 requires the project's responsible entity to have legal-person status. In principle, it should be established as a joint venture between the generation and load parties, although either party may invest independently. Under the industrial-park model, the entity may be established by the park administrative committee or a third party, but a public-grid enterprise that operates transmission services may not invest. The project's responsible entity should in principle invest in the connecting lines, substations, energy storage, and operations platform. It must sign agreements with internal parties, including the power source and loads, covering ownership allocation, operation and maintenance, balancing responsibilities, internal fee standards and settlement, and liability for breach.

Accordingly, the multi-user route does not automatically eliminate financing or coordination costs. The project as a whole must participate in market submissions, while internal green electricity is allocated among users according to their time-segmented electricity consumption and the agreed terms. Whether the arrangement improves economics depends on whether the different loads can improve generation-load matching at the hourly level, not simply on connecting several enterprises to the same dedicated line.

1.5 Provincial rules: the same national floor, different operating boundaries

Document 650 delegates detailed operating rules to the provinces, and each province has developed its own implementation plan. This section compares the provincial requirements. The main areas of variation are surplus-power treatment, the spatial relationship between generation and load, voltage-level ceilings, eligible users, and settlement arrangements; each row should be read with the cited original provincial document and its current legal status.



Table 1. Provincial rules and surplus feed-in

Province/ status	Implementation document	Priority industries	Key generation thresholds	Surplus-power feed-in and reverse-flow rules
Hebei — Formal	Notice of the Hebei Provincial Development and Reform Commission on Organising Applications for Green Electricity Direct Connection Projects	Key industries including computing power, steel, cement, chemicals, hydrogen production, lithium-ion battery manufacturing, and biomedicine	Self-generation/self-consumption $\geq 60\%$; green power as a share of total electricity consumption $\geq 30\%$; feed-in $\leq 20\%$	No reverse feed-in before the Jibei Power Grid spot market operates continuously; feed-in $\leq 20\%$
Hunan — Formal	Implementation Plan for the Orderly Promotion of Green Electricity Direct Connection Development in Hunan Province	Existing loads operated by export-oriented enterprises with binding decarbonisation needs and by computing-power enterprises (including data centres)	Self-generation/self-consumption $\geq 60\%$; green power as a share of total load $\geq 30\%$; feed-in $\leq 20\%$	May participate in spot trading, using a primarily self-consumption model with surplus-power feed-in as a supplement
Heilongjiang — Formal	Heilongjiang Province Implementation Plan for Single-User Green Electricity Direct Connection Development	Energy-intensive industries such as chemicals, iron and steel, and cement; green industries such as graphite-based new materials, clean-energy equipment, and energy conservation and environmental protection; coordinated development of computing power and renewable energy; industries associated with emerging industries identified in the provincial plan, such as high-end equipment, biomanufacturing, and green hydrogen	Self-generation/self-consumption $\geq 60\%$; green power $\geq 30\%$; feed-in $\leq 20\%$	For hydrogen-based projects, feed-in $\leq 40\%$ from 2026 to 2027 and $\leq 20\%$ thereafter. Existing captive power-plant projects may not feed power back to the grid
Jiangxi — Formal	Jiangxi Province Implementation Plan for the Orderly Promotion of Green Electricity Direct Connection Development	No specific industries	Self-generation/self-consumption $\geq 60\%$; green power $\geq 30\%$; feed-in $\leq 20\%$	Permits a primarily self-consumption model with surplus-power feed-in as a supplement; reverse power flow is prohibited during periods when renewable-power absorption is constrained
Hubei — Formal	Notice on the Orderly Promotion of Green Electricity Direct Connection Projects	No specific industries	Self-generation/self-consumption $\geq 60\%$; green power $\geq 30\%$; feed-in $\leq 20\%$	Full self-consumption is encouraged. Feed-in is an exception, capped at 20%, and requires a grid-connection opinion
Sichuan — Trial	Sichuan Province Trial Implementation Plan for the Orderly Promotion of Green Electricity Direct Connection Development	Directly or indirectly export-oriented enterprises with binding decarbonisation needs, and computing-power enterprises (including data centres)	Self-generation/self-consumption $\geq 60\%$; green power $\geq 30\%$	Feed-in capped at 10% in (Three Prefectures and One City) and 20% elsewhere; no feed-in across constrained transmission sections
Yunnan — Formal	Yunnan Province Implementation Plan for Green Electricity Direct Connection Development	Green aluminium, silicon, and photovoltaics, batteries for clean-energy applications, nonferrous metals (including rare and precious metals), data centres, hydrogen energy, and phosphorus chemicals	Self-generation/self-consumption $\geq 60\%$; green power $\geq 30\%$; feed-in $\leq 20\%$	No reverse power flow when the spot market is suspended; when permitted, feed-in capped at 20%
Zhejiang — Formal	Zhejiang Province Notice on Promoting Green Electricity Direct Connection Development	No specific industries	Self-generation/self-consumption $\geq 60\%$; green power $\geq 30\%$; feed-in $\leq 20\%$	Feed-in capped at 20%. Grid-supplied electricity purchases capped at 234% of self-supplied electricity ($\leq 186\%$ from 2030); electricity purchase and sale transactions suspended for breach
Shandong — Formal	Notice on Strengthening and Standardising Green Electricity Direct Connection Development	Existing loads at computing-power facilities, offshore oil and gas fields, and key coastal ports (Qingdao Port, Yantai Port, Rizhao Port, Weihai Port, Binzhou Port, Dongying Port, Weifang Port)	Self-generation/self-consumption $\geq 60\%$; green power $\geq 30\%$; feed-in $\leq 20\%$	The share of feed-in electricity in total available generation must not exceed 20%; during periods when renewable power is curtailed on the public grid, power may not be fed back to the public grid. For green electricity direct connection projects linking offshore wind power to offshore oil and gas platforms, hydrogen/ammonia/methanol production, computing-power facilities, etc., the share of green power from direct-connection projects fed into the grid may be relaxed to 40%.

Table 1. Provincial rules and surplus feed-in

Province/ status	Implementation document	Priority industries	Key generation thresholds	Surplus-power feed-in and reverse-flow rules
Liaoning — Formal	Liaoning Province Green Electricity Direct Connection Construction Plan (2025 to 2027)	No specific industries	Self-generation/self-consumption ≥60%; green power ≥30%	Projects subject to existing-scheme indicators: feed-in ≤20%. New projects should in principle use all power on-site; exception projects may feed in ≤20%
Ningxia — Formal	Ningxia Hui Autonomous Region Green Electricity Direct Connection Implementation Plan	No specific industries	Self-generation/self-consumption ≥60%; green power ≥30% (increase by ≥1.5 percentage points each year); feed-in ≤20%	Full self-consumption is encouraged. Where necessary, feed-in is capped at 20%; in principle, avoid reverse power flow during periods when renewable-power absorption is constrained
Qinghai — Formal	Qinghai Province Green Electricity Direct Connection Implementation Plan	No specific industries	Self-generation/self-consumption ≥60%; green power ≥30%; feed-in ≤20%	No reverse power flow before continuous spot-market operation; thereafter, surplus-power feed-in may be used as a supplement
Guangxi — Formal	Guangxi Green Electricity Direct Connection Development Implementation Plan	Steel/nonferrous metals/building materials/petrochemicals/chemicals/clean-energy equipment/transportation/data centres; export-oriented industries such as electric vehicles/energy-storage batteries/aluminium/cement/paper-making, etc.	Self-generation/self-consumption ≥60%; green power ≥30%; feed-in ≤20%	New and export-oriented projects: feed-in ≤20%. Captive power-plant projects may not feed power back to the grid or resell it
Jilin — Formal	Jilin Province Implementation Plan for the Construction and Development of Green Electricity Direct Connection Projects	Hydrogen-based green energy (green hydrogen/green ammonia/green methanol/sustainable aviation fuel, etc.), iron and steel, computing-power/data centres, and automobile manufacturing	Self-generation/self-consumption ≥60%; green power ≥30%	For new projects, feed-in ≤40% before 2028 and ≤20% thereafter; existing projects ≤20%
Inner Mongolia — Single-user Trial	Inner Mongolia Autonomous Region Implementation Plan for the Construction and Development of Single-User Green Electricity Direct Connection Projects (Trial)	Hydrogen-based green fuels; Horinger data-centre cluster; electrolytic aluminium industry; national-level zero-carbon industrial parks	In principle, 100% self-consumption; reverse power flow is prohibited; self-consumed green power must account for at least 30% of the declared annual load	In principle, no reverse power flow. Grid-connected hydrogen-based green-fuel projects may be subject to transitional feed-in arrangements
Inner Mongolia — Multi-user Draft for public comment	Inner Mongolia Autonomous Region Implementation Plan for the Construction and Development of Multi-User Green Electricity Direct Connection Projects	Computing-power facilities/emerging industries such as green hydrogen-ammonia-methanol; Horinger data-centre cluster; electrolytic aluminium; national-level zero-carbon industrial parks; steel/cement/polycrystalline silicon	Green power as a share of total load ≥30%	Non-hydrogen projects likewise have zero feed-in; hydrogen-based projects are subject to transitional feed-in caps of 40%/20%
Chongqing — Draft for public comment	Notice on the Orderly Promotion of Green Electricity Direct Connection Development	No specific industries	Self-generation/self-consumption ≥60%; green power ≥30%; feed-in ≤20%	Supports a primarily self-consumption model with surplus-power feed-in as a supplement; no surplus-power feed-in within constrained transmission sections
Fujian — Formal	Notice on the Construction of Green Electricity Direct Connection Projects	No specific industries	Self-generation/self-consumption ≥60%; green power ≥30%; feed-in ≤20%	Surplus-power feed-in permitted, capped at 20%
Anhui — Draft for public comment	Notice on Promoting Green Electricity Direct Connection Development	No specific industries	Self-generation/self-consumption ≥60%; green power ≥30%	Excerpt does not specify a particular feed-in cap

Note: These thresholds are annual policy-compliance floors, not project-level economic optima. “Grid feed-in” means renewable electricity delivered to the public grid. Draft consultation documents do not constitute final rules and should not be used as definitive investment conditions. Source: Compiled by the authors based on documents from provincial development and reform commissions/energy bureaus.¹⁰

Table 2. Provincial project frameworks: generation–load spatial relationships, voltage, and settlement arrangements

Province/Region	Generation–load siting and voltage limit	Electricity pricing, settlement, and charges
Hebei	Distance not specified; voltage ≤220 kV	Not detailed
Hunan	Same electricity supply area; projects may cross administrative boundaries	Transmission and distribution tariffs charged on a capacity/demand basis; self-consumed electricity is not currently subject to incremental cross-subsidies; unauthorised reductions/exemptions prohibited
Heilongjiang	Distance limit not specified	Document 1192 applies. Grid exports above the approved volume are not settled; province-wide allocation applies
Jiangxi	Same prefecture-level city; ≤50 km; ≤220 kV	Transmission and distribution tariffs charged on a capacity/demand basis; electricity exported to the grid is excluded from mechanism-based pricing
Hubei	Same county/district or two adjacent counties; ≤220 kV	Equitably allocated under Document 1192
Sichuan	Distance limit not specified; ≤220 kV	Implement Document 1192; unauthorised reductions/exemptions prohibited. critical-peak tariffs do not currently apply in the Three Prefectures and One City
Yunnan	Same prefecture-level city; ≤50 km from the collector station; ≤220/330 kV	During the transition period, self-consumed electricity is charged on a standby-capacity basis; off-grid projects are not currently charged standby fees
Zhejiang	Same prefecture-level city; cross-city projects require joint review; ≤220 kV	Refer to Document 1192; line-loss charges at grid-export interfaces are payable
Shandong	Same county/district; cross-county projects require special assessment; ≤220 kV	Fees payable in accordance with Document 1192 and relevant Shandong provincial policies
Liaoning	Distance limit not specified	Fees paid under applicable rules; unauthorised reductions/exemptions prohibited
Ningxia	Distance limit not specified	Implement Document 650 and Document 1192; all applicable fees must be borne equitably
Qinghai	Distance limit not specified; ≤330 kV	Fees charged under national electricity-pricing and fiscal rules
Guangxi	Same prefecture-level city; ≤50 km; ≤220 kV	Fees charged under Document 1192. Where generation–load mismatch causes grid exports to exceed 20%, settlement is capped at 20%
Jilin	Same city or prefecture-level city; ≤220 kV	Fees charged under national and provincial rules
Inner Mongolia (Single-user)	Distance limit not specified	Fees charged under national and autonomous-region rules; unauthorised local reductions/exemptions prohibited
Inner Mongolia (Multi-user)	Distance limit not specified	Equitable allocation; government funds and surcharges apply to both grid-connected and off-grid projects; unified settlement
Chongqing	Same district/county; ≤30 km; ≤220 kV	The public-comment draft does not detail the pricing mechanism
Fujian	No generation–load distance limit at this stage	Overall project settlement under Document 1192; internal allocation among multiple users may be adjusted by agreement
Anhui	Distance limit not specified	Document 1192 applies; grid companies install metering devices at boundary points at no charge

Source: Compiled from documents issued by provincial development and reform commissions/energy bureaus, analysis by Earth and Life Symbiz

Table 3. Practical implications of provincial spatial and settlement rules for steel projects

Province/Region	Implications for steel projects
Hebei	Steel is among the industries prioritised for encouragement, but the voltage limit is 220 kV and distance criteria have not yet been clarified; reverse power flow is prohibited before the Jibei spot market enters continuous operation. Projects should be modelled primarily on a self-generation/self-consumption basis.
Hunan	Geographic rules are relatively flexible, but grid-service charges remain a core component of project economics.
Heilongjiang	Power export cannot be treated as a reliable revenue source; retrofits of captive power plants face particularly stringent constraints on reverse power flow.
Jiangxi	Both the geographic conditions and the 220 kV cap must be satisfied at project initiation; capacity charges must be modelled and must not be assumed to be waived.
Hubei	The site-selection boundary is narrow; proximity to good renewable resources and early engagement with the grid are decisive.
Sichuan	Project economics depend heavily on local congestion and the applicable power-export cap.
Yunnan	The rare 330 kV option supports large loads, but the 50 km and same-city rules strictly constrain resource selection.
Zhejiang	High-value industrial loads may strengthen the business case, but strict controls on electricity imports and exports call for conservative sizing of generation and load capacity.
Shandong	County-level rules and exposure to the electricity export market both reinforce a “self-consumption first” design.
Liaoning	The key uncertainty lies in the policy status and the actual review criteria for any exceptional power-export arrangements.
Ningxia	Excellent resource conditions do not automatically translate into savings: the delivered-electricity price benchmark and treatment of all network costs remain decisive.
Qinghai	The 330 kV option supports large projects, but power export is restricted before continuous spot-market operation, increasing the value of flexible loads and storage.
Guangxi	Explicit policy support for steel is positive, but projects must still be configured around local consumption rather than planned power export.
Jilin	The phased power-export cap provides some flexibility for early projects but tightens after 2028.
Inner Mongolia (single user)	Zero-export treatment makes hourly matching, storage, and operational flexibility central to a viable design.
Inner Mongolia (multi-user)	The multi-user model may improve load matching but adds complexity in cost allocation and settlement governance among users.
Chongqing	The strictest distance rule among the comparison cases requires early screening of resources and transmission corridors; electricity-price treatment remains a due-diligence gap.
Fujian	Flexible spatial boundaries are attractive, but the final rules and multi-user contracting arrangements remain undetermined.
Anhui	A clear metering boundary facilitates implementation, but the power-export rules are incomplete; conservative analysis using a zero-export base-case scenario remains advisable.

A review of the implementation plans and notices issued by different provinces shows four patterns:

First, the national compliance baseline is converging, but local operating conditions are diverging.

Most documents retain the current thresholds: self-consumption of no less than 60% and a load-side green-electricity share of 30%, with the latter required to rise to 35% before 2030. Restrictions on surplus electricity feed-in are strict: most provinces cap it at $\leq 20\%$, while some projects and regions prohibit reverse power flows altogether. Inner Mongolia, for example, requires all projects other than grid-connected hydrogen-based green-fuel projects to self-generate and self-consume all electricity and expressly prohibits feed-in to the public grid. Heilongjiang prohibits projects that add green electricity direct connection to existing coal- and gas-fired captive power plants from sending electricity in reverse to the public grid. As distributed photovoltaics and other renewable generation connect at scale, congestion is shifting from the transmission backbone to the distribution grid. Unrestricted surplus feed-in would create severe reverse-power-flow congestion on distribution grids. Local consumption internalises system-balancing and congestion costs at the project level. The policy therefore keeps green electricity direct connection projects focused on self-generation and self-consumption and prevents them from becoming centralised power stations that use full-grid feed-in to profit from price differentials.

Second, project geography may constrain development more than headline policy ratios.

The vast majority of provinces treat location within the same administrative area as a core siting principle. Jiangxi, Yunnan, and Guangxi combine a same-prefecture-level-city rule with a 50 km restriction; Chongqing applies a 30 km limit and same-district/county screening; Hubei limits projects to the same county or an adjacent county. Most jurisdictions set an upper voltage limit of 220 kV, while Qinghai and Yunnan permit 330 kV.

For large electric-arc-furnace loads, a viable project must clear geographic and voltage screens before resource quality matters. These limits also avoid the high investment and power losses associated with long-distance dedicated lines and protect the policy intent of nearby, on-site consumption. Provincial policies nevertheless leave some room for cross-regional green electricity direct connections.

Third, policy access signals reflect local industrial strategies but do not replace system constraints.

Among the industries prioritised for encouragement, computing-power facilities and green hydrogen-ammonia-methanol projects are the leading priorities, followed by traditional energy-intensive industries such as steel, aluminium, and chemicals; export-oriented enterprises are routinely included. Yunnan's green aluminium and silicon industries, together with Inner Mongolia's hydrogen-based fuels and computing-power clusters, show how wind and solar resource advantages can be translated into incentives to retain industry.

Fourth, provincial policies broadly follow the core principle of Document 1192: direct connection is not a fee exemption.

Nearly all provisions either implement the national electricity-pricing framework directly or require costs to be shared fairly, and some expressly prohibit unauthorised fee reductions or exemptions.

Chapter 2

Drivers and delivery models

2.1 Investment case and models

After Chapter 1 established the policy framework and clarified the compliance boundaries for green electricity direct connection, this section examines commercial viability and implementation pathways. Policy feasibility does not establish commercial viability. A steelmaker's decision to pursue physical direct connection turns on two linked questions: what is the underlying investment driver, and which direct-connection model can address it?

This section therefore matches each potential driver to the available evidence and to the direct-connection models assessed in Chapter 3. Under current policy and market conditions, reducing electricity costs is the only driver that is both broadly applicable and suitable for standardised quantitative modelling. That finding sets the priority for enterprise decisions and provides the analytical basis for the economic assessment in Chapter 3.

Chapter 2 tests these drivers one by one. The matrix frames the question: for Chinese steel companies in 2026, which drivers carry real weight and which fall away under scrutiny?

2.1.1 Green-electricity procurement drivers

Drivers	Conditions under which each driver applies
China Emission Allowance (CEA) compliance	Steel mills must be covered by the national carbon market, and that coverage must price electricity-related emissions that green power can reduce
CBAM carbon-cost relief	The EU border levy must price steelmakers' indirect (electricity) emissions, and green power must be credited at a known deduction rate
Product-standard market access (ResponsibleSteel and the Low Carbon Emission Steel Standard)	Enough buyers must be willing to pay a premium for the higher certification level that reduced indirect emissions can confer on low-carbon steel, and procurement volumes must be material relative to the steel mill's output
Lower electricity costs	Given EAFs' consumption of 400 to 450 kWh per tonne, the project must procure green power below the grid-delivered price and have mature integrated operations to reduce total electricity costs

2.1.2 Direct-connection delivery models

Method / pathway	What it entails	Questions the analysis must answer
Self-build: grid-connected or off-grid	Steelmakers use a grid-connected or off-grid configuration and build and own wind-solar-storage plants	Project economics: how much green power can be self-consumed under policy constraints, how system costs vary with green-electricity penetration, and when those costs fall below the cost of grid procurement
Third-party investment: grid-connected or off-grid	Using the same connection arrangements, an energy operator builds and owns the plant and sells electricity through a long-term power purchase agreement (PPA) or energy-services agreement	Energy-operator considerations: the resource, market, and counterparty conditions under which an investor would actually finance and hold the asset
Cross-provincial direct connection	Resource-rich provinces supply electricity via dedicated long-distance lines to provinces with concentrated demand, addressing local resource scarcity	Cross-provincial conditions: transmission-corridor coordination, approvals from both provincial grid companies, and inter-provincial regulatory accounting

2.2 Electricity cost as the main driver

Steel companies may seek green electricity for three reasons: to reduce electricity costs, respond to domestic and international carbon-price pressures, and use low-carbon product certification to expand sales. Each driver is examined below.

2.2.1 China ETS and stand-alone EAFs

The way the China ETS affects steel companies depends on the process route and emissions boundary. Steel companies covered by the China ETS are BF-BOF long-process enterprises and generally operate captive power plants. Recovered coke-oven gas, blast-furnace gas, and basic oxygen furnace gas

can be used for captive generation or as resource-recovery fuels for heating, hydrogen production, chemical feedstocks, or top-gas recycling. Standalone short-process EAF enterprises, by contrast, rely mainly on purchased electricity and have not yet entered the China ETS allowance-compliance system.

(1) Long-process perspective: The China ETS influences energy decisions through the interaction between captive power plants and by-product gases

The BF-BOF long process still requires electricity from outside the facility. Because it uses large quantities of recovered by-product gases for captive generation, long-process enterprises generally have high shares of self-generated electricity. Under current China ETS management rules, captive power plants with annual greenhouse gas emissions reaching 26 ktCO₂e (or comprehensive energy consumption of approximately 10 kt of standard coal equivalent) are treated as key emitting entities in the power-generation sector and must account for and verify emissions and comply with allowance requirements in accordance with the Guidelines for Accounting and Reporting Greenhouse Gas Emissions of Enterprises—Power Generation Facilities. For long-process enterprises, the China ETS effect depends on whether the facility is designated a key emitting entity in the relevant list and how the emissions boundary is drawn. At present, the power-generation sector allocates free allowances primarily through a benchmark method centred on carbon intensity. Total allowance quantities are determined mainly by actual electricity generation, heat supply, the applicable unit benchmark value, and peak-shaving correction coefficients, among other factors.¹¹

When long-process enterprises adopt green electricity direct connection, the immediate effect is to change both the sources of electricity supply and the uses of by-product gases. Direct-connection projects can serve part of the existing load, displacing some captive generation and freeing by-product gases for higher-value uses such as chemical feedstocks, top-gas carbon recycling, and high-purity hydrogen production. The economics of this

substitution depend heavily on the allowance shortfall and carbon price. Replacing captive generation is competitive only when the avoided-carbon benefit from “reduced allowance shortfall × carbon price” covers the green-electricity premium, direct-connection line construction, and energy-storage deployment, and when the incremental premium from alternative uses of by-product gases exceeds the revenue from power generation.

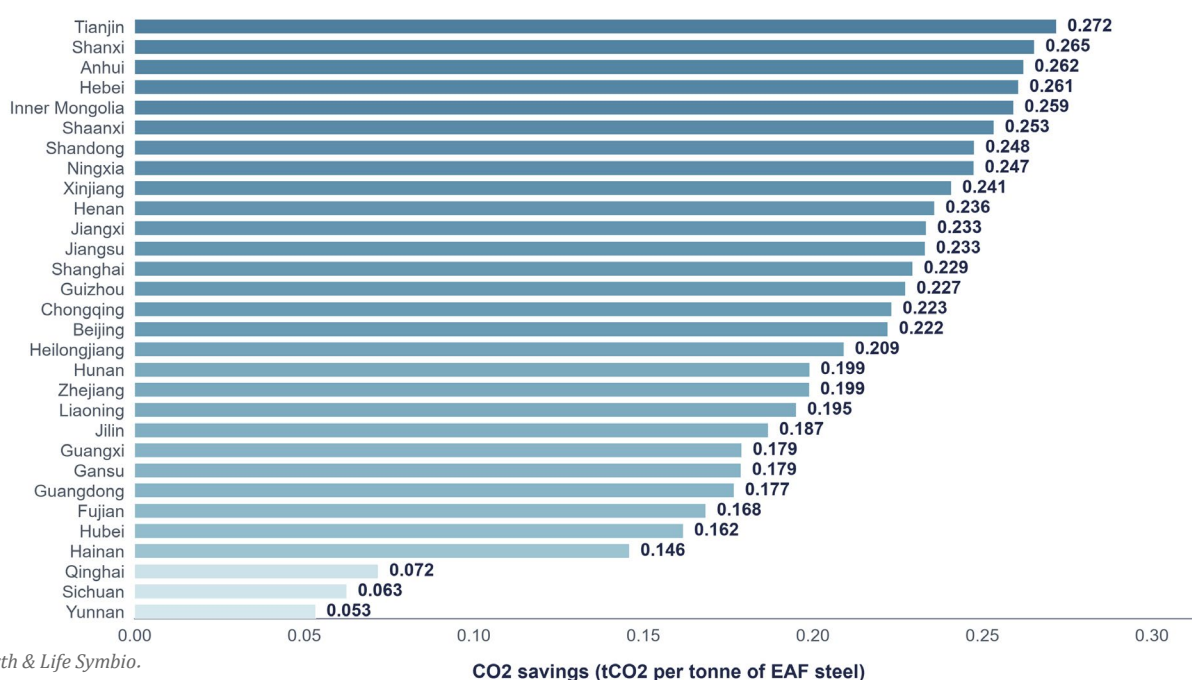
The China ETS still operates under an institutional framework of “intensity control, with free allocation as the main approach,” and the allowance allocation scheme generally follows the principle of “roughly balanced at the sector level, with a slight shortfall.” For long-process enterprises, the China ETS provides a clear direction for emissions reduction and a price signal, but current carbon prices and allowance constraints are not strong enough to drive major low-carbon technology retrofits.

(2) Short-process perspective: Green electricity direct connection mainly reduces Scope 2 emissions, while marginal incentives for carbon compliance are limited

For short-process EAF enterprises, the most direct effect of green electricity direct connection is to replace some purchased grid electricity, reducing Scope 2 (indirect) carbon emissions from electricity use and materially improving the electricity-related carbon footprint of steel products over their life cycle. Assuming electricity consumption of approximately 400 kWh per tonne of steel for EAF steelmaking, avoided indirect carbon dioxide emissions relative to local-grid supply can be calculated using the latest regional-grid average emission factors for the country and each province. Because short-process enterprises are not yet included in the China ETS allowance-compliance system, and because these indirect emissions reductions cannot yet be converted into allowance-related revenue under the China ETS, the direct economic incentive for short-process enterprises to deploy green electricity direct connection remains limited under current China ETS rule

Figure 3. Provincial CO₂-Saving potential of EAF steel made with green electricity

(400 kWh per tonne of steel; green electricity emission factor = 0)



2.2.2 CBAM: limited electricity incentive

The mechanism by which green electricity direct connection affects exports to the EU under the EU CBAM is similar to that of the national carbon market; the decisive issue is how the emissions boundary is defined. CBAM's definitive regime began in January 2026. The first declaration and certificate surrender for 2026 imports are due by 30 September 2027. According to estimates by the China Iron and Steel Industry Association, China's 2025 exports to the EU of steel products and articles covered by CBAM totaled approximately 10.52 Mt. Under current CBAM accounting rules, direct emissions predominate for steel products and cover fuel combustion, process reactions, and process heating; indirect emissions from electricity consumption are not yet included in the CBAM certificate-cost calculation boundary for primary steel products.^{12,13}

This accounting boundary creates different CBAM response strategies by process route:

(1) Long-process perspective: use green electricity to replace fossil energy and reduce direct emissions

For the BF-BOF long process, the main CBAM abatement opportunity is direct-emissions reduction. When electricity delivered through a direct-connection arrangement powers water electrolysis to produce hydrogen, that hydrogen can partially displace carbon-based reductants in a retrofitted blast furnace, while coke retains a structural role in the burden. This can substantially reduce fuel combustion and process emissions in key stages including blast-furnace injection, direct reduction, and reheating furnaces; electrification upgrades in other thermal processes can also directly reduce fossil-energy consumption. This green-electricity-driven process transformation can directly lower the

CBAM carbon-emission intensity of exported steel products. If using green electricity shifts by-product gas from captive power generation to top-gas carbon cycling or high-purity hydrogen production, the value of its CBAM premium depends on the type of fossil fuel ultimately displaced by that gas and the resulting emissions reductions.

(2) Short-process perspective: constrained by the indirect-emissions boundary, CBAM's direct incentive effect remains limited

For standalone short-process EAF operations, electricity delivered through a direct-connection arrangement mainly replaces purchased grid electricity and sharply cuts Scope 2 emissions. Because current CBAM charging rules focus mainly on direct emissions, the indirect reductions from using green electricity in EAFs cannot be converted into CBAM certificate deductions on an equal basis. Within the current CBAM accounting boundary, electricity delivered through a direct-connection arrangement therefore provides only a limited direct economic incentive for short-process steel exports.

CBAM exporters do not benefit merely because a particular product line uses physical green electricity. If actual values cannot be provided, the new rules apply a relatively high default carbon-emission intensity without distinguishing among process routes. Steel companies using electricity delivered through a direct-connection arrangement therefore need a rigorous monitoring, reporting and verification (MRV) system compliant with EU standards to substantiate their "actual values"; otherwise, default-value accounting renders their investment in emissions reductions from green electricity ineffective. CBAM's formal implementation phase also establishes the

principle that embedded carbon emissions are accounted for within the boundary of the production installation (or production site) (installation): for goods with the same functional unit produced within the same installation, emissions from different production routes must be weighted and averaged. This rule prevents enterprises from avoiding CBAM payments by designating a production line supplied with directly connected green electricity exclusively for EU exports. Even if EU-bound steel is produced entirely on a dedicated line powered by directly connected green electricity, it does not automatically receive a separate CBAM emissions value. Where the same CN-code product is made through other, higher-emission routes within the same installation, its embedded emissions are calculated as a weighted average across those routes. Green power alone therefore offers limited reductions in the reported CBAM emissions of steel; reductions in direct emissions and the emissions embodied in precursors are more consequential.¹⁴

2.2.3 Low-carbon market access: a marginal incentive

Demand for certified low-carbon steel is currently concentrated mainly in the EU, and some buyers require authoritative certifications such as ResponsibleSteel (RS) and the Low Carbon Emission Steel Standard (C2F). For carbon-accounting mutual recognition, RS has established cooperation with the Chinese C2F standard, creating mutual recognition and interoperability between their certification definitions. Both standards use dynamic grading systems based on the scrap ratio and include indirect emissions in their accounting. Reducing indirect emissions through green electricity can therefore raise a steelmaker's product certification level. Demand from buyers willing to pay a premium for low-emission steel remains negligible relative to total steel-mill output, and the green premium remains extremely limited. Low-carbon certification can improve project feasibility only in marginal situations involving specific buyers; it is insufficient to support the project's investment rationale on its own.

2.2.4 Electricity costs across steel routes

The preceding analysis shows that electricity delivered through a direct-connection arrangement can be used across the BF-BOF long process, H₂-DRI, and the scrap-based EAF short process, but its marginal benefits for China's national carbon-market allowance compliance, responding to the EU CBAM, and accessing low-carbon steel markets are currently limited. Reducing overall electricity costs is therefore the most fundamental and broadly applicable economic driver for steel enterprises deploying electricity delivered through a direct-connection arrangement.

For the BF-BOF long process, the main opportunities are opportunity-cost-based substitution of conventional utility power and extension of green

hydrogen along the long-process chain. The route has a lengthy process chain and a complex energy-use structure, with fossil energy (coal and coke) overwhelmingly dominant. The most direct use of electricity delivered through a direct-connection arrangement is to replace conventional utility electricity. Two conditions govern the viability of this substitution: the carbon-market price signal must be strong enough to change the enterprise's energy-use structure, and the delivered all-in electricity price of electricity delivered through a direct-connection arrangement must be competitive with the grid's proxy-purchase price. Electricity delivered through a direct-connection arrangement can also power water electrolysis to produce hydrogen. Provided that process retrofits, a hydrogen-rich supply, and safety safeguards are in place, green hydrogen can be used for blast-furnace injection, subsequent rolling reheating, or the supply of protective gas, creating a potential pathway to replace coking coal and fossil-carbon inputs. Because coke-oven gas (COG), blast-furnace gas (BFG), and converter gas (LDG) already have established power-generation or heating uses within steelworks, the practical value of introducing green electricity and green hydrogen into these applications depends heavily on the opportunity-cost trade-off with the existing cascade-utilisation pathways for by-product gases. Emissions reductions from existing long-process assets likewise depend on energy-efficiency upgrades to thermal equipment; relevant industry technical exchanges and phased technical achievements provide concrete examples.^{15,16}

H₂-DRI: a long-term pilot pathway constrained by high energy use and low energy efficiency. The H₂-DRI-EAF pathway can absorb large volumes of green electricity because electrolytic hydrogen production combined with EAF steelmaking makes its electricity consumption per tonne of steel far higher than that of conventional scrap-based EAFs. It nevertheless faces severe technical and economic bottlenecks. Its technology readiness level (TRL) is currently 6–7, far below that of mature scrap-based EAFs (TRL 9), and it remains largely at the demonstration and pilot stage.

Hydrogen metallurgy involves four levels of energy conversion—"electrical energy → hydrogen chemical energy → thermal energy → metallic chemical energy"—making it difficult for overall energy-use efficiency to exceed 40%; a large amount of the energy in green electricity is lost during intermediate conversion. By contrast, scrap-based EAFs involve only three levels—"electrical energy → thermal energy → metal"—and have a theoretical thermal efficiency of 70%–85%. Finally, hydrogen metallurgy requires enormous fixed-asset investment; green hydrogen costs far more than black hydrogen, while capital expenditure on electrolyzers and balance-of-plant (BOP) systems accounts for a relatively high share of green-hydrogen production costs and is unlikely to decline in the short term.

Scrap-based EAF short process: an opportunity to improve economics despite high electricity-price sensitivity. EAF steel accounts for only about 10% of China's steel output (far below the global average of 30%), leaving substantial scope for structural substitution and incremental growth. EAFs rely on electricity as their core energy source (electricity consumption per tonne of steel is about 400–450 kWh) and are highly sensitive to electricity prices; the vast majority of standalone EAF enterprises therefore stagger operations during periods with flat or valley electricity prices. Against this backdrop, the key question is whether electricity delivered through a direct-connection arrangement can provide short-process enterprises with a practical and competitive cost-reduction option. This report's quantitative economic assessment focuses specifically on EAF applications.

From a project-development perspective, steelmakers obtain directly connected green electricity through two main routes. The first is a capital-intensive self-build model in which the company invests in wind, solar, storage, a dedicated line, and associated transformation and distribution equipment. The second is an asset-light partnership in which a renewable developer or integrated-energy service provider finances and owns the assets, while the steelmaker purchases electricity under a long-term PPA or an energy-performance-contracting arrangement. Building on the driver and model analysis above, Chapter 3 focuses on EAF steelmakers and develops a quantitative model to assess the economics of different direct-connection configurations.



Chapter 3

Project economics and delivery models

3.1 Economic assessment of self-built direct-connection projects

This chapter evaluates whether self-built direct-connection projects can create economic value for a stylised scrap-based EAF enterprise under the Chinese policy, electricity-price, and operating assumptions established in this report. The analysis centres on three questions:

- 1 Under the constraints of Document 650, how do direct-connection models differ across pure PV+storage, pure wind power+storage, and wind-power-and-storage hybrid configurations?
- 2 As the share of green electricity delivered through direct connection increases, how does the system's total cost evolve?
- 3 Under what conditions can green electricity direct connection outperform conventional grid procurement?

To answer these questions, the report develops an hourly techno-economic model covering renewable generation, energy-storage dispatch, grid interaction, and the defined steel-production boundary. The scenarios use green-electricity shares of 30%, 50%, 70%, 90%, and 100% off-grid.

3.1.1 Policy constraints and cost-accounting rules

To assess project economics and technical feasibility, this study develops a two-stage optimisation and search model subject to the mandatory constraints of Document 650. For each target level of demand-side green-electricity penetration, the model conducts an exhaustive two-stage "coarse search + fine search" across the available capacity ranges for three technology pathways: "solar PV + storage (S+B)," "wind + storage (W+B)," and "wind-solar complementarity + storage (S+W+B)." The objective is to minimise the enterprise's total annual electricity cost and identify the optimal system capacity configuration. All solutions must satisfy the following policy constraints:

(1) Definition of the key electricity metric: the self-generation and self-consumption ratio

Policy requires grid-connected projects to follow the principle of "determining the source according to the load." Annual renewable electricity generated and consumed on-site must account for at least 60% of total available generation. Here, total available generation is a theoretical maximum: the generation possible from a given installed capacity under the available resource conditions.

(2) Assumption for surplus-electricity disposal: a prudent "zero reverse feed-in" setting under normalised consumption constraints

Although Document 650 permits, in principle, surplus electricity to be sold to the grid at no more than 20% in areas with continuously operating electricity spot markets, local implementation rules and grid-hosting limits have tightened restrictions on reverse feed-in. For example, the Jibei Power Grid strictly prohibits reverse feed-in because it does not yet have continuous spot-market operation. Document 688 expressly prohibits grid-connected projects from feeding electricity into the public grid during periods of difficult consumption identified by provincial energy authorities. The Inner Mongolia Autonomous Region Implementation Plan for the Development and Construction of Green Electricity Direct-Connection Projects for Single Electricity Users (Trial) likewise requires all renewable generation from other direct-connection projects, except designated hydrogen-based green-fuel projects, to be consumed on-site rather than fed into the grid. Because midday solar PV congestion and renewable-energy absorption difficulties are now common across many parts of China, surplus feed-in remains subject to substantial policy and grid-capacity uncertainty. To make the financial assessment and stress tests robust, the model uses zero reverse feed-in of surplus electricity (zero export) as the baseline scenario.¹⁷

(3) Renewable-energy utilisation-rate constraint: a compromise between national flexibility and prudent local targets

At the national level, the renewable-energy utilisation framework (Documents No. 650 and 1192) remains relatively flexible: "localities may reasonably set renewable-energy utilisation-rate targets based on information such as the proportions of self-consumed and grid-connected electricity in the project-development plan, generation-load matching, and regulation capacity." Local implementation has been more cautious. The Shandong Province Implementation Plan for Promoting the Orderly Development of Green Electricity Direct Connection requires direct-connection projects to achieve a renewable-energy utilisation rate no lower than the province's public-grid average for the same period. The Inner Mongolia Autonomous Region likewise requires projects to follow annual utilisation targets set by the regional Energy Bureau. Guangxi and Qinghai do not specify renewable-energy utilisation-rate targets, but their integrated generation, network, load, and storage policies require rates of at least 90% in Qinghai and 95% in Guangxi. These rules reflect two concerns: avoiding additional regional consumption pressure from high curtailment at direct-connection projects, and avoiding excessive storage-configuration and operating burdens for enterprises pursuing a 100% utilisation rate. Given the current approximate national wind and solar utilisation levels (for example, wind power 91.9% and solar PV 91.2%

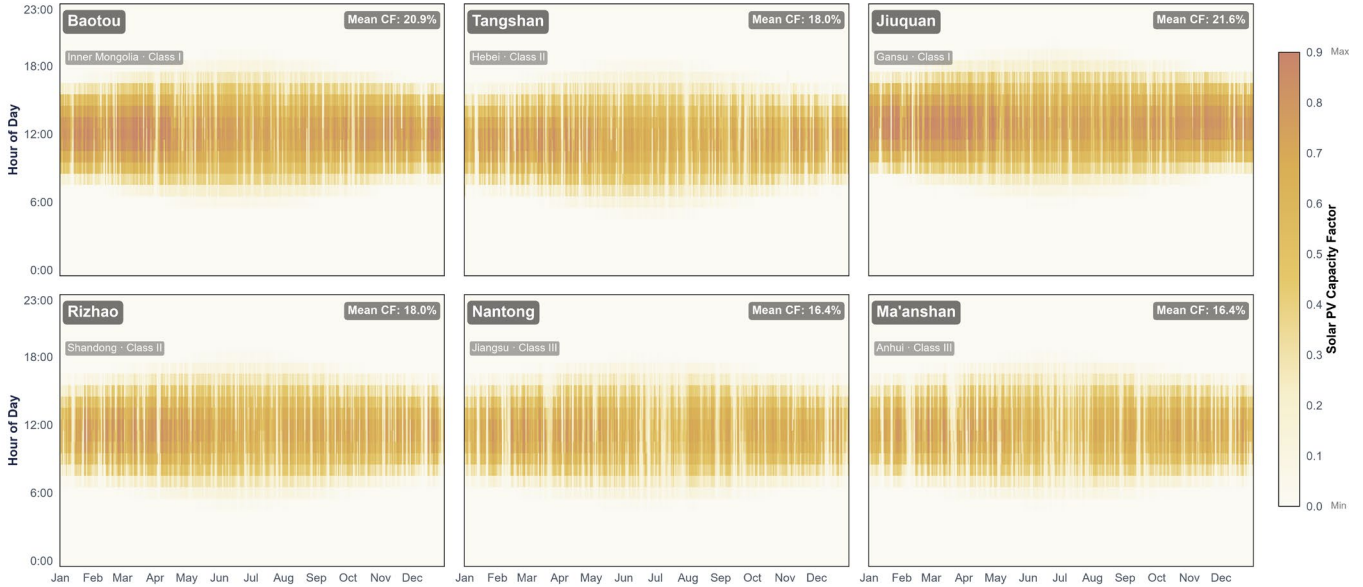
in the first quarter of 2026), the model uses a 90% renewable-energy utilisation rate as its core constraint, balancing compliance and economic performance.^{18,19}

3.1.2 Resources set the ceiling for what is achievable

The report selects six representative cities—Baotou, Jiuquan, Tangshan, Rizhao, Nantong and Maanshan—

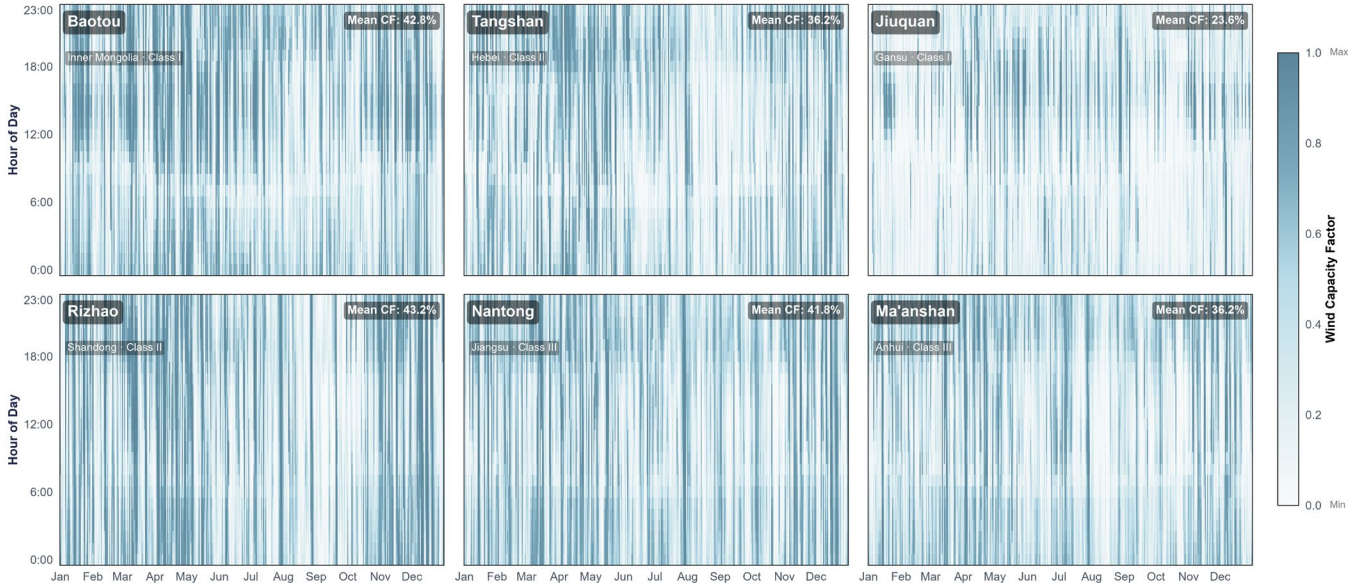
covering China's Class I/II/III wind and solar resource zones and its principal steelmaking belts. All subsequent economic calculations use these six cities. Hourly wind and solar profiles derive from Modern-Era Retrospective analysis for Research and Applications, Version 2 (MERRA-2) reanalysis data for 2023, converted to capacity-factor curves via Renewables.ninja.

Figure 4. Solar PV Resource Availability— Hourly Capacity Factor (365 days x 24 hours)



Source: Earth & Life Symbio. Data: Renewables. ninja (MERRA-2, 2023) | 6 representative cities across China

Figure 5. Wind Resource Availability— Hourly Capacity Factor (365 days x 24 hours)



Source: Earth & Life Symbio. Data: Renewables. ninja (MERRA-2, 2023) | 6 representative cities across China

These profiles show the expected asymmetry: solar output is concentrated around midday and into the afternoon, while wind output is lower during the day

and higher overnight. The extent of this complementarity in each city is decisive for project economics.

3.1.3 What does direct connection save?

The benchmark is a commercial and industrial steel user subject to a two-part tariff. Its all-in electricity bill has three main components: the energy charge, the capacity (basic) charge, and the power-factor adjustment charge. A green electricity direct connection project is economically competitive mainly when it can replace or optimise the energy and capacity charges. The user's delivered electricity price at the plant gate comprises five core components: the direct cost of market-based electricity procurement (or grid-company proxy procurement), the volumetric transmission and distribution (T&D) charge, the line-loss charge at the grid-injection stage, the system operation fee, and government funds and surcharges. After green-electricity direct connection is introduced, plant electricity consumption is divided between "direct-connection self-supplied electricity" and "grid-drawn electricity":

For grid-connected projects, the situation is more complex, and the tariff structure under Document 1192 is central to the analysis. Electricity drawn from the public grid still provides back-up supply, but the project does not necessarily bear the same tariff stack as a standard commercial and industrial customer. The relevant question is therefore not whether a direct-connection project pays no network costs, but which electricity, capacity, and system operation charges remain payable under the applicable provincial rules.

Direct-connection self-supplied portion: The economic assessment asks which of the five charges listed above this electricity can lawfully avoid or replace, including market-based electricity procurement costs, some T&D charges, and line-loss charges.

3.1.3.1 Energy costs beyond the optimum

Under different green-electricity penetration targets, the three technical routes were systematically modelled and optimised: pure photovoltaic + storage (S+B), pure wind + storage (W+B), and wind-solar complementarity + storage (S+W+B).

Simulation results show that pure photovoltaic + storage performs worst economically; in several representative cities, its LCOE exceeds the benchmark price for grid-company proxy procurement. The route is constrained by the strong intraday intermittency of photovoltaic output and its zero output at night. This extreme imbalance, with output 'highly concentrated at midday and a complete cessation of supply at night,' means that achieving a high green-electricity share target requires long-duration, large-capacity storage to shift energy across time periods. Wind, by contrast, generally has more annual utilisation hours than photovoltaics and a more even output profile. The disadvantage is especially pronounced in regions with strong solar resources. In Baotou, Inner Mongolia, for example, where solar radiation resources are exceptionally abundant, midday spot prices have frequently fallen to zero or even negative prices. An enterprise buying through market-based channels can obtain electricity at extremely low cost around midday, sharply reducing the arbitrage opportunity and economic value of building a dedicated pure-photovoltaic direct-connection line.

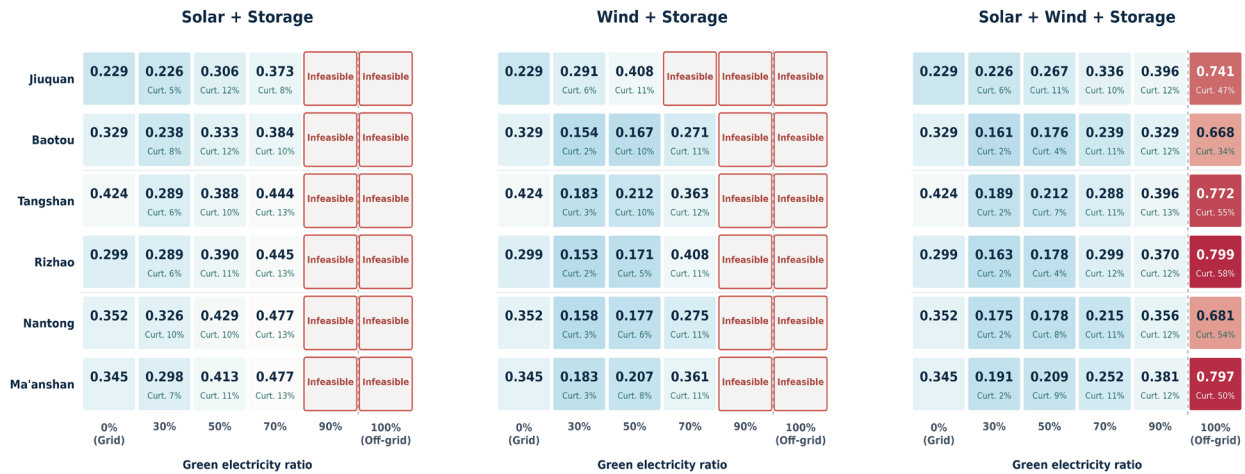
Further analysis shows that at higher green-electricity consumption-share targets, single-source routes such as pure photovoltaic + storage and pure wind + storage are techno-economically infeasible in both grid-connected and off-grid modes. Here, "infeasible" has a specific engineering meaning: after searching the full installed-capacity space, the optimisation algorithm found no valid solution set that simultaneously satisfies the 60% minimum self-consumption rate floor, the renewable-energy utilisation rate, and the specified green-electricity penetration target without requiring oversized storage beyond commercially reasonable limits.

Within the ranges specified in this paper for the six cities, green-electricity targets, technology pathways, and cost parameters, wind-solar complementarity + storage generally provides the lowest-life-cycle-cost solution in the central scenario. Its advantage comes from complementary peak-shaving across both intraday and seasonal resource fluctuations.

Figure 6. Feasibility and LCOE of Green Electricity Schemes

LCOE(CNY/kWh): warmer colours indicate higher cost; red outline indicates infeasibility

LCOE (CNY/kWh) 0.2 0.3 0.4 0.5 0.6 0.7 0.8 Infeasible



Source: Earth & Life Symbio analysis.

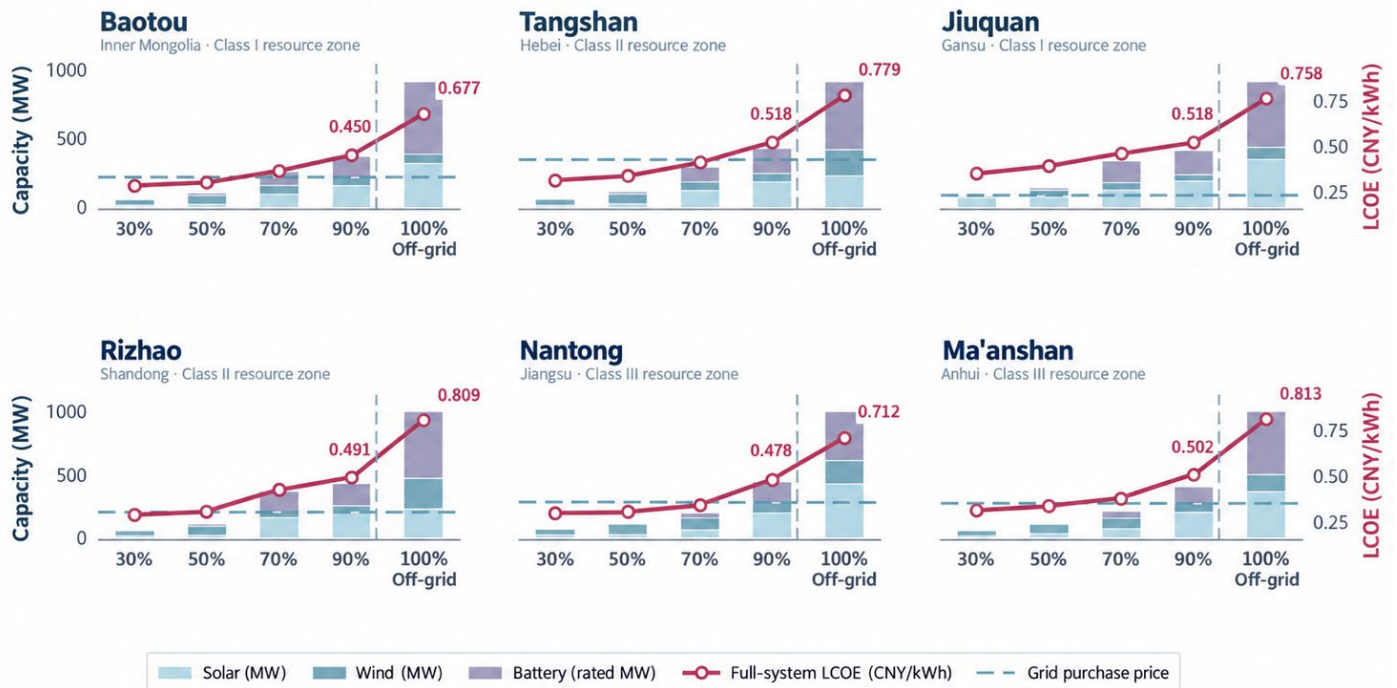
Note: Full-cost LCOE across the six cities: grid-connected 30%/50%/70%/90% green-electricity shares and off-grid 100% reliability
0% = grid baseline; 100% = off-grid scheme

The cost advantage of a green electricity direct-connection project is markedly non-linear; it does not expand in proportion to the green-electricity share. The model shows that LCOE usually reaches its minimum at a green-electricity penetration of around 30% and then rises as higher targets require disproportionately more generation capacity and long-duration storage. Across the 30%-50% range, the core scenarios show a clear advantage over grid-company proxy procurement prices in several pilot

cities. Once the share reaches 70%, however, the LCOE differential narrows sharply and in some cities exceeds the proxy-purchase price, using the April 2026 grid-company proxy procurement price as the comparator. As the target moves beyond 70% towards 100%—meaning a fully off-grid system that must meet a 100% reliability requirement—total installed capacity and levelised cost rise sharply because the system must cover extreme periods of renewable shortfall.

Figure 7. Renewable Capacity and LCOE by Green Power Target

1 Mtpa scrap-EAF • Solar+wind+battery • 30 km • 30%-90% grid-connected, 100% off-grid



Source: Earth & Life Symbio.

Energy-storage deployment is the decisive driver of the exponential cost increase at high green-electricity shares and in off-grid systems. In the fully off-grid scenario with 100% power-supply reliability, installed storage capacity and storage's share of total capital expenditure both grow far faster than wind and solar capacity. To offset extremely low wind-and-solar output during extreme weather without the grid's "safety net," the system must carry substantial redundant storage as its final safety buffer. That physical redundancy directly drives the steep increase in LCOE under a fully off-grid, self-sufficient configuration.

Regional differences in resource quality and grid conditions create sharply different project-feasibility boundaries. Resource endowment and the prevailing local grid tariff jointly determine each city's "parity threshold," the upper limit of the green-electricity share at which direct-connection LCOE can remain below the cost of grid-purchased electricity. The regional differences are pronounced:

Regional resource and tariff differences materially constrain green electricity direct connection projects. Wind and solar resource quality varies by location, while existing tariff structures produce large differences in the "parity threshold" across regions.

Regions with higher benchmark tariffs offer more headroom. In Nantong and Tangshan, for example, the relatively high grid benchmark tariffs allow green-electricity LCOE to remain below conventional grid-electricity costs across a broader target range, even as the share approaches 70%.

Low-benchmark-tariff regions face a different economic reality. In Jiuquan, the existing grid benchmark tariff is so low that green-electricity LCOE crosses the benchmark-tariff threshold even at a very low green-electricity target share, despite potentially favourable wind and solar resources. Gansu's grid-company proxy procurement price for commercial and industrial electricity fell from CNY 0.276/kWh at the beginning of the year to CNY 0.149/kWh in June, the lowest in the country. The main reason was a large installed base of renewable generation, high photovoltaic and wind-power output in June, ample electricity supply, and relatively limited local demand, which drove market prices sharply lower. As a result, the LCOE of a direct-connection electricity supply has no clear advantage over the local electricity tariff. Projects with a high share of electricity delivered through direct connection therefore face more severe economic challenges in energy bases and other low-price regions.

On the other hand, the Price Department of the NDRC issued the Notice on Provincial Grid Transmission and Distribution Tariffs for the Fourth Regulatory Cycle, Regional Grid Transmission Prices and Related Matters (NDRC Price [2026] No. 1077) on 10 July 2026, effective from 1 August 2026. National T&D tariffs generally fell in the fourth cycle. In

provinces where the tariff fell, the relevant comparison is between the cost of self-generated electricity in a direct-connection project and the T&D charge avoided on that electricity. A lower network charge reduces the saving delivered by direct connection; a higher charge increases it.

3.1.3.2 Capacity and grid-service charges

Off-grid projects are the clearest case: projects never connected to the public grid pay neither system-operation fees nor transmission-and-distribution charges because they do not incur supply-security charges.

For grid-connected projects, the situation is more complex, and the price structure under Document 1192 is central to the analysis.

Grid-injection line-loss charges: self-generated and self-consumed electricity can avoid the corresponding charge. Document 1192 provides that "when the project consumes electricity, it shall participate directly in market trading, shall not be served through grid-company proxy procurement, and shall bear upstream line-loss charges according to the electricity drawn from the grid." Self-generated and self-consumed electricity therefore does not incur line-loss charges.

Government funds and surcharges cannot be avoided. Although Document 1192 contains no explicit provision, Document 688 clearly states that both grid-connected and off-grid projects must pay government funds and surcharges in full under current policy, consistent with the principle of "fair and reasonable social responsibility."

System operation fee: temporary exemption for self-consumed electricity. Document 1192 states: "When a project uses the public grid, it is treated as a commercial and industrial user and, for the time being, pays the system operation fee based on the electricity drawn from the grid." Self-generated and self-consumed electricity therefore does not incur the system operation fee. The charging regime is gradually shifting toward assessment based on occupied capacity and other methods, so this component currently produces savings.

Because system operation fees have risen steadily in recent years, the savings from this exemption are expected to increase. In 2026, nationwide system operation fees rose by approximately CNY 0.03/kWh²⁰ on average compared with 2025, and we expect them to continue increasing over the next few years. The main drivers are several structural cost increases:

First, beginning in 2026, the fixed-cost recovery ratio for the capacity tariff of coal-fired power will rise to no less than 50%; if a transition to full cost recovery occurs in the future, the scale of capacity charges will expand substantially;

Second, capacity electricity charges will increase as regulating power sources such as pumped-storage hydropower are successively commissioned;

Third, the high renewable penetration on the grid will trigger a sharp increase in demand for ancillary services such as frequency and voltage regulation, directly reflecting the rise in system-balancing costs;

Fourth, mechanism-based renewable electricity and contracts-for-difference charges are introduced. Projects included in the mechanism-based volume receive a form of price protection: during periods of high renewable output, a generator may still submit a negative-price bid into the market while retaining support for its revenue. The associated contracts-for-difference charge, however, can increase system operation charges.

Rising system operation fees increase the savings on self-generated and self-consumed electricity from green electricity direct connection projects, strengthening their appeal. Document 1192, however, stipulates that system operation fees will, for the time being, be based on electricity drawn from the grid, with a gradual transition to charging based on occupied capacity and other methods. In the future, charges will therefore be allocated by occupied capacity rather than electricity volume. For now, the exemption for self-generated and self-consumed green electricity is a policy benefit. If charges shift to occupied capacity while system operation fees continue to rise, green-electricity direct connection will not necessarily remain advantageous; its economics will depend mainly on whether the project can reduce transformer capacity.

Capacity electricity charges and energy-based T&D charges require a more granular breakdown, because the single-capacity T&D tariff in Document 1192 bundles the two into one formula: under current policy, the capacity (demand) charge constitutes the first term, while the energy-based T&D charge is converted, using the provincial average load factor, into the fixed-cost second term.

First term before the plus sign (grid-connection capacity): safety is the binding constraint. Document 1192 defines grid-connection capacity as the sum of receiving-transformer capacity and the simultaneously used capacity of directly connected high-voltage motors. Because an EAF is powered through a transformer, its grid-connection capacity is physically equivalent to its load capacity unless the project can provide minimum firm capacity through “renewable generation and energy storage” or credibly reduce grid-connection demand through backup power and the EAF’s own demand-side response flexibility. Declaring a lower grid-connection capacity may reduce fixed charges on paper, but it creates safety risks. Renewable-energy and energy-storage systems

are constrained by extreme weather, including prolonged wind and solar drought, and cannot guarantee stable, reliable capacity in every period. If an internal supply-demand imbalance causes exchanges with the public grid to exceed the declared upper limit, the project may face substantial financial penalties, forced disconnection, and severe losses from production stoppages. Until long-term validated operating data are available, the model therefore assumes conservatively that grid-connection capacity equals load capacity. Direct-connection projects consequently have little scope to reduce this first-term cost at the outset. After operations begin, the project should apply to change its grid-connection capacity based on a reasonableness assessment.

Second term after the plus sign (conversion of energy-based T&D charges): the provincial average load factor determines the economics. The policy converts variable T&D charges linked to actual electricity consumption into a fixed cost. As a result, the provincial average load factor becomes the core parameter determining whether the project is economically advantageous. The T&D charges paid no longer decline as self-generated and self-consumed electricity increases; they depend entirely on grid-connection capacity and the provincial average load factor. When grid-connection capacity equals load capacity, the single-capacity model has a cost advantage if the enterprise’s actual load factor exceeds the provincial average. If the actual load factor is lower, the single-capacity T&D tariff is uneconomic.

The national framework has not yet provided a single definition of this load factor. Published provincial average load factors range widely, at approximately 39% to 60%, and depend heavily on the formula, sampling method, and accounting boundary adopted in local rules. The only two publicly available formulas, published by Ningxia and Inner Mongolia, define the average load factor using operating capacity equal to the sum of in-service receiving-transformer capacity and the capacity of high-voltage motors connected without a transformer. Both samples are limited to commercial and industrial two-part-tariff users at 110 kV and above, with Inner Mongolia also covering 66 kV, who are subject to capacity-based tariffs. Users charged by measured demand are excluded. Because the maximum demand of capacity-billed users is usually well above 62.5% of transformer capacity, the provincial average load factor derived from this sample is materially higher than the load factor of a representative EAF.

The average load factor can be estimated for a 100-tonne nominal-capacity EAF. Under the latest capacity-replacement policy, a 100-tonne nominal-capacity EAF has a theoretical annual output of approximately 0.75 Mt. This 0.75 Mt/y furnace illustration assumes 400 kWh/t, equivalent to about 300 GWh of electricity use a year. The national

standard Code for Design of Steelmaking Engineering (GB 50439-2015) recommends a 60-100 MVA transformer. At 80 MVA, the EAF's average load factor is approximately 42.8%, below the provincial averages cited in most of the report. Under a single capacity-based network tariff, this lower load factor means that T&D charges do not show a clear economic advantage.^{21,22}

High-reliability power-supply projects may remain on a two-part tariff. Nearby-consumption projects with high reliability requirements and the required capacity backup may continue paying T&D charges under the current two-part tariff. An EAF supplied by two circuits in accordance with GB 50439-2015, with either circuit capable of serving the full load, meets the conditions for high-reliability power supply. Whether to choose the capacity (demand)-based path under Document 1192 also depends on whether backup capacity is included in the "simultaneously used receiving-transformer capacity."

Where high-voltage buses are common, lines provide mutual backup, transformers operate simultaneously, and receiving-transformer capacity matches load capacity, grid-connection capacity does not double because of line redundancy. The project can compare its actual load factor with the province-wide average load factor for industrial and commercial two-part-tariff users at 110 kV and above, then choose a tariff after accounting for the energy-based T&D charges on self-generated and self-consumed electricity under the two-part tariff.

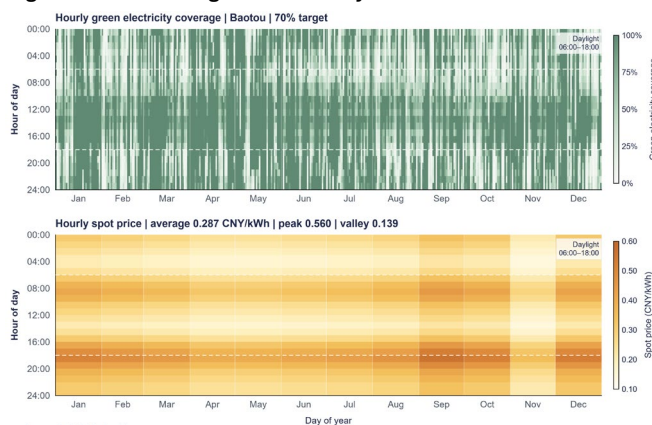
Where low-voltage buses are common, transformers provide mutual backup, and both operate simultaneously, capacity connected to the public grid is calculated from the receiving transformers in simultaneous use and may reach approximately twice the load capacity. The capacity (demand)-based path is generally uneconomic, so the project should retain the current two-part tariff: the energy charge is based on self-generated and self-consumed electricity plus grid-drawn electricity, and the capacity (demand) charge is calculated under current policy. With both transformers operating simultaneously, the basic charge based on maximum demand is generally preferable to the charge based on transformer capacity. If the project already has a complete and reliable internal backup power supply that can be incorporated into the overall power-supply reliability plan and cover the corresponding accident operating conditions, the grid side need not be configured in advance according to the traditional arrangement of two mutually redundant transformers, each operating at approximately 50% load factor. The project should reassess the number and capacity of grid-side receiving transformers based on normal operating load, power-supply requirements under accident conditions, the reliability of the internal backup power supply, and the transformers' operating mode.

Lower self-consumption costs for green electricity, together with savings in system-operation and grid-

injection line-loss charges, do not guarantee a lower all-in electricity cost. Green electricity direct connection can cover only the share of consumption guaranteed by the green-energy supply. Wind and solar power are inherently intermittent. Even a project with a green-electricity share as high as 70% still must meet 20% to 30% of its electricity demand through retail or spot markets, and a direct-connection project often cannot supply itself precisely during the high-price periods when spot prices surge. The impact varies markedly by region. In systems such as Gansu, where renewable energy is highly saturated, non-peak prices are extremely low and peak prices are relatively moderate. Coastal grids with tight supply-demand balances, by contrast, impose severe spot-price penalties on deficit electricity when wind and solar output is insufficient during the evening peak.

The spot-market effect cannot be quantified with complete precision, but to establish an order of magnitude we construct an annual spot-price curve for each city over 8760 hours. A rule dictionary assigns monthly and time-of-day multipliers to the benchmark price, a city-specific volatility factor adjusts those multipliers to reflect local market tightness, and normally distributed noise recreates the jagged and partly unpredictable character of real spot prices.

Figure 8. When does green electricity fall short - and what does it cost?



Source: Earth and Life Symbio.

Note: 365x24 heatmaps of hourly green-electricity coverage (top) and hourly spot prices (bottom)

The two heatmaps present the report's synthetic core price scenarios. In the upper chart, green marks periods of complete green-electricity coverage, while red and yellow mark deficit periods with heavy reliance on the grid; in the lower chart, darker shades mark higher scenario prices. Their overlap represents the modelled temporal risk mechanism: when renewable supply is abundant, the grid power being displaced may be relatively inexpensive; when the project faces a supply shortfall, grid purchases may happen precisely during high-price periods. This mechanism should be tested against actual local market data before being used for project forecasting.

This temporal mismatch is an intermittent but material hidden cost. Without production flexibility, such as the ability to stop an EAF in the evening, or appropriately sized storage, users will see expected

savings from direct supply eroded hour by hour by the spot-market spread between peak and off-peak prices.

3.1.4 Savings per tonne are small

LCOS and project payback show how electricity savings translate into steelmaking costs and

investment returns. LCOS falls in most grid-connected cases, with savings of up to around 3%. The result has a clear structural explanation: electricity is a significant operating cost, but LCOS is dominated by EAF capital depreciation and scrap costs. Direct connection optimises a second-tier component of the cost structure, so the saving per tonne is limited.

LCOS (CNY/t)							Post-tax simple payback (years)					
Jiuquan · Gansu	¥4058	¥4049	¥4048	¥4057	¥4088	¥4178	Base	11.9y	12.7y	14.7y	17.0y	
	¥4133	¥4096	¥4062	¥4048	¥4065	¥4140		Base	7.4y	7.0y	8.6y	11.1y
	¥4208	¥4164	¥4114	¥4091	¥4106	¥4194		Base	7.1y	6.9y	8.6y	11.1y
	¥4205	¥4147	¥4100	¥4071	¥4086	¥4208		Base	7.6y	7.2y	10.7y	12.7y
	¥4177	¥4135	¥4087	¥4068	¥4084	¥4147		Base	7.1y	6.4y	7.2y	10.8y
	¥4102	¥4082	¥4058	¥4054	¥4086	¥4206		Base	7.0y	6.7y	7.6y	10.6y
Baotou · Inner Mongolia	0% (Grid)	30%	50%	70%	90%	100% (Off-grid)	0% (Grid)	30%	50%	70%	90%	100% (Off-grid)
	¥4133	¥4096	¥4062	¥4048	¥4065	¥4140		Base	7.4y	7.0y	8.6y	11.1y
	¥4208	¥4164	¥4114	¥4091	¥4106	¥4194		Base	7.1y	6.9y	8.6y	11.1y
	¥4205	¥4147	¥4100	¥4071	¥4086	¥4208		Base	7.6y	7.2y	10.7y	12.7y
	¥4177	¥4135	¥4087	¥4068	¥4084	¥4147		Base	7.1y	6.4y	7.2y	10.8y
	¥4102	¥4082	¥4058	¥4054	¥4086	¥4206		Base	7.0y	6.7y	7.6y	10.6y
Tangshan · Hebei	0% (Grid)	30%	50%	70%	90%	100% (Off-grid)	0% (Grid)	30%	50%	70%	90%	100% (Off-grid)
	¥4133	¥4096	¥4062	¥4048	¥4065	¥4140		Base	7.4y	7.0y	8.6y	11.1y
	¥4208	¥4164	¥4114	¥4091	¥4106	¥4194		Base	7.1y	6.9y	8.6y	11.1y
	¥4205	¥4147	¥4100	¥4071	¥4086	¥4208		Base	7.6y	7.2y	10.7y	12.7y
	¥4177	¥4135	¥4087	¥4068	¥4084	¥4147		Base	7.1y	6.4y	7.2y	10.8y
	¥4102	¥4082	¥4058	¥4054	¥4086	¥4206		Base	7.0y	6.7y	7.6y	10.6y
Rizhao · Shandong	0% (Grid)	30%	50%	70%	90%	100% (Off-grid)	0% (Grid)	30%	50%	70%	90%	100% (Off-grid)
	¥4133	¥4096	¥4062	¥4048	¥4065	¥4140		Base	7.4y	7.0y	8.6y	11.1y
	¥4208	¥4164	¥4114	¥4091	¥4106	¥4194		Base	7.1y	6.9y	8.6y	11.1y
	¥4205	¥4147	¥4100	¥4071	¥4086	¥4208		Base	7.6y	7.2y	10.7y	12.7y
	¥4177	¥4135	¥4087	¥4068	¥4084	¥4147		Base	7.1y	6.4y	7.2y	10.8y
	¥4102	¥4082	¥4058	¥4054	¥4086	¥4206		Base	7.0y	6.7y	7.6y	10.6y
Ma'anshan · Anhui	0% (Grid)	30%	50%	70%	90%	100% (Off-grid)	0% (Grid)	30%	50%	70%	90%	100% (Off-grid)
	¥4133	¥4096	¥4062	¥4048	¥4065	¥4140		Base	7.4y	7.0y	8.6y	11.1y
	¥4208	¥4164	¥4114	¥4091	¥4106	¥4194		Base	7.1y	6.9y	8.6y	11.1y
	¥4205	¥4147	¥4100	¥4071	¥4086	¥4208		Base	7.6y	7.2y	10.7y	12.7y
	¥4177	¥4135	¥4087	¥4068	¥4084	¥4147		Base	7.1y	6.4y	7.2y	10.8y
	¥4102	¥4082	¥4058	¥4054	¥4086	¥4206		Base	7.0y	6.7y	7.6y	10.6y

Chapter 4

Third-party models and cross-provincial lines

4.1 Third-party models and settlement risk

Most standalone EAF steelworks cannot independently absorb the large capital expenditure required to build renewable projects. Among the 94 steelworks surveyed, 44% were operating on very thin margins, 50.4% were around break-even, and 5.6% were loss-making. A more feasible route is therefore for a third-party integrated-energy service provider to finance and own the renewable assets, then sell electricity to the steelworks through a long-term PPA or an energy-performance-contracting arrangement. The model works only if both sides can capture durable commercial value. In practice, several mechanisms make that difficult. From the energy provider's perspective, direct connection is also attracting thematic interest in capital markets, but fundraising does not establish stable long-term project cash flow.²⁴

1. Low-price regions offer little investment incentive: In regions where electricity is cheap and supply exceeds demand, integrated energy service providers have little reason to invest in new plants. A provider will offer a price materially below the grid benchmark only when alternative revenue channels, such as selling surplus electricity to the grid or securing a guaranteed-consumption project with a mechanism-based tariff, are extremely limited. Steel companies, for their part, want a price below the prevailing regional tariff; that same low tariff removes the investor's incentive to build. Gansu illustrates the problem. With severe electricity oversupply, its industrial and commercial grid-company proxy procurement tariff had fallen to CNY 0.149/kWh by June 2026, the lowest in the country. A PPA would have to undercut that floor, leaving the provider with little return on investment. The deeper mismatch is geographic: regions with such large power surpluses generally have little steelmaking capacity, so low-cost green-electricity supply is far from heavy-industrial loads.

2. High-price regions have even less reason to sell electricity cheaply: In power-importing (deficit) regions where steel mills are concentrated, generators have little reason to offer price concessions. Guangdong is a typical electricity-importing market. It has a large concentration of EAF loads but faces a structural electricity deficit of more than 200 TWh. In March 2026, its day-ahead and real-time spot-market averages repeatedly approached CNY 1/kWh, while even the PV mechanism tariff reached CNY 0.36/kWh. In a tightly balanced grid, generators can earn high per-kWh returns either from guaranteed-consumption volumes or the spot wholesale market. They therefore have little reason to

sign a discounted long-term PPA with a single steel customer.

For generators and project investors, three additional constraints often cause PPA transactions to fail outright:

3. High-quality resources near steelworks are already allocated. High-quality wind and solar resources near steelworks are not freely available: development capacity is planned and allocated by government, and much of it is already tied to mechanism-based renewable-electricity projects with guaranteed purchase arrangements. The capacity available to an investor near a particular load therefore depends less on investment appetite than on the small amount of unallocated development capacity. The scarce asset is not the renewable resource itself, but the development right and project allocation.

4. Counterparty risk turns a ten-year contract into a high-risk negotiation. The value of a PPA to a service provider depends on the user's ability to operate steadily and pay throughout the contract term, which is precisely what creates concern about a single steelworks' ability to survive for ten years. When choosing between a discounted long-term PPA and selling mechanism-based renewable electricity or participating in short-term spot transactions, operators often favour the latter because the associated consumption risk does not depend on the creditworthiness of one commercial and industrial customer. This helps explain why these projects are usually developed by asset developers rather than long-term generation operators. The developer builds and sells the asset, transferring it to a bank, insurer, or other financial institution and monetising the contract cash flow early. The structure reflects the reluctance of both sides to bear long-term default risk. Any reduction, suspension, or insolvency on the load side can materially damage the generator. The commercial case therefore depends heavily on a counterparty seeking rapid asset monetisation rather than a long-term, stable electricity relationship.

A PPA becomes commercially workable only when its value extends beyond a simple price comparison and the contract allocates risk and value over time. The parties may agree a stepped price path, with a higher initial price to accelerate recovery of the generator's fixed investment and lower prices later, while the generator purchases low-carbon steel from the steelworks for wind-turbine towers and solar mounting structures. This creates a reciprocal offtake arrangement while leaving both parties free to contract with other suppliers and buyers; the circular arrangement between Salzgitter and Ørsted in Europe illustrates the concept.²⁵

4.2 Feasibility of cross-provincial direct connection

The underlying problem is geographic: low-cost surplus renewable power is often far from steel loads.

Unless the steelworks is relocated near a generation site, can a cross-provincial direct connection bridge the gap?

A cross-provincial direct connection could address this spatial mismatch in principle. In practice, physical cross-provincial connections are difficult to implement and have limited feasibility.

1) Approval and coordination are complex

- a. For interprovincial projects, especially in the receiving province where the load is located, building a dedicated cross-provincial line requires coordinated approval from the energy authorities in both provinces and from both provincial grid companies. The market still lacks a unified framework for coordinating these cross-regional projects.
- b. When a dedicated line crosses a provincial boundary, it remains unclear how the sending province's renewable-energy consumption responsibility weighting and the receiving province's energy-consumption dual-control (or carbon-emissions dual-control) indicator should be allocated and credited.

2) Long-distance interprovincial transmission faces constraints

- a. Where the renewable source is far from the user, a long interprovincial line, for example more than 200 km, would incur material alternating-current (AC) losses and voltage drops and might require a direct-current (DC) scheme. Wind, solar, and a DC line alone cannot reliably maintain voltage, frequency, and power quality when renewable output is low or load changes quickly. Such a system would usually need converter stations supported by the AC grid, so it would not operate as a fully independent supply outside the public grid. That configuration would fall outside the ordinary meaning of green electricity direct connection.
- b. Apart from a small number of early interprovincial power-supply arrangements involving coal-fired power plants, such as the Yangcheng Power Plant in Shanxi directly supplying coal-fired electricity to Jiangsu through a point-to-grid, dedicated-line arrangement, actual cases of a new interprovincial direct connection combining a supporting power source with a dedicated line are extremely rare.

Cross-provincial direct-connection projects are therefore likely to remain limited. Where they are considered, priority should go to sites near provincial boundaries, where the load and renewable resource are geographically close and short dedicated lines, existing interprovincial supply links, and coordinated dispatch can be combined. For steelworks without nearby direct-connection resources, virtual green-electricity procurement, including VPPAs, will generally be more practical than a long-distance physical connection that depends entirely on interregional transmission infrastructure.



Chapter 5

Conclusions and recommendations

5.1 A narrow, conditional opportunity

The analysis can now answer the two questions framed by the matrices within the evidence boundary of the standalone scrap-based EAF baseline scenario. Under that scenario, a lower delivered electricity cost is the most direct and quantifiable cash-flow driver. ETS allowance value, relief from certificate costs associated with indirect electricity emissions under CBAM, and a general downstream procurement premium are unlikely to be the primary drivers for most projects. Direct connection is a narrow opportunity for steelmakers, not a universal solution. It can be tested for both BF-BOF and EAF routes, but its benefits depend on policy treatment and project conditions. A self-built project is competitive only under limited conditions, including a moderate green-electricity share, complementary wind, solar, and storage, credible local generation-load matching, grid connection, a relatively high project load factor, and reliable back-up arrangements. Third-party projects, including energy-performance-contracting models, face their greatest risk at settlement: the load-side customer may delay, reduce, or stop payments, exposing the provider to material losses. Direct connection may become more attractive as system operation charges rise, the national ETS develops, and demand for low-carbon steel grows, but those potential benefits are not part of the EAF model's quantified result.

5.2 Recommendations

The framework's remaining gaps map directly onto the division of responsibilities established by the policies: national authorities set pricing and accounting rules, provincial governments handle site selection and procedures, and grid companies manage interconnection interfaces. The recommendations follow that division.

5.2.1 Recommendations for national authorities

First, capital is a first-order obstacle. Support for concessional financing, including green finance, transition finance, or fund support, would ease upfront capital pressure. Under third-party arrangements, generators or investors generally must fund renewable generation, lines, substations, and energy storage before recovering their investment through users' electricity settlements over several years. Delayed payment, lower electricity use, or a production shutdown would directly reduce project cash flow. The power-supply side therefore needs a backstop guarantee, such as a project risk fund led by the fiscal authorities and covering both generators and loads, to address power offtake after load withdrawal.

Second, calculation standards should be transparent. The economics of direct renewable power supply projects depend on parameters such as how average load factor is defined, the calculation formulas, and the criteria for including sample enterprises. These parameters remain provincially defined, provisional, or insufficiently transparent. The national authorities should publish the methodology, applicable user sample, voltage levels, and update cycle underlying the provincial average load factors used for the single-capacity tariff under Document 1192. Because enterprises seeking better project economics may apply to reduce interconnection capacity, the authorities should also issue quantitative standards for assessing whether the requested capacity is reasonable.

Thirdly, carbon value is not yet effectively internalised. National authorities should strengthen the national ETS in three ways. First, shorten the transition period for free allocation and progressively reduce the share of free allowances, strengthening the carbon price signal for energy-structure and process choices. Secondly, include Scope 2 emissions from purchased electricity in steel-sector emissions accounting and allowance allocation so that green-electricity use creates recognisable compliance value. Metered, traded, and retired green electricity and direct-connection electricity should be deductible from purchased-electricity emissions under uniform rules; electricity drawn from the public grid should be calculated using the applicable emissions factor, with the generation-side and consumption-side accounting boundaries adjusted to avoid double counting. Thirdly, expand national ETS coverage to include standalone EAF steelmakers and set benchmarks that reflect the different emissions structures of EAF and BF-BOF production. Together, these measures would allow actual reductions in indirect emissions from green-electricity use to be reflected in compliance emissions, allowance demand, and product carbon footprints. They would turn green electricity from an additional procurement cost into a measurable and verifiable source of carbon value, strengthening the incentive to procure green electricity and invest in direct connection.

Fourth, make the multi-user model workable and establish a clearer cross-provincial pathway. Document 688 provides a foundation for multi-user projects, but operating details still need standardisation, including hourly traceability, responsibilities for metering and data submission, allocation of responsibilities among users, and transparent approval procedures. Cross-provincial projects still lack unified national rules for interconnection, dispatch, settlement, and renewable-energy consumption accounting. During the pilot phase, authorities should handle them as case-specific arrangements requiring coordination across provincial and grid procedures. They should not be treated as unavailable, and no predictable regulatory timetable should be assumed.

5.2.2 Recommendations for grid companies and regulators

First, grid companies and regulators should establish a coordinated project-development process. They should define responsibilities with local governments, generators, power users, and competent authorities; maintain a standing coordination mechanism; and resolve implementation bottlenecks promptly. They should also streamline pre-construction procedures, coordinate internal approvals, reduce duplicate reviews, and provide a single, predictable service pathway for direct-connection projects. Grid companies should publish the method and data used to calculate provincial average load factors, specify how system operation charges are allocated, clarify the treatment of back-up capacity and simultaneous transformer use, and reduce settlement uncertainty. These measures would improve project delivery without turning project-specific economics into a blanket exemption from network charges.

Second, define as soon as possible which system operation charges can be apportioned according to "occupied capacity." Document 1192 treats a project that uses the public grid as an industrial and commercial user: it temporarily pays system operation charges based on electricity drawn from the grid and is to transition gradually to payment based on occupied capacity and other methods. If charges eventually shift from electricity volume to occupied capacity, the charging basis will change. They are currently collected by electricity volume from all industrial and commercial users and comprise around 10 sub-items. The generation-side capacity charge is calculated by capacity but is currently collected by electricity volume. If the system shifts to occupied capacity, only the generation-side capacity charge is calculated by capacity; the other items are not. Grid companies should therefore define which charges can be allocated by occupied capacity, so the system-operation charge structure can become more granular and peak-load responsibility clearer.

5.2.3 Recommendations for renewable developers and energy operators

First, shift from low-price competition to screening for target loads. Generators should not try to win every user by cutting contracted prices. They should prioritise customers with stable loads, high electricity consumption, a clear need to consume renewable electricity or address product carbon footprints, and the ability to pay over the long term. The best-fit customers are those that can capture value through energy-cost savings, export compliance, supply-chain emissions reductions, or low-carbon product premiums. The commercial case therefore extends beyond offering the lowest electricity price.

Secondly, complete a genuine generation-load matching assessment before investment and avoid deliberately optimistic assumptions about project

returns. Wind and solar resources, user load, storage configuration, and curtailment should be modelled at an hourly or finer resolution. Contract prices should not be based on optimistic annual utilisation hours or daily average load factors. Generators should quantify how much renewable output can be consumed directly by the user, how much must be exported to the public grid, and how much grid electricity is needed to cover shortfalls. The contracted volume should be the deliverable electricity confirmed by generation-load matching, storage, and back-up checks, not theoretical output derived from installed capacity.

Thirdly, move from selling electricity from a single source to operating an integrated generation, network, load, and storage system. Generators need capabilities in renewable-output forecasting, load forecasting, storage dispatch, market trading, imbalance management, public-grid back-up supply, and green-electricity attribute accounting. For variable loads such as EAFs, the project's value lies not only in supplying renewable electricity but also in using storage, load adjustment, and market trading to reduce the user's delivered electricity cost. A generator that builds the generation assets but does not operate the system will struggle to create and share value over the project's life.

5.2.4 Recommendations for steel companies

First, adopt a plant-specific approach. A direct-connection design must be built around the specific renewable resource available near the steelworks; physical direct connection should not be pursued as a default. Projects that can satisfy the requirements for nearby renewable resources, generation-load matching, self-generation and self-consumption, green-electricity share, system security, metering, and emissions accounting are scarce. Physical direct connection should therefore not be treated as the single green-electricity route for every steelmaker. Each steelworks should assess its site and grid conditions, available renewable resources, production load curve, process route, storage and back-up configuration, network costs, and long-term contract risk before selecting a procurement model. Where the conditions are favourable, the company can develop a physical direct connection combining dedicated renewable generation, a private line, and storage. Where renewable resources are remote, cross-regional coordination costs are high, or physical connection is not yet feasible, the company can use cross-regional green-electricity trading, a long-term PPA, or a virtual power purchase agreement (VPPA) to secure a defined volume, price mechanism, and environmental attributes for a specified period.

Secondly, strengthen renewable-output forecasting, load simulation, storage-dispatch optimisation, and the use of flexibility in steelmaking. Only after validating the design against actual operating data, product-quality requirements, and supply-reliability requirements should the company quantify any

potential reduction in grid-connection capacity and apply for a lower contracted capacity. During project planning, load forecasts and connection capacity should be assessed conservatively; no capacity saving should be assumed in advance. Companies should also deploy energy-management and carbon-accounting systems that support operational optimisation and robust product-footprint management.

Thirdly, prioritise by process route and by offtaker. Direct connection has the clearest electricity application in scrap-based EAF lines and future hydrogen-based capacity. For BF-BOF steelmakers, assessment should also cover the opportunity cost of purchased electricity versus self-generation from by-product gases, and the value of diverting BFG, COG, or LDG to other uses. Downstream procurement commitments can provide a conditional value stream, but any premium must be validated through contracted offtake and tested against the applicable product-carbon and environmental-attribute rules. A steelworks without credible contracted demand should not assume that a claimed green-steel premium will finance the project.



Appendix A • Methodology

A.1 Scope, scenarios, and search architecture

The economic assessment uses techno-economic simulation over all 8760 hours of the year. It pairs a stylised scrap-EAF load with a dedicated wind-PV-storage system and operates the pair independently in each of six selected cities. This screening model supports comparison; it does not establish project bankability or provide a full plant-reliability simulation. Each scenario enumerates candidate configurations (PV capacity, wind capacity, and battery size), simulates hourly dispatch over the year, excludes candidates that violate specified policies or analytical screens, and selects the lowest-cost feasible configuration. The production, electrical, and tariff boundaries are defined in the appendix and do not represent every EAF or integrated steel plant.

Three scenario types are assessed. The pure-grid baseline (0% green electricity) prices all plant electricity consumption at the full delivered electricity tariff. The 30% scenario retains the national minimum; the 50%, 70% and 90% scenarios allow a three-point tolerance around their targets. The model deliberately uses exact targets instead of an “at least X%” floor: because renewable electricity costs less than grid power over most of the range, a floor would let the optimiser drift toward its preferred share and return the same configuration for nominally different scenarios, weakening the sensitivity analysis. The off-grid scenario requires 100% supply reliability and has no grid connection (Section A.6). For each target, the model searches three technology pathways: solar-storage, wind-storage, and wind-solar-storage. The hybrid pathway also requires at least 20% of combined wind and PV capacity to come from each resource, preventing a nominally “hybrid” solution from degenerating into a single-resource configuration. The search grid scales with load: renewable capacity is enumerated in increments of 1/12 of peak demand up to 4 times peak demand (12 times in the off-grid scenario), and battery candidates pair power increments of 1/4 of peak demand with commercial durations of 2 hours and 4 hours (4 hours and 8 hours off-grid). Infeasible regions are pre-screened by energy balance before dispatch simulation.

A.2 Input data

The hourly wind and PV capacity-factor curves for the six cities are based on MERRA-2 2023 reanalysis data, generated with Renewables.ninja and adjusted to local time (UTC+8). These data represent a single meteorological year, not a P90/P99 resource assessment. The EAF demand curves come from the five-stage furnace-state model described in Section A.8. Grid-tariff inputs use the 2026 provincial tariff schedules selected for the report. Hourly spot-price curves are synthetic scenario series built from month-by-hour multiplier rules, city-specific volatility factors, and normally distributed noise. All technical cost parameters are centralised in a shared configuration file.

A.3 Hourly dispatch model (grid-connected)

Dispatch follows a strict, rule-based sequence within each hour. It represents a conservative physical-tracking scenario, not an idealised co-optimisation of storage, spot prices, demand response, and production dispatch. Available renewable output serves the load first. Surplus electricity charges the battery, subject to its power rating and remaining state-of-charge headroom; one-way losses apply to both charging and discharging. Surplus beyond the battery’s absorption capacity may be exported when policy allows, subject to the model’s monthly and instantaneous

caps. In the core scenarios, permitted exports are set to zero as a conservative assumption. During deficits, the battery discharges first and the residual deficit is purchased from the grid. By construction, the battery can charge only from renewable surplus, consistent with the report’s conservative traceability premise.

A.4 Policy compliance screening

Each candidate configuration must pass four tests before cost evaluation. The achieved green-electricity share (renewable electricity delivered to the specified load, including direct self-consumption and battery discharge) must fall within the scenario tolerance band. The self-use ratio under Document 650 (direct self-consumption plus battery charging divided by total available generation) is modelled at no lower than 60%; this treatment of storage is an accounting assumption intended to avoid double counting and should be checked against the project’s metering rules. The grid-export share may not exceed the provincial cap used in the scenario. Finally, the model applies a pure-curtailment screen. The report’s policy-based screening inference is that pure curtailment should not exceed 20% of available generation; the core model uses a stricter 10% screen (90% utilisation) as a conservative stress scenario. Neither value is a universal statutory curtailment threshold. Configurations that fail the selected screens are excluded, so the results remain conditional on these assumptions.

A.5 Cost accounting and tariff settlement

Investment costs are annualised using a capital-recovery factor over the project discount rate and the individual life of each asset, with fixed operations and maintenance (O&M) costs added; wind and solar BOP costs are increased by 10%, and battery capital costs by 5%. The dedicated line is priced per kilometre and megawatt over a reference distance of 30 km, scaled to the EAF’s rated power and annualised on the same basis. Capacity charges are calculated from the monthly maximum hourly electricity drawn from the grid, adjusted for a 0.9 power factor, and priced at the prevailing capacity tariff. Thus, even a project that relies entirely on the grid for only one evening in a month must pay that month’s capacity charge on its full residual peak. This is the mechanism behind the persistence of capacity charges discussed in Section 3.1.3.2.

The grid-only case pays the local delivered tariff. Direct-connection cases buy any shortfall at spot market prices plus transmission and distribution charges. The resulting cost difference reflects both renewable self-supply and the change in grid procurement. In the 0% baseline scenario, all electricity consumption is charged at the delivered tariff specified in the report. In direct-connection scenarios, grid-imported deficit electricity is charged at the scenario’s hourly market price plus applicable network charges and markups; self-consumed green electricity is subject to the applicable two-part-tariff wheeling treatment and government funds and surcharges; and permitted exports receive only the scenario’s energy-export value. Standby capacity-reserve cost is an analytical sensitivity parameter representing reserved reliability arrangements, not a separately identified universal statutory charge; its interaction with capacity charges must be verified for each project.

Each evaluated configuration reports the cost metrics used throughout Chapter 2. LCOE-generation is renewable-system cost per kilowatt-hour of actual generation. LCOE-full (the headline metric) equals renewable-system cost plus the self-consumption wheeling fee, divided by the green electricity delivered to the load: the true all-in price per

kilowatt-hour of green electricity at the furnace gate. LCOE-grid is the all-in cost of grid-imported electricity. LCOE-blended divides the project's total electricity bill (renewable system, line, grid purchases, capacity charges, wheeling, and standby costs, less export revenue) by total electricity consumption. LCOS adds the EAF's annualised capital and variable costs and divides by annual steel output.

A.6 Off-grid search: 100% reliability with realistic storage

The off-grid scenario answers "What is the cost of absolute self-sufficiency under the model assumptions?" The alternative question, "What is the cheapest compliant combination?", is outside this scenario's purpose. Reliability is modelled as zero unserved energy over the 8760 hours of the selected weather year, with a small numerical tolerance.

A.7 Financial model for payback analysis

The payback results in Section 3.1.4 are based on a discounted-cash-flow model applied to the optimiser's physical output. Project capital cost is increased by 20.5% over equipment cost to reflect development, grid connection, land, and contingency costs. O&M is set at 1.5% for solar PV, 2.0% for wind, and 2.5% for batteries as a share of capital expenditure. Mid-life battery replacement is priced at 1.05 times equipment and installation cost and excludes non-recurring development and grid-connection costs. The dedicated connection is modelled as a fixed "dumbbell" structure comprising 110 kV substations at both ends plus line cost per kilometre. Avoided cost is calculated from the actual provincial delivered price: energy procurement cost plus CNY 0.016/kWh for line losses plus the provincial system operation charge.

A.8 Calibration of the five-stage EAF physical model

The EAF melting-cycle model is calibrated to a 60-minute furnace-state profile based on the literature: arc ignition and well piercing, 10 minutes, rated power 40%; primary melting, 35 minutes, 95%; refining and holding, 5 minutes, 30%; tapping and charging, 10 minutes, 0%. After aggregation to a one-hour model time step, average equivalent power is 64.6% of rated power. This hourly representation smooths sub-hourly EAF peaks, so it does not replace studies of 15-minute maximum demand, protection, transformers, and contract capacity. Before applying the model to plant decisions, reconcile annual output, electricity intensity, planned availability, power factor, transformer capacity, auxiliary loads, and the maximum-demand curve in one internally consistent engineering balance.

A.9 Model implementation

The grid-connected green-electricity-share scenarios and pure-grid baseline are generated by `search_forced_green_ratio.py` using the zero-export central scenario. The off-grid 100% reliability search is performed by `search_offgrid_100pct.py`. The scrap-EAF physical model and rigid-versus-flexible dispatch comparison are performed by `scrap_eaf_model.py` and `compare_rigid_vs_flexible.py`. Each script reads a unified YAML configuration and outputs CSV result files used to generate the charts.

A.10 Limitations of the Method

The economic conclusions presented in this report are derived from a grid search rather than continuous optimization. The model enumerates wind, solar, and energy-storage configurations on discrete step sizes; consequently, the reported "lowest-cost configuration" is only the optimum on that discrete grid. Because wind/solar capacities and storage combinations are enumerated in place of continuous optimization, the approach is subject to three layers of limitation.

First, step size determines resolution. Capacity is increased in increments of 1/12 of peak load, so the gap between the grid solution and the true continuous optimum remains unquantified. Cost differences smaller than one step between cities or green-power ratios can be interpreted only as ordinal rankings.

Second, the feasible region is truncated by hard thresholds (60 % self-generation rate, curtailment rate, and green-power ratio tolerance). The objective function is discontinuous at these thresholds, and enumeration does not guarantee a global optimum. Achievable green-power ratios jump with capacity step size; within a narrow feasible interval it is possible that no grid point falls inside the interval, producing an apparent "no feasible configuration" that does not necessarily mean the project itself is infeasible.

Third, the computational cost of enumeration grows exponentially with the number of variables, so all other variables must be fixed in advance: dedicated-line distance is set at 30 km; storage duration is restricted to the two discrete values of 2 h and 4 h (corresponding to 4 h and 8 h of autonomy); charge/discharge rate is held to a single value; the wind-solar mix is constrained only by a 20 % lower bound; and the technology pathways examined are limited to PV-plus-storage, wind-plus-storage, and wind-solar-plus-storage.

In addition, project-level flexibility is excluded from the configuration choices. The load curve is generated once by a five-stage furnace model and thereafter held fixed. Dispatch follows the rigid sequence "renewables first for direct supply, surplus to storage, shortfall purchased from the grid." Production schedules are not aligned with periods of high wind or solar output, furnace cycles and steel-tapping rhythms are not adjusted, storage is not charged or discharged according to price signals, and neither demand response nor forecast-error correction participates in the decision process.

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