Iraq's Electricity Crisis

An analytical study of planning, generation, fuel, grid infrastructure, contracts, and financial sustainability, 2003 to 2026

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Iraq's electricity crisis represents one of the most enduring infrastructure failures since 2003. Despite substantial increases in generation capacity and investment over more than two decades, the sector had not transitioned by 2026 to a model of stable, financially sustainable, and technically reliable power supply. The historical trajectory reveals that explaining the crisis merely as a deficit in generation plants fails to account for its persistence, because increases in nameplate capacity and actual output have been accompanied by widening gaps in fuel supply, transmission, distribution, metering, revenue collection, and the allocation of risk within contracts.

Nameplate capacity reached approximately 35.9 GW in 2021, while peak actual output reached only around 21.1 GW, meaning that roughly 14.8 GW of installed capacity did not translate into available generation at peak demand. In the summer of 2024, declared output reached approximately 27.4 GW, while demand was estimated at 48 GW. In 2026, during periods of fuel shortage, output fell to around 22 GW against an officially estimated need of approximately 60 GW.

The study concludes that the crisis is the product of five interacting gaps, namely the supply-demand gap, the gap between nameplate capacity and available output, the gas and fuel gap, the transmission, distribution, and revenue collection gap, and the gap in the allocation of risk and costs across government, investment, and fuel contracts.

> *The outcome: Iraq did not lack power station construction so much as it lacked an integrated electricity value chain, one that begins at gas in the wellhead and ends at the metered and billed kilowatt-hour reaching the consumer.*

1. **Study Problem and Methodology**

The study seeks to answer a central question, namely why the substantial increases in generation capacity and expenditure since 2003 have failed to resolve the electricity crisis. Addressing this question requires moving beyond assessments organised around the names of individual ministers or governments, because the lifecycle of an electricity project typically spans several phases, including preparation and feasibility study, contracting, construction, and operation, and each phase may fall under a different administration.

Accordingly, the study adopts the project and the system as its units of analysis, tracing the decision chain from planning to operation across eight stages, specifically planning and demand forecasting, contracting, financing, construction, fuel supply, transmission linkage, distribution, operations and maintenance, and finally metering and revenue collection. It also distinguishes carefully between the nameplate capacity of power stations, available capacity, peak actual output, and estimated demand or need.

An important methodological caveat concerns the 2026 figures. The declared need figure of approximately 60 GW is an official estimate of requirement rather than necessarily a measured peak load derived by the same methodology used in certain earlier years. The study therefore employs the figures for directional comparison and causal analysis, without treating the entire time series as a statistically homogeneous dataset.

2. **From 2003 to 2007, Reconstruction and the Onset of Structural Crisis**

Iraq entered 2003 with an electricity system that had endured more than a decade of wars, sanctions, and neglected maintenance and investment. Effective capacity had declined after the war to approximately 3 to 4 GW, while summer demand was considerably higher. The initial post-2003 direction was therefore logical, focusing on restoring existing units and repairing stations and grid networks as rapidly as possible.

Reconstruction programmes set ambitious targets to raise generation to approximately 6,000 MW, yet these targets were not met within their original timelines. By 2006, average peak generation stood at roughly 4.3 GW against demand of approximately 8.2 GW. Demand had risen rapidly, driven by population growth, the opening of markets to air conditioning and household appliances, urban expansion, subsidised tariffs, and weak metering.

It would be inaccurate to claim that transmission and distribution were entirely neglected during this period, since reconstruction programmes did include grid investments. The problem lay rather in insufficient synchronisation between generation, transmission, distribution, and fuel supply. From the earliest years, instances emerged in which transmission bottlenecks or faults on high-voltage lines forced technically available generation capacity offline.

> *The initial flaw was not the decision to pursue rapid repair, but the prolonged persistence of an emergency mentality beyond its appropriate lifespan and the failure to transition early enough to managing the system as a long-term programme.*

3. From 2008 to 2013, the Major Generation Expansion and Gas Turbine Selection

As the supply-demand gap widened, Iraq embarked from 2008 onward on a substantial leap in generation capacity, contracting packages of gas turbines from GE and Siemens with a combined capacity of approximately ten thousand megawatts. The selection of gas turbines was logical on several grounds, including speed of deployment, lower initial capital costs relative to certain alternatives, operational flexibility, the potential for later conversion to combined cycle, and Iraq's possession of substantial gas resources.

The problem, however, lay not in the technology itself but in the manner in which turbine procurement was converted into an integrated power plant. A turbine requires civil works, fuel and cooling systems, transformers, a switching station, transmission lines, control systems, installation contracts, and testing. When equipment purchase contracts are separated from EPC, fuel supply, and grid connection agreements, the probability increases that equipment will stand ready before the rest of the system is in place.

Gas shortages led to a number of turbines being operated on liquid fuels such as crude oil, heavy fuel oil, or gas oil. Although some turbines can technically function on these fuels, doing so raises maintenance costs, reduces efficiency and available capacity, and consumes fuel that could otherwise be exported or put to alternative use.

4. The 2010 Master Plan and the Implementation Gap

The 2010 Electricity Master Plan represents an important milestone in assessing the sector's trajectory, because it was not merely a generation plan but addressed fuel supply, transmission, distribution, and demand forecasting. It stated clearly that the success of new capacity additions was conditional upon the parallel development of gas supply, station-to-grid connections, and transmission networks. It also prioritised the conversion of gas turbines from simple to combined cycle wherever economically justified.

This means that the problem was not invariably an absence of technical knowledge or planning. The fundamental difficulty emerged instead in the asynchronous implementation of the plan's components. In multiple cases, the power station preceded the gas supply, or new capacity outstripped the grid's evacuation capability, or the conversion to combined cycle was delayed, transforming solutions designed as transitional phases into long-term operating conditions.

It is also important to distinguish between nameplate capacity and net summer capacity. A gas turbine loses a portion of its output as ambient air temperature rises, which means that the nameplate rating does not reflect the amount of electricity that can be guaranteed during a July or August afternoon in

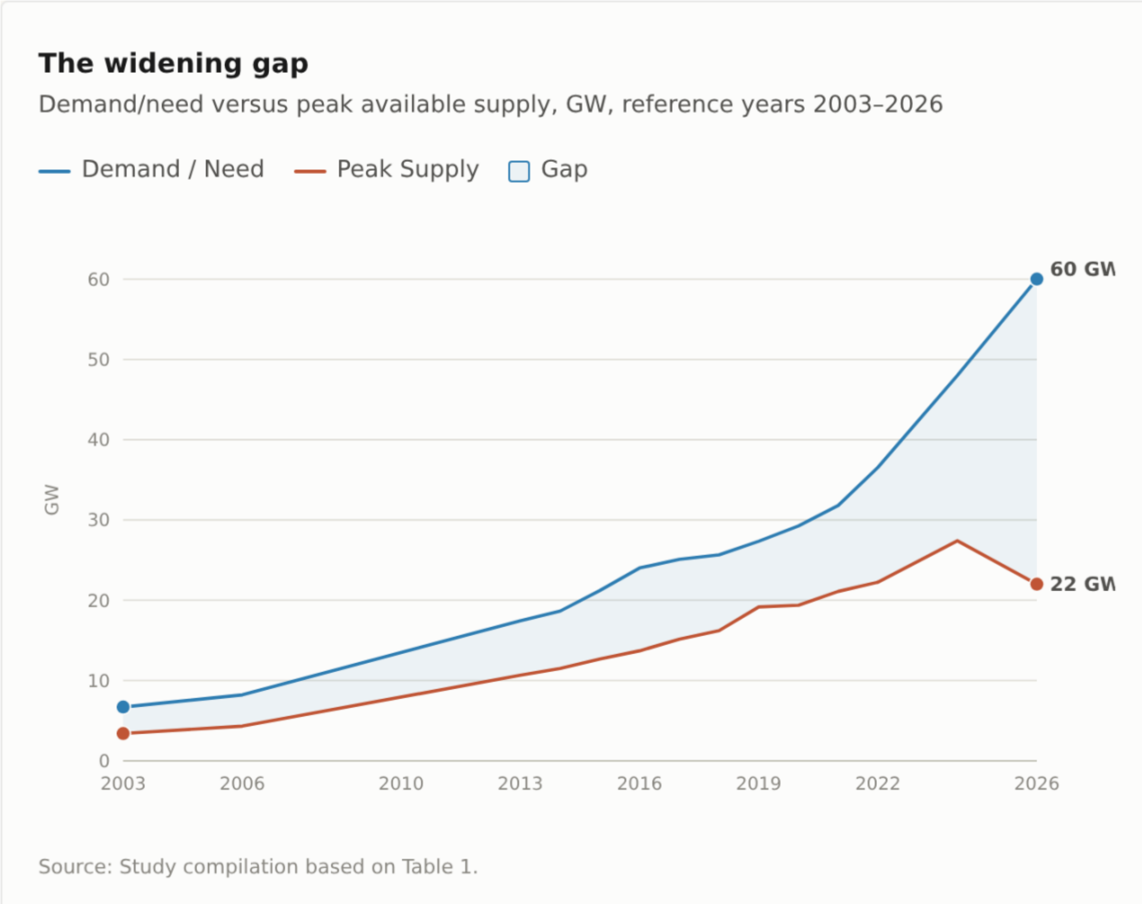
Iraq. The correct planning methodology must rely on net guaranteed capacity under Iraqi summer conditions, not nameplate figures alone.

5. **The Evolution of Supply and Demand, a Quantitative Reading of the Gap**

Table 1. Demand versus peak supply in reference years, 2003 to 2026

YEAR	DEMAND / NEED (GW)	PEAK SUPPLY / OUTPUT (GW)	GAP (GW)
2003*	~6.7	~3.4	~3.3
2006	8.21	4.32	3.89
2013	17.45	10.66	6.80
2014	18.65	11.51	7.15
2015	21.22	12.69	8.54
2016	24.02	13.70	10.32
2017	25.10	15.14	9.96
2018	25.65	16.21	9.44
2019	27.35	19.17	8.18
2020	29.26	19.37	9.90
2021	~31.8	21.1	~10.7
2022	36.56	22.25	14.31
2024	~48	27.4	~20.6
2026**	~60	~22	~38

Reference data compiled from the Ministry of Electricity, JICA, the IMF, and official Iraqi sources.
* 2003 figures are approximate estimates. ** 2026 is an official estimate of need, not necessarily a measured peak load by the same methodology as prior years.



The table and chart demonstrate that generation rose substantially over the period, but demand rose faster. To describe the sector as having failed to add capacity is therefore inaccurate. The more precise characterisation is that capacity additions were insufficient to close the gap, and that a large proportion of nameplate capacity was not in fact available at peak demand.

6. The Impact of the ISIS War, 2014 to 2017

The ISIS war did not create Iraq's electricity crisis, since the crisis predated 2014, but it multiplied its costs and delayed its resolution. Power stations, transmission lines, substations, and distribution networks suffered extensive damage in the affected provinces, forcing the state to rebuild assets on which it had already spent. World Bank studies estimated the damage to the electricity sector in the affected areas at billions of dollars.

These losses coincided with the collapse in oil prices after 2014 and the diversion of a large share of public resources toward security and military operations. Nevertheless, total output continued to rise during part of the war years, confirming that ISIS was a compounding and delaying factor rather than the sole explanation for the crisis's persistence after liberation.

7. **After 2017, Reconstruction and the Rise of Independent Power Producers**

Following the decline of major military operations, rehabilitation and expansion programmes resumed, and the role of independent power producers (IPPs) grew. The IPP model involves private investors financing, constructing, and operating a power station, with the state purchasing electricity under a long-term contract. This model is used globally and can be effective when risks are distributed in a balanced manner.

Some of Iraq's early IPP contracts, however, employed Take-or-Pay structures under which the state committed to minimum payments provided the station was available according to the contract's terms, even if the state could not receive all the electricity due to fuel shortages or grid constraints. Take-or-Pay is not inherently flawed, since it helps secure project financing. The difficulty arises when the state simultaneously bears the fuel supply burden, grid provision, the purchase guarantee, the risk of non-dispatch, and sovereign guarantees.

Under such arrangements, what is termed private investment in some cases more closely resembles private financing with extensive revenue protection, while systemic risks remain with the state. Published oversight reports have disclosed substantial payments for undelivered energy in previous years, attributable to these contractual structures or to the unavailability of fuel and grid connections.

Table 2. Selected major government and investment power projects

PROJECT	MODEL	CAPACITY (MW)	COST / PUBLISHED COMMITMENT	FUEL	ENERGY PURCHASE TARIFF
GE MegaDeal 2008	Govt. equipment/turbines	~7,000	~$3 billion	Gas / multi-fuel	N/A (state-owned asset)
Siemens MegaDeal	Govt. turbines & components	~3,150	~€1.5 billion	Gas / liquid fuel	N/A
Wasit Thermal	Govt. steam	2,540	Phased, multiple large contracts	Liquid / gas	N/A
Bismayah (initial phases)	IPP, combined cycle	3,000	~$3 billion	Gas (state-supplied)	$32–47/MWh
Bismayah (expansion)	IPP	+1,500 (planned)	n.a.	Gas	n.a.
Rumaila Investment	IPP, combined cycle	~3,000	$2.5 billion	Gas	$32–47/MWh
Amara Combined	IPP, CCGT	750	~$500 million (per developer)	Gas	Long-term PPA
Silver Crescent / Muthanna	IPP	250 (referenced phase)	n.a.	Gas / HFO	$24.94/MWh (gas); $32.37 (HFO); $36.81 (combined cycle)

Amounts are not directly comparable unless scope of work is equivalent. Some equipment contracts do not include full EPC, grid, or fuel.

8. **Iranian Gas, from Transitional Solution to High-Risk Strategic Dependency**

The import of Iranian gas to feed Iraqi power stations began effectively in 2017, following the signing of framework agreements in earlier years. The import was originally a logical solution to bridge the fuel gap quickly. The problem emerged, however, when this source became an essential component of operating thousands of megawatts without a ready domestic alternative of equivalent scale.

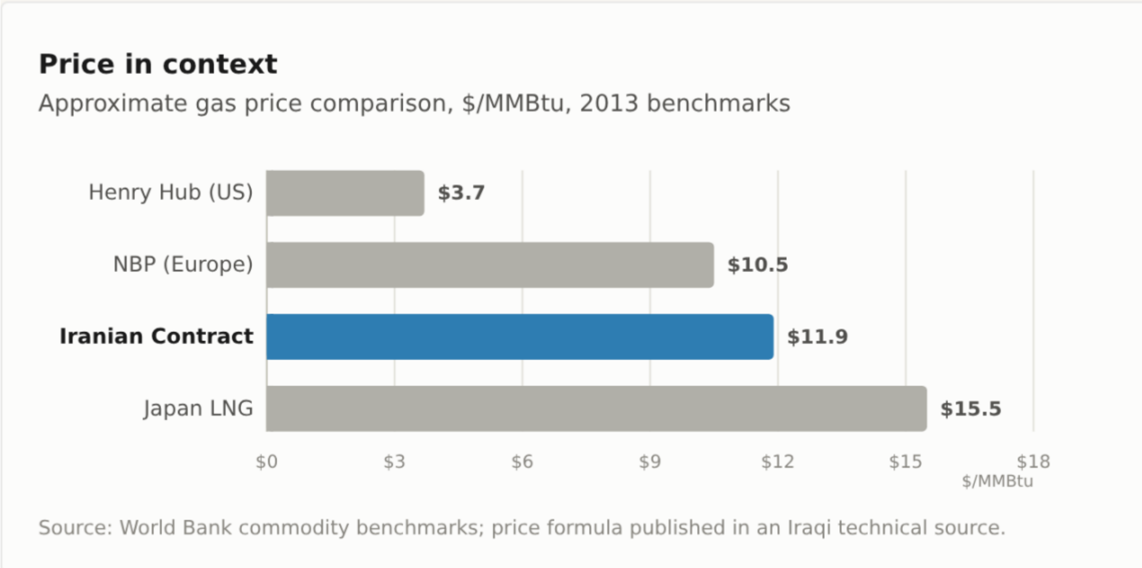
In 2024, Iraq renewed the supply contract for five years, with contractual volumes reaching approximately 50 million cubic metres per day. The Ministry of Electricity announced that the contract included a commitment to supply stability during peak periods. It would therefore be inaccurate to say the contract contained no stability clause. The more precise observation is that the practical outcome demonstrated the insufficiency of the enforcement mechanisms, guarantees, and fallback options in preventing the effects of reductions and interruptions.

A strategic gas contract should be assessed not by price alone, but also by minimum firm quantity commitments, penalties for non-delivery, compensation for lost electricity output, performance guarantees, precise definitions of force majeure, arbitration mechanisms, and contingency provisions in the event of supply interruption. Where investment power stations depend on state-supplied gas, the risks embedded in the fuel contract transfer directly into the power purchase agreement.

The Iranian Gas Price at the Time of the Original Agreement

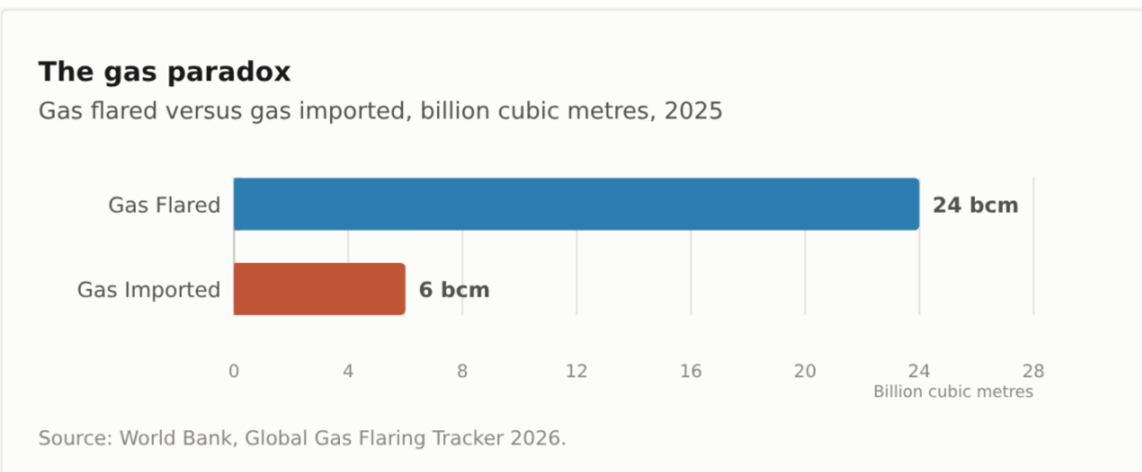
According to a price formula published in a specialised technical source, the Iranian gas price was linked approximately to the Brent crude price. Using the 2013 average Brent price, the formula yields a price of approximately $11.9 per million British thermal units. When compared against 2013 benchmarks, this figure was close to the European price, more than three times the American Henry Hub price, and below the Japanese LNG price.

The characterisation of the price as “four times the global price” is therefore imprecise, since no single global gas price exists. The more pertinent economic question, however, is why Iraq, as a pipeline importer from a neighbouring country under a long-term contract, did not secure a larger discount relative to distant gas market prices, and why the formula was so heavily linked to oil, thereby transferring the risk of rising Brent prices directly into the cost of electricity.



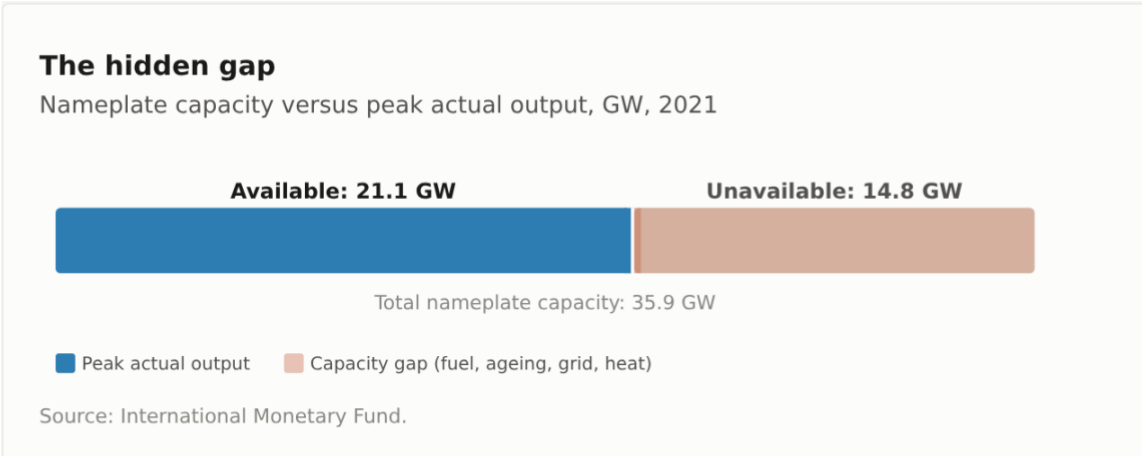
Iraq’s Gas Paradox

World Bank data for 2025 indicate that Iraq flared approximately 24 billion cubic metres of gas, while importing roughly 6 billion cubic metres. This does not mean that all flared gas could be immediately converted to power station fuel, since it requires gathering, processing, compression, liquids separation, and pipeline construction. The comparison does, however, establish that the core of the problem is not an absence of the natural resource, but a delay in building the infrastructure needed to convert it into usable fuel.



9. Nameplate Capacity Versus Actual Output, the Hidden Gap

Iraq’s nameplate capacity stood at approximately 35.9 GW in 2021, while peak actual output reached roughly 21.1 GW. This means that approximately 14.8 GW of nameplate capacity was unavailable at peak demand, owing to a combination of factors including fuel shortages, equipment ageing, deferred maintenance, high ambient temperatures, operation on suboptimal fuel, and grid bottlenecks.



> *Before contracting for new capacity, a financial question must precede the decision, specifically how many megawatts of existing capacity can be restored at a cost lower than building a new megawatt.*

To this end, the study proposes establishing a national registry for every generation unit, specifying its nameplate capacity, available capacity, lost capacity, the cause of the loss, remaining useful life, restoration cost, and required fuel. The state would then compare the cost per restored megawatt against the cost per new megawatt before making investment decisions.

10. **Transmission, Distribution, Losses, and Revenue Collection**

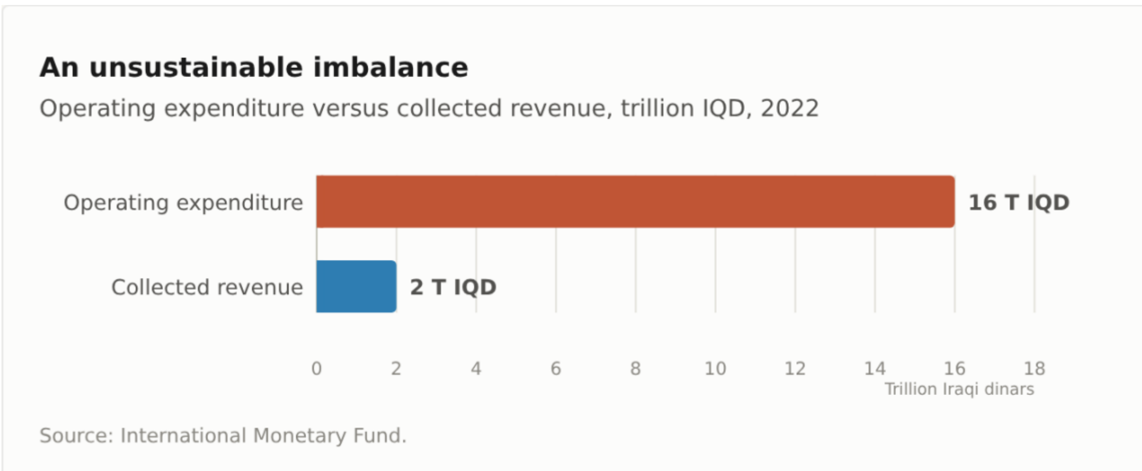
A new power station has no complete economic value if the grid cannot evacuate its output or if a high proportion of electricity is lost before reaching the consumer. It is necessary to correct the notion that investment in transmission and distribution was entirely absent, since investments were made. The difficulty was that the chronological and financial balance between these investments and generation additions was not always sufficient.

Distribution losses reached approximately 55 per cent according to IMF estimates in 2024. This figure does not mean that 55 per cent of electricity is lost as heat. It encompasses technical losses and commercial losses related to unauthorised connections, theft, unmetered consumption, and weak billing and collection. Reducing these losses therefore yields three simultaneous benefits, namely recovering a portion of energy through technical improvements, curbing economically irrational consumption, and raising revenue.

Every new generation project must accordingly be linked from the day of its approval to a Generation Evacuation Plan, ensuring that no new capacity enters the pipeline unless the transmission lines and substations required to carry its output are funded and scheduled for commissioning on the same timeline.

11. **The Financial Economics of the Sector**

The electricity crisis cannot be separated from its financial model. Operating expenditure in 2022 reached approximately 16 trillion Iraqi dinars, while collected revenue amounted to roughly 2 trillion dinars, according to IMF data. This gap renders the sector structurally dependent on public funding and undermines its capacity to finance maintenance and modernisation from its own revenues.



Financial reform does not mean immediately raising tariffs on consumers before improving service and metering. The sequence most likely to prove socially sustainable is as follows. First, install reliable meters. Then improve supply. Then reduce unauthorised connections. Then raise billing and collection rates. Only then transition gradually to tariffs more closely linked to cost, while maintaining protection for the basic consumption tier of low-income households.

12. **Economic Comparison, the True Cost per Megawatt-Hour**

An investment power station cannot be assessed solely by its electricity purchase tariff if the state provides the gas. The true cost to the treasury comprises the investor's tariff, the value of fuel, fuel transportation, payments for non-dispatched energy, guarantees and risk allocation, and then grid costs and losses. The following comparison presents approximate scenarios rather than an accounting audit of contracts that are not fully published.

Table 3. Approximate scenarios for the true cost per MWh before grid and losses				
MODEL	TARIFF / NON-FUEL COST ($/MWH)	GAS PRICE ($/MMBTU)	FUEL COST ($/MWH)	APPROXIMATE TOTAL ($/MWH)
IPP combined cycle, tariff only	32–37	n.a.	n.a.	32–37
IPP combined + Iranian gas at $7.15/MMBtu	32–37	7.15	~47.4	~79–84
IPP combined + Iraqi processed gas at $2/MMBtu	32–37	2.00	~13.3	~45–50
Silver Crescent, simple cycle + local gas at $2	24.94	2.00	~20.9	~46
Silver Crescent, combined cycle + local gas at $2	36.81	2.00	~13.3	~50
Silver Crescent, combined cycle + imported gas at $8	36.81	8.00	~53.1	~90

Analytical calculations using approximate heat rates for combined cycle and simple cycle configurations. Figures are not a substitute for auditing actual contracts and operating data.

The comparison reveals that fuel economics may be more consequential than the investor's tariff itself. The same plant can produce electricity at approximately $45 to $50 per MWh when using low-cost domestic gas, while approaching $80 to $90 per MWh when using expensive imported gas. Investment in gathering and processing domestic gas is therefore not merely a petroleum or environmental project, but a direct component of electricity sector reform.

13. An Integrated Causal Diagnosis of the Crisis

The historical trajectory can be summarised as eight overlapping and mutually reinforcing dysfunctions. None operates in isolation; each amplifies the effects of the others.

A dysfunction in problem definition, treating the crisis as a megawatt deficit rather than as a failure of the integrated system. **A dysfunction in investment sequencing,** whereby in certain phases equipment procurement preceded the completion of EPC works, fuel supply, and grid connection. **A dysfunction in gas strategy,** as gas-fired capacity expanded faster than the development of domestic gas gathering, processing, and transport. **A dysfunction in efficiency,** with units continuing to operate in simple cycle mode or on suboptimal fuel for periods well beyond their intended transitional phase. **A dysfunction in the balance between generation and grid infrastructure,** as transmission, distribution, and metering capacity did not always develop at the same pace as generation additions. **A dysfunction in certain investment contracts,** loading the state with a large share of fuel, grid, and non-dispatch risks alongside extensive revenue guarantees. **A dysfunction in external dependency,** as imported gas became a strategic element without an equivalent ready alternative upon disruption. **A dysfunction in the financial model,** with high operating costs set against limited collection and substantial technical and commercial losses.

> *The recurring pattern was as follows. A new station was built, followed by a fuel or grid shortfall, leading to output below potential, compounded by losses and weak revenue collection, against a backdrop of rising demand, producing a new gap, prompting a contract for additional capacity, and beginning the cycle again.*

14. A Proposed Reform Framework, 2026 to 2035

14.1 Shifting from "Increase Capacity" to "Reduce the Cost of Delivered Electricity"

The sector's top-level policy indicator should transition from the number of megawatts added to the cost of the net kilowatt-hour that reaches the consumer with acceptable quality and reliability. This requires evaluating every project according to its net summer capacity, fuel cost, conversion efficiency, the grid's ability to evacuate its output, and the full lifecycle operating cost.

14.2 Restoring Existing Capacity Before Building New

All unavailable capacity should be classified by cause, whether fuel, maintenance, cooling, ageing, grid constraints, or economic non-viability. Rehabilitation programmes should then be ranked by a cost-per-restored-megawatt index and compared against the cost per new megawatt.

14.3 Gas Before the Station

No new gas-fired station should be approved without a binding fuel supply agreement, a funded gas pipeline, and a commissioning schedule that precedes the station's entry into service. High priority should be given to projects that capture flared gas and connect it to load centres and high-efficiency stations.

14.4 Combined Cycle Conversion on Economic Merit

A national programme should assess every simple-cycle turbine with respect to remaining useful life, fuel type, cost, and the additional capacity obtainable through conversion. Conversion should not be a blanket policy but an economic decision that selects the highest return on each invested dollar.

14.5 Reforming the IPP Model and Contracts

New contracts should be based on competition and transparency in tariff setting, efficiency and availability guarantees, and a measurable distribution of fuel, grid, force majeure, and dispatch risks. Neither Take-or-Pay nor Take-and-Pay should be applied as a doctrinal default; the model chosen should be the one that achieves the lowest financing cost without excessively transferring risk to the treasury.

14.6 Redesigning Imported Gas Contracts

Any strategic gas contract should include firm quantity commitments, seasonal scheduling, penalties and compensation for delivery shortfalls, performance guarantees, a clear arbitration mechanism, and a pricing formula that reduces unnecessary linkage to oil. Most importantly, imported gas should serve as a transitional reserve or a diversified source rather than a single point of failure in electricity security.

14.7 **Transmission, Distribution, and Smart Meters**

Every generation project should be linked to a funded evacuation plan. Bottlenecks on the 400 kV and 132 kV systems should be addressed urgently, distribution networks rehabilitated, and smart meters deployed alongside geographically measurable supply zones. Tariff adjustment should follow improvements in metering and service, with clear protection for the basic consumption tier.

14.8 **New Performance Indicators**

The sector should adopt net summer available capacity rather than nameplate capacity alone, Plant Availability Factor and forced outage rate, heat rate and fuel cost per MWh, separated technical and commercial transmission and distribution losses, billing and collection rates, SAIDI and SAIFI for measuring the duration and frequency of interruptions, and the cost of delivered kWh as the measure of true cost at the consumer end.

15. **Conclusion**

The trajectory from 2003 to 2026 does not demonstrate that Iraq failed to invest or to add capacity. Generation output rose several-fold, large stations entered service, transmission lines and substations were built, the private sector participated, and gas and combined-cycle programmes commenced. These efforts, however, did not historically operate within a single synchronised tempo, and the result was a persistent gap between what Iraq possessed in nameplate terms and what it could actually generate, transmit, and sell.

Iraq's electricity crisis is, at its core, a crisis of value chain management. A turbine requires fuel, fuel requires processing and a pipeline, a station requires a grid, the grid requires distribution and a meter, and the meter requires revenue collection. Revenue collection, in turn, requires a standard of service that is socially defensible. If any link in this chain fails, investment in the remaining links does not yield its full value.

> *The required shift in public policy is a transition from the question "how many stations shall we build?" to the question "what will guaranteed net electricity at the meter cost us, and what is the least expensive and most reliable means of obtaining it?"*

References and Principal Data Sources

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Note on Figures

The data were compiled from multiple published sources, some representing nameplate capacity, others available capacity, peak output, or estimated need. The study has indicated cases where comparison is not fully homogeneous. Contract cost scenarios and gas price assumptions are analytical estimates and are not a substitute for access to original contracts and actual operating data.