
| RESEARCH ARTICLE**Capacity Without Cash How Overcapacity, Forecast Errors And Grid Bottlenecks Magnify Payment Stress In Electricity Markets Evidence, Risk Analytics And Policy Lessons For Ghana And Emerging Economies****Elikplim Kwabla Apetorgbor***Energy Economist and Policy Specialist, Accra, Ghana***Corresponding Author:** Elikplim Kwabla Apetorgbor, **E-mail:** elikplimapetorgbor@gmail.com**| ABSTRACT**

Electricity-sector payment crises are commonly attributed to tariffs, collection failures, fuel costs and weak utility governance. Those factors are material, but they do not fully explain why payment stress often persists even when a country possesses apparently adequate—or surplus—generation capacity. This paper develops an integrated energy-finance framework showing how three planning and infrastructure failures interact: contracted overcapacity, demand-forecast error and grid bottlenecks. Overcapacity converts planning optimism into inflexible fixed payment obligations; forecast errors distort the timing, scale and location of investment; and transmission constraints prevent nominal capacity from becoming deliverable and billable energy. Their interaction raises the fixed-cost burden per kilowatt-hour sold, creates curtailment and deemed-energy claims, increases redispatch and fuel costs, weakens the cash-conversion cycle, and transfers commercial risk from generators to utilities and ultimately to the sovereign. Using an analytical case-study methodology, the paper triangulates official Ghanaian data and policy documents for 2019–2026 with international evidence and peer-reviewed literature on capacity expansion, load forecasting, market design and utility finance. Ghana illustrates the central paradox: the system moved from shortage-driven emergency procurement to excess contracted capacity, yet later experienced periods in which realised demand exceeded base forecasts while network and liquidity constraints continued to limit efficient dispatch. The result is not a simple surplus or shortage problem, but a deliverability-and-cash-flow problem. The paper introduces a Payment Stress Identity, a Deliverable Reserve Margin and an interaction-based Payment Stress Multiplier to connect engineering conditions with financial outcomes. It concludes that payment sustainability requires integrated generation-transmission planning, probabilistic forecasting, locational procurement, contract flexibility, disciplined reserve margins, transparent dispatch and curtailment rules, and a financeable payment waterfall. The principal policy implication is direct: capacity procurement should be approved only when the system can demonstrate a credible need, a deliverable network path and a funded payment path under downside scenarios.

| KEYWORDS

electricity overcapacity; demand forecasting; transmission congestion; payment arrears; power purchase agreements; capacity charges; curtailment; utility finance; Ghana; emerging markets.

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1. Introduction

The financial distress of electricity sectors is often diagnosed downstream. Attention is directed to non-cost-reflective tariffs, distribution losses, poor collections, foreign-exchange depreciation, fuel-supply shocks and weak governance. These are immediate drivers of liquidity pressure, but they are frequently the visible symptoms of earlier planning and investment

decisions. A power system can be technically long in megawatts and financially short in cash. It can also be nationally surplus yet locally constrained. The central proposition of this paper is that payment stress is magnified when capacity procurement, demand forecasting and network development are treated as separate policy domains rather than as one integrated financial-engineering problem.

Overcapacity is not simply the difference between installed capacity and peak demand. The financially relevant concept is contracted capacity whose fixed costs remain payable irrespective of dispatch. Likewise, a forecast error is not merely a statistical deviation. When embedded in a long-term power purchase agreement (PPA), sovereign support agreement, fuel commitment or transmission investment, the error becomes a contingent fiscal liability. Grid bottlenecks are also more than engineering inconveniences. They can strand low-cost generation, force expensive redispatch, increase losses, create curtailment compensation and reduce the energy volumes over which fixed obligations are recovered. The three conditions therefore interact through the utility cash flow and the sovereign balance sheet.

Ghana provides a particularly instructive setting. Following severe shortages during 2013–2016, emergency and non-competitive procurement added thermal capacity faster than demand and network capability. The World Bank subsequently characterised the country as having significant excess generation capacity and noted that fixed costs from surplus thermal contracts were not fully recognised in tariffs (World Bank, 2024a). The 2023 Integrated Power Sector Master Plan (IPSMP) reported sufficient capacity to meet peak demand and an 18 per cent reserve margin through 2025, while also identifying transmission constraints and recommending that future procurement be aligned with system need, location and timing (Energy Commission, 2023). Yet the 2026 Energy Outlook reported that 2025 demand tracked the high case and exceeded the base-case peak forecast by 3.8 per cent, demonstrating that the risk environment is dynamic rather than permanently characterised by low demand (Energy Commission, 2026).

This apparent contradiction is analytically valuable. Historic over-procurement does not eliminate future adequacy risk, and faster-than-expected demand growth does not validate all legacy contracts. What matters is whether the capacity is dependable, economically dispatchable, fuelled, correctly located and transferable through the grid at the time and place required. The policy objective should therefore shift from gross megawatt adequacy to least-cost deliverable adequacy, and from nominal revenue requirements to cash-realistic payment adequacy.

The paper makes four contributions. First, it establishes a causal framework linking overcapacity, forecast error and grid bottlenecks to payment stress. Second, it distinguishes installed, dependable, contracted and deliverable capacity, thereby clarifying why headline reserve margins can mislead financial analysis. Third, it develops practical metrics—the Payment Stress Identity, Deliverable Reserve Margin and Payment Stress Multiplier—that can be incorporated into integrated resource planning, tariff reviews, PPA approvals and sovereign-risk assessment. Fourth, it translates the analysis into an implementable reform agenda for regulators, system operators, utilities, investors and finance ministries in Ghana and comparable emerging markets.

2. Methodology and analytical scope

The study applies an integrative analytical case-study method. It combines: (i) documentary analysis of Ghanaian energy statistics, outlooks, wholesale-market reports, tariff decisions, utility financial statements and sector-recovery programmes; (ii) review of multilateral surveillance and financing documents; (iii) synthesis of peer-reviewed literature on electricity-market design, capacity expansion under uncertainty, forecasting, transmission planning and utility financial viability; and (iv) transparent scenario arithmetic. The evidence window is principally 2019–2026, with selected foundational literature used to establish the economics of reliability, capacity remuneration and market risk.

The paper does not claim an econometrically identified causal coefficient for Ghana. Publicly available contract-level data remain incomplete, while the allocation of payments among energy charges, capacity charges, fuel obligations, exchange-rate adjustments and legacy arrears changes over time. The approach is therefore mechanism-based: it identifies observable channels, formulates testable propositions and demonstrates their financial significance through equations and sensitivity cases. This design is appropriate for policy and risk-management analysis where contract confidentiality and data fragmentation constrain conventional panel estimation.

Three boundaries are important. First, the paper does not argue that reserve capacity is wasteful. Adequate reserves are essential for reliability, contingencies, maintenance and hydrological or fuel uncertainty. The problem is capacity above an economically justified reserve margin, especially when procured through rigid obligations. Second, the paper does not attribute Ghana's sector deficit solely to excess capacity. Recent World Bank analysis estimated that excess generation capacity represented only a portion of the 2023 shortfall, while distribution losses, collection performance, tariff gaps, fuel costs and exchange-rate

movements were also decisive (World Bank, 2024a). The argument is that overcapacity acts as a stress multiplier. Third, the paper treats transmission as an economic asset. Grid reinforcement is not merely a reliability expenditure; it can unlock lower-cost dispatch, exports, loss reduction and contract-value recovery.

3. Concepts: from nominal adequacy to deliverable and financeable adequacy

3.1 Four capacity concepts

Installed capacity is the nameplate sum of generating units. Dependable capacity adjusts nameplate capacity for derating, maintenance, hydrology, fuel availability and technical performance. Contracted capacity is the quantity for which the buyer bears fixed or availability obligations under PPAs or regulated cost recovery. Deliverable capacity is the dependable output that can reach load through the transmission and distribution network under credible operating contingencies. Financial analysis should focus on contracted and deliverable capacity, not nameplate capacity alone.

Concept	Definition	Primary risk if mismeasured	Financial consequence
Installed capacity	Nameplate megawatts physically connected or commissioned.	Overstates adequacy when units are unavailable, unfuelled or derated.	False comfort and delayed corrective investment.
Dependable capacity	Capacity expected to be available under defined operating conditions.	Underestimates outage, hydrology and fuel risk.	Emergency fuel or short-term procurement costs.
Contracted capacity	Capacity carrying fixed, availability or take-or-pay obligations.	Obligations remain even when energy is not dispatched.	Capacity payments, arrears and sovereign support.
Deliverable capacity	Dependable capacity that can reach demand through the network.	National surplus masks zonal scarcity and congestion.	Curtailment, deemed energy, redispatch and losses.

3.2 Reserve margin and the deliverability correction

The conventional planning reserve margin is:

$$RM = (K_{dep} - D_{peak}) / D_{peak}$$

where K_{dep} is dependable capacity and D_{peak} is coincident peak demand. This measure is necessary but insufficient. A system with constrained corridors may have a high national reserve margin and a low zonal reserve margin.

The proposed Deliverable Reserve Margin is:

$$DRM = (K_{del} - D_{peak}) / D_{peak}$$

where K_{del} is dependable capacity after transmission, fuel and operating constraints. The gap RM minus DRM is the deliverability discount. A large discount indicates that generation expenditure is not being converted efficiently into reliable, saleable energy.

3.3 Forecast error as a balance-sheet variable

For a planning horizon h , demand forecast error may be represented as $FE_h = (D_{actual,h} - D_{forecast,h}) / D_{forecast,h}$. A negative error arising from over-forecast demand can produce excess contractual capacity; a positive error can produce emergency procurement, accelerated fuel use or inadequate reserves. Both directions are costly. The relevant risk measure is not simply absolute forecasting error, but the asymmetric financial loss attached to each direction. In systems with rigid PPAs, downside demand error can be especially expensive because fixed payments continue while sales volumes fall. In systems with weak reserve and grid investment, upside demand error can be expensive because marginal supply comes from liquid fuels,

imports or emergency plants. Probabilistic and scenario-based planning is therefore superior to a single deterministic forecast (Hilbers et al., 2021; Pineda et al., 2016; Goteti et al., 2025).

4. The payment-stress transmission mechanism

4.1 The Payment Stress Identity

Let total sector payment obligations in period t be:

$$O_t = CP_t + EP_t + F_t + CE_t + FX_t + RD_t + DS_t$$

where CP denotes capacity or availability payments, EP energy payments, F fuel obligations, CE curtailment or deemed-energy compensation, FX exchange-rate and indexation adjustments, RD redispatch and balancing costs, and DS debt-service or legacy-arrears payments. Cash available for upstream settlement is:

$$C_t = [Q_{\text{billed},t} \times \text{Tariff}_t \times (1 - L_t) \times \text{Col}_t] + X_t + G_t - \text{OPEX}_t$$

where Q_{billed} is billable energy, L represents aggregate technical and commercial losses, Col the collection ratio, X net export or ancillary-service receipts, G fiscal transfers and OPEX retained distribution and system-operation expenditure. The Payment Stress Index is $\text{PSI}_t = O_t / C_t$. PSI above one indicates that current obligations exceed available cash and the deficit must be financed by arrears, borrowing, levy revenue, budget transfer, contract restructuring or supplier forbearance.

4.2 How overcapacity raises the numerator and weakens the denominator

Overcapacity raises CP_t because fixed costs are designed to recover debt service, return on equity and fixed operation and maintenance irrespective of actual dispatch. Under take-or-pay, take-and-pay with minimum offtake, availability-based or deemed-dispatch structures, the buyer carries volume risk. If demand is below the procurement case, fixed costs are spread across fewer sold kilowatt-hours, increasing the average revenue requirement. The resulting tariff increase can suppress demand, encourage self-generation and worsen non-payment, creating a feedback loop between excess capacity and reduced utility sales.

The arithmetic is direct. An illustrative 100 MW contract with a fixed availability charge of US\$10–15/kW-month creates US\$12–18 million of annual fixed obligations before energy and fuel charges. Five hundred megawatts of unnecessary contracted capacity would therefore create US\$60–90 million in annual fixed obligations under those illustrative terms. These values are not estimates of any Ghanaian PPA; they demonstrate why modest errors in long-term demand assumptions can create material cash liabilities when translated into financeable contracts.

Overcapacity also changes bargaining power. Once assets are financed and sovereign-supported, restructuring can trigger compensation claims, extended tenors, refinancing costs or investor-state disputes. Governments may postpone payment rather than formally default, converting a planning error into arrears. The cost then compounds through interest, foreign-exchange exposure and deteriorating supplier confidence. Eberhard et al. (2016, 2017) show that IPPs can mobilise capital and improve supply, but their success depends on credible planning, competitive procurement, financeable yet balanced risk allocation and a financially viable off-taker.

4.3 How forecast errors become contractual and fiscal risk

Forecasts determine not only how much capacity is procured but also when, where and with what technology. Deterministic forecasts create a point-estimate bias: they encourage decision-makers to treat one trajectory as a commitment rather than a probability distribution. Political incentives may further favour optimistic demand assumptions because large industrial projects, mines, exports or economic-growth programmes are expected to materialise. When such anchor loads are delayed, downsized or self-supplied, the system retains the contracted obligations but loses the anticipated revenue base.

Forecast error is path-dependent. A plant procured too early imposes a carrying cost during the years before demand catches up. A plant procured in the wrong zone may remain underutilised even when aggregate demand rises. A fuel contract aligned to the forecast can generate separate take-or-pay liabilities. An exchange-rate-indexed PPA converts local-currency revenue uncertainty into hard-currency payment risk. The interaction between demand error, fuel commitments and currency depreciation can therefore be multiplicative rather than additive.

Modern planning literature recommends stochastic, robust, adaptive and real-options approaches. Pineda et al. (2016) demonstrate that forecast errors and market design affect expansion outcomes; Caunhye et al. (2022) show the value of flexible

investment under uncertainty; Hilbers et al. (2021) show that sampling choices for demand and weather materially affect model results; and Goteti et al. (2025) find that explicitly modelling uncertainty can produce more robust capacity strategies. The practical implication is that procurement should be staged, modular and triggered by observable demand milestones rather than locked to a single forecast.

4.4 How grid bottlenecks convert surplus into scarcity and cash into claims

Transmission constraints can make a national capacity surplus coexist with zonal shortages. When low-cost generation cannot reach load, the system operator must redispatch more expensive local units, constrain generation, increase reserves or shed load. The utility may then pay for the constrained generator under deemed-energy or availability provisions while also paying the replacement generator. Congestion can therefore create a double-payment effect: payment for energy not delivered plus payment for energy used to maintain security.

Grid bottlenecks also reduce billable energy through technical losses and outage-related sales suppression. They can delay the connection of new customers and industrial loads that were assumed in demand forecasts. In renewable systems, congestion increases curtailment and weakens project revenues unless the PPA reallocates the risk to the off-taker. In thermal systems, constraints may strand efficient combined-cycle plants and force the dispatch of less efficient simple-cycle or liquid-fuel units closer to load. The financial consequence is a higher weighted average generation cost even though cheaper capacity exists.

The IEA (2023, 2024, 2025a) and IRENA (2024a, 2025) identify grid investment, flexibility and connection bottlenecks as central constraints on secure and affordable power transitions. NREL's transmission-planning work similarly emphasises the system value of coordinated, interregional and forward-looking investment (Simeone et al., 2024). Transmission delay is thus not a neutral postponement; it destroys option value in generation investment and can cause the sector to pay for assets it cannot fully use.

4.5 Interaction effects: why the whole is more expensive than the parts

The interaction can be represented conceptually as:

$$\Delta\text{PSI} \approx \beta_1\text{OC} + \beta_2|\text{FE}| + \beta_3\text{GB} + \beta_4(\text{OC} \times \text{FE}) + \beta_5(\text{OC} \times \text{GB}) + \beta_6(\text{FE} \times \text{GB})$$

OC is the excess contracted-capacity ratio, FE forecast error and GB a grid-bottleneck index such as constrained energy, congestion hours or the difference between dependable and deliverable capacity. The interaction terms are crucial. Overcapacity combined with a negative demand error reduces dispatch and raises fixed cost per unit sold. Overcapacity combined with grid bottlenecks raises curtailment and replacement dispatch. Forecast error combined with grid bottlenecks mislocates both generation and network investment. Where PPAs are foreign-currency indexed and utilities collect in local currency, depreciation multiplies all three effects.



Risk combination	Operational outcome	Cash-flow outcome	Typical balance-sheet destination
Overcapacity + demand over-forecast	Low plant factors; fixed obligations remain.	Higher fixed cost per sold kWh.	Utility arrears or tariff shock.
Overcapacity + grid bottleneck	Curtailment of contracted plant; costly replacement dispatch.	Potential double payment and higher fuel cost.	Off-taker and sovereign.
Demand under-forecast + weak grid	Local shortages despite national capacity.	Emergency procurement, liquid fuel and lost sales.	Utility, consumers and budget.
Forecast error + FX depreciation	Local-currency revenues diverge from indexed obligations.	Rapid increase in unpaid bills.	Public debt and supplier balance sheets.
All three + high losses	Low cash conversion across entire value chain.	Persistent payment waterfall deficit.	Sector-wide circular debt.

5. Ghana: evidence of the capacity–forecast–network–payment nexus

5.1 From shortage response to excess contractual capacity

Ghana's post-2013 procurement illustrates how emergency reliability decisions can create long-duration financial consequences. The World Bank reports that Ghana had about 5,640 MW of installed capacity in 2023 against actual peak demand of approximately 3.6 GW, and that emergency and non-competitive procurement during and after the 2012–2016 supply crisis culminated in expensive excess thermal capacity (World Bank, 2024a). The same assessment notes that fixed costs associated with surplus capacity became an explicit government liability where tariffs did not recognise them.

The 2023 IPSMP reached a more nuanced conclusion: 4,763 MW of capacity was sufficient to meet demand and the planned 18 per cent reserve margin through 2025, so additional conventional thermal generation was not required before 2026 (Energy Commission, 2023). It also recommended that future procurement follow the IPSMP's timing, location, size and technology requirements and explicitly warned against creating overcapacity. This is an important governance principle: procurement authority should be subordinate to an approved integrated plan rather than to bilateral project development momentum.

However, excess capacity was not the only or even the largest driver of the financial deficit. The World Bank estimated its direct contribution to the 2023 power-sector shortfall at roughly 4 per cent, while non-cost-recovery tariffs, distribution losses, collection weaknesses, fuel costs and currency depreciation were more substantial (World Bank, 2024a). The correct policy conclusion is therefore not that overcapacity is irrelevant, but that it locks an avoidable fixed cost into an already weak cash system. In risk-management terms, it reduces the headroom available to absorb other shocks.

5.2 Forecast performance: the danger of treating one historical error as permanent

Ghana's recent demand data demonstrate why planning must remain adaptive. In the first half of 2024, peak demand was reported at 3,604 MW, 2.6 per cent below projection, partly reflecting load curtailment from fuel contingencies; exports were also markedly below projection (Energy Commission, 2024a). Yet by 2025, peak demand reached 4,283 MW, 3.8 per cent above the base-case projection and 8.4 per cent above 2024. Total consumption including losses reached 27,015 GWh, 4.6 per cent above the base case and 9.3 per cent higher year-on-year (Energy Commission, 2026).

This shift carries two lessons. First, demand forecasts should not be evaluated solely by annual error because suppressed demand, outages, fuel constraints and delayed connections can make measured consumption an endogenous outcome of supply limitations. Second, a period of faster demand growth does not automatically make all existing capacity economical. The system must determine whether the growth is firm, creditworthy, geographically aligned with generation and supported by fuel and network capability. Exports are particularly important because they can monetise surplus capacity, but they require dependable fuel, transmission availability, creditworthy counterparties and disciplined separation of domestic and export obligations.

A robust forecast governance regime should therefore publish base, high and low cases; probability weights; forecast-versus-actual attribution; and milestone triggers for procurement. The Energy Commission's use of scenarios in the IPSMP and its later comparison of actual demand with base and high cases is good analytical practice. The next step is to make these scenarios binding inputs into licensing, PPA approval, fuel contracting, grid investment and sovereign-guarantee decisions.

5.3 Grid constraints and the location problem

The 2023 IPSMP incorporated current transmission constraints by dividing Ghana into modelling zones. It found that additional transmission and/or local generation would be required beyond the mid-2020s, particularly in the Middle Belt and NEDCo regions; recommended upgrades between the Western generation enclave, the Middle Belt and the eastern system; and emphasised that transmission investment lowers system costs and expands export opportunities (Energy Commission, 2023). This confirms that aggregate capacity is not a sufficient measure of adequacy.

The location of generation affects both technical losses and payment stress. When generation is concentrated far from growing load centres, the system bears higher losses, congestion risk and network reinforcement costs. Conversely, a well-sited generation enclave can reduce losses and relieve fuel take-or-pay obligations by enabling efficient local gas consumption. The financial appraisal of a new plant should therefore include its marginal transmission cost, congestion relief value, avoided losses, effect on existing PPA dispatch and impact on fuel commitments—not merely its plant-level tariff.

The absence of a completed network path at commercial operation date is especially dangerous. A generator may be technically complete and entitled to availability payments while the transmission connection or downstream evacuation corridor is delayed. This separates project completion risk from system completion risk and places the resulting cash burden on the off-taker. Bankability must therefore be redefined to include coordinated completion of generation, fuel, grid and payment infrastructure.

5.4 The payment waterfall and sovereign transmission of risk

Ghana's payment stress is visible in the accumulation of arrears and continued budget support. The IMF reported that net payables to IPPs and fuel suppliers exceeded US\$2 billion at end-2024 (IMF, 2025a). By the first half of 2025, payments through the Cash Waterfall Mechanism improved, but net payables to IPPs still stood at about US\$1.2 billion at end-June and additional amounts were owed to fuel suppliers (IMF, 2025b). The IMF's December 2025 review projected a 2026 energy-sector shortfall of approximately US\$1.1 billion and noted that government transfers continued to absorb obligations not covered by ECG cash flows (IMF, 2025c).

Distribution performance remains the principal cash gateway. World Bank programme documents reported ECG distribution losses of about 28.4 per cent in 2022 and collection rates around 80 per cent, while a 2025 PURC regulatory brief indicated that ECG power losses in 2024 accounted for approximately 32 per cent of purchases (World Bank, 2024b; PURC, 2025). These losses reduce C_t in the Payment Stress Identity. When combined with fixed capacity payments and foreign-currency indexation, even an improving demand trajectory may fail to produce adequate upstream settlement.

The policy significance is that the Cash Waterfall Mechanism can allocate available cash but cannot create cash. A transparent waterfall is necessary for fairness and discipline, yet it is not a substitute for cost-reflective procurement, loss reduction, collection improvement and contract optimisation. When obligations structurally exceed sector cash generation, the waterfall becomes a rationing mechanism and unpaid balances migrate to the sovereign, generators, fuel suppliers and banks.

Indicator	Recent Ghana evidence	Risk interpretation
Installed capacity versus peak	About 5,640 MW installed versus about 3.6 GW peak in 2023.	Headline surplus, but not all capacity is equally dependable, economic or deliverable.
Planning reserve	IPSMP found 4,763 MW sufficient for peak plus 18% reserve through 2025.	New conventional procurement required strict sequencing.
Forecast deviation	2025 peak 4,283 MW, 3.8% above base forecast; energy 4.6% above base.	Forecast risk changes direction; adaptive triggers are essential.
Grid constraints	IPSMP modelled zonal constraints and prescribed corridor upgrades.	National reserve margin overstates local deliverability.
Distribution cash conversion	High losses and incomplete collection remain material.	Sales growth does not translate one-for-one into cash.
Payment stress	Large IPP/fuel arrears and recurring budget support.	Commercial risk ultimately migrates to the sovereign.

6. Comparative evidence from other emerging electricity markets

Ghana's experience is not unique. Pakistan's circular debt illustrates how capacity payments, currency depreciation, high losses, weak collections and demand underperformance can reinforce one another. The World Bank's 2024 Pakistan Development Update identified distribution reform as central to arresting the power-sector deficit and highlighted the role of fixed capacity obligations in a system where sales growth and revenue recovery have not kept pace (World Bank, 2024c). The lesson is that renegotiating generation contracts without improving distribution cash conversion provides temporary relief but not structural solvency.

Vietnam's renewable expansion demonstrates the network dimension. Rapid project development in resource-rich provinces outpaced grid reinforcement, producing congestion and curtailment risk. World Bank and ESMAP grid-integration guidance stresses that procurement volumes, connection schedules, dispatch rules and curtailment allocation must be coordinated before contracts are awarded (World Bank, 2020; World Bank, 2024d). The lesson for thermal as well as renewable PPAs is that the buyer should not assume unlimited network absorption.

Nigeria demonstrates the fiscal implications of a weak off-taker and tariff shortfall. Sector-recovery programmes have sought to improve tariff alignment, settlement discipline, metering and distribution performance because upstream generation cannot remain financeable when downstream cash collection is structurally inadequate (World Bank, 2023a). Across Sub-Saharan Africa,

Trimble et al. (2016) found that quasi-fiscal deficits were widespread and that hidden costs arose from underpricing, losses, overstaffing and under-collection. Overcapacity adds a fixed contractual layer to these established sources of financial weakness.

The broader literature on IPPs confirms a balanced conclusion. Long-term contracts and sovereign support can mobilise capital where markets and utilities are not creditworthy, but these instruments transfer demand, currency, fuel and political risk to the public sector (Eberhard et al., 2016; Foster & Rana, 2020). Competitive procurement, credible least-cost plans and transparent contract management are therefore not procedural preferences; they are core sovereign-risk controls.

7. A quantitative risk-management framework

7.1 Core metrics for regulators, utilities and investors

Metric	Formula or definition	Decision use
Contracted excess-capacity ratio	$CECR = \max[0, (K_{\text{contract}} - K_{\text{required}}) / K_{\text{required}}]$.	Tests whether fixed obligations exceed least-cost need.
Deliverability discount	$DD = 1 - (K_{\text{deliverable}} / K_{\text{dependable}})$.	Measures network/fuel erosion of dependable capacity.
Forecast-at-risk	Distribution of demand error over the PPA and planning horizon.	Sets procurement triggers, reserve bands and stress cases.
Fixed-cost absorption ratio	$FCAR = \text{fixed generation obligations} / \text{net billed kWh}$.	Tracks tariff pressure from low utilisation.
Upstream payment coverage	$UPC = \text{cash available for generators and fuel} / \text{current upstream bills}$.	Signals arrears accumulation before default.
Curtailment liability ratio	$CLR = \text{curtailment/deemed-energy payments} / \text{total generation payments}$.	Identifies misalignment between PPA and grid capability.
FX mismatch ratio	Foreign-currency obligations / naturally hedged foreign-currency receipts.	Quantifies depreciation exposure.
Payment Stress Index	$PSI = \text{total obligations} / \text{cash available}$.	Integrated liquidity and solvency warning indicator.

7.2 Illustrative sensitivity analysis

Table 5 is an illustrative stress test, not an estimate of Ghana's confidential contractual obligations. It shows how the same contracted portfolio can produce sharply different payment outcomes depending on demand, network deliverability, losses and currency. The baseline assumes annual sector cash available for upstream settlement of US\$1.50 billion and obligations of US\$1.50 billion. Each scenario isolates or combines shocks.

Scenario	Obligations (US\$bn)	Cash available (US\$bn)	PSI	Interpretation
Balanced baseline	1.50	1.50	1.00	Current bills can be paid.
10% demand shortfall with rigid capacity cost	1.50	1.38	1.09	Fixed cost is spread over lower sales.
Grid bottleneck: 8% constrained energy plus redispatch	1.60	1.42	1.13	Curtailement and replacement dispatch raise cost.
Higher losses/collection leakage	1.50	1.28	1.17	Downstream inefficiency transmits upstream.
Combined demand, grid and FX shock	1.72	1.23	1.40	Interaction creates rapid arrears accumulation.
Mitigated case: staged capacity, grid upgrade, loss reduction	1.43	1.57	0.91	Cash headroom permits debt clearance and investment.

The model highlights the convexity of stress. A 10 per cent reduction in sales does not merely create a 10 per cent problem when costs are fixed and foreign-currency indexed. If congestion simultaneously raises redispatch cost and losses reduce collections, the payment gap can widen disproportionately. This is why downside stress testing should be compulsory before PPA approval and repeated during tariff reviews.

7.3 From project financeability to system financeability

Traditional project finance asks whether a generator has a financeable PPA, sovereign support, fuel arrangements and a secure payment mechanism. System financeability asks an additional set of questions: Is the capacity needed under multiple demand scenarios? Can it be dispatched economically? Is the fuel available at an affordable price? Can the network evacuate it under N-1 conditions? Is the off-taker's cash flow sufficient after realistic losses and collections? Who bears curtailment and forecast risk? A project can be individually financeable while making the system less financeable.

The distinction is central to energy finance. Credit enhancement can lower the project's weighted average cost of capital while increasing contingent liabilities for the sovereign. The correct objective is not to minimise the financing cost of each project in isolation, but to minimise risk-adjusted total system cost while preserving reliability. This requires finance ministries, regulators and system planners to evaluate guarantees as a portfolio rather than transaction by transaction.

8. Contract and market design reforms

8.1 Replace unconditional volume-risk transfer with balanced flexibility

New PPAs should distinguish risks that the generator can manage from risks that only the buyer or system operator can manage. Construction, availability, heat rate and operating performance generally belong with the generator. Sovereign change-in-law and discriminatory political risk may belong with government. Demand risk should not be transferred automatically to the public buyer through unqualified take-or-pay when the forecast is uncertain. Alternatives include lower minimum offtake, declining capacity charges, merchant tails, capacity step-downs after debt amortisation, demand-triggered expansion phases, tolling structures and competitive availability procurement.

Curtailement provisions should separate generator-caused, network-caused, economic and system-security curtailment. Compensation should be capped, transparently measured and conditioned on plant availability and compliance. Where a project is developed ahead of the network, the party controlling the delay should bear the cost. NREL's PPA guidance and World Bank

renewable-integration work emphasise that contracts must support dispatch and grid integration rather than undermine them (NREL, 2016; World Bank, 2024d).

8.2 Make procurement locational, competitive and plan-bound

Competitive procurement should be based on a regulator-approved capacity and transmission need. Bids should be evaluated on adjusted system cost, including connection, losses, congestion relief, fuel infrastructure, flexibility, emissions, ancillary services and currency exposure. A low plant tariff at the wrong node can be more expensive than a higher tariff at a constrained load centre.

Procurement approval should expire if financial close or construction does not occur within a defined window, because delayed projects can overlap with later procurements and create excess capacity. Capacity should be released in tranches, with each tranche contingent on verified demand, network progress and retirement of inefficient units. The Ghana IPSMP's recommendation that timing, location, size and technology follow the plan should be made legally enforceable rather than advisory (Energy Commission, 2023).

8.3 Improve forecast governance

Forecasting should be institutionally separated from project promotion. A central planning body should publish assumptions for GDP, industrial loads, mining, exports, electric mobility, distributed generation, energy efficiency, tariffs and suppressed demand. Forecasts should be independently reviewed and back-tested. Large customers and distribution utilities should be required to submit verifiable load forecasts, connection schedules and self-generation plans.

Forecast accuracy should be reported by horizon, customer class and zone, with explicit attribution of errors to economic growth, outages, tariffs, weather, exports, customer migration and data quality. Because forecast uncertainty grows with horizon, the commitment profile of procurement should be shorter and more flexible at longer horizons. Real options—such as expandable sites, modular turbines, storage-ready substations and staged network reinforcement—have measurable value under uncertainty (Caunhye et al., 2022).

8.4 Align tariffs and the payment waterfall with efficient cost

Cost-reflective tariffs are necessary, but consumers should not be asked to finance avoidable planning errors indefinitely. Regulatory prudence review should determine which costs were efficiently incurred, competitively procured and consistent with approved plans. Legacy obligations may require negotiated restructuring, but future tariffs should distinguish efficient current cost from legacy debt service. This improves transparency and protects both consumers and investors.

The payment waterfall should prioritise current efficient obligations, fuel required for least-cost dispatch and essential network operations, while separately budgeting legacy arrears. Allocations should be based on verified invoices, metered energy, availability, contractual priority and transparent rules. Monthly public reporting of bills, payments, arrears, exchange-rate adjustments and curtailment claims would improve discipline and reduce information asymmetry.

9. Integrated policy framework for Ghana

Reform	Lead institutions	Industry implementation	Risk reduced
Legally bind procurement to the IPSMP and transmission plan.	Ministry, Energy Commission, PURC, Cabinet.	No PPA, guarantee or licence without need and deliverability certificates.	Overcapacity and political procurement risk.
Create an Independent System and Market Operator with transparent dispatch.	Government, Parliament, GRIDCo, regulators.	Publish merit order, constraints, curtailment and settlement data.	Dispatch discrimination and congestion cost.
Adopt probabilistic demand and export forecasting.	Energy Commission, ECG, NEDCo, GRA, GMet.	Base/high/low distributions, back-testing and milestone triggers.	Forecast and timing risk.
Introduce a PPA portfolio risk register.	Ministry of Finance, Energy Ministry, PURC.	Track capacity, FX, fuel, termination and curtailment exposure.	Contingent fiscal liabilities.
Use locational and system-cost competitive procurement.	Energy Commission, PURC, System Operator.	Score bids on connection, losses, flexibility and fuel, not tariff alone.	Mislocation and hidden network cost.
Accelerate priority transmission corridors and digital control.	GRIDCo, Ministry of Finance, private investors.	Transmission PPPs, SCADA/EMS, dynamic line rating and reactive support.	Congestion, losses and curtailment.
Reduce ECG/NEDCo losses and strengthen collections.	Utilities, PURC, Government.	Feeder metering, smart meters, GIS, enforcement and public-sector payment discipline.	Cash-conversion risk.
Separate current bills from legacy arrears.	Ministry of Finance, CWM administrator.	Funded amortisation plan and transparent current-bill coverage.	Recurring arrears and supplier distress.
Develop regional export as a bankable surplus-management tool.	ECG, GRIDCo, WAPP, Ministry.	Creditworthy contracts, transmission rights and fuel-backed schedules.	Idle capacity and FX mismatch.
Institute annual integrated stress testing.	PURC, Energy Commission, Ministry of Finance.	Test demand, FX, fuel, hydrology, outages and grid delays.	Systemic payment stress.

10. Implementation roadmap

10.1 First 100 days: establish visibility and control

The Government should establish a joint Power-Sector Risk Committee chaired by the Ministry of Finance and comprising the Energy Ministry, Energy Commission, PURC, GRIDCo, ECG, NEDCo, GNPC/Ghana Gas and the system operator. Its initial task should be a single reconciled database of all PPAs, fuel contracts, guarantees, arrears, capacity obligations, exchange-rate indices, termination exposures and network dependencies.

A temporary gate should apply to new sovereign-supported generation commitments until each project receives three certifications: a Capacity-Need Certificate, a Grid-Deliverability Certificate and a Payment-Affordability Certificate. Projects already advanced should be ranked by sunk cost, system need, contractual exposure and network readiness rather than by political sponsorship.

10.2 Within 12 months: embed risk discipline

The Energy Commission should update the IPSMP using 2025 actual demand and publish probability-weighted scenarios. GRIDCo should publish a coordinated transmission plan with project schedules, congestion costs and nodal adequacy indicators. PURC should incorporate the Payment Stress Index, fixed-cost absorption ratio and curtailment liability ratio into tariff and investment reviews. The Ministry of Finance should publish an annual statement of energy-sector contingent liabilities and conduct portfolio stress tests under depreciation, demand and fuel-price shocks.

The Cash Waterfall Mechanism should be upgraded from an allocation instrument into a performance dashboard. It should disclose current-bill coverage by supplier class, arrears ageing, variance from dispatch, fuel-credit notes and exchange-rate adjustments. Distribution utilities should be placed under binding loss and collection trajectories, with management incentives and sanctions tied to feeder-level results.

10.3 Two to five years: restructure the physical and commercial architecture

Priority transmission corridors should be financed through a mix of regulated investment, concessional finance and carefully structured transmission PPPs. Project selection should be based on quantified congestion relief, avoided generation cost, export value, loss reduction and resilience. Digital system-operation capability—SCADA, energy management systems, automated generation control, weather forecasting and nodal metering—should be treated as finance infrastructure because it improves dispatch, settlement and forecasting.

Legacy PPAs should be optimised through transparent portfolio negotiation rather than ad hoc bilateral pressure. Options include tenor extension in exchange for lower capacity charges, conversion from take-or-pay to take-and-pay, refinancing, dispatch flexibility, export rights, fuel-efficiency improvements and retirement of inefficient units. Any concession granted by investors should be matched by credible payment discipline and protection against future unplanned procurement.

11. Implications for investors, lenders and rating analysts

Investors should not equate a sovereign guarantee with absence of risk. Guarantees transfer project risk to a sovereign whose fiscal capacity may already be strained by energy arrears. Due diligence should assess the entire payment chain: tariff approval, billing, losses, collection, cash waterfall, fuel credits, exchange-rate treatment, dispatch priority, grid capability and political willingness to pay. A strong PPA with a weak system can still produce restructuring risk.

Lenders should require independent demand and grid studies, downside debt-service coverage under curtailment, and visibility on competing capacity. They should also examine whether the project increases or reduces system cost. Projects that relieve congestion, displace liquid fuel, provide flexibility or support exports may remain valuable even in a capacity-surplus system. Conversely, a nominally low-cost baseload plant can worsen payment stress if it adds inflexible capacity at the wrong location.

Credit-rating and sovereign-risk analysis should treat energy-sector arrears as debt-like obligations. IMF surveillance increasingly recognises unpaid IPP and fuel bills within debt sustainability analysis. A PPA portfolio risk register, reconciled payment data and transparent contract terms would therefore improve not only sector governance but also sovereign credit assessment and the cost of capital.

12. Discussion

The analysis reframes the conventional surplus-capacity debate. The relevant question is not whether installed capacity exceeds peak demand, but whether the portfolio delivers the right reliability service at the least risk-adjusted cost and can be paid from sector cash flows. A reserve margin can be simultaneously too high nationally and too low locally. Demand can be over-forecast in one planning cycle and under-forecast in the next. Grid reinforcement can appear expensive in a capital budget while producing large savings in generation payments, fuel, losses and exports. These conditions require a system perspective.

The framework also clarifies the limits of common remedies. Tariff increases improve revenue but can entrench inefficient costs and provoke demand destruction if procurement discipline is not improved. PPA renegotiation lowers fixed obligations but can impair investment confidence if undertaken without transparent principles. Loss reduction improves cash but cannot fully offset unlimited contractual procurement. Export expansion can monetise surplus capacity but may create new credit and fuel risks. The reforms are complements, not substitutes.

A deeper institutional implication follows. Power-sector planning is a form of public financial management. Every capacity decision creates a long-duration payment profile; every transmission delay changes the value of contracted generation; and every forecast assumption can migrate into sovereign debt. Finance ministries should therefore participate before contracts are signed, not only after arrears accumulate. Similarly, regulators should review total system cost and prudence, not merely pass through invoices.

For energy-transition policy, the framework warns against repeating thermal-era mistakes with renewable procurement. Solar and wind have low marginal costs, but excessive or poorly located contracting can still create curtailment, network and payment liabilities. The appropriate response is not to slow clean-energy investment indiscriminately, but to co-optimize generation, storage, flexibility, transmission and demand. The IEA and IRENA evidence shows that generation investment is increasingly outpacing grid investment globally, making this lesson urgent (IEA, 2025b; IRENA, 2025).

13. Conclusion

Payment stress in electricity markets is not generated solely at the meter or tariff hearing. It is often designed years earlier through optimistic demand forecasts, uncoordinated capacity procurement and delayed network investment. Overcapacity raises fixed obligations; forecast errors distort the timing and location of assets; and grid bottlenecks prevent contracted capacity from

becoming delivered and billable energy. Their interaction increases average cost, curtailment, redispatch, foreign-exchange exposure and arrears.

Ghana's experience demonstrates both the danger of shortage-driven over-procurement and the danger of static diagnosis. The country has carried excess contractual capacity and substantial payment arrears, yet recent demand has also outperformed base forecasts. The solution is neither indiscriminate cancellation nor indiscriminate expansion. It is disciplined, probabilistic and integrated planning focused on deliverable capacity, efficient system cost and funded payment paths.

The governing rule should be simple but demanding: no new capacity should receive a licence, PPA, guarantee or regulated cost recovery unless the system can demonstrate a credible need, a deliverable network path and a financeable payment path under downside scenarios. When that rule is embedded in competitive procurement, balanced contracts, transparent dispatch, loss reduction and portfolio stress testing, private capital can remain financeable without making the sovereign the residual insurer of every planning error.

Policy propositions for immediate adoption

1. Make the Integrated Power Sector Master Plan and Transmission Master Plan legally binding on procurement, licensing and sovereign guarantees.
2. Require Capacity-Need, Grid-Deliverability and Payment-Affordability certificates before any regulated-market PPA is executed.
3. Adopt probabilistic, zonal and customer-class demand forecasts with published back-testing and procurement triggers.
4. Measure and disclose the Deliverable Reserve Margin rather than relying solely on national installed capacity.
5. Evaluate bids on risk-adjusted total system cost, including congestion, losses, fuel, flexibility and currency—not plant tariff alone.
6. Reform PPAs to include staged capacity, balanced curtailment rules, capacity-charge step-downs and merchant or export flexibility.
7. Create a consolidated PPA, fuel and guarantee portfolio risk register managed jointly by the energy and finance authorities.
8. Upgrade the Cash Waterfall Mechanism into a public settlement dashboard and separate current bills from legacy-arrears amortisation.
9. Accelerate high-value transmission corridors, SCADA/EMS, metering and reactive-power investments using quantified congestion savings.
10. Tie distribution-utility governance, management incentives and fiscal support to feeder-level loss, billing and collection performance.
11. Use regional exports selectively to monetise surplus capacity, subject to fuel security, credit support and transmission rights.
12. Conduct annual integrated stress tests covering demand, FX, fuel, hydrology, outages, grid delays and curtailment liabilities.

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