HOW NOT TO DO PPPs IN AFRICA

Lessons from the World Bank's Nigeria Power Sector Interventions, 2009–2019

A Critical Analysis of NEGIP (ICR P106172) and PSGP (ICR P120207)

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EXECUTIVE SUMMARY

This report examines a decade of World Bank power sector interventions in Nigeria through two projects that collectively deployed or approved over $900 million in financing and $600 million in Partial Risk Guarantees[1]: the Nigeria Electricity and Gas Improvement Project (NEGIP, P106172, 2009–2018, rated Moderately Unsatisfactory) and the Power Sector Guarantees Project (PSGP, P120207, 2014–2019, rated Moderately Satisfactory).

The PSGP, approved in 2014, backed the Azura Edo IPP (459 MW, $877M)[2] and the proposed Qua Iboe IPP (533 MW, $1.14 billion, subsequently cancelled)[3]. This report argues that despite a 'Moderately Satisfactory' outcome rating, the PSGP represents a systemic failure of PPP design, sequencing, and institutional accountability. The Bank invested in generation capacity backed by USD-denominated take-or-pay obligations while knowingly proceeding with a distribution sector that had been captured by politically connected investors with no sectoral competence. This was something the Bank was fully aware of – having worked on the privatization process for a decade.

What makes this failure inexcusable is that the Bank had prior warning. NEGIP—a concurrent project active when the PSGP was designed—deployed a $600M PRG series for gas supply to power plants. Of the seven to ten gas supply agreements originally envisaged, exactly one was signed. That single deal—the Accugas-Calabar arrangement—failed to increase power generation because the Calabar plant was dispatched at half capacity due to transmission constraints at the site and also the same DISCO revenue collapse that would later afflict the PSGP. NEGIP's gas guarantee objective was rated Negligible. The Bank approved the PSGP anyway.

The result: a sector financial deficit of approximately $1 billion at PSGP project close[4], a Country Director reduced to acting as a debt collector, and a Bank now seeking to scale the same model across Sub-Saharan Africa.

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[1] NEGIP ICR: World Bank Implementation Completion and Results Report, Nigeria Electricity and Gas Improvement Project (P106172), ICR Report No. ICR00005073, June 2020. PSGP ICR: World Bank Implementation Completion and Results Report, Nigeria Power Sector Guarantees Project (P120207), Report No. 155732-NG, March 2021. Both documents publicly available at World Bank Open Knowledge Repository.

[2] PSGP ICR, Annex 4, Table 4.4. Total project cost of $877 million includes EPC contract, financing costs, and owner's costs at financial close December 2015.

[3] PSGP ICR, para. 57 and Annex 4, Table 4.4. Note: Table 4.4 cost figure of $2,131/kW excludes the $136 million transmission line and gas pipeline. QIPP cancellation confirmed at PSGP project close December 2019.

[4] PSGP ICR, para. 54, footnote 28.

1. The Setup: A Story Too Good to Be True

Nigeria's fundamental power sector problem at the time of PSGP approval was not insufficient generation capacity. By 2014 the country had over 10 GW of installed generation — and was delivering barely 4,000 MW to the grid. That 60 percent utilisation gap was not a mystery: a transmission system that could not wheel available power to demand centres, and distribution companies collecting 50–60 percent of the energy they received while disconnecting feeders to areas with high losses. The evidence was not buried — it was in every NERC quarterly report, in NEGIP's live ISRs, and in the lived experience of every Nigerian business running a diesel generator. Nigeria did not need more generation capacity behind a broken distribution sector. It needed investment in DISCOs and transmission. The Bank's PAD acknowledged distribution sector weakness in footnotes. It treated generation as the binding constraint. That diagnosis was wrong, and the consequences of that diagnostic failure are documented in this report.

In May 2014, the World Bank Board approved the Power Sector Guarantees Project (PSGP) for Nigeria. The Project Appraisal Document told a compelling story: a country embarking on transformational power sector reform, privatizing its generation and distribution assets, establishing a single-buyer model through the Nigerian Bulk Electricity Trading PLC (NBET), and readying itself for a wave of greenfield independent power producers. The Bank's Partial Risk Guarantees would provide the credit enhancement to unlock private capital.

This story was substantially true. What the PAD omitted—or buried in subordinate clauses—was the other story: the distribution companies (DISCOs) privatized between November 2013 and October 2015 had been acquired by politically connected buyers who had very little or no sector experience and did not have the funding or commitment for making capital investments necessary to reduce technical and commercial losses. Aggregate technical, commercial, and collection (ATC&C) losses were already running at 35 percent at appraisal[5]—not the 25.6 percent stated in the privatization agreements, and nowhere near the 13.4 percent[6] target set for 2017. The Bank was present throughout the privatization. It was on the ground. In the Ministry. It knew the situation. It proceeded anyway.

The ICR's own language, written seven years later[7], is candid about what this meant: *'A financially weak or unstable distribution subsector will quickly extend the contagion to the rest of the sector, and any financial buffers created in the intermediary or investments in generation would rapidly deplete or*

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[5] PSGP ICR, para. 21. The 35 percent actual ATC&C loss baseline at appraisal, the 25.6 percent figure in the privatization Performance Agreements, and the 13.4 percent MYTO target for 2017 are all drawn from the Bank's own project documentation. Independent corroboration: Lexology (2017), "The Nigerian Privatization Mistake," documents that pre-privatization DISCO losses "had been at between 40 and 50 percent of the power wheeled to them through the transmission system."

[6] PSGP ICR, para. 21 and Annex 1. The ATC&C reduction trajectory was embedded in the Multi-Year Tariff Order (MYTO) and the Performance Agreements signed between BPE and each DISCO at the November 2013 privatization handover.

[7] PSGP ICR, para. 52. The ICR's acknowledgement that "a financially weak or unstable distribution subsector will quickly extend the contagion to the rest of the sector" is all the more significant because the PSGP was approved in May 2014 and the ICR was written with the benefit of the full project implementation record.

be rendered illiquid and eventually insolvent.' (PSGP ICR, para. 52). This sentence describes exactly what happened. It should have been in the PAD in 2014 as a hard conditionality. It was not.

What the PAD also omitted was any serious engagement with what the Bank's own concurrent Nigeria project was already showing. The Nigeria Electricity and Gas Improvement Project—an active, live Bank operation in the same sector, in the same country—had been struggling for years with the same institutional pathology. The Bank team drafting the PSGP PAD was fully aware of NEGIP. It was the same unit. It chose not to learn from it.

FINDING 1: THE BANK INVERTED THE LOGIC OF REFORM

The correct sequencing is: fix the sector's financial flows before investing in new generation. Money flows from consumers to DISCOs to NBET to generators. If distribution is insolvent from Day One, no amount of generation investment can produce a financially viable sector. The Bank approved generation guarantees before distribution reform—a sequencing error it acknowledged only after the project closed.

This error was not unprecedented or unforeseeable. The Bank's own NEGIP project had already documented it.

2. The Ignored Precedent: NEGIP (2009–2018)

Any credible analysis of the PSGP must be read in conjunction with the Nigeria Electricity and Gas Improvement Project (NEGIP, P106172), which ran from Board approval in June 2009 to closure in December 2018. NEGIP was still an active World Bank operation when the PSGP was designed and approved. Its struggles were documented in real time in Implementation Status Reports that were publicly available to the PSGP preparation team. Its failure to achieve its gas supply objectives was a direct consequence of the same institutional pathology—DISCO sector collapse, tariff shortfalls, non-enforcement of electricity market contracts—that the PSGP would later encounter. The Bank ignored the warning.

2.1 What NEGIP Was

NEGIP was a $300 million IDA credit (plus $100 million Additional Financing)[8] combined with a $600 million series of IDA Partial Risk Guarantees. It had two distinct objectives: (i) to improve the availability and reliability of gas supply to increase power generation in existing public sector power plants; and (ii) to improve the power network's capacity and efficiency to transmit and distribute quality electricity.

Component 1—the PRG series—was designed to unlock private sector investment in gas exploration, production, processing, and pipeline infrastructure by mitigating payment risk from the public sector GENCOs (power generation companies). The guarantee structure was premised on an expectation that seven to ten gas supply agreements would be concluded between private gas producers (Shell,

[8] NEGIP ICR, para. 1–3. Board approval June 16, 2009; Additional Financing approved April 2013; project closed December 31, 2018. See also World Bank Project Page: https://projects.worldbank.org/en/projects-operations/project-detail/P106172

Chevron, ExxonMobil, AGIP, Pan Oceanic, Total, Addax) and PHCN-owned GENCOs. The Shell and Chevron deals alone were expected to require $315 million of the $400 million originally approved.

Component 2—investment lending—financed rehabilitation of transmission substations, distribution transformers, and prepaid metering. This component performed considerably better than the PRG series.

2.2 The PRG Component: A $600 Million Failure in Slow Motion

What actually happened to NEGIP's $600M PRG series is a textbook case of institutional failure at multiple levels. Of the seven to ten gas supply agreements originally envisaged, exactly one was ever signed[9]. The face value of the single guarantee actually issued was $111.8 million—18.6 percent of the $600 million authorised. The remaining $488.2 million was cancelled[10].

The Shell deal collapsed in 2012 when Shell decided to divest its onshore Nigerian holdings[11]. The Chevron deal fell apart in December 2013[12] when the FGN completed the PHCN privatization without transferring PHCN's obligations under the gas supply agreement to NBET—the newly created bulk electricity trader. Chevron, having already navigated years of difficult negotiations with one integrated counterpart, declined to restart the process with the newly disaggregated institutional structure. Three other GSAs for NIPP generation companies (Alaoji, Olorunsogo, Sapele) were proposed but not implemented.

The one deal that was concluded—a gas supply agreement between Accugas Limited and the Calabar Generation Company—illustrates precisely why upstream guarantees cannot substitute for downstream sector viability. Accugas had built a 100 km pipeline to the Calabar plant. The IDA guarantee supported a $111.8 million standby letter of credit in favour of Accugas as security against payment default by NDPHC (the state-owned holding company that owned Calabar GENCO). The guarantee mobilised a genuine private sector investment of $240 million.

But Calabar GENCO was dispatched at only half capacity—260 MW against a design capacity of 560 MW[13]. There were two reasons: The transmission line could only evacuate half the power generating capacity of Calabar. Second, DISCOs were not absorbing the electricity. They had been disconnecting feeders to areas with high collection losses, thereby rejecting up to 2 GW of system load and curtailing GENCO output to approximately 3,500 MW despite declared available capacity of over 5,500 MW. NDPHC, unable to sell Calabar's output, was forced to use revenue from its other seven power plants to meet Calabar's take-or-pay gas obligations to Accugas—thereby depriving those plants of maintenance funds.

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[9] NEGIP ICR, para. 16–22. The seven to ten projected GSAs included Shell (Eastern and Western assets), Chevron, ExxonMobil, AGIP, Pan Oceanic, Total, and Addax. The $315 million Shell/Chevron estimate is from NEGIP ICR, para. 18.

[10] NEGIP ICR, para. 22. Of the $600 million in PRGs authorised, $111.8 million was utilised for the Accugas-Calabar guarantee; $488.2 million was cancelled.

[11] NEGIP ICR, para. 20. Shell's onshore divestment programme affected multiple gas supply negotiations across Nigeria.

[12] NEGIP ICR, para. 21. The PHCN privatization of November 2013 restructured counterparty relationships in a way that required Chevron to restart complex negotiations with a disaggregated institutional structure, which it declined to do.

[13] NEGIP ICR, para. 35. The plant's design capacity of approximately 561 MW (also described as 560 MW in some documents) was never approached during the project period due to transmission curtailment and DISCO load rejection.

> *'The sole IDA guarantee issued under the approved series provided*[14] the credit enhancement to mobilize the payment security that Calabar GENCO was obligated to provide to Accugas... [However] the FGN (via TCN) decision to limit its offtake from Calabar plant has caused the actual amount of power dispatched to the grid from the Calabar plant to be less than half of Calabar's actual generation capacity.' — NEGIP ICR, para. 35

The NEGIP ICR rates the efficacy of Objective 1 (gas supply) as Negligible[15]. The overall project outcome is Moderately Unsatisfactory. The gas guarantee component, evaluated independently, would be rated Unsatisfactory. The ICR explicitly states: *'For as long as the sector challenges continue, it is unlikely that any more long-term gas supply arrangements for power generation would come into effect.'* (para. 35).

2.3 NEGIP's Lessons Were Available Before PSGP Was Approved

The Bank approved the PSGP in May 2014. At that point, NEGIP was five years into its implementation and already encountering serious problems. The Shell deal had collapsed in 2012. The Chevron deal would collapse in December 2013—five months before the PSGP Board date. The NEGIP ISR dated January 2014 (ISR #8) rated the project Moderately Satisfactory[16]—but with detailed narrative that documented the emerging problems with all three gas supply arrangements.

By June 2015—the same year Azura Edo IPP reached financial close[17] under the PSGP—NEGIP's ISRs moved to Moderately Unsatisfactory for both Development Objectives and Implementation Progress. The DISCO revenue collapse that was killing NEGIP's gas supply objectives was the same collapse that would eventually threaten the PSGP's payment guarantee.

The NEGIP ICR, published in June 2020, contains a lesson that should have been written into the PSGP PAD in 2014:

> *'Deficiencies in the power sector reform implementation process*[18] *have shifted the main bottleneck in the electricity sector from that of an insufficient supply of grid-based power to one of (i) poor revenue collection and payment discipline from DISCOs to NBET and (ii) lack of incentive for the privatized DISCOs to increase their electricity supply and sales to customers... Expanding the available upstream electricity supply by itself is not going to increase grid-based electricity consumption.'* — NEGIP ICR, para. 81

And more directly:

> *'A key lesson in the use of payment guarantees*[19] *is that while the instrument provides comfort to the seller, it does not make the buyer more creditworthy.'* — NEGIP ICR, para. 82

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[14] NEGIP ICR, para. 35. Quote begins: "The sole IDA guarantee issued under the approved series provided the credit enhancement to mobilize the payment security that Calabar GENCO was obligated to provide to Accugas..." The $240 million Accugas private investment figure is also from this paragraph.

[15] NEGIP ICR, Section III, Outcome Rating. Objective 1 (gas supply PRG programme) rated Negligible; Objective 2 (transmission and distribution investment) rated Substantial. Combined weighted outcome: Moderately Unsatisfactory.

[16] NEGIP ISR #8, January 2014. ISRs are available on the World Bank project page. The ISR narrative documented emerging problems with the Shell and Chevron gas supply arrangements while maintaining the MS rating.

[17] NEGIP ISR #10, June 2015. PSGP financial close: December 2015 (PSGP ICR, para. 1).

[18] NEGIP ICR, para. 81.

[19] NEGIP ICR, para. 82.

These are not new insights. They are documented failures from a project that was running in parallel with PSGP's preparation. The question the PSGP ICR does not ask—and the evaluation system does not require it to ask—is why these lessons were not applied.

FINDING 2: NEGIP'S GAS GUARANTEE FAILED FOR THE SAME REASONS AS PSGP, FIVE YEARS EARLIER

NEGIP deployed $600M in PRGs for gas supply to Nigerian power plants between 2009 and 2018. Of the seven to ten transactions envisaged, one was completed. That one deal—the Accugas-Calabar arrangement—failed to increase power generation to target because the Calabar plant was curtailed to half capacity by the same DISCO revenue collapse that would later afflict the PSGP.

The NEGIP ICR explicitly states that 'payment guarantees provide comfort to the seller but do not make the buyer more creditworthy.' This lesson was available to the PSGP preparation team in 2013–2014. The PSGP PAD does not reference NEGIP. The Bank proceeded to approve a second, larger PRG programme for the same sector in the same country with the same structural defects.

3. The DISCO Privatization: Captured Before the PSGP Was Designed

The Bank's prior involvement in creating the conditions for this failure[20] is documented in its own project records. The World Bank's Privatization Support Project (PSP, P070293, 2001–2009)—analysed separately on this platform—directly financed the advisory services, regulatory design, and institutional strengthening that restructured NEPA, designed the wholesale electricity market, and prepared the distribution assets for private sale. Bank staff were embedded in the Bureau of Public Enterprises, reviewed transaction terms, and advised on the regulatory framework throughout the process. When the privatization produced politically connected buyers with no sector competence and ATC&C baselines misrepresented in the sale agreements, this was not an administrative oversight the Bank could claim to have missed. It had the field presence and the institutional knowledge to have known. What follows documents what the evidence showed, and what the Bank chose not to treat as a hard constraint.

The privatization of Nigeria's distribution companies was the foundational act on which the entire sector reform—and the PSGP—depended. It was, from the outset, a deeply compromised process. Buyers were selected who had the political connections to win the bids but lacked the technical and operational capacity to run electricity distribution businesses. Many had no prior experience in the power sector. The assets were acquired at valuations that did not reflect the capital expenditure required to reduce losses and improve collection.

The privatization agreements set ATC&C loss reduction targets that bore no relationship to the actual baseline. The NERC was supposed to independently verify actual losses and revise the MYTO tariffs accordingly. This never happened in a systematic way. DISCOs continued to operate with 35 percent

[20] World Bank PSP ICR (ICR00001418, February 2011), Project P070293. The PSP ICR records 518 staff-weeks of supervision over 2001–2009, direct financing of BPE transaction advisory services, and institutional support to the regulatory architecture that structured the DISCO privatization. See mdbreform.com, "Nigeria PSP: The Bank Knew" (March 2026) for detailed analysis of the Bank's institutional knowledge at the time of the 2013 privatization.

losses—representing enormous quantities of power stolen, unbilled, or uncollected—while their financial obligations to NBET accumulated as arrears.

The Bank was not a bystander to this process. It supported the FGN on the power sector reform program, including the privatization itself. World Bank staff were present in Nigeria, in the meetings, reviewing the documents. The Bank knew what the actual loss baseline was. It knew who the buyers were. It chose to tell a positive story in the PSGP PAD—citing the reform roadmap and the tariff orders—while omitting the inconvenient truth that the buyers of the DISCOs had already begun extracting value from their assets rather than investing in them.

The NEGIP ICR, written about events from the same period, is blunt: the privatization 'was primarily able to attract only local investors who had limited experience in running utilities[21] and limited ability to inject the required capital to meet the performance improvement targets.' (NEGIP ICR, para. 59). This was known in 2013. It was not treated as a hard constraint in the PSGP design.

In 2015, DISCOs' payables to the rest of the market accumulated at NGN 476 billion[22] (US$1.56 billion) between January 2015 and December 2016, of which the tariff shortfall component represented NGN 420 billion (US$1.38 billion). Tariff shortfalls continued to accumulate at approximately US$1 billion [23]per year in 2017 and 2018. This was not an unexpected deterioration. It was the trajectory that both NEGIP's implementation experience and any serious reading of the DISCO privatization outcomes would have predicted.

FINDING 3: THE DISTRIBUTION SECTOR WAS ALREADY CAPTURED WHEN THE GENERATION GUARANTEE WAS APPROVED

ATC&C losses at 35% versus privatization agreement baseline of 25.6% and targets of 13.4% by 2017. The MYTO tariffs were built on a false baseline. DISCO buyers lacked sector competence. The Bank knew this—NEGIP's ISRs documented the consequences in real time.

By approving the PSGP, the Bank committed NBET—the central buyer—to USD-denominated take-or-pay obligations that DISCOs would structurally be unable to fund. The $1 billion sector deficit by project close was predictable.

4. Ownership Structure: Who Put the Deal Together, and Why It Matters

[21] NEGIP ICR, para. 59. The full sentence reads: "the privatization was primarily able to attract only local investors who had limited experience in running utilities and limited ability to inject the required capital to meet the performance improvement targets." Independent corroboration: Okorie et al. (2017), "The Impact of Privatization of Power Sector in Nigeria," IOSR Journal, documents that "several of the bidders had little to no prior experience in the power sector" and that "some of these businesses were formed specifically to compete for the energy blocks." See also IOSR Journal of Humanities and Social Sciences, Vol. 23, Issue 1. The political economy dimension is documented in: Privatization of Nigeria's Power Sector from the Perspectives of the General Agreement (IOSR-JHSS, 2017), which states that "the outcome of the power privatization was heavily influenced by political considerations against economic or technical capacities of the eventual preferred bidders."

[22] PSGP ICR, para. 54. The tariff shortfall component of NGN 420 billion and the accumulation period January 2015–December 2016 are also from this paragraph.

[23] PSGP ICR, para. 54 and footnote 28. The ICR explicitly documents tariff shortfalls continuing "at approximately US$1 billion per year in 2017 and 2018."

Understanding how Azura and Calabar were assembled — who initiated each project, in what sequence the contractual commitments were made, and which investors were brought in at which stage — is essential to evaluating the governance of both transactions. The two projects differ significantly in their origins and ownership structures, but they converge in ways that raise important questions about how broadly the World Bank Group's financial exposure was distributed across the Nigerian gas-to-power chain.

Azura-Edo: The Developer Locked In the Terms Before the Investors Arrived

The Azura project originated with Amaya Capital[24], a small West African-focused investment firm co-founded by Sundeep Bahanda (a former Deutsche Bank managing director), Phillip Ihenacho (a Nigerian financier and former CEO of Afrinvest), and David Ladipo. Amaya identified the Edo State site, negotiated the land lease with the Edo State Government through a 2010 Memorandum of Understanding, and most critically, negotiated the Power Purchase Agreement with NBET before assembling the wider investor consortium.

This sequencing is the central governance issue with the Azura transaction. The PPA — which set the pricing terms, the capacity payment obligations, and the take-or-pay structure — was effectively determined by the developer in bilateral negotiations with the Nigerian government before institutional investors, commercial lenders, or the World Bank itself had formally entered the picture. The commercial terms that would ultimately determine Nigeria's fiscal exposure for twenty years were therefore not the product of competitive tendering or independent price discovery. They were the product of a negotiation between a developer whose interest was to maximize contractual protection and a government whose institutional capacity to evaluate complex PPAs was, at the time of the 2013 privatization process, limited.

Financial close was achieved in December 2015. At that point the equity consortium comprised Amaya Capital, American Capital Energy and Infrastructure, ARM-Harith Infrastructure Fund, and Aldwych International (later Anergi Group). Actis, a London-based emerging-markets infrastructure investor, subsequently acquired American Capital's stake and became the majority shareholder. Africa50 — a pan-African investment platform backed by twenty-eight[25] African governments and established by the African Development Bank — invested in December 2019, after the plant had already reached commercial operations. The Edo State Government holds a 2.5 percent equity stake[26] in the operating company, Azura Power West Africa Limited (APWAL).

The current equity structure of Azura Power Holdings, the primary holding company, is as follows:

Shareholder	Role / Background	Entry Stage
Actis LLP (majority)	London-based growth-markets infrastructure PE fund	Acquired stake from American Capital, 2016
Amaya Capital	Original developer; co-founders Bahanda, Ihenacho, Ladipo	Development stage, pre-financial close

[24] PSGP ICR, para. 36–40. The project origins, developer structure, and PPA negotiation sequence are documented in the ICR. See also public corporate filings and press coverage of Azura-Edo financial close, December 2015.
[25] Africa50 press releases, December 2019. Africa50 is an infrastructure investment platform established by the African Development Bank and backed by African governments and institutions.
[26] PSGP ICR, para. 38. Azura Power West Africa Limited (APWAL) is the special purpose vehicle operating company. The Edo State equity interest was part of the host-state arrangement negotiated as part of the 2010 Memorandum of Understanding.

Africa50	Pan-African fund backed by 28 governments and AfDB	Post-commissioning, December 2019
Anergi Group	Pan-African energy investment company (formerly Aldwych International)	Financial close, 2015
Edo State Government	2.5% equity in APWAL (operating company)	Part of host-state arrangement

Debt financing of approximately $700 million was provided by fifteen lenders from nine countries[27], including IFC (as both equity holder and lender), Standard Chartered, Rand Merchant Bank, FMO (Dutch development bank), Proparco (French), DEG and KfW (German), CDC (UK), DFC/OPIC (US), and Swedfund (Swedish). The World Bank IBRD provided a Partial Risk[28] Guarantee of $237 million, and MIGA provided political risk insurance. The total project cost was approximately $900 million[29].

Calabar: A Government Plant, a Last-Minute Gas Supplier, and a Deal That Went Wrong

Calabar presents a structurally different case. The 561 MW plant was built by the Niger Delta Power Holding Company (NDPHC), a federal government-owned entity, as part of the National Integrated Power Project (NIPP) programme initiated under President Obasanjo. Unlike Azura, Calabar is a government asset: NDPHC owns the Calabar Electricity Generation Company (CEGC), and the plant was never, at the time of the transactions examined here, transferred to a private operator. The privatization of the NIPP GENCOs was contemplated but not completed, meaning the government remained both owner and guarantor of the plant's obligations.

The critical transaction at Calabar is therefore not the power plant itself but the gas supply arrangement. The original gas supply was to come from Addax Petroleum[30]'s offshore Adanga field, but negotiations between Addax and the NNPC joint venture broke down while the pipeline from the field to the Calabar plant was already under construction. With the plant nearing completion and facing potential idleness, NDPHC turned to Accugas — a wholly-owned subsidiary of Seven Energy International Limited — as an alternative supplier. Accugas had operations close to the Calabar plant and was already supplying gas to Ibom Power Station and UNICEM. A Gas Sales Agreement (GSA) was signed between NDPHC and Accugas on December 8, 2011[31].

The GSA established a take-or-pay obligation requiring NDPHC to pay for 131 million[32] standard cubic feet per day of gas regardless of how much was actually dispatched. A World Bank Partial Risk Guarantee was later provided under the Nigeria Electricity and Gas Improvement Project (NEGIP) to

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[27] PSGP ICR, para. 39. Named lenders include IFC, Standard Chartered, Rand Merchant Bank, FMO (Netherlands), Proparco (France), DEG and KfW (Germany), CDC (UK), DFC/OPIC (US), and Swedfund (Sweden), among others.
[28] PSGP ICR, para. 1 and Annex 1. The IBRD PRG of $237 million backstopped NBET's payment obligations under the Azura PPA. MIGA political risk insurance terms are not publicly disclosed.
[29] PSGP ICR, para. 39. The $900 million figure represents total project cost at financial close including EPC contract, financing costs, development fees, and contingencies.
[30] NEGIP ICR, para. 26–28. The Addax/Adanga field negotiations, the pipeline construction, and the subsequent switch to Accugas as supplier are documented in the NEGIP ICR.
[31] NEGIP ICR, para. 28. TheCable (Nigeria) subsequently published a detailed investigation of the full terms of the Calabar GSA and the IDA guarantee structure.
[32] NEGIP ICR, para. 29. The 131 mmscfd take-or-pay volume was sufficient to generate the plant's full 561 MW capacity.

backstop the payment obligations. The GSA was initially signed as a contractual arrangement with side agreements that drew the federal government as a guarantor of Accugas's construction loans — an arrangement that Nigeria's then-Attorney General flagged as problematic[33] in correspondence with NDPHC in 2013, noting that the securitization structure allowed Accugas to draw down on funds provided by NDPHC. The renegotiation of these terms took approximately three years, during which the Calabar plant remained underutilized.

The Overlap: One Network Across Both Transactions

The most analytically important feature of the Azura-Calabar story is not the individual ownership structures but the overlaps between them. These overlaps are structural, not coincidental.

The most direct overlap is through Phillip Ihenacho. At the time the critical commercial terms of the Azura project were being structured, Ihenacho was simultaneously advisor and Chairman of Azura Po[34]wer and Interim CEO of Seven Energy International — the parent company of Accugas, which was developing the gas supply infrastructure that would serve Calabar and, through the Escravos-Lagos Pipeline System, also supply gas to Azura. Both projects therefore drew on the same gas infrastructure network, and a single individual occupied senior positions in the developer of the power project and the parent of the gas supplier.

The second overlap is through the World Bank Group itself. IFC invested in Seven Energy through multiple tranches[35]: an initial equity stake in April 2014, a further $30 million through the IFC African, Latin American and Caribbean Fund (managed by IFC's Asset Management Company) at the same time, and an anchor investment of up to $50 million in Seven Energy's inaugural bond issue in October 2014. MIGA then provided a $200 million guarantee against expropriation risk to Accugas in September 2015[36]. IFC also held a debt position in Azura. The World Bank Group was therefore simultaneously a lender and guarantor to the power plant (Azura/PSGP), an equity investor in the gas company whose subsidiary supplied gas to Calabar (Seven Energy/IFC), and an insurer of that gas company's infrastructure assets (MIGA). The Bretton Woods Project raised concerns in December 2018 about the adequacy of IFC's due diligence on Seven Energy given the governance controversies surrounding some individuals in that company's network.

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[33] TheCable (Nigeria). "Revealed: The $1.2bn Azura Power Deal and How Nigeria Could Lose Billions." TheCable investigative reporting on the Calabar GSA securitisation structure and the Attorney General's concerns about the IDA guarantee arrangements, published October 2019.

[34] Corporate records and press reporting. Ihenacho's concurrent roles as Chairman of Azura Power Holdings and Interim CEO of Seven Energy International (parent of Accugas) during the critical 2013–2015 period when the key commercial terms of both transactions were being structured are documented in company filings and financial press.

[35] IFC investment data and press releases: equity stake April 2014; $30 million through IFC African, Latin American and Caribbean Fund (AMC) simultaneously; anchor investment of up to $50 million in Seven Energy's inaugural bond October 2014. See also Bretton Woods Project coverage of IFC's Seven Energy due diligence concerns (December 2018).

[36] MIGA project disclosure, September 2015. The MIGA guarantee covered Accugas's midstream infrastructure assets—principally the 100-kilometre pipeline from the Uquo field to the Calabar plant—against expropriation and related political risks.

The third overlap is through the infrastructure fund network. African Infrastructure Investment Managers (AIIM) was part of the original Azura equity consortium[37] at financial close in 2015. When Savannah Petroleum acquired Seven Energy in 2019, AIIM simultaneously acquired a 20 percent stake in Accugas as part of the same transaction. The same infrastructure fund class therefore held positions in the Azura power platform and in the Accugas gas infrastructure that served Calabar.

Overlap	Through whom / what	Significance
Developer-to-gas-supplier	Phillip Ihenacho: Chairman Azura + Interim CEO Seven Energy (Accugas parent)	Same person structured both sides of the gas-to-power chain
World Bank Group financial exposure	IFC equity/bonds in Seven Energy; MIGA $200M guarantee on Accugas; IBRD PRG on Azura; IDA PRG on Calabar GSA	WBG held simultaneous financial stakes in power plant, gas supplier, and gas infrastructure insurer
Infrastructure fund network	AIIM: equity in Azura (2015) + 20% of Accugas acquired via Savannah deal (2019)	Fund-level positioning across both the generation and fuel supply assets
Gas supply infrastructure	Both plants draw from Uquo field / Accugas/Seven Energy pipeline network	Shared physical infrastructure creates shared supply-side risk

5. The Azura Deal: A Structurally Defective Bargain

5.1 The Cost Benchmarking Problem

The Azura Edo IPP—a 459 MW open cycle gas turbine (OCGT) plant near Benin City—reached financial close in December 2015 at a total project cost of $877 million, or approximately $1,910–1,950 per kilowatt[38] of installed capacity. The ICR's own efficiency analysis (Annex 4, Table 4.4) shows what this means in context.

Plant	Capacity	Cost per kW	Source	Status
OECD Benchmark (OCGT)	700 MW	$978/kW	IEA / ESMAP	Benchmark
OECD Benchmark (CCGT)	580 MW	$869/kW	IEA / ESMAP	Benchmark
Shell Afam VI (CCGT)	650 MW	$831/kW	World Bank	Benchmark
Agip Okpai (CCGT)	480 MW	$963/kW	World Bank	Benchmark
AES Barge (OCGT)	270 MW	$889/kW	World Bank	Benchmark

[37] PSGP ICR and Savannah Petroleum press releases (2019). AIIM's acquisition of 20 percent of Accugas as part of the Savannah Petroleum acquisition of Seven Energy in 2019 created a fund-level overlap between the Azura generation platform and the Calabar gas supply infrastructure.

[38] PSGP ICR, Annex 4, Table 4.4. Benchmark comparators in the same table: Shell Afam VI CCGT $831/kW, Agip Okpai CCGT $963/kW, AES Barge OCGT $889/kW. OECD benchmark from IEA/ESMAP data cited in ICR footnote 57: openknowledge.worldbank.org/handle/10986/23970.

Azura Edo IPP (OCGT)	459 MW	$1,910–1,950/kW	ICR Table 4.4	Operational
QIPP (CCGT – cancelled)	**533 MW**	**$2,131/kW***	**ICR Table 4.4**	**Cancelled**

* QIPP cost excludes the $136M transmission line and the gas pipeline. Source: PSGP ICR Table 4.4; World Bank openknowledge.worldbank.org/handle/10986/23970 (ICR footnote 57).

The OECD benchmark for an OCGT plant in 2016 was $978 per kilowatt—roughly half the Azura cost. Even within Nigeria, comparing Azura to Shell's Afam VI CCGT ($831/kW) and Agip's Okpai CCGT ($963/kW)—both more efficient plant types—Azura is an outlier. The ICR rates efficiency 'Modest' precisely because of this, noting the project cannot be considered a least-cost solution.

Why was Azura so expensive? Because it was an unsolicited proposal. The EPC contract for construction was competitively procured, but the project itself—the decision to build this plant, at this location, at this scale, on this technology—was never subject to competitive IPP procurement. The ICR is characteristically euphemistic: 'It would appear that the Azura project was an unsolicited proposal[39]... there was no evidence found by the ICR team of any formal process in the Government for evaluating unsolicited proposals like the Azura project.' (PSGP ICR, para. 85[40]). In plain language: the Bank backed an overpriced, non-competitively procured project, then reviewed the EPC contract and called it due diligence.

5.2 The Take-or-Pay Arrangement

The Azura PPA was structured as a take-or-pay arrangement with a USD-denominated bulk tariff of US[41]¢9.14 per kilowatt-hour. NBET was obligated to pay Azura regardless of how much power the DISCOs absorbed and regardless of how much NBET collected from those DISCOs. This is normal project finance logic—lenders require a creditworthy off-taker obligation to service debt. The problem is that NBET was not creditworthy. The creditworthiness was provided by the FGN sovereign indemnity and the World Bank's Partial Risk Guarantee.

The currency structure made this worse. DISCOs collected tariffs in naira. NBET paid generators in naira—but was obligated to make dollar-equivalent payments to Azura. When the naira lost 30 percent[42] of its value against the dollar in June 2016, NBET's real payment obligations surged. The 2015–16 tariff shortfalls that accumulated as a result were eventually to be funded under the Power

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[39] PSGP ICR, para. 85. The ICR's finding that there was "no evidence found by the ICR team of any formal process in the Government for evaluating unsolicited proposals like the Azura project" is the Bank's own post-hoc acknowledgement that competitive IPP procurement was absent.
[40] PSGP ICR, para. 85, full passage: "It would appear that the Azura project was an unsolicited proposal... there was no evidence found by the ICR team of any formal process in the Government for evaluating unsolicited proposals like the Azura project."
[41] PSGP ICR, para. 43–45. The US¢9.14/kWh bulk generation tariff and the take-or-pay structure of the PPA are confirmed in the ICR and in NBET public payment data. BusinessDay Nigeria and TheCable documented this tariff level as above comparable plants in contemporaneous coverage.
[42] Central Bank of Nigeria exchange rate data. The June 2016 devaluation moved the official rate from approximately N197/$ to N280/$, with the IEFX window subsequently trading above N300/$. The PSGP ICR para. 54 acknowledges the consequent escalation of dollar-denominated sector obligations.

Sector Recovery Programme—the reform operation the Bank approved in 2020[43], six years after the PSGP.

There is a further perversity in the dispatch logic that receives insufficient attention in the ICR. Nigeria has significant installed hydropower capacity. Hydro has near-zero marginal cost. Under a rational least-cost dispatch regime, hydro should be dispatched ahead of gas-fired OCGT. But Azura's take-or-pay structure means NBET must pay for Azura capacity whether or not it is dispatched. The incentive structure therefore favours curtailing cheaper hydro to ensure Azura's contracted availability is utilised—a direct transfer of efficiency losses onto consumers and the government. The NEGIP ICR documents the identical dispatch logic problem at the Calabar GENCO, where an absence of enforced merit-order dispatch resulted in TCN's inability to prioritise the NDPHC-owned plant at levels sufficient to meet its take-or-pay obligations. The Bank encountered this problem in 2014–2018 under NEGIP. It did not treat it as a design constraint for the PSGP.

FINDING 4: TAKE-OR-PAY + USD DENOMINATION + BROKEN DISCOS = STRUCTURAL TRANSFER TO THE SOVEREIGN

The Azura PPA transferred currency risk, dispatch risk, and DISCO payment risk onto NBET and the FGN from Day One. This was not an unfortunate outcome of macroeconomic deterioration—it was the designed architecture of the deal.

A least-cost development plan would have required consideration of hydro alternatives. Competitive IPP procurement would have produced a lower tariff. Both were absent. The NEGIP experience with the Calabar GENCO showed exactly this dispatch problem years before Azura was commissioned.

The dispatch inversion this creates is quantified in Annex A. Nigeria operates approximately 2,638 MW of installed hydropower capacity across Kainji, Jebba, Shiroro, and Zungeru. These plants run on water. Their marginal cost of generation is between $3 and $5 per megawatt-hour. Under any rational merit-order dispatch regime, hydro is the first call on the Nigerian grid — dispatched ahead of every gas-fired plant in the system. The take-or-pay structure of Azura and Calabar destroys that logic. Because NBET must pay the full capacity charge for both plants regardless of dispatch, the System Operator faces contractual obligations that override the merit order. Azura and Calabar cost between $110 and $170 per megawatt-hour all-in. They are the most expensive plants on the Nigerian grid. The incentive structure means that whenever the System Operator must choose between dispatching hydro and dispatching the IPPs, the contractual arithmetic favours the IPPs: if Azura runs, NBET pays for energy it can use; if Azura does not run, NBET still pays the capacity charge in dollars while the hydro megawatt-hours flow for nothing.

The scale of this distortion is quantifiable. The combined annual invoice for Azura and Calabar is approximately $480 million. Against this, Nigeria's four hydro stations at comparable generation volumes would cost approximately $15–20 million per year in operations and maintenance. The differential — approximately $460 million annually — represents the cost of the dispatch inversion. As the naira has depreciated from ₦360 to over ₦1,500 per dollar, the naira cost of this dollar drain

[43] World Bank Power Sector Recovery Operation (PSRO), Program for Results, P167569, approved June 2020, $750 million IDA financing.

has quadrupled. The seasonal dimension compounds it: Nigeria's rainy season (May to October) is precisely when hydro potential peaks and the economic case for dispatching it is strongest, yet the take-or-pay structure structurally incentivises the System Operator to curtail free hydro in favour of plants whose owners must be paid whether they generate or not. None of this was invisible at the time of project design. The Bank had a least-cost planning obligation. No credible least-cost development plan existed for Nigeria at PSGP approval — a fact the ICR itself acknowledges — and the absence of such a plan is precisely what allowed this structural absurdity to proceed.

The broader data context for this analysis is in Annex A, which documents the full merit-order curve for the Nigerian grid, the foreign-exchange burden of the capacity payment structure, and the seasonal dynamics of the dispatch inversion. The central finding is simple: Nigeria did not need more generation capacity behind a broken distribution sector. What it needed — and what was not financed — was investment in the DISCOs and the transmission corridors that were preventing the grid from using the generation it already had.

5.3. The Gas Supply Guarantee: Nigeria's Second Layer of Contractual Exposure

Most analyses of the World Bank's Nigeria power sector engagement focus on the electricity payment guarantee — the PSGP Partial Risk Guarantee backstopping NBET's obligations to Azura under the PPA. What is less widely discussed is that the Bank simultaneously issued a second and structurally similar guarantee on the gas supply side, specifically to support the Accugas GSA with the Calabar plant. When both guarantees are considered together, the government of Nigeria's exposure under World Bank-backed contractual structures becomes substantially larger than either transaction alone suggests.

Key Parameters of the Gas Supply Guarantee

The terms of the Accugas Gas Sales Agreement and the Calabar plant's operational performance — including the cascading failure caused by transmission constraints and DISCO load rejection — are documented in Sections 2.2 and 4 above. The table below consolidates the key guarantee parameters.

Parameter	Detail
GSA signed	December 8, 2011 (NDPHC and Accugas)
Gas supplier	Accugas Limited, wholly-owned subsidiary of Seven Energy International
Contracted volume	131 mmscfd (take-or-pay)
Plant dispatch reality	~50% of contracted capacity (per NEGIP ICR)
World Bank PRG (NEGIP AF)	$111.8 million; backed by JPMorgan standby letter of credit
IDA Indemnity Agreement	G-2430, signed June 2017; sovereign indemnity irrespective of disputes
MIGA guarantee (Accugas)	$200 million against expropriation of midstream infrastructure (September 2015)
PRG on gas activated	November 2016, in connection with full GSA commencement
Monthly obligation	~$10 million regardless of dispatch
Arrears by September 2019	$66.6 million immediately due; PRG trigger threatened
Accugas parent acquirer	Savannah Petroleum (acquired Seven Energy 2019); AIIM acquired 20% of Accugas

What makes the Calabar gas guarantee particularly significant analytically is that it demonstrates the full vertical extent of the Bank's guarantee commitments in the Nigerian gas-to-power chain. The Bank guaranteed payment for the electricity (Azura, PSGP). It guaranteed payment for the gas (Calabar/Accugas, NEGIP). It insured the gas infrastructure against expropriation (MIGA/Accugas). And it invested in the gas company itself (IFC/Seven Energy). Every link in the contractual chain from fuel supply to electricity payment carried a World Bank Group financial instrument, while the Bank simultaneously advised the Nigerian government on the policy framework governing all of them.

6. The Government of Nigeria's Consolidated Exposure

The financial obligations that the Nigerian government assumed across the Azura and Calabar transactions are rarely presented in consolidated form. Each instrument — the PPA, the PRG, the GSA, the indemnity agreement, the federal government support agreements, the MIGA insurance — was negotiated and presented separately. Aggregated, they represent a sovereign exposure of a scale and structure that, as of the time of this writing, remains only partially visible in Nigeria's public accounts.

Direct Contractual Obligations Under the Power Purchase Agreements

Under the Azura PPA, NBET is obligated to pay a combined capacity and energy charge. The capacity payment alone represents approximately $30 million per month at the contracted rate[44]. At the naira-dollar exchange rate prevailing at the time Azura reached commercial operations in May 2018 (approximately ₦305/$), the annual capacity obligation was roughly ₦110 billion. By 2024-25, with the naira having depreciated to approximately ₦1,500 per dollar, the same dollar-denominated obligation translates to over ₦540 billion per year. The physical electricity output has not changed. The naira cost has quintupled.

The Azura contract includes a Put-Call Option Agreement (PCOA)[45] which provides that in the event of termination due to government breach, the investors may require the government to purchase the plant at a pre-agreed termination payment formula. Estimates of the potential termination liability under the PCOA, including outstanding debt, equity returns, and compensation provisions, suggest an exposure exceeding $1.2 billion — a figure that TheCable reported explicitly in October 2019 when describing the accumulated pressure on the government from both Azura and Calabar simultaneously.

The Guarantee Layer: Contingent Liabilities Backed by Sovereign Indemnity

Behind the contractual payment obligations sit the guarantee structures. These are technically contingent liabilities — they are triggered only if the government fails to meet its contractual

[44] PSGP ICR, para. 46. The capacity payment structure and its approximate monthly value in dollar terms are documented in the ICR. The naira equivalent calculations use CBN official exchange rates: approximately N305/$ at May 2018 commercial operations; N1,500+/$ by 2024–25.

[45] PSGP ICR, para. 48. The PCOA termination payment structure, including the formula for calculating buyout obligations in the event of government breach, is described in the ICR. TheCable (October 2019) reported the estimated termination exposure as exceeding $1.2 billion.

obligations — but in a context of persistent sector illiquidity they represent realistic rather than remote risks. The IDA Indemnity Agreement for the Calabar gas guarantee is explicit that Nigeria's reimbursement obligations to IDA are unconditional; a payment under the guarantee becomes a sovereign debt to the World Bank, with all the credit-rating and borrowing-cost implications that entails.

Exposure Item	Instrument	Amount (approx.)
Azura – power payment guarantee	World Bank IBRD Partial Risk Guarantee (PSGP)	$237 million face value
Azura – political risk	MIGA political risk insurance	Undisclosed; standard project coverage
Azura – termination payment (PCOA)	Federal government put-call obligation	Est. $1.0–1.2 billion if triggered
Calabar – gas payment guarantee	IDA PRG (NEGIP AF); IDA Indemnity Agreement G-2430	$111.8 million standby LC via JPMorgan
Calabar – gas supply infrastructure	MIGA guarantee on Accugas/Seven Energy assets	$200 million (expropriation cover)
Annual Azura capacity + energy obligation	NBET PPA (NDPHC/FGN backstop)	~$360 million/year (dollar terms)
Annual Calabar gas obligation (take-or-pay)	GSA with Accugas (NDPHC)	~$120 million/year ($10M/month)
Combined annual dollar-indexed obligation	Azura PPA + Calabar GSA	~$480 million/year (constant dollars)
Naira equivalent at 2024–25 FX rate	At ~₦1,500/$	Approx. ₦720 billion per year

The Systemic Layer: CBN Interventions and Policy Lending

The contractual obligations described above sit within a broader pattern of fiscal support to the electricity sector that has accumulated over the decade since the 2013 privatization. The Central Bank of Nigeria launched the Nigerian Electricity Market Stabilization Facility[46] in 2014, initially allocating approximately ₦213 billion to generation companies, distribution companies, and gas suppliers. This was followed by the Power and Aviation Intervention Fund and additional liquidity facilities channelled through commercial banks. These instruments provided cash to electricity sector participants at a time when market revenues were insufficient to cover costs, effectively monetizing the sector deficit into quasi-fiscal liabilities on the CBN's balance sheet.

A Nigerian government payment structure — the ₦701 billion Payment Assurance Facility[47] — was subsequently established to defray GENCO arrears. Of this amount, ₦373 billion was designated for payment to Azura and Accugas, reflecting their disproportionate share of total sector invoicing relative to their share of installed capacity. The remaining generation companies, comprising the bulk

[46] Central Bank of Nigeria press releases and World Bank Power Sector Recovery Operation Program Document (P167569, 2020). The CBN's NEMSF, Power and Aviation Intervention Fund, and subsequent liquidity facilities are documented in the PSRO Program Document.
[47] Nigerian Federal Ministry of Finance and NBET payment data. The Payment Assurance Facility and the distribution of ₦373 billion designated for Azura and Accugas were reported in Nigerian financial press including TheCable and BusinessDay.

of the privatized NIPP and legacy PHCN plants, shared the remainder — a distribution that provoked open legal challenge by thirteen generation companies[48] before the Abuja High Court.

The World Bank's Power Sector Recovery Operation (PSRO), approved in June 2020 at $750 million in IDA financing[49], added a further layer. Its stated objectives included restoring the sector's financial sustainability, strengthening distribution company governance, and stabilizing government finances associated with the power sector. Whatever the counterfactual, the fiscal effect was to provide the Nigerian treasury with budget support at the moment when the combined obligations under the Azura PPA, the Calabar GSA, and the accumulated sector arrears had reached their highest level of stress. The government's ability to continue honoring the contractual obligations to IPP investors — without triggering the PRGs — was therefore at least partially sustained by development finance resources that arrived precisely when market revenues could not do the job.

The institutional logic of the PSRO deserves to be stated plainly. The World Bank approved the Azura-Edo IPP guarantee in 2014 in a sector it had co-designed since 2001, knowing that distribution companies were institutionally captured and financially non-viable. It approved a second gas supply guarantee under NEGIP in 2016 for a plant operating at half capacity because those same DISCOs were rejecting load. It watched the tariff shortfall accumulate at approximately $1 billion per year. And then, in June 2020, it arrived with $750 million in IDA financing to rescue the sector from a crisis it had materially helped create. The World Bank Country Director for Nigeria who announced the PSRO, Shubham Chaudhuri, declared that "the lack of reliable power has stifled economic activity and private investment and job creation" and that the operation would help "turn around the power sector and set it on a fiscally sustainable path."[50]

These are not wrong observations. But they are observations the Bank could have made — and acted on — before approving the PSGP in 2014. The PSRO is not a solution to the sector's structural problems. It is a downstream debt instrument deployed to manage the fiscal consequences of upstream lending decisions that should not have been made in the form they were. The Bank is not being paid to fix it — it is pushing additional IDA loans onto the same sovereign, loading the borrower with a further $750 million of debt obligations to manage the fiscal consequences of lending decisions the Bank itself made and should not have made in the form it did. This is the full arc of the Bank's Nigeria power sector engagement: architect of the design, guarantor of the contracts, financier of the sector arrears those contracts produced, and now creditor of the remediation operation. At each stage, the borrower accumulates more debt. At each stage, the Bank books another approval.

The Distribution of Risk: Who Was Protected, and at What Cost

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[48] Nigerian court records and financial press reporting. The legal challenge by thirteen GENCOs to the Payment Assurance Facility allocation was reported in Premium Times and BusinessDay Nigeria.

[49] World Bank PSRO (P167569), approved June 29, 2020.

[50] World Bank Press Release, "Nigeria to Keep the Lights on and Power its Economy," June 23, 2020. Shubham Chaudhuri served as World Bank Country Director for Nigeria. Full quote: "The lack of reliable power has stifled economic activity and private investment and job creation, which is ultimately what is needed to lift 100 million Nigerians out of poverty" and "The objective of this operation is to help turn around the power sector and set it on a fiscally sustainable path. This is particularly urgent at a time when the government needs all the fiscal resources it can marshal to help protect lives and livelihoods amidst the COVID-19 pandemic." Available at: https://www.worldbank.org/en/news/press-release/2020/06/23/nigeria-to-keep-the-lights-on-and-power-its-economy

The financial structure of the Azura and Calabar transactions achieved its stated purpose: it protected private investors from the payment and political risks associated with the Nigerian electricity market. Azura's lenders — fifteen institutions from nine countries — had their principal protected by the PRG backstop, the PCOA termination payment, and MIGA political risk insurance. Accugas — and through it, Seven Energy's lenders — had their gas payment obligations protected by the NEGIP PRG and the IDA indemnity. IFC, as an equity investor in both Azura and Seven Energy, benefited from the same guarantee structures it helped design.

The costs of this protection architecture fell on Nigeria. The government absorbed the currency risk — as the naira depreciated, dollar-denominated obligations expanded in local-currency terms with no corresponding increase in electricity output. It absorbed the dispatch risk — under take-or-pay structures, payment obligations continued even when grid constraints prevented full utilization of the contracted capacity. It absorbed the institutional risk — when NBET could not pay and the sector liquidity gap widened, the federal government became the de facto backstop for a market whose design it had been advised to adopt. And it absorbed the political risk of appearing, to its own population and legislature, to have signed contracts that paid international investors large dollar-denominated sums for electricity that continued to be intermittently available at best.

The World Bank's own ICR documentation acknowledges elements of this dynamic. The PSGP ICR notes that the guarantee structure required Bank staff to **"periodically remind the Government to honour its guaranteed payment obligations for specific guarantees to the private developer,"** and acknowledged that this scrutiny "**may strain the relationship with government counterparts, and be at odds with the World Bank's ability to pursue overall dialogue on sector viability."** That sentence describes the outcome of a design in which the Bank simultaneously structured the contractual obligations, guaranteed them, insured them, and then monitored the sovereign's compliance with them. It is a sentence that an institution acting solely as a trusted adviser to a government would not need to write.

7. Domestic Controversy and Parliamentary Scrutiny

The World Bank's project documents present the Azura-Edo IPP as a landmark success in mobilising private capital for Nigerian infrastructure. The domestic political record tells a different story. From the time the PPA terms became partially public, the project attracted sustained criticism in Nigeria's National Assembly, investigative press, and financial analysis community. This criticism was not fringe commentary. It identified, with precision, the same structural defects that the Bank's own ICR would acknowledge five years later—and that NEGIP's implementation experience had already demonstrated.

Nigeria's House of Representatives launched at least two formal investigations[51] into the Azura PPA. Legislators questioned the monthly capacity payments structure under which NBET was obligated to pay Azura for contracted capacity regardless of whether the electricity was dispatched or absorbed by the distribution sector. The term 'capacity payment' obscures the economics: NBET was paying approximately $30 million per month to Azura—in US dollars—while collecting naira from DISCOs

[51] National Assembly records and Nigerian press. The House of Representatives Committee on Power investigations into the Azura PPA terms, including the monthly capacity payment structure and the sovereign indemnity provisions, were covered by Premium Times, TheCable, and BusinessDay between 2017 and 2020.

who were already remitting only a fraction of their energy invoices. Parliamentary scrutiny of this structure was not technical nitpicking. It was a recognition that the sovereign had assumed, through the FGN indemnity backstopping the PRG, a contingent liability of approximately $1.2 billion over the PPA term.

Nigerian investigative reporting—from the International Centre for Investigative Reporting, Sahara Reporters, The Cable, and Premium Times—converged on the same arithmetic. If the PPA collapsed, or if NBET defaulted on payment obligations triggering a drawdown on the World Bank-backed standby letter of credit, the FGN's net exposure was estimated at over $1 billion. This figure represented not just Azura's construction debt but the cumulative payment obligations under the take-or-pay structure. The ICIR's analysis explicitly framed the transaction as Nigeria potentially losing more than $1 billion in exchange for a $237 million loan component—an asymmetric risk transfer that the Bank's project documents described as 'credit enhancement for the off-taker.'

The currency mismatch—USD take-or-pay obligations collected from a naira-revenue base—was the thread connecting all of these criticisms into a single structural diagnosis. When the naira devalued 30 percent in June 2016, every dollar-denominated obligation in Nigeria's power sector became proportionally more expensive in naira terms. NBET's capacity to meet Azura's PPA did not devalue with the currency—it became, in real terms, more onerous. The domestic critics who flagged currency risk in 2015 were identifying, before financial close, the mechanism that would dominate the sector's financial trajectory for the following decade. The Bank proceeded anyway.

FINDING 5: DOMESTIC CRITICS WERE RIGHT

Nigeria's National Assembly, investigative press, and financial analysts identified—before and at financial close—the same structural defects the Bank's ICR would acknowledge in 2021: capacity payments regardless of dispatch, $1.2bn contingent liability exposure, tariff above least-cost benchmarks, transmission constraints, and currency mismatch. These were not post-hoc complaints. They were concurrent warnings.

The Bank's decision to proceed, in possession of both NEGIP's real-time failure evidence and Nigeria's domestic scrutiny of the Azura terms, is the core accountability question this report raises.

8. The Country Director as Debt Collector

The most revealing institutional consequence of the PSGP guarantee structure was its effect on the World Bank's relationship with the Nigerian government. The ICR acknowledges this in a carefully worded paragraph that deserves to be read with full attention:

> *'The World Bank's scrutiny on the ongoing payment obligations during times of heightened risk of default may strain the relationship with government counterparts, and be at odds with the World Bank's ability to pursue overall dialogue on sector viability and other priorities, as it requires periodically reminding the Government to honor its*

> *guaranteed payment obligations*[52] for specific guarantees to the private developer.' (PSGP ICR, para. 86)[53]

It appears that the Country Director / Senior Staff regularly engaged with the Federal Ministry of Finance on ensuring that NBET's monthly payment obligation to Azura was met—so that the letter of credit backstopping the guarantee was not drawn and the PRG was not called. The structural dynamic this reflects is what the ICR's carefully worded paragraph 86 identifies: a guarantee operation that required Bank staff to periodically remind the government to honour payment obligations to a specific private developer.

This is the structural tension the ICR acknowledges but cannot fully capture in a rating: operational staff drawn into ensuring a specific private payment obligation was met, at the expense of the broader sector reform engagement the Bank's role requires. The incompatibility between creditor and advisor functions, once a guarantee is live, is not a contingent risk. It is a design consequence.

Consider what this meant for the Bank's ability to push difficult structural reforms in Nigeria's power sector during this period. The government knew that the Bank had a financial interest in ensuring Azura was paid. The Bank knew the government knew this. Every conversation about tariff reform, DISCO performance improvement, or gas sector restructuring took place in the shadow of this payment obligation. The creditor relationship infected the advisory relationship.

A version of this problem had also appeared under NEGIP. The NEGIP ICR notes that the Bank was simultaneously trying to support power sector reform and managing the contingent liability exposure of the Accugas-Calabar guarantee. But the NEGIP guarantee had been concluded only in 2016—two years before project closure—and the plant's dispatch problems meant the guarantee tension was never fully realised. Under PSGP, with a fully operational commercial plant running from early 2018, the creditor-advisory conflict operated at full intensity for two years.

FINDING 6: THE PRG CONVERTED THE BANK'S ADVISORY ROLE INTO A CREDITOR ROLE

A guarantee operation in a weak-sector environment does not merely provide credit enhancement—it creates a conflict of interest that compromises the Bank's advisory independence for the entire life of the guarantee.

The Bank cannot simultaneously be the government's impartial advisor on sector reform and a creditor whose monthly payment depends on government action. This structural tension should be a design constraint on PRG deployment, not an afterthought in the ICR. NEGIP's experience with the Accugas-Calabar guarantee was a precursor to the full-blown version that materialised under PSGP.

The structural tension documented in this section — the Bank acting simultaneously as guarantor, creditor, and policy adviser — is not an accident of project design. It is the predictable consequence of combining financial exposure with advisory independence within the same institutional structure. Recent proposals to merge the World Bank, IFC, and MIGA would not resolve this tension. They would

[52] PSGP ICR, para. 86. Full quote: "The World Bank's scrutiny on the ongoing payment obligations during times of heightened risk of default may strain the relationship with government counterparts, and be at odds with the World Bank's ability to pursue overall dialogue on sector viability and other priorities, as it requires periodically reminding the Government to honor its guaranteed payment obligations for specific guarantees to the private developer."
[53] PSGP ICR, para. 86, ibid.

make it the permanent operating condition of every engagement. The Nigerian power sector provides the precise test case. IFC held equity in Seven Energy (the parent of Accugas). MIGA insured Accugas infrastructure against expropriation. IBRD guaranteed Azura's power purchase agreement. IDA guaranteed the Calabar gas supply agreement. The World Bank country team simultaneously advised the Nigerian government on tariff reform, DISCO governance, and sector financial stabilisation. Every link in the gas-to-power chain carried a World Bank Group financial instrument — while the same institution was supposed to be the government's impartial adviser on the policy framework governing all of them.

The core comparative advantage of the World Bank is not its balance sheet. It is the perception — carefully cultivated and often decisive in practice — that when it advises a government on tariffs, procurement rules, or institutional restructuring, that advice is driven by development objectives and not by any financial stake in the outcome. The Nigerian experience demonstrates exactly how quickly that perception erodes. The PSGP ICR's own paragraph 86 acknowledges that the guarantee structure required Bank staff to periodically remind the government to honour payment obligations to a specific private developer, and that this scrutiny "may strain the relationship with government counterparts, and be at odds with the World Bank's ability to pursue overall dialogue on sector viability." Under a merged institutional structure, this would not be an edge case to be managed. It would be the normal operating condition: the merged institution holding equity in the IPP, insuring its investors against political risk, guaranteeing its off-taker's payment obligations, and advising the government on the tariff and regulatory framework that determines whether those payments are made. The advisory function would not be separate from the financial exposure. It would be the instrument through which the financial exposure is managed.

The full argument — including the comparison with the IMF, EBRD, and ADB governance models, the procurement integrity dimension, and the anti-corruption implications — is set out in Annex B. The conclusion is not subtle: merger eliminates the structural mechanism designed to limit the entanglement of advisory and investment functions. The efficiency gains from integration are real but quantifiable. The credibility costs are harder to measure and slower to manifest — but they are the costs that ultimately determine whether governments treat Bank advice as analytical guidance or as one input among many from a counterpart with financial stakes of its own. The Bank's balance sheet can be recapitalised. Its reputation as a disinterested adviser cannot.

9. The ICR Rating System: Blind to Sector-Level Damage

The PSGP received an overall outcome rating of 'Moderately Satisfactory.' This rating is mechanically derived from three sub-ratings: Relevance (High), Efficacy (Substantial), and Efficiency (Modest). Under IEG guidelines, this combination yields Moderately Satisfactory. The logic is internally consistent. It is also profoundly misleading.

The rating is 'Moderately Satisfactory' in the same way a surgeon might rate an operation 'Moderately Satisfactory' because the patient is technically alive but will require lifelong dialysis as a result of the procedure. Azura is operational and generating power—that is the Efficacy finding. The macroeconomic context deteriorated—that is the explanation for sectoral distress. The guarantee was not called—that is the evidence of implementation success. What the rating cannot capture:

- A sector financial deficit of approximately $1 billion accumulated by project close (PSGP ICR, para. 54, footnote 28).
- Distribution sector performance remained unreformed for the entire PSGP implementation period, confirming the sequencing error identified at appraisal.
- No accompanying distribution or sector reform operation was in place from project approval in 2014 to project close in 2019 (PSGP ICR, para. 63).
- The Qua Iboe IPP—the second transaction in the Series—consumed years of Bank staff time and was cancelled entirely.
- Cheaper hydro generation was curtailed to service Azura's take-or-pay obligations.
- The Country Director's bandwidth was consumed by monthly payment enforcement rather than sector reform dialogue.

Consider the contrast with NEGIP. The NEGIP ICR—covering a project whose gas guarantee programme resulted in $488M of unused guarantees and a Negligible efficacy rating on its core objective—produced an overall outcome rating of Moderately Unsatisfactory. This is, perversely, a more honest rating than PSGP's Moderately Satisfactory: it reflects actual failure more accurately. But even the MU rating did not trigger any institutional reckoning. The Bank approved the PSGP while NEGIP was still rated MU in its ISRs. Both ratings are, ultimately, bureaucratic artefacts that protect the institution from accountability for the sum of harm its operations produced.

This is not a failure of individual judgment. It is a failure of institutional architecture. The World Bank has no mechanism for requiring the officers who designed and approved a project to account for the gap between what they said it would achieve and what it actually delivered. Project teams move on to new assignments. Country Directors rotate. Regional Vice Presidents are promoted. The evaluation is written by a different team, years later, and its findings carry no consequence for the careers of those whose decisions it documents. Under this system, accountability is structural impossible: the people who made the decisions are no longer responsible for the outcomes by the time the outcomes are measured, and the people who measure the outcomes have no authority over those who made the decisions. Annex C of this report documents who specifically approved these two projects — by name, by title, and with the signed documents as evidence.

The ICR authors are aware of most of these problems. The Lessons and Recommendations sections of both ICRs contain genuinely valuable analysis of sequencing failures, the absence of least-cost planning, competitive procurement gaps, and the advisory-creditor tension. But this analysis has no effect on the ratings. The rating methodology rewards delivery of outputs—megawatts commissioned, private capital mobilised—and cannot penalise sector-level damage that occurs downstream of those outputs.

FINDING 7: THE ICR RATING MASKS INSTITUTIONAL CULPABILITY BEHIND METHODOLOGICAL CONSTRAINTS

The 'Moderately Satisfactory' rating for the PSGP is technically compliant with IEG methodology. It is analytically dishonest. A rating system that cannot register a $1 billion sector deficit, a compromised advisory role, and a six-year sequencing failure as 'Unsatisfactory' outcomes is a rating system designed to protect the institution that funds the evaluations.

NEGIP, with a Negligible efficacy rating on its PRG component, was only able to achieve a Moderately Unsatisfactory overall rating—marginally more honest, but equally without institutional consequence. Both ratings demonstrate the same systemic limitation.

10. Timeline of Institutional Failure

The following timeline reconstructs the sequence of decisions and outcomes across both NEGIP and PSGP that produced a decade of compounding failure in Nigeria's power sector.

Date	Event
Jun 2009	NEGIP approved. Board authorises $400M in PRGs for gas supply to PHCN-owned GENCOs. Seven to ten gas supply agreements envisaged with Shell, Chevron, ExxonMobil, AGIP, Pan Oceanic, Total, and Addax.
Nov 2013 – Oct 2015	DISCO privatization completed. Politically connected bidders with no sector experience acquire distribution assets at discounted valuations. ATC&C losses already running at 35%, not the 25.6% stated in privatization agreements.
Dec 2013	Chevron gas supply deal collapses when FGN completes PHCN privatization without transferring GSA obligations to NBET. Shell deal had collapsed in 2012. NEGIP's $400M original PRG series is effectively dead.
May 2014	World Bank Board approves PSGP (P120207). PAD presents highly positive narrative. Distribution sector weakness acknowledged in footnotes, not treated as a prerequisite for generation investment. NEGIP—still active and already facing serious implementation problems—is not referenced as a cautionary precedent.
Dec 2015	Azura Edo IPP reaches financial close. USD-denominated take-or-pay PPA at US¢9.14/kWh signed with NBET—a naira-collecting off-taker with no creditworthiness. NEGIP's single gas guarantee (Accugas-Calabar, $111.8M) approved by PSGP Board in Jul 2016; effective Sep 2017.
Jun 2015 – Jan 2017	NEGIP ISRs rate the project Moderately Unsatisfactory on both Development Objectives and Implementation Progress. Calabar GENCO dispatched at half capacity due to DISCO revenue collapse. The Bank approves PSGP while its sister project rates MU for 18 months.
Jun 2016	Naira loses 30% of its value against the US dollar. NBET's dollar payment obligations to Azura increase sharply. Sector deficit begins accumulating.
Mar 2017	Government produces Power Sector Recovery Programme (PSRP). No accompanying World Bank reform operation yet.
Jan 2018	Azura reaches commercial operations—one year ahead of schedule. Country Director begins monthly visits to the Finance Minister to ensure NBET payments and avoid PRG call.
Dec 2018	NEGIP closes. Outcome: Moderately Unsatisfactory. Gas guarantee component efficacy: Negligible. Of $600M in PRGs authorised, $111.8M used. The rest cancelled.

Dec 2019	PSGP closes. QIPP (533 MW, $1.14bn) cancelled after two 12-month extensions. Sector financial deficit reaches approximately $1 billion (Final ISR, Jan 2020).
Jun 2020	World Bank Board approves PSRO PforR ($750M)—the distribution sector reform operation that should have preceded generation investment. Published the same month: the NEGIP ICR.
Mar 2021	PSGP ICR published. Outcome rated 'Moderately Satisfactory.' Sector-level $1 billion deficit invisible to the rating methodology. NEGIP's lessons—published nine months earlier—not referenced in the PSGP ICR.

11. The Replication Risk: Scaling a Failed Template

The most troubling dimension of the PSGP story is not what happened in Nigeria. It is what the Bank and IFC are doing with the lessons. The PSGP ICR was published in March 2021. The NEGIP ICR was published in June 2020. Both documents identify the same core failures: inadequate sequencing, the absence of least-cost planning, the creditor-advisory conflict inherent in PRG structures, and the systemic problem of sector-wide financial non-viability undermining upstream investment.

These findings have not prevented the Bank and IFC from actively promoting the Azura model—PRG-backed, USD-denominated, take-or-pay IPPs—as the template for scaling private power investment across Sub-Saharan Africa. The institutional logic is straightforward. Azura was operationally successful—it was completed ahead of schedule, it operates at over 96 percent availability, it generates megawatts that Nigeria genuinely needs. The Bank's IBRD guarantee was not called. IFC booked a successful investment. MIGA provided political risk insurance without a claim. From inside the institution, this looks like a success. The $1 billion sector deficit is NBET's problem. The DISCO failure is the government's problem. The tariff shortfall is a fiscal issue to be addressed through another lending operation. The Bank has exits for every component of the damage it helped create.

NBET maintains a public website (nbet.com.ng) that publishes current payment and sector data. The data shows that the payment crisis has not resolved. The structural conditions that produced it—broken DISCOs, USD take-or-pay obligations, absent least-cost planning—remain substantially in place. The distribution sector recovery operations approved in 2020 are works in progress. Meanwhile, IFC is structuring comparable deals in Ghana, Côte d'Ivoire, Senegal, and elsewhere. The Azura 'template-making contracts' (PSGP ICR, para. 47) are being applied to markets whose distribution sectors may be even weaker than Nigeria's was in 2014.

What is remarkable about the replication risk is that it operates across a clear institutional memory failure. The Bank does not lack ICRs documenting Nigeria's sector problems. NEGIP's ICR was published nine months before the PSGP's ICR. Neither document references the other. The institutional ecosystem—preparation teams, country departments, sector practice groups—appears to operate with no systematic mechanism for ensuring that the lessons documented in one project's ICR are applied in the design of a subsequent project in the same sector. The ICR is written. The lessons are recorded. And then nothing happens.

FINDING 8: THE BANK IS SCALING A MODEL BEFORE EVALUATING ITS OUTCOMES

The PSGP ICR was published in 2021. The NEGIP ICR was published in 2020. Both document the same structural failure: PRG-backed generation investment in a sector whose distribution layer was institutionally captured and financially non-viable.

The sector deficit documented in both ICRs has not resolved. The distribution reform operations recommended were approved concurrently with project closure, not before. IFC is actively structuring comparable PRG-backed IPPs across West and East Africa. The Bank is not learning from Nigeria—it is replicating it.

FINDING 9: TWO ICRS. ONE DECADE OF FAILURE. ZERO CROSS-REFERENCE.

NEGIP ICR (June 2020) and PSGP ICR (March 2021) document essentially the same institutional failure in Nigeria's power sector from overlapping time periods. Neither document references the other. NEGIP's core lesson—that guarantees 'provide comfort to the seller but do not make the buyer more creditworthy'—was available to the PSGP preparation team in 2013–2014. It was not applied.

The Bank's evaluation architecture produces lessons that are stored and forgotten. The institutional incentive structure rewards approvals and disbursements, not learning. Until project ratings can penalise institutional failures that are documented in predecessor project ICRs, the Bank's knowledge management will remain a compliance exercise rather than an operational constraint.

12. What Good Practice Would Have Required

This report is not an argument against private power investment in Africa. Nigeria genuinely needed—and continues to need—new generation capacity. The argument is that the specific choices made in designing and approving the PSGP were wrong, and that correcting them does not require abandoning PPP frameworks. It requires applying the Bank's own stated principles consistently—and treating the documented failures of predecessor projects as binding constraints on subsequent design.

12.1 Condition Generation Investment on Distribution Viability

The Bank requires a 'satisfactory macroeconomic framework' before approving Development Policy Financing. PSGP ICR footnote 47 makes this analogy explicitly, noting that a least-cost development plan should serve as 'a prerequisite for WBG sector interventions, similar to the satisfactory macroeconomic framework requirement for Development Policy Financing.' The same logic applies to distribution sector viability: a minimum standard of DISCO performance—defined by independently verified ATC&C losses, collection rates, and investment trajectories—should be a hard prerequisite for generation investment backed by sovereign guarantees. NEGIP's documented experience with the Calabar GENCO provides the precise causal mechanism: gas supply guaranteed; generation available; dispatch curtailed because DISCOs refuse to absorb it. This mechanism was fully established before the PSGP Board date.

12.2 Require Competitive IPP Procurement

Competitive solicitation of IPPs—rather than evaluation of unsolicited proposals—is standard good practice. It produces lower tariffs, greater transparency, and better cost benchmarking. The Bank reviewed the EPC contract for Azura as a substitute for IPP-level competition. This is inadequate. The procurement of the private developer, not just the construction contractor, should be subject to competitive process as a condition of Bank support.

12.3 Structure Currency Risk Symmetrically

USD-denominated take-or-pay obligations paid by a naira-collecting off-taker in a country with chronic currency volatility is a recipe for fiscal transfer. Where full hedging is unavailable, the tariff structure should include indexed local-currency tranches that reduce sovereign exposure to exchange rate movements. The Bank has the financial expertise to design such structures. The Azura deal chose not to.

12.4 Require a Least-Cost Development Plan

No integrated resource plan or least-cost development plan existed for Nigeria's power sector at the time of PSGP approval. This meant there was no framework within which to evaluate whether an OCGT at $1,950/kW was better value than expanded hydro, transmission improvements, or demand-side interventions. The Bank should require a credible LCDP as a condition of guarantee operations in the power sector, with independent review of the selected technology and cost relative to the plan. NEGIP's investment component—which rehabilitated transmission and distribution infrastructure—achieved substantially better physical outcomes than its PRG component. The ICR comparison between these two components suggests that targeted infrastructure investment in existing systems may yield more immediate sector benefit than greenfield generation backed by structural financial guarantees.

To be direct: what Nigeria needed — and what the Bank should have required as a prerequisite — was not a new IPP. It was a functioning distribution sector. Every naira invested in greenfield generation behind DISCOs collecting 50 percent of energy delivered was a naira adding to a contractual liability rather than to electricity access. The right investment programme was in metering, feeder rehabilitation, loss reduction, and the management contract reform that would give DISCOs an incentive to absorb the power the grid was already offering. The transmission corridors bottlenecking generation from the eastern NIPP plants required capital investment that the NEGIP Component 2 began but did not complete. These were not glamorous transactions. They do not attract fifteen institutional lenders from nine countries. They do not mobilise \$900 million in a single financial close. But they address the actual constraint, and they do not transfer twenty years of currency risk onto the sovereign in the process.

12.5 Define the Advisory-Creditor Boundary

When a PRG is issued, the Bank should define upfront what activities are and are not permissible for its operational staff in the guaranteeing country. A Country Director should not be in the position of making monthly payment enforcement visits to the Finance Minister. Where guarantee payment enforcement is required, it should be handled by a dedicated treasury function, not the country team, to preserve the advisory relationship.

12.6 Require Cross-Project Learning Before New Approvals

Before any new project in a sector where the Bank has an active or recently closed predecessor project with MU or worse ratings, preparation documentation should explicitly engage with the predecessor project's ICR findings and explain why the specific structural failures identified will not recur. This is not a bureaucratic requirement—it is the minimum standard of due diligence that professional institutional practice demands. It would have required the PSGP preparation team to address, specifically, why NEGIP's experience with gas supply guarantees in Nigeria's power sector did not constitute a warning against a second, larger generation guarantee programme in the same environment.

13. Conclusion

The Nigeria Power Sector Guarantees Project is rated 'Moderately Satisfactory.' The Nigeria Electricity and Gas Improvement Project is rated 'Moderately Unsatisfactory.' Together, they represent a decade of World Bank engagement in Nigeria's electricity sector that produced: a $600M PRG series whose core objective was rated Negligible; a greenfield OCGT plant priced at twice the OECD benchmark cost; a sector financial deficit of approximately $1 billion; a Country Director reduced to monthly payment enforcement; and a Bank now seeking to scale the same model across Sub-Saharan Africa.

The Bank backed a non-competitively procured, overpriced OCGT plant with USD take-or-pay obligations, in a sector whose distribution layer it knew to be institutionally captured and financially insolvent, without a least-cost plan, without a complementary distribution reform operation, and without a credible framework for managing the creditor-advisory conflict that would inevitably arise. It did so because the transaction was bankable: Azura was a well-structured project finance deal, the sponsors were credible, the EPC contractor was competent, and the financial engineering was sound. Bankability, as Nigeria's power sector now demonstrates, is not the same as development effectiveness.

What makes this failure categorically different from a simple sequencing error is that the Bank had prior documented warning. NEGIP was running in parallel. Its PRG component was failing for the same reasons—in real time, visible in publicly available ISRs—while the PSGP was being designed. NEGIP's ICR lesson that 'payment guarantees provide comfort to the seller but do not make the buyer more creditworthy' was not an ex-post insight. It was a finding that careful operational review of a concurrent project would have produced during PSGP preparation. The institutional system did not produce that review. It was not designed to.

The Azura mobile app—which publishes real-time operational data about the plant's performance—is available on the App Store. NBET's website publishes real-time sector payment data. The evidence of what happened is public. The question is whether the Bank's evaluation and learning systems are designed to surface it, or to obscure it behind a 'Moderately Satisfactory' rating and a Lessons section that no one is required to act on.

That question—whether the Bank learns from its failures or institutionalises them—is the central question of MDB reform.

Annex C of this report names the individuals who carried these projects to approval: Onno Ruhl, World Bank Country Director for Nigeria across both the NEGIP (2009) and PSGP (2014) approvals;

and Makhtar Diop, Regional Vice President for Africa, whose signature appears on the PSGP Statutory Committee Report of April 16, 2014 — the document that formally recommended the project to the Board. Both are distinguished development professionals with long careers in international development finance. The argument of this report is not that they acted in bad faith. It is that the institutional system they operated within gave them no structural reason to confront, as a binding constraint, the evidence that NEGIP was already producing in real time. Under a system where approvals are rewarded, outcomes are evaluated by others, and consequences flow to borrowers rather than lenders, the rational institutional behaviour is exactly what this report documents: approve, disburse, move on. Until that system changes, the names in Annex C will keep being replaced by different names doing the same thing.

The deeper question raised by Nigeria's power sector is not who specifically was responsible — the Task Team Leader, the Practice Manager, the Country Director, the Vice President, or the Board. Annex C names them. The answer, examined honestly, is: all of them, and therefore none of them. Each individual in the approval chain operated rationally within a system that rewarded approvals, insulated decision-makers from outcomes, and placed the consequences of failure on borrowers rather than lenders. The Task Team Leader was promoted. The Country Director rotated. The Vice President moved on. The Board noted the risks, expressed confidence in management, and moved to the next item. No individual was irrational. The system was.

What makes the World Bank structurally different from any other development actor — and what makes this accountability vacuum self-sustaining — is the sovereign guarantee architecture that underpins every loan on its balance sheet. The Bank lends only to sovereigns, or with sovereign guarantees. It holds preferred creditor status. It has never recorded a default. This is why it carries a AAA rating from every major agency — a rating that allows it to borrow cheaply and on-lend at near-concessional rates. The rating is real and the mechanism is legitimate. But its consequence is this: the Bank is institutionally invulnerable to the outcomes of its own lending decisions. When a project fails, the loss falls on the borrower — in the form of debt that must be serviced regardless of whether the project delivered — not on the Bank. The Bank's balance sheet is protected by the very sovereign guarantee that transfers the risk to the country. It cannot lose. It has no financial stake in whether the canal floods the city.

This is the structural logic behind Nigeria's power sector outcome in its most compressed form. The Bank co-designed the privatisation architecture over a decade. It guaranteed the contracts that locked the sovereign into USD-denominated payment obligations. It watched the distribution sector collapse under the weight of those obligations. It then arrived with $750 million in new IDA lending to help manage the fiscal consequences of the crisis its earlier instruments had helped create. At each stage, the Bank booked an approval. At each stage, Nigeria accumulated more debt. The Bank's AAA rating was never in question. Nigeria's debt-to-GDP ratio continued to rise.

This needs to change. Not because the individuals involved were corrupt or incompetent — they were not — but because a development institution whose balance sheet is permanently insulated from the development outcomes of its lending has no structural mechanism for learning from failure. The reform agenda is not primarily about staffing, culture, or evaluation methodology. It is about incentive architecture. Until the Bank has some form of financial exposure to the outcomes of its lending decisions — through outcome-linked pricing, claw-back provisions on fees, or mandatory co-financing of remediation operations from its own capital rather than through additional sovereign debt — the approval machine will continue to operate exactly as it does. The Task Team Leaders will rotate. The Country Directors will move on. The Annex C names will change. And Nigeria — or the next Nigeria — will be left holding the guarantee.

March 2026 | All analysis based on publicly available World Bank ICR Report No. ICR4788 (NEGIP, P106172) and ICR Report No. 155732-NG (PSGP, P120207) and field observation.

ANNEX A

Nigeria's Power Sector: The Broken Market — Capacity, Dispatch, and the Cost of the Wrong Investment Model

The data in this annex is drawn from NERC quarterly reports, NBET market publications, and World Bank project documents including the NEGIP ICR (P106172) and the PSGP ICR (P120207). It is presented not as neutral background but as the quantitative foundation for the structural arguments made in this report. The central fact—that Nigeria has over 13 GW of installed generation capacity but typically delivers between 3.5 and 5 GW to the national grid—is not a statistic about energy poverty. It is the signature of a broken market, and it explains why two World Bank projects deploying over $900 million in financing and guarantees produced a sector financial deficit of approximately $1 billion.

1. The Capacity-Dispatch Gap

The most striking feature of Nigeria's electricity sector is the scale of the gap between what is available and what is delivered. As of 2024–25, installed generation capacity exceeds 13 GW across thermal, hydro, and embedded sources. Available capacity—plants that are technically functional and have fuel—runs at approximately 6 GW. The electricity actually dispatched to the national grid typically ranges between 3,500 and 5,000 MW. This represents a utilisation rate of approximately 35–40 percent of installed capacity.

Generation Category	Approximate Level
Installed capacity	~13–14 GW
Available (fuelled & operational)	~6 GW
Typically dispatched to grid	3.5–5 GW
Utilisation rate (installed)	~35–40%
PSGP-era sector financial deficit	~$1 billion by project close

Table C1. Generation capacity versus actual dispatch, Nigeria national grid.

This gap is not primarily a technical problem. It is an institutional and financial problem. The three main causes—DISCO load rejection, transmission constraints, and gas supply shortfalls—are each a consequence of the policy and governance failures documented in this report. The chart below, drawn from NERC data, illustrates the persistent divergence between investment in the sector and electricity actually delivered.

Nigeria Power Sector Snapshot (2015–2026)

Key operational indicators compiled from sector regulator summaries, system operator data, and market reports.

Year	Installed Capacity (MW)	Available Capacity (MW)	Power Delivered to Grid (MW)	Grid Collapses
2015	12500	6000	3500	10
2016	12500	6200	4000	28
2017	12500	6500	4200	21
2018	13000	6200	4000	13
2019	13000	6000	3900	11
2020	13200	5800	3600	4
2021	13200	6000	4000	4
2022	13500	6200	4200	7
2023	13600	6400	4500	8
2024	13600	6500	4800	12
2025	13800	6300	4500	12
2026	13800	6200	4300	9

Key Structural Observations
- Installed capacity rose to ~13–14 GW, but delivered electricity remained ~3.5–4.8 GW.
- Roughly 60% of generation capacity is unavailable or curtailed at any time.
- Transmission constraints and weak distribution company finances limit dispatch.
- Recurring grid collapses indicate persistent system instability.

Figure C1. Installed generation capacity versus electricity delivered to the grid, Nigeria, 2005–2024.

2. DISCO Load Rejection and the Financial Cascade

The single largest cause of Nigeria's capacity-dispatch gap is not gas shortages or transmission failures. It is distribution company load rejection: the practice by which DISCOs disconnect feeders serving areas with high collection losses, effectively refusing to take electricity that the grid is offering. The NEGIP ICR documents that DISCOs were rejecting up to 2 GW of available system load at peak periods—reducing dispatch from available levels exceeding 5,500 MW to approximately 3,500 MW. This behaviour is economically rational for a DISCO collecting perhaps 50–60 percent of the energy it distributes; it is catastrophically destructive at the system level.

The financial transmission mechanism runs directly through the sector: when DISCOs reject load, GENCOs reduce output; GENCOs' gas obligations do not reduce under take-or-pay; GENCOs cannot pay gas suppliers; NBET cannot collect from DISCOs to pay GENCOs; NBET cannot pay IPPs under their PPAs. The PRG backstop is then the last line of defence—exactly the position the PSGP was designed to avoid but structurally guaranteed to reach.

Market Stage	Key Dysfunction	Documented Scale
DISCOs	ATC&C losses 35–50%; load rejection of ~2 GW	NGN 476bn arrears by end-2016

NBET	Collects 50–70% of invoiced energy; structural deficit	~$1bn annual shortfall 2017–18
GENCOs	Unpaid by NBET; unable to service gas obligations	Maintenance funding diverted
Gas suppliers (Accugas)	Take-or-pay invoked at ~$10m/month on half-capacity plant	$66.6m unpaid by Sept 2019
Sovereign / PRG	FGN backstop of last resort; indemnity unconditional	~$237m PSGP + $111.8m NEGIP PRGs

Table C2. Financial cascade from DISCO under-performance to sovereign exposure.

The Calabar plant exemplifies this chain in full. Contracted for 561 MW, it operated at approximately half capacity—260 MW—not because Accugas failed to supply gas, but because TCN could not dispatch output that DISCOs would not absorb. NDPHC paid take-or-pay charges on gas it could not use, while simultaneously failing to collect payment for the electricity it could not sell. This is the precise mechanism the NEGIP ICR documented in detail. It was fully established before the PSGP Board date.

3. Transmission—The Physical Constraint

Nigeria's transmission system, operated by TCN, represents a second binding constraint. The NEGIP ICR documents that energy wheeled through the transmission system did not increase significantly over the project's ten-year life, even as installed generation capacity grew, because transmission investment did not keep pace with generation additions. Several northern and eastern corridors remain constrained, preventing full evacuation of generation from NIPP plants. The Calabar-Port Harcourt corridor operates at levels well below the Calabar plant's rated output—a physical constraint that compounds the financial one.

Power Plant	Installed Capacity	Typical Dispatch	Primary Constraint
Calabar (Odukpani)	~561 MW	~260 MW	Grid evacuation; DISCO load rejection
Alaoji NIPP	~1,074 MW	<500 MW	Grid evacuation limits
Geregu	~435 MW	Variable	Gas supply and transmission
Omotosho	~500 MW	Variable	Gas supply intermittency
Ihovbor (Benin NIPP)	~450 MW	Variable	Pipeline and gas reliability

Table C3. Transmission constraints affecting dispatch of selected power plants.

The map below illustrates the major transmission corridors and documented bottleneck zones. The Bank's NEGIP investment component allocated resources to transmission rehabilitation—and this component performed substantially better than the PRG series. Yet the transmission investment programme was insufficient to enable full utilisation of the generation capacity that the PRG programme was simultaneously supporting. This is the infrastructure corollary of the sequencing error: not only was distribution not fixed before generation was added, transmission was not expanded to carry the generation that was already there.

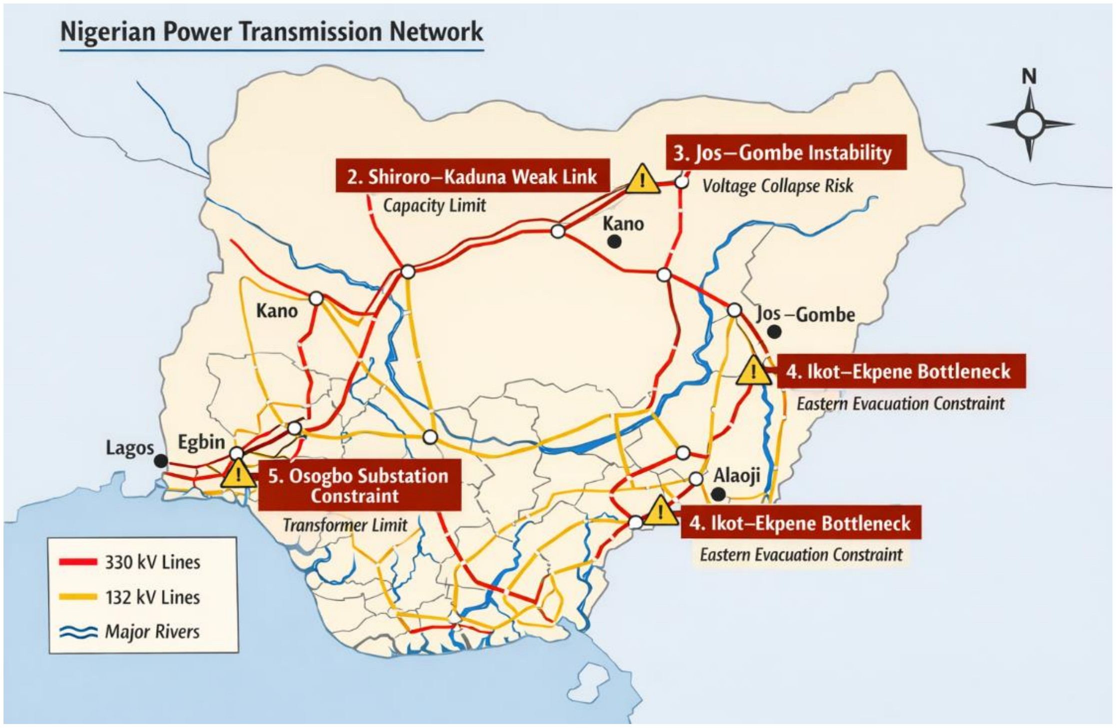

Figure C2. Major transmission corridors and grid bottleneck zones, Nigeria national grid.

4. The Dispatch Inversion: Merit Order, Take-or-Pay, and the Foreign Exchange Burden

The take-or-pay structure of the Azura and Calabar PPAs does not merely create an abstract fiscal liability. It actively inverts Nigeria's electricity dispatch order, forcing the grid to run its most expensive plants as base load while curtailing generating capacity that is, in effective economic terms, free. This dispatch inversion is not a side-effect of the guarantee structure. It is a logical consequence of it. It has been operating continuously since Azura reached commercial operations in 2018, and the Bank's project documents contain no analysis of it.

Nigeria operates approximately 2,638 MW of installed hydropower capacity: Kainji (760 MW), Jebba (578 MW), Shiroro (600 MW), and Zungeru (700 MW). These plants run on water. Their fuel cost is zero. Their marginal cost of generation—once built and amortised—is between \$3 and \$5 per megawatt-hour, representing only operations and maintenance expenses. Under any rational economic dispatch regime, hydro is the first call on the Nigerian grid: it is dispatched ahead of every gas-fired plant in the country, without exception.

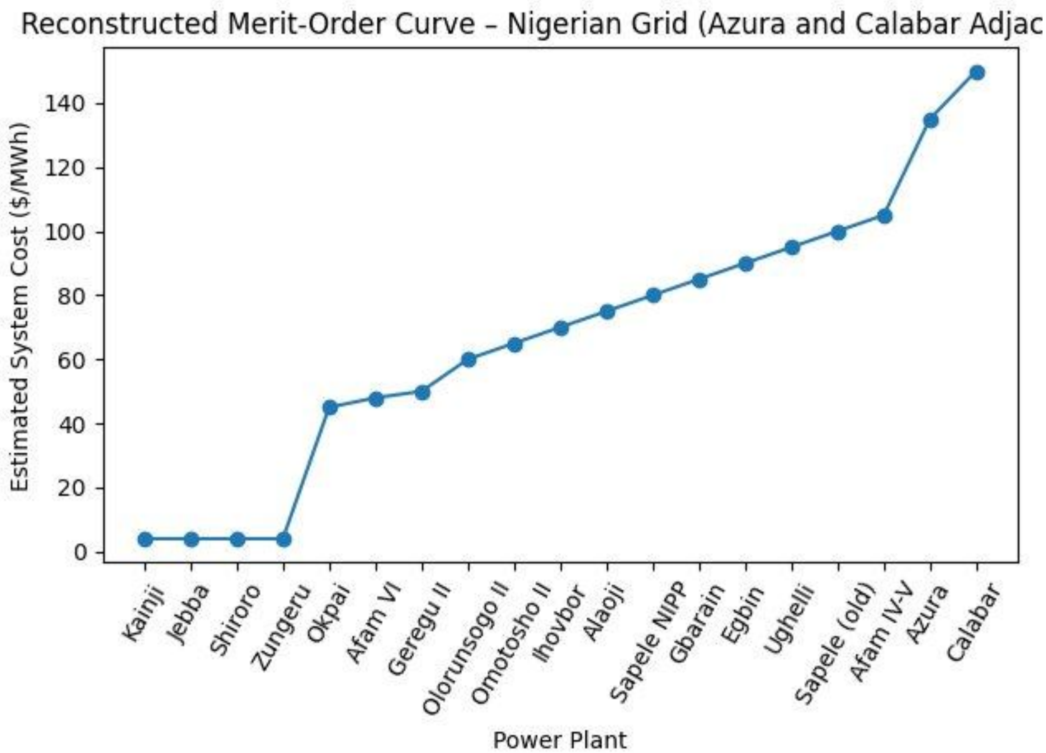

Figure 1. Reconstructed merit-order curve for the Nigerian grid. Azura and Calabar, shown at far right, sit above every other generating plant in the system.

The take-or-pay structure of Azura and Calabar destroys this logic. Because NBET must pay the full capacity charge for both plants regardless of dispatch, the System Operator faces a contractual obligation that overrides the merit order. The effective system cost of Azura and Calabar—once capacity payments, energy payments, and the foreign-exchange indexation are included—is between $110 and $170 per megawatt-hour. They are not the cheapest plants on the Nigerian grid. They are the most expensive. Yet the take-or-pay structure means that whenever the System Operator must choose between dispatching hydro and dispatching Azura or Calabar, the contractual arithmetic favours the IPPs: if Azura runs, NBET pays for energy it can use; if Azura does not run, NBET still pays the capacity charge in dollars while the hydro megawatt-hours flow for nothing. The result is that available hydro generation is curtailed to accommodate plants whose owners must be paid whether they generate or not.

The scale of this distortion is quantifiable. The combined annual invoice for Azura and Calabar is approximately $480 million—a figure that has remained broadly constant in dollar terms while its naira equivalent has quadrupled as the exchange rate has depreciated. Against this, Nigeria's four hydro stations, at full utilisation across a comparable generation volume, would cost the system roughly $15–$20 million per year in O&M. The differential between these two numbers—approximately $460 million annually—represents the cost of the dispatch inversion. It is not a cost that appears in the PSGP ICR. It does not feature in the Azura project's efficiency analysis. It is simply what Nigeria pays, every year, to service contractual obligations whose fundamental structural defect was visible before financial close.

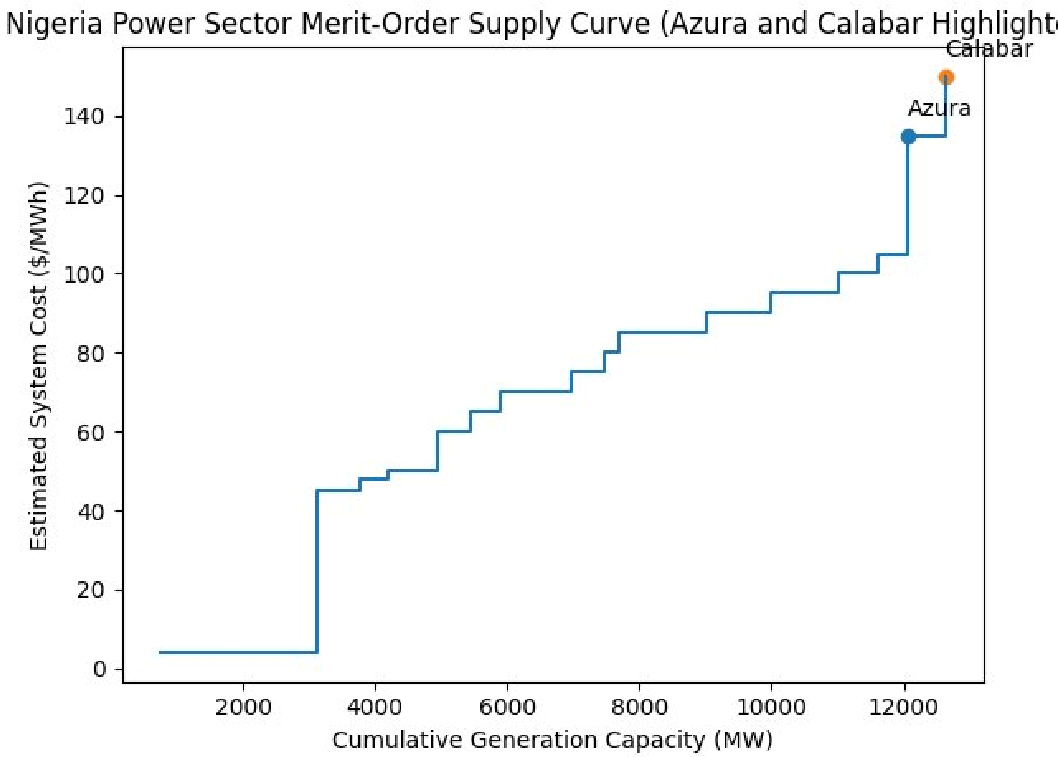

Figure 2. Nigeria power sector merit-order supply curve. Azura and Calabar (highlighted) represent a step-change above all other grid capacity.

The seasonal dimension is particularly egregious. Nigeria's rainy season runs from approximately May to October. This is when the country's river systems are at maximum flow, reservoir levels are highest, and hydro generation potential peaks. It is precisely the period during which the economic case for dispatching hydro ahead of gas-fired generation is strongest. Yet the take-or-pay structure means that this is also the period during which NBET's dollar obligations to Azura and Calabar are most costly to leave unused. The System Operator is structurally incentivised to accept IPP output at $110–$170 per megawatt-hour while curtailing hydro that could run for $4. The result is that hydro generation is curtailed in the periods when it is most abundant, to accommodate the contractual economics of plants that cost thirty times more to run.

The NEGIP ICR had already documented this mechanism in operation at Calabar. The plant was dispatched at only half its design capacity—260 MW against 560 MW—not because the plant was unavailable but because the system was curtailing load at the distribution level. But the inverse problem is equally destructive and receives no attention in the ICR literature: when the system is curtailing output at the generation level to manage the take-or-pay arithmetic, it is the hydro stations that bear the curtailment. TCN's System Operator, instructed to honour contractual dispatch obligations to the IPPs, issues the reduction order to Kainji or Jebba. The contractual beneficiary is the IPP and its lenders; the efficiency cost falls on the system.

There is also a foreign-exchange dimension that operates independently of the dispatch logic. Every dollar paid to Azura and Calabar under their capacity charge structures leaves Nigeria's foreign-exchange reserves. Hydro generation displaces no foreign currency at all. The $480 million annual combined invoice therefore represents not only a fiscal cost but a balance-of-payments cost—a permanent structural drain on Nigeria's dollar position to pay for electricity that its existing domestic infrastructure could partially supply. As the naira has depreciated from ₦360 to over ₦1,500 per dollar, the naira cost of this dollar drain has quadrupled. The volume of electricity has not changed. The dollar-denominated obligation structure means that the naira cost has.

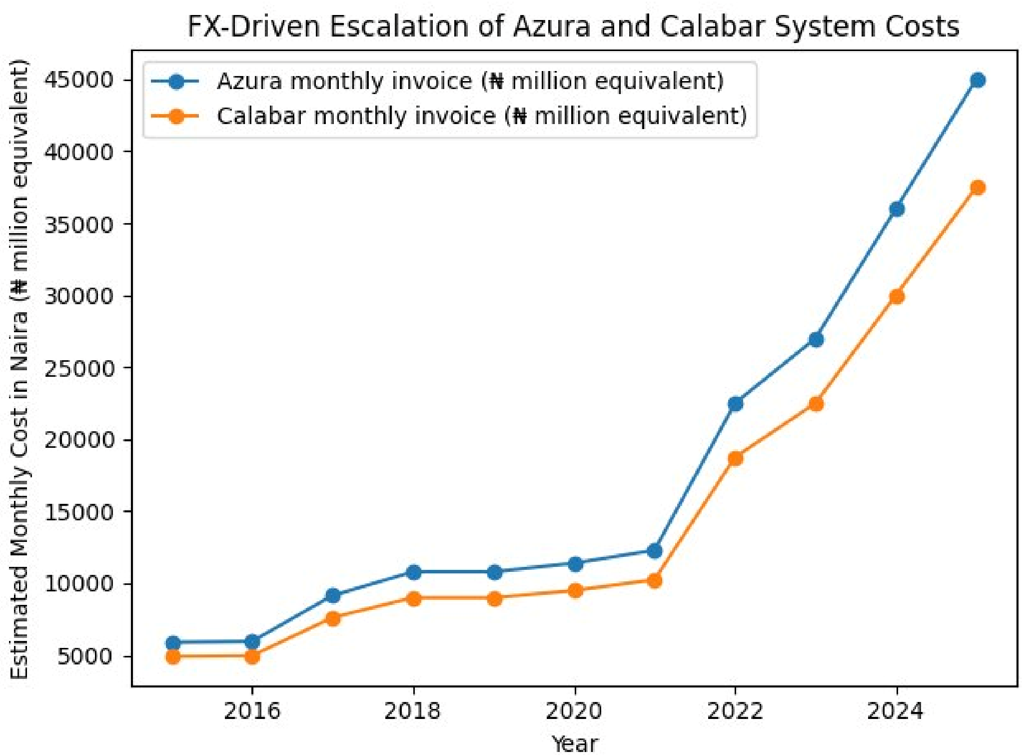

Figure 3. FX-driven escalation of Azura and Calabar system costs (naira equivalent). The dollar invoice is constant; the naira cost has more than quadrupled as the exchange rate has depreciated.

None of this was invisible at the time of project design. The Nigerian grid's installed hydro capacity was documented in every sector assessment the Bank produced. The merit-order implications of adding dollar-denominated take-or-pay generation above 2,600 MW of near-zero-marginal-cost hydro were derivable from first principles. The Bank had a least-cost planning obligation. No credible least-cost development plan existed for Nigeria at PSGP approval—a fact the ICR itself acknowledges—and the absence of such a plan is precisely what allowed this structural absurdity to proceed. A project that might have failed a credible least-cost screen was approved in the absence of one. The PSGP ICR acknowledges this. The dispatch consequences it describes have been operating continuously since commercial operations began.

5. Grid Stability as an Indicator of System Stress

The Nigerian grid has experienced repeated collapses—events in which sudden imbalances propagate across the network faster than the System Operator can respond, causing blackouts across large portions of the country. The frequency of these events provides an operational indicator of system stress that complements the financial data. The concentration of collapses in 2016–17 coincides directly with the financial shock documented in the main report: the 30 percent naira devaluation in June 2016, the accumulation of DISCO arrears, and the period in which NBET's capacity to meet its PPA obligations first came under serious pressure. System operators managing a grid under financial stress—where dispatch decisions are influenced by contractual take-or-pay obligations rather than merit order—face a structurally harder operational challenge.

Year	Estimated Grid Collapses	Key Sector Event
2015	~10	DISCO privatization completed; sector deficits accumulate
2016	~27	Naira devaluation (-30%); tariff shortfall shock; NEGIP rated MU
2017	~22	Post-election policy pause; energy sector review ongoing
2018	~13	Azura reaches commercial operations; Country Director payment visits begin
2019	~11	PSGP closes; QIPP cancelled; sector deficit ~$1bn
2020	~4	PSRP approved; NEGIP ICR published
2021	~8	PSGP ICR published (rated Moderately Satisfactory)
2022	~7	Sector payment arrears continue
2023	~9	FX depreciation accelerates; naira obligations escalate
2024	~8	Combined Azura+Calabar invoice ~$480m; naira equivalent >₦720bn

Table C4. Estimated annual grid collapses and concurrent sector events.

6. Gas Supply—The Upstream Constraint

Nigeria's thermal generation fleet, which accounts for the majority of installed capacity, is heavily dependent on natural gas. The gas supply chain has been subject to three categories of constraint: pipeline infrastructure limitations, pricing disputes between suppliers and NNPC, and operational disruptions in the Niger Delta. These constraints are not independent of the financial cascade. When DISCOs underremit and NBET's liquidity deteriorates, upstream gas pricing disputes are harder to resolve—NNPC has less incentive to supply gas at below-market rates to plants that will not be paid. The financial collapse of the electricity market reinforces the gas supply constraint, and vice versa. This is not a sector with multiple independent problems. It is a sector with one structural problem—the insolvency of the DISCO layer—that propagates simultaneously up and down the value chain.

Plant	Installed Capacity	Gas Arrangement	Documented Constraint
Calabar (Odukpani)	561 MW	Accugas GSA; take-or-pay 131 mmscfd; IDA PRG $111.8m	Plant at 50% capacity; take-or-pay invoked on unused gas
Geregu	435 MW	NNPC gas supply agreement	Pipeline interruptions; gas pressure instability

Omotosho	500 MW	NNPC supply via Escravos-Lagos pipeline	Intermittent supply; force majeure events
Ihovbor	450 MW	NNPC supply	Pipeline reliability; supply fluctuations
Alaoji NIPP	1,074 MW	Multiple suppliers; partial delivery	Gas delivery shortfalls and grid evacuation

Table C5. Gas supply arrangements and constraints for selected Nigerian thermal plants.

7. What the Data Means for the PRG-Backed IPP Model

The data in this annex documents a system that, despite tens of billions of dollars in investment, delivers less than 40 percent of its installed capacity to end users. It documents a financial market in which the central off-taker is structurally unable to collect enough revenue to meet its contractual obligations. It documents transmission infrastructure that cannot evacuate the generation the PRG programme was designed to support.

A PRG-backed IPP with a USD take-or-pay PPA does not solve any of these constraints. It adds a dollar-denominated obligation on top of a naira market that is structurally insolvent. It adds generation capacity to a system already curtailing the generation it has. It adds a take-or-pay fuel obligation to a gas supply chain that already struggles to recover its costs. And as the naira depreciates—from ₦306 at Azura financial close in 2015 to over ₦1,500 in 2024–25—the dollar-denominated obligations expand in local-currency terms with no corresponding increase in electricity output or revenue collection.

The Bank's ICRs for both NEGIP and PSGP acknowledge these constraints in their Lessons sections. The project ratings do not reflect them. The pipeline of comparable transactions across Sub-Saharan Africa does not incorporate them as design constraints. That is the institutional failure this annex documents in numbers: not a lack of data, but a systematic failure to let the data constrain the approvals.

ANNEX B

Institutional Separation and the World Bank as Trusted Adviser: Why The Merger With IFC Deserves Scrutiny

Introduction

Recent proposals to merge the operational functions of the World Bank, the International Finance Corporation, and the Multilateral Investment Guarantee Agency have revived a long-standing debate about institutional design in development finance. Advocates argue that closer alignment would accelerate private investment mobilization and reduce transaction costs. The case has surface plausibility: why maintain separate institutional silos when the same project often requires a sovereign guarantee, private equity, and political risk insurance simultaneously?

The answer lies in what makes the World Bank different from other international financial institutions. Its core comparative advantage is not its balance sheet. It is the perception—carefully cultivated and often decisive in practice—that when it advises a government on power sector tariffs, procurement rules, or institutional restructuring, that advice is driven by development objectives and not by any financial stake in the outcome. The Nigerian power sector experience demonstrates how quickly that perception erodes when advisory and investment roles converge within the same institutional structure. It also provides a concrete test case for what full integration would look like.

The Architecture of Separation

The tripartite structure of the World Bank Group was not an accident of institutional history. IBRD and IDA provide sovereign lending and policy advice. IFC invests directly in private-sector projects. MIGA provides political risk insurance to protect those investments. The separation of these mandates allows governments to engage with the Bank on regulatory reform and public investment policy without the concern that recommendations are shaped by the Bank's financial exposure to the private-sector entities those reforms would affect.

This matters most in sectors where regulation directly determines the financial viability of private investments. Power sector tariffs are the paradigm case. A development institution advising a government on electricity tariff policy while simultaneously holding guarantees on power purchase agreements with dollar-denominated capacity charges has an institutional interest in tariff outcomes that is difficult to disentangle from its advisory function. The formal separation of World Bank guarantees from IFC equity investments from MIGA insurance is the structural mechanism designed to limit this entanglement. Merger removes that mechanism.

The Nigerian Power Sector as a Test Case

The development of the Azura-Edo and Calabar power plants illustrates how blended finance structures can create institutional tensions even within the existing separated architecture—and therefore how much worse those tensions would become in an integrated one.

Both projects were designed to mobilize private capital for Nigeria's electricity sector. The World Bank provided partial risk guarantees. IFC took equity. MIGA provided political risk insurance. The World Bank country team simultaneously advised the Nigerian government on tariff reform, distribution sector restructuring, and the financial stabilization of the bulk electricity market. When the electricity sector entered a sustained liquidity crisis—driven by distribution company failures and tariff shortfalls—the Bank's advisory engagement with the government on these structural issues took place against the backdrop of its own financial exposure to the projects whose viability depended on resolving them.

The PSGP Implementation Completion Report is candid about one consequence. Paragraph 86 notes that the Bank's guarantee obligations required "periodically reminding the Government to honor its guaranteed payment obligations for specific guarantees to the private developer," and that this scrutiny "may strain the relationship with government counterparts, and be at odds with the World Bank's ability to pursue overall dialogue on sector viability and other priorities." This sentence describes the advisory-creditor conflict in operation. It appears in a Lessons section that carries no rating consequence and imposes no design constraint on future operations.

Under a merged institutional structure, this conflict would not be an edge case to be managed. It would be the normal operating condition. The merged institution would simultaneously hold equity in the IPP, insure its investors against political risk, guarantee its off-taker's payment obligations, and advise the government on the tariff and regulatory framework that determines whether those payments are made. The advisory function would not be separate from the financial exposure. It would be the instrument through which the financial exposure is managed.

Institutional Capture in Blended Finance Structures

The risk that integration creates is not straightforward corruption or bad faith. It is subtler and more structurally determined. When a development institution becomes financially exposed to specific projects through guarantees, co-investment, or insurance, it acquires an interest in their continued viability. That interest shapes institutional incentives in ways that are difficult to observe and harder to control.

Consider the sequencing pressure this creates. A merged institution that has already committed IFC equity, a Bank guarantee, and MIGA insurance to a power project has a strong institutional incentive to approve the accompanying policy-based financing that stabilizes the sector in which that project operates—regardless of whether the policy reform conditions are genuinely met. The alternative—allowing the sector to deteriorate to the point where the guarantee is called—is institutionally costly in ways that withholding a DPF tranche is not. The pressure is real even when individual staff act in good faith. It is a structural consequence of combining financial exposure with policy conditionality within the same institution.

This dynamic is visible in the Nigerian case. The World Bank approved the Power Sector Recovery Programme in 2020—a policy-based lending operation intended to stabilize the electricity market—six years after the PSGP was approved and two years after Azura reached commercial operations. The timing was not coincidental. The sector's financial deterioration directly threatened the payment structure supporting the guarantee the Bank had issued. The PSRP was in part a downstream response to the upstream commitments the Bank had already made. Whether the policy conditions attached to the PSRP were calibrated to what the sector actually needed, or to what the existing financial exposures required, is a question the ICR system is not designed to ask.

What Other Institutions Understand

The importance of separating advisory from investment functions is reflected in the governance design of comparable institutions. The IMF does not invest in private projects. Its surveillance and policy advice functions are structured around the premise that neutrality in macroeconomic advice requires the absence of financial stakes in the entities that advice affects. The EBRD invests in private enterprises but does not perform the sovereign policy-advisory role that characterizes the World Bank's engagement with borrowing governments. Its governance structure reflects this narrower mandate.

The ADB maintains distinct operational windows for sovereign and private-sector operations. The separation is imperfect—the tensions between advisory and investment functions appear there too—but the institutional architecture at least creates organizational visibility for conflicts when they arise. Full merger eliminates that visibility. Conflicts of interest that are currently identifiable because they cross institutional boundaries become invisible when those boundaries disappear.

Procurement, Anti-Corruption, and Governance Credibility

Integration also creates risks beyond the advisory-creditor conflict. The World Bank's sovereign lending operations rely on procurement rules designed to ensure transparency and competition in public projects. These rules are central to the Bank's reputation for institutional integrity.

An integrated institution that simultaneously promotes private investment through its IFC arm and advises governments on procurement frameworks faces an inherent tension. The Azura case illustrates this concretely: the PSGP ICR acknowledges that the project was an unsolicited proposal with "no evidence found by the ICR team of any formal process in the Government for evaluating unsolicited proposals." The Bank supported a non-competitively procured project, then reviewed the EPC contract and characterized the result as due diligence. This outcome was possible within the existing separated structure. It would be structurally encouraged in a merged one, where the institution's private-sector investment arm has an organizational interest in seeing specific projects proceed and the sovereign advisory arm is simultaneously shaping the procurement environment in which they operate.

The Bank's anti-corruption work faces an analogous risk. Strengthening regulatory institutions and improving oversight of public–private partnerships requires that advisory functions remain visibly independent of financial interests in specific transactions. That independence is structural, not just procedural. Procedures can be documented and compliance can be certified. The institutional reality that an integrated Bank-IFC-MIGA entity holds equity in the IPP while advising the regulator on IPP licensing frameworks cannot be procedurally managed away.

Conclusion

The proposal to merge the World Bank, IFC, and MIGA should be evaluated not only on efficiency grounds but on what it would do to the Bank's core institutional asset: its credibility as a trusted and impartial adviser to governments. The Nigerian power sector experience suggests that even within the existing separated structure, blended finance operations create advisory-creditor tensions that the ICR system documents but does not discipline. Full integration would make those tensions the permanent institutional condition rather than the manageable exception.

The efficiency gains from integration are real but quantifiable. The credibility costs are harder to measure and slower to manifest—but they are the costs that ultimately determine whether governments treat Bank advice as analytical guidance or as one input among many from a counterpart with financial stakes of its own. Once that credibility erodes, it does not return quickly. The Bank's balance sheet can be recapitalized. Its reputation as a disinterested adviser cannot.

ANNEX C

The Approval Chain: Who Authorised These Projects and What They Said

Institutional accountability requires that the names of those who authorised these projects be on the record alongside the analysis of their outcomes. The three documents reproduced below are publicly available on the World Bank Open Documents platform. Together they establish who approved the Nigeria Electricity and Gas Improvement Project (NEGIP) in 2009 and the Power Sector Guarantees Project (PSGP) in 2014, in what institutional capacity, and what they said at the time. The outcomes documented in this report are the outcomes of decisions those individuals made.

Document 1: NEGIP Board Approval, June 16, 2009

World Bank Press Release. Nigeria Electricity and Gas Improvement Project (NEGIP), Board Approval. June 16, 2009. US$200 million IDA credit plus US$400 million in Partial Risk Guarantees. World Bank Open Documents.

Source: World Bank Open Documents — https://documents.worldbank.org/en/publication/documents-reports/documentdetail

The Board of the World Bank approved US$600 million of assistance to the Power and Gas sectors in Nigeria: US$200 million in IDA Credits for network investments and technical assistance, and US$400 million in Partial Risk Guarantees in support of domestic gas market development. The press release stated that the project would address "one of the critical bottlenecks in the supply chain for power generation" — the absence of reliable gas supply to existing power plants. Seven to ten gas supply agreements were envisaged. Of these, exactly one was ever signed. The gas guarantee programme's efficacy was ultimately rated Negligible by IEG.

Country Director, Nigeria (at approval): Onno Ruhl. **Statement at approval:** "We are especially excited about the prospect that our support to the power sector might help solve the perennial problem of generation capacity lying idle whilst Nigerians stay without light."

Note: At the time of NEGIP's Board approval, Nigeria already had substantial installed generation capacity that was being underutilised — not primarily because of gas shortages, but because of transmission constraints and the financial collapse of the distribution sector. The "generation capacity lying idle" problem acknowledged by the Country Director in 2009 was still present at PSGP project closure in 2019, having been compounded, not resolved, by a decade of upstream investment.

Document 2: PSGP Statutory Committee Report, April 16, 2014

Official Document. Statutory Committee Report to the President, IBRD. Power Sector Guarantees Project (PSGP), Federal Republic of Nigeria. Documents G2300-NG and G2310-NG. Dated at Washington, D.C., April 16, 2014.

Source: World Bank Official Documents — https://documents.worldbank.org/en/publication/documents-reports

The Statutory Committee, constituted under Section 7 of Article V of the IBRD Articles of Agreement, reviewed the proposal to provide Partial Risk Guarantees as part of a series under the Power Sector Guarantees Project. The Committee approved: (i) a PRG for commercial debt mobilisation of up to

US$125 million, plus a PRG to enhance NBET creditworthiness of up to US$120 million, each for the Azura Edo Independent Power Project; and (ii) a PRG to enhance NBET creditworthiness of up to US$150 million for the Qua Iboe Independent Power Project.

The Committee found that the Project "comes within the purposes of the Bank as set forth in Article I of said Articles of Agreement, and that said Project is designed to promote the development of the productive facilities and resources of the Federal Republic of Nigeria." The Committee's report was signed by three signatories:

Signatories to the Statutory Committee Report: (1) Senior Vice President and Group General Counsel, IBRD; (2) Makhtar Diop, Regional Vice President, Africa; (3) Nominee selected by the Governor for the Federal Republic of Nigeria. Dated: April 16, 2014. Makhtar Diop signed the Statutory Committee Report as the Regional Vice President responsible for the Africa Region, and in that capacity was the senior officer who carried the PSGP to the Board for approval.

PSGP Task Team and Senior Responsible Officers (from PSGP ICR cover sheet): Country Director: Onno Ruhl; Sector Manager: Paul Noumba Um; Project Team Leader: Peter J. Mousley; ICR Team Leader and Primary Author: Peter J. Mousley / Zachary A. Kaplan.

Statutory Committee Report — Signed Document (Official World Bank Record)

OFFICIAL DOCUMENTS G-2300-NG
G 2310-NG

STATUTORY COMMITTEE REPORT

TO: The President, International Bank for Reconstruction and Development

Report of the Committee under Section 4 (iii) of Article III of the Articles of Agreement on proposed Partial Risk Guarantees (PRGs), in respect of the Power Sector Guarantees Project to the Federal Republic of Nigeria

The undersigned Committee constituted under Section 7 of Article V of the Articles of Agreement of the International Bank for Reconstruction and Development (the Bank) hereby submits its report pursuant to Section 4, (iii) of Article III of said Articles in respect of the proposal that the Bank grant to the Federal Republic of Nigeria (the Borrower) the following Partial Risk Guarantees (PRGs) as part of a series under the Power Sector Guarantees Project: (i) a PRG for commercial debt mobilization, in an amount up to US$125 million (plus interest thereon) as well as a PRG to enhance the creditworthiness of Nigeria Bulk Electricity Trading Plc, (NBET), in an amount up to US$120 million (plus interest thereon), each for the Azura Edo Independent Power Project; and (ii) a PRG to enhance the creditworthiness of NBET, in an amount up to US$150 million (plus interest thereon), for the Qua Iboe Independent Power Project. The purpose of the said PRGs is to increase the supply of electricity received by Nigerian consumers (the Project).

1. The Committee has carefully studied the merits of the proposal to provide such PRGs, and of the purpose to which the proceeds of the underlying commercial loans so guaranteed are to be applied.

2. The Committee is of the opinion that the Project in support of which the proceeds of the underlying commercial loans so guaranteed are to be applied comes within the purposes of the Bank as set forth in Article I of said Articles of Agreement, and that said Project is designed to promote the development of the productive facilities and resources of the Federal Republic of Nigeria and is in the interest of the Federal Republic of Nigeria and of the members of the Bank as a whole.

3. Accordingly, the Committee finds that said Project merits financial assistance from the Bank in the form of the aforesaid PRGs, and hereby recommends said Project for such assistance.

COMMITTEE

Senior Vice President and Group
General Counsel

Nominee Selected by Governor for
Federal Republic of Nigeria

Regional Vice President
Africa

Dated at Washington, D.C.

April 16, 2014

Statutory Committee Report, Federal Republic of Nigeria — Power Sector Guarantees Project (Page 2 of 2). Signed by: Senior VP & Group General Counsel; Makhtar Diop, Regional VP Africa; FRN Nominee. Dated: April 16, 2014.

Document 3: PSGP Executive Board Chair Summary, May 1, 2014

Official Document. Chair Summary, Executive Board Meeting. Nigeria Power Sector Guarantees Project. May 1, 2014.

Source: World Bank Open Documents — https://documents.worldbank.org/en/publication/documents-reports/documentdetail/P120207

The Executive Directors endorsed a series of IBRD Partial Risk Guarantees in support of the Power Sector Reform Program of Nigeria, estimated in aggregate at US$700 million in its initial phase. The Board approved the three specific PRGs described above. The Chair Summary records the following Board statements:

> *"Directors highlighted the critical role of the Power Sector Reform Program in accelerating economic growth and shared prosperity in Nigeria. They acknowledged the high-risk high-reward nature of this transformational proposal."* — PSGP Executive Board Chair Summary, May 1, 2014

> *"Directors encouraged continued cooperation between the World Bank, IFC, and MIGA in supporting the proposed projects and the government's reform program."* — PSGP Executive Board Chair Summary, May 1, 2014

> *"Directors noted that achievement of the Project's development impact requires long-term financial viability of the sector, including a sound regulatory framework, and a reduction in the high level of technical and commercial losses in the power system."* — PSGP Executive Board Chair Summary, May 1, 2014

This last statement deserves to be read carefully. The Executive Directors, in approving the PSGP on May 1, 2014, explicitly noted that the project's development impact depended on "a reduction in the high level of technical and commercial losses in the power system." ATC&C losses were running at 35 percent at the time of approval — not the 25.6 percent stated in the privatization agreements. They did not reduce. They remained at between 35 and 50 percent throughout the PSGP implementation period and beyond. The Board knew this was the condition of approval. The condition was never met. No consequence followed.

The Accountability Gap

The three documents above represent the public record of institutional decision-making. They show that the risks were identified — generation capacity lying idle (2009), high distribution losses as a prerequisite for project impact (2014), the high-risk nature of the PSGP (2014) — and that the approvals were granted regardless. The individuals named above were experienced development professionals operating within a system whose incentive structure rewards approvals over outcomes. The argument of this report is not that these individuals acted in bad faith. It is that the institutional architecture they operated within did not require them to confront, as a binding constraint, the evidence that was already in front of them.

Onno Ruhl served as Country Director for Nigeria from approximately 2009 to 2014 — spanning both the NEGIP approval and the PSGP approval. He was the senior Bank official in Nigeria for the entire period during which the Bank was designing the project structure that this report documents as a systemic failure. He was present for NEGIP's struggling implementation. He was present when the Shell and Chevron gas deals collapsed. He signed off on the PSGP PAD that presented a positive narrative about the same sector whose institutional pathology was documented in real time in NEGIP's ISRs. The Board Chair Summary he presented to the Executive Directors on May 1, 2014 did not reference NEGIP. The PSGP PAD did not reference NEGIP.

Makhtar Diop was the Regional Vice President for Africa at the time of PSGP approval. His signature appears on the Statutory Committee Report of April 16, 2014 — the document that formally recommended the PSGP for Board approval. As Regional VP he was the most senior Africa-region officer in the PSGP approval chain. The project went to the Board with his endorsement. The outcomes documented in this report are the outcomes of a project he signed off on.

The Executive Board's own language — "high-risk high-reward," "long-term financial viability," "reduction in technical and commercial losses" — acknowledged the structural preconditions for success. Those preconditions were not met before approval, not conditioned in the project design, and not achieved during implementation. The PSGP was rated Moderately Satisfactory. No Board member has been asked to account for the gap between what they said the project required and what the project delivered.

Is anyone accountable? Is anyone responsible?