CHANGA ENERGY

The Great Power Bottleneck

Energy Compendium 2H 2026 — demand has already arrived; the delivery system has not

GE Vernova: 116 GW of backlog + slot reservations, large-frame turbines constrained through 2030 — 14,500 km South African transmission gap to 2034

“DEMAND HAS ARRIVED. DELIVERY HAS NOT.”

E&P / Cleantech / Power & Utilities
London · Johannesburg | 31 July 2026

The scarce asset is delivery — and the market still prices it like capacity

VISION

Global electricity demand grows ~3.6%/yr through 2030. The constraint has moved from generation to delivery — wires, turbines, transformers, tariffs — in both developed markets and South Africa.

PROOF

Two symmetric case studies, each grounded in disclosed order books, legislated reform and published network plans: the global turbine/grid bottleneck (Part One) and South Africa's statutory unbundling (Part Two).

CONTRIBUTION

Where capital should go: regulated wires, clean-firm equipment, gas midstream. In South Africa, the constraint has shifted to transmission, distribution, affordability and market execution — returns depend on delivery and customer credit, not just transmission access.

116 GW

GE Vernova backlog + slot reservations; large-frame turbines constrained through 2030

14,500 km

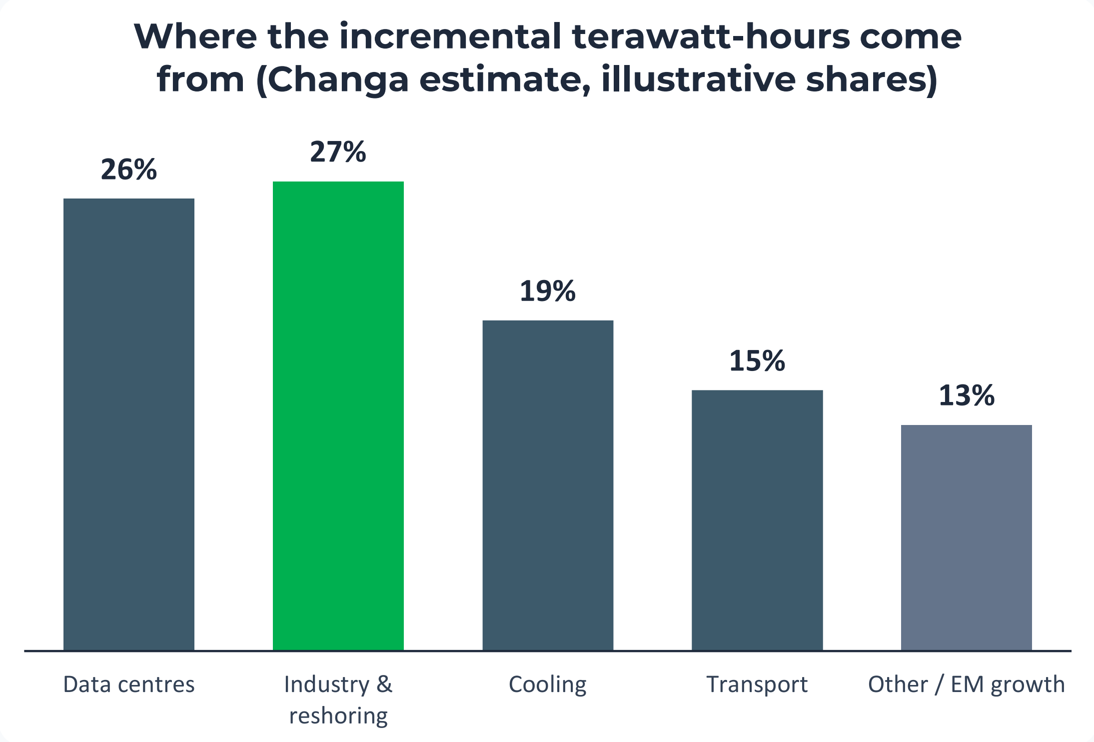
SA transmission required by 2034 — 82% of route-km outside construction/ITIPP Stage 1

PART ONE

The Global Landscape

Sub-sectors have converged. The bottleneck has migrated from generation to the wires — and the returns are moving toward whoever owns delivery.

Data centres are the catalyst — not the whole story



~3.6%/yr

IEA global electricity demand growth, 2026–30 — the annual increment roughly half again larger than the prior decade.

28,200 → 33,600 TWh by 2030 · +1,100 TWh/yr · ~50% of US growth is data-centres.

A hyperscaler wants several hundred MW of continuous, low-carbon power at a site within ~30 months. No single sub-sector can deliver that alone.
Whoever assembles the package captures the economics.

Source: Changa Energy estimates based on IEA Electricity 2026 demand analysis. Buckets are indicative and overlap at the margin.

Stop counting announced gigawatts — contracted load is the only credible signal

1. Press-released capacity
2. Interconnection requests
3. Sites with land & permits
4. **Sites with executed utility agreements**
5. **Contracted, creditworthy, energised load**

The gap between (1) and (5) is where the sector's next disappointment lives. Developers file in several queues for one project — headline queue data is close to useless as a demand signal.

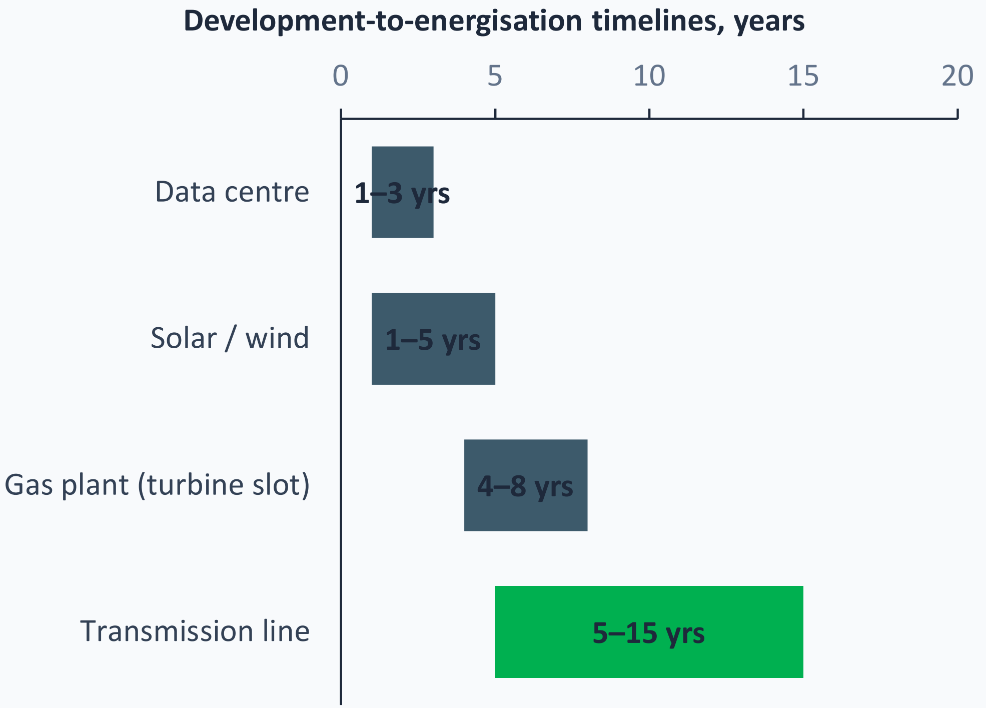
What we want to see from more of from utilities

Test	What good looks like	What worries us
Announced vs contracted GW	Contracted >50% of announced	**A 10:1 ratio with a bullish capex slide**
Minimum bill / take-or-pay	Multi-year, IG counterparty	**“Advanced negotiations”**
Curtailment rights	Interrupt at defined notice	**Firm service to a variable customer**
Cost allocation	Large-load tariff class	**Residential ratepayers carry the network**
Capex timing	Spend follows contract signature	**Spend precedes commitment**

Own the utilities with spare capacity, constructive commissions, developable land and a credible transmission plan. Avoid names capitalising infrastructure ahead of firm commitment — disallowance risk dressed up as rate-base growth.

Source: FERC large-load interconnection rulemaking; Changa Energy analysis.

New generation is fast. New grid is slow — by five to fifteen years



Where the investable expressions sit

IEA: over 2,500 GW of renewable, storage and large-load capacity is stalled in grid queues globally.

Cable costs are up nearly 2x since 2019; transformer prices +75%. You cannot arbitrage a permitting timeline with capital.

Where that leaves the investable list — and the near-term unlock from grid-enhancing technologies — is the next slide.

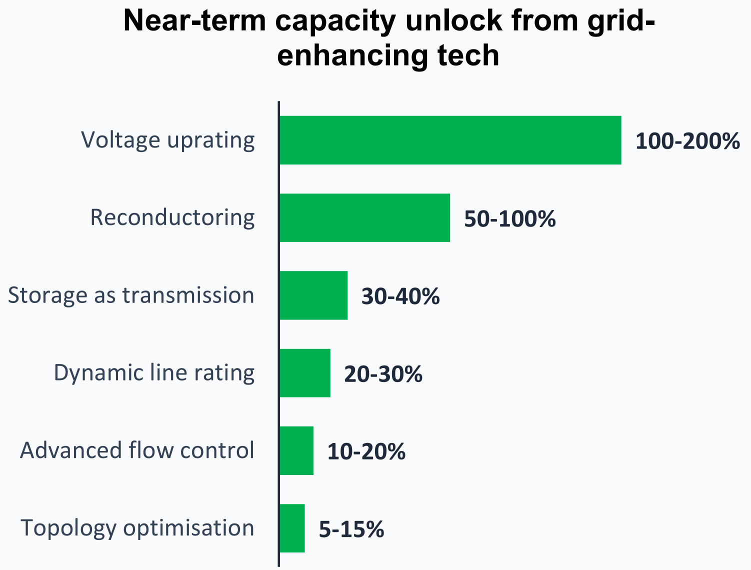
"Speed-to-power is becoming an economic development variable." Load is migrating toward jurisdictions with spare capacity.

Source: IEA Electricity 2026 (grid lead times); OEM disclosure; Changa Energy.

The investable scarcity is wires, equipment and execution

The opportunity is not exotic. It is regulated transmission, grid equipment and specialised contractors with hard-to-replace capabilities.

Category	What underwrites it
Regulated transmission	Rate-base growth with explicit recovery; returns depend on cost allocation and affordability headroom.
Transformers / switchgear	Long lead times, order-book visibility and pricing power; risk is capacity additions catching a peak.
HVDC / cables	Supply-chain bottleneck for long-distance and offshore/grid expansion. Project timing matters.
Grid automation	Dynamic line ratings, topology optimisation, power-flow control and storage-as-transmission.
Specialist EPC	Execution capability, labour access, right-of-way management and safety record become differentiators.



DILIGENCE PRIORITY

Recoverable capex is not the same as value-accretive capex. Test permitted routes, equipment delivery dates, regulatory compact and equity needs.

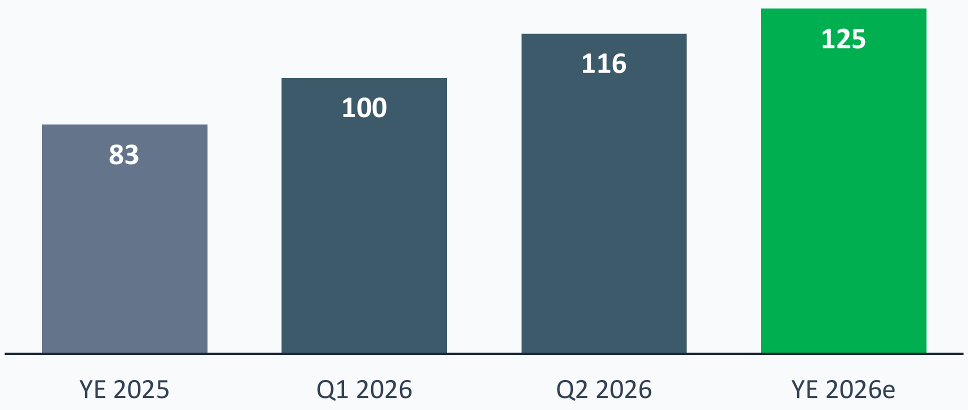
CASE STUDY LENS

FERC's large-load proceedings show that cost allocation is now a political question, not just a technical one.

Source: IEA Electricity 2026 Grids; FERC large-load proceedings; Changa Energy analysis.

Three OEMs control large-frame turbine capacity, and the backlog keeps climbing

GE Vernova combined gas turbine backlog + slot reservations, GW



BULL CASE

Annual production capacity is being pushed toward ~20 GW. A backlog several times annual output, at rising prices, is multi-year earnings visibility with genuine pricing power. Turbine pricing has moved several-fold in three years.

BEAR CASE

A slot reservation is not a plant. FERC's refusal to bend PJM rules for the Chestnut Run project shows regulators will not underwrite equipment risk. If reservations belong to speculative developers, the back half of the backlog is softer than it looks.

How I would test it: ask for the split of backlog by customer type - utility, IPP with contracted offtake, hyperscaler direct, merchant developer - and the deposit structure. The OEMs know this number. Very few have volunteered it.

Source: GE Vernova Q1/Q2 2026 Form 8-K; company investor commentary. Annual production capacity ramping toward ~20 GW.

Gas remains the bridge — discipline is the E&P test

E&P — THE BRIDGE FUEL

EIA STEO, Jul-26: US LNG exports 17.4 Bcf/d (2026e) → 18.6 (2027e) · gas ~40% of US generation · Henry Hub $3.67/MMBtu.

- Gas fills the dispatchable gap intermittent renewables cannot cover at five-nines uptime.
- Test managements on: can Haynesville, Permian associated gas and Appalachia respond at a price that also clears LNG?
- Discipline evidence so far: producers holding FCF, dividends, buybacks rather than re-levering into the windfall (Wood Mackenzie).

Question	Underwriting focus
Molecules	Can Haynesville, Permian associated gas and Appalachia clear power burn plus LNG without breaking discipline?
Takeaway	Where does pipe, compression or basis become the constraint rather than resource depth?
Contracts	Are new gas plants backed by long-term offtake or merchant scarcity rents vulnerable to policy response?
Capital discipline	Do management teams hold post-2020 FCF frameworks through a sustained high-price narrative?

“Underwrite durable free cash flow at mid-cycle, not at spot. If a name only works at spot, you are being paid for geopolitics, not for assets.”

Source: Wood Mackenzie cash-windfall analysis; EIA gas demand outlook; Changa Energy analysis.

Affordability and funding are the ceiling on utility growth

Rate-base opportunity is enormous, but customer bills, equity needs and cost allocation now cap what can actually be deployed.

Test	Good looks like	What worries us
Starting bill level	Below-average bills vs peers	**High bill base before data-centre capex**
Bill vs income growth	Bill CAGR tracks income / CPI	**Bill CAGR outpaces wages into election cycle**
Large-load tariff	Separate class + contribution in aid of construction	**Residential customers carry network socialisation**
Regulatory compact	Supportive commission with transparent recovery tools	**History of disallowances and retroactive politics**
Funding plan	FFO/debt protected; equity not persistent or discounted	**Rate-base CAGR funded by serial dilution**

INVESTOR STANCE

Own utilities with spare capacity, constructive commissions, developable land, a credible transmission plan and visible customer contributions. Avoid infrastructure spend ahead of firm commitment — that is disallowance risk dressed up as rate-base growth.

Source: Changa Energy affordability framework; FERC large-load proceedings; utility regulatory disclosure.

Four buckets separate bankable cleantech from venture risk in a listed wrapper

Bucket	Contents	What underwrites the return
Mature and economic	Utility solar, selected 2–4h storage, grid equipment	Cost position, contracted offtake
Economic with constraints	Onshore wind, distributed generation, transmission tech	Siting, interconnection, permitting
Policy-dependent	Hydrogen, sustainable fuels, parts of CCS	Subsidy durability — a political variable
Pre-commercial / capital-intensive	Long-duration storage, advanced nuclear, industrial decarbonisation	Nothing yet — venture risk in a listed wrapper

SUPPLY CHAIN BIFURCATION

Lowest-cost equipment versus domestically secure equipment — the answer differs by buyer. Capacity without a durable cost advantage, differentiated technology or contracted demand is a working-capital problem waiting to be written down.

SCREEN FOR

- Tariff and anti-dumping exposure
- Foreign-entity restrictions
- Domestic content compliance
- Mineral sourcing and utilisation
- Inventory obsolescence risk

Source: S&P Global 2026 themes; Wood Mackenzie; Changa Energy analysis.

A 9% rate-base CAGR funded with persistent equity at a discount is not a 9% earnings story

FUNDING-ADJUSTED GROWTH

- Internally funded capex as a share of total programme
- Equity issuance as a percentage of market cap
- FFO / debt and retained cash flow
- Interest coverage ratio
- Project-level vs parent guarantees on debt
- Expected return spread over cost of capital

SEVEN QUESTIONS FOR THE ROOM

1. Which demand forecasts are contracted, and at what credit quality?
2. Who owns scarce, deliverable grid, generation and equipment capacity?
3. How much incremental gas demand does power-plus-LNG actually create?
4. Can utilities fund this cycle without destroying affordability or diluting?
5. Will E&Ps hold discipline through a sustained high-price environment?
6. Which cleantech models survive less generous policy?
7. Where is consensus extrapolating announcements rather than cash flow?

> *“The demand side is genuinely extraordinary. The delivery side is behaving exactly as long-cycle industrial systems always behave when you ask them to move five times faster than they did last decade.”*

Source: Changa Energy analysis. Close of Part One — the global landscape.

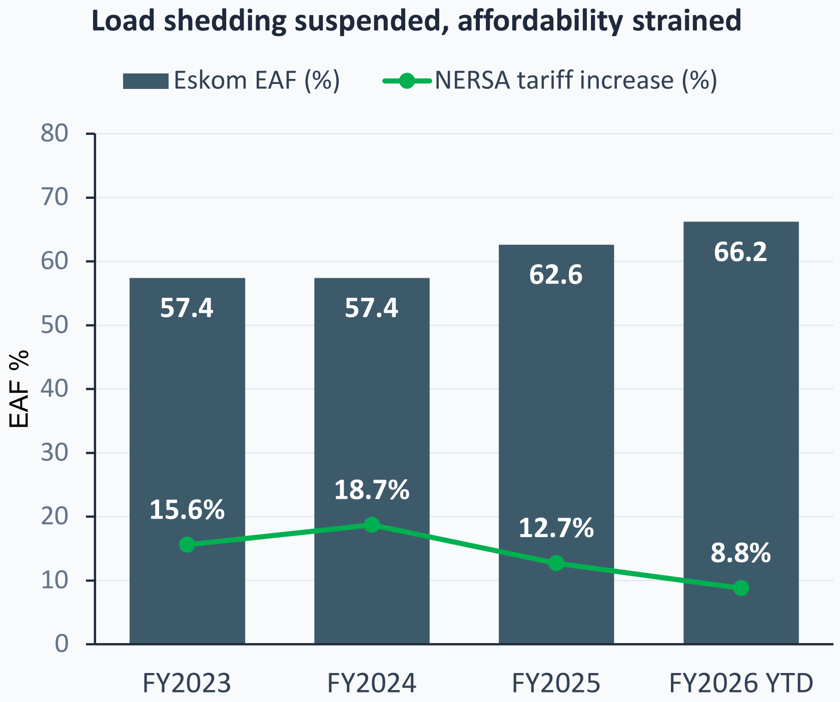
PART TWO

South Africa: the Unbundling and the Grid Wall

The crisis is no longer generation. It is the wires, and it is the tariff.

02 / 02

South Africa suspended load shedding and broke affordability in the same four years



A full year without load shedding; FY2026 YTD EAF near 66%, single-day EAF above 80% on 20 Jul 2026. Our read: this creates the conditions for a utility death spiral unless tariffs, customer retention and network-cost recovery are addressed together.

WHAT HAS ACTUALLY CHANGED

1 Jan 2025	Electricity Regulation Amendment Act in force — ends Eskom's transmission monopoly, opening a five-year transitional period for transmission arrangements while wholesale-market rules and institutions are established.
1 Jul 2024	NTCSA begins independent operations as Transmission System Operator; interim mandate strengthened by ministerial approval, Dec 2025
Early 2026	SAWEM Market Code submitted to NERSA — day-ahead, intraday, reserve and balancing markets with defined Balance Responsible Parties
Apr→Q3 2026	The originally anticipated April 2026 implementation has shifted, with regulatory milestones extending into Q3 2026; full functionality is targeted by 2031, but operational readiness remains conditional on an indicative timetable.

Source: Electricity Regulation Amendment Act; NTCSA/NERSA disclosure; NERSA SAWEM Market Code consultation timeline (as at Jul 2026); Eskom tariff announcements and EAF disclosure. FY2026 EAF is YTD to 20 Jul 2026 (66.2%); single-day EAF reached 80.2% on 20 Jul 2026. Changa Energy analysis.

Four-fifths of South Africa’s 2034 transmission route-km remains unbuilt and unprocured

TDP REQUIREMENT TO 2034

14,500 km

210 transformers · ~56 GW

5x the prior decade's pace

UNDER CONSTRUCTION NOW

1,445 km

16,900 MVA · 31 projects

unlocks ~16 GW by 2028

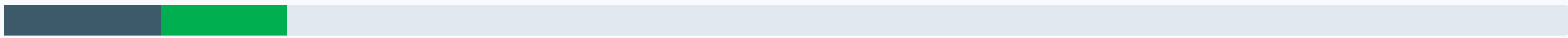
ITIPP STAGE 1 (PRIVATE)

1,164 km

400kV · N.Cape, NW, Gauteng

Transmission Determination Mar-25

DELIVERY GAP, ROUTE-KM SHARE OF THE 2034 REQUIREMENT



■ Under construction ~10%   ■ ITIPP Stage 1 ~8%   ■ Remaining route-km, not yet in construction or ITIPP Stage 1 ~82%

DBSA estimates the full TDP 2025–34 investment need at roughly R440bn — against R112bn approved for the first five years. 61 projects in execution unlock ~30 GW of connection capacity by 2030; 47 further priority projects target ~37 GW by 2033. This residual is the single largest private infrastructure opportunity in the country — and why the Independent Transmission Infrastructure Procurement Programme (ITIPP) matters more than any generation programme currently in the market.

Source: NTCSA Transmission Development Plan 2025–2034; Transmission Determination of 28 March 2025; Changa Energy calculations. Percentages are of route-km, indicative.

Storage turns a merchant wind farm from a penalty liability into a dispatchable product

Under the SAWEM Market Code, Balance Responsible Parties face financial penalties for deviation between forecast and actual output. That single mechanism changes what a renewable asset is worth.

REVENUE STACKING: POSSIBLE, NOT YET CONTRACTED

Two revenue lines are already contracted: BESIPPPP capacity and net-energy payments under 15-year PPAs. Everything else is anticipated, not booked — SAWEM balancing/ancillary revenue depends on go-live; merchant arbitrage, ancillary-market size and curtailment-avoidance value are assumptions until market rules, metering and settlement are finalised.

TRADING CAPABILITY DIFFERENTIATES

The largest 2026 C&I deals are aggregated through licensed traders with diversified portfolios, not bilateral developer-to-user PPAs. NERSA has held back updated trading rules after criticism they were over-restrictive — a margin pool built on regulatory sand.

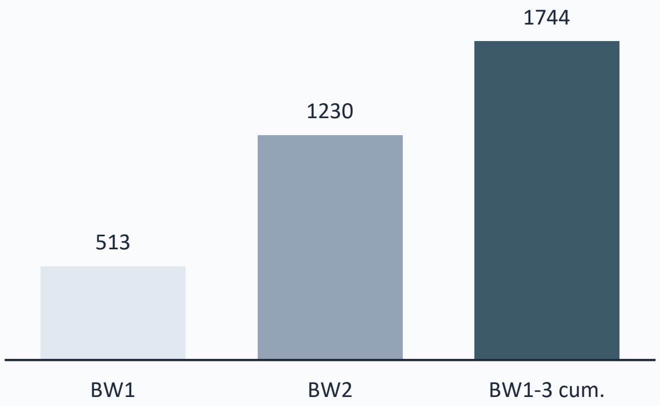
CURTAILMENT BECOMES PRICEABLE

Bid Window 7 PPAs were revised to remove grid-unavailability and curtailment allowances. Government has stopped absorbing curtailment risk and pushed it to the IPP. Modelling BW7 assets on BW4 assumptions is wrong by a wide margin.

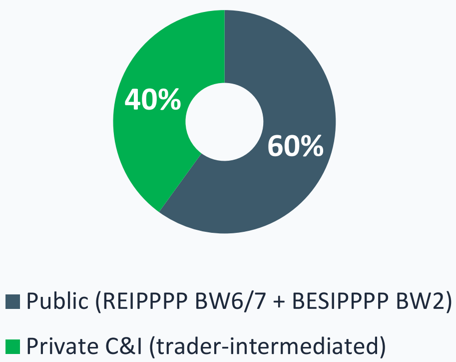
Source: SAWEM Market Code; BESIPPPP programme disclosure; REIPPPP Bid Window 7 PPA terms; NERSA trading rules consultation; Changa Energy analysis.

2026 tracked deal flow still leans public ~60:40 — but private capital is now investment-grade

BESIPPPP procured to date, MW



2026 deal flow by tracked capacity, MW (Changa estimate)



TARIFF ARBITRAGE

R3.00/kWh grid tariff vs ~R0.95/kWh solar cost. Payback compressed from 8+ years (2022) to under 5 years (2026).
REIPPPP BW7: R458–514/MWh.

MINING & CBAM HEDGING

Mining houses hedge grid instability and lower LCOE — increasingly to satisfy CBAM.
Sibanye alone: 765 MW contracted.

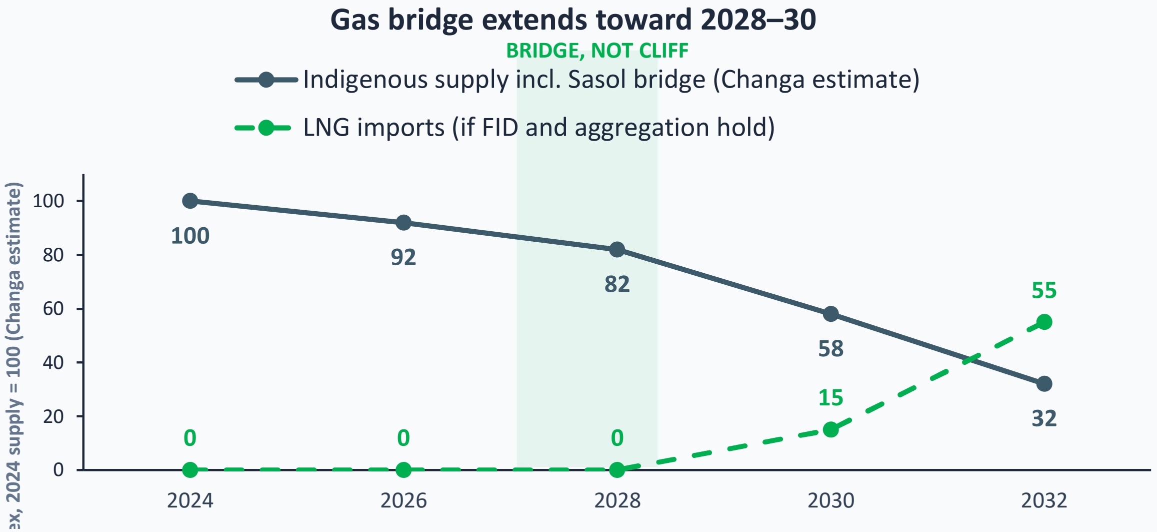
MUNICIPAL SELF-DEFENCE

Municipalities build wheeling frameworks to stop C&I customers disconnecting — but FY2026 tariff reform quietly tightened the economics.

As of mid-2026, domestic capital underwrites up to 475 MW without foreign debt; trader Etana closed >500 MW in the 12 months to Jun 2026

Source: DMRE/IPP Office; SAPVIA; Engineering News; Changa Energy analysis. 'Deal flow' = tracked SA capacity (MW), Jan–Jun 2026; includes preferred-bidder awards pre-financial-close, excludes unsigned announcements.

Sasol's gas bridge extends toward 2028–30 — LNG replacement isn't locked in before then either



REPLACEMENT PIPELINE — TIMING IS EVERYTHING

70,000–100,000 jobs are potentially exposed across gas-reliant industries (IGUA-SA estimates).

Sasol's Mozambique-gas and methane-rich-gas bridge aims to extend supply beyond June 2028, toward 2030. Matola FSRU→ROMPCO gas from ~mid-2028 needs >40 PJ/a demand; Zululand Energy Terminal (Richards Bay, 3 MTPA FSRU, ExxonMobil HoA, ~R15bn).

Both FIDs are slipping (Matola 2H27, ZET now 2028) — and LNG may not land before 2030 either.

Aggregation vehicles

Matola needs >~40 PJ/a aggregated industrial demand. A Rompco-style state-private vehicle or single gas aggregator is the right shape — whoever holds that mandate holds a valuable position.

The inland pipeline problem

Richards Bay and Durban can land LNG; existing pipelines can't move it inland. A second import route via Mozambique is being pursued in parallel. Midstream, not regas, is the constraint.

Gas-to-power as the coal bridge

Eskom decommissions Camden, Hendrina and Grootvlei 2027-2030. South Africa's gas-to-power procurement targets ~3,000 MW nationally (initial ~2,000 MW window) — not one Eskom-owned Richards Bay plant; Richards Bay is one candidate anchor-tenant site among several.

Source: TIPS March 2026 gas study; draft Gas Master Plan; project sponsor disclosure; ZET/ExxonMobil announcements; Changa Energy.

Returns are migrating to whoever owns delivery, not generation, across every SA sub-sector

Where I would concentrate	Why	Principal risk
Private transmission (ITIPP / BOT)	Availability-based revenue, state-linked counterparty, enormous unprocured pipeline	**NTCSA standalone credit; servitudes; global equipment queue**
Grid-scale and hybrid BESS	Revenue-stacking optionality once SAWEM launches; curtailment mitigation in congested corridors now; BW2 priced ~35% below BW1	**Ancillary services market saturating faster than expected**
Licensed traders / aggregators	Capturing the margin between IPPs and C&I demand; portfolio diversification beats bilateral PPAs	**NERSA trading rules still unsettled and previously over-restrictive**
Gas import and midstream	Structural, non-discretionary demand; Sasol bridge (Mozambique gas, methane-rich gas) extends indigenous supply toward 2028-2030, then import-dependent	**FID slippage past 2030; LNG aggregation, terminal timing and FX exposure; anchor-tenant concentration**
C&I distributed generation platforms	Tariff arbitrage at R3.00 vs ~R0.95/kWh; CBAM-driven corporate demand	**Wheeling charge reform; municipal reticulation litigation**

Where I would be more careful than the market currently is: anything whose returns depend on the SAWEM launch date holding, anything relying on municipal-level cooperation, and merchant renewable assets carrying post-BW7 curtailment terms without storage.

Source: DMRE / IPP Office; NTCSA TDP 2025-2034; SAWEM Market Code; Engineering News; Changa Energy analysis.

Distribution and Eskom’s likely market response to this shift

Gap	Why it matters	What changes
Municipal distribution & revenue integrity	Municipal arrears to Eskom exceed R110bn; illegal connections, non-technical losses and deferred maintenance erode collection even where generation is fixed	**A wholesale market can't stay solvent if a large share of the retail chain can't collect, account for and remit revenue**
Eskom Green (approved Jul 2026)	Eskom's own renewable-development vehicle, targeting up to 32 GW by 2040 — a direct answer to the C&I customer migration this report describes	**Must compete on products customers actively choose — firmed clean power, wheeling, time-of-use, storage-backed supply — not tariff protection**

The transmission-and-tariff thesis holds structurally, but collection integrity and Eskom's own competitive response are the two variables the market still has to solve.

Source: Eskom FY2025/26 results; Eskom Green board approval, July 2026; National Treasury municipal finance data; Changa Energy analysis.

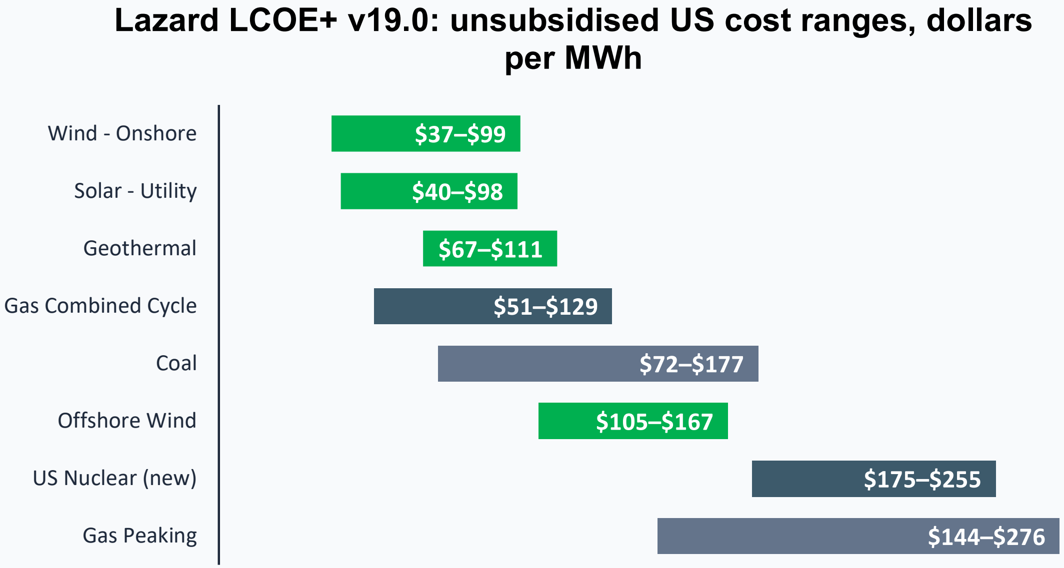
Regional integration and execution capacity should also be considered

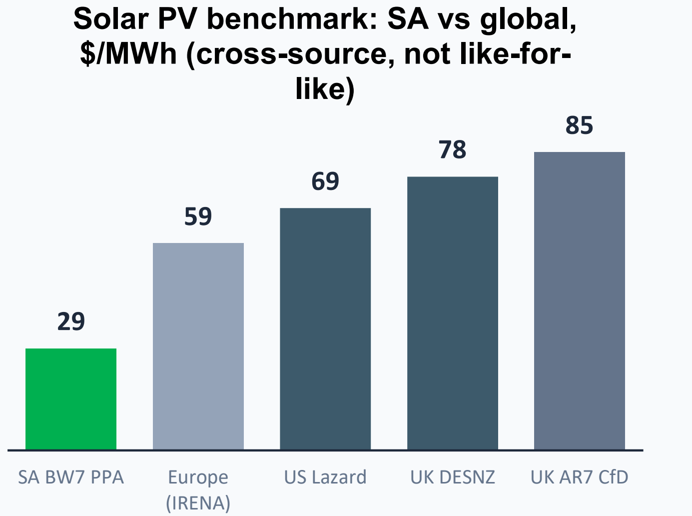
Gap	Why it matters	What changes
Regional integration	Southern Africa offers cross-border transmission, hydropower diversity, regional balancing and export markets for periods of domestic surplus — the report frames scarcity as a domestic-only problem	**Interconnection can lower the cost of SA's own scarcity; shared reserves and ancillary services reduce the capital SA must carry alone**
Execution capacity	Capital isn't the binding constraint — converting it into commissioned infrastructure is: servitude acquisition, environmental approvals, community agreements, transformer/cable procurement, local EPC capacity, security and vandalism all gate delivery speed	**Test programme timelines against delivery capacity, not just funding approval — a funded project that can't be built on time is still a bottleneck**

Scarcity is real, but it isn't only South Africa's to solve alone, and it isn't only a funding problem — regional interconnection and delivery capacity both change the cost of the constraint.

Source: SAPP; SADC regional infrastructure planning; NTCSA grid connection data; Changa Energy analysis.

Renewables are still cheapest globally — but South Africa's cost edge isn't a clean apples-to-apples read



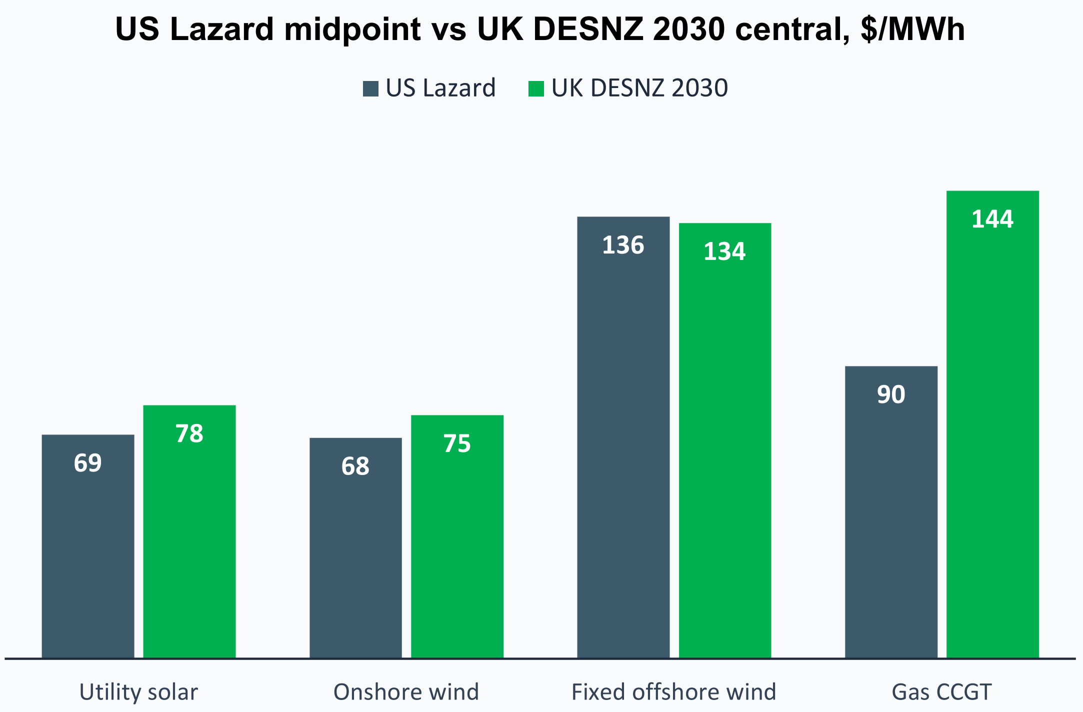


SA's BW7 tariff clears roughly a third of UK/European LCOE and less than half the US low end — but these aren't like-for-like: contract vintage, FX rate, indexation, grid-connection and curtailment allocation, financing terms and contract duration all differ. The fair read: SA's renewable resource is highly competitive; delivered system cost is increasingly set by networks, flexibility and risk allocation, not generation cost alone.

Gas combined cycle sits at a 15-year high LCOE even as new-build gas volumes accelerate — developers are ordering plants at prices Lazard says have not caught up to current quotes. Storage LCOS for a 4-hour system runs $144–$276/MWh, rising for the first time in years as tariffs cut off low-cost cell supply.

Source: Lazard LCOE+ v19.0 and LCOS v11.0, July 2026; UK DESNZ Electricity Generation Costs 2025; IRENA Renewable Power Generation Costs 2025; UK CfD AR7; Green Building Africa REIPPPP BW7; Changa Energy analysis.

UK DESNZ confirms the US cost curve — and load factor, not headline LCOE, decides what CCGT is worth



LOAD FACTOR, NOT HEADLINE LCOE

DESNZ 2030 CCGT is £111/MWh at 93% load factor. At 30% load factor, the same technology is £147/MWh (~$191/MWh). Capacity value, not the plant, is what moves the number.

COMPARABILITY CAVEAT

REIPPPP and UK CfD are contracted tariffs; Lazard, DESNZ and IRENA are LCOE estimates. Read the gap as directional, not a point-estimate ranking.

Bottom line: headline LCOE still matters, but investable value is moving to cost and time to a dependable delivered MW.

Source: Lazard LCOE+ v19.0, July 2026; UK DESNZ Electricity Generation Costs 2025 Annex A/B; UK CfD Allocation Round 7 results; Changa Energy analysis.

INVESTMENT IMPLICATIONS AND RISKS

Where capital should concentrate — and what can break the thesis

Concentrate capital in	Why	Principal risk
Regulated wires / grid equipment	Physical scarcity, recoverable capex, long lead times	**Permitting, disallowance, equipment inflation**
Gas turbine OEMs / services	Backlog visibility, pricing power, service attachment	**Reservation softness, supply-chain ramp, customer mix**
Low-cost gas + advantaged midstream	Dispatchable load growth and LNG pull	**Producer discipline breaks; takeaway bottleneck**
Clean-firm / BESS platforms	Hourly matching, balancing, curtailment mitigation	**Market saturation; LCOS inflation; rule slippage**
SA private transmission / ITP	Availability-style revenue and enormous unprocured pipeline	**NTCSA credit, servitudes, tariff pass-through**
SA traders / aggregators	Margin between IPPs and C&I demand; portfolio value	**NERSA trading rules, municipal reticulation risk**
SA gas import / midstream	Non-discretionary demand; indigenous supply declining as Sasol bridge extends to 2028-30	**FID slippage, anchor-tenant concentration**

The best exposures own scarcity that customers must pay for; the weakest own promises that need policy or queues to clear.

AVOID
Curtailment-exposed renewables without storage; utilities ahead of load; policy-dependent cleantech.

FAVOUR
Funded, permitted, deliverable MWs with customer credit, cost allocation and delivery dates.

Source: Changa Energy analysis; sources across IEA, GE Vernova, Lazard, NTCSA, NERSA, Eskom, IPP Office and gas-market disclosures.

Demand has arrived — whether the delivery system catches up is not on the market's timetable

GLOBALLY

- Demand growth is durable, but data centres aren't the whole picture — IEA sees them near half of US electricity-demand growth to 2030, not global growth
- Scarcity rents are moving toward deliverability: transmission owners, transformer, turbine and cable suppliers gain strategic value
- Firmness and flexibility are becoming more valuable than energy alone — delivered at the right place and time, reliably
- Affordability will constrain investment — sound capital plans can still outrun customer bill headroom and balance-sheet capacity
- Contract quality will separate genuine demand from speculative demand — deposits, take-or-pay, credit and cost allocation matter

SOUTH AFRICA

- Generation recovery changes the agenda: from restoring supply to institutionalising reliability, cutting cost, building the network
- Transmission is the principal physical constraint, but not independent of distribution readiness and connection processes
- Market reform is irreversible; its timetable is conditional — Eskom should prepare to compete in the market, not resist it
- C&I customers are becoming contestable customers — Eskom's answer has to be service and product, not tariff protection
- Storage and gas add real value, but neither is a low-risk default — revenue stacking and LNG economics must be proven, not assumed

Energy Compendium 2H 2026 — demand has already arrived; the delivery system has not. In both markets, the scarce asset is delivery — and the market still prices it like capacity.

Changa Energy analysis — interpretation, not primary source data. See cited slides for underlying figures.

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PART ONE — GLOBAL

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