

WHITE PAPER 05 - CAMEROON STEEL

CAMEROON'S HYDRO GRID CAN POWER LOW-CARBON STEEL IF LARGE USERS GET FIRM SUPPLY, CLEAR TARIFFS AND GAS

Power and gas for heavy industry in Cameroon, what an electric steelworks needs from the grid, the tariff system and the gas sector after the Hilli FLNG left Kribi, and the policy steps that would make it bankable.

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How to read this paper. Every number carries a unit, a year and a source marker such as [S01]. Figures and tables carry a status chip: sourced (read from a published source), derived (our arithmetic on sourced inputs, shown in Annex A), assumed (a stated planning assumption) or illustrative (a scenario or a picture of how something works, not a forecast). Project figures come from Cameroon Steel's reference configuration RC-1 and are planned or indicative, not commitments. Generated images are labelled "Illustrative view" and are not photographs of any project.

What this paper is not. It is not a feasibility study, a tariff proposal, an offer or a commitment. It does not disclose commercial terms. It sets out the energy evidence behind Cameroon Steel's own project at Mboro, in the Kribi industrial-port zone, and uses it to show what a large electric steelworks would ask of Cameroon's energy system.

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EXECUTIVE SUMMARY: THE GRID IS AN ASSET, BUT HEAVY INDUSTRY NEEDS FIRM SUPPLY, A TARIFF AND GAS

Cameroon's hydro-dominated grid, at about 226 g CO_{2e} per kWh in 2024, gives an electric steelworks a carbon advantage that few competitors can match. But firm, high-quality supply for a load of about 36 to 38 MW rising to about 94 to 99 MW on average does not yet exist on terms a lender can rely on. It needs a dedicated 225 kV connection such as the line and substation being built to the Kribi port, a published tariff for users above 10 MW, and, for any future direct-reduction plant, a gas allocation that reflects the new balance after the Hilli FLNG left Kribi in July 2026.

89.6 %

Hydro share of Cameroon's electricity, 2025 (8,119.9 GWh)

2,033 / 1,278 MW

Installed capacity and peak demand, 2025

150 MW

Industrial demand unmet, October 2026, pending the Nachtigal line

18 to 105 FCFA/kWh

Range of large-user price benchmarks; none published above 10 MW

~9 bcf/yr

Gas for a 1 Mtpa DRI plant, 11% to 12% of 2025 output

Source: ARSEL 2025 [S01]; Business in Cameroon, 9 October 2026 [S02]; ARSEL tariff data [S03][S04]; SNH 2025 [S05]; derived.

The answer in brief

This paper asks what an electric steelworks needs from Cameroon's energy system, and whether the system can provide it. It sets out the energy evidence behind Cameroon Steel's own project, a steel complex at Mboro, in the Kribi industrial-port zone, and uses it as a worked example. The complex has a design capacity of 1 Mtpa [S06], to be built in phases, with a first phase focused on reinforcing bar and wire rod from an electric arc furnace melt shop [S07]; its foundation stone was laid on 30 December 2024 by the Prime Minister representing the Head of State [S08]. Its melt shop makes billets, sold as such to re-rollers that import about 60% of their charge or rolled into bars and rod; with rebar capacity well above demand, the tonnage is aimed at replacing imports and at exports to the Central African Economic and Monetary Community (CEMAC) (White papers 04 and 09). Its reference configuration, RC-1, provides planned and indicative energy figures, which are labelled as such throughout.

The short answer is that Cameroon has the physical ingredients for low-carbon electric steel but not yet the rules that would make supply firm, priced and financeable. Ten findings support that conclusion.

- 01 Energy decides the competitiveness of electric steel.** RC-1 Phase 1 would use about 0.96 MWh of electricity per tonne of bars and rod at the planning value of 450 kWh per tonne of liquid steel in the furnace, and about 1.0 MWh at the upper planning value of about 490 kWh with 30% direct-reduced iron in the charge. Across the price benchmarks observed in Cameroon, that is US\$30 to US\$170 a tonne, a spread of

about US\$140, equal to about a fifth of the export price of rebar (US\$620 to US\$630 FOB on 3 October 2026) [S07][S09].

- 02 **The grid is low-carbon and hydro-based.** Hydro produced 89.6% of Cameroon's 8,119.9 GWh in 2025 [S01]. At about 226 g CO₂e/kWh in 2024, the grid emits less than half the world average (471 g) and about a third of Indonesia's (680 g), the origin of 78% of Cameroon's billet imports in 2023 [S10][S11].
- 03 **Capacity is not firm supply.** Cameroon had 2,033 MW installed against a 1,278 MW peak in 2025 [S01], yet 150 MW of industrial demand is unmet until the 400 kV Nachtigal evacuation line is completed, now due in November 2026 [S02]. The Kribi gas plant ran at about 30% of capacity, and Nachtigal delivered 28% below plan because of hydrology [S01].
- 04 **There is no published tariff for large users.** Regulated tariffs stop at 10 MW [S03]. Legacy high-voltage contracts averaged 18.4 FCFA/kWh in 2025, the top medium-voltage band costs about 43.7 FCFA/kWh all-in in 2026, and the regulator's cost-reflective average is 105.46 FCFA/kWh [S01][S03][S04]. A cost-based price for a firm high-voltage baseload would sit at roughly half the system average before the cost of firmness (derived).
- 05 **Tariff structure matters as much as level.** Under a capacity-plus-energy structure, an arc-furnace load with RC-1 Phase 1's shape would pay about 32% more per kWh than a flat load of the same energy (derived from [S03]). Measurement intervals, rewards for scheduling load around peaks and reactive-energy rules must be explicit.
- 06 **An arc furnace needs a strong connection and its own compensation.** A simplified screening suggests that a furnace with a transformer of the 30 to 33 MVA class needs about 4,000 to 7,000 MVA of short-circuit power at the connection point to keep flicker within the high-voltage planning level, or about 2,000 to 3,500 MVA with a static var compensator (derived; inputs from [S12][S13]). A 30 kV feeder would be too weak; a dedicated 225 kV bay is needed.
- 07 **Kribi's new 225 kV supply can carry Phase 1.** The 42 km double-circuit line from the Kribi gas plant and the 225/30 kV substation (3 x 60 MVA) at the port will offer 100 MW at first and 330 to 400 MW later, with commissioning planned for the end of 2026 [S14][S15]. The first 100 MW is shared by every user of the port platform. Phase 1, at 55 MVA maximum demand, would take about half of it; the 1 Mtpa works, at about 160 MVA, needs the later stage [S07].
- 08 **The FLNG's departure changed the gas balance.** About 95% of Cameroon's 75.5 bcf of gas went to LNG in 2025 [S05]. With the vessel gone since July 2026 [S16], plausible domestic uses at Kribi add up to about 20 to 36 bcf a year (derived). The binding unknown is the remaining certified reserve of the Sanaga Sud field, which is not public [S17].
- 09 **Gas for direct reduction is affordable but not yet available on financeable terms.** A 1 Mtpa DRI module would need about 8.4 to 9.1 bcf a year, nearly twice what the Kribi power plant used in 2025. At 2025 prices of about US\$3.2/Mscf (power) and US\$5.0 to 5.6/Mscf (industry) [S05], gas would cost US\$27 to US\$51 per tonne of DRI, against traded HBI at US\$340 to US\$370 a tonne in March 2026 [S18] (derived). Reserves, a price formula and DR-grade pellets are the constraints.
- 10 **Hydro, not solar, is the renewable that matters for steel.** A solar plant at Kribi would yield about 1,335 kWh per kWp a year [S19]; 50 MWp would cover about 23% of Phase 1's electricity but none of its night-time

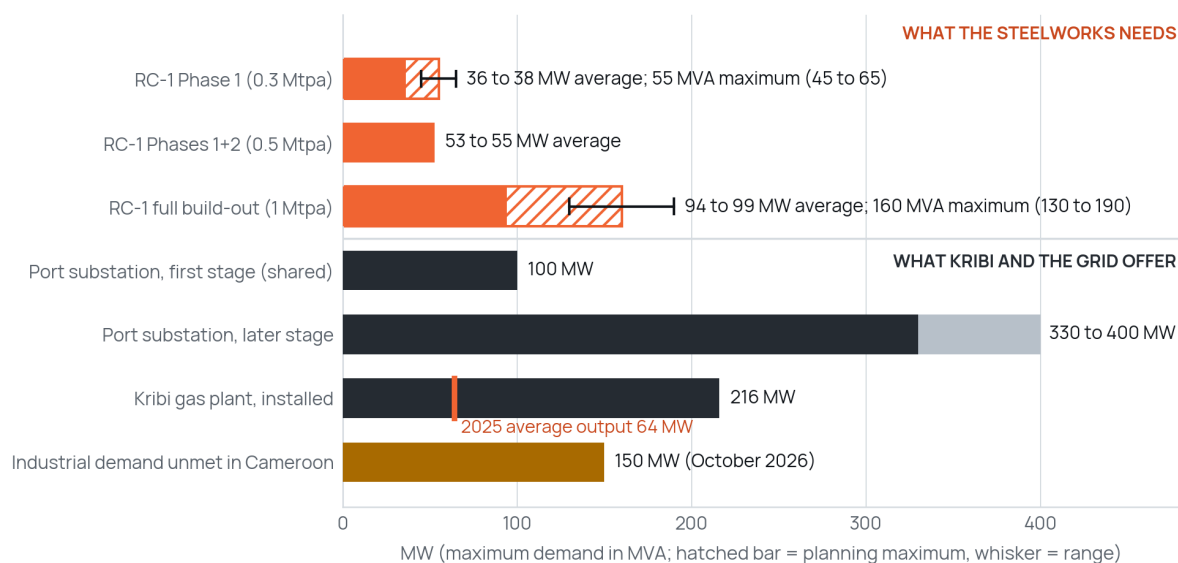
load. A contracted hydro supply, reported under the market-based method, could bring Scope 2 emissions close to zero and the plant close to low-emission steel thresholds (derived from [S20]).

What the steelworks would need, and what exists today

Figure ES.1 sets the indicative electricity demand of RC-1 against the supply being built at Kribi. Table ES.1 summarises, for each requirement, what exists today and what is missing.

Phase 1 fits the port substation's shared first 100 MW; 1 Mtpa needs its later stage

RC-1 average load (bars at 450 kWh/t; labels to 490 kWh/t) and maximum demand against Kribi supply; the first 100 MW serves the whole port platform



DERIVED **Figure ES.1.** Phase 1 fits the port substation's shared first 100 MW; 1 Mtpa needs its later stage. Average load at the 450 kWh/t planning value (solid) and planned maximum demand (hatched, with range) of the RC-1 reference configuration against the port substation, whose first 100 MW serves the whole port platform, the Kribi gas plant and the industrial demand currently unmet nationally. RC-1 values are planned and indicative.

Source: Cameroon Steel reference configuration RC-1 (planning estimate) [S07]; PAK, 6 August 2025 and 19 August 2026 [S14][S15]; ARSEL 2025 [S01]; Business in Cameroon, 9 October 2026 [S02]. Kribi gas plant average output = 559.67 GWh / 8,760 h (derived).

Table ES.1 What an electric steelworks needs from Cameroon's energy system, what exists and what is missing

Requirement	What RC-1 indicates (planned)	What exists or is under way	What is missing
Electricity	289 to 302 GWh/yr in Phase 1; 753 to 796 GWh/yr at 1 Mtpa (450 to 490 kWh/t in the furnace)	8,119.9 GWh national generation, 89.6% hydro (2025)	Firm delivery to Kribi; 150 MW of industrial demand already unserved
Capacity and connection	55 MVA in Phase 1; about 160 MVA at 1 Mtpa	225 kV line and 225/30 kV substation, 100 MW shared by the port platform, then 330 to 400 MW, due end-2026	A dedicated 225 kV bay; a dated plan for the later stage
Power quality	Dynamic compensation for a furnace of the 30 to 33 MVA class	International standards; one domestic arc-furnace precedent	Published fault levels at Kribi; a grid code for fluctuating loads
Price	A predictable, cost-based contract for 10 to 20 years	MV tariff up to 10 MW; legacy HV contracts; transmission tariff	A published large-user framework above 10 MW
Contract route	Utility contract or independent producer with wheeling	Law No. 2011/022 allows sales to eligible customers	Published balancing, back-up and certificate rules
Gas for reheating	None in Phase 1; up to about 0.83 bcf/yr at 1 Mtpa	Kribi gas plant supply; 2025 industrial price about US\$5.0 to 5.6/Mscf	A gas allocation and pipeline to the zone

Requirement	What RC-1 indicates (planned)	What exists or is under way	What is missing
Gas for DRI (reserve)	About 8.4 to 9.1 bcf/yr for 1 Mtpa DRI	Sanaga Sud production 74.3 bcf (2025); FLNG gone	Certified reserves, price formula, DR-grade pellets
Low-carbon attribute	Scope 2 near zero on contracted hydro	Grid at about 226 g/kWh (2024)	Wheeling and certificates of origin

Source: Chapters 1 to 9 of this paper; RC-1 values are planned and indicative [S07].

Why Phase 1 is planned without gas

RC-1 heats billets for its first mills by induction rather than in a gas-fired furnace [S07]. The choice adds about 90 GWh a year to Phase 1's electricity demand but removes any need for a gas contract until Phase 2. Given the uncertainty created by the FLNG's departure, that sequencing insulates the first phase from the gas question, and concentrates its energy needs on two things that can be settled by the end of 2027: a large-user power contract and a dedicated 225 kV connection with on-site compensation.

The later phases are different. Phases 2 and 3 would add gas-fired reheating, at up to about 0.83 bcf a year, and, more importantly, would need firm capacity to cover dry seasons and transmission outages. The natural source is the Kribi gas plant, through a dedicated part of its output or an extension within its 330 MW licence [S21] [S22]. A direct-reduction module for Cameroonian ore, held in reserve for after 2034, would need about ten times as much gas as the reheating furnaces [S07].

The furnace can move its load in time, not give it up

A single furnace must run for about 7,300 to 7,900 hours a year to cast Phase 1's nameplate tonnage (White paper 03, Chapter 5). Its flexibility is therefore schedulable, not interruptible: heats can be timed around the evening peak and maintenance placed in the tightest weeks, but each hour of curtailment costs about one heat (about 40 t), some 4,000 t of liquid steel per 100 hours, that cannot be recovered. Contracts should reward scheduling and cap emergency load-shedding (Chapter 9).

Five policy steps

The paper's recommendations are rules that would serve every large user, not concessions to a single project (Chapter 10):

1. **A large-user tariff framework above 10 MW**, published by ARSEL, based on the cost of serving a high-voltage, high-load-factor customer, with a two-part structure, a reward for load scheduled away from the system peak, explicit reactive-energy rules, indexation by formula and terms of 10 to 20 years.
2. **A grid code for fluctuating loads**, adopting the IEC TR 61000-3-7 approach to flicker and a recognised harmonic standard, with published fault levels at major nodes, mandatory connection studies and shared monitoring.
3. **A domestic gas allocation and price framework**, starting with an independent audit of the Sanaga Sud reserves, priorities and price formulas by class of user, tax clarity on industrial gas, and responsibility for a pipeline to the industrial zone.
4. **Workable wheeling and third-party access**, implementing the existing law with balancing rules, back-up tariffs and certificates of origin for hydro and solar.
5. **Integrated planning for the Kribi zone**, with a demand register, capacity reservation against milestones, shallow connection charges, firm capacity at Kribi and industrial offtake for new hydro.

CAMEROON DOES NOT NEED TO SUBSIDISE ENERGY TO ATTRACT HEAVY INDUSTRY. IT NEEDS TO PUBLISH THE RULES ON WHICH LARGE USERS CAN PLAN AND BORROW.

Cameroon Steel, White paper 05

Why this matters beyond one plant

The questions this paper asks of Cameroon's energy system are not specific to steel. Any large industrial load considering the Kribi industrial-port zone, whose development clusters include steelmaking linked to mineral exports [S23], will ask the same ones: how firm is the supply, at what price, under what contract, with what power quality, and with what gas. The 53 companies authorised to settle in the port's industrial and logistics zone between 2018 and 2025 [S24], the bitumen plant that received its refining licence in 2026 [S25] and the industrial buyer that began taking gas at Kribi in 2025 [S05] all depend on the same infrastructure and the same rules.

The policy steps proposed here therefore serve Cameroon's wider industrial strategy. The national development strategy to 2030 names mining, metallurgy and steel among its priority sub-sectors [S26], and the 2023 Mining Code provides for local transformation of part of the country's mineral output [S27]. An energy framework that makes one electric steelworks bankable would make the next large user bankable too.

There is also a timing argument. The FLNG's departure, the State's buy-back of the utility and its pending acquisition of the Kribi and Dibamba thermal plants [S28][S29], the commissioning of Nachtigal and of the new Kribi transmission line, and the entry into force of the EU's carbon border mechanism [S30] all fall within 2025 to 2027. The rules written in this window will shape Cameroon's industrial energy system for a generation.

What remains uncertain

The paper's main conclusions are robust to the evidence gaps listed in Chapter 11, but several sizes and dates depend on data not yet public: the fault level at the Kribi 225 kV node, the furnace's guaranteed electricity per tonne (planned within 450 to 490 kWh), the remaining gas reserves of Sanaga Sud, the terms of existing high-voltage contracts, the text of the connection and market codes, and the schedule of the port substation's later stage. Most of these can be closed by data that public institutions already hold. Cameroon Steel's own front-end engineering will replace RC-1's benchmark-based figures with supplier guarantees.

How this paper is organised

Chapters 1 to 5 cover energy in steel economics, Cameroon's power system, tariffs and contracting, the power quality an arc furnace needs and Kribi's new power infrastructure. Chapters 6 and 7 turn to natural gas after the FLNG and to gas for direct reduction, Chapter 8 to renewables and storage, Chapter 9 to an indicative energy plan and Chapter 10 to the policy recommendations. Chapter 11 lists the evidence gaps; the annexes give the method, a glossary, the sources and the data behind every chart.

Statement of interest. This paper is published by Cameroon Steel, which is developing a steelworks at Kribi. It is written to inform public debate; its analysis is independent of any commercial offer, and every figure is sourced or labelled with its status.

CHAPTER 1

ENERGY DECIDES THE COST AND THE CARBON OF ELECTRIC STEEL

For an electric steelworks, energy is the largest cost that the plant's own decisions can change. A bar and wire-rod works of the RC-1 Phase 1 type would use about 0.96 to 1.0 MWh of electricity per tonne of product; across the prices observed in Cameroon in 2025 and 2026, that is US\$30 to US\$170 a tonne, a spread equal to about a fifth of the export price of rebar. The price of electricity, and how firmly it is delivered, therefore decide whether such a plant competes with imports.

1.1 Energy is 20% to 40% of the cost of making steel

The World Steel Association (worldsteel) estimates that energy accounts for 20% to 40% of the cost of steel production, and attributes a reduction of about 60% in the energy needed per tonne of crude steel since 1960 to efficiency gains [S31]. The range is wide because it covers very different plants. An integrated works that starts from iron ore and coking coal buys most of its energy as coal. An electric steelworks buys it mainly as electricity, and, if it makes its own iron, as natural gas.

In an electric arc furnace (EAF) plant, the largest single cost is the metallic charge: the scrap, direct-reduced iron (DRI), hot-briquetted iron (HBI) or pig iron that is melted. Electricity comes next, followed by graphite electrodes, alloys, refractories, oxygen and labour. The metallic charge is priced on world markets and is largely outside a plant's control. Electricity is different: it is bought locally, under contracts and tariffs that national policy shapes. In Cameroon, where no regulated tariff is published for loads above 10 MW [S01], the electricity price for a large steelworks is not a market datum but the outcome of a negotiation with the utility and the regulator.

This matters more in Cameroon than in most steel markets, for two reasons that recur throughout this paper:

- **The country is short of iron units, not of rolling capacity.** Cameroon's rolling mills run at about half of their roughly 1.2 Mt of installed transformation capacity [S32][S33], local scrap covers only about 40% of their needs [S32], and billets were the largest steel import in 2023, at 161 kt, 78% of them from Indonesia [S11]. Any plant that adds iron units, by melting more scrap or by making DRI, adds energy demand: electricity for melting, gas for reduction.
- **The power system is hydro-based and the gas system has just lost its main buyer.** About 90% of Cameroon's electricity came from hydro in 2025 [S01], and the floating liquefaction vessel that took about 95% of the country's gas output left Kribi in July 2026 [S05][S16]. Both facts change what an energy-intensive plant can expect, and are developed in Chapters 2 and 6.

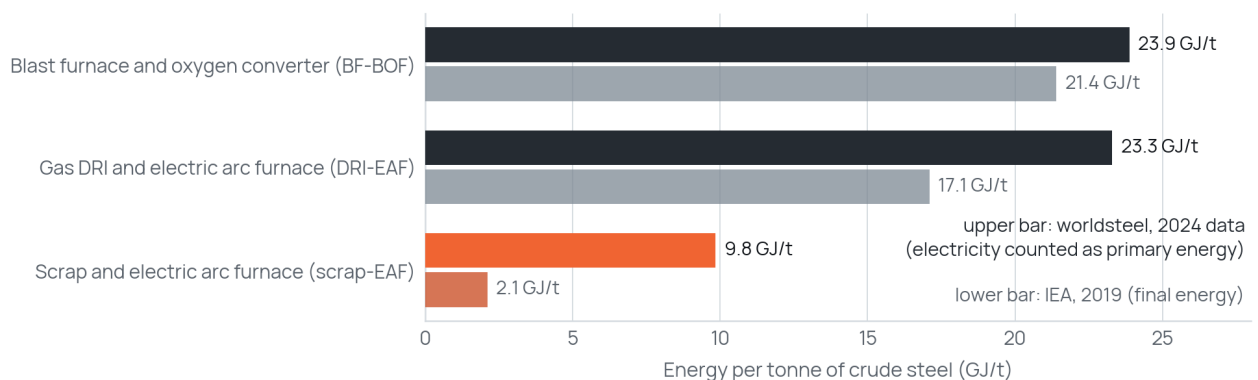
1.2 Three routes to steel have three very different energy profiles

Steel is made by three main routes, and each has a distinct energy signature (Figure 1.1).

- **Blast furnace and basic oxygen furnace (BF-BOF)**. Iron ore is reduced to liquid pig iron in a blast furnace, using coke made from coking coal, then refined to steel in an oxygen converter. Most of the energy is coal, and most of the emissions are direct.
- **Direct reduction and electric arc furnace (DRI-EAF)**. Iron ore pellets are reduced in the solid state, usually in a shaft furnace, by a gas made from natural gas (or, in future, hydrogen). The DRI is then melted in an EAF. Gas supplies the chemistry of reduction; electricity supplies the melting.
- **Scrap and electric arc furnace (scrap-EAF)**. Recycled steel is melted directly. No reduction is needed, so the energy demand is mostly electricity for melting.

Scrap-fed electric steel needs 10% to 40% of the energy of ore-based routes

Energy intensity by steelmaking route; the range depends on how electricity is counted



SOURCED Figure 1.1. Scrap-fed electric steel needs 10% to 40% of the energy of ore-based routes. worldsteel's 2024 data count electricity as primary energy and include upstream inputs; the International Energy Agency (IEA) counts final energy only, which is why its figures are lower. Source: worldsteel, Sustainability Indicators 2025 (2024 data) [S34]; IEA, Iron and Steel Technology Roadmap (2020) [S35].

On worldsteel's basis, the 2024 energy intensities were 23.88 GJ per tonne of crude steel for BF-BOF, 23.30 GJ/t for DRI-EAF and 9.84 GJ/t for scrap-EAF [S34]. The IEA's final-energy figures are 21.4, 17.1 and 2.1 GJ/t respectively [S35]. The two sets differ mainly because worldsteel converts each MWh of electricity into about 9.8 GJ of primary energy, while the IEA counts the MWh itself [S35]. Whichever basis is used, the ranking is stable: making iron from ore is energy-intensive, and melting scrap is not.

The same ranking applies to carbon. worldsteel's 2024 intensities are 2.34 t CO₂ per tonne of crude steel for BF-BOF, 1.47 t for DRI-EAF and 0.69 t for scrap-EAF, against a world average of 1.92 t [S34]. For the two electric routes, a large part of the footprint is the electricity itself, which is why the carbon content of the grid matters so much (Section 1.6 and Chapter 8).

WHY THIS MATTERS FOR CAMEROON

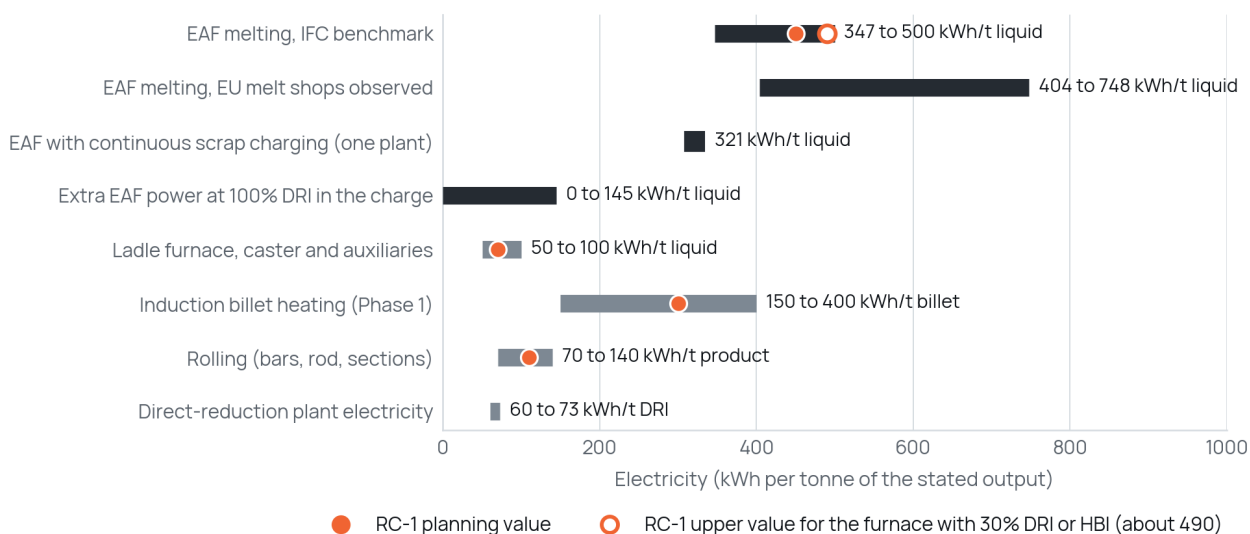
An electric steelworks in Cameroon would combine two energy carriers that the country has but does not yet price for heavy industry: hydro-based electricity for melting, and natural gas for making iron units. The route choice is therefore also a choice about which energy policy the plant depends on.

1.3 Melting takes most of the electricity in an electric steelworks

Inside an electric steelworks, electricity is used at five main points. Figure 1.2 shows the published ranges for each, and the planning values that Cameroon Steel uses for its reference configuration RC-1 (Table 1.1).

Melting is the largest electricity use: 350 to 500 kWh per tonne of liquid steel

Published ranges by process step and the planning values used for the RC-1 configuration



SOURCED Figure 1.2. Melting is the largest electricity use: 350 to 500 kWh per tonne of liquid steel in a modern furnace. Bars show published ranges; orange dots are the RC-1 planning values and the open circle the upper planning value for the furnace with 30% DRI or HBI. Units differ by step (per tonne of liquid steel, billet, product or DRI).

Source: IFC, EHS Guidelines for Integrated Steel Mills (2007) [S36]; European Commission, Iron and Steel BREF (2013) [S37]; EC Innovation Centre for Industrial Transformation (ICIT), Consteel and Energiron fact sheets [S38] [S39]; Cameroon Steel reference configuration RC-1 (planning estimate) [S07]; upper planning value derived (Annex A).

The arc furnace. The International Finance Corporation (IFC) benchmark for EAF melting is 1,250 to 1,800 MJ per tonne of liquid steel, which is 347 to 500 kWh/t [S36]. European melt shops reported 404 to 748 kWh/t in the reference document on best available techniques, with electrode consumption of 2 to 6 kg/t [S37]. Continuous charging with scrap preheating can bring the figure lower: one plant using the Consteel process reported 321 kWh/t, with power savings of 10% to 15% and electrode use below 1 kg/t [S38]. RC-1 uses 450 kWh/t as its planning value, within the IFC range of 347 to 500 kWh/t [S07].

The penalty for ore-based iron in the charge. DRI carries residual oxides and gangue that must be melted and slagged off. The Energiron fact sheet indicates that each additional 10% of DRI in the charge raises EAF electricity by about 14.5 kWh/t [S39]; extrapolated, an all-DRI charge needs about 145 kWh/t more than an all-scrap charge (derived). RC-1 plans a charge with about 30% imported DRI or HBI, within a range of 20% to 50% [S07]. Read as an all-scrap value, the 450 kWh/t planning value plus the increment for 30% DRI gives about 494 kWh/t. This paper therefore carries two values throughout, as White paper 03 does: 450 kWh/t as the RC-1 planning value and about 490 kWh/t as the upper planning value with 30% DRI or HBI in the charge (derived).

The ladle furnace and auxiliaries. After tapping, steel is refined and brought to casting temperature in a ladle furnace (LF), then cast into billets. The oxygen plant, water treatment, compressed air and buildings add to the load. RC-1 assumes 70 kWh per tonne of liquid steel for all of these together, in a range of 50 to 100 kWh/t [S07]. Oxygen use is planned at about 35 Nm³ per tonne of liquid steel [S07].

Rolling. The mill that turns billets into bars, rod or sections uses 70 to 140 kWh per tonne of product on the IFC benchmark [S36]; the European Union's 2022 best-available-techniques conclusions for ferrous metals processing give 100 to 500 MJ/t for bars and rods, about 28 to 139 kWh/t [S40]. RC-1 uses 110 kWh/t [S07].

Reheating. Billets must be heated to rolling temperature. Gas-fired reheating furnaces for bars and rods use 600 to 1,900 MJ/t, and 1,400 to 2,200 MJ/t for beams and blooms, on the EU benchmark [S40]. RC-1 plans electric induction heating in Phase 1 and a gas-fired walking-beam furnace for the sections mills of Phases 2 and 3, at about 1.3 GJ per tonne of product [S07].

Table 1.1 Energy inputs by process step, benchmarks and RC-1 planning values

Process step	Energy carrier	Published benchmark	RC-1 planning value	Status
EAF melting	Electricity	347 to 500 kWh/t liquid (IFC); 404 to 748 (EU)	450 kWh/t liquid	sourced
EAF melting, upper planning value	Electricity	+14.5 kWh/t per +10% DRI on an all-scrap base	about 490 kWh/t liquid with 30% DRI or HBI	derived
DRI in the charge	Electricity	+14.5 kWh/t per +10% DRI	30% DRI or HBI (20% to 50%)	sourced / assumed
Electrodes	Graphite	2 to 6 kg/t liquid (EU)	not modelled	sourced
Ladle furnace, caster, auxiliaries	Electricity	not benchmarked as a group	70 kWh/t liquid (50 to 100)	assumed
Oxygen	Electricity (air separation)	not benchmarked here	35 Nm ³ /t liquid (25 to 45)	assumed
Induction billet heating (Phase 1)	Electricity	vendor ranges vary with hot charging	300 kWh/t billet (150 to 400)	assumed
Gas-fired reheating (Phases 2 and 3)	Natural gas	0.6 to 2.2 GJ/t (EU, by product)	1.3 GJ/t product (1.1 to 1.6)	sourced / assumed
Rolling	Electricity	70 to 140 kWh/t product (IFC)	110 kWh/t product	sourced
Direct reduction (reserve)	Natural gas, electricity	9.2 to 10 GJ and about 73 kWh per t DRI	10 GJ/t DRI (9.2 to 10)	sourced / assumed

Source: IFC 2007 [S36]; EU BREF 2013 [S37]; Commission Implementing Decision (EU) 2022/2110 [S40]; EC ICIT Energiron [S39]; Danieli, Suez Steel 2026 [S41]; Cameroon Steel reference configuration RC-1 (planning estimate) [S07].

Added together on RC-1 planning values, Phase 1 would use about 289 GWh of electricity a year for its name-plate output of 300,000 t of finished products, or 0.96 MWh per tonne, and no gas [S07]; at the upper planning value of about 490 kWh/t in the furnace, about 302 GWh, or 1.0 MWh per tonne (derived). At full build-out to 1 Mtpa, electricity would rise to about 753 to 796 GWh a year, or 0.75 to 0.80 MWh per tonne, because the later phases reheat with gas rather than induction, and gas use would reach about 0.91 PJ a year [S07]. Chapter 9 sets out the full phase-by-phase balance.

1.4 Phase 1 is planned without gas, which trades a gas risk for a power load

RC-1 plans to heat billets for its first rolling mills by induction rather than in a gas-fired furnace [S07]. That design choice has three effects that bear directly on this paper.

First, **Phase 1 needs no gas allocation at all**. Reheating 300,000 t of billets in a gas furnace at 1.3 GJ/t would burn about 0.39 PJ a year, around 0.36 bcf (derived). Using induction instead removes the plant's dependence on a gas contract in the years when Cameroon's gas sector is being restructured after the departure of the Hilli FLNG (Chapter 6).

Second, **it adds about 90 GWh a year to the power demand**, some 31% of Phase 1's electricity (derived from 300 kWh/t on 300,000 t). In energy terms the two options are close: 300 kWh is 1.08 GJ, against 1.3 GJ of gas, because induction puts heat directly into the billet while a furnace loses much of it through the flue. In cost terms, the comparison depends entirely on the electricity tariff and the gas price, which is why both are analysed in this paper.

Third, **induction heating suits hot charging**. Billets that leave the caster still hot need only a top-up to reach rolling temperature, so the actual energy use depends on how closely the caster and mill are synchronised. The planning range of 150 to 400 kWh/t reflects that uncertainty [S07].

DESIGN NOTE

Induction heating converts a gas question into a power question. It is the right choice for a first phase only if the electricity supply is firm and priced for a high-load-factor industrial user. That is the condition this paper examines.

1.5 The tariff can move the cost of a tonne of steel by US\$140

The electricity cost per tonne follows from the plant's intensity and the price paid. Cameroon has no published tariff for loads of the size of a steelworks, so Table 1.2 uses three benchmarks that are developed in Chapter 3: the average price actually realised on the six legacy high-voltage (HV) contracts in 2025, 18.4 FCFA/kWh; the all-in price of the highest published medium-voltage (MV) band, 9 to 10 MW, in 2026, about 43.7 FCFA/kWh; and the regulator's cost-reflective average for 2025, 105.46 FCFA/kWh [S01][S03][S04].

Table 1.2 Electricity cost per tonne of product at three price benchmarks (derived)

Price benchmark	FCFA/kWh	Phase 1, 0.96 MWh/t: FCFA/t	Phase 1: US\$/t	Full build-out, 0.75 MWh/t: US\$/t	Phase 1 cost as share of rebar at US\$625/t
Legacy HV contracts, average realised, 2025	18.4	17,723	29.5	23.1	4.7%
MV 9 to 10 MW band, all-in, 2026	43.7	42,091	70.2	54.9	11.2%
Cost-reflective average, 2025	105.46	101,578	169.3	132.4	27.1%

Source: ARSEL 2025 annual report [S01]; ARSEL tariff tables [S03]; ARSEL decision of 19 December 2025 [S04]; RC-1 balances at the 450 kWh/t planning value [S07]; Turkish rebar export price US\$620 to 630/t FOB, 3 October 2026 [S09]. US\$ at 600 FCFA (planning rate). Electricity only, excluding VAT, reactive-energy charges and connection costs. At the upper planning value of about 490 kWh/t, Phase 1 costs are about 4% higher.

The spread between the first and last rows is about US\$140 per tonne of product in Phase 1. White paper 04 (Chapter 8) sets these power costs beside the cost of metallics and conversion in an indicative comparison of a Kribi billet with an imported one. For comparison, Turkish rebar was offered for export at US\$620 to US\$630 a tonne FOB on 3 October 2026, and Chinese billets at US\$465 to US\$470 [S09]. A steelworks paying the cost-reflective average would spend more than a quarter of the value of its product on electricity; one paying the legacy HV price would spend under 5%.

THE TARIFF, NOT THE FURNACE, WILL DECIDE WHETHER AN ELECTRIC STEELWORKS IN CAMEROON CAN COMPETE WITH IMPORTED STEEL.

Cameroon Steel, White paper 05

The existing steel industry already feels this. Cameroon's metallurgical plants paid substantial electricity bills in 2024: about 8.37 bn FCFA for Prometal, 3.81 bn for Metafrique, 3.11 bn for Acero Metal and 1.61 bn for Aciéries du Cameroun [S42]. Prometal, which operates an arc-furnace melt shop at Douala described as the first of its kind in Central Africa [S43], has a load of about 40 MW and moved to a high-voltage supply through an access contract with the transmission company SONATREL, with a dedicated 50 MVA transformer [S42][S01]. When tariffs for large accounts rose in January 2023, the steel producers protested publicly against a feared increase of about 30%, while the regulator, the Agence de Régulation du Secteur de l'Électricité (ARSEL), put the average increase for MV bills at 12% [S44][S45]. The episode shows how sensitive the sector is to the tariff and how little predictability large users currently have.

1.6 Energy also sets the carbon footprint, which buyers and border rules increasingly price

For an electric steelworks, the electricity supply largely determines the indirect (Scope 2) emissions. At Cameroon's 2024 average grid intensity of about 226 g CO₂e per kWh [S10], Phase 1's 0.96 MWh/t would carry about 0.22 t CO₂ per tonne of product (about 0.23 t at 1.0 MWh/t). On a grid at the 2024 world average of about 471 g/kWh [S10], the same plant would carry about 0.45 t, and on Indonesia's grid, at about 680 g/kWh, about 0.65 t (derived).

RC-1's own estimate, which adds the direct (Scope 1) emissions from electrodes, charge carbon and lime, is about 0.32 t CO₂ per tonne of product for Scopes 1 and 2, and about 0.58 t when the upstream emissions of the imported DRI are included [S07]; the upper planning value adds about 0.01 t (derived; White paper 06 sets out the full carbon balance). Both are well below the worldsteel route averages for DRI-EAF (1.47 t) and BF-BOF (2.34 t), and below the scrap-EAF average (0.69 t) [S34].

Carbon now has a price at Europe's border. The European Union's Carbon Border Adjustment Mechanism (CBAM) entered its definitive phase on 1 January 2026, covers all of chapter 72 of the Combined Nomenclature, including billets, rebar, wire rod and DRI, and set a certificate price of €82.32 per tonne of CO₂e for the third quarter of 2026 [S30][S46][S47]. For iron and steel, CBAM currently counts direct emissions only [S46], so at that price every 0.1 t of direct CO₂ per tonne of steel is worth about €8 a tonne at the EU border before deductions (derived). The carbon content of the electricity matters instead for customers' supply-chain reporting and for low-emission steel standards; Chapter 8 explains why a contracted hydro supply is worth more to an exporter than the grid average.

ABOUT 0.96 TO 1.0 MWH OF ELECTRICITY GOES INTO EVERY TONNE OF BARS AND ROD: THE PRICE OF THAT ENERGY DECIDES THE PLANT'S COMPETITIVENESS.

Cameroon Steel, White paper 05

1.7 What this means for policy and for investors

The economics of electric steel in Cameroon reduce to three energy questions, which the following chapters answer in turn:

1. **Is there enough firm power, delivered with the quality an arc furnace needs?** Chapters 2, 4 and 5 show that Cameroon has capacity on paper, but that delivering firm, high-quality supply to a large fluctuating load requires dedicated transmission and compensation.
2. **At what price, under what contract?** Chapter 3 shows that the tariff framework stops at 10 MW, leaving large users to negotiate case by case.
3. **Is there gas, and at what price, for reheating and later for making iron?** Chapters 6 and 7 show that the gas balance changed fundamentally in July 2026.

The answers matter beyond one plant. Cameroon's industrial strategy, the Stratégie Nationale de Développement 2020-2030 (SND30), names mining, metallurgy and steel among its priority sub-sectors [S26]. An energy framework that works for an electric steelworks would also work for the other large loads the Kribi industrial-port zone aims to attract.

CHAPTER 2

CAMEROON HAS THE CAPACITY ON PAPER, BUT NOT YET FIRM SUPPLY WHERE INDUSTRY NEEDS IT

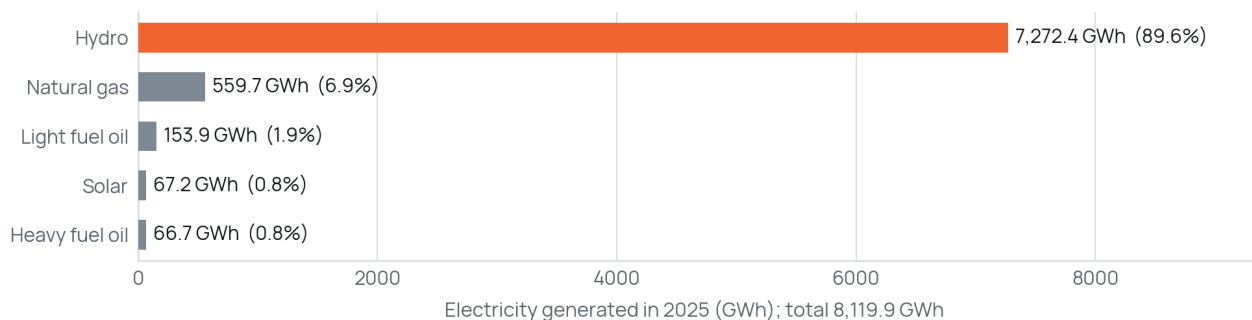
Cameroon had 2,033 MW of installed capacity against a peak demand of 1,278 MW in 2025, and hydro produced nine-tenths of its electricity. Yet 150 MW of industrial demand is waiting for a transmission line, the Kribi gas plant ran at about 30% of its capacity, and the largest new hydro plant delivered 28% less than planned. The system's constraint is not installed capacity but firm, deliverable supply at the nodes where large loads connect.

2.1 Hydro supplied nine-tenths of Cameroon's electricity in 2025

The electricity regulator's annual report for 2025, published on 7 September 2026, gives the most recent official picture of the system [S01]. Cameroon generated 8,119.9 GWh in 2025. Hydro plants produced 7,272.4 GWh, or 89.6% of the total; natural gas 559.7 GWh (6.9%); light fuel oil 153.9 GWh (1.9%); solar 67.2 GWh (0.8%); and heavy fuel oil 66.7 GWh (0.8%) (Figure 2.1).

Hydro supplied nine-tenths of Cameroon's electricity in 2025

Generation by source, national system, 2025 (regulator's annual report)



SOURCED Figure 2.1. Hydro supplied nine-tenths of Cameroon's electricity in 2025. All of the natural gas generation came from the Kribi gas-fired plant.

Source: ARSEL, Rapport d'activités 2025 (7 September 2026) [S01].

Two features of this mix matter for an electric steelworks. First, the electricity is low-carbon: in the international dataset compiled by Ember and published by Our World in Data, Cameroon's average grid intensity was about 226 g CO₂e per kWh in 2024, less than half the world average of about 471 g [S10]. Second, the system depends on rainfall. Hydro output varies with river flows, and only part of the hydro fleet is backed by storage, so a dry year or a late rainy season shifts the burden onto the gas and oil plants.

The international dataset and the regulator's report do not tell exactly the same story. Ember's figures for 2024 show 7.26 TWh of generation with hydro at about 72%, and a hydro value that is unchanged at 5.23 TWh in every year from 2020 to 2024, which suggests an estimate rather than metered output [S48]. The regulator's 2025

data show more generation and a much higher hydro share, partly because the 420 MW Nachtigal plant came fully on line in March 2025 [S49] and partly because the Kribi gas plant was offline from September 2024 to February 2025 [S50]. This paper uses the regulator's data for the structure of the system and the Ember series for international comparison, and flags the difference as an evidence gap (Chapter 11).

2,033 MW

Installed capacity, 2025 (ENEO 1,003 MW, independent producers 1,030 MW)

1,278 MW

Peak demand, 2025

89.6 %

Hydro share of generation, 2025 (8,119.9 GWh)

147.8 h

Average outage time per customer, 2025 (target 74.1 h)

Source: ARSEL 2025 [S01].

2.2 Two separate grids, one utility back in public hands

Cameroon's electricity flows on two grids that are not yet connected. The Southern Interconnected Grid (RIS) carries about 94% of demand and links the Sanaga hydro cascade to Douala, Yaoundé, Edéa and Kribi; the Northern Interconnected Grid (RIN) carries the remaining 6% [S01]. Kribi, and therefore any steelworks in its industrial-port zone, sits on the southern grid.

The sector's institutions have changed rapidly in 2025 and 2026:

- **Distribution and supply.** The State bought the 51% stake that Actis held in the national utility ENEO for 78 bn FCFA in February 2026, raising its holding to 95% [S28]; the company was renamed Socadel in May 2026 [S51]. This paper uses "the utility" for both names.
- **Transmission.** Law No. 2011/022 of 14 December 2011 on the electricity sector provided for a public transmission system operator [S52], and the Société Nationale de Transport de l'Électricité (SONATREL) was incorporated in October 2015 [S52]. SONATREL publishes a regulated transmission tariff (Chapter 3) [S53].
- **Generation.** About half of installed capacity, 1,030 MW, belongs to independent power producers (IPPs) [S01]. The utility's purchases from IPPs rose to 254.25 bn FCFA in 2025 [S01]. In August 2026 the State announced it was exercising a pre-emption right to buy Globeleq's stakes in the Kribi and Dibamba thermal plants, for about 80 bn FCFA with closing expected by the end of 2026, against a background of 137 bn FCFA of unpaid IPP invoices [S29].
- **Regulation.** ARSEL sets tariffs, approves the utility's allowed revenue and publishes the regulated tariff grids [S54] [S04].

The system serves few large customers. In 2025 the utility had 6 high-voltage customers, 31 "special" medium-voltage customers, 2,526 other MV customers and about 2.19 million low-voltage customers [S01]. National electricity access was 71%, and 25% in rural areas [S55]. A single 1 Mtpa electric steelworks would be one of the very largest loads on this system.

2.3 The utility's finances shape what a large user can be offered

The financial position of the sector matters to a large user as much as its physical capacity, because it determines what the utility can promise and whether it can keep its promises. Four public figures summarise the position:

- the utility's purchases from independent producers rose from 156.13 bn FCFA in 2024, itself 17% more than the year before, to 254.25 bn FCFA in 2025 [S56] [S01];

- the regulator's adjusted decision on the utility's allowed revenue for 2025 recorded a tariff subsidy of 96.99 bn FCFA, the gap between the cost-reflective average of 105.46 FCFA/kWh and the 83.46 FCFA/kWh actually collected from MV and LV customers [S04];
- unpaid invoices owed to independent producers stood at about 137 bn FCFA in 2026 [S29];
- in May 2026 the government cited a sector deficit of about 13 bn FCFA a month when proposing higher tariffs for some business customers [S57].

These numbers explain both the opportunity and the risk for a large industrial customer. The opportunity is that a creditworthy user that pays a cost-based price for a high-load-factor supply improves the utility's finances rather than worsening them. The risk is that a utility under this pressure may be unable to honour a firm supply commitment in a dry year, or may seek to revise a contract once signed. Both point to the same conclusion: large-user supply should rest on published rules and, where possible, on contracts with identifiable sources of firm capacity, rather than on bespoke arrangements with a utility whose finances are under strain.

2.4 The fleet combines a hydro cascade with a small thermal back-up

Table 2.1 summarises the plants that matter most for a large load on the southern grid.

Table 2.1 Main generating plants on the southern grid, capacity and 2025 performance

Plant	Type and location	Capacity	2025 output and remarks	Source
Song Loulou	Hydro, Sanaga river	384 MW (8 units)	The cascade's largest plant, in service since the 1980s; the utility sought financing for a dam-safety rehabilitation programme in 2025	[S58][S59]
Edéa	Hydro, Sanaga river	265 to 276 MW (sources differ)	Downstream of Song Loulou; mainly supplies the adjacent aluminium smelter	[S59][S60]
Nachtigal	Hydro, Sanaga river, upstream of Yaoundé	420 MW (7 x 60 MW)	Fully commissioned March 2025; 2,070.68 GWh in 2025, 28% below plan because of hydrology; 3,613,785 MWh injected May 2025 to May 2026	[S49][S01][S61]
Memve'ele	Hydro, Ntem river, south	211 MW	557.0 GWh in 2025, 129% above plan; utility purchase price 43.93 FCFA/kWh	[S01][S62]
Lom Pangar	Regulating dam, Lom river (upper Sanaga basin)	About 6 bn m ³ reservoir; 30 MW plant	Reservoir regulates Sanaga flows; plant islanded on the eastern network; 58.0 GWh in 2025	[S01][S59]
Kribi (KPDC)	Gas, 13 dual-fuel engines, near Kribi	216 MW (licence 330 MW)	559.67 GWh against 1,031.24 GWh planned (minus 46%), about 30% capacity factor; guaranteed availability about 180 MW	[S01][S63][S21][S64]
Dibamba (DPDC)	Heavy fuel oil, near Douala	86 MW	Thermal back-up	[S60][S29]
Limbé	Heavy fuel oil	85 MW	Thermal back-up	[S60]

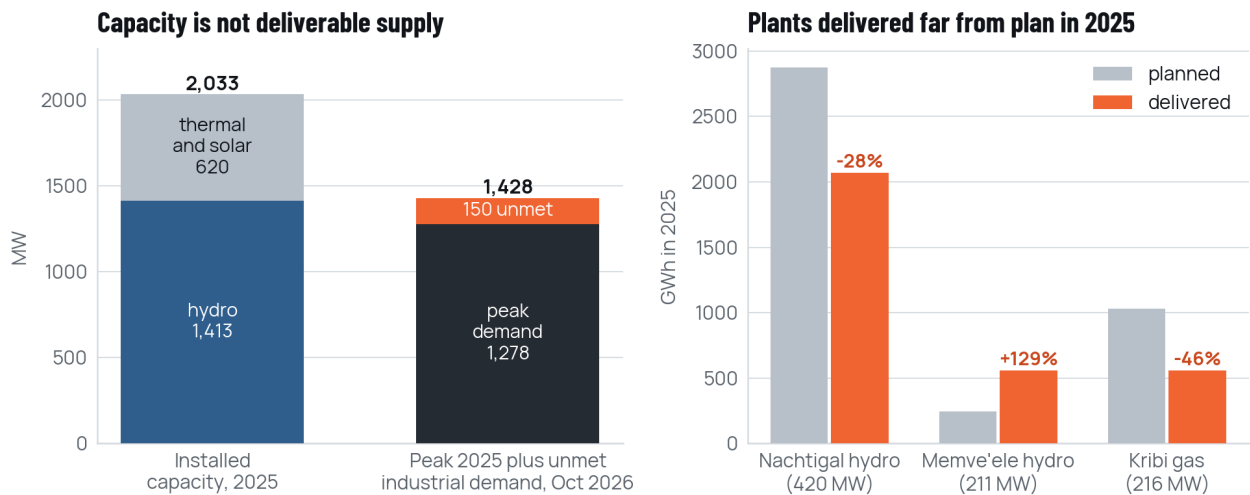
Source: as listed. Capacities of Dibamba and Limbé as tagged in OpenStreetMap (extract of 10 October 2026); Song Loulou and Edéa from the business press and the World Bank's 2019 completion report on Lom Pangar, which differ by a few MW for Edéa; regulator's data used for 2025 output.

The backbone of the southern grid is the Sanaga cascade: Song Loulou and Edéa downstream, Nachtigal upstream, and the Lom Pangar reservoir, which stored about 6.3 bn m³ of water in 2016 to even out the river's seasonal flow [S59]. Memve'ele, on the Ntem in the far south, is the hydro plant closest to Kribi; its 225 kV evacuation line runs north towards Yaoundé [S65]. The Kribi gas plant, built in 2013 and owned 56% by Globeleq and 44% by the State [S21], is the only significant thermal plant in the south and the only gas-fired plant on the grid in 2025.

2.5 Capacity is not the same as deliverable supply

On paper, Cameroon's capacity exceeded its 2025 peak by 755 MW, a margin of 59% (derived). In practice, the system could not serve all of its customers. Figure 2.2 shows why the paper margin overstates what a new industrial customer could rely on.

Cameroon has 755 MW of capacity above its peak, yet 150 MW of industrial demand is unserved



SOURCED Figure 2.2. Cameroon has 755 MW of capacity above its peak, yet 150 MW of industrial demand is unserved. Left: installed capacity, peak demand and unmet industrial demand. Right: planned and delivered output of three plants in 2025.

Source: ARSEL 2025 [S01]; Business in Cameroon, 9 October 2026 [S02]. Planned values for Nachtigal and Memve'ele back-calculated from the reported deviations (derived).

Four mechanisms separate installed capacity from firm supply:

- **Transmission.** On 9 October 2026, Business in Cameroon reported that delays to the evacuation line of the Nachtigal plant leave 150 MW of industrial demand unmet; the 400 kV line is now due in November 2026, the Edéa-Béon substation was 95% built, and the World Bank added US\$50m of financing in June 2026 [S02]. The 400 kV Nkolokoumou to Edéa line, with a transfer capacity of 1,500 MW, was about 65% to 66% complete in 2025 [S01]. Generation that cannot reach the load is not supply.
- **Hydrology.** Nachtigal is a run-of-river plant: it produced 28% less than planned in 2025 because of river flows [S01]. Memve'ele, by contrast, produced 129% more than planned [S01]. Hydro output is real but variable, and only the reservoirs make it partly dispatchable.
- **Thermal dispatch and gas.** The Kribi gas plant delivered 559.67 GWh against 1,031.24 GWh planned in 2025, a capacity factor of about 30% (derived) [S01][S63]. It had been offline from September 2024 to February 2025 over a debt of 137 bn FCFA [S50]. In May 2025, only about 13 MW of the local thermal capacity was reported as available to the Kribi area, the rest flowing into the southern grid [S24].
- **Network losses and reliability.** Transmission efficiency was 94.6% and distribution efficiency 72% in 2025 [S01]. The average customer was without power for 147.83 hours in the year, twice the target of 74.1 hours, with an average of 64 interruptions [S01].

GENERATION THAT CANNOT REACH THE LOAD IS NOT SUPPLY: 150 MW OF INDUSTRIAL DEMAND IS WAITING FOR A LINE, NOT FOR A POWER PLANT.

Based on Business in Cameroon, 9 October 2026 [S02]

For an energy-intensive plant, the lesson is that a supply contract must specify not only energy and price but **firmness**: how many MW are guaranteed, through which transmission path, with what back-up, and with what compensation when supply fails.

2.6 Outage statistics describe the distribution network more than the high-voltage grid

In 2025 the average customer lost supply for 147.83 hours, about 1.7% of the year, over about 64 interruptions, or about 2.3 hours per interruption on average (derived from [S01]). These averages are dominated by the distribution network, where almost all customers are connected and where most faults occur. A customer supplied directly at 225 kV is exposed only to faults on the transmission system and to shortfalls in generation, so the national figures overstate the number of interruptions a high-voltage steelworks would see.

They understate, however, the risk of the events that matter most to such a plant. The first is a **generation shortfall in the dry season**, when hydro output falls and the thermal fleet, including the Kribi gas plant, must make up the difference. The second is the **loss of a single transmission path**, which at the end of a radial branch can interrupt supply to a whole industrial zone at once. For an arc furnace, a short interruption costs the heat in progress and some refractory wear; a long one stops the caster and the mills and puts the plant's essential services on back-up power.

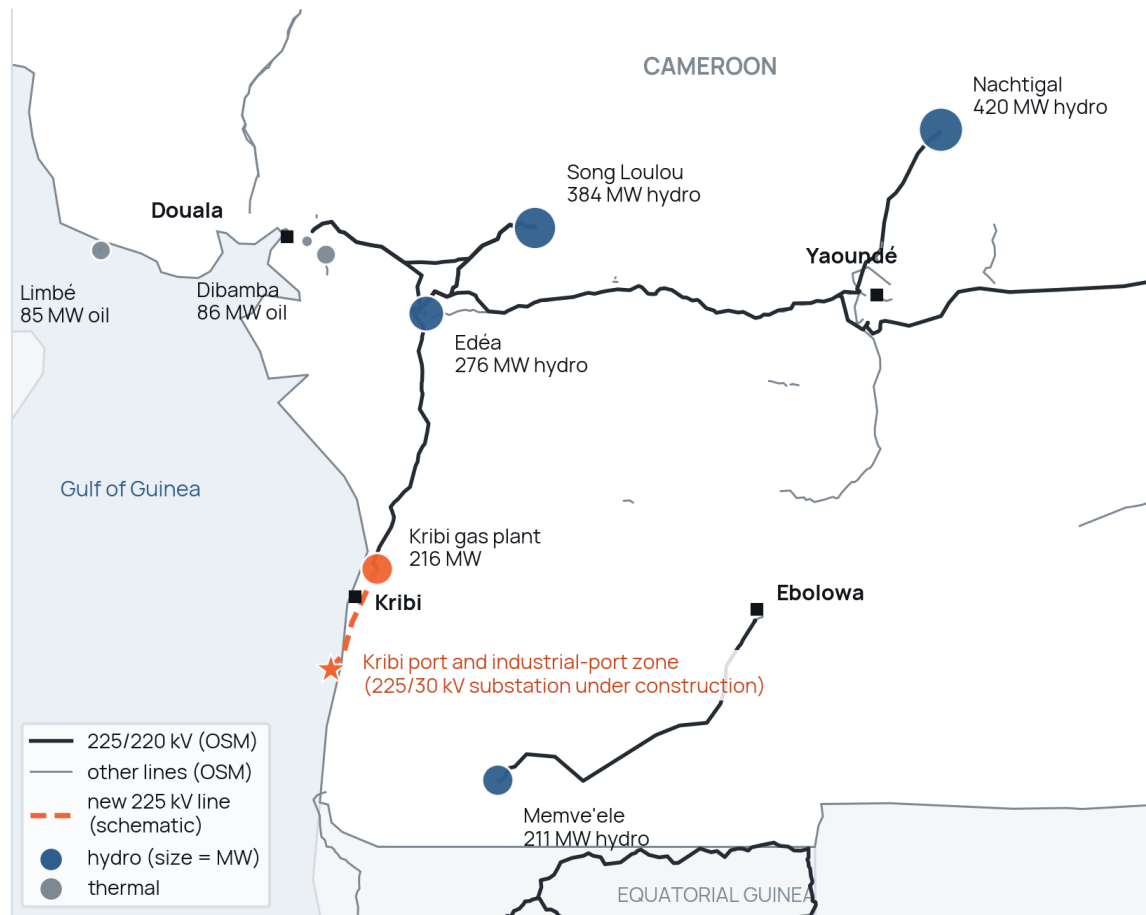
A supply contract for a large user should therefore distinguish between three things that national statistics blend together: the **firm capacity** the supplier guarantees, the **schedulable load** that the plant agrees to move within the day, with any emergency load-shedding capped in hours and events, and **planned outages** that are notified in advance. It should also oblige the supplier and the transmission operator to report reliability indicators at the plant's own connection point, so that both sides manage the same numbers. The regulator's target of 74.1 hours of average outage time per customer [S01] shows the direction of improvement for the system as a whole; a large user needs a target for its own node.

2.7 Kribi sits at the southern end of the southern grid

Figure 2.3 shows the southern grid as mapped in OpenStreetMap on 10 October 2026. The Sanaga plants feed a 225 kV ring around Douala, Edéa and Yaoundé. Kribi is connected to Edéa by a 225 kV line from the substation at the Kribi gas plant. Memve'ele connects towards Ebolowa and Yaoundé. The new 225 kV line from the Kribi gas plant to the port, due at the end of 2026, is shown schematically; it is the subject of Chapter 5.

Kribi sits at the southern end of the hydro-based southern grid

Southern Interconnected Grid as mapped in OpenStreetMap, 10 October 2026; the 400 kV Nachtigal line is not yet mapped



SOURCED Figure 2.3. Kribi sits at the southern end of the hydro-based southern grid. Lines and plants as mapped by OpenStreetMap contributors; plant sizes proportional to capacity. The map is not a complete record of the network: the 400 kV Nachtigal evacuation line, for example, is not yet mapped.

Source: OpenStreetMap contributors (ODbL), power features extracted via the Overpass API on 10 October 2026 [S60]; Natural Earth; PAK communications on the 225 kV line [S14][S15].

Being at the end of a radial branch has two consequences. The fault level (the short-circuit power available at a node, a measure of the network's electrical stiffness) is usually lower at the end of a branch than in the meshed core, which matters for an arc furnace (Chapter 4). And supply depends on few paths: a fault on the Kribi to Edéa line, or a shortfall at the Kribi gas plant, would be felt directly. The port authority describes the new arrangement as offering N-2 redundancy through the southern grid via Memve'ele, Nachtigal, Song Loulou, Edéa and the Kribi gas plant [S14], a claim that the grid operator's own studies should confirm for each large connection.

2.8 A steelworks would be one of the largest loads on the system

Set against the national system, an electric steelworks is large but not disproportionate (derived from the RC-1 balances [S07] and ARSEL 2025 [S01]):

- **Phase 1 (0.3 Mtpa)** would use about 289 to 302 GWh a year at 450 to 490 kWh/t in the furnace, 3.6% to 3.7% of 2025 generation, at an average load of 36 to 38 MW, about 3% of the 2025 peak. That is about 30% of the 969 GWh consumed by all six existing high-voltage customers in 2025.
- **Phases 1 and 2 (0.5 Mtpa)** would use about 422 to 443 GWh, 5.2% to 5.5% of 2025 generation, at an average of 53 to 55 MW.

- **Full build-out (1 Mtpa)** would use about 753 to 796 GWh, 9.3% to 9.8% of 2025 generation, at an average of 94 to 99 MW, 7.4% to 7.8% of the peak; its planned maximum demand of about 160 MVA (130 to 190) [S07] would equal about an eighth of the national peak.

A load of this size is visible in national dispatch. It needs to be planned with the grid operator rather than simply connected, and it will influence which new capacity is built.

2.9 The pipeline adds hydro and, possibly, gas

Cameroon's undeveloped hydro potential is large: the US International Trade Administration estimates it at about 115,000 GWh a year, of which about 4% is developed [S66]. The projects closest to realisation that matter for the south are:

- **Kikot-Mbebe**, a 500 MW hydro project on the Sanaga developed by EDF and the State, estimated at about 650 bn FCFA (about €990m), with works projected to start in 2027 and commissioning expected between 2031 and 2033 [S67][S68];
- **Grand Eweng**, a hydro scheme on the Sanaga proposed by the developer Hydromine under a 2019 letter of intent, of about 1,000 MW in a first phase and up to 1,800 MW in all; its current timetable is not in the public record [S69];
- **the extension of the Kribi gas plant** by 114 MW to its licensed 330 MW, for which the African Development Bank (AfDB) offered financing of 28.5 bn FCFA in 2020, but which has not been built [S22][S01];
- **two new gas-fired plants**, of 350 MW at Bekoko and 150 MW at Douala, announced in early 2025 subject to confirmation of gas availability by the national hydrocarbons company, SNH [S50].

The hydro projects would deepen the low-carbon character of the grid but add seasonal variability unless backed by storage. The gas projects would add firm capacity but depend on a gas supply that, after July 2026, must be re-planned (Chapter 6). For an electric steelworks the best outcome is both: hydro energy for most of the year and firm gas-fired capacity for dry periods and outages.

2.10 What this means for an electric steelworks at Kribi

THREE IMPLICATIONS

- **The grid is an asset for carbon and a risk for firmness.** At about 226 g CO₂e/kWh on average [S10], and much lower in a wet year, the grid gives an electric steelworks a carbon advantage over most competitors (Chapter 8). Firm delivery to Kribi, however, depends on new transmission and on the gas plant.
- **The location has a hidden strength.** The Kribi gas plant's engines sit about 40 km from the port platform. Reciprocating engines start and change output quickly, which makes them a natural partner for a fluctuating industrial load and for a hydro-dominated grid, provided their gas supply is assured.
- **Connection must be planned, not requested.** A steelworks of RC-1 size should be studied by the grid operator as a project in its own right: load flow, fault level, flicker and harmonics, protection and contingency, as set out in Chapters 4 and 5.

CHAPTER 3

LARGE USERS HAVE NO PUBLISHED TARIFF, SO THEIR PRICE DEPENDS ON NEGOTIATION RATHER THAN RULES

Cameroon's regulated electricity tariffs stop at 10 MW. The six legacy high-voltage customers paid an average of 18.4 FCFA/kWh in 2025, the highest published medium-voltage band costs about 44 FCFA/kWh all-in in 2026, and the regulator puts the cost-reflective average at 105 FCFA/kWh. A new large user therefore negotiates in the gap between a legacy price the utility cannot afford to extend and a system average that no steelworks could pay. A published large-user framework, built on the cost of serving a high-voltage baseload, would close that gap.

3.1 The regulated tariff grid stops at 10 MW

Medium-voltage tariffs are set by ARSEL. Decision No. 00000427 of 12 December 2022 fixed the tariffs, excluding taxes, for MV customers of the utility for 2023 to 2025, and the minimum thresholds for negotiation with "large accounts" (grands comptes) [S54]. The tariff has two parts: a monthly fixed charge per kW of subscribed power, and an energy charge per kWh. Within each band of subscribed power there are two regimes, one for customers who use their subscribed power for up to 400 hours a month and a cheaper one for those who use it longer, which rewards a high load factor [S03].

Table 3.1 Selected bands of the regulated medium-voltage tariff (2023 base) and their escalation

Subscribed power	Fixed charge (FCFA per kW per month)	Energy charge (FCFA/kWh)	Escalation on 1 January 2024, 2025, 2026
0 to 0.05 MW	none	80 to 95 off-peak; 125 peak	+5% a year
0.5 to 1 MW	5,500	55 to 95	+5% a year
3 to 4 MW	8,200 (up to 400 h/month); 7,000 (above)	35 to 40	+10% a year
9 to 10 MW (highest published)	18,090 (up to 400 h/month); 15,500 (above)	14 (up to 400 h/month); 9 (above)	+10% a year

Source: ARSEL, tariff tables under Decision No. 00000427, MV 2023 to 2025 [S03]; Decision No. 00000427 of 12 December 2022 [S54].

With the three annual increases of 10% applied, the 9 to 10 MW band in 2026 works out at about 43.7 FCFA/kWh all-in for a customer using its subscribed power 650 hours a month, or about US\$0.073/kWh at 600 FCFA per US\$ (derived from [S03]). This is the highest published reference price for an industrial customer in Cameroon.

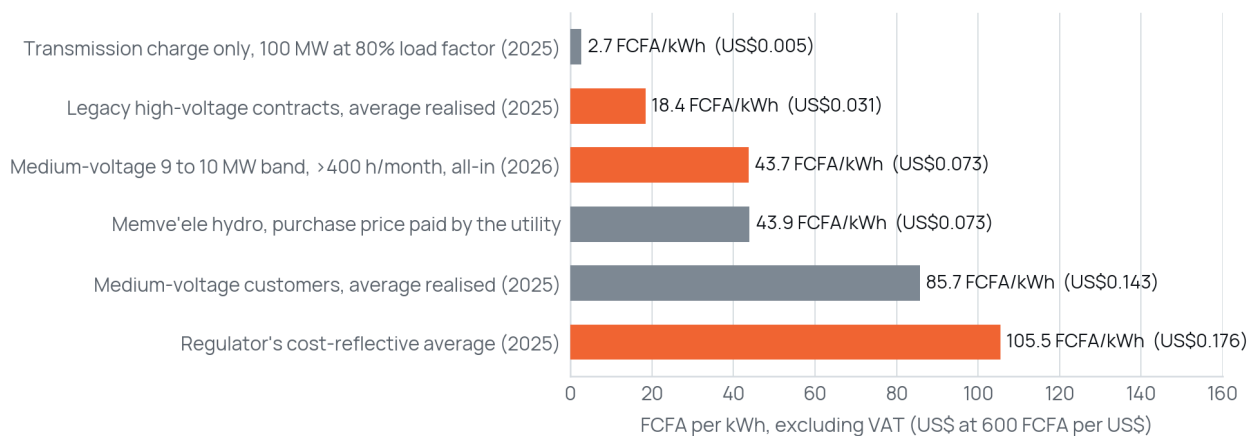
Above 10 MW, there is no published tariff. Supply to such customers is governed by bilateral high-voltage contracts, and the regulator's 2025 report notes that it revised "certain HT customers' contracts" during the year [S01]. A steelworks with an average load of 36 to 38 MW in Phase 1, and 94 to 99 MW at full build-out [S07], falls entirely outside the regulated grid.

3.2 What large users actually pay spans a factor of six

Figure 3.1 brings together the price benchmarks that bound a negotiation for a large load.

No price is published for a 50 MW load: the benchmarks span 18 to 105 FCFA/kWh

Electricity price benchmarks for large users in Cameroon; orange bars bracket a negotiated high-voltage contract



DERIVED Figure 3.1. No price is published for a 50 MW load: the benchmarks span 18 to 105 FCFA/kWh. Orange bars are the three benchmarks used in this paper to bracket a high-voltage contract; grey bars are context.

Source: ARSEL 2025 annual report [S01]; ARSEL MV tariff tables with escalation to 2026 [S03]; ARSEL decision of 19 December 2025 on the utility's allowed revenue [S04]; SONATREL transmission tariff, ARSEL Decision No. 0000017D [S53]. US\$ at 600 FCFA.

- **Legacy high-voltage contracts: 18.4 FCFA/kWh.** The six HV customers took 969.03 GWh in 2025 and paid 17.80 bn FCFA, an average of 18.4 FCFA/kWh (derived from [S01]). These contracts are old and the price is far below any current estimate of the cost of supply.
- **Medium-voltage customers, average realised: 85.7 FCFA/kWh** in 2025, and 85.6 for special MV customers (derived from [S01]).
- **The regulator's cost-reflective average: 105.46 FCFA/kWh** for 2025, against 83.46 FCFA/kWh actually collected from MV and LV customers; the difference was covered by a tariff subsidy of 96.99 bn FCFA [S04].
- **A wholesale reference: 43.93 FCFA/kWh**, the price the utility pays for the output of the Memve'ele hydro plant [S01].
- **Transmission only: about 2.7 FCFA/kWh.** SONATREL's tariff from 1 January 2025 combines a withdrawal charge of 16.18 m FCFA per MW per year, 0.41 FCFA per kWh and 4.48 m FCFA per connection point; for a 100 MW load at an 80% load factor this comes to about 2.7 FCFA/kWh (derived from [S53]).

The direction of policy is upward. Tariffs had been frozen from 2012 until early 2023, when HV prices rose by 6% to 10%, followed by MV increases from 1 January 2024 [S70]. In May 2026 the government proposed a further 15% rise for low-voltage business customers consuming more than 220 kWh a month, citing a sector deficit of 13 bn FCFA a month [S57].

3.3 Neither end of the range can be the answer for new industry

The legacy HV price cannot simply be extended to new loads. At 18.4 FCFA/kWh it is well below the 43.93 FCFA/kWh the utility pays for Memve'ele's hydro output [S01], and the sector is already in deficit, with a tariff subsidy of 96.99 bn FCFA in 2025 [S04] and 137 bn FCFA of unpaid invoices to independent producers in 2026 [S29]. Every additional MWh sold at the legacy price would widen that gap.

The cost-reflective average cannot be the answer either. It is an average across all customers, including the 2.19 million low-voltage connections and a distribution network that delivered only 72% of the energy it received in 2025 [S01]. A steelworks connected at 225 kV uses none of the distribution network, takes power around the clock, and can be metered and billed at a single point. Its cost of supply is structurally lower.

INDICATIVE COST STACK FOR A FIRM HIGH-VOLTAGE BASELOAD (DERIVED, NOT A TARIFF PROPOSAL)

- **Energy:** about 44 FCFA/kWh, taking the Memve'ele purchase price as a proxy for recent hydro [S01].
- **Transmission:** about 2.7 FCFA/kWh on the SONATREL tariff at 100 MW and an 80% load factor [S53].
- **Transmission losses:** about 2.5 FCFA/kWh at the 2025 transmission efficiency of 94.6% [S01].
- **Reserves, firmness and system services:** to be priced; the cost of keeping gas-fired capacity available for dry periods is the main unknown.

On this basis, a cost-reflective price for a firm HV baseload would sit at roughly half of the 105 FCFA/kWh system average before the cost of firmness is added. The figures are illustrative arithmetic on published inputs, not an estimate of any contract.

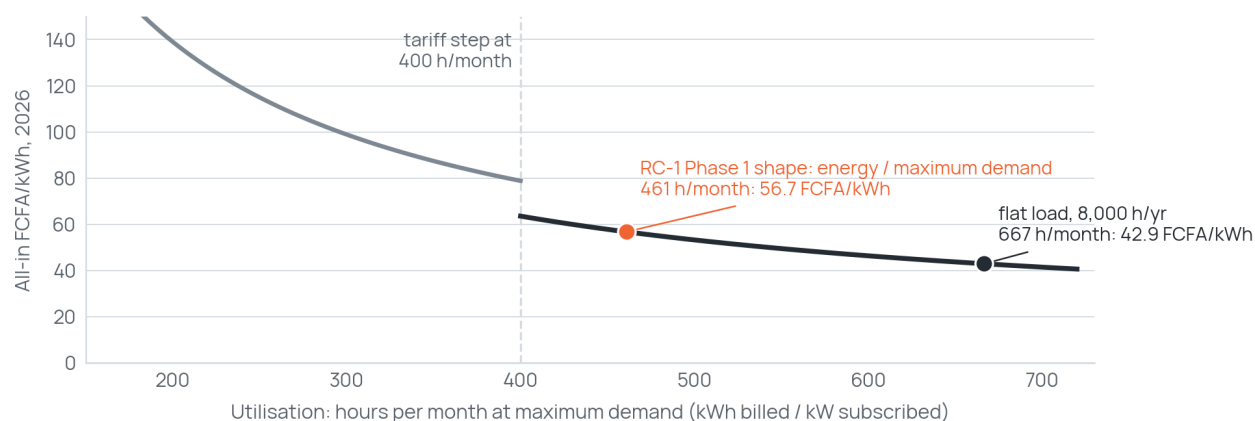
This is the core argument for a published large-user framework (Chapter 10). Without one, each large user negotiates alone, the utility has no basis for refusing an uneconomic price or for justifying a high one, and lenders cannot see how the price will evolve.

3.4 The tariff's structure matters as much as its level

Two customers with the same annual consumption can pay very different average prices under a capacity-plus-energy tariff, because the fixed charge is spread over fewer or more kWh. Figure 3.2 shows this for the structure of the 9 to 10 MW band.

Under a capacity-plus-energy tariff, a peaky load pays about a third more per kWh

All-in price of the 9 to 10 MW medium-voltage band as a function of utilisation (structure only; not applicable above 10 MW)



DERIVED Figure 3.2. Under a capacity-plus-energy tariff, a peaky load pays about a third more per kWh. The curve shows the all-in 2026 price of the 9 to 10 MW band against utilisation; the band does not apply above 10 MW and is used here only to illustrate the structure.

Source: ARSEL tariff tables [S03]; Cameroon Steel reference configuration RC-1 (planning estimate), balances and maximum demand [S07]; power factor 0.95 assumed.

A perfectly flat load of 8,000 hours a year uses its subscribed power about 667 hours a month and would pay about 42.9 FCFA/kWh. An arc-furnace plant is not flat. RC-1 Phase 1 would consume about 289 GWh a year against a planned maximum demand of 55 MVA [S07]; at a power factor of 0.95 that is about 5,530 hours a year at maximum demand, or 461 hours a month, and the same tariff structure would charge about 56.7 FCFA/kWh, some 32% more (derived). At the upper planning value of about 302 GWh, utilisation rises to about 481 hours a month and the premium falls to about 28%.

Three features of tariff design therefore matter to an electric steelworks:

1. **How maximum demand is measured.** A 15-minute averaging window smooths the furnace's second-by-second swings; a shorter window would penalise them. The window should be stated in the contract.
2. **Whether scheduled load is rewarded.** An arc furnace can time its heats within the day, for example to stay off the evening peak, with little loss of output. It cannot give up hours of melting without losing tonnage, because a single furnace needs most of the year to reach Phase 1's nameplate (Chapter 9). A tariff that rewards load scheduled away from the peak, through time-of-use energy prices or a lower capacity charge, turns that flexibility into a resource for a hydro-dominated grid; curtailment should be limited to rare, capped emergencies.
3. **How reactive energy is charged.** Arc furnaces draw large amounts of reactive power. Charges for reactive energy, and the obligation to compensate it locally, should be explicit, because they drive the size of the compensation equipment described in Chapter 4.

3.5 Four ways to contract, and a hybrid that combines them

Table 3.2 compares the contracting routes open to a large user in Cameroon.

Table 3.2 Contracting options for a large electricity user in Cameroon

Option	How it works	Price basis	Firmness	Main risks	Precedent in Cameroon
Regulated MV supply	Utility supply under the ARSEL grid	Published tariff, escalated yearly	Utility's normal service	Not available above 10 MW	About 2,500 MV customers [S01]
Bilateral HV contract with the utility	Negotiated supply at 225 kV or 90 kV	Negotiated; ARSEL oversight	Depends on contract terms and grid	Revision by the regulator; utility's finances	Six HV customers, legacy contracts [S01]
Power purchase from an independent producer, with transmission access	IPP sells to the user; SONATREL transmits for a regulated fee	Freely negotiated; transmission at the ARSEL tariff	Depends on the plant and back-up arrangements	Balancing and back-up rules; enforceability of access	Law No. 2011/022 allows IPPs to sell to eligible customers [S52]; Prometal moved to HV under a SONATREL access contract [S42][S01]
Captive generation	Own plant on site (gas engines, solar)	Own cost of fuel and capital	High for engines, low for solar alone	Gas allocation; licensing; cost	Not documented for steel
Hybrid (recommended)	Utility or IPP contract for energy, dedicated firm capacity at the Kribi gas plant, on-site solar	Blend of the above	High	Complexity; needs a framework	None yet

Source: as listed; Cameroon Steel analysis.

Bilateral utility contracts are the default today. Their weakness is that they are bespoke, and the regulator's revision of some HV contracts in 2025 [S01] shows that their terms are not immune to change.

Direct purchase from an independent producer has a legal basis. Law No. 2011/022 allows independent producers to sell to eligible customers, mainly industrial companies, at freely negotiated prices, provided their cost structures are submitted to ARSEL [S52]. SONATREL's published transmission tariff [S53] gives a price for using the network, and Prometal's high-voltage access contract with SONATREL shows that an industrial user can obtain transmission access [S42][S01]. What is not yet visible in the public record is a complete set of rules for wheeling: how imbalances are settled, who provides back-up when the producer's plant is unavailable, and how the producer's sales to the grid and to the industrial user are separated. ARSEL's website lists orders (arrêtés) establishing a connection code and a market code, but their texts could not be retrieved for this paper [S71], so whether they already cover these points is an open question (Chapter 11).

Captive generation gives the most control but needs gas, a licence and capital. For a steelworks at Kribi, the logical form of firm thermal capacity is not a new plant on site but a dedicated block at the existing Kribi gas plant, which holds a licence for 330 MW but has built 216 MW [S21][S22], or a contract for part of its existing output.

A LARGE USER NEEDS A FRAMEWORK, NOT A FAVOUR: PUBLISHED RULES FOR PRICE, FIRMLINESS AND WHEELING ARE WORTH MORE TO A LENDER THAN A LOW PRICE THAT MAY BE REVISED.

Cameroon Steel, White paper 05

3.6 Closing the gap over time

A large-user framework does not need to resolve every legacy contract at once. A credible transition would work in three steps.

First, **new large loads would be priced under the published framework from the start**, so that every new investment is made on a cost-based price that the utility can sustain. That stops the gap from widening.

Second, **legacy high-voltage contracts would converge to the framework over a published period**, at a pace that the customers concerned can absorb. The six legacy contracts consumed 969 GWh in 2025 at about 18.4 FCFA/kWh [S01]; bringing them gradually towards a cost-based level would reduce the need for the tariff subsidy, which reached 96.99 bn FCFA in 2025 [S04], and would put new and existing industrial users on the same footing.

Third, **the framework would be reviewed on a fixed cycle**, aligned with the regulator's annual decision on the utility's allowed revenue [S04]. Each review would update the indices in the price formula and publish the results, so that every large user can see how its price was set.

The framework would also make the system's cross-subsidies visible. Today, the gap between the cost-reflective average and the prices collected is covered by a single subsidy line [S04]. Separating the cost of serving high-voltage customers from the cost of serving low-voltage households would show who pays for what, which is a precondition for any sustainable reform of the sector's finances.

3.7 What lenders will look for in a power contract

A steelworks financed with long-term debt will need a power supply that lenders can rely on for the life of the loans. In practice that means:

- **Term and indexation:** a contract of at least the debt tenor, with a price formula indexed to identifiable costs (hydro purchase prices, gas prices, inflation) rather than revised at discretion.
- **Firmness and remedies:** a guaranteed capacity, a defined transmission path and compensation for curtailment beyond agreed limits.
- **Change in law and tariff revision:** protection, or at least predictability, if the regulator revises large-user contracts.
- **Counterparty strength:** the utility's capacity to perform. The State's buy-back of the utility [S28], its pre-emption of the Kribi and Dibamba thermal plants [S29] and the IMF's assessment of a high risk of debt distress [S72] all bear on how lenders will view a utility contract and whether they will seek State support or a direct contract with a generator.

The 2023 dispute between the steel producers and the regulator is a reminder of what is at stake. When higher tariffs for large accounts were announced, the steel industry feared an increase of about 30%; ARSEL answered that the average MV bill would rise by about 12%, equivalent to about 0.72% of production cost [S44][S45]. Whatever the true figure, the episode showed that large users had no published basis on which to anticipate their costs. A framework with published principles would remove that uncertainty for every large user, not only for steel.

CHAPTER 4

AN ARC FURNACE NEEDS A STRONG CONNECTION AND ITS OWN COMPENSATION, OR IT DISTURBS EVERYONE ELSE

An electric arc furnace draws power in rapid, irregular pulses that cause voltage flicker, harmonics and unbalance on the network. For a furnace of the RC-1 Phase 1 type, with a transformer of the 30 to 33 MVA class, a simplified screening suggests that the connection point needs a short-circuit power of roughly 2,000 to 7,000 MVA to stay within international flicker limits, depending on compensation. At the end of a radial branch such as Kribi, that means a direct high-voltage connection and dynamic compensation on site, sized from a measured study rather than assumed.

4.1 An arc furnace is the most disturbing load a grid can host

An arc furnace melts steel by striking electric arcs between graphite electrodes and the metal charge. During the first minutes of each charge, the "bore-in" phase, the electrodes burn down into cold, irregular scrap. Pieces collapse, the arcs lengthen and shorten many times a second, and from time to time an electrode touches the charge and creates a momentary short circuit. Once a liquid pool forms, the arcs become more stable; during the final refining on a flat bath, the load is nearly steady. Then the power is switched off for tapping and recharging, and the cycle starts again.

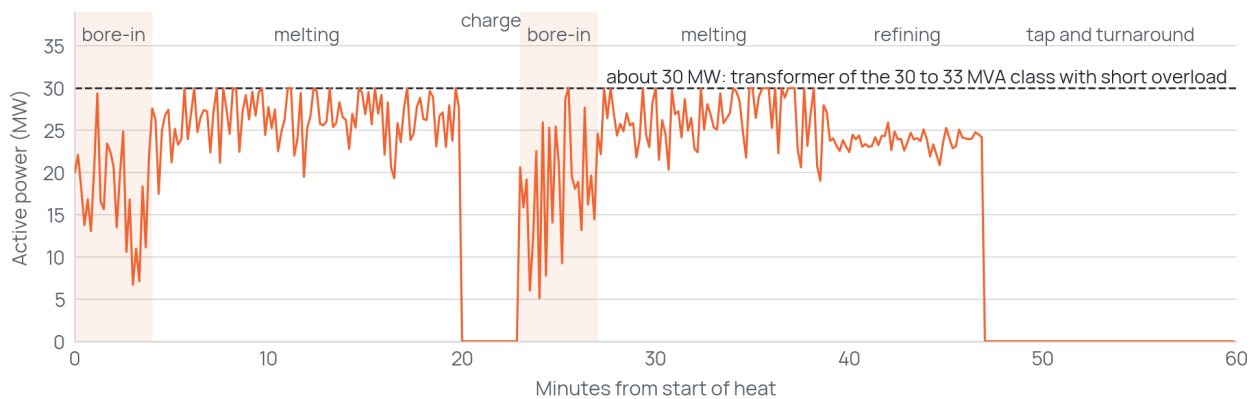
Figure 4.1 illustrates that cycle for one heat of a furnace of the 40 t class with a transformer of the 30 to 33 MVA class, the classes planned for RC-1 Phase 1 [S07]. The figure is a constructed illustration rather than a measurement, but its shape is typical: two bore-in periods of violent fluctuation, two melting periods near the transformer's limit, a steadier refining period and a power-off interval.

These fluctuations travel back into the network and cause four kinds of disturbance:

- **Flicker.** Rapid voltage fluctuations make lamps flicker. The human eye is most sensitive to fluctuations at around 8 to 10 per second, which is where arc furnaces emit strongly. Flicker is measured with a standard instrument and expressed as short-term severity (Pst, over 10 minutes) and long-term severity (Plt, over 2 hours); a value of 1.0 corresponds to the level at which flicker becomes irritating to many people [S13].
- **Harmonics.** The arc does not draw a clean sine-wave current. The distorted current creates voltage harmonics that overheat transformers and motors and disturb electronic equipment. Rectifiers for rolling-mill drives and induction heating add further harmonics of their own.
- **Unbalance.** The three phases of the furnace draw unequal currents, which unbalances the network voltage and heats rotating machines, including generators.
- **Reactive power swings.** The furnace circuit is highly inductive, so it draws large and fluctuating amounts of reactive power. Voltage falls when reactive demand rises, which lengthens melting time inside the plant and degrades supply for neighbours.

An arc furnace draws power in violent pulses, worst during bore-in

One 60-minute heat of about 40 t, 10-second resolution (illustrative; 17.9 MWh, about 447 kWh/t)



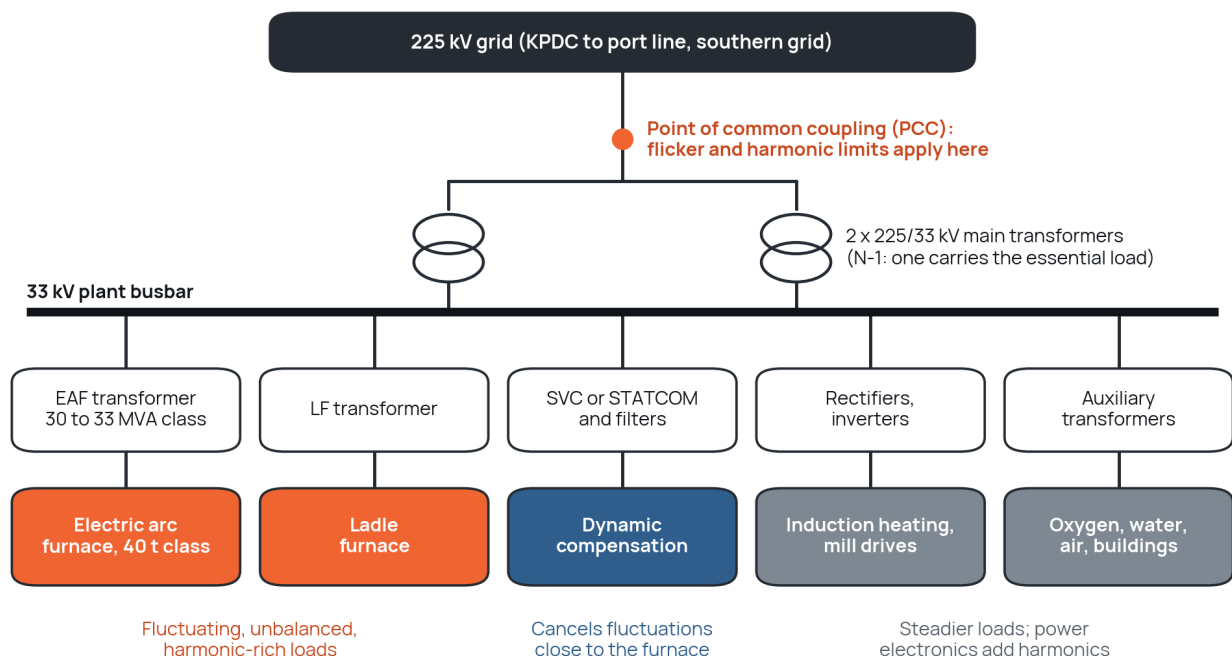
ILLUSTRATIVE Figure 4.1. An arc furnace draws power in violent pulses, worst during bore-in. Illustrative 60-minute heat of about 40 t at 10-second resolution, with active power capped at about 30 MW; real fluctuations are faster still, at frequencies of a fraction of a hertz to tens of hertz. The round 60-minute cycle and the cap are illustrative; White paper 03 derives planning cycles of about 55 to 59 minutes at a lower average power.

Source: Cameroon Steel illustration built from RC-1 planning values (furnace of the 40 t class, transformer of the 30 to 33 MVA class, 450 kWh/t) [S07].

The arc furnace is not the only large load in a steelworks. The ladle furnace behaves like a smaller arc furnace without the bore-in phase; induction heaters and mill drives are steady but harmonic-rich; oxygen plants and pumps are conventional motor loads. Figure 4.2 shows how these loads are typically arranged around one plant busbar, with the compensation equipment connected next to the furnace.

The arc furnace and its compensator share one busbar, behind a strong 225 kV connection

Simplified single-line diagram of an electric steelworks of the RC-1 Phase 1 type (illustrative)



ILLUSTRATIVE Figure 4.2. The arc furnace and its compensator share one busbar, behind a strong 225 kV connection. Simplified single-line diagram; furnace and transformer classes are RC-1 Phase 1 planning values.

Source: Cameroon Steel, from RC-1 Phase 1 planning values (an EAF of the 40 t class with a transformer of the 30 to 33 MVA class, a ladle furnace, rectifier-fed mill drives and induction heating, a 225/33 kV main substation) [S07].

4.2 The mills and induction heaters add a different kind of disturbance

The arc furnace is the dominant source of flicker, but it is not the only source of disturbance in an electric steelworks. Rolling-mill motors are driven through power-electronic converters, and induction heaters are supplied through rectifiers and inverters. These loads are much steadier than the furnace, but they draw currents rich in characteristic harmonics. A six-pulse rectifier, for example, produces harmonics at orders 5, 7, 11 and 13 and so on (orders six times an integer, plus or minus one); twelve-pulse arrangements cancel the lowest of these. RC-1 Phase 1 includes rectifier-fed drives for its wire-rod line [S07], and induction heating for 300,000 t of billets a year would add a steady load of about 11 MW of power-electronic equipment (derived from the planning value of 300 kWh/t over 8,000 hours).

The furnace and the drives interact. The furnace emits a broad spectrum of harmonics, including even orders, during bore-in; the drives emit a narrow set of characteristic ones continuously. The filter banks of the furnace's compensation system must therefore be designed together with the harmonic profile of the mills, and both must be checked against the network's own resonances. This is why the connection study recommended at the end of this chapter covers the whole plant, not the furnace alone.

4.3 The limits are set at the point where the plant meets the public network

Power-quality limits apply at the point of common coupling (PCC), the point on the public network nearest to the plant at which other customers are, or could be, connected. The international reference for fluctuating loads connected at medium, high and extra-high voltage is the IEC technical report 61000-3-7, whose second edition (2008) sets out how a network operator should allocate flicker emission limits to individual installations so that the total stays within planning levels [S13]. For harmonics, the most widely used reference is IEEE Standard 519, last revised in 2022 [S73].

KEY POWER-QUALITY REFERENCES (INTERNATIONAL; CAMEROON'S OWN CODE TO BE CONFIRMED)

- **Flicker planning levels, IEC TR 61000-3-7:2008:** indicative Pst of 0.9 and Plt of 0.7 in MV networks; Pst of 0.8 and Plt of 0.6 in HV and EHV networks [S13]. Each installation receives a share of these levels according to its share of the network's capacity.
- **Voltage harmonic limits at the PCC, IEEE Std 519-2022:** from 1 kV to 69 kV, 3.0% for any single harmonic and 5.0% total harmonic distortion (THD); from 69 kV to 161 kV, 1.5% and 2.5%; above 161 kV, which includes 225 kV, 1.0% and 1.5% [S73].
- **Summation of several furnaces:** flicker from several independent sources is commonly combined with a cubic law, so two identical furnaces produce about 1.3 times the Pst of one rather than twice [S13].
- **Cameroon:** ARSEL lists a connection code among its regulatory texts [S71], but whether it sets flicker, harmonic and unbalance limits for large fluctuating loads could not be verified for this paper.

These references matter for two reasons. They define what the grid operator can require of a steelworks, and they define what the steelworks can demand of the network in return: a connection strong enough that reasonable compensation brings emissions within limits.

4.4 A furnace of the 30 to 33 MVA class needs a 2,000 to 7,000 MVA connection

The electrical stiffness of a network node is measured by its short-circuit power (S_{sc}), the power that would flow into a fault at that point. A stiff node, with high S_{sc} , barely notices a fluctuating load; a weak node amplifies it. To screen an arc furnace, this paper uses a simplified relation of its own, which takes the 99th-percentile short-term flicker as proportional to the ratio of two short-circuit powers:

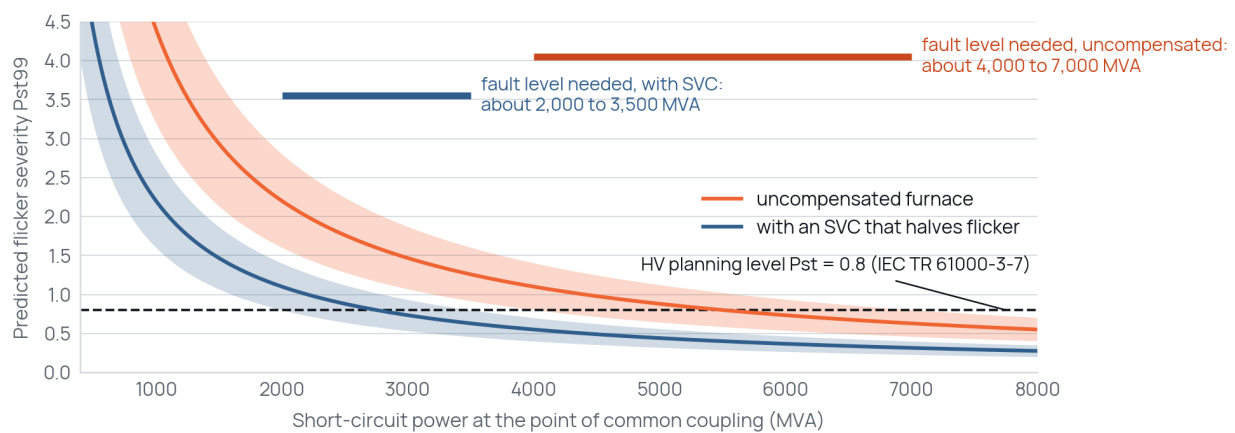
$$Pst99 = Kst \times SscF / SscPCC$$

where SscF is the short-circuit power of the furnace circuit (the power that flows when the electrodes are short-circuited on the charge, set by the furnace transformer, reactor and secondary circuit), SscPCC is the short-circuit power at the point of common coupling, and Kst is an empirical factor that reflects the type, weight and density of the scrap. According to the International Union for Electricity Applications (UIE), as cited in [S12], Kst lies between 48 and 85.

For RC-1 Phase 1, this paper assumes SscF at about twice the rating of a transformer of the 30 to 33 MVA class (assumed; the usual range is 1.5 to 2.5 times the rating), and gives the results to one significant figure. Figure 4.3 shows the resulting flicker estimate against the short-circuit power at the PCC.

A furnace of the 30 to 33 MVA class needs a 2,000 to 7,000 MVA connection to stay within flicker limits

Predicted short-term flicker Pst99 = Kst x SscF / SscPCC, Kst 48 to 85, SscF about twice the rating of the 30 to 33 MVA class (screening estimate)



DERIVED Figure 4.3. A furnace of the 30 to 33 MVA class needs a 2,000 to 7,000 MVA connection to stay within flicker limits. Screening estimate with Kst between 48 and 85; the blue band assumes a static var compensator that halves flicker.

Source: simplified screening relation by Cameroon Steel (Annex A); Kst range according to the UIE, as cited in US Patent 10,145,612 (Siemens, 2018), which also notes that SVCs reduce generated flicker by approximately half [S12]; HV planning level from IEC TR 61000-3-7:2008 [S13]; furnace transformer class from RC-1 [S07]; SscF assumption by Cameroon Steel.

Two results follow (derived):

- **Without compensation**, keeping Pst99 below the HV planning level of 0.8 would require a short-circuit power at the PCC of about 4,000 to 7,000 MVA, more than a hundred times the furnace rating.
- **With a static var compensator** that halves flicker, as reported for SVCs in practice [S12], the requirement falls to about 2,000 to 3,500 MVA.

These are screening numbers, not design values: actual emission depends on the furnace's charging practice, electrode control and secondary circuit, and the share of the planning level the network operator allocates to the plant may be well below 0.8. But they show the order of magnitude. A furnace of this size is a demanding load for any node that is not in the meshed core of a strong grid.

At full build-out, with two or three melt lines, the flicker from several furnaces would combine. With the cubic summation law, two identical furnaces would emit about 26% more flicker than one [S13], so the compensation and connection must be sized for the final configuration, not only for Phase 1.

4.5 A 30 kV feeder would be too weak; a 225 kV bay is needed

The fault level at Kribi's 225 kV node has not been published and is the first number a connection study must establish (Chapter 11). What can be said now is that connecting the furnace through the port platform's 225/30 kV substation would be the weakest option. A 30 kV busbar fed by three 60 MVA transformers would typically offer a short-circuit power of the order of 1,000 to 1,500 MVA, even with a stiff 225 kV source behind it (derived, assuming transformer impedances of 12% to 18%). That is below even the compensated requirement estimated above, and every other tenant on the same 30 kV network would share the disturbance.

The logical arrangement is a dedicated 225 kV bay at the port substation, a short 225 kV link to the steelworks and a 225/33 kV substation on site, with the furnace and its compensation on the plant's own 33 kV busbar, as RC-1 provides for with its planned 225/33 kV substation [S07]. The PCC is then at 225 kV, where the fault level is highest and where the other users are furthest away electrically. Chapter 5 compares the connection options in detail.

4.6 Compensation removes most of the disturbance close to the furnace

Several measures reduce a furnace's impact on the network. They are complementary rather than alternatives, and the right combination depends on the measured fault level and the share of the planning level allocated to the plant (Table 4.1).

Table 4.1 Measures that reduce the network impact of an arc furnace

Measure	What it does	Effect on flicker	Effect on harmonics and power factor	Remarks
High-voltage connection (225 kV PCC)	Connects where the network is stiffest	Large: flicker scales inversely with fault level	Harmonic voltages also lower	Precondition at a weak node
Static var compensator (SVC): thyristor-controlled reactor plus filter banks	Absorbs the furnace's reactive power swings within about a cycle	Roughly halves flicker [S12]	Filter banks correct power factor and absorb harmonics	Mature; large footprint
STATCOM (voltage-source converter)	Injects or absorbs reactive current electronically, faster than an SVC	Larger reduction than an SVC is claimed by suppliers	Can actively cancel some harmonics	Higher cost; smaller footprint
Passive harmonic filters alone	Tuned capacitor-reactor branches	Little or none	Correct power factor; absorb harmonics	Risk of resonance if not studied
Series reactor and electrode control	Stabilise the arc inside the furnace	Moderate, at source	Improves power factor in operation	Part of furnace design
Charging practice and scrap preparation	Denser, cleaner charge; continuous charging	Lower Kst, especially at bore-in	Indirect	Links to the metallic-charge strategy
Dedicated generation nearby	Fast-acting engines supply reactive power	Some support to voltage	Some support	Kribi gas plant engines are about 40 km away

Source: US Patent 10,145,612 [S12]; IEC TR 61000-3-7 [S13]; EC ICIT, Consteel fact sheet [S38]; Cameroon Steel analysis.

For a plant of RC-1's size at a node of uncertain strength, the prudent assumption is that dynamic compensation, SVC or STATCOM, will be required from Phase 1, with harmonic filters designed together with it, and that space and budget should be reserved for extending it when further melt lines are added. RC-1 reserves space for its 225/33 kV substation and reactive compensation, with room to extend both [S07].

4.7 A weak grid raises further issues beyond flicker

Flicker is the best-known problem, but a large fluctuating load on a modest system raises others that the connection study must address:

- **Frequency and reserves.** In Phase 1, the furnace would switch about 20 to 30 MW on and off roughly once an hour (Figure 9.2). On a system with a peak of 1,278 MW [S01], each step is about 2% of peak. The grid needs fast reserves to absorb these steps, and a sudden trip of the whole plant would remove up to about 50 MW at once. Hydro units and gas engines can provide such reserves, but the obligation must be planned and paid for.
- **Resonance.** Capacitor banks for power-factor correction can resonate with the network's inductance at a harmonic frequency and amplify the very harmonics they are meant to absorb. A harmonic impedance study of the Kribi node is needed before filters are specified.
- **Protection.** Fault currents, relay settings and the coordination between the plant's protection and SONATREL's must be designed together, especially if the plant later adds on-site generation.
- **Voltage stability.** A heavily loaded radial line with a large inductive load at its end can suffer voltage collapse after a contingency. Reactive support at the load end is part of the answer.

4.8 The steelworks and the grid operator should own the study together

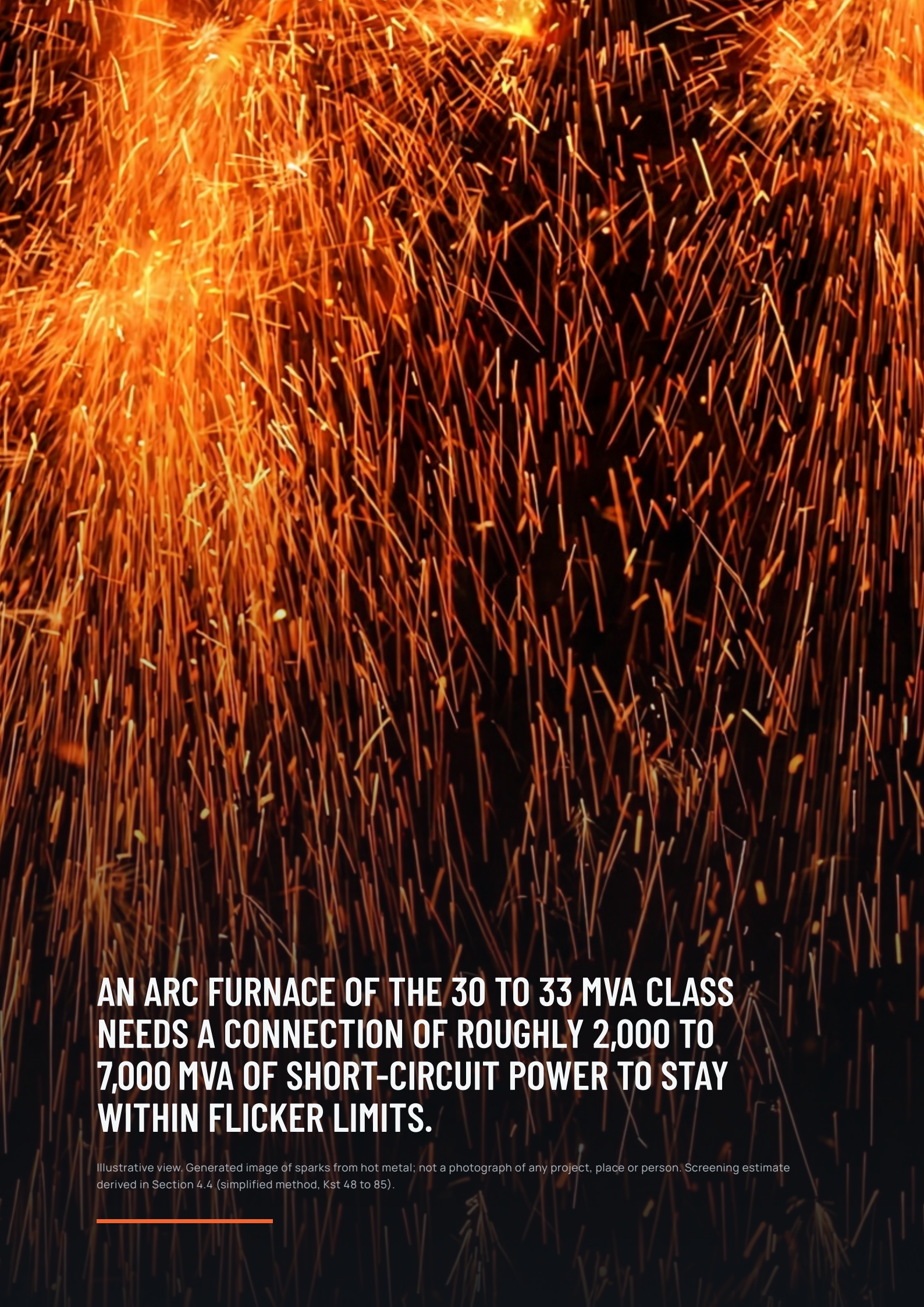
Cameroon already hosts an arc-furnace steelworks: Prometal's melt shop in Douala, supplied at high voltage through a dedicated 50 MVA transformer under an access contract with SONATREL [S43][S42][S01]. Its power-quality arrangements are not in the public record, but its experience is the closest domestic precedent and should inform the grid code for fluctuating loads (Chapter 10).

For a new steelworks at Kribi, a power-quality programme would include five steps:

1. **Measure the network.** Minimum and maximum fault levels at the Kribi 225 kV node under normal and contingency conditions, background flicker and harmonics, and a harmonic impedance scan.
2. **Allocate emission limits.** The grid operator assigns the plant its share of the flicker and harmonic planning levels, following the IEC TR 61000-3-7 approach [S13].
3. **Design compensation against the allocation.** Size the SVC or STATCOM and filters to meet the allocated limits for the final configuration, with guarantees measured at the PCC.
4. **Verify at commissioning.** Measure emissions with the furnace at full production and adjust before acceptance.
5. **Monitor continuously.** Install permanent power-quality meters at the PCC with data shared with the grid operator, so that problems are seen and solved jointly.

POWER QUALITY IS A SHARED ASSET: THE STEELWORKS PAYS FOR COMPENSATION, THE GRID OPERATOR PROVIDES A STRONG CONNECTION, AND BOTH MEASURE.

Cameroon Steel, White paper 05



**AN ARC FURNACE OF THE 30 TO 33 MVA CLASS
NEEDS A CONNECTION OF ROUGHLY 2,000 TO
7,000 MVA OF SHORT-CIRCUIT POWER TO STAY
WITHIN FLICKER LIMITS.**

Illustrative view. Generated image of sparks from hot metal; not a photograph of any project, place or person. Screening estimate derived in Section 4.4 (simplified method, Kst 48 to 85).

CHAPTER 5

KRIBI'S NEW 225 KV SUPPLY CAN CARRY A FIRST-PHASE STEELWORKS; 1 MTPA NEEDS ITS LATER STAGE AND A DEDICATED BAY

The Port Autonome de Kribi (PAK) is building a 42 km double-circuit 225 kV line from the Kribi gas plant to a new 225/30 kV substation on the port platform, rated for 100 MW at first and 330 to 400 MW later, with commissioning planned for the end of 2026. A first-phase steelworks with a 55 MVA maximum demand would fit within the first stage, which the whole port platform shares, but would take about half of it; a 1 Mtpa works, at about 160 MVA, needs the later stage. The arrangement that best protects the zone's other tenants is a dedicated 225 kV bay feeding the steelworks' own substation.

5.1 The port is bringing high-voltage power to its industrial zone

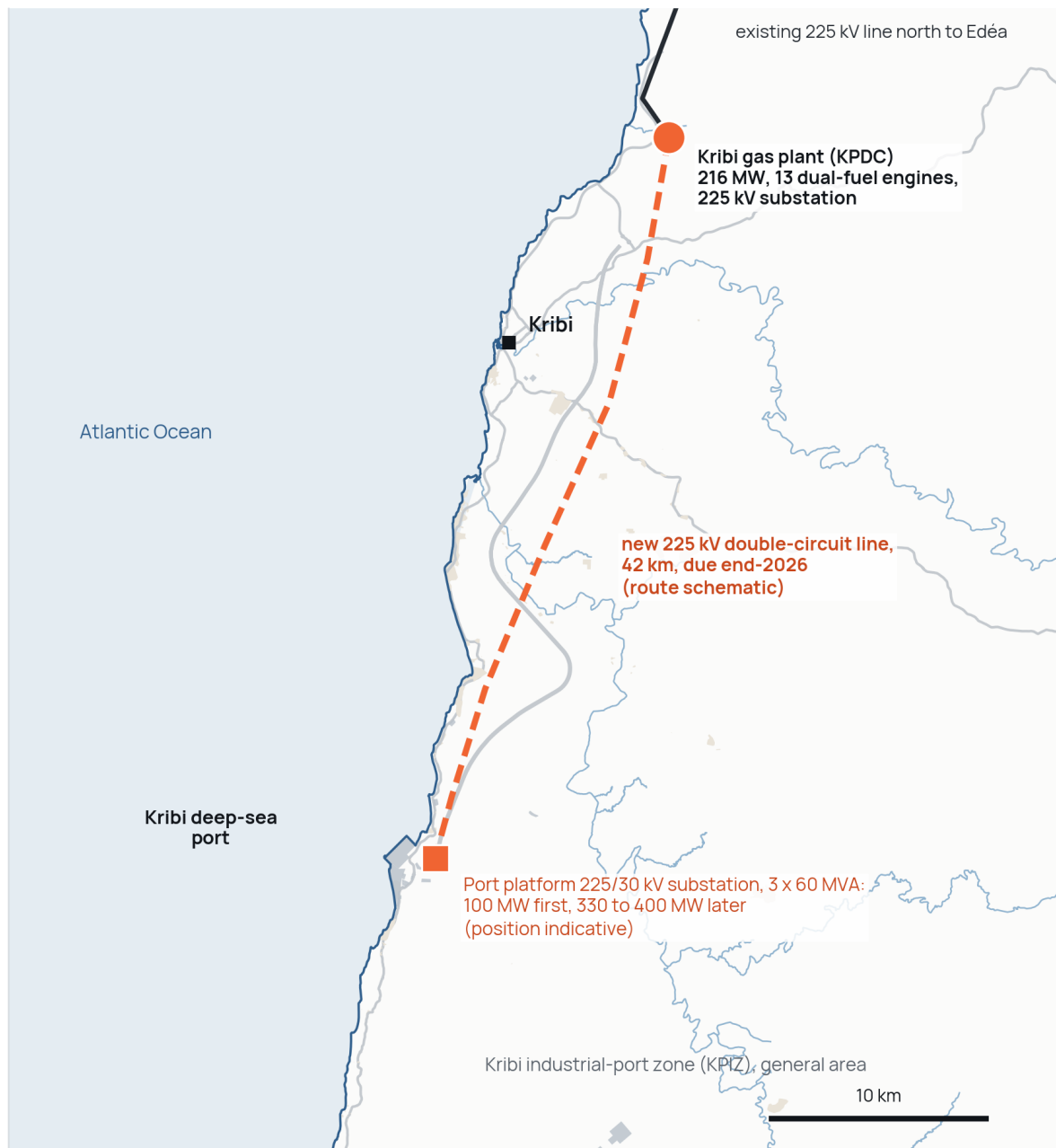
Until now, the Kribi port platform has depended on a weak local supply. In May 2025, a business daily reported that only about 13 MW of the 176 MW of local thermal capacity was available to the Kribi area, the rest being exported into the southern grid [S24]. That was not enough for heavy industry, and the port authority decided to build its own high-voltage link.

On 6 August 2025, PAK launched the works for a **225 kV double-circuit line, 42 km long, from the Kribi gas plant (KPDC) to the port**, with a **225/30 kV substation of three 60 MVA transformers**. PAK describes the capacity as **100 MW immediately and 330 to 400 MW at a later stage**, at a cost of about 35 bn FCFA, with commissioning planned for the end of 2026, and claims N-2 redundancy through the southern grid via Memve'ele, Nachtigal, Song Loulou, Edéa and the Kribi gas plant [S14]. On 19 August 2026, the Minister of Water and Energy (MINEE) visited the substation, the line and a new water plant that is due to produce from early 2027 [S15]. A planning ministry (MINEPAT) mission in April 2026 also highlighted the substation as a driver of the zone's industrial development [S74].

Below the substation, PAK tendered 3.5 bn FCFA of servicing works in May 2026 for 20 ha at Mboro: a 30 kV network and substation, potable water, fibre, roads, drainage, wastewater treatment and solar street lighting, to be built over one year from PAK's 2026 to 2028 budget [S75].

A dedicated 225 kV line will bring firm supply 42 km from the Kribi gas plant to the port

Kribi power infrastructure on an OpenStreetMap base (coast, roads, land use); no site boundaries are shown



SOURCED **Figure 5.1.** A dedicated 225 kV line will bring firm supply 42 km from the Kribi gas plant to the port. The route of the new line is drawn schematically between its two published end points; the port substation's position is indicative. No site boundaries are shown.

Source: OpenStreetMap contributors (ODbL) [S60]; PAK, "Kribi franchit la ligne électrique 225 kV" (6 August 2025) and "Énergie et infrastructures: un nouvel élan pour la compétitivité du Port de Kribi" (19 August 2026) [S14][S15]; PAK, Guide du Port de Kribi (2020) for the port position [S76]; Engineering News (22 August 2022) for the KPDC engines [S64].

This infrastructure serves a zone with explicit industrial ambitions. The Kribi Port Industrial Zone (KPIZ), managed by KPIZ S.A. with PAK and private partners AGL, Arise IIP and Belmont, was launched in February 2026 over about 4,000 ha [S77][S78]. Its development clusters include "steelmaking linked to mineral exports" (sidérurgie liée aux exportations minières) [S23], and 53 companies had been authorised to settle in the port's industrial and logistics zone between 2018 and May 2025 [S24]. Cameroon Steel's steel complex at Mboro, whose foundation stone was laid on 30 December 2024 by the Prime Minister representing the Head of State, is one of the projects that the new supply is meant to serve [S08][S79].

Table 5.1 Kribi power infrastructure relevant to an electric steelworks

Asset	Key parameters	Status (October 2026)	Source
Kribi gas-fired plant (KPDC)	216 MW installed, 13 dual-fuel engines; licence 330 MW; owned 56% Globeleq, 44% State (State pre-emption under way)	Operating; 559.67 GWh in 2025 (about 30% capacity factor)	[S21][S64][S01][S29]
KPDC to Edéa 225 kV line	Links Kribi to the southern grid	Operating	[S60]
KPDC to port 225 kV line	Double circuit, 42 km	Under construction; commissioning planned end-2026	[S14][S15]
Port platform substation	225/30 kV, 3 x 60 MVA; 100 MW first, 330 to 400 MW later	Under construction	[S14][S15]
30 kV network at Mboro	Network and substation for 20 ha of serviced land	Tendered May 2026; one-year works	[S75]
Water plant for the port platform	Intake and treatment	Production planned early 2027	[S15]
KPDC extension to 330 MW	+114 MW within the existing licence	Not built; AfDB financing offered in 2020	[S22][S01]

Source: as listed.

5.2 Phase 1 fits within the shared first stage; the full works needs the later stage

Figure ES.1, in the executive summary, sets the steelworks' demand against this infrastructure. The numbers can be summarised simply (derived from RC-1 [S07] and PAK [S14]):

- **Phase 1 (0.3 Mtpa)**: average load 36 to 38 MW and planned maximum demand 55 MVA (45 to 65). At maximum demand the plant would take about half of the 100 MW first stage. Three 60 MVA transformers give 180 MVA in total and about 120 MVA with one transformer out of service (derived), so Phase 1 could be supplied with transformer redundancy, but would leave limited room for other large tenants in the first stage.
- **Phases 1 and 2 (0.5 Mtpa)**: average load 53 to 55 MW. A second melt line would add a second furnace; maximum demand has not been estimated in RC-1, but it would approach or exceed what the first stage can supply alongside other users.
- **Full build-out (1 Mtpa)**: average load 94 to 99 MW and planned maximum demand 160 MVA (130 to 190), about 40% to 50% of the later 330 to 400 MW stage.

The practical conclusion is that a steelworks should be planned into the substation's later stage from the start, even if Phase 1 is supplied from the first stage. The sequencing risk is not that the grid arrives too late (the line and substation are due at the end of 2026, before any steelworks could be built) but that the first stage is committed to other tenants and the later stage is not financed in time.

42 km

225 kV double-circuit line, Kribi gas plant to port

3 x 60 MVA

225/30 kV transformers at the port substation

100 MW

First-stage capacity; 330 to 400 MW later

55 MVA

RC-1 Phase 1 planned maximum demand (planned, indicative)

Source: PAK [S14][S15]; Cameroon Steel reference configuration RC-1 (planning estimate) [S07].

5.3 The steelworks would share the substation with a growing industrial zone

The new supply is not built for one customer. The port's industrial zone already hosts companies such as Atlantic Cocoa, whose contract in 2018 was the first, Cimpor, Cadyst and All Bitumen [S24]. All Bitumen holds about 60 ha for a bitumen plant and received a refining licence and tax incentives in 2026 [S25]. An industrial buyer at Kribi began purchasing natural gas from SNH in the second half of 2025, taking 3.088 bcf in two quarters [S05], which shows that energy-intensive industry is already present. PAK has also signed a memorandum of understanding, on 4 November 2025, for a mineral terminal whose completion its Director General, speaking in March 2026, expected within five to six years [S80][S81] (White paper 02, Chapter 2), and plans an agricultural terminal of about 50 bn FCFA on 9.2 ha, with construction from 2027 and operations from 2029 [S82].

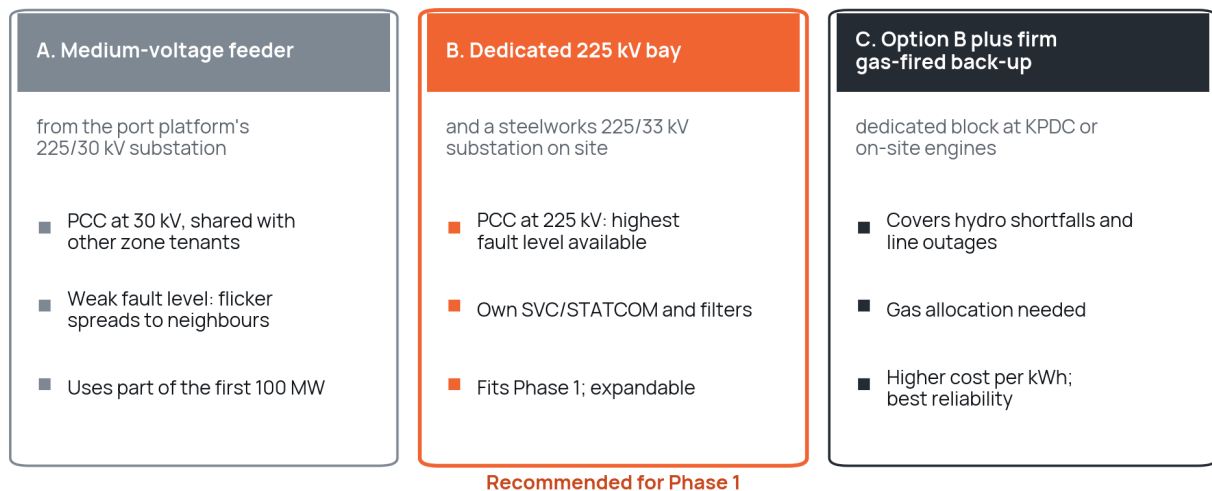
Each of these users will draw on the same 100 MW first stage, and several will add electrical loads that are sensitive to voltage quality, such as process controls, refrigeration and motor drives. That is a further reason to connect an arc furnace at 225 kV rather than through the zone's 30 kV network, and to plan the substation's later stage on the basis of a register of all prospective tenants rather than one project at a time.

5.4 Three ways to connect the steelworks, and why a dedicated bay is best

A steelworks at Mboro could connect to the new infrastructure in three ways (Figure 5.2, Table 5.2).

A dedicated 225 kV connection keeps the furnace's disturbances off the zone's shared network

Three ways to connect an electric steelworks at Kribi (illustrative comparison)



ILLUSTRATIVE Figure 5.2. A dedicated 225 kV connection keeps the furnace's disturbances off the zone's shared network. Option B is the recommended arrangement for Phase 1; option C adds firm gas-fired capacity for later phases.

Source: Cameroon Steel analysis; PAK substation parameters [S14].

Option A, a medium-voltage feeder from the port's 225/30 kV substation, is the cheapest to build, but it places the point of common coupling at 30 kV, where the fault level is lowest and where other tenants are connected. Chapter 4 showed that a 30 kV busbar fed by three 60 MVA transformers would typically offer 1,000 to 1,500 MVA of short-circuit power, below what even a compensated furnace of the 30 to 33 MVA class needs. The flicker and harmonics of the arc furnace would be shared with every other user of the zone's 30 kV network.

Option B, a dedicated 225 kV bay at the port substation feeding the steelworks' own 225/33 kV substation, moves the point of common coupling to 225 kV. RC-1 already reserves space for a 225/33 kV substation with reactive compensation [S07]. This option gives the furnace the stiffest available connection, keeps its disturbances off the zone's distribution network, and lets the steelworks own and operate its compensation. It also lets the steelworks' load grow into the substation's later stage without rebuilding the zone's 30 kV network.

Option C combines B with firm gas-fired capacity: either a contract for a dedicated part of the Kribi gas plant's output or an extension within its 330 MW licence, or, less efficiently, engines on site. It is the most reliable arrangement, and the one most likely to be needed when the works grows beyond Phase 1, because it covers both dry-season hydro shortfalls and outages on the transmission path.

Table 5.2 Comparison of connection options for an electric steelworks at Kribi

Criterion	A. 30 kV feeder	B. Dedicated 225 kV bay (recommended for Phase 1)	C. B plus firm gas-fired capacity
Point of common coupling	30 kV, shared	225 kV	225 kV
Fault level available	Lowest (of the order of 1,000 to 1,500 MVA)	Highest available at Kribi (to be measured)	As B, plus support from nearby engines
Effect on other tenants	Shares flicker and harmonics	Disturbance mitigated at 225 kV	As B
Capacity	Limited to part of the first 100 MW	Grows into the 330 to 400 MW stage	As B, plus dedicated firm MW
Security of supply	Depends on 30 kV network	N-1 on line and transformers	N-1 plus local generation
Gas required	No	No	Yes, for the dedicated capacity
Who builds	Zone network	Steelworks substation; bay at port substation	As B; generator for the gas block
Fit with RC-1 phases	Unsuitable for an arc furnace	Phase 1 onward	Phases 2 and 3

Source: Cameroon Steel analysis; fault levels derived in Chapter 4; PAK [S14]; Cameroon Steel reference configuration RC-1 (planning estimate) [S07].



ILLUSTRATIVE Illustrative view. Generated image of a high-voltage line on lattice towers crossing forested hills; not a photograph of any project, place or person. The 225 kV link is the steelworks' single most important energy asset.

5.5 Redundancy must be checked node by node, and essential loads need their own back-up

PAK describes the new supply as N-2 secure [S14]. That is a strong claim, and it should be confirmed by the grid operator's studies for each large connection. The double-circuit line gives redundancy against the loss of one circuit, and three transformers give redundancy against the loss of one transformer. But both circuits share the same towers and corridor, and the upstream supply depends on the Kribi gas plant and on the single 225 kV path from Kribi to Edéa visible in the public map of the network (Figure 2.3). A storm, a tower failure or a fault at the gas plant's substation could interrupt the port platform's supply.

For a steelworks, interruptions are expensive. A single furnace needs most of the year to reach Phase 1's name-plate, so the output of an interrupted heat is hard to recover; that is a reason to secure firm supply rather than to accept interruptions. What must never be lost is the supply to **essential loads**: cooling water for the furnace panels and caster, cranes holding ladles of liquid steel, fume extraction and emergency lighting. These loads, a small fraction of the total, need a dedicated back-up supply, normally standby generators with automatic start, sized as part of the plant's safety design.

5.6 Connection costs need clear and published rules

The 225 kV line and substation were initiated by the port authority at a reported cost of about 35 bn FCFA [S14]. How the costs of shared assets are recovered from tenants, and how the costs of dedicated assets (a 225 kV bay, a link line, the plant substation) are allocated between the steelworks, PAK and SONATREL, are not set out in the public record. SONATREL's tariff includes a charge of 4.48 m FCFA per year per connection point and an annual withdrawal charge of 16.18 m FCFA per MW [S53], but connection charges for new assets are a separate question.

Two principles would help every industrial tenant, not only steel (Chapter 10):

1. **Shallow connection charges for shared assets.** A tenant pays for the dedicated assets that serve only it (its bay, its line, its substation) and pays for shared network assets through the regulated transmission tariff, not through an up-front contribution negotiated case by case.
2. **Capacity reservation with milestones.** A large user can reserve capacity in the substation's later stage against defined project milestones and a reservation fee, so that the zone can plan its expansion and the user can finance its plant.

5.7 The grid will arrive before the steelworks; the risk is in the sequence after that

The timetables now align better than they did a year ago. The 400 kV Nachtigal evacuation line is due in November 2026 [S02]; the 225 kV Kribi line and substation at the end of 2026 [S14]; the port's water plant in early 2027 [S15]. Cameroon Steel's indicative schedule targets front-end engineering and utilities agreements in 2027, the environmental certificate by the end of 2028, the start of Phase 1 works in the first quarter of 2029, a first heat in the second half of 2030 and ramp-up in 2031; Phase 2 would follow in 2032 to 2034 and Phase 3 after 2034, subject to market and financing [S07]. These are targets, not commitments.

The supply will therefore exist before the plant. The risks lie in what happens next: whether the first stage is fully committed before a steelworks connects, whether the later 330 to 400 MW stage is designed and financed in time for the larger phases, and whether gas is available for the firm capacity that the later phases will need. The next two chapters turn to gas.

CHAPTER 6

THE HILLI FLNG'S DEPARTURE MAKES CAMEROON'S GAS A DOMESTIC QUESTION, AND RESERVES ARE NOW THE BINDING UNKNOWN

Until July 2026, about 95% of Cameroon's gas output fed the Hilli Episeyo floating liquefaction vessel moored off Kribi. Its departure removes a buyer of about 72 bcf a year, while every plausible domestic use at Kribi, including a 1 Mtpa direct-reduction plant, adds up to about 20 to 36 bcf a year. Gas is physically close to the industrial zone; what industry lacks is a certified view of remaining reserves, a transparent price and published allocation rules.

6.1 A small, concentrated gas sector built around one export outlet

Cameroon's gas sector is small and concentrated. The national hydrocarbons company, the Société Nationale des Hydrocarbures (SNH), holds the State's interests and markets its share of production. In 2025 the country produced 75.475 bcf of natural gas, of which 24.069 bcf was the State's share and 51.406 bcf the partners' [S05]. Almost all of it, 74.324 bcf or about 98.5%, came from the offshore Sanaga Sud field near Kribi, operated by Perenco [S05]. The onshore Logbaba field near Douala produced 1.150 bcf [S05]. Production had fallen by 6.3% in 2024 to 2,043.27 million m³ [S83].

No recent, field-by-field statement of Cameroon's gas reserves is public. The volume on the record for the Kribi fields is the 500 bcf of reserves on which Golar LNG's heads of agreement with SNH and Perenco of December 2014 was premised, to be produced at about 1.2 Mt of LNG a year over about eight years [S84]; an allocation made twelve years ago is not a basis for a supply contract. The industrial gas market in Douala is in difficulty: deliveries by Gaz du Cameroun, which distributes Logbaba gas to Douala industry, fell by 62.9% in 2024, the company was taken over by Cameroon Holdings Ltd in July 2025, and its share capital was cut by 86.4% a year later [S85][S86]. In 2023 the government suspended a 20% increase in its industrial gas price [S87].

The sector was built around one outlet. In June 2018 Golar LNG began commercial operations of the Hilli Episeyo floating LNG (FLNG) vessel off Kribi, with a design capacity of 2.4 Mt a year in four trains [S88][S89]. The project rested on the 500 bcf allocation [S84]; how much of it has been produced is not public (evidence gap 4). Cameroon used about 1.4 Mt of LNG capacity a year, with an option on 1.6 Mt [S89].



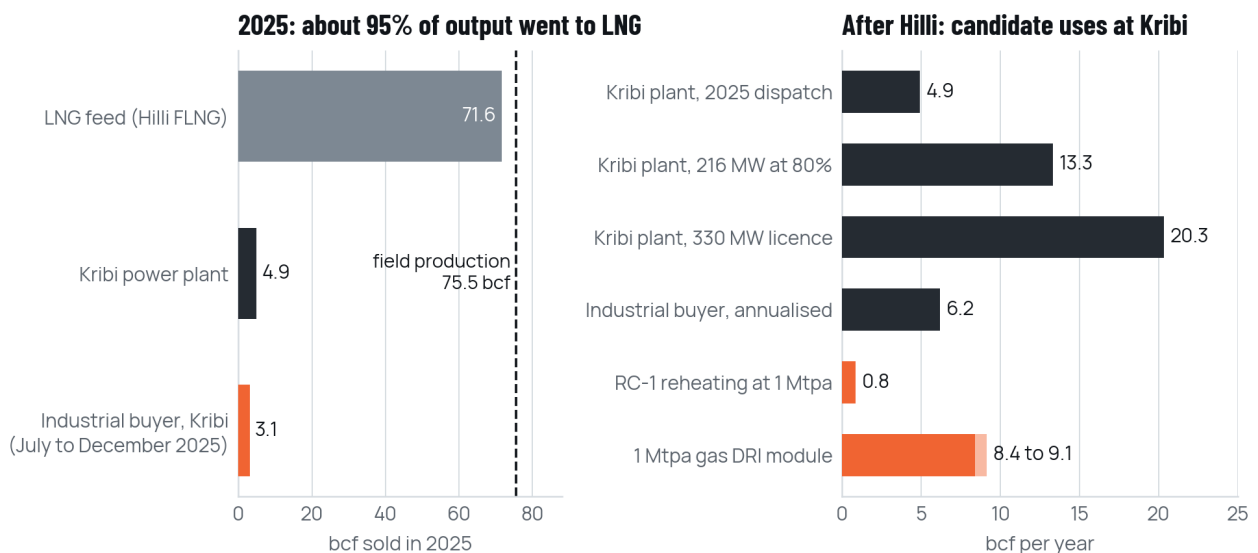
ILLUSTRATIVE Illustrative view. Generated image of a gas pipeline installation at a coastal facility; not a photograph of any project, place or person.

6.2 The vessel left in July 2026, and with it the main buyer

In May 2025 Golar and its partners approved the deployment of their first vessel in an Argentine gas export project [S90]. The Perenco charter in Cameroon ended in July 2026 and the vessel left Kribi; press reports projected a loss of gas revenue of about 235 bn FCFA for 2026 and 2027 [S16]. After the departure, the Kribi power plant continues to receive gas through the existing pipelines, but no replacement liquefaction has been announced [S17][S91]. A critical press commentary in June 2026 summed up eight years of the arrangement as "eight years of rental, zero infrastructure" [S91].

The scale of the change is visible in SNH's 2025 accounts (Figure 6.1). The State sold 17.905 bcf as LNG feed for US\$148.2m and the partners 53.716 bcf for US\$448.1m, together about 71.6 bcf, or about 95% of output [S05]. The domestic market took the rest: 4.920 bcf for the Kribi power plant and 3.088 bcf, in the third and fourth quarters only, for an industrial buyer at Kribi [S05]. SNH reports sales by buyer, and their sum (79.6 bcf) exceeds the field production of 75.5 bcf; this paper shows the figures as published and lists the reconciliation as an evidence gap (Chapter 11).

Hilli's exit removes a 72 bcf/yr buyer; plausible uses at Kribi total about 20 to 36 bcf/yr



DERIVED Figure 6.1. Hilli's exit removes a 72 bcf/yr buyer; plausible uses at Kribi total about 20 to 36 bcf/yr. Left: gas sales by buyer in 2025. Right: candidate domestic uses after July 2026. Power-plant scenarios use the plant's 2025 gas use per GWh; the industrial buyer's half-year purchase is doubled.

Source: SNH, Données pétrolières 2025 [S05]; ARSEL 2025 [S01]; RC-1 gas balance [S07]; DRI gas use 9.2 to 10 GJ/t [S39][S41]; 1 Mscf = 1.094 GJ.

The right-hand panel of Figure 6.1 lists the candidate domestic uses at Kribi (derived):

- **The Kribi power plant** used 4.92 bcf in 2025 to generate 559.67 GWh, about 8.8 Mscf per MWh. At an 80% capacity factor, the same 216 MW plant would need about 13.3 bcf a year; extended to its licensed 330 MW, about 20.3 bcf.
- **The industrial buyer at Kribi** would use about 6.2 bcf over a full year at its 2025 half-year rate.
- **Reheating furnaces for a 1 Mtpa steelworks**, in RC-1's Phases 2 and 3, would use about 0.91 PJ a year, about 0.83 bcf [S07]; Phase 1 uses no gas.
- **A 1 Mtpa gas-based DRI module** would use about 8.4 to 9.1 bcf a year (Chapter 7).

Without a DRI plant, these uses add up to about 20 bcf a year; with the plant extended to 330 MW and a 1 Mtpa DRI module, about 36 bcf. Both totals are well below the 72 bcf a year that went to LNG in 2025. Two further gas-fired plants announced in 2025, of 350 MW at Bekoko and 150 MW at Douala, were subject to SNH confirming gas availability [S50] and would compete for the same resource.

FOR THE FIRST TIME, CAMEROON'S MAIN GAS FIELD NEAR KRIBI HAS NO EXPORT BUYER. WHETHER THAT BECOMES AN INDUSTRIAL OPPORTUNITY DEPENDS ON RESERVES, PRICE AND RULES, NOT ON PROXIMITY.

Cameroon Steel, White paper 05

6.3 Domestic industry has been leaving gas, not joining it

The domestic gas market's recent history is a warning. In Douala, where Gaz du Cameroun has supplied industrial customers from the Logbaba field, deliveries fell by 62.9% in 2024, and press coverage described the city's industrial users as turning away from natural gas [S85]. The distributor changed hands in July 2025 and cut its share capital by 86.4% a year later [S86]; in 2023 the government had suspended a planned 20% increase in its industrial gas price [S87].

The causes of this decline deserve their own study, and the Douala market is supplied from a different and much smaller field than Kribi. But the lesson for Kribi is clear: industrial users do not take gas because it is nearby. They take it when supply is reliable, the price is predictable and the contract is enforceable. A domestic gas strategy built around the Sanaga Sud field must offer all three to win industrial customers after the FLNG.

6.4 The binding unknown is how much gas is left

On these numbers the near-term physical supply looks ample. The difficulty is that it is not known how long it would last.

The Sanaga Sud reserves developed for the Hilli project were about 600 bcf, of which 500 bcf was allocated to the FLNG, and the field is in natural decline [S17][S84]. Over eight years of LNG operation at rates of the order of the 72 bcf sold in 2025, the cumulative feed would be of the same order as the 500 bcf allocation (derived, an approximation that should be replaced by SNH's production records). Remaining certified reserves of Sanaga Sud are not public [S17]. A plant that needs gas for twenty years, such as a DRI module, cannot be financed on a field whose remaining life is unknown.

New supply exists on paper. The cross-border Yoyo-Yolanda discovery, shared with Equatorial Guinea, holds about 2.5 Tcf, would cost about US\$4bn to develop, and has been associated with a target of an additional 300 MMscf/d through the Bipaga facilities "from 2026", but has no final investment decision [S17][S83]. SNH offered nine exploration blocks in August 2025; five were in production-sharing negotiations in 2026, four of them with Murphy [S17]. None of these will produce gas for industry at Kribi before the end of the decade unless decisions are taken soon.

Table 6.1 Gas resources relevant to Kribi and their degree of certainty

Resource	Size	Status	Certainty for an industrial contract	Source
Sanaga Sud and Ebome, developed for the FLNG	About 600 bcf developed; 500 bcf allocated to the FLNG	Producing; in natural decline	Unknown: remaining certified reserves not public	[S17] [S84]
Sanaga Sud production, 2025	74.324 bcf	Producing	Reported production, not a reserve	[S05]
Logbaba (onshore, Douala)	1.150 bcf produced in 2025	Producing; operator restructured	Low volume; serves Douala	[S05] [S85] [S86]
Yoyo-Yolanda (cross-border)	About 2.5 Tcf	Discovered; about US\$4bn development; no FID	Not available before a decision and several years of works	[S17] [S83]
2025 licensing round	9 blocks offered; 5 in negotiation	Exploration	Speculative	[S17]
Etinde and other discoveries	Not found in the public record for this paper	Unknown	Unknown	Chapter 11

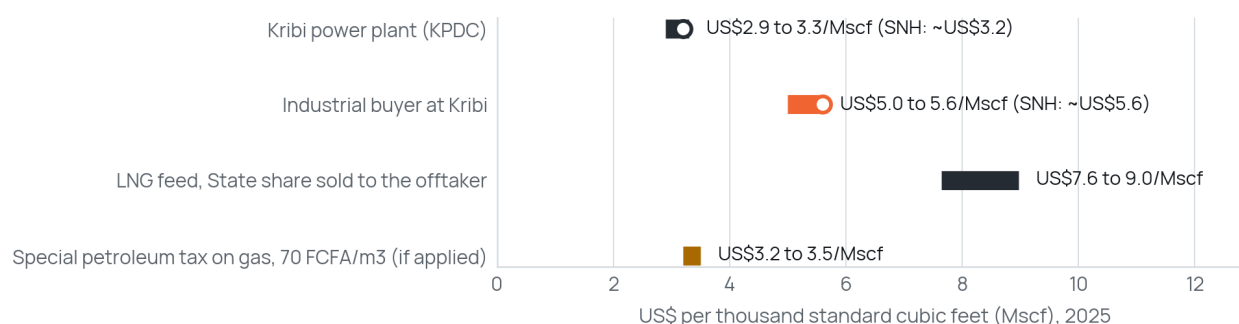
Source: as listed.

6.5 Prices: power gas at about US\$3.2, industrial gas at about US\$5.0 to 5.6

SNH's 2025 accounts also give the first public set of domestic gas prices by buyer (Figure 6.2). The Kribi power plant paid 1,810 to 1,858 FCFA per thousand standard cubic feet (Mscf), about US\$3.2 at SNH's exchange rates; the industrial buyer at Kribi paid 3,135 FCFA/Mscf, about US\$5.0 to 5.6 at the same rates (SNH: about US\$5.6); and the State's share of LNG feed sold for US\$7.64 to US\$8.97/Mscf [S05] [S92]. SNH's quarterly exchange rates ranged from 624.9 FCFA per US dollar in the first quarter to 561.0 in the fourth [S05]. In energy terms, US\$3.2/Mscf is about US\$2.9 per GJ and US\$5.0 to 5.6/Mscf about US\$4.6 to 5.1 per GJ (derived).

Power-sector gas sold at about US\$3.2/Mscf in 2025, industry paid about US\$5.0 to 5.6

SNH gas sales prices by buyer, 2025, converted at SNH's quarterly rates (561 to 625 FCFA per US\$)



DERIVED **Figure 6.2.** Power-sector gas sold at about US\$3.2/Mscf in 2025, industry paid about US\$5.0 to 5.6. Prices in FCFA as published by SNH; ranges reflect conversion at SNH's quarterly exchange rates; the special petroleum tax is shown for scale and its application to industrial gas is unresolved.

Source: SNH, Données pétrolières 2025 [S05]; SNH, key figures 2025 [S92]; Business in Cameroon on gas taxation [S87]; tax converted at 28.317 m³ per Mscf (derived).

Two features of this price structure matter for policy. First, **the LNG feed price was well above the domestic prices**. With the vessel gone, the upstream partners lose their best-paying outlet, and a domestic price set at the power-sector level may not justify the investment needed to sustain production. Second, **taxation is unre-**

solved. A special petroleum tax (STPP) of 70 FCFA per m³ on natural gas has applied since 1 January 2023 [S87]; that is about 1,980 FCFA/Mscf, or US\$3.2 to US\$3.5 at 2025 exchange rates (derived), roughly equal to the power-sector gas price itself. Whether, and at what rate, it applies to gas sold to industry has not been confirmed in a primary text for this paper. For an industrial project, the difference between paying it and not paying it is the difference between two very different business cases.

6.6 Three reference points for a domestic gas price

Setting a domestic gas price after the FLNG is a policy choice. Three reference points, all available from public data, bound it (derived from [S05] and [S01]):

- **The export alternative.** The State's share of LNG feed sold at US\$7.64 to US\$8.97/Mscf in 2025 [S05]. With no liquefaction at Kribi, this is no longer an available outlet, but it shows the value the upstream partners have lost and the price they would compare any domestic offer against if export capacity returned.
- **The power-sector price.** The Kribi power plant paid about US\$3.2/Mscf [S05]. At its 2025 gas use of about 8.8 Mscf per MWh, that is a fuel cost of about 17 FCFA/kWh.
- **The power-equivalent value.** Even at the top of the LNG feed price, US\$8.97/Mscf, the fuel cost of gas-fired generation at the plant's 2025 efficiency would be about 47 FCFA/kWh, close to the 43.93 FCFA/kWh the utility pays for Memve'e's hydro output [S01]. Gas-fired power remains competitive on fuel cost with recent hydro purchase prices across most of the range of 2025 gas prices, although this comparison excludes the capital costs of both.

The policy implication is that there is room between the current power-sector price and the value of gas as fuel for a domestic price that would sustain upstream investment without making gas-fired power uncompetitive. Where in that range the price is set, and how it is indexed, is exactly what a published framework should determine.

6.7 Firm gas for power at Kribi comes first

For industry at Kribi, the first priority for gas is not a direct-reduction plant but the power plant. A firm electricity supply to the industrial zone depends on the Kribi gas plant being able to run when hydro output is low and when the transmission path from Edéa is interrupted. In 2025 the plant ran at about 30% of its capacity [S01]; running it as firm back-up for a growing industrial load would need more gas, about 13 bcf a year at an 80% capacity factor (derived). A gas allocation that secures the power plant's supply would therefore benefit every tenant of the zone, and is the natural first step of the framework set out below.

6.8 What an allocation framework for industrial gas should contain

The departure of the FLNG is an opportunity to re-plan Cameroon's gas as a domestic industrial resource. For an energy-intensive project at Kribi, an allocation framework would need six elements:

SIX ELEMENTS OF AN INDUSTRIAL GAS ALLOCATION FRAMEWORK

1. **An independent reserve audit** of Sanaga Sud and Ebome, published in summary, with a deliverability profile by year. Without it, no long-term contract can be financed.
2. **A priority order for domestic uses**, setting out how much gas is reserved for power generation (including firm capacity for industry), for industrial heat and for chemical uses such as direct reduction, and for how long.
3. **A transparent price formula** for each class of user, high enough to sustain upstream investment and predictable enough for industrial financing, with indexation rules stated in advance.
4. **Tax clarity**, in particular on whether the STPP applies to industrial gas and at what rate.
5. **Infrastructure responsibilities**: who builds and owns a gas pipeline from the Kribi gas plant's receiving facilities to the port's industrial zone, about 40 km away, and how its cost is recovered.
6. **Standard contract terms**: take-or-pay levels, supply interruption remedies and the treatment of new discoveries such as Yoyo-Yolanda.

For an electric steelworks, the first gas needs are modest and come late: none in Phase 1, under 1 bcf a year for reheating at full build-out [S07]. The larger question, gas for making iron from Cameroonian ore, is examined in the next chapter.

CHAPTER 7

A 1 MTPA DIRECT-REDUCTION PLANT WOULD NEED ABOUT 9 BCF OF GAS A YEAR: AFFORDABLE, BUT ONLY WITH CERTIFIED SUPPLY AND DR-GRADE ORE

Gas-based direct reduction consumes 9.2 to 10 GJ per tonne of DRI, so a 1 Mtpa module would need about 8.4 to 9.1 bcf of gas a year, 11% to 12% of Cameroon's 2025 output and nearly twice what the Kribi power plant burned. At 2025 domestic prices, the gas would cost US\$27 to US\$51 per tonne of DRI, a small share of the US\$340 to US\$370 a tonne at which hot-briquetted iron traded into Italy in March 2026. The obstacles to making iron at Kribi are not the price of gas but twenty years of certified supply and a source of direct-reduction-grade pellets.

7.1 Direct reduction turns gas into the chemistry of ironmaking

Iron ore is iron oxide. To make steel from ore, the oxygen must be removed, and in direct reduction this is done in the solid state, well below the melting point of iron. Pellets of high-grade ore descend through a shaft furnace while a hot reducing gas, rich in hydrogen and carbon monoxide, flows upwards. The gas is made from natural gas, either in a separate reformer (as in the MIDREX process) or inside the shaft itself (as in the Energiron ZR process). The product is direct-reduced iron (DRI), a porous metallic iron that is either charged hot into a neighbouring arc furnace, cooled, or pressed into dense briquettes, hot-briquetted iron (HBI), that can be shipped safely.

Natural gas therefore plays two roles: it provides the heat and it provides the reducing agents. The published benchmarks are close to one another:

- MIDREX plants use about 2.35 Gcal of natural gas per tonne of DRI, about 9.84 GJ [S93];
- the Energiron process uses about 10 GJ of natural gas and about 73 kWh of electricity per tonne of DRI, and about 8.3 GJ and 60 kWh when 73% of the reducing gas is hydrogen [S39];
- Suez Steel's Energiron ZR plant in Egypt reported sustained consumption below 2.2 Gcal per tonne, about 9.2 GJ, in April 2026 [S41].

The technology is mature and widely used. World DRI production reached 151.0 Mt in 2025, of which 65.1% was gas-based; MIDREX plants made 54.5% and HYL/Energiron plants 10.0% of the total [S94]. HBI accounted for 11.6 Mt, or 7.7% of DRI, and international trade in DRI and HBI was about 10.8 Mt [S94]. Africa's gas-based DRI is concentrated in North Africa, with Algeria at 6.7 Mt, Egypt at 6.1 Mt and Libya at 1.75 Mt. On Midrex plant statistics, sub-Saharan Africa produced only 0.09 Mt in 2025, and its two gas-based plants were idle [S94]; worldsteel, whose figures include estimates for plants outside that survey, puts East African DRI output at about 2.7 Mt in 2025, in Uganda, Kenya and Tanzania [S95].

151.0 MtWorld DRI production, 2025;
65.1% gas-based**0.09 Mt**Sub-Saharan Africa DRI produc-
tion, 2025, Midrex plant statist-
ics (worldsteel estimates about
2.7 Mt in East Africa)**9.2 to 10 GJ/t**Natural gas per tonne of DRI,
shaft furnaces**0.25 to 2.5 Mtpa**Range of single-module sizes in
operation or on order

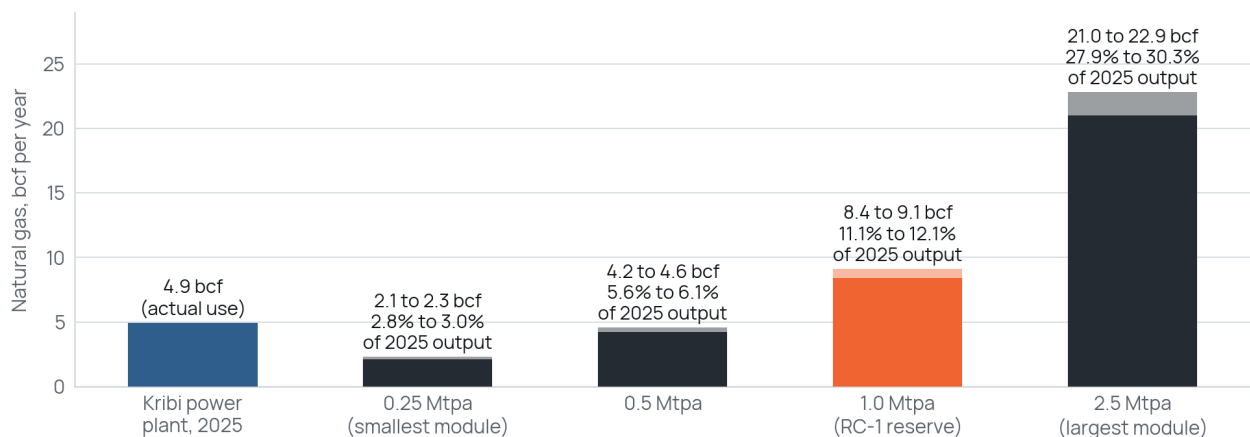
Source: Midrex, 2025 World Direct Reduction Statistics [S94]; worldsteel, World Steel in Figures 2026 [S95]; EC ICIT Energiron [S39]; Danielli, Suez Steel (2026) [S41]; Midrex history [S96].

7.2 Gas demand rises in proportion to module size

Shaft-furnace modules are built in a wide range of sizes. The smallest recent example is a 0.25 Mtpa Energiron ZR micro-module that started in Bolivia in October 2025 [S94]; the first 1.0 Mtpa MIDREX MEGAMOD was built for JSW at Dolvi in India [S96]; and the largest single module, 2.5 Mtpa, has operated in Algeria since 2018 [S96] [S94]. Figure 7.1 converts these sizes into annual gas demand.

A 1 Mtpa DRI plant would burn about 9 bcf a year, nearly twice the Kribi power plant's 2025 use

Gas demand of shaft-furnace DRI modules at 9.2 to 10 GJ per tonne of DRI, full-year operation



DERIVED Figure 7.1. A 1 Mtpa DRI plant would burn about 9 bcf a year, nearly twice the Kribi power plant's 2025 use. Bars show the range at 9.2 to 10 GJ per tonne of DRI and full-year operation; percentages are shares of Cameroon's 2025 gas output of 75.5 bcf.

Source: DRI gas use [S39][S41]; module sizes [S94][S96]; SNH 2025 output and Kribi power plant use [S05]; 1 Mscf = 1.094 GJ (derived).

A 1 Mtpa module, the size that RC-1 reserves for a later phase based on Cameroonian ore, would need about 8.4 to 9.1 bcf a year, or about 23 to 25 MMscf a day (derived). That is 11% to 12% of 2025 output and about 1.7 to 1.9 times the gas burned by the Kribi power plant in 2025. Over a twenty-year life, it would consume about 170 to 180 bcf (derived), a large share of what may remain in Sanaga Sud (Chapter 6).

The electricity demand of a DRI plant is modest by comparison: at about 73 kWh per tonne [S39], a 1 Mtpa module would use about 73 GWh a year (derived), about a tenth of the electricity of a 1 Mtpa melt shop and rolling mill. The larger electrical effect is in the arc furnace, where each additional 10% of DRI in the charge adds about 14.5 kWh per tonne of liquid steel [S39].

RC-1 treats the DRI module as a reserve: about 1 Mtpa of DRI capacity (0.8 to 1.1 Mtpa), planned for after 2034, subject to ore quality of at least 64% Fe, gas supply and approvals [S07]. Until then, the plant's ore-based iron units would be imported DRI or HBI, about 30% of the metallic charge in the planning case [S07].

7.3 Ore-based iron units matter because Cameroon is short of scrap

The reason an electric steelworks in Cameroon needs DRI at all is the scarcity of scrap. Local scrap covers only about 40% of the needs of Cameroon's existing mills [S32], and billets, the semi-finished steel those mills roll, were the largest steel import in 2023, at 161 kt [S11]. In September 2026, Prometal arranged a €40m facility with Afreximbank to import billets as Cameroonian scrap became scarcer [S32][S97]. A new melt shop cannot assume that domestic scrap will cover its needs.

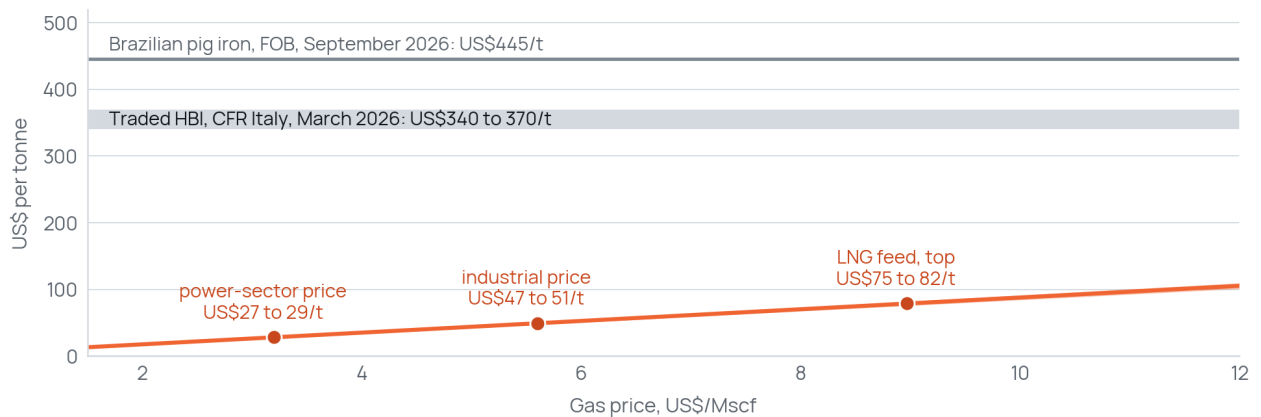
RC-1 therefore plans a mixed charge. At nameplate, the Phase 1 furnace would melt about 363,000 t of metallica a year, of which about 254,000 t of scrap and about 109,000 t of imported DRI or HBI [S07]. Only about 30,000 t a year of the scrap (a planning range of 0 to 60,000 t) is expected from domestic sources, against the only quantified national study, which put scrap arising at 53,000 to 61,833 t a year in 2006 [S98]; the rest would be imported, so that Phase 1 would bring about 351,000 t a year of metallica and consumables through the port [S07] (White paper 02). DRI and HBI also bring a metallurgical benefit: they contain almost none of the copper and tin that accumulate in recycled scrap, so they dilute these residual elements, which matters for wire rod and other demanding products. The energy cost of that benefit is the additional furnace electricity described in Chapter 1. The gas question in this chapter is therefore the question of where, in the long run, the plant's clean iron units come from: from abroad, as DRI or HBI made with other countries' gas, or from Kribi, made with Cameroon's.

7.4 At Cameroonian prices, the gas would cost US\$27 to US\$51 per tonne of DRI

Figure 7.2 shows the gas cost per tonne of DRI as a function of the gas price, against two traded benchmarks for imported iron units.

At Cameroonian gas prices, fuel costs US\$27 to US\$51 per tonne of DRI

Gas cost per tonne of DRI (band: 9.2 to 10 GJ/t) against traded prices of imported iron units



DERIVED Figure 7.2. At Cameroonian gas prices, fuel costs US\$27 to US\$51 per tonne of DRI. The orange band covers 9.2 to 10 GJ per tonne; points mark the 2025 SNH prices to the power plant and to industry and the top of the LNG feed price. Grey bands show traded HBI and pig iron prices.

Source: SNH 2025 gas prices [S05]; DRI gas use [S39][S41]; SteelOrbis, 16 March 2026, HBI CFR Italy [S18]; GMK Center, 4 October 2026, Brazilian pig iron FOB [S99].

At the power-sector price of about US\$3.2/Mscf, the gas for a tonne of DRI would cost about US\$27 to US\$29; at the industrial price of about US\$5.0 to 5.6/Mscf, about US\$42 to US\$51; and at the top of the 2025 LNG feed price, US\$8.97/Mscf, about US\$75 to US\$82 (derived). For comparison, Libyan HBI was offered at about US\$370 a tonne CFR Italy in March 2026 and Venezuelan HBI at about US\$340 [S18]; Brazilian pig iron fell to about US\$445 a tonne FOB in September 2026 [S99]; and Chinese billets were offered at US\$465 to US\$470 FOB on 3 October 2026 [S09].

The comparison shows that gas is not the dominant cost of DRI at Cameroonian prices. The largest cost is the iron-bearing feed: DR-grade pellets, whose price is set on international markets and carries a premium over ordinary iron ore. The benchmark for ordinary 62% Fe ore averaged US\$100.2 per dry tonne in 2025 [S100]; DR-grade pellet prices were not available in a form that could be verified for this paper. A domestic DRI plant would therefore be competitive with imported HBI only if it combines cheap gas with a reliable source of pellets, ideally from Cameroonian ore.

GAS AT CAMEROONIAN PRICES IS A SMALL PART OF THE COST OF IRON. THE CONSTRAINT IS TWENTY YEARS OF CERTIFIED GAS AND A SOURCE OF DR-GRADE PELLETS.

Cameroon Steel, White paper 05

7.5 Ore quality decides whether Cameroonian ore can feed a DRI plant

Shaft furnaces need high-grade feed. worldsteel notes that current DRI processes require ore with at least 64% iron, a quality that represents less than 20% of global supply [S101]. Public reporting of Cameroon's Mbalam deposit refers to direct-shipping ore grading above 62% Fe [S08], which is suited to blast furnaces and sinter plants rather than to direct reduction. Producing DR-grade feed from Cameroonian ore would therefore require concentration and pelletising, a substantial investment of its own.

The policy framework points in this direction. Cameroon's Mining Code of 2023 provides for local transformation of 15% of mine production [S27]. Cameroon Steel's sister company, Cameroon Mining Company, holds the Mbalam exploitation permit [S08]; its mining convention is reported to commit it to transform 15% of its production locally, and the same press report presents Cameroon Steel as the future national steel hub of that programme [S102]. Making iron at Kribi from Cameroonian ore would satisfy that intent more fully than any other route. It is also why the gas question matters: a local-transformation policy for iron ore implies a gas allocation policy for direct reduction.

Agora Industry's analysis of the global steel transition warns that DR-grade ore supply is likely to lag demand by 2030 [S103]. That cuts both ways: it raises the value of a future Cameroonian DR-pellet supply, and it means that a plant at Kribi cannot assume imported DR pellets will remain cheap or abundant.

7.6 Make or buy: domestic DRI against imported DRI and HBI

Table 7.1 compares the two ways an electric steelworks at Kribi could obtain ore-based iron units.

Table 7.1 Imported DRI and HBI against a domestic gas-based DRI module at Kribi

Criterion	Imported DRI or HBI (RC-1 Phases 1 to 3)	Domestic gas-based DRI at Kribi (RC-1 reserve, after 2034)
Gas needed	None	About 8.4 to 9.1 bcf a year for 1 Mtpa
Electricity	EAF penalty only (about 14.5 kWh/t per 10% DRI)	About 73 GWh a year for the module, plus EAF penalty
Iron feed	Bought as finished DRI or HBI	DR-grade pellets (at least 64% Fe), imported or from Cameroonian concentrate
Market exposure	International DRI and HBI trade of about 10.8 Mt (2025); few exporters	Pellet market; gas price formula

Criterion	Imported DRI or HBI (RC-1 Phases 1 to 3)	Domestic gas-based DRI at Kribi (RC-1 reserve, after 2034)
Logistics	Import through existing port terminals	Pellet import or domestic supply; bulk handling depends on the mineral terminal agreed in a memorandum of understanding in November 2025, with completion expected within five to six years
Capital	None for ironmaking	A shaft furnace, gas supply and pellet handling
Carbon	Upstream emissions of the exporter (RC-1 assumes about 0.7 t CO ₂ per t DRI)	Direct emissions of gas reduction at Kribi; electricity from a low-carbon grid; hydrogen blending possible later
Value added in Cameroon	Melting and rolling only	Ironmaking, and eventually ore processing
Main precondition	Reliable import supply and price	Certified gas reserves, a price formula, a pipeline and pellet supply

Source: [S39][S41][S94][S101][S80][S81][S07]; Cameroon Steel analysis.

The table explains RC-1's sequence. Imported DRI or HBI requires no gas and no capital for ironmaking, and it allows the melt shop and mills to be built and run while the gas and ore questions are resolved. A domestic module adds value and resilience but depends on three conditions that do not yet exist: certified gas for its life, a published price formula, and a pellet supply. The international market for DRI and HBI is also thin: trade data show about 10.8 Mt in 2025, or about 13.2 Mt including origins under sanctions, with Russia (as HBI) and India the largest exporters [S94]. That is a supply-security argument for eventually making iron at home.

7.7 A small module could be a stepping stone

There is a middle path. A 0.25 Mtpa module of the size started in Bolivia in 2025 [S94] would need only about 2.1 to 2.3 bcf a year, less than half of what the Kribi power plant used in 2025 and under 3% of 2025 national output (derived). It would cover about two-thirds of RC-1's planned full-build-out DRI use of about 0.36 Mt a year [S07], could run on imported pellets while Cameroonian concentrate is developed, and would give the gas sector a first long-term industrial customer of manageable size. Whether such a module is economic at that scale is a question for a feasibility study; this paper only notes that the gas required is within reach.

7.8 Hydrogen later, gas first

Shaft furnaces can use hydrogen in place of part of the natural gas. The Energiron data show that with 73% hydrogen in the reducing gas, natural gas use falls from about 10 to 8.3 GJ per tonne [S39]. Fully hydrogen-based reduction needs about 54 kg of hydrogen per tonne of DRI, which, at current electrolyser efficiencies, implies roughly 2.4 to 2.8 MWh of electricity per tonne of DRI for the hydrogen alone (derived from [S93][S35]). For a 1 Mtpa module, that would be 2.4 to 2.8 TWh a year, about a third of Cameroon's entire 2025 generation (derived). Hydrogen-based iron at Kribi is therefore a long-term option tied to new hydro capacity, not a near-term plan (Chapter 8). A gas-based plant designed to accept hydrogen blending keeps the option open.

7.9 What would make a DRI plant at Kribi possible

The conditions follow directly from this chapter and the previous one:

1. **An independent reserve audit** showing at least twenty years of supply at about 9 bcf a year for a 1 Mtpa module, or a smaller module sized to what is certified.

2. **A gas allocation and price formula** for industrial chemical use, separate from power-sector gas, with clear tax treatment.
3. **A pipeline** from the gas receiving facilities at the Kribi power plant to the industrial zone.
4. **A pellet strategy**: imported DR pellets first, with a path to Cameroonian concentrate that matches the local-transformation policy.
5. **Bulk port capacity** for pellets. The mineral terminal agreed in a memorandum of understanding on 4 November 2025 is expected by PAK's Director General to be completed within five to six years [S80][S81], which would precede a module planned for after 2034; neither date is firm, so a DRI plan should not assume the terminal until its first stage is financed (White paper 02, Chapter 2).

None of these is needed for Phase 1 of an electric steelworks. All of them are needed before a DRI module can be financed, which is why they belong in national energy and mining policy now rather than in a project's later phases.

CHAPTER 8

HYDRO IS CAMEROON'S RENEWABLE ADVANTAGE FOR STEEL; SOLAR AND STORAGE HELP AT THE MARGIN BUT CANNOT FIRM AN ARC FURNACE

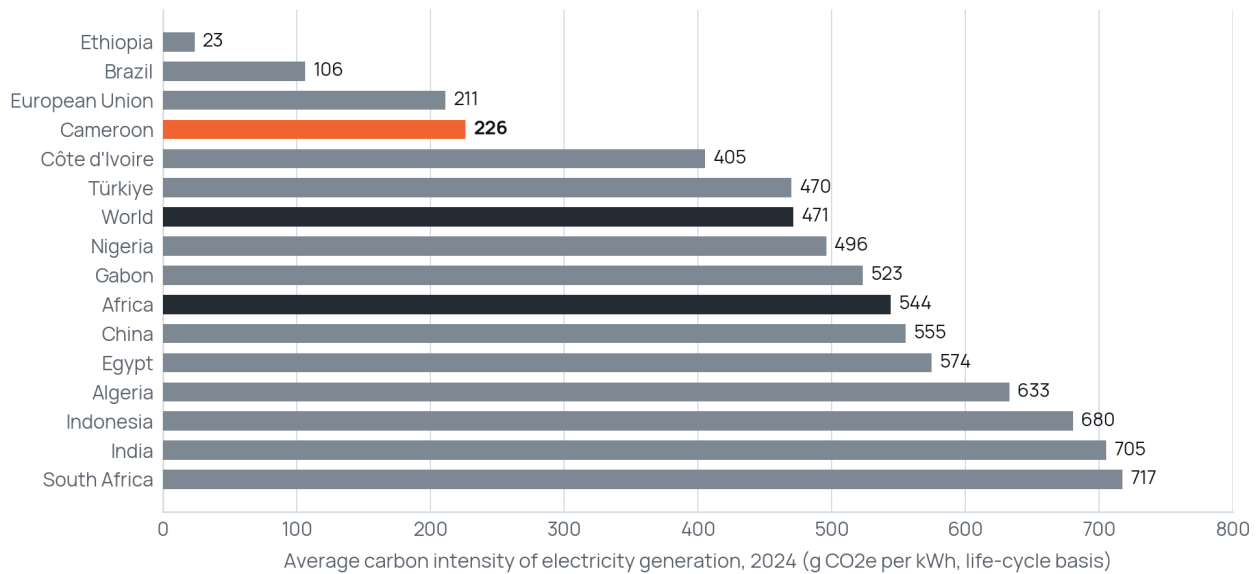
Cameroon's grid already emits about 226 g CO_{2e} per kWh, half the world average, because it runs on hydro, and its undeveloped hydro potential is about 115 TWh a year. That, rather than solar, is the country's renewable asset for heavy industry. A solar plant at Kribi would produce about 1,335 kWh per kWp a year, a 15% capacity factor with a mid-year trough: a 50 MWp array would supply about a fifth of a first-phase steelworks' electricity, but almost none of its night-time or peak demand. The best renewable strategy for an electric steelworks is a long-term hydro-backed supply contract, with solar where it lowers cost and storage used for resilience and power quality rather than bulk energy.

8.1 Cameroon's grid is already a low-carbon asset

Figure 8.1 compares the average carbon intensity of electricity generation in 2024 across Cameroon, its neighbours and the countries that supply steel to Central Africa or compete with it.

Cameroon's grid emits half the world average per kWh and a third of Indonesia's

Indonesia supplied 78% of Cameroon's billet imports in 2023; Türkiye and China are the reference export mills



SOURCED Figure 8.1. Cameroon's grid emits half the world average per kWh and a third of Indonesia's. Average intensity of electricity generation in 2024, life-cycle basis. Indonesia supplied 78% of Cameroon's billet imports in 2023.

Source: Our World in Data, carbon intensity of electricity generation, Ember data, accessed 10 October 2026 [S10]; billet import origins from UN Comtrade [S11].

At about 226 g CO₂e/kWh, Cameroon's grid was cleaner in 2024 than the world average (about 471 g), the African average (about 544 g), and the grids of the main steel exporters to the region: China (about 555 g), Türkiye (about 470 g), India (about 705 g) and Indonesia (about 680 g), which supplied 78% of Cameroon's billet imports in 2023 [S10][S11]. Only a few countries with large hydro fleets, such as Ethiopia and Brazil, do markedly better.

For a steelworks using about 0.96 MWh per tonne of product, as RC-1 Phase 1 would at its planning value [S07], the indirect (Scope 2) emissions at each of these grid intensities would be (derived; about 4% higher at the upper planning value of 1.0 MWh/t):

- about 0.22 t CO₂ per tonne in Cameroon;
- about 0.45 t at the world average;
- about 0.65 t in Indonesia.

Two caveats apply. First, the 226 g figure is an average on a life-cycle basis, which includes the emissions of building and operating hydro plants. Using only combustion emissions and the regulator's 2025 generation data, the operational intensity would be much lower, about 74 g/kWh in 2025 (an estimate, derived in White paper 06, Annex A, by applying the emission rate of gas and oil generation implied by the 2024 data to the 2025 generation mix). Second, lenders and carbon accountants often use a combined-margin factor, which gives more weight to the thermal plants that run at the margin and to new capacity; the harmonised factor for Cameroon could not be retrieved for this paper (Chapter 11). The planning range used by Cameroon Steel is 200 to 300 g/kWh, centred on 226 [S07].

8.2 The carbon value of clean power depends on who is counting

The carbon advantage of Cameroon's grid is real, but its commercial value depends on the rule that is applied.

At the EU border, under CBAM as it stands, electricity's emissions do not count for steel. The CBAM regulation lists iron and steel among the goods for which only direct emissions are taken into account [S46]. For an electric steelworks, the direct emissions are small (electrodes, charge carbon, lime and any gas burned on site), so the CBAM charge on its exports would be low whatever the grid. The grid matters for CBAM chiefly through the precursors: DRI made with gas carries its own direct emissions.

For customers, investors and standards, Scope 2 counts in full. Buyers who report their own supply-chain (Scope 3) emissions, and the low-emission steel standards now emerging, look at the whole footprint. The IEA's threshold for "near-zero emission" crude steel falls from 0.40 t CO₂e per tonne for steel made entirely from ore to 0.05 t for steel made entirely from scrap [S20]. For a charge with about 70% scrap, as planned for RC-1 Phase 1 [S07], the threshold would be about 0.155 t (derived). At the grid average of 226 g/kWh, Scope 2 alone (about 0.22 t) would exceed that threshold; with a contracted hydro supply reported under the market-based method, Scope 2 could approach zero and the plant could approach the near-zero band.

That is the central renewable insight for an electric steelworks in Cameroon: **a dedicated hydro contract is worth more than the grid average**, because it lets the plant claim the hydro attribute that the grid average dilutes. It is also the reason why the wheeling and large-user rules of Chapter 3 matter for climate policy as well as for price.

ON A HYDRO CONTRACT, A CAMEROONIAN ELECTRIC STEELWORKS COULD REACH THE LOW-EMISSION BAND THAT MOST OF ITS COMPETITORS CANNOT.

Cameroon Steel, White paper 05

8.3 Reporting clean power: two methods, two answers

Companies report the emissions of the electricity they buy in two ways. The **location-based** method applies the average emission factor of the grid where the electricity is consumed: for a plant at Kribi, about 226 g CO₂e/kWh on the 2024 average [S10]. The **market-based** method applies the emission factor of the electricity the company has contracted, provided the contract carries a credible claim to the attributes of specific generation, such as a certificate of origin from a hydro plant.

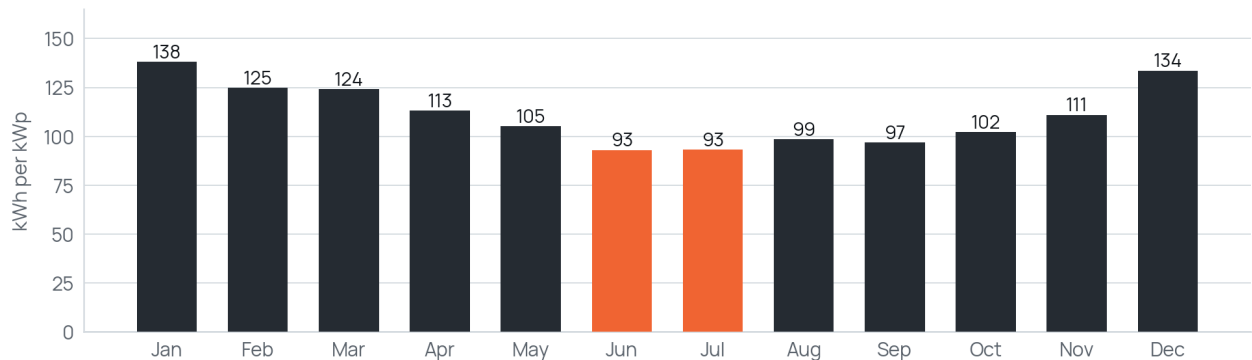
On the location-based method, every user of Cameroon's grid shares the same average, and a steelworks cannot do better than the grid. On the market-based method, a steelworks that contracts hydro output can report close to zero Scope 2 emissions, while the grid average for other users rises correspondingly. The second method is what most buyers of low-emission steel will look for, but it requires two things Cameroon does not yet have: the legal ability to contract with a specific producer, through wheeling or a dedicated utility product, and a registry that issues and cancels certificates so that the same hydro output is not claimed twice. Both are part of the recommendations in Chapter 10.

8.4 A solar plant at Kribi would yield about 1,335 kWh per kWp a year

The European Commission's Joint Research Centre publishes a validated solar model for Africa, PVGIS, based on satellite radiation data. For Kribi, a fixed crystalline-silicon array at its optimal tilt of 6 degrees, with 14% system losses, would produce about 1,335 kWh per kWp a year, a capacity factor of about 15% [S19]. Output peaks from December to February, at about 134 to 138 kWh per kWp a month, and falls to about 93 kWh in June and July, when cloud cover over the coast is heaviest (Figure 8.2).

A solar plant at Kribi would yield about 1,335 kWh per kWp a year, a 15% capacity factor

Monthly output of 1 kWp of fixed crystalline-silicon PV at the optimal 6 degree tilt, 14% system losses (PVGIS, 2005 to 2023 climate)



SOURCED Figure 8.2. A solar plant at Kribi would yield about 1,335 kWh per kWp a year, a 15% capacity factor. Monthly output of 1 kWp at 6 degree tilt; the June and July trough coincides with part of the rainy season.

Source: JRC PVGIS v5.3, radiation database PVGIS-SARAH3, climate 2005 to 2023, Kribi (2.94 N, 9.91 E), accessed 10 October 2026 [S19].

Solar is now cheap to build. IRENA reports that new utility-scale solar commissioned worldwide in 2024 had a global weighted average levelised cost of US\$0.043/kWh, against US\$0.034 for onshore wind and US\$0.057 for new hydropower [S104]. At the planning rate of 600 FCFA per US dollar, US\$0.043/kWh is about 26 FCFA/kWh (derived), below the MV band price and far below the cost-reflective average of Chapter 3. Costs in Cameroon would be higher than the global average because of financing costs, logistics and the lower yield, but solar energy would still compete with grid energy on a per-kWh basis.

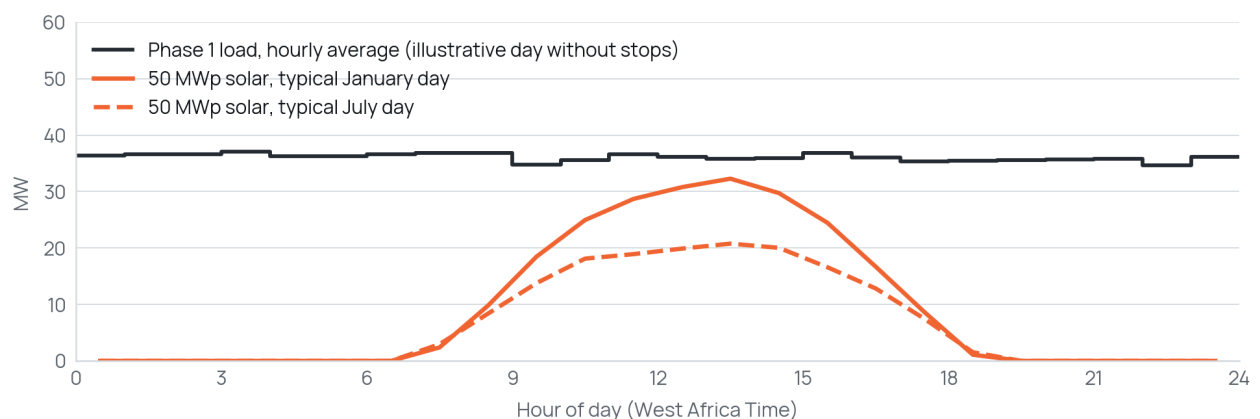
Cameroon's solar output was 67.2 GWh in 2025, 0.8% of generation [S01], so the resource is barely used.

8.5 Solar covers the middle of the day, not the furnace's night shift

The limitation of solar for a steelworks is its shape, not its cost. Figure 8.3 sets the output of a 50 MWp array against an illustrative day of Phase 1 load.

A 50 MWp solar array would cover Phase 1 load only around midday

Solar output from PVGIS average daily irradiance (performance ratio 0.80) against an illustrative Phase 1 load day



ILLUSTRATIVE Figure 8.3. A 50 MWp solar array would cover Phase 1 load only around midday. Solar output from PVGIS average daily irradiance (performance ratio 0.80) for January and July; the load line is an illustrative hourly average for a day without stoppages.

Source: JRC PVGIS v5.3 daily profiles [S19]; illustrative Phase 1 load from RC-1 benchmarks [S07].

A 50 MWp array would produce about 67 GWh a year, about 22% to 23% of Phase 1's 289 to 302 GWh (derived). On a January day it would meet most of the load around midday; on a July day, at most about 20 MW; and at night, nothing. It would therefore reduce the energy bought from the grid but not the firm capacity the plant must contract, and it would not reduce the maximum demand on which capacity charges are based, because the furnace peaks at any hour.

Solar's contribution can be raised in three ways, none of them a substitute for firm supply:

- **Rooftops and land on site.** Mill halls and stores have large roofs, and Phase 1's roofs and yards could host several MWp. On-site solar avoids wheeling and transmission charges, but its size is limited by the area available.
- **Off-site solar with wheeling.** A larger plant elsewhere on the southern grid could supply the steelworks through SONATREL's network under the independent-producer provisions of Law No. 2011/022 [S52], if wheeling and balancing rules are in place (Chapter 3).
- **Scheduling flexible loads.** Some auxiliary loads, such as water treatment and part of the oxygen production with liquid storage, can be shifted to the middle of the day.

8.6 Batteries are for resilience and power quality, not bulk energy

Battery storage has become much cheaper: IRENA reports that the cost of battery storage projects fell by 93% between 2010 and 2024, to about US\$192 per kWh [S104]. For a steelworks, that opens four uses, in decreasing order of value:

1. **Ride-through for essential loads.** A battery can carry cooling water, cranes and fume extraction through short interruptions while standby generators start.
2. **Fast frequency and voltage support.** A battery inverter can respond within milliseconds, helping the grid absorb the furnace's load steps and potentially contributing to flicker mitigation when its converter is designed to act like a STATCOM.
3. **Peak shaving.** By discharging during the highest 15-minute periods, a battery can reduce the billed maximum demand under a capacity-plus-energy tariff (Figure 3.2).
4. **Shifting solar energy into the evening.** This is the least economic use for an arc furnace. Carrying Phase 1's average load of about 36 to 38 MW through a 12-hour night would require more than 400 MWh of storage (derived), many times the capacity needed for the first three uses.

Table 8.1 Renewable and storage options for an electric steelworks at Kribi

Option	Energy contribution	Firm capacity	Carbon effect	Price reference	Preconditions
Grid supply (average)	All needs	As contracted	About 226 g/kWh average (2024)	Chapter 3 benchmarks	Large-user contract
Contracted hydro supply (existing or new plants)	Large share of needs	Seasonal; needs firming	Market-based Scope 2 near zero	Memve'ele purchase price 43.93 FCFA/kWh (wholesale)	Wheeling or utility green contract; firming rules
On-site rooftop and ground solar	A few per cent to about a fifth	None	Reduces grid energy	IRENA global average US\$0.043/kWh (2024)	Roof and land area
Off-site solar with wheeling	Up to about a quarter in daytime	None	Reduces grid energy	As above plus transmission (about 2.7 FCFA/kWh)	Wheeling and balancing rules

Option	Energy contribution	Firm capacity	Carbon effect	Price reference	Preconditions
Battery storage	Small	Short duration only	Indirect	IRENA project cost about US\$192/kWh (2024)	Clear role: ride-through, support, peak shaving
Gas engines (comparison)	Any share	High	About 0.5 t CO ₂ /MWh at the Kribi plant's 2025 efficiency (derived)	Fuel about 17 to 30 FCFA/kWh at 2025 gas prices (derived)	Gas allocation

Source: [S10][S01][S104][S19][S53][S05]; Cameroon Steel analysis. Gas-engine figures derived from the Kribi plant's 2025 gas use and output and the IPCC default emission factor for natural gas (Annex A).

8.7 Hydro is the renewable that matters, and a large user can help build it

Cameroon's hydro potential, about 115,000 GWh a year with only about 4% developed [S66], is the foundation of a low-carbon industrial strategy. The near-term projects on the southern grid are Kikot-Mbebe, 500 MW, with commissioning expected between 2031 and 2033 [S68], and the proposed Grand Eweng, of 1,000 MW in a first phase and up to 1,800 MW [S69]. Recent experience shows both the value and the variability of hydro: Nachtigal delivered 28% below plan in 2025 because of river flows, while Memve'ele delivered 129% above plan [S01].

A large industrial customer can help finance new hydro. A long-term offtake contract from a creditworthy industrial buyer, paid in part in hard-currency-linked prices if the buyer exports, improves the bankability of a new plant compared with sales to a financially stretched utility alone. In return, the industrial buyer obtains a long-term price and a renewable attribute it can report. For this to work, the contract must deal with seasonality. A single-furnace plant that needs most of the year's hours to reach its nameplate cannot absorb sustained dry-season curtailment, since each lost hour costs about one heat of about 40 t (Chapter 9). The hydro supply must therefore be firmed with gas-fired capacity, at a price, while the plant schedules its melting around the daily peak.

8.8 What a hydro-backed supply contract would contain

A long-term hydro-backed contract for an electric steelworks would differ from an ordinary supply contract in five ways:

1. **Volume shape.** Hydro output is seasonal. The contract would specify a baseload volume for the wet season and a reduced, firmed volume for the dry season, rather than a flat profile all year.
2. **Firming.** The difference between the steelworks' load and the hydro volume in dry periods would be covered by firm gas-fired capacity, priced separately. The plant's contribution is to schedule its melting away from the daily peak, not to accept sustained curtailment.
3. **Price and indexation.** A long-term price linked to the cost of the hydro plant, with transparent indexation, would give the plant a cost it can plan around and the hydro project a revenue it can finance.
4. **Attributes.** Certificates of origin, issued and cancelled through a registry, would let the steelworks report the hydro supply under the market-based method and let the hydro project prove its output was not sold twice.
5. **Transmission and balancing.** A wheeling arrangement with the transmission company, and a balancing rule for the hours when supply and demand diverge.

None of these elements is technically unusual. What Cameroon lacks is the published framework within which they can be negotiated, which is why the policy recommendations of Chapter 10 come before any specific contract.

8.9 Hydrogen-based iron is a long-term option tied to new hydro

The longest-term link between renewables and steel is hydrogen. Hydrogen-based direct reduction needs about 54 kg of hydrogen per tonne of DRI, equivalent to roughly 2.4 to 2.8 MWh of electricity per tonne for electrolysis alone (derived from [S93][S35]). A 1 Mtpa hydrogen-based module would therefore need 2.4 to 2.8 TWh a year, about a third of Cameroon's entire 2025 generation. That is achievable only with new hydro on the scale of the large Sanaga projects.

Africa has a first precedent. In Namibia, the Hylron Oshivela project, inaugurated on 11 April 2025, combines 25 MW of solar, a 13.4 MW battery and a 12 MW electrolyser to make hydrogen-based iron at pilot scale, with plans to grow in stages [S105][S106]. Its scale is a reminder of how far there is to go: Cameroon's opportunity is to keep the hydrogen route open, by choosing gas-based reduction plants that can accept hydrogen blending (Chapter 7), and by planning large hydro with industrial offtake in mind.

CHAPTER 9

AN ELECTRIC STEELWORKS AT KRIBI CAN BE SUPPLIED IN THREE STEPS: GRID POWER FIRST, FIRM GAS-BACKED CAPACITY FOR GROWTH, GAS FOR IRON LAST

Cameroon Steel's reference configuration RC-1 indicates an energy demand that rises from about 289 to 302 GWh of electricity a year, an average load of 36 to 38 MW and no gas in Phase 1, to about 753 to 796 GWh, 94 to 99 MW and 0.91 PJ of reheating gas at 1 Mtpa, before any direct-reduction module; the ranges run from the planning value of 450 kWh per tonne in the furnace to the upper value of about 490. These are planned, indicative values. A three-step energy plan matches that growth to Kribi's infrastructure: a dedicated 225 kV connection with on-site compensation for Phase 1; firm, gas-backed capacity in the port substation's later stage for Phases 2 and 3; and a gas allocation for direct reduction only once reserves are certified. Managed well, the plant's schedulable load, with melting timed around the grid's peaks, can make it a useful partner for a hydro-based grid, but it cannot offer sustained interruption.

9.1 RC-1's indicative demand by phase

RC-1 is the reference configuration Cameroon Steel uses to plan its steel complex at Mboro. It is phased. Phase 1 is a bar and wire-rod works with a nameplate capacity of about 0.3 Mtpa of finished products and an expected sustained output of 270,000 to 300,000 t a year, built around one electric arc furnace of the 40 t class, a ladle furnace, a billet caster, induction billet heating, a rebar mill and a high-speed wire-rod mill. Its melt shop makes billets, and output can be flexed between rolled products and merchant billets for the re-rollers that today import about 60% of their charge (billet imports were 161 kt in 2023) [S32][S11]. Because domestic rebar capacity, about 627 kt, is already three and a half times demand of about 180 kt [S107], Phase 1's tonnage is aimed at replacing imported billets and wire rod and at CEMAC exports, not at new rebar sales (White papers 04 and 09). Phase 2 adds a second melt line and a light and medium sections mill for about 0.2 Mtpa. Phase 3 adds melt-shop capacity and a heavy-sections and H-beam mill for about 0.5 Mtpa, bringing the complex to about 1 Mtpa. A direct-reduction module for Cameroonian ore is held in reserve [S07]. Table 9.1 gives the energy balance that follows from RC-1's planning values.

Table 9.1 RC-1 indicative energy and utilities balance by phase (planned and indicative values)

Indicator	Phase 1	Phases 1 and 2	Full build-out	Status
Finished products (t/yr), nameplate	300,000	500,000	1,000,000	planned
Expected sustained output, Phase 1 (t/yr)	270,000 to 300,000	not yet estimated	not yet estimated	derived
Liquid steel (t/yr)	319,149	531,915	1,063,830	derived
Metallic charge (t/yr)	362,669	604,449	1,208,897	derived
of which imported DRI or HBI at a 30% share (t/yr)	108,801	181,335	362,669	assumed share
Electricity at 450 kWh/t in the furnace (MWh/yr)	288,957	421,596	753,191	derived
Electricity at the upper value of about 490 kWh/t (MWh/yr)	301,723	442,872	795,745	derived
Electricity per tonne of product (MWh/t)	0.96 to 1.01	0.84 to 0.89	0.75 to 0.80	derived
Average load at 8,000 h/yr (MW)	36.1 to 37.7	52.7 to 55.4	94.1 to 99.5	derived
Maximum demand (MVA)	55 (45 to 65)	about 85 to 110 (derived)	160 (130 to 190)	assumed
Reheating gas (GJ/yr)	0	260,000	910,000	derived
Reheating gas (bcf/yr)	0	0.24	0.83	derived
Oxygen (million Nm ³ /yr)	11.2	18.6	37.2	derived
Scope 2 emissions at 226 g/kWh (t CO ₂ /yr)	65,304	95,281	170,221	derived
Scope 1 and 2 intensity (t CO ₂ /t product)	0.32	0.33	0.33	derived

Source: Cameroon Steel reference configuration RC-1 (planning estimate), edition 10 October 2026: capacities, benchmarks and balances at nameplate [S07]; upper-value rows at about 490 kWh/t in the furnace and the sustained-output range derived (Annex A; White paper 03, Chapter 5); maximum demand for Phases 1 and 2 as interpolated in White paper 03, Chapter 9 (derived); Scope 2 and intensity at 450 kWh/t, about 0.01 t higher at 490; gas converted at 1.094 GJ per Mscf. Values are planned or indicative and will change with front-end engineering.

Three features of this balance shape the energy plan:

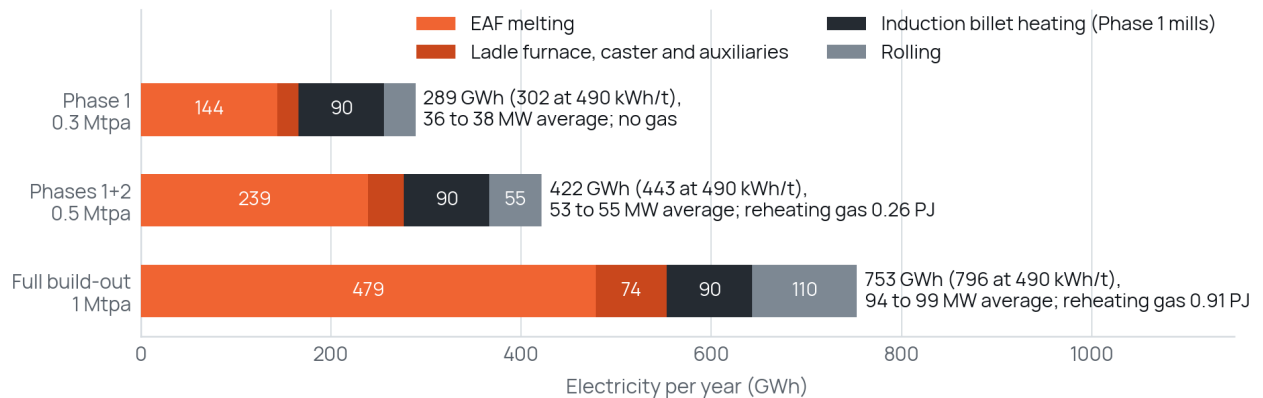
- **Phase 1 is all-electric.** Billets are heated by induction, so Phase 1 needs no gas contract [S07].
- **Electricity per tonne falls as the works grows,** from 0.96 to 0.75 MWh/t, because the later mills reheat with gas and because induction heating is confined to the Phase 1 mills.
- **Gas arrives with Phase 2,** at about 0.24 bcf a year, and reaches about 0.83 bcf at full build-out, a small fraction of the 4.9 bcf the Kribi power plant used in 2025 [S05].

9.2 Melting is half to two-thirds of the electricity

Figure 9.1 breaks the electricity demand down by end use.

Electricity demand rises from 0.29 TWh in Phase 1 to 0.75 TWh at 1 Mtpa

RC-1 electricity by end use and phase at the 450 kWh/t planning value (planned, indicative); melting is half to two-thirds



DERIVED Figure 9.1. Electricity demand rises from 0.29 TWh in Phase 1 to 0.75 TWh at 1 Mtpa; melting is half to two-thirds of the total. RC-1 planning values (planned, indicative); totals at the upper value of about 490 kWh/t in the furnace are shown in brackets.

Source: Cameroon Steel reference configuration RC-1 (planning estimate): 450 kWh/t liquid for the EAF (upper value about 490), 70 kWh/t liquid for the ladle furnace, caster and auxiliaries, 300 kWh/t billet for induction heating of the Phase 1 mills, 110 kWh/t product for rolling [S07].

In Phase 1, the arc furnace takes about 144 GWh a year (50%) at the planning value, or about 156 GWh at the upper value, induction heating about 90 GWh (31%), rolling about 33 GWh (11%) and the ladle furnace and auxiliaries about 22 GWh (8%). At full build-out, the arc furnaces take about 479 GWh (64%), rolling about 110 GWh, the ladle furnaces and auxiliaries about 74 GWh and induction heating still about 90 GWh (derived from [S07]).

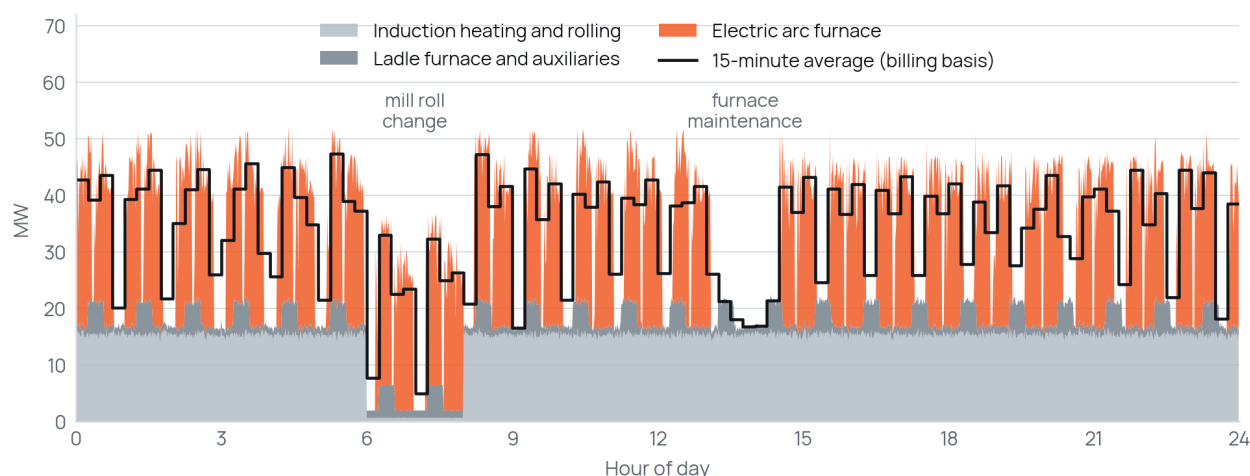
The planning values carry real uncertainty. Using the low and high ends of RC-1's benchmark ranges (347 to 500 kWh/t for the furnace, 50 to 100 for auxiliaries, 150 to 400 for induction heating, 70 to 140 for rolling), Phase 1 electricity would range from about 193 to 354 GWh a year (derived). The furnace's charge also matters. Read as an all-scrap value, the 450 kWh/t planning value rises by about 14.5 kWh/t for each 10% of DRI in the charge [S39], which is why this paper carries about 490 kWh/t, and about 302 GWh a year in Phase 1, as the upper planning value for RC-1's 30% DRI or HBI [S07]. Raising the DRI share further, to 50%, would add another 29 kWh per tonne, about 9 GWh a year. A supply contract for Phase 1 should therefore be written around a range, with a mechanism to adjust contracted capacity after the first year of operation.

9.3 The load swings by 30 to 35 MW within each hour

Average loads hide the shape that matters for the grid. Figure 9.2 is an illustrative operating day of the Phase 1 works, built from RC-1's planning values at one-minute resolution.

Phase 1 load would swing between about 16 and 51 MW within each hour

Illustrative operating day of the RC-1 Phase 1 works at one-minute resolution (not a forecast)



ILLUSTRATIVE Figure 9.2. Phase 1 load would swing between about 16 and 51 MW within each hour. Illustrative operating day: induction heating and rolling form a steady base; the arc furnace adds 20 to 30 MW when its power is on, capped at about 30 MW of active power for a transformer of the 30 to 33 MVA class; the black line is the 15-minute average used for billing.

Source: Cameroon Steel illustration from RC-1 benchmarks: heats of about 40 t and about 18 MWh (450 kWh/t) at roughly one per hour; induction heating 11.25 MW and rolling 4.13 MW while the mill runs; auxiliaries 1.3 MW plus ladle-furnace pulses [S07]. Not a forecast.

Three numbers from this illustration are useful for contracting (derived):

- the **steady base** of about 16 to 18 MW (mill, induction heating and auxiliaries) runs whenever the mill runs;
- the **furnace adds 20 to 30 MW** for about 45 minutes in every hour, so the instantaneous load moves by about 30 to 35 MW within each cycle;
- the **15-minute average** peaks at about 47 MW, against a planned maximum demand of 55 MVA (45 to 65) [S07]. The ratio of average load to maximum demand is about 65% to 70%, which is why the structure of the capacity charge matters (Chapter 3).

The illustration also shows the two kinds of planned stoppage that a supply contract must accommodate: a mill stop, for example for a roll change, which removes the steady base for an hour or two, and a furnace stop for maintenance, which removes the fluctuating component. Each is a step change of 15 to 30 MW that the grid operator should know about in advance.

9.4 A three-step energy plan

Table 9.2 sets out a plan that matches each phase of the steelworks to the energy infrastructure available at Kribi and to the policy steps proposed in Chapter 10.

Table 9.2 A phased energy plan for an electric steelworks at Kribi (indicative)

Element	Step 1: Phase 1 (works from 2029, first heat H2 2030)	Step 2: Phases 2 and 3 (indicative, from 2032)	Step 3: DRI reserve (after 2034, indicative)
Grid connection	Dedicated 225 kV bay at the port substation; 225/33 kV plant substation	Extension within the substation's 330 to 400 MW stage	As step 2
Contracted capacity	About 55 MVA (45 to 65)	Up to about 160 MVA (130 to 190)	Plus the DRI module's load
Energy supply	Large-user contract with the utility or an independent producer	Add firm gas-backed capacity at the Kribi gas plant	As step 2; hydro supply for hydrogen blending later

Element	Step 1: Phase 1 (works from 2029, first heat H2 2030)	Step 2: Phases 2 and 3 (indicative, from 2032)	Step 3: DRI reserve (after 2034, indicative)
Power quality	SVC or STATCOM and filters from a connection study	Extend for further furnaces (cubic flicker summation)	As step 2
Gas	None	0.24 to 0.83 bcf/yr for reheating, by pipeline from the gas plant	About 8.4 to 9.1 bcf/yr for 1 Mtpa of DRI
Renewables	On-site solar where economic; hydro attribute if wheeling rules allow	Long-term hydro contract linked to new capacity	Hydrogen-ready shaft furnace
Essential loads	Standby generators and battery ride-through	Extend	Extend
Flexibility	Melting scheduled around peaks; capped emergency load-shedding	As step 1, across several furnaces	DRI module can modulate within limits
Policy prerequisite	Large-user tariff; grid code for fluctuating loads	Gas allocation; wheeling rules	Certified reserves; DRI gas price formula

Source: Cameroon Steel analysis; Cameroon Steel reference configuration RC-1 (planning estimate) [S07]; PAK [S14]; gas volumes derived (Chapters 6 and 7).

Step 1 relies only on infrastructure that will exist by the end of 2026: the 225 kV line and substation [S14]. Its critical needs are contractual (a large-user supply contract) and technical (the connection study and compensation). It needs no gas, which insulates the first phase from the uncertainty created by the FLNG's departure.

Step 2 depends on two things outside the plant: the substation's later stage of 330 to 400 MW, and firm thermal capacity to cover dry seasons and transmission outages. The natural source of that capacity is the Kribi gas plant, through a dedicated part of its output or an extension within its 330 MW licence [S21][S22], which in turn requires a gas allocation. Reheating gas for the sections mills is small and could be delivered by a pipeline spur from the gas plant.

Step 3 depends on the gas and ore conditions set out in Chapter 7. It should not be a planning assumption until reserves are certified and a DR-grade pellet supply is identified.

PHASE 1 NEEDS NO GAS, A DEDICATED 225 KV BAY AND A LARGE-USER CONTRACT. EVERYTHING ELSE CAN FOLLOW THE GRID AND GAS REFORMS.

Cameroon Steel, White paper 05

9.5 What the electricity would cost in Phase 1

At the three price benchmarks used in this paper, Phase 1's electricity bill at the planning value of 289 GWh would differ by a factor of almost six (derived from [S07][S01][S03][S04]); at the upper value of about 302 GWh each figure is about 4% higher:

- at the legacy high-voltage average of 18.4 FCFA/kWh, about 5.3 bn FCFA a year;
- at the 2026 all-in price of the 9 to 10 MW MV band, 43.7 FCFA/kWh, about 12.6 bn FCFA a year, and about 16.4 bn FCFA at the 56.7 FCFA/kWh that the same structure would imply for the plant's peaky load shape;
- at the regulator's cost-reflective average of 105.46 FCFA/kWh, about 30.5 bn FCFA a year.

For comparison, Cameroon's largest existing steel group, Prometal, paid about 8.37 bn FCFA for electricity in 2024 for a load of about 40 MW [S42]. These are indicative operating-cost figures based on public price benchmarks, not estimates of any contract. They show why the price framework of Chapter 3 is the single largest energy variable in the plant's economics, larger than any plausible gain from energy efficiency inside the plant,

and why the structure of the capacity charge matters as much as the energy price. White paper 04 (Chapter 8) places this power cost beside the cost of metallics and conversion in an indicative comparison of a Kribi billet with an imported one.

9.6 Schedulable load can make the steelworks a partner for the grid, within limits

An arc-furnace steelworks is often seen as a problem for a grid. On a hydro-based system with seasonal short-falls, it can also be part of the solution, because part of its load can be moved within the day at low cost.

SOURCES OF FLEXIBILITY IN AN ELECTRIC STEELWORKS (INDICATIVE, PHASE 1)

- **Heat scheduling.** At the expected sustained output, the furnace is not scheduled to operate for about 1,000 to 1,800 hours a year, some three to five hours a day. Placing those hours in the evening peak of the dry season moves the furnace's average of about 18 MW out of the peak without reducing annual output.
- **Ladle-furnace holding.** Holding steel at temperature in the ladle furnace lets the melt shop delay the next power-on by minutes around a system event.
- **Planned maintenance timing.** Furnace relines and mill roll changes can be scheduled for the periods when the grid is tightest.
- **Auxiliary shifting.** Oxygen production with liquid storage and water treatment can be moved within the day.
- **Peak shaving.** Power management that prevents the furnace and ladle furnace from peaking together lowers the billed maximum demand.

Derived from the illustrative load profile (Figure 9.2) and RC-1 planning values [S07].

This flexibility is schedulable, not interruptible. A single furnace needs about 7,300 to 7,900 hours a year to cast Phase 1's nameplate tonnage (White paper 03, Chapter 5), so each hour of curtailment beyond the planned non-melting hours costs about one heat (about 40 t) that cannot be recovered later: about 4,000 t of liquid steel, some 1.3% of nameplate liquid output, for every 100 hours (derived). On a system with a peak of 1,278 MW [S01], moving the furnace's 20 to 30 MW out of the evening peak is worth about 1.6% to 2.3% of peak demand, a useful contribution for a grid that left 150 MW of industrial demand unserved in 2026 [S02]. The large-user framework should therefore reward scheduling, through time-of-use energy prices or a capacity charge measured at the system peak, and cap any emergency load-shedding in hours and events a year, with notice that lets the heat in progress be finished safely.

9.7 Energy management inside the plant

The plant's own practices determine where it falls within the benchmark ranges. The main levers in an electric steelworks are well known:

- **Furnace practice.** Continuous charging with scrap preheating, as in the Consteel process, has achieved about 321 kWh/t with power savings of 10% to 15% and electrode consumption below 1 kg/t [S38]; good scrap preparation and foamy-slag practice reduce energy and flicker together.
- **Hot charging.** Synchronising the caster and mill so that billets reach the induction heaters still hot reduces Phase 1's induction energy towards the low end of its 150 to 400 kWh/t range [S07].
- **Metering and monitoring.** Sub-metering of every major consumer, with real-time dashboards for kWh per tonne, power-on time, electrode use and power quality at the point of common coupling, turns benchmarks into daily targets.
- **Reporting.** Publishing energy intensity and Scope 2 emissions annually, on both the location-based and market-based methods, supports the low-emission positioning described in Chapter 8.

CHAPTER 10

FIVE RULES, NOT SUBSIDIES, WOULD MAKE CAMEROON'S ENERGY SYSTEM READY FOR HEAVY INDUSTRY

Cameroon does not need to subsidise energy to attract an electric steelworks; it needs to publish the rules on which large users can plan and borrow. Five steps would make the energy system bankable for heavy industry: a large-user tariff framework above 10 MW; a grid code for fluctuating loads; a domestic gas allocation and price framework after the FLNG; enforceable wheeling and third-party access; and integrated planning of substations, firm capacity and hydro around industrial zones. Each would benefit every large user, and none commits public money to a single project.

10.1 The case for rules rather than deals

The previous chapters show a consistent pattern. Cameroon has the physical ingredients of a low-carbon heavy-industry platform: a hydro grid at about 226 g CO₂e/kWh [S10], a new 225 kV supply to the Kribi industrial-port zone [S14], a gas field next to the port that has just lost its export buyer [S05][S16], and about 115 TWh a year of undeveloped hydro potential [S66]. What it lacks are published rules for the transactions that turn these ingredients into investable supply.

Today, a large user negotiates its electricity price without a published tariff [S01], its connection without a published code for fluctuating loads, its gas without published allocation rules, and its access to independent producers without published wheeling and balancing rules. Each negotiation is bespoke, slow and revisable, and lenders discount it accordingly. The steel producers' 2023 dispute over tariffs [S44][S45] and the regulator's 2025 revision of certain high-voltage contracts [S01] show the cost of that uncertainty.

The recommendations below are therefore framed as public rules, not as concessions to one project. They draw on the evidence in Chapters 1 to 9 and are summarised in Table 10.1.

10.2 Publish a large-user tariff framework above 10 MW

What. ARSEL, with the Ministry of Water and Energy (MINEE), should publish a tariff framework for customers above 10 MW connected at 90 kV or 225 kV, extending the logic of the existing MV grid [S54][S03] rather than replacing it. Its principles should be:

- **Cost of service at high voltage.** The price should reflect the cost of serving a high-voltage, high-load-factor customer: energy, transmission, losses and the cost of firmness, without the distribution and low-voltage costs embedded in the 105 FCFA/kWh system average [S04]. Chapter 3's indicative stack suggests this is roughly half the system average before firmness is priced.

- **Two-part structure with utilisation regimes.** A capacity charge on a stated 15-minute maximum demand and an energy charge, with regimes that reward high utilisation, as the MV grid already does above 400 hours a month [S03].
- **A reward for scheduled load.** Time-of-use energy prices, or a capacity charge measured at the system peak, that reward load moved out of the peak, with any emergency load-shedding capped in hours and events a year and compensated beyond the cap.
- **Explicit reactive-energy rules** that reward local compensation.
- **Indexation by formula.** Annual adjustments tied to published indices (hydro purchase prices, gas prices, inflation), replacing discretionary revisions.
- **Long terms.** Contracts of 10 to 20 years, so that lenders can match them to debt.
- **A transition path for legacy contracts.** The six legacy high-voltage contracts at about 18.4 FCFA/kWh [S01] should converge over a published period to the framework, so that new and existing users compete on equal terms.

Why. It would give every large user a published basis for its business case, give the utility a principled basis for pricing, and give lenders a framework they can analyse.

10.3 Adopt a grid code for fluctuating loads

What. ARSEL and SONATREL should publish, or confirm and complete, the power-quality chapter of the connection code for large fluctuating loads such as arc furnaces, rolling mills and large motors. ARSEL's website lists a connection code among its regulatory texts, but its content could not be verified for this paper [S71]. The code should:

- adopt the emission-allocation approach of IEC TR 61000-3-7 for flicker, with the planning levels of Pst 0.8 and Plt 0.6 at high voltage as the default [S13], and a recognised standard for harmonics such as IEEE Std 519-2022 [S73];
- oblige the transmission operator to publish minimum and maximum fault levels at 90 kV and 225 kV nodes, so that investors can screen sites;
- require a connection study for any load above a threshold, with the plant paying for its compensation and the network operator providing the connection strength;
- require permanent power-quality monitoring at the point of common coupling, with data shared between plant and operator, and commissioning tests before acceptance.

Why. Clear obligations protect other users from disturbance and protect the steelworks from open-ended demands. Cameroon already has a domestic precedent to learn from in Prometal's high-voltage arc-furnace connection in Douala [S42][S01].

CLEAR OBLIGATIONS PROTECT OTHER USERS FROM DISTURBANCE AND PROTECT THE STEELWORKS FROM OPEN-ENDED DEMANDS.

Cameroon Steel, White paper 05

10.4 Create a domestic gas allocation and price framework

What. SNH, the ministries responsible for hydrocarbons and energy, and the upstream partners should replace the FLNG-era arrangement with a domestic framework that includes:

- an **independent audit of remaining reserves** in Sanaga Sud and Ebome, published in summary with a deliverability profile [S17][S84];
- a **priority order and indicative volumes** for power generation (including firm capacity for industry), industrial heat and chemical uses such as direct reduction;
- **price formulas by class of user**, set high enough to sustain upstream investment and predictable enough for industrial financing, building on the 2025 reference prices of about US\$3.2/Mscf for power and US\$5.0 to 5.6/Mscf for industry [S05];
- **tax clarity** on whether, and at what rate, the special petroleum tax of 70 FCFA/m³ applies to industrial gas [S87];
- **infrastructure responsibility** for a pipeline from the Kribi gas plant's receiving facilities to the industrial-port zone;
- **standard contract terms**, and a rule for how new discoveries such as Yoyo-Yolanda [S17] are brought into the domestic system.

Why. Gas is the only domestic source of firm thermal power and the only near-term route to making iron from Cameroonian ore. Without published allocation rules, neither a firm-capacity contract nor a direct-reduction plant can be financed.

10.5 Make wheeling and third-party access work in practice

What. Law No. 2011/022 already allows independent producers to sell to eligible customers at negotiated prices [S52], and SONATREL publishes a transmission tariff [S53]. The missing pieces are operational:

- publication of the market code and the balancing rules: how a large user's consumption is matched with its producer's injections, how imbalances are settled and at what price;
- a **back-up and top-up tariff** for when the contracted producer is unavailable;
- a **certificate of origin** scheme, so that hydro or solar supplied under contract can be claimed under the market-based Scope 2 method;
- a published list of the eligibility threshold for customers who may contract directly.

Why. Wheeling would let large users contract directly with new hydro and solar projects, improving their bankability and letting industry claim the low-carbon attribute that Chapter 8 shows is worth more than the grid average.

THE TEST OF A GOOD FRAMEWORK

A lender reading a large user's power, gas and connection contracts should be able to answer four questions from published documents alone: how the price will move, how firm the supply is, what happens when it fails, and who pays for the assets. Today, none of the four can be answered from the public record for a load above 10 MW.

10.6 Plan substations, firm capacity and hydro around industrial zones

What. PAK, KPIZ S.A., SONATREL, the utility, SNH and MINEE should plan the Kribi industrial-port zone's energy supply as a single programme:

- a **demand register** of prospective tenants with phased loads, updated yearly, to size the port substation's later stage of 330 to 400 MW [S14];
- **capacity reservation** against project milestones and a reservation fee, so that large users can finance their plants and the zone can plan its expansion;
- **shallow connection charges**, so that each tenant pays for its dedicated assets and contributes to shared assets through regulated tariffs;
- **firm capacity at Kribi**, through the extension of the Kribi gas plant within its 330 MW licence [S21][S22] or new capacity, once gas is allocated;
- **industrial offtake for new hydro**, such as Kikot-Mbebe [S68], so that large users help finance the low-carbon capacity they will consume.

Why. It would align the timing of the zone's energy supply with its tenants' investments and avoid the situation, visible nationally today, of industrial demand waiting for transmission [S02].

Table 10.1 Policy recommendations, responsibilities and timing

No.	Recommendation	Lead	Partners	Suggested timing	Benefit for all large users
1	Large-user tariff framework above 10 MW	ARSEL	MINEE, utility, SONATREL, industry bodies	Consultation 2027; in force 2028	Published, cost-based price and indexation
2	Grid code for fluctuating loads	ARSEL, SONATREL	Utility, industry	2027	Clear power-quality obligations; published fault levels
3	Domestic gas allocation and price framework	SNH and the ministries responsible for hydrocarbons and energy	Upstream partners, ARSEL	Reserve audit 2027; framework 2027 to 2028	Financeable gas contracts for power and industry
4	Wheeling, balancing and certificates of origin	ARSEL, SONATREL	IPPs, utility	2027 to 2028	Direct contracts with hydro and solar producers
5	Integrated energy planning for the Kribi zone	PAK, KPIZ S.A.	SONATREL, utility, SNH, MINEE	Demand register 2027; later-stage substation design 2027 to 2028	Capacity when tenants need it; fair connection charges
6	Energy data transparency	ARSEL, SNH, SONATREL	Statistics institute	Annual from 2027	Fault levels, gas balance, grid emission factors

Source: Cameroon Steel recommendations, based on the evidence in Chapters 1 to 9. Timing is indicative.

The sixth line in the table is a cross-cutting request. Several of this paper's evidence gaps (Chapter 11) are basic public data: the fault levels at major nodes, a reconciled national gas balance, and a harmonised grid emission factor. Publishing them annually would cost little and would help every investor.

10.7 Sequencing the five steps

The five steps do not need to wait for one another, but some are needed sooner than others.

First, by 2027: the tariff framework and the grid code. These are the two rules a first-phase electric steelworks needs before it can sign a supply contract and specify its compensation. Both are within the regulator's existing powers, both can build on texts that already exist (the MV tariff grid [S54][S03] and the connection code listed on the regulator's website [S71]), and both would benefit every large user immediately.

In parallel, from 2027: the gas reserve audit. The audit is the precondition for everything else in gas, from firm power at Kribi to any direct-reduction plant. It takes time, so it should start as soon as possible after the FLNG's departure, even though an electric steelworks' first phase does not need gas.

By 2028: wheeling, balancing and certificates; the gas allocation framework. These rules matter for the second phase of an electric steelworks and for the first contracts between industrial users and new hydro or solar producers. They require more consultation, because they affect the utility's revenue and the upstream partners' economics.

Continuously: integrated planning of the Kribi zone. The demand register, capacity reservation and connection-charge policy should start with the commissioning of the 225 kV line at the end of 2026 [S14] and be updated every year.

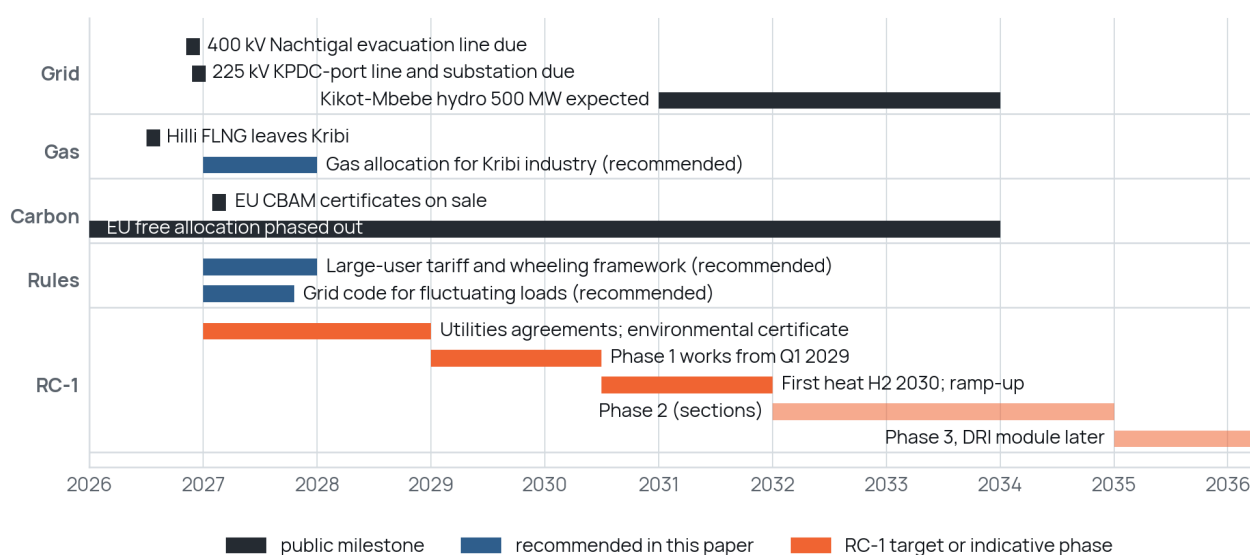
None of these steps commits public money to a particular project. Each sets out how costs and risks are shared between the State, the utility, the transmission company, the gas sector and the users, which is precisely what investors and lenders need to see.

10.8 The milestones ahead

Figure 10.1 places these recommendations alongside the public milestones that are already scheduled and the indicative targets of RC-1.

The energy milestones Cameroon and an electric steelworks must meet, 2026 to 2036

Public milestones, recommended policy steps and RC-1 targets (targets and indicative phases are not commitments)



ILLUSTRATIVE Figure 10.1. The energy milestones Cameroon and an electric steelworks must meet, 2026 to 2036. Public milestones (dark), recommended policy steps (blue) and RC-1 targets or indicative phases (orange; not commitments).

Source: Business in Cameroon, 9 October 2026 [S02]; PAK, 6 August 2025 [S14]; Kikot-Mbebe [S68]; FLNG departure [S16]; CBAM [S108][S109]; Cameroon Steel reference configuration RC-1 (planning estimate), indicative schedule [S07].

The sequence is favourable if the next two years are used well. The grid and port milestones fall at the end of 2026 and early 2027. The policy steps proposed here could be in place by 2028. Phase 1 of an electric steelworks is targeted to start works in the first quarter of 2029, after its environmental certificate, with a first heat in the second half of 2030 and ramp-up in 2031 [S07]. The European Union's free allocation for its own steelmakers falls to zero by 2034 [S109], when low-carbon steel will be most valuable.

FIRM POWER, A PUBLISHED PRICE AND AN ALLOCATED GAS SUPPLY: THREE RULES THAT WOULD MAKE CAMEROON'S HYDRO GRID AN INDUSTRIAL ASSET.

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10.9 What large users can offer in return

Rules work best when obligations run both ways. In exchange for a published framework, an electric steelworks and other large users can offer the energy system:

- **long-term, high-load-factor demand** that improves the utilisation of new transmission and generation;
- **investment in their own compensation and dedicated assets**, so that the shared network is not burdened by their disturbances;
- **schedulable load**, through melting timed around the system peak and scheduled maintenance, worth about 1.6% to 2.3% of the national peak for a single plant of RC-1's first phase (Chapter 9);
- **anchor offtake for new hydro**, through long-term contracts that improve the bankability of projects such as Kikot-Mbebe;
- **transparency**, through shared power-quality data and published energy and emissions indicators.

CHAPTER 11

THIRTEEN EVIDENCE GAPS REMAIN, AND MOST CAN BE CLOSED BY PUBLISHING DATA THAT ALREADY EXIST

This paper relies on public sources, and several numbers that matter for an electric steelworks are not yet in the public record. The most important are the fault level at Kribi's 225 kV node, the remaining certified gas reserves of Sanaga Sud, the terms of large-user and wheeling contracts, and the text of the grid connection code. Most of these gaps can be closed by data that institutions already hold; others will be closed by Cameroon Steel's own studies as the project advances. This chapter lists each gap, why it matters and how it will be resolved.

11.1 Why the gaps matter

Every chapter of this paper has drawn a conclusion from incomplete evidence, and has said so. A reader who wants to act on the conclusions needs to know which ones are robust and which depend on numbers still to be confirmed. The conclusions that are **robust to the gaps** are these:

- Cameroon's electricity is predominantly hydro and low-carbon, whichever dataset is used [S01][S10].
- No regulated tariff exists for loads above 10 MW, and the published benchmarks span a factor of about six [S01][S03][S04].
- An arc furnace of RC-1 Phase 1 size needs a strong high-voltage connection and dynamic compensation at any plausible fault level at Kribi.
- The Hilli FLNG's departure removed the main buyer of Cameroonian gas [S05][S16].
- Phase 1 of an electric steelworks needs no gas [S07].

The conclusions that **depend on the gaps** concern sizes and timing: how much compensation is needed, how much gas is available for how long, at what price large users will contract, and when the port substation's later stage will be built.

11.2 The gaps and how they will be closed

Table 11.1 Evidence gaps, their importance and the route to resolution

No.	Gap	Why it matters	How it will be resolved	Who holds the data	Target
1	Fault levels (minimum and maximum, normal and contingency) at the Kribi 225 kV node and the port's 30 kV busbar	Sets the size of compensation and the choice of connection (Chapters 4 and 5)	Request to SONATREL; connection study by the steelworks' engineers	SONATREL	Front-end engineering, 2027

No.	Gap	Why it matters	How it will be resolved	Who holds the data	Target
2	Background flicker and harmonics at Kribi	Determines the share of planning levels available to a new plant	Power-quality measurement campaign at the port substation after commissioning	SONATREL, PAK	2027
3	Text and power-quality provisions of ARSEL's connection code and market code	Defines obligations for fluctuating loads and wheeling rules (Chapters 3 and 4)	Formal request to ARSEL; links listed on its website could not be opened on 10 October 2026 [S71]	ARSEL	Before connection application
4	Remaining certified reserves and deliverability profile of Sanaga Sud and Ebome, and the volume already produced against the 500 bcf allocated to the FLNG in 2014	Decides whether firm gas-fired capacity and a DRI module can be financed (Chapters 6 and 7)	Independent reserve audit; request to SNH and the operator	SNH, operator	Before any gas contract
5	Reconciliation of SNH 2025 gas sales by buyer (79.6 bcf) with field production (75.5 bcf)	Affects the gas balance in Figure 6.1	Clarification from SNH on reporting bases (stocks, fiscal versus physical volumes)	SNH	2027
6	Application of the special petroleum tax (70 FCFA/m ³) to industrial gas	Can nearly double the delivered gas price for industry (Chapter 6)	Primary legal text and administrative ruling	Ministry of Finance, SNH	Before a gas term sheet
7	Terms of existing high-voltage contracts and the basis of the 2025 revisions	Sets precedent for a large-user contract (Chapter 3)	Public summary by ARSEL of the principles applied, without commercial detail	ARSEL, utility	With the large-user framework
8	IFI-harmonised combined-margin grid emission factor for Cameroon	Determines Scope 2 accounting for lenders (Chapter 8)	Retrieve from the IFI harmonised dataset; compare with the average of 226 g/kWh	International financial institutions	ESIA stage
9	Difference between the regulator's 2025 generation mix and the international dataset for 2024	Affects the grid intensity used in carbon claims	Reconcile ARSEL plant data with Ember inputs; prefer metered data	ARSEL, Ember	2027
10	Firm availability of the Kribi gas plant and terms for a dedicated block or extension	Determines how Phases 2 and 3 are firmed (Chapters 5 and 9)	Discussions with the plant's owners after the State's acquisition closes	KPDC owners, utility	After closing, expected end-2026
11	Schedule and financing of the port substation's later stage (330 to 400 MW)	Determines when the full works can connect (Chapter 5)	Demand register and planning with PAK and KPIZ S.A.	PAK, KPIZ S.A., SONATREL	2027 to 2028
12	DR-grade pellet supply and prices; the extent of Cameroonian concentrate options	Decides the economics of a DRI module (Chapter 7)	Market study of DR-pellet suppliers; ore studies under the mining convention	Market, Cameroon Mining Company	Before the DRI reserve is activated
13	Supplier-guaranteed furnace electricity per tonne (planned within 450 to 490 kWh/t) and furnace availability	Sets Phase 1 demand (about 289 to 302 GWh a year) and the hours left for scheduling around peaks (Chapters 1 and 9)	Performance guarantees in front-end engineering; transformer rating	Technology supplier, Cameroon Steel	Front-end engineering, 2027

Source: Cameroon Steel analysis.

11.3 Gaps that are specific to the project

Some uncertainties belong to the steelworks rather than to the public record, and Cameroon Steel will resolve them through its own engineering:

- **Benchmarks versus guarantees.** RC-1's energy figures are planning values from published benchmarks [S07]. Front-end engineering with the technology supplier will replace them with guaranteed consumption figures for the furnace, ladle furnace, induction heaters and mills. The Phase 1 electricity estimate, planned at about 289 to 302 GWh a year, could move within the wider range of about 193 to 354 GWh shown in Chapter 9.
- **Maximum demand for Phases 1 and 2.** RC-1 estimates maximum demand for Phase 1 and the full works but not for the intermediate stage, for which White paper 03, Chapter 9, interpolates about 85 to 110 MVA (derived). It will be estimated when the second melt line is specified.
- **Metallic charge.** The share of imported DRI or HBI, planned at about 30% within a range of 20% to 50% [S07], affects both furnace electricity and Scope 3 emissions. It will depend on scrap availability and prices, which are the subject of other papers in this series.
- **The induction-heating trade-off.** The planning value of 300 kWh per tonne of billet depends on how much hot charging is achieved. Plant trials after commissioning will establish the real figure.

11.4 Data that would help every investor

Several gaps would disappear if a few institutions published data they already hold. Chapter 10 recommends an annual energy data release covering: fault levels at major high-voltage nodes; a reconciled national gas balance by field and by buyer; generation by plant with planned and actual output; and a harmonised grid emission factor. The regulator's 2025 annual report [S01] and SNH's 2025 petroleum data [S05] already go a long way: this paper could not have been written without them. Extending them in these directions would serve every industrial investor considering Cameroon.

11.5 How this paper will be updated

This is a first edition. Cameroon Steel intends to update it when material new evidence becomes available, in particular:

- after the 225 kV Kribi line and substation are commissioned, with measured network data;
- after the State's acquisition of the Kribi and Dibamba thermal plants closes [S29];
- after the publication of any large-user tariff framework, gas allocation framework or wheeling rules;
- after Cameroon Steel's front-end engineering for Phase 1.

Each update will state what changed and why, and will keep the status labels (sourced, derived, assumed, illustrative) used throughout this edition.

ANNEX A

METHOD, ASSUMPTIONS AND CALCULATIONS

This annex sets out how the figures in this paper were produced: the evidence statuses, the conventions and conversion factors, the assumptions with their ranges, and the arithmetic behind every derived number. The data behind each chart are tabulated in Annex D and published with the web edition as data files, and the charts are generated by a script from the same values, so that text, tables and charts cannot drift apart.

A.1 Evidence statuses

Every figure in this paper carries one of four statuses, shown as a chip on each exhibit:

- **Sourced:** read from a published source listed in Annex C.
- **Derived:** Cameroon Steel's arithmetic on sourced or planned inputs, shown in this annex.
- **Assumed:** a stated planning assumption, with a range.
- **Illustrative:** a scenario or a picture of how something works, not a forecast.

Three further words qualify RC-1 values only, never a sourced figure: planned (a value of the reference configuration), indicative (a later phase or a value still to be engineered) and target (a schedule date).

Project figures come from the Cameroon Steel reference configuration RC-1 (planning estimate), edition of 10 October 2026, as revised on that date (RC-1.1) [S07]. They are planned or indicative values derived from published benchmarks and will be replaced by supplier guarantees at front-end engineering. They are not commitments.

A.2 Conventions and conversion factors

- **Currency.** The CFA franc (FCFA, XAF) is pegged to the euro at 655.957 FCFA per euro. The US dollar rate floats; this paper uses a planning rate of 600 FCFA per US dollar (range 560 to 650) [S07], except where a source states its own rate. SNH's 2025 accounts use quarterly rates from 624.9 to 561.0 FCFA per US dollar [S05].
- **Gas volumes and energy.** 1 Mscf (thousand standard cubic feet) is taken as 1.037 MMBtu, or about 1.094 GJ on a higher-heating-value basis; 1 bcf is therefore about 1.094 PJ. 1 m³ is 35.315 standard cubic feet, so 1 Mscf is 28.317 m³. With these factors, 9.2 to 10 PJ is 8.4 to 9.1 bcf [S39][S41].
- **Electricity.** 1 MWh is 3.6 GJ of final energy. worldsteel counts each MWh as about 9.8 GJ of primary energy [S35].
- **Tonnes.** Finished products are bars, wire rod and sections; liquid steel is steel tapped from the furnace; the metallic charge is scrap plus DRI or HBI. Nameplate output is the design capacity; expected sustained output is the planning range for a mature year (270,000 to 300,000 t in Phase 1).
- **Operating hours.** Average loads are annual energy divided by 8,000 operating hours a year, as in RC-1 [S07].

A.3 Assumptions and ranges

Table A.1 Assumptions used in this paper, with ranges and status

Parameter	Value	Range	Status	Basis
FCFA per US\$ (planning rate)	600	560 to 650	assumed	RC-1 [S07]
EAf electricity, planning value	450 kWh/t liquid	347 to 500	sourced	IFC 2007 [S36]
EAf electricity, upper planning value with 30% DRI or HBI	About 490 kWh/t liquid (493.5)	not applicable	derived	450 + 3 x 14.5 [S39]
Furnace transformer, Phase 1	30 to 33 MVA class	about 30 MW of active power with short-term overload	assumed	RC-1 [S07]
Ladle furnace, caster and auxiliaries	70 kWh/t liquid	50 to 100	assumed	RC-1 [S07]
Induction billet heating (Phase 1)	300 kWh/t billet	150 to 400	assumed	RC-1 [S07]
Rolling	110 kWh/t product	70 to 140	sourced	IFC 2007 [S36]
Gas-fired reheating (Phases 2 and 3)	1.3 GJ/t product	1.1 to 1.6	assumed	RC-1 [S07]; EU BAT range [S40]
Gas for DRI	9.2 to 10 GJ/t DRI	RC-1 planning 10 (9.2 to 10)	sourced / assumed	[S39][S41][S07]
DRI or HBI share of the metallic charge	30%	20% to 50%	assumed	RC-1 [S07]
EAf penalty for DRI	14.5 kWh/t per 10% DRI	not given	sourced	Energiron [S39]
Metallic yield	0.88 t liquid per t metallics	0.85 to 0.91	assumed	RC-1 [S07]
Casting and rolling yield	0.94 t product per t liquid	0.92 to 0.96	assumed	RC-1 [S07]
Grid emission factor	226 g CO ₂ e/kWh	200 to 300	sourced	Ember via OWID, 2024 [S10]
Natural gas emission factor	0.0561 t CO ₂ /GJ	not applicable	sourced	IPCC 2006 default [S07]
Oil-fired generation emission factor	0.75 t CO ₂ /MWh	0.70 to 0.80	assumed	Paper assumption for light and heavy fuel oil plants
Maximum demand, Phase 1	55 MVA	45 to 65	assumed	RC-1 [S07]
Maximum demand, full build-out	160 MVA	130 to 190	assumed	RC-1 [S07]
Power factor for maximum demand	0.95	0.90 to 0.98	assumed	Paper assumption (compensated plant)
Furnace short-circuit power SscF	About twice the rating of a transformer of the 30 to 33 MVA class	1.5 to 2.5 x the rating	assumed	Paper screening assumption
Flicker factor Kst	48 to 85	not applicable	sourced	UIE, as cited in [S12]

Parameter	Value	Range	Status	Basis
SVC flicker reduction	factor 0.5	not given	sourced	[S12]
Port 30 kV transformer impedance	12% to 18%	not applicable	assumed	Typical values for 60 MVA units
PV performance ratio (daily profile)	0.80	0.75 to 0.85	assumed	Paper assumption
Rebar export reference price	US\$625/t	US\$620 to 630	sourced	AISU, 3 October 2026 [S09]

Source: as listed.

A.4 Derivations

RC-1 balances. Liquid steel equals finished products divided by the casting and rolling yield (0.94); the metallic charge equals liquid steel divided by the metallic yield (0.88); the DRI or HBI quantity equals the metallic charge times 30%. Electricity equals liquid steel times (450 + 70) kWh/t, plus 300 kWh/t on the 300,000 t of the Phase 1 mills, plus 110 kWh/t on all finished products. For Phase 1 this gives 319,149 t of liquid steel and 288,957 MWh; for the full works 1,063,830 t and 753,191 MWh [S07]. At the upper planning value the furnace uses 40 kWh more per tonne of liquid steel: 301,723 MWh in Phase 1, 442,872 MWh for Phases 1 and 2 and 795,745 MWh at full build-out, or 37.7, 55.4 and 99.5 MW on 8,000 hours (derived). Reheating gas is 1.3 GJ/t on the products of Phases 2 and 3: 260,000 GJ for 200,000 t and 910,000 GJ for 700,000 t.

Electricity cost per tonne (Table 1.2). Cost per tonne equals the electricity intensity (0.963 MWh/t in Phase 1; 0.753 MWh/t at full build-out) times the price in FCFA/kWh times 1,000, converted at 600 FCFA per US dollar. For example, $0.963 \times 43.7 \times 1,000 = 42,091$ FCFA/t, or US\$70.2/t. At the upper planning value, 1.006 MWh/t, every cost is 4.4% higher.

Medium-voltage all-in price (Figures 3.1 and 3.2). All-in price = (monthly fixed charge per kW / hours of use at subscribed power + energy charge) $\times 1.1$ cubed, where 1.1 cubed (1.331) applies the three annual increases of 10% for the 3 to 10 MW bands in 2024, 2025 and 2026 [S03]. At 650 hours a month in the 9 to 10 MW band: $(15,500 / 650 + 9) \times 1.331 = 43.7$ FCFA/kWh. For RC-1 Phase 1: 288,957 MWh / (55 MVA $\times$ 0.95) = 5,530 hours a year, or 461 hours a month, giving 56.7 FCFA/kWh. At 301,723 MWh: 5,775 hours a year, or 481 a month, giving 54.8 FCFA/kWh, 28% above the flat-load 42.9.

Legacy high-voltage price. $17.80 \text{ bn FCFA} / 969.03 \text{ GWh} = 18.4 \text{ FCFA/kWh}$ [S01].

Transmission charge. For a 100 MW load at an 80% load factor (700,800 MWh a year): $(16.18 \text{ m FCFA} \times 100 + 0.41 \text{ FCFA} \times 700.8 \text{ m kWh} + 4.48 \text{ m FCFA}) / 700.8 \text{ m kWh} = 2.7 \text{ FCFA/kWh}$ [S53].

Kribi gas plant. Capacity factor = $559.67 \text{ GWh} / (216 \text{ MW} \times 8,760 \text{ h}) = 29.6\%$. Gas use = $4.92 \text{ bcf} / 559.67 \text{ GWh} = 8.79 \text{ Mscf per MWh}$, or about 9.6 GJ per MWh, an electrical efficiency of about 37%. At 80% capacity factor: $216 \times 0.8 \times 8,760 = 1,514 \text{ GWh}$, needing 13.3 bcf; at 330 MW, 20.3 bcf. Fuel cost per kWh at US\$3.2/Mscf: $8.79 \times 3.2 / 1,000 = \text{US}\0.028 , or about 17 FCFA; at US\$5.6/Mscf, about 30 FCFA. Emissions: $9.6 \text{ GJ/MWh} \times 0.0561 = 0.54 \text{ t CO}_2/\text{MWh}$ [S05][S01].

Combustion-only grid intensity, 2025 (Chapter 8). About 74 g/kWh, an estimate taken from White paper 06 (Chapter 3 and Annex A), so that the series prints one value with one derivation. The emission rate of gas and oil generation implied by the 2024 data, about 771 g/kWh, is applied to the gas and oil generation that the regulator reports for 2025 ($559.7 + 153.9 + 66.7 = 780.3 \text{ GWh}$) [S01], which gives about 602 kt of CO₂; divided by total generation of 8,119.9 GWh, this is about 74 g/kWh. Hydro and solar are counted at zero on this basis. The difference from the life-cycle average of 226 g/kWh for 2024 [S10] reflects both the basis (combustion versus life cycle) and the year and data source (Chapter 2).

Gas for direct reduction (Figure 7.1). Gas in bcf = module capacity in Mt x GJ per tonne / 1.094. For 1 Mt: $9.2 / 1.094 = 8.4$ bcf; $10 / 1.094 = 9.1$ bcf; 23 to 25 MMscf a day over 365 days. Over twenty years: 168 to 183 bcf. Gas cost per tonne of DRI = gas price x GJ per tonne / 1.094; at US\$5.6/Mscf: 47 to 51 US\$/t.

Gas balance (Figure 6.1). Candidate domestic uses: the Kribi plant at its 2025 dispatch (4.92 bcf), at an 80% capacity factor (13.3 bcf) and extended to 330 MW (20.3 bcf); the industrial buyer at twice its half-year purchase (6.2 bcf); RC-1 reheating at full build-out ($910,000 \text{ GJ} / 1.094 = 0.83$ bcf); a 1 Mtpa DRI module (8.4 to 9.1 bcf). Without DRI: $13.3 + 6.2 + 0.8 = 20.3$ bcf. With the plant at 330 MW and DRI: $20.3 + 6.2 + 0.8 + 9.1 = 36.5$ bcf.

FLNG cumulative feed (Chapter 6). Operation from June 2018 to July 2026 is about eight years [S88][S16]. At 60 to 72 bcf a year, the cumulative feed would be about 490 to 580 bcf, the same order as the 500 bcf allocation [S84]. This is an approximation to be replaced by SNH's production records.

Special petroleum tax. $70 \text{ FCFA/m}^3 \times 28.317 \text{ m}^3/\text{Mscf} = 1,982 \text{ FCFA/Mscf}$, or US\$3.2 at 625 FCFA per US dollar and US\$3.5 at 561 [S87][S05].

Flicker screening (Figure 4.3). $\text{Pst99} = \text{Kst} \times \text{SscF} / \text{SscPCC}$ is a simplified screening relation used by this paper, not a calculation from a standard; the Kst range of 48 to 85 is the UIE's, as cited in [S12]. SscF is taken at about twice the rating of a transformer of the 30 to 33 MVA class. The short-circuit power needed at the PCC is SscF multiplied by Kst and divided by the planning level of 0.8: about 4,000 MVA at Kst 48 and about 7,000 MVA at Kst 85. With an SVC halving flicker [S12]: about 2,000 to 3,500 MVA. Results are given to one significant figure; Figure 4.3 and its table in Annex D are drawn from these rounded results. Several equal furnaces combine by a cubic law [S13]: two furnaces give 2 to the power one-third, about 1.3, times the flicker of one.

30 kV fault level. A transformer's contribution to a fault on its secondary side is approximately its rating divided by its per-unit impedance. Three 60 MVA transformers at 12% give $3 \times 60 / 0.12 = 1,500$ MVA; at 18%, 1,000 MVA. A finite 225 kV source lowers these values further.

Solar (Chapter 8). PVGIS v5.3 PVcalc for 2.94 N, 9.91 E, crystalline silicon, 1 kWp, 14% system losses, optimal slope (6 degrees), radiation database PVGIS-SARAH3 for 2005 to 2023: 1,334.7 kWh per kWp a year [S19]. Capacity factor = $1,334.7 / 8,760 = 15.2\%$. A 50 MWp array: $50 \times 1,334.7 = 66.7$ GWh a year, 23% of Phase 1's 289 GWh and 22% of 302 GWh. Daily profiles use PVGIS DRcalc average irradiance by hour for January and July, shifted from UTC to West Africa Time, times 50 MW per 1,000 W/m² times a performance ratio of 0.80.

Scope 2 and the near-zero threshold. Scope 2 per tonne = $0.963 \text{ MWh/t} \times \text{grid factor}$. The IEA near-zero threshold is $0.40 - 0.35 \times \text{scrap share} \text{ t CO}_2\text{e per tonne}$ [S20]; at a 70% scrap share (253,868 t of scrap in 362,669 t of metallics in Phase 1 [S07]) it is 0.155 t.

Illustrative load profiles (Figures 4.1 and 9.2). Each heat follows a fixed sequence: bore-in (4 minutes, 20 MW mean), melting (16 minutes, 27 MW), recharge (3 minutes, off), bore-in (4 minutes, 20 MW), melting (12 minutes, 27 MW), refining (8 minutes, 24 MW) and tapping and turnaround (13 minutes, off), with random variation of 35% during bore-in, 14% during melting and 4% during refining (fixed random seed), and active power capped at 30 MW, about what a transformer of the 30 to 33 MVA class delivers with short-term overload. The mean energy per heat is about 18 MWh, or about 450 kWh per tonne on a heat of about 40 t, consistent with the RC-1 planning value. Steady loads are 11.25 MW for induction heating ($300 \text{ kWh/t} \times 37.5 \text{ t/h}$), 4.13 MW for rolling ($110 \text{ kWh/t} \times 37.5 \text{ t/h}$) and 1.3 MW of auxiliaries, plus a 4.5 MW ladle-furnace pulse for 20 minutes an hour. The profiles show the character of the load and are not forecasts.

Upper planning value for the furnace (Chapter 1). 450 kWh/t, read as an all-scrap value, plus 14.5 kWh/t for each 10 percentage points of DRI or HBI in the charge [S39]: $450 + 3 \times 14.5 = 493.5 \text{ kWh/t}$ at RC-1's 30%, used as the upper planning value of about 490 kWh/t (as in White paper 03); 522.5 kWh/t at 50%.

Schedulable load and the cost of curtailment (Chapter 9). About 8,000 heats of about 40 t at nameplate need about 7,300 to 7,900 furnace hours at about 55 to 59 minutes tap to tap (450 to 490 kWh/t), out of the 8,760 hours in a year (White paper 03, Chapter 5 and Annex A). At the 7,000 to 7,700 operating hours that give the expected sustained output, the furnace is not scheduled to operate for the remaining 1,060 to 1,760 of the year's 8,760 hours, about three to five hours a day. Beyond those hours, one hour of curtailment costs about one heat (about 40 t): 100 hours cost about 4,000 t of liquid steel, about 1.25% of 319,149 t. Moving 20 to 30 MW out of the peak equals 1.6% to 2.3% of the 2025 peak of 1,278 MW [S01].

Phase 1 metallics and port inbound (Chapter 7). Domestic scrap is planned at 30,000 t a year (0 to 60,000 t), bounded by the only quantified national study of scrap arising, 53,000 to 61,833 t a year in 2006 [S98]; the rest of the 253,868 t of scrap and the 108,801 t of DRI or HBI are imported, which with about 6% of consumables gives about 351,000 t a year of port inbound cargo at nameplate [S07].

Phase 1 electricity range (Chapter 9). Low case: $319,149 \text{ t} \times (347 + 50) \text{ kWh/t} + 300,000 \text{ t} \times (150 + 70) \text{ kWh/t} = 192.7 \text{ GWh}$. High case: $319,149 \text{ t} \times (500 + 100) + 300,000 \text{ t} \times (400 + 140) = 353.5 \text{ GWh}$.

A.5 Maps

The maps were drawn by Cameroon Steel from OpenStreetMap data (© OpenStreetMap contributors, Open Database Licence), extracted through the Overpass API on 24 July 2026 (coast, roads, land use around Kribi) and 10 October 2026 (power lines, substations and plants in southern Cameroon) [S60], and from Natural Earth country boundaries. OpenStreetMap is a volunteer dataset: it is not a complete or authoritative record of the network, and the 400 kV Nachtigal line, for example, was not mapped at the time of extraction. The route of the new 225 kV line from the Kribi gas plant to the port is drawn schematically between its published end points, and the port substation's position is indicative. No site boundaries are shown.

A.6 Quality checks

Before publication, the text was checked for consistency between every figure quoted in the prose, the tables and the chart data; for the units, years and sources of every number; and for the absence of confidential or commercially sensitive information. Generated images are labelled "Illustrative view" and are not photographs of any project.

ANNEX B

GLOSSARY OF TERMS AND ABBREVIATIONS

This glossary explains the technical terms, units and abbreviations used in this paper, in plain language for readers who are not specialists in power systems or steelmaking.

Terms

Term	Meaning
Arc furnace, electric arc furnace (EAF)	A furnace that melts scrap, DRI or HBI with electric arcs struck between graphite electrodes and the metal charge
Auxiliaries	The supporting equipment of a steelworks: pumps, fans, compressors, the oxygen plant, cranes and buildings
Balancing	Matching a customer's consumption with its supplier's injections into the grid, and settling the differences
Billet	A semi-finished steel product of square section, cast continuously and rolled into bars, rod or light sections
Bore-in	The first minutes of melting each charge, when the arcs burn into cold scrap and the electrical load is most unstable
Capacity charge	The part of a tariff paid per kW of subscribed or maximum demand, regardless of energy used
Capacity factor	Energy actually produced in a year divided by what the plant would produce at full output all year
Combined margin	A grid emission factor that blends the plants operating at the margin today with recently built plants; used by lenders for project accounting
Compensation (reactive)	Equipment that supplies or absorbs reactive power close to a load, stabilising voltage
Connection code	The rules that define the technical obligations of users connected to a network
Direct reduction, direct-reduced iron (DRI)	Removing oxygen from iron ore in the solid state with a reducing gas; the product is porous metallic iron
DR-grade pellets	Iron ore pellets of high iron content (at least about 64% Fe) and low impurities, suitable for direct reduction
Eligible customer	Under Cameroon's electricity law, a customer allowed to buy from an independent producer at a negotiated price
Fault level, short-circuit power (Ssc)	The power that would flow into a short circuit at a point of the network; a measure of the network's electrical stiffness
Firmness	The degree to which a supply is guaranteed, in MW and hours, with remedies if it fails
Flicker (Pst, Plt)	Rapid voltage fluctuations that make lamps flicker; Pst is short-term severity over 10 minutes, Plt long-term over 2 hours
Floating LNG (FLNG)	A vessel that liquefies natural gas offshore for export
Harmonics	Currents and voltages at multiples of the 50 Hz supply frequency, created by non-linear loads such as arcs and power electronics
Hot-briquetted iron (HBI)	DRI pressed hot into dense briquettes that can be shipped and stored safely
Hot charging	Feeding billets to the reheating step while still hot from the caster, saving energy
Independent power producer (IPP)	A privately or jointly owned generator that sells power under contract

Term	Meaning
Induction heating	Heating billets with a high-frequency magnetic field that induces currents in the steel
Interruptible load	A load that the grid operator may curtail for longer periods under agreed conditions, usually in return for a lower price; a single-furnace melt shop cannot offer it without losing output
Ladle furnace (LF)	A smaller arc furnace that refines liquid steel and adjusts its temperature before casting
Levelised cost of electricity (LCOE)	The average cost per kWh of a plant over its life, including capital and operating costs
Load factor, utilisation	Average load divided by maximum demand, or hours of use at maximum demand
Market-based method	A way of reporting Scope 2 emissions that uses the emission factor of contracted supply rather than the grid average
Maximum demand	The highest average load over a stated interval (often 15 minutes), used to set capacity charges
Merchant billet	A billet sold to another company's rolling mill rather than rolled by its maker
Metallic charge	The iron-bearing materials melted in the furnace: scrap, DRI, HBI or pig iron
N-1, N-2	Security criteria: the system still supplies the load after the loss of one (or two) elements, such as a line or transformer
Nameplate and sustained output	Nameplate output is a plant's design capacity; sustained output is what it is expected to produce in a mature year, after planned and unplanned stops
Point of common coupling (PCC)	The point on the public network nearest to a customer where other customers are or could be connected; power-quality limits apply there
Re-roller	A rolling mill that buys billets or scrap-based billets and rolls them into bars or rod, without its own steelmaking
Reactive power	The part of electrical power that sustains magnetic fields; it loads networks and lowers voltage without doing useful work
Reheating furnace	A gas-fired furnace that heats billets or blooms to rolling temperature
Run-of-river	A hydro plant with little storage, whose output follows river flow
Scope 1, 2, 3	Direct emissions of a plant; emissions from the electricity it buys; other emissions in its supply chain
Schedulable load	A load whose timing can be shifted within the day, for example melting around the grid's peaks, without reducing annual output
Shaft furnace	The vertical reactor in which pellets are reduced to DRI by a rising flow of reducing gas
Static var compensator (SVC)	Equipment of thyristor-controlled reactors and capacitor filters that absorbs a furnace's reactive power swings
STATCOM	A static synchronous compensator: a power-electronic converter that supplies or absorbs reactive power very quickly
Time-of-use price	An energy price that varies with the time of day, higher at the system peak
Take-or-pay	A contract clause under which the buyer pays for a minimum quantity whether or not it takes it
Wheeling	Transporting electricity bought from one producer across the network to a customer, for a transmission fee

Source: Cameroon Steel.

Abbreviations and units

Abbreviation	Meaning
AfDB	African Development Bank
ARSEL	Agence de Régulation du Secteur de l'Électricité, the electricity regulator
bcf, Tcf	Billion and trillion standard cubic feet of natural gas

Abbreviation	Meaning
bcm	Billion cubic metres
BF-BOF	Blast furnace and basic oxygen furnace route
CBAM	The European Union's Carbon Border Adjustment Mechanism
CEMAC	Central African Economic and Monetary Community
CO ₂ e	Carbon dioxide equivalent
FCFA	CFA franc of Central Africa (XAF), pegged at 655.957 per euro
FID	Final investment decision
GJ, PJ	Gigajoule, petajoule (one million GJ)
GWh, TWh	Gigawatt-hour, terawatt-hour
HV, MV, LV	High, medium and low voltage
IEA	International Energy Agency
IFC	International Finance Corporation
IRENA	International Renewable Energy Agency
KPDC	Kribi Power Development Corporation, owner of the Kribi gas-fired plant
KPIZ	Kribi Port Industrial Zone, managed by KPIZ S.A.
kV	Kilovolt
MINEE	Ministère de l'Eau et de l'Énergie, the Ministry of Water and Energy
MINEPAT	Ministère de l'Économie, de la Planification et de l'Aménagement du Territoire
Mscf, MMscf/d	Thousand standard cubic feet; million standard cubic feet per day
Mtpa	Million tonnes per annum
MVA, MW	Megavolt-ampere (apparent power), megawatt (active power)
Nm ³	Normal cubic metre
OSM	OpenStreetMap
PAK	Port Autonome de Kribi, the Kribi port authority
PVGIS	Photovoltaic Geographical Information System of the European Commission's Joint Research Centre
RC-1	Cameroon Steel's reference configuration for the steel complex at Mboro
RIS, RIN	Southern and Northern Interconnected Grids (Réseau Interconnecté Sud, Nord)
SNH	Société Nationale des Hydrocarbures, the national hydrocarbons company
SONATREL	Société Nationale de Transport de l'Électricité, the transmission company
STPP	Special tax on petroleum products
THD	Total harmonic distortion
UIE	International Union for Electricity Applications
US\$	United States dollar

Source: Cameroon Steel.

ANNEX C

SOURCES

Every source cited in this paper is listed below with its [S-id] marker, numbered in order of first citation. Links were checked on or before 10 October 2026. Publications of the Port Autonome de Kribi are cited by title and date without a link.

Table C.1 Sources cited in this paper

ID	Title	Publisher	Date	Link or reference
S01	Rapport d'activités 2025 de l'ARSEL	ARSEL (electricity regulator)	7 Sep 2026	https://arsel-cm.org/wp-content/uploads/2026/09/Rapport-ARSEL-2025.pdf
S02	Nachtigal power line delays leave 150 MW of industrial demand unmet	Business in Cameroon	9 Oct 2026	https://www.businessincameroon.com/public-management/0910-16939-nachtigal-power-line-delays-leave-150-mw-of-industrial-demand-unmet
S03	Tableaux tarifaires, Décision ARSEL N°00000427 (MT 2023-2025)	ARSEL	uploaded Jan 2026	http://arsel-cm.org/wp-content/uploads/2026/01/TABLEAUX-TARIFAIRES-decision-MT-2023-2025.pdf
S04	Décision fixant le montant de la RMA ENEO au titre de l'exercice 2025 (réajustée)	ARSEL	19 Dec 2025	http://arsel-cm.org/wp-content/uploads/2026/01/Decision-fixant-le-Montant-de-le-RMA-Eneo-au-titre-de-lexercice-2025-du-19-12-2025.pdf
S05	Données pétrolières 2025	SNH	posted Jun 2026	https://snh.cm/wp-content/uploads/2026/06/Donnees-petrolieres-2025.pdf
S06	Industrialisation: la voie royale de l'émergence	Cameroon Tribune	2 Jan 2025	https://cameroon-tribune.cm/article.html/68558/fr.html/details_2
S07	Cameroon Steel reference configuration RC-1 (planning estimate), edition 10 October 2026 (RC-1.1): phases, benchmarks with ranges, indicative balances and schedule	Cameroon Steel	10 Oct 2026	Planning figures, not commitments. Not published as a separate document; the figures used are set out in this paper (Annex A; plotted values in Annex D)
S08	Kribi: le Premier ministre, chef du gouvernement est là	Cameroon Tribune	30 Dec 2024	https://cameroon-tribune.cm/article.html/68499/fr.html/details_2
S09	Weekly steel prices (archive 40468)	Arab Iron & Steel Union (AISU)	3 Oct 2026	https://aisusteel.org/en/archives/40468
S10	Carbon intensity of electricity generation (Ember data)	Our World in Data	Dataset accessed Oct 2026	https://ourworldindata.org/grapher/carbon-intensity-electricity
S11	UN Comtrade public API, Cameroon (reporter 120), HS 72/73 and 6-digit lines, 2019-2023	UN Statistics Division	acc. 10 Oct 2026	https://comtradeapi.un.org/public/v1/preview/C/A/HS?reporterCode=120&period=2023&partnerCode=0&flowCode=M&cmdCode=72,73,7207,7208,7209,7210,7213,7214,7216,7217,7304,7305,7306,7308
S12	US Patent 10,145,612: Flicker reduction in electric arc furnaces by means of flicker prediction from the state determination in the initial phase of the smelting process	Siemens (assignee now Siemens Energy Global)	Granted 4 Dec 2018	https://patents.google.com/patent/US10145612
S13	IEC TR 61000-3-7:2008, Electromagnetic compatibility, Part 3-7: Assessment of emission limits for the connection of fluctuating installations to MV, HV and EHV power systems (Ed. 2.0); indicative planning levels for flicker: Table 2 (section 4.2.1)	International Electrotechnical Commission (table title read in the preview on the VDE Verlag site; values checked against secondary reproductions)	2008	https://www.vde-verlag.de/iec-normen/preview-pdf/info_iectr61000-3-7[ed2.0].en.pdf

ID	Title	Publisher	Date	Link or reference
S14	Kribi franchit la ligne électrique 225 kV	PAK	6 Aug 2025	Port Autonome de Kribi publication, cited by title and date (no link given)
S15	Énergie et infrastructures: un nouvel élan pour la compétitivité du Port de Kribi	PAK	19 Aug 2026	Port Autonome de Kribi publication, cited by title and date (no link given)
S16	Le navire usine quitte le Cameroun, le gaz s'arrête	Camer.be	9 Jul 2026	https://www.camer.be/93911/12:1/le-navire-usine-quitte-le-cameroun-le-gaz-sarrete-cameroon.html
S17	Cameroon's SNH eyes Yoyo-Yolanda and new exploration blocks to sustain gas growth	Business in Cameroon	6 Jul 2026	https://www.businessincameroon.com/energy/0607-16422-cameroon-s-snh-eyes-yoyo-yolanda-and-new-exploration-blocks-to-sustain-gas-growth
S18	European buyers uninterested in BPI and HBI purchases, prices up nominally due to freight	SteelOrbis	16 Mar 2026	https://www.steelorbis.com/steel-prices/steel-prices-market-analyses/scrap-and-raw-materials/european-buyers-uninterested-in-bpi-and-hbi-purchases-prices-up-nominally-due-to-freight-1441884.htm
S19	PVGIS v5.3 web services (PVcalc, DRcalc), Kribi 2.94 N 9.91 E, PVGIS-SARAH3 2005 to 2023	European Commission, Joint Research Centre	Accessed 10 Oct 2026	https://re.jrc.ec.europa.eu/api/v5_3/
S20	Achieving Net Zero Heavy Industry Sectors in G7 Members	IEA	19 May 2022	https://iea.blob.core.windows.net/assets/c4d96342-f626-4aea-8dac-df1d1e567135/AchievingNetZeroHeavyIndustrySectorsinG7Members.pdf
S21	Kribi Power Development Corporation	MIGA (World Bank Group)	2014	https://www.miga.org/project/kribi-power-development-corporation-0
S22	The AfDB praises the impacts of the planned extension of the Kribi gas-fired power plant	Business in Cameroon	1 Jul 2020	https://www.businessincameroon.com/energy/0107-10486-the-afdb-praises-the-impacts-of-the-planned-extension-of-the-kribi-gas-fired-power-plant
S23	Zone industrielo-portuaire de Kribi (KPIZ): jusqu'à +8 points de croissance et 150 000 emplois...	Investir au Cameroun	4 Mar 2026	https://www.investiraucameroun.com/gestion-publique/0403-23163-zone-industrialo-portuaire-de-kribi-kpiz-jusqu-a-8-points-de-croissance-et-150-000-emplois-attendus-sur-15-ans
S24	Zone industrielle Kribi: 400 milliards FCFA investis et 53 entreprises autorisées à s'implanter depuis 2018	Investir au Cameroun	20 May 2025	https://www.investiraucameroun.com/gestion-publique/2005-22033-zone-industrielle-kribi-400-milliards-fcfa-investis-et-53-entreprises-autorisees-a-s-implanter-depuis-2018
S25	Cameroon speeds up Kribi bitumen plant with tax breaks and refining license	Business in Cameroon	10 Jun 2026	https://www.businessincameroon.com/public-management/1006-16302-cameroon-speeds-up-kribi-bitumen-plant-with-tax-breaks-and-refining-license
S26	Stratégie Nationale de Développement 2020-2030 (SND30)	Republic of Cameroon / MINEPAT (hosted by FAOLEX)	2020	https://faolex.fao.org/docs/pdf/cmr211554.pdf
S27	Loi n° 2023/014 du 19 décembre 2023 portant Code minier (official text, mirror)	Rural-info (copy of the official text)	19 Dec 2023	http://rural-info.net/wp-content/uploads/2024/11/Loi-N°2023-014-du-19-decembre-2023-portant-Code-Minier.pdf
S28	Cameroon completes buyback of Eneo in a CFA78 billion deal with Actis	Business in Cameroon	c. 20 Feb 2026	https://www.businessincameroon.com/energy/2002-15795-cameroon-completes-buyback-of-eneo-in-a-cfa78-billion-deal-with-actis
S29	Au Cameroun, l'État veut reprendre les centrales de Kribi et Dibamba à Globeleq	Forbes Afrique	11 Aug 2026	https://forbesafrique.com/au-cameroun-letat-veut-reprendre-les-centrales-de-kribi-et-dibamba-a-globeleq/
S30	Carbon Border Adjustment Mechanism	European Commission (DG TAXUD)	n.d., accessed Oct 2026	https://taxation-customs.ec.europa.eu/carbon-border-adjustment-mechanism_en

ID	Title	Publisher	Date	Link or reference
S31	Energy use in the steel industry (fact sheet)	World Steel Association (copy hosted by the Australian Steel Institute)	2016	https://www.steel.org.au/getattachment/bfc722b0-1320-4d04-84df-30bdd500aa5b/fact_energy_2016.pdf
S32	Cameroun: le groupe Prometal décroche 26 milliards FCFA auprès d'Afreximbank...	Sikafinance	30 Sep 2026	https://www.sikafinance.com/marches/cameroun-le-groupe-prometal-decroche-26-milliards-fcfa-aupres-dafreximbank-pour-renforcer-sa-production-dacier-et-conquerir-de-nouveaux-marches_64623
S33	Cameroun: Prometal décroche 26,2 milliards FCFA d'Afreximbank	Camer.be	1 Oct 2026	https://www.camer.be/actualites/economie/cameroun-prometal-decroche-262-milliards-fcfa-dafreximbank.html
S34	Sustainability Indicators 2025 report	worldsteel	Nov 2025 (upd. Feb 2026)	https://worldsteel.org/zh-hans/wider-sustainability/sustainability-indicators/sustainability-indicators-report-2025/
S35	Iron and Steel Technology Roadmap	IEA	Oct 2020	https://iea.blob.core.windows.net/assets/eb0c8ec1-3665-4959-97d0-187ceca189a8/Iron_and_Steel_Technology_Roadmap.pdf
S36	Environmental, Health, and Safety Guidelines for Integrated Steel Mills	IFC / World Bank Group	30 Apr 2007	https://www.ifc.org/content/dam/ifc/doc/2000/2007-integrated-steel-mills-ehs-guidelines-en.pdf
S37	Best Available Techniques Reference Document, Iron and Steel (EUR 25521)	EC JRC	2013	https://bureau-industrial-transformation.jrc.ec.europa.eu/sites/default/files/2019-11/IS_Adopted_03_2012.pdf
S38	Enhanced EAF steelmaking through continuous charging (Consteel)	EC ICIT	n.d., accessed Oct 2026	https://innovation-centre-for-industrial-transformation.ec.europa.eu/innovative-techniques/enhanced-eaf-steelmaking-through-continuous-charging-scrap-preheating-and
S39	ENERGIRON technology (DRI-EAF with natural gas or H ₂)	EC ICIT	ref. 12 Feb 2026	https://innovation-centre-for-industrial-transformation.ec.europa.eu/innovative-techniques/energiron-technology-drieaf-production-route-using-natural-gas-or-h2
S40	Commission Implementing Decision (EU) 2022/2110, BAT conclusions, ferrous metals processing	European Commission (OJ L 284)	11 Oct 2022	https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32022D2110
S41	Suez Steel sets new benchmark in energy consumption for DRI production	Danieli	16 Apr 2026	https://www.danieli.com/en/news-media/news/suez-steel-sets-new-benchmark-energy-consumption-dri-production_37_1051.htm
S42	Prometal, Acero Metal, Aciéries du Cameroun... qui est le plus gros consommateur d'électricité de la métallurgie camerounaise	EcoMatin	15 Jul 2026	https://ecomatin.net/prometal-acero-metal-acieries-du-cameroun-qui-est-le-plus-gros-consommateur-deelectricite-de-la-metallurgie-camerounaise
S43	Matériaux de construction: l'offensive locale	Cameroon Tribune	24 Apr 2023	https://www.cameroon-tribune.cm/article.html/56766/en.html/details_2
S44	Hausse des tarifs d'électricité: l'ARSEL minimise l'impact sur les entreprises	EcoMatin	6 Jan 2023	https://ecomatin.net/hausse-des-tarifs-deelectricite-larsel-minimise-limpact-de-cette-operation-sur-les-entreprises-cmr
S45	Électricité: les aciéries s'insurgent contre la hausse des tarifs	EcoMatin	10 Jan 2023	https://ecomatin.net/electricite-les-acieries-sinsurgent-contre-la-hausse-des-tarifs-deelectricite
S46	Regulation (EU) 2023/956 (CBAM), Annex I	EUR-Lex (OJ L 130)	16 May 2023	https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32023R0956
S47	Price of CBAM certificates	European Commission	5 Oct 2026 (latest)	https://taxation-customs.ec.europa.eu/carbon-border-adjustment-mechanism/price-cbam-certificates_en

ID	Title	Publisher	Date	Link or reference
S48	Electricity production by source (Ember / Energy Institute data)	Our World in Data	Dataset accessed Oct 2026	https://ourworldindata.org/grapher/electricity-prod-source-stacked
S49	Cameroon country profile	International Hydropower Association	n.d., accessed Oct 2026	https://www.hydropower.org/country-profiles/cameroon
S50	Kribi gas power plant resumes operations after debt resolution; Cameroon to build two new gas power plants	Business in Cameroon (also Forbes Afrique on pre-emption)	Feb to Mar 2025	https://www.businessincameroon.com/energy/2702-14501-kribi-gas-power-plant-resumes-operations-after-debt-resolution ; https://www.businessincameroon.com/energy/1103-14518-cameroon-to-build-two-new-gas-power-plants-adding-500-mw-to-grid ; https://forbesafrique.com/au-cameroun-letat-veut-reprendre-les-centrales-de-kribi-et-dibamba-a-globeleq/
S51	Cameroon renationalises power company Eneo, renames it Socadel	Enerdata	11 May 2026	https://www.enerdata.net/publications/daily-energy-news/cameroon-renationalises-power-company-eneo-renames-it-socadel.html
S52	Reforming Cameroon's power sector (on Law No. 2011/022 of 14 December 2011)	IFLR (Orrick Herrington & Sutcliffe; ENEO)	3 Jun 2016	https://www.iflr.com/article/2gjw2n5ocpr2orkj9qxcrliflr1000/reforming-cameroons-power-sector
S53	Tarif transport et GRT (Décision 0000017D)	ARSEL	17 Jan 2025	http://arsel-cm.org/wp-content/uploads/2026/01/TARIF-TRANSPORT-ET-GRT-1.pdf
S54	Décision N°00000427 fixant les tarifs de vente HT d'électricité des clients MT et seuils minima de négociation "Grands Comptes"	ARSEL	12 Dec 2022	http://arsel-cm.org/wp-content/uploads/2025/12/2022_decision_n_00000427_d_arsel_fixant_tarifs_de_vente_hors_t_axes_delectricite_clients_de_la_mt_en_eo_12_12_2022_19_05_30.pdf
S55	Cameroon's journey toward affordable, reliable and universal electricity access	World Bank	16 Jan 2025	https://www.banquemondiale.org/fr/news/feature/2025/01/16/cameroon-journey-toward-affordable-reliable-and-universal-electricity-access-for-all
S56	Cameroon's power purchases from IPPs rise 17% to CFA156.1bn in 2024	Business in Cameroon	14 Jan 2026	https://www.businessincameroon.com/energy/1401-15608-cameroon-s-power-purchases-from-ipp-rise-17-to-cfa156-1bn-in-2024
S57	Cameroon plans higher electricity rates for some businesses to ease sector strain	Business in Cameroon	8 May 2026	https://www.businessincameroon.com/energy/0805-16144-cameroon-plans-higher-electricity-rates-for-some-businesses-to-ease-sector-strain
S58	Eneo seeks CFA54bln to secure future for vital Songloulou dam	Business in Cameroon	15 May 2025	https://www.businessincameroon.com/public-management/1505-14658-eneo-seeks-cfaf54bln-to-secure-future-for-vital-songloulou-dam
S59	Cameroon, Lom Pangar Hydropower Project (P114077): Implementation Completion and Results Report (ICR00004891)	World Bank	23 Dec 2019	https://documents1.worldbank.org/curated/en/625471579097390098/pdf/Cameroon-Lom-Pangar-Hydropower-Project.pdf
S60	OpenStreetMap power features (lines, substations, plants), southern Cameroon, via the Overpass API; Kribi base extract (coast, roads, land use)	OpenStreetMap contributors (ODbL)	Extracts 24 Jul and 10 Oct 2026	https://www.openstreetmap.org (raw extracts published with the web edition)
S61	Énergie: Nachtigal franchit le cap des 3,6 TWh injectés dans le réseau en un an	Journal du Cameroun	15 Jun 2026	https://fr.journalducameroun.com/energie-nachtigal-franchit-le-cap-des-36-twh-injectes-dans-le-reseau-en-un-an/
S62	Energy: MINEE announces works to boost the production of Memvéélé hydroelectric power station (211 MW)	Business in Cameroon	3 Jul 2020	https://www.businessincameroon.com/energy/0307-10497-energy-minee-announces-works-to-boost-the-production-of-memveele-hydroelectric-power-station-211-mw

ID	Title	Publisher	Date	Link or reference
S63	Décision N°0000018D (prévisionnelle 2025)	ARSEL	17 Jan 2025	http://arsel-cm.org/wp-content/uploads/2025/12/2025_decision_n0000018d_arsel_du_17012025_previsionnelle.pdf
S64	Wärtsilä to upgrade Cameroon-based Kribi power plant to boost reliability	Engineering News	22 Aug 2022	https://www.engineeringnews.co.za/article/wartsila-to-upgrade-cameroon-based-kribi-power-plant-to-boost-reliability-2022-08-22
S65	Cameroon: Nyambizan to Yaoundé line nears completion	African Energy	27 May 2022	https://www.africa-energy.com/news-centre/article/cameroon-nyambizan-yaounde-line-nears-completion
S66	Cameroon: Energy (Country Commercial Guide)	US International Trade Administration	13 Apr 2026	https://www.trade.gov/country-commercial-guides/cameroon-energy
S67	Cameroon moves forward on 500MW Kikot-Mbebe dam with land transfer decree	Business in Cameroon	22 May 2025	https://www.businessincameroon.com/public-management/2205-14683-cameroon-moves-forward-on-500mw-kikot-mbebe-dam-with-land-transfer-decree
S68	Government, EDF push to deliver hydro promises as Cameroon moves to diversify energy sources	Business in Cameroon	4 Dec 2025	https://www.businessincameroon.com/energy/0412-15443-government-edf-push-to-deliver-hydro-promises-as-cameroon-moves-to-diversify-energy-sources
S69	Cameroon plans to build 1 GW Grand Eweng hydropower project	Enerdata	Jul 2019	https://www.enerdata.net/publications/daily-energy-news/cameroon-plans-build-1-gw-grand-eweng-hydropower-project.html
S70	Cameroon implements new electricity price hike to achieve financial balance	Business in Cameroon	7 Feb 2024	https://www.businessincameroon.com/energy/0702-13622-cameroon-implements-new-electricity-price-hike-to-achieve-financial-balance
S71	Regulatory texts listed on the regulator's website: orders on the connection code and the market code (files could not be opened on the access date)	ARSEL	Accessed 10 Oct 2026	https://www.arsel-cm.org
S72	IMF staff concludes Post-Financing Assessment mission to Cameroon (PR 26/314)	IMF	1 Oct 2026	https://www.imf.org/en/news/articles/2026/10/01/pr26314-imf-staff-concludes-assesment-cameroon
S73	IEEE Std 519-2022, IEEE Standard for Harmonic Control in Electric Power Systems	IEEE	2022	https://standards.ieee.org/ieee/519/10677/
S74	Port de Kribi: une dynamique industrielle portée par les financements publics	Journal du Cameroun (D. Mebenga)	20 Apr 2026	https://fr.journalducameroun.com/port-de-kribi-une-dynamique-industrielle-portee-par-les-financements-publics/
S75	Le port de Kribi engage 3,5 milliards FCFA pour préparer l'arrivée de nouveaux industriels	Ecomatin (L. Onguene)	11 May 2026	https://ecomatin.net/cameroun-le-port-de-kribi-engage-35-milliards-fcfa-pour-preparer-larrivee-de-nouveaux-industriels
S76	Guide du Port de Kribi	Port Autonome de Kribi	Aug 2020	Port Autonome de Kribi publication, cited by title and date (no link given)
S77	Cameroon launches \$860m Kribi industrial zone; PAK, AGL, Arise IIP and Belmont launch €795m KPIZ	Ecofin Agency; Business in Cameroon	27 Feb 2026	https://www.ecofinagency.com/news/2702-53326-cameroon-launches-860m-kribi-industrial-zone-to-process-raw-materials-locally ; https://www.businessincameroon.com/public-management/2202-15797-pak-agl-arise-iip-and-belmont-launch-795m-kribi-port-industrial-zone
S78	Bulletin d'information du PAK n° 264	Port Autonome de Kribi	Feb 2026	Port Autonome de Kribi publication, cited by title and date (no link given)
S79	Cameroun, Complexe moderne de sidérurgie de Kribi: le PM Joseph Dion Ngute effectue la pose de la première pierre	Camer.be	5 Jan 2025	https://www.camer.be/87795/12:1/cameroun-complexe-moderne-de-siderurgie-de-kribi-le-pm-joseph-dion-ngute-effectue-la-pose-de-la-premiere-pi-cameroon.html

ID	Title	Publisher	Date	Link or reference
S80	Port de Kribi: un terminal minéralier d'avenir (memorandum of understanding for a mineral terminal)	Port Autonome de Kribi	4 Nov 2025	Port Autonome de Kribi publication, cited by title and date (no link given)
S81	Zone industrialo-portuaire de Kribi (KPIZ): jusqu'à +8 points de croissance et 150 000 emplois attendus sur 15 ans	Investir au Cameroun	4 Mar 2026	https://www.investiraucameroun.com/gestion-publique/0403-23163-zone-industrialo-portuaire-de-kribi-kpiz-jusqu-a-8-points-de-croissance-et-150-000-emplois-attendus-sur-15-ans
S82	Cameroon's Kribi port plans CFA50 billion agricultural terminal	Business in Cameroon	9 Oct 2026	https://www.businessincameroun.com/public-management/0910-16938-cameroon-s-kribi-port-plans-cfa50-billion-agricultural-terminal-with-80-of-funding-still-to-be-raised
S83	Gaz: le Cameroun veut doper sa production de 8,5 millions de m³ par jour à partir de 2026	EcoMatin	7 Feb 2025	https://ecomatin.net/gaz-le-cameroun-veut-doper-sa-production-de-85-millions-de-m3-par-jour-a-partir-de-2026
S84	Golar signs Heads of Agreement for the development of a Floating Liquefaction export project in Cameroon (news release, filed with the US Securities and Exchange Commission on Form 6-K)	Golar LNG Ltd	24 Dec 2014	https://www.sec.gov/Archives/edgar/data/0001207179/000117184314006037/newsrelease.htm
S85	Gaz du Cameroun en chute libre: -62,9% de livraisons en 2024	Cameroun24	c. Apr 2026	https://cameroun24.net/article/73653-gaz-du-cameroun-en-chute-libre-62-9-de-livraisons-en-2024-les-industriels-de-douala-tournent-le-dos-au-gaz-naturel.html
S86	Cameroon gas operator slashes share capital by 86% a year after takeover	Business in Cameroon	9 Oct 2026	https://www.businessincameroun.com/energy/0910-16932-cameroon-gas-operator-slashes-share-capital-by-86-a-year-after-takeover
S87	Industrial gas: Cameroon suspends GDC's 20% price hiking plan	Business in Cameroon	18 Jul 2023	https://www.businessincameroun.com/energy/1807-13291-industrial-gas-cameroon-suspends-gdc-s-20-price-hiking-plan
S88	Cameroon FLNG Terminal	Global Energy Monitor (GEM.wiki; tertiary)	last edit 10 Oct 2026	https://www.gem.wiki/Cameroon_FLNG_Terminal
S89	Perenco, SNH to increase utilization of Golar's Hilli Episeyo FLNG	Offshore Engineer	Jul 2021	https://www.oedigital.com/news/489311-perenco-snh-to-increase-utilization-of-golar-s-hilli-episeyo-flng
S90	Golar, partners approve first vessel in Argentine gas export project	Rigzone	6 May 2025	https://www.rigzone.com/news/golar_partners_approve_first_vessel_in_argentine_gas_export_project-06-may-2025-180446-article/
S91	Cameroun: SNH, huit ans de location, zéro infrastructure	AllAfrica (Camer.be)	1 Jun 2026	https://fr.allafrica.com/stories/202606010513.html
S92	Chiffres-clés du 1er janvier au 31 décembre 2025	SNH	20 Jun 2026	https://www.snh.cm/chiffres-cles-du-1er-janvier-au-31-decembre-2025/
S93	Hydrogen uses in ironmaking (V. Chevrier, Midrex)	US DOE H2@Scale	1 Aug 2018	https://www.energy.gov/sites/prod/files/2018/08/f54/fcto-h2-scale-kickoff-2018-8-chevrier.pdf
S94	2025 World Direct Reduction Statistics	Midrex Technologies	Sep 2026	https://www.midrex.com/world-dri-statistics/world-dri-production-reaches-151-0-mt-in-2025/Midrex-STATS-book-2025-FINAL.pdf
S95	World Steel in Figures 2026	World Steel Association (worldsteel)	4 Jun 2026	https://worldsteel.org/data/world-steel-in-figures/world-steel-in-figures-2026/
S96	Midrex history	Midrex Technologies	n.d., accessed Oct 2026	https://www.midrex.com/history/

ID	Title	Publisher	Date	Link or reference
S97	40 millions d'euros d'Afreximbank: Prometal sécurise ses billettes d'acier alors que la ferraille camerounaise s'épuise	Cameroun24	10 Oct 2026	https://cameroun24.net/article/76267-40-millions-d-euros-d-afreximbank-prometal-securise-ses-billettes-d-acier-alors-que-la-ferraille-camerounaise-s-epuise.html
S98	Bidoung J., Fomethe A., Yantio G., Melo U., La récupération et le recyclage des déchets ferromagnétiques: analyse de la situation au Cameroun (Déchets, Revue francophone d'écologie industrielle n°48)	ENSP Yaoundé / MIPROMALO	Q4 2007	https://eid.episciences.org/7942/pdf
S99	Average prices for Brazilian pig iron fell by \$20/t in September	GMK Center	4 Oct 2026	https://gmk.center/?p=129748
S100	Commodity Markets Outlook, Historical Data, Annual (xlsx)	World Bank	2 Sep 2026	https://thedocs.worldbank.org/en/doc/74e8be41ceb20fa0da750cda2f6b9e4e-0050012026/related/CMO-Historical-Data-Annual.xlsx
S101	Climate change and the production of iron and steel (policy paper)	worldsteel	Web page accessed 10 Oct 2026	https://worldsteel.org/climate-action/climate-change-and-the-production-of-iron-and-steel/
S102	Cameroon Mining Company confirme l'entrée du projet Mbalam dans sa phase irréversible d'exécution	Camer.be via AllAfrica	12 Dec 2025	https://fr.allafrica.com/stories/202512120475.html
S103	15 Insights on the Global Steel Transformation	Agora Industry	15 Jun 2023	https://www.agora-industry.org/publications/15-insights-on-the-global-steel-transformation
S104	Renewable Power Generation Costs in 2024	International Renewable Energy Agency (IRENA)	July 2025	https://www.irena.org/Publications/2025/Jun/Renewable-Power-Generation-Costs-in-2024
S105	Global Gateway: Namibia becomes pioneer for Africa's green transition	European Commission (INTPA)	11 Apr 2025	https://international-partnerships.ec.europa.eu/news-and-events/news/global-gateway-namibia-becomes-pioneer-africas-green-transition-2025-04-11_en
S106	Namibia opens renewables-powered green iron plant	Energize	15 Apr 2025	https://energize.co.za/article/namibia-opens-renewables-powered-green-iron-plant
S107	Production: les acteurs en présence	Cameroon Tribune	11 May 2026	https://cameroon-tribune.cm/article.html/76600/fr.html/details_2
S108	EU adopts CBAM Omnibus Regulation	EY	22 Oct 2025	https://www.ey.com/en_gl/technical/tax-alerts/eu-adopts-cbam-omnibus-regulation
S109	Directive (EU) 2023/959 (EU ETS revision)	EUR-Lex (OJ L 130)	16 May 2023	https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32023L0959

ANNEX D

DATA TABLES

This annex gives the values plotted in every chart of this paper, with units, status and sources, so that readers can check or reuse the numbers without the charts. The same values are published as data files with the web edition, and the charts are generated from them by script (Annex A). Diagrams are summarised rather than tabulated. Statuses follow the convention of Annex A: sourced, derived, assumed or illustrative.

D.1 Executive summary

Table D.1 Data for Figure ES.1: Phase 1 fits the port substation’s shared first 100 MW; 1 Mtpa needs its later stage (status: derived)

Item	Value	Unit	Status
RC-1 Phase 1 (0.3 Mtpa), average load	36.1 to 37.7	MW	planned (derived)
RC-1 Phase 1, maximum demand	55 (45 to 65)	MVA	assumed
RC-1 Phases 1 and 2 (0.5 Mtpa), average load	52.7 to 55.4	MW	planned (derived)
RC-1 full build-out (1 Mtpa), average load	94.1 to 99.5	MW	planned (derived)
RC-1 full build-out, maximum demand	160 (130 to 190)	MVA	assumed
Port substation, first stage, shared by the whole port platform	100	MW	sourced
Port substation, later stage	330 to 400	MW	sourced
Kribi gas plant, installed	216	MW	sourced
Kribi gas plant, 2025 average output	63.9	MW	derived
Industrial demand unmet in Cameroon, October 2026	150	MW	sourced

Source: Cameroon Steel reference configuration RC-1 (planning estimate) [S07], average loads at 450 to 490 kWh/t in the furnace; PAK [S14][S15]; ARSEL 2025 [S01]; Business in Cameroon, 9 October 2026 [S02].

D.2 Chapter 1, energy in steel economics

Table D.2 Data for Figure 1.1: Scrap-fed electric steel needs 10% to 40% of the energy of ore-based routes (status: sourced)

Route	worldsteel 2024 data (GJ/t crude steel)	IEA 2019, final energy (GJ/t)
Blast furnace and oxygen converter (BF-BOF)	23.88	21.4
Gas DRI and electric arc furnace (DRI-EAF)	23.30	17.1
Scrap and electric arc furnace (scrap-EAF)	9.84	2.1

Source: worldsteel [S34]; IEA [S35].

Table D.3 Data for Figure 1.2: Melting is the largest electricity use: 350 to 500 kWh per tonne of liquid steel in a modern furnace (status: sourced)

Process step	Low	High	RC-1 planning value	Unit	Basis
EAF melting, IFC benchmark	347	500	450 (upper 490)	kWh/t liquid	IFC 2007
EAF melting, EU melt shops observed	404	748	n/a	kWh/t liquid	EU BREF 2013
EAF with continuous scrap charging (one plant)	321	321	n/a	kWh/t liquid	EC ICIT
Extra EAF power at 100% DRI in the charge	0	145	n/a	kWh/t liquid	derived
Ladle furnace, caster and auxiliaries	50	100	70	kWh/t liquid	assumed
Induction billet heating (Phase 1)	150	400	300	kWh/t billet	assumed
Rolling (bars, rod, sections)	70	140	110	kWh/t product	IFC 2007
Direct-reduction plant electricity	60	73	n/a	kWh/t DRI	Energiron

Source: [S36][S37][S38][S39][S07]; upper value derived (Annex A).

D.3 Chapter 2, Cameroon's power system

Table D.4 Data for Figure 2.1: Hydro supplied nine-tenths of Cameroon's electricity in 2025 (status: sourced)

Source	GWh, 2025	Share (%)
Hydro	7,272.4	89.6
Natural gas	559.7	6.9
Light fuel oil	153.9	1.9
Solar	67.2	0.8
Heavy fuel oil	66.7	0.8
Total	8,119.9	100.0

Source: ARSEL 2025 [S01].

Table D.5 Data for Figure 2.2: Cameroon has 755 MW of capacity above its peak, yet 150 MW of industrial demand is unserved (status: sourced)

Item	Value	Unit	Status
Installed capacity, 2025	2,033	MW	sourced
of which hydro (69.5% of capacity)	1,413	MW	derived
Peak demand, 2025	1,278	MW	sourced
Industrial demand unmet, October 2026	150	MW	sourced
Nachtigal hydro (420 MW): planned 2025	2,875.9	GWh	derived
Memve'ele hydro (211 MW): planned 2025	243.2	GWh	derived
Kribi gas (216 MW): planned 2025	1,031.2	GWh	sourced
Nachtigal hydro (420 MW): delivered 2025	2,070.7	GWh	sourced
Memve'ele hydro (211 MW): delivered 2025	557.0	GWh	sourced

Item	Value	Unit	Status
Kribi gas (216 MW): delivered 2025	559.7	GWh	sourced

Source: ARSEL 2025 [S01]; ARSEL forecast decision 2025 [S63]; Business in Cameroon [S02].

Table D.6 Data for Figure 2.3: Kribi sits at the southern end of the hydro-based southern grid (status: sourced)

Plant or feature	Type (OSM tag)	Capacity (MW) or count
Song Loulou	hydro	384
Edéa	hydro	276
Nachtigal	hydro	420
Memve'ele	hydro	211
Kribi gas plant (KPDC)	gas	216
Dibamba	oil	86
Limbé	oil	85
Logbaba	gas	30
High-voltage line segments mapped (225 or 220 kV)		54
Other line segments mapped		61

Source: OpenStreetMap contributors, extract of 10 October 2026 [S60].

D.4 Chapter 3, tariffs and contracting

Table D.7 Data for Figure 3.1: No price is published for a 50 MW load: the benchmarks span 18 to 105 FCFA/kWh (status: derived)

Benchmark	FCFA/kWh	US\$/kWh at 600 FCFA	Status
Transmission charge only, 100 MW at 80% load factor (2025)	2.70	0.005	derived
Legacy high-voltage contracts, average realised (2025)	18.40	0.031	derived
Medium-voltage 9 to 10 MW band, >400 h/month, all-in (2026)	43.70	0.073	derived
Memve'ele hydro, purchase price paid by the utility	43.93	0.073	sourced
Medium-voltage customers, average realised (2025)	85.70	0.143	derived
Regulator's cost-reflective average (2025)	105.46	0.176	sourced

Source: [S01][S03][S04][S53].

Table D.8 Data for Figure 3.2: Under a capacity-plus-energy tariff, a peaky load pays about a third more per kWh (status: derived)

Hours per month at subscribed power	All-in FCFA/kWh, 2026	Note
200	139.0	
300	98.9	
400	78.8	
401	63.4	
461	56.7	RC-1 Phase 1 shape

Hours per month at subscribed power	All-in FCFA/kWh, 2026	Note
500	53.2	
600	46.4	
667	42.9	flat load, 8,000 h/yr
720	40.6	

Source: ARSEL MV tariff tables, 9 to 10 MW band, escalated by 1.331 to 2026 [S03]; Cameroon Steel reference configuration RC-1 (planning estimate) [S07]; derived.

D.5 Chapter 4, power quality for arc furnaces

Table D.9 Data for Figure 4.1: An arc furnace draws power in violent pulses, worst during bore-in (status: illustrative)

Phase	Start (min)	End (min)	Mean power (MW)	Random variation
bore-in	0	4	20	35%
melting	4	20	27	14%
charge	20	23	0	0%
bore-in	23	27	20	35%
melting	27	39	27	14%
refining	39	47	24	4%
tap and turnaround	47	60	0	0%
Energy per heat			17.86 MWh	

Source: Cameroon Steel illustration from RC-1 values [S07].

Table D.10 Data for Figure 4.2: The arc furnace and its compensator share one busbar, behind a strong 225 kV connection (status: illustrative)

Diagram element	Summary
Voltages	Point of common coupling at 225 kV; plant busbar at 33 kV
Feeders shown	EAF of the 40 t class (transformer of the 30 to 33 MVA class); ladle furnace; SVC or STATCOM and filters; rectifiers and inverters; auxiliary transformers

Source: Cameroon Steel reference configuration RC-1 (planning estimate) [S07]; illustrative diagram.

Table D.11 Data for Figure 4.3: A furnace of the 30 to 33 MVA class needs a 2,000 to 7,000 MVA connection to stay within flicker limits (status: derived)

Short-circuit power at PCC (MVA)	Pst99, uncompensated	Pst99, with SVC (factor 0.5)
500	6.4 to 11	3.2 to 5.6
1,000	3.2 to 5.6	1.6 to 2.8
1,500	2.1 to 3.7	1.1 to 1.9
2,000	1.6 to 2.8	0.8 to 1.4
3,000	1.1 to 1.9	0.53 to 0.93

Short-circuit power at PCC (MVA)	Pst99, uncompensated	Pst99, with SVC (factor 0.5)
4,000	0.8 to 1.4	0.4 to 0.7
5,000	0.64 to 1.1	0.32 to 0.56
6,000	0.53 to 0.93	0.27 to 0.47
8,000	0.4 to 0.7	0.2 to 0.35

Source: simplified screening relation (Annex A); Kst 48 to 85 according to the UIE, as cited in [S12]; SscF about twice the rating of a transformer of the 30 to 33 MVA class (assumed); planning level 0.8 [S13]; derived from the requirement rounded to one significant figure (Pst99 = 0.8 x requirement / short-circuit power).

D.6 Chapter 5, Kribi's power infrastructure

Table D.12 Data for Figure 5.1: A dedicated 225 kV line will bring firm supply 42 km from the Kribi gas plant to the port (status: sourced)

Feature	Value
225 kV line, Kribi gas plant to port	42 km, double circuit
Port substation	225/30 kV, 3 x 60 MVA
Capacity, first stage	100 MW
Capacity, later stage	330 to 400 MW
Kribi gas plant	216 MW, 13 dual-fuel engines

Source: PAK [S14][S15]; Engineering News [S64]; OpenStreetMap [S60].

Table D.13 Data for Figure 5.2: A dedicated 225 kV connection keeps the furnace's disturbances off the zone's shared network (status: illustrative)

Option	Characteristics shown
A. Medium-voltage feeder	PCC at 30 kV, shared with other zone tenants; Weak fault level: flicker spreads to neighbours; Uses part of the first 100 MW
B. Dedicated 225 kV bay	PCC at 225 kV: highest fault level available; Own SVC/STATCOM and filters; Fits Phase 1; expandable
C. Option B plus firm gas-fired back-up	Covers hydro shortfalls and line outages; Gas allocation needed; Higher cost per kWh; best reliability

Source: Cameroon Steel analysis; PAK [S14].

D.7 Chapter 6, natural gas

Table D.14 Data for Figure 6.1: Hilli's exit removes a 72 bcf/yr buyer; plausible uses at Kribi total about 20 to 36 bcf/yr (status: derived)

Item	bcf per year	Status
Field production, 2025	75.5	sourced
Sales 2025: LNG feed (Hilli FLNG)	71.6	sourced
Sales 2025: Kribi power plant	4.9	sourced
Sales 2025: Industrial buyer, Kribi (July to December 2025)	3.1	sourced

Item	bcf per year	Status
Candidate use: Kribi plant, 2025 dispatch	4.9	sourced
Candidate use: Kribi plant, 216 MW at 80%	13.3	derived
Candidate use: Kribi plant, 330 MW licence	20.3	derived
Candidate use: Industrial buyer, annualised	6.2	derived
Candidate use: RC-1 reheating at 1 Mtpa	0.8	derived
Candidate use: 1 Mtpa gas DRI module	8.4 to 9.1	derived
Total of candidate uses without DRI	20.3	derived
Total with plant at 330 MW and 1 Mtpa DRI	36.5	derived

Source: SNH 2025 [S05]; ARSEL 2025 [S01]; Cameroon Steel reference configuration RC-1 (planning estimate) [S07]; [S39][S41]; derived.

Table D.15 Data for Figure 6.2: Power-sector gas sold at about US\$3.2/Mscf in 2025, industry paid about US\$5.0 to 5.6 (status: derived)

Buyer or item	Low (US\$/Mscf)	High (US\$/Mscf)	SNH stated (US\$/Mscf)
Kribi power plant (KPDC)	2.90	3.30	3.2
Industrial buyer at Kribi	5.00	5.60	5.6
LNG feed, State share sold to the offtaker	7.64	8.97	n/a
Special petroleum tax on gas, 70 FCFA/m ³ (if applied)	3.20	3.50	n/a

Source: SNH 2025 [S05][S92]; [S87]; derived conversions.

D.8 Chapter 7, gas for direct reduction

Table D.16 Data for Figure 7.1: A 1 Mtpa DRI plant would burn about 9 bcf a year, nearly twice the Kribi power plant's 2025 use (status: derived)

Use	bcf per year	Share of 2025 output	Status
Kribi power plant, 2025 actual	4.9		sourced
0.25 Mtpa DRI module	2.1 to 2.3	2.8% to 3.0%	derived
0.5 Mtpa DRI module	4.2 to 4.6	5.6% to 6.1%	derived
1.0 Mtpa DRI module	8.4 to 9.1	11.1% to 12.1%	derived
2.5 Mtpa DRI module	21.0 to 22.9	27.9% to 30.3%	derived

Source: [S39][S41][S94][S05]; derived.

Table D.17 Data for Figure 7.2: At Cameroonian gas prices, fuel costs US\$27 to US\$51 per tonne of DRI (status: derived)

Gas price (US\$/Mscf) or reference	Gas cost (US\$ per t DRI)
2.00	17 to 18
3.20	27 to 29
4.00	34 to 37
5.60	47 to 51

Gas price (US\$/Mscf) or reference	Gas cost (US\$ per t DRI)
7.00	59 to 64
8.97	75 to 82
10.00	84 to 91
12.00	101 to 110
Traded HBI, CFR Italy, March 2026	340 to 370 (price per tonne)
Brazilian pig iron, FOB, September 2026	445 (price per tonne)

Source: [S05][S39][S41][S18][S99]; derived.

D.9 Chapter 8, renewables and storage

Table D.18 Data for Figure 8.1: Cameroon's grid emits half the world average per kWh and a third of Indonesia's (status: sourced)

Country or region	g CO ₂ e/kWh, 2024
Ethiopia	23
Brazil	106
European Union	211
Cameroon	226
Côte d'Ivoire	405
Türkiye	470
World	471
Nigeria	496
Gabon	523
Africa	544
China	555
Egypt	574
Algeria	633
Indonesia	680
India	705
South Africa	717

Source: Our World in Data, Ember data [S10].

Table D.19 Data for Figure 8.2: A solar plant at Kribi would yield about 1,335 kWh per kWp a year, a 15% capacity factor (status: sourced)

Month	kWh per kWp
Jan	138.2
Feb	124.9
Mar	124.2

Month	kWh per kWp
Apr	113.3
May	105.3
Jun	93.1
Jul	93.1
Aug	98.7
Sep	96.8
Oct	102.3
Nov	111.0
Dec	133.7
Year	1,334.7

Source: JRC PVGIS v5.3 [S19]; capacity factor 15.2%; optimal slope 6 degrees.

Table D.20 Data for Figure 8.3: A 50 MWp solar array would cover Phase 1 load only around midday (status: illustrative)

Hour (West Africa Time)	Phase 1 load, illustrative (MW)	50 MWp solar, January (MW)	50 MWp solar, July (MW)
00:00	36.4	0.0	0.0
01:00	36.6	0.0	0.0
02:00	36.6	0.0	0.0
03:00	37.1	0.0	0.0
04:00	36.2	0.0	0.0
05:00	36.2	0.0	0.0
06:00	36.6	0.0	0.0
07:00	36.8	2.4	3.0
08:00	36.9	9.8	8.4
09:00	34.8	18.5	13.8
10:00	35.5	24.9	18.1
11:00	36.6	28.7	18.9
12:00	36.1	30.8	19.9
13:00	35.8	32.3	20.8
14:00	36.0	29.7	20.0
15:00	36.8	24.5	16.6
16:00	36.0	16.7	12.8
17:00	35.4	8.7	7.5
18:00	35.4	1.1	1.5
19:00	35.6	0.0	0.0
20:00	35.7	0.0	0.0

Hour (West Africa Time)	Phase 1 load, illustrative (MW)	50 MWp solar, January (MW)	50 MWp solar, July (MW)
21:00	35.8	0.0	0.0
22:00	34.6	0.0	0.0
23:00	36.1	0.0	0.0

Source: [S19]; Cameroon Steel reference configuration RC-1 (planning estimate) [S07]; illustrative.

D.10 Chapter 9, an energy plan for an electric steelworks

Table D.21 Data for Figure 9.1: Electricity demand rises from 0.29 TWh in Phase 1 to 0.75 TWh at 1 Mtpa; melting is half to two-thirds of the total (status: derived)

End use (MWh per year)	Phase 1	Phases 1 and 2	Full build-out
EAF melting	143,617	239,362	478,723
Ladle furnace, caster and auxiliaries	22,340	37,234	74,468
Induction billet heating (Phase 1 mills)	90,000	90,000	90,000
Rolling	33,000	55,000	110,000
Total	288,957	421,596	753,192
Total at the upper value of about 490 kWh/t in the furnace	301,723	442,872	795,745

Source: Cameroon Steel reference configuration RC-1 (planning estimate) [S07]; derived.

Table D.22 Data for Figure 9.2: Phase 1 load would swing between about 16 and 51 MW within each hour (status: illustrative)

Period of the illustrative day	Mean of 15-minute averages (MW)	Highest 15-minute average (MW)	Lowest 15-minute average (MW)
00:00 to 06:00, normal operation	36.6	47.3	20.1
06:00 to 08:00, mill roll change	21.9	33.0	4.9
08:00 to 13:00, normal operation	36.0	47.2	16.6
13:00 to 14:30, furnace maintenance	20.0	26.0	16.8
14:30 to 24:00, normal operation	36.0	44.4	18.1
One-minute values, normal hours	36.2	51.4 (99th pct.)	16.4 (5th pct.)

Source: Cameroon Steel illustration from RC-1 benchmarks [S07]; furnace active power capped at about 30 MW; not a forecast.

D.11 Chapter 10, policy recommendations

Table D.23 Data for Figure 10.1: The energy milestones Cameroon and an electric steelworks must meet, 2026 to 2036 (status: illustrative)

Group	Milestone	Year(s)	Status
Grid	400 kV Nachtigal evacuation line due	2026	sourced

Group	Milestone	Year(s)	Status
Grid	225 kV KPDC-port line and substation due	2026	sourced
Grid	Kikot-Mbebe hydro 500 MW expected	2031 to 2033	sourced
Gas	Hilli FLNG leaves Kribi	2026	sourced
Gas	Gas allocation for Kribi industry (recommended)	2027	recommended
Carbon	EU CBAM certificates on sale	2027	sourced
Carbon	EU free allocation phased out	2026 to 2033	sourced
Rules	Large-user tariff and wheeling framework (recommended)	2027	recommended
Rules	Grid code for fluctuating loads (recommended)	2027	recommended
RC-1	Utilities agreements; environmental certificate	2027 to 2028	target
RC-1	Phase 1 works from Q1 2029	2029 to 2030	target
RC-1	First heat H2 2030; ramp-up	2030 to 2031	target
RC-1	Phase 2 (sections)	2032 to 2034	indicative
RC-1	Phase 3, DRI module later	After 2034 (drawn 2035 to 2036)	indicative

Source: [S02][S14][S68][S16][S108][S109][S07].

CAMEROON STEEL

FROM MINERAL RESOURCE TO INDUSTRIAL VALUE

Cameroon Steel is developing a steel complex at Mboro, in the Kribi industrial-port zone, to turn Cameroonian iron into the bars, rods and sections that Central Africa builds with. This paper is published for information and does not constitute an offer or a commitment.