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Overview of the Power Sector in Ghana

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Abstract

Aware of the crucial role electrification plays in sustaining economic growth and accelerating social development, Ghana was one of the first nations in sub-Saharan Africa (SSA) to implement, back in 1989, a national plan to universalize electricity access. This vision has led the country to hold one of the highest electrification rates in the region today, with 84% of the population connected to the grid. In addition, the country was able to attract independent power producers (IPPs) to meet its growing demand and now has an impressive generation park with more than 5,000 MW installed capacity.

However, the sector still faces many challenges. The power supply has been unreliable due to shortages of natural gas supply, and the thermal power plants had to turn to expensive liquid fuels. There is an excess of thermal installed capacity, which increased the capacity charges. The grid suffers from high commercial and technical losses. All these factors contribute to increasing the power system costs, which combined with a high incidence of unpaid electricity bills created a chronic financial deficit. The potential of renewable energies (other than hydro) remains locked, and almost 4.5 million people, living mostly in Ghana's rural areas, still lack access to electricity.

This report provides an overview of the power sector in Ghana, focusing on understanding the underlying reasons for the current challenges throughout the value chain and the direction in which the sector is moving to resolve them, and finally exploring potential solutions to some of the issues identified.

Keywords: Power; Ghana; Energy; Energy poverty; Electricity access; Off-grid solutions.

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1. Introduction

Aware of the crucial role electrification plays in sustaining economic growth and accelerating social development, Ghana was one of the first nations in sub-Saharan Africa (SSA) to implement, back in 1989, a national plan to universalize electricity access. This vision has led the country to hold one of the highest electrification rates in the region today, with 84% of the population connected to the grid. In addition, the country was able to attract independent power producers (IPPs) to meet its growing demand and now has an impressive generation park with more than 5,000 MW installed capacity.

However, the sector still faces many challenges. The power supply has been unreliable due to shortages of natural gas supply, and the thermal power plants had to turn to expensive liquid fuels. There is an excess of thermal installed capacity, which increased the capacity charges. The grid suffers from high commercial and technical losses. All these factors contribute to increasing the power system costs, which combined with a high incidence of unpaid electricity bills created a chronic financial deficit in the sector. The potential of renewable energies (other than hydro) remains locked, and almost 4.5 million people, living mostly in Ghana's rural areas, still lack access to electricity.

At IESE Fuel Freedom Chair for Energy and Social Development we believe that both the private and public sector should play an important role in addressing these challenges and creating, together, a future with affordable, reliable and cleaner energy solutions, accessible to all.

To this end, it is fundamental that entrepreneurs, executives, the public sector and investors gain a comprehensive understanding of the sector, developing a critical view of its challenges and opportunities. This report provides an overview of the power sector in Ghana, focusing on understanding the underlying reasons for the current challenges throughout the value chain and the direction in which the sector is moving to resolve them.

Our analysis is based on a literature review and field interviews with stakeholders.

In addition to this document, we provide a report with complementary information on the potential of the Pay-As-You-Go (PAYG) business model to serve the part of the rural population that has no electricity access.

We hope these documents can provide useful information to Ghanaian entrepreneurs, executives, leaders and other interested parties in order to boost their participation in finding the solutions the sector needs.

2. Power Sector Structure

In Ghana, until recently, exclusively state-owned companies operated through the power system value chain, in a sort of vertically integrated monopoly. Although the sector was reformed and unbundled in the late 1990s, it was only in 2010 that the first IPP, Sunon-Asogli, joined the sector, starting the commercial operations of a new thermal power plant. Since then, several private power

producers have followed. At the beginning of 2019, Power Distribution Services Ghana (PDS),[1] a private consortium, was granted a concession to operate the southern distribution network system, until then operated by the state-owned utility Electricity Company of Ghana (ECG).

Under the current unbundled structure, the main actors in each link of the value chain are:

- Power production: carried by Volta River Authority (VRA) and Bui Power Authority (state-owned companies), as well as by several IPPs.
- Transmission: run by GRIDCO, a state-owned company that is also the system operator and market administrator.
- Distribution: Two main utilities are in charge—the state-owned Northern Electricity Distribution Company (NEDCo, a subsidiary of VRA), operating in the north; and PDS, serving the southern regions. Also, since 2009, Enclave Power (a small, private distributor) has supplied electricity to around 50 industries located in an industrial park. These three companies are in charge of both network activities (grid expansion, maintenance and connections) and commercial operations, such as metering, billing and revenue collection.

The retail market is composed of both regulated and deregulated markets. In the regulated market, distribution companies supply electricity to consumers at regulated tariffs determined by the Public Utility Regulatory Commission (PURC), and in the deregulated market, bulk consumers can procure electricity directly from power producers, at prices negotiated bilaterally.

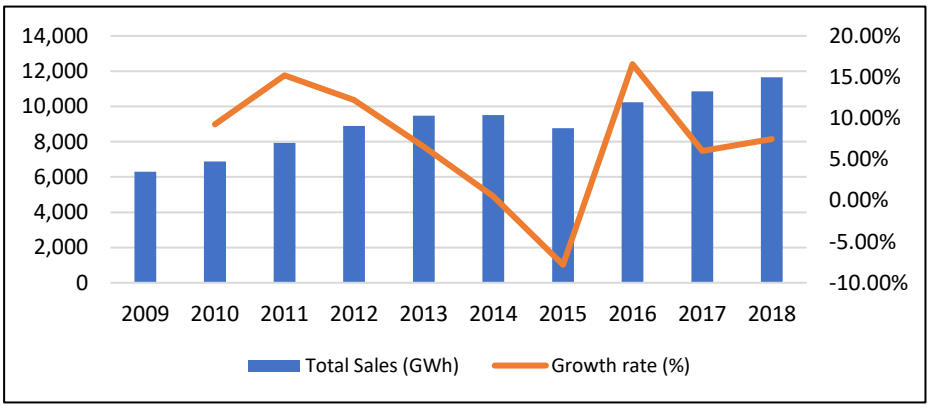
The sector also encompasses several important institutional stakeholders, such as policy makers and regulatory agencies (at national and regional levels), consumer associations and advocacy groups, as shown in Exhibit 1.

3. Electricity Consumption

Over the last 10 years consumption has almost doubled; however, it has not risen at a constant rate. As indicated in Figure 1, the annual growth rate has fluctuated between an 18% growth and a 10% decline. Electricity consumption grew steadily until 2013, with a strong deceleration in 2014 and a decrease in 2015 due to a severe power crisis that limited the supply of electricity. The crisis was known locally as *Dumsor* (meaning "on and off"), as the country was immersed in a period of load shedding, which left a profound impact on the country (see Section 6 for more information).

[1] PDS is a consortium led by Meralco, a Philippine distribution company, with the participation of three Ghanaian companies (TG Energy Solutions Ghana, Santa Power and GTS Power) and AEnergia S.A. of Angola (Power Distribution Services Ghana 2019).

Figure 1
Electricity Sales (GWh) and Annual Growth (%), 2009–2018



Note: Data do not include the technical and commercial losses.

Source: Prepared by the authors based on data from the Energy Commission (*National Energy Statistics*, 2018).

Since then, consumption levels have been recovering at a 9.92% compound annual growth rate (CAGR)—in the period 2015-2018—driven by the residential sector. Indeed, as illustrated in Table 1, while residential electricity consumption grew at an average of 25.58% per year between 2015 and 2018, the non-residential segment registered an annual decrease in electricity consumption of 10.35%. In the same period, both sectors registered an increase in the number of consumers of 2.89% CAGR (residential) and 1.16% CAGR (industrial).

Table 1
Consumption (GWh) and CAGR (%) by Sector, 2009–2018

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	CAGR 2009–2018	CAGR 2015–2018
Residential	2,275	2,483	2,527	2,819	3,060	2,772	2,436	3,932	3,931	4,824	8.71%	25.58%
Non-residential	924	966	1,199	1,549	1,532	1,529	1,531	1,068	1,356	1,103	1.99%	-10.35%
Special load tariff	2,951	3,174	3,901	4,153	4,435	4,680	4,274	4,626	4,880	5,046	6.14%	5.69%
Street lighting	144	254	296	370	445	540	536	603	679	683	18.88%	8.41%
Total	**6,294**	**6,877**	**7,923**	**8,891**	**9,471**	**9,520**	**8,776**	**10,230**	**10,847**	**11,656**	**7.09%**	**9.92%**

Note: Special load tariffs are mainly applied to industries or big consumers with minimum levels of demand or connected at medium or high voltages. For more information about tariff structure consult: Public Utilities Regulatory Commission, "Electricity Rate Setting Guidelines." December 1999.

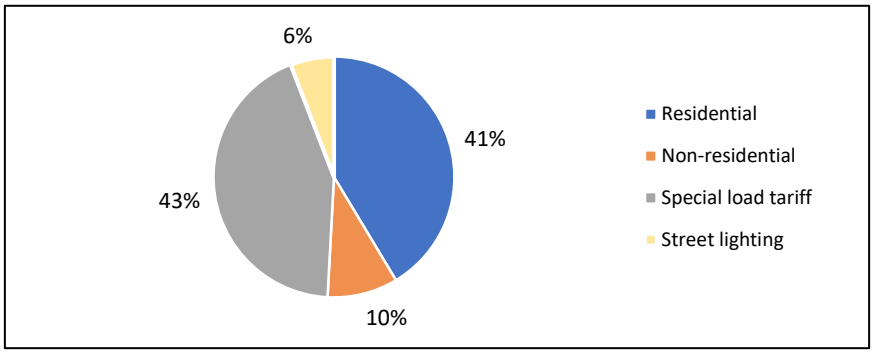
Source: Prepared by the authors based on data from the Energy Commission (*National Energy Statistics,* 2018).

Consumption decrease in the non-residential sector is, in great part, explained by the application of high electricity tariffs for businesses and industries, which reportedly have been cross-subsidizing the residential sector. This situation incentivized this category of consumers to install captive diesel backup generators, which also enabled them to take advantage of a post-crisis period of low oil/diesel prices. As reported by the Energy Commission of Ghana (2018), in 2017 "the industries found the use of embedded generation, mostly diesel, to be less expensive in some periods of their operations, particularly, when their consumption exceeds 300 units during each month." Indeed, the average electricity cost of backup generation for non-residential customers

in 2017 could be up to 28% cheaper than the tariff for consumptions above 300 kWh/month.[2] As a result, in 2017, the embedded backup generator accounted for 3,600 GWh, a significant 21% of the total electricity produced in the country. This is equivalent to the generation of approximately 500 MW for a combined cycle of a thermal power plant.

Currently, the industrial and residential sectors are the main consumers, as shown in Figure 2.

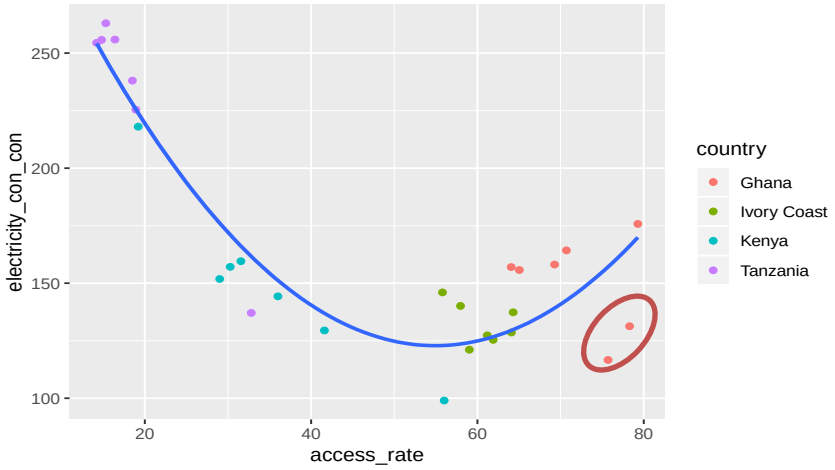
Figure 2
Electricity sales by tariff category (%), 2018



Source: Prepared by the authors based on data from the Energy Commission (*National Energy Statistics*, 2018).

Electricity consumption per capita in Ghana in 2018 was approximately 0.39 MWh, still below the world average of 2.81 MWh in 2016 (International Energy Agency 2016). In Figure 3 we compare the evolution of the average residential electricity consumption per capita—for the part of the population with electricity access—in four countries.

Figure 3
Residential Electricity Consumption Per Capita (for the Population with Electricity Access) and Access Rate in Selected Countries, 2010–2016



Source: Prepared by the authors using data from the World Bank and the International Energy Agency (IEA). Note: The red circle indicates years 2014/2015 in Ghana, where consumption decreased significantly due to load shedding.

[2] Calculation by the authors based on data from Table 3 from the Energy Commission (*Energy Outlook*, 2018).

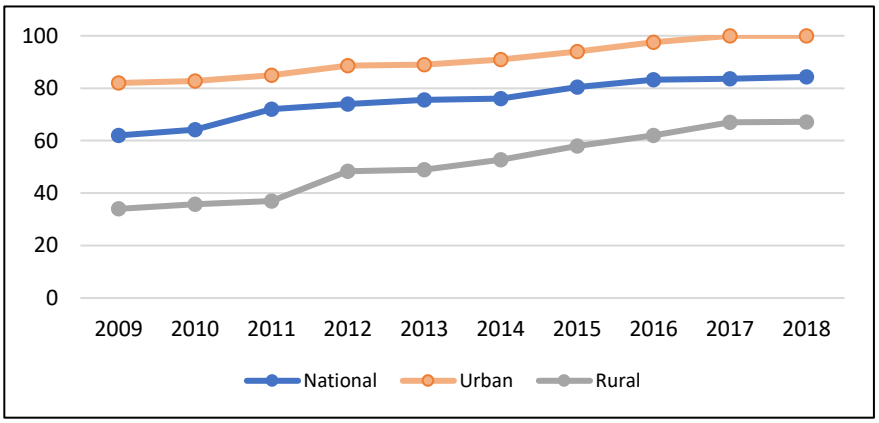
Although these results cannot be extrapolated to other countries, they show that, for this data set:

- Contrary to general perception, as the access rate increases, the consumption per capita of the households connected seems to decrease—at least up to a certain level of access rate, at which point the consumption per capita grows again. This could be explained by the fact that, usually, the population with higher purchasing power is connected first and that as the grid is extended to the more remote—and frequently poorer areas—the consumption per capita tends to decrease.
- In the case of Ghana, there is an upward trend in electricity consumption that was interrupted by the 2014/2015 power crisis/load shedding (see the circle marked in red in Figure 3).

4. Access Rate

Ghana was one of the first nations in SSA to implement, back in 1989, a national plan to universalize electricity access. This vision has led the country to hold one of the highest electrification rates in the region today, with 84.3% of the population connected to the grid. Figure 4 illustrates the evolution of access in the past 10 years:

Figure 4
Electricity Access Rate, 2019–2018



Source: The Energy Commission (*National Energy Statistics*, 2018).

This achievement is the result of a long-term vision, guided by the National Electrification Scheme (NES) initiated in 1989 and implemented through specific measures and projects, such as the National Electrification Master Plan 1990–1920, with the support of several international funding agencies and donors. The target is to achieve universal access by 2020.

Under the NES framework, one of the successful measures has been the Self-Help Electrification Programme (*SHEP*), under which the communities seeking to beconnected to the grid, previously specified by NES, should provide part of the material and logistics needed, such as low-voltage electricity poles. In addition, they should ensure that at least 30% of households in the community are wired and willing to get a connection (Ministry of Energy 2010; Kumi 2017).

Another measure is to grant connections free of access charges (no fee applied) for the households that request a connection as soon as the grid is installed and commissioned in their community. Thus, households have a strong incentive to connect to the grid immediately.

One of the remaining problems in terms of electricity access is the gap between urban and rural rates, as illustrated in Figure 2 above. In rural areas, 33% of the population is yet to be connected, representing approximately 4.6 million people.

Based on the 2018 access rate, in Table 2 we estimate the population, houses and households not connected to an electricity source—all of them in rural areas.

Table 2
Population, Houses and Dwelling Units Without Electricity Access, 2018

	Population w/o access (1)	Houses w/ o access (2)	Households w/o access (Dwelling units) (3)
Without access (A)		640,198	1,062,146
Without access with estimated lower occupancy (B)	4,673,442	756,220	1,217,042

Source: Prepared by the authors based on the following data and assumptions:

- Population without access = 29,767,148 (total population 2018) x 16% (where 16% = 100 - 84% access rate)
- Houses without access = population without access/average population per house (7.3 in [i] and 6.18 in [ii])
- Households without access = population without access/average household size (4.4 in [i] and 3.84 in [ii])
  - (i) We took the average population per house of 7.3 and average household size of 4.4 from the 2010 census (Ghana Statistical Service 2012)
  - (ii) We estimated an updated average population per house of 6.18 and an average household size of 3.84 for 2018, based on the proportional reduction observed in the period 2000–2010.

It is important to remark that, according to the 2010 census (Ghana Statistical Service 2012), 51.5% of the households live in rooms of compound houses, sharing facilities (which could be a bathroom, kitchen and/or social areas) with other individuals or families. Just 40.5% inhabit separate/detached houses or flats/apartments. The remaining 8% live in improvised accommodation, tents or huts. Therefore, the number of households (and dwelling units) is higher than the number of houses.

One of the challenges to electrify the remaining rural areas is the high cost of extending the main grid to remote localities. As the government looks for cost-efficient solutions, it is expected that a significant part of these areas will be electrified through off-grid solutions, such as mini-grids (see Section 12, Off-grid Solutions, for more information).

5. Power Production and Capacity

Ghana relies on two main technologies to produce electricity: thermal and hydropower plants, accounting for 63% and 37%, respectively, of the total generation (2018). Renewables production (at utility scale) accounted for 0.2% in 2018 (see Table 3). The whole portfolio of power plants, with installed capacity, fuels and owner, can be consulted in Exhibit 2.

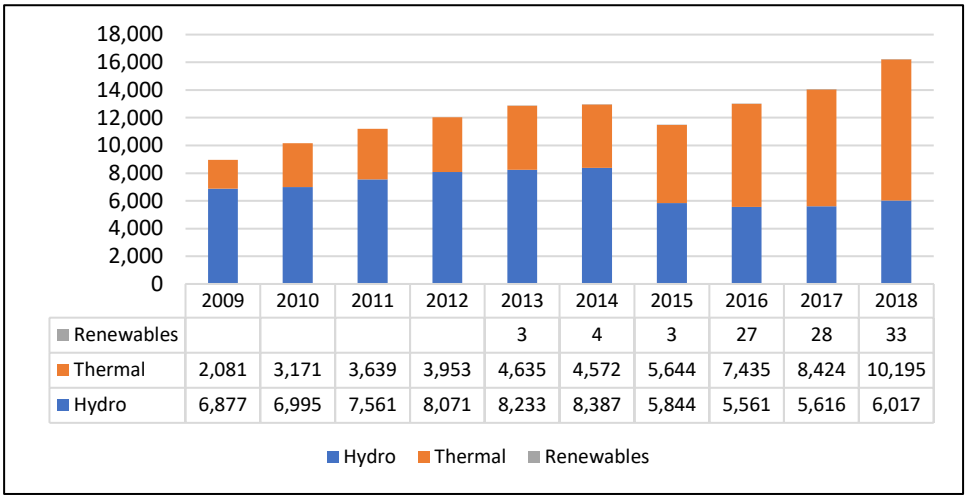
Table 3
Installed Capacity and Electricity Production by Sources, December 2018

	Connection	Source	Installed capacity MW	Installed capacity %	Electricity production GWh	Electricity production %
Traditional sources	Grid: transmission level	Hydro	1,580	32%	6,017	37%
		Thermal	3,200	66%	9,803	63%
		Thermal	66		392	
Modern renewables	Grid: sub-transmission level	Utility solar	42.50	1.5%	33	0.20%
		Waste	0.10		0.32	0.00%
	Grid: distribution level (embedded)	Distributed solar PV	17.13		N/A	N/A
		Small hydro	4.00			
	Mini-grid	Solar	0.31			
		Wind	0.01			
	Off-grid	Solar	7.27			
		Wind	0.01			
		Net imports			247.00	2%
		TOTAL	**4,917**		**16,245**	

Source: Prepared by the authors based on data from the Energy Commission (*National Energy Statistics*, 2018).

As shown in Figure 5, the share of thermal and hydro sources in the electricity mix has changed drastically over the past 10 years. In 2009, thermal accounted for 23% of production and hydro for 77%. In 2018, the shares were 63% thermal and 37% hydro.

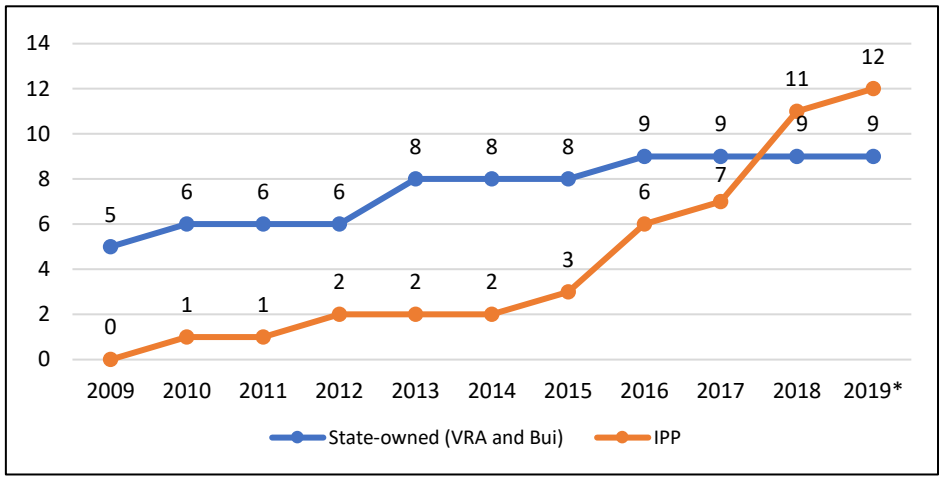
Figure 5
Generation Per Sources (GWh), 2009–2018



Source: Prepared by the authors based on data from the Energy Commission (*National Energy Statistcis,* 2018).

This was the result of the rapid introduction of several new thermal plants by IPPs, the decision to reduce the overreliance on hydroelectric sources and the intention to harness the indigenous and Nigerian natural gas resources. The number of IPPs increased, especially from 2015, as a response to the 2014–2015 power crisis (see Figure 6 below). Indeed, in 2009 VRA was the only producer, while in 2018 the private IPPs held 46% of the installed capacity and accounted for 41% of the production.

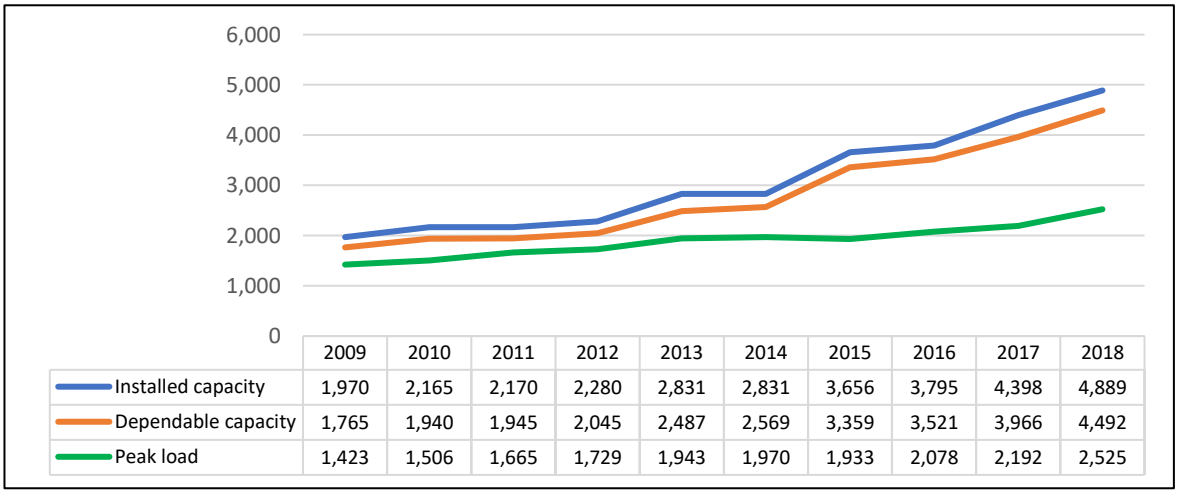
Figure 6
Number of Power Plants in Operation, by Ownership (State-Owned or IPPs), 2009–2019



Source: Prepared by the authors.

The production (Figure 5) and the peak load (Figure 7, below) increased at similar paces in the period 2009–2018—at 6.84% and 6.6% CAGR, respectively. The installed capacity, however, increased from 1970 MW in 2009 to 4889 MW in 2018, representing a CAGR of 10.6%. In Figure 7, we see how the gap between the installed capacity and the system peak load (peak demand) has been increasing over the past few years, especially from 2015, after the power crisis.

Figure 7
Evolution of Installed Capacity, Dependable Capacity and Peak Load, 2009–2018



	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Installed capacity	1,970	2,165	2,170	2,280	2,831	2,831	3,656	3,795	4,398	4,889
Dependable capacity	1,765	1,940	1,945	2,045	2,487	2,569	3,359	3,521	3,966	4,492
Peak load	1,423	1,506	1,665	1,729	1,943	1,970	1,933	2,078	2,192	2,525

Note: Dependable capacity is usually defined as the maximum power that a power plant is able to supply under specific conditions for a given period, without exceeding approved technical parameters, such as temperature and stress.

Source: The Energy Commission (*National Energy Statistics*, 2018).

The reserve margin in 2018 (the difference between dependable capacity and peak load) sat at 1,967 MW, while the required margin for reliability of supply would have been just 454 MW (equivalent to 18% of the peak load). Therefore, there was an excess installed capacity of around 1500 MW (at the end of 2018).

Considering the generation projects already committed to—which will be commissioned in the upcoming years—and the projected demand, the overcapacity is likely to remain until 2023. Indeed, during the 2019 to 2023 period, capacity reserves will hold between 39% and 28%, still significantly higher than the minimum 18% required (Republic of Ghana 2019).

Overcapacity is the result of the lack of coordinated and central planning to procure new capacity, especially during the crisis periods. As explained in the Integrated Power System Master Plan for Ghana (USAID, Republic of Ghana, Energy Commission, ICF 2018), "procuring or renting such 'emergency power plants' over short rental periods tends to result in high end-user tariffs, and in an attempt to mitigate the cost of the emergency plants, they were contracted on a long-term basis—thus spreading the costs over a longer period. There was, however, no assessment of the impact of the extension of these emergency procurements on the longer-term supply-demand balance, bearing in mind that other long-term power projects were being negotiated at the same time."

This situation is contributing to the financial deficit of the sector, as the power plants are being paid not just for electricity produced, but also for the capacity available. Capacity charges are paid by utilities to IPPs, whether or not the plants are dispatched, and they have been reported to be around $24 million per month.[3]

To minimize the situation of overcapacity, the government recently entered a process of reviewing and renegotiation more than 20 power purchase agreements (PPAs), signed with thermal IPPs, that were meant to become operational in the upcoming years. The process included the termination or postponement of commencement dates.

6. Power Crisis: 2012–2016

Understanding the causes and consequences of the 2012–2016 power crisis, including the 2014/2015 electricity shortfall, is fundamental in order to comprehend some of the key challenges that the sector is currently facing and the measures that the government is putting in place. Below, we summarize the events that marked this turbulent period:

- Several power crises preceded the last one. The causes were usually a combination of severe droughts (compromising the hydro reservoirs) and the lack of timely investment to increase capacity and diversify sources, mainly due to the inability to raise the funds to invest in a sector that was already indebted.

[3] Capacity charges are a common retribution mechanism in PPAs, especially for thermal plants. They are designed, in principle, to guarantee a fair return on investment and/or, similar to a take-or-pay clause, protect the IPP in the case that the offtake of electricity is lower than anticipated. In the case of Ghana, however, the charges for idle capacity reached a significant amount due to the overcapacity situation. The authors did not find official information about how capacity charges were negotiated or calculated in Ghana, nor accurate information about the amounts paid. However, several stakeholders confirmed that, at the beginning of 2019, around $20–30 million was paid. This information was also reported in several newspapers, such as (Ghana Web 2019).

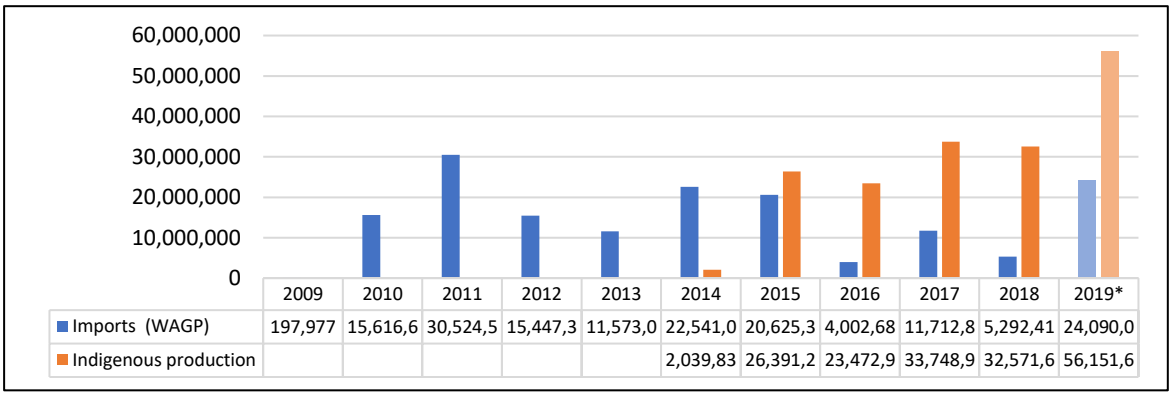
- After a drought in 2006/2007, the country invested—directly or through IPPs—in new thermal plants. By then, Ghana had no supply of indigenous natural gas, thus the plants would use Nigerian natural gas—to be delivered through the West Africa Gas Pipeline (WAGP)—a cheaper alternative than liquid fuels.
- The vast majority of new thermal power plants were built in Tema, in the east side of the country, an industrial and port zone near the capital Accra, therefore near the demand center. Tema was also designated as the main point of delivery of the natural gas coming from Nigeria through the WAGP. The second point of delivery was Takoradi, although the pipeline capacity was lower in the section between Tema and Takoradi. WAGP commercial operations started in 2011.
- However, in 2012, there was an accidental disruption in the WAGP and the supply of natural gas was shut down, leaving the thermal plants without fuel.
- In addition, some thermal plants in the Takoradi-Aboadze region had technical problems and were shut down too.
- To compensate for the loss of availability of the thermal plants, the hydropower plants were overused from 2012 to 2014, reducing the reservoirs to minimum levels.
- The pipeline was fixed in 2013, but the supply of natural gas from Nigeria never returned to contractual levels for several reasons, including "gas supply challenges from the Niger Delta region due to unfavorable upstream investment climate; persistent sabotage of natural gas transportation pipeline (i.e., the Escravos Lagos Pipeline System); and challenges with timely payment for gas already supplied/consumed by VRA" (USAID, Republic of Ghana, Energy Commission, ICF 2018)
- With no natural gas and low hydro reserves, in 2014/2015, the generation system collapsed, and the country was exposed to brownouts, having to recur to load shedding and rationing schemes.
- Emergency capacity (using expensive liquid fuels) was contracted—at the same time that more natural gas-based power plants were being built or committed to, based on demand forecast prior to the new situation. Without coordinated planning, this led to an excess of installed capacity.
- In addition, VRA had to procure expensive backup liquid fuels such as heavy fuel oil (HFO) and light crude oil (LCO), which deteriorated further the already weak financial situation of the power sector.
- During this period of unreliable supply, the tariffs were not raised. When the supply was normalized, the tariffs were updated to reflect the increasing generation costs. The tariff increase, combined with the advent of a period of low oil prices and the perception of an unreliable power system, incentivized customers (especially commercial and industrial users) to reduce consumption and invest in captive diesel generators or solar photovoltaic (PV) systems.
- The demand, therefore, has been recovering more slowly than anticipated, aggravating the gap between installed capacity and peak demand.

7. Current Challenges in Fuel Supply

In 2014/2015, at the peak of the power crisis, the production of the indigenous associated natural gas commenced in the Jubilee field, although problems were reported on the floating production and storage unit (FPSO), which resulted in interrupted supply during the first years. Later, in 2017, the Tweneboa Enyenra Ntomme (TEN) field also started to produce associated gas. Both are offshore sites, and the gas produced in these fields is transported to the mainland through pipelines, where, at the Atuabo gas processing facility, it is processed to later be transported via Ghana Gas pipelines to the thermal power plants in the Takoradi/Aboadze enclave. In 2018, another offshore field with bigger reserves, Sankofa, started commercial production of non-associated natural gas, which was also meant to be used in power production.

Figure 8 shows the inconsistent imports through the WAGP and the evolution of the domestic production of natural gas in millions of British Thermal Units (MMBtu).

Figure 8
Natural Gas Imports and Local Production (MMBtu), 2008–2019



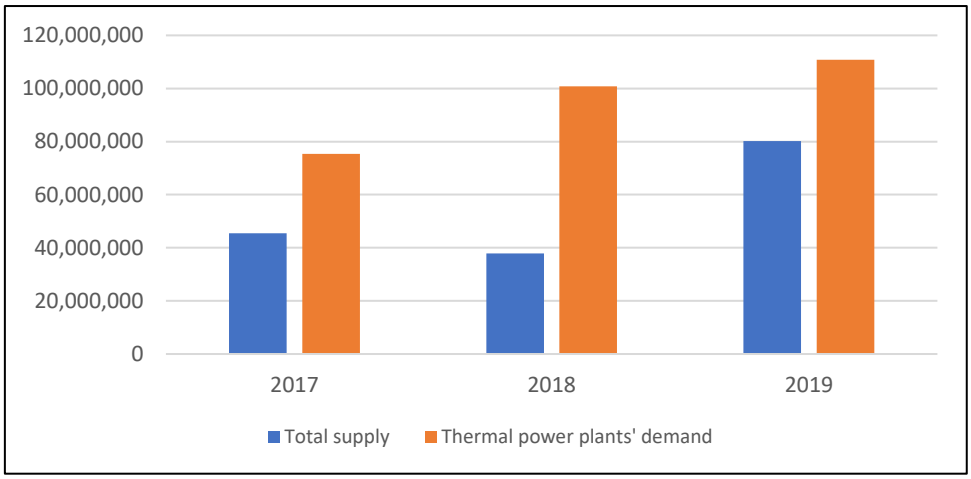
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*
Imports (WAGP)	197,977	15,616,6	30,524,5	15,447,3	11,573,0	22,541,0	20,625,3	4,002,68	11,712,8	5,292,41	24,090,0
Indigenous production						2,039,83	26,391,2	23,472,9	33,748,9	32,571,6	56,151,6

* Data for 2019 are the authors' estimation based on data from the Electricity Supply Plan for the Ghana Power System (2019). To estimate the 2019 imports, authors used the planned WAGP supply of 60 million standard cubic feet per day (MMscf/d) on average, using a conversion rate of (one thousand standard cubic feet) 1 Mscf = 1.1 MMBtu. To estimate the 2019 indigenous production, the authors used the planned total supply of 80,241,689 MMBtu minus the calculated import from WAGP.

Source: Prepared by the authors, with data from the Energy Commission (*National Energy Statistics,* 2018), with the exception of data for 2019 as described above.

The discovery of these vast reserves of natural gas (estimated at approximately 1,887 billion cubic feet [Bcf]), along with the imported supply from Nigeria through the WAGP, should be able to guarantee the steady supply of natural gas that the power sector desperately needs. However, this is not the reality yet. As indicated in Figure 9, the supply of natural gas has been much lower than the needs of the thermal plants.

Figure 9
Comparison of Natural Gas Total Supply and Natural Gas Needed by the Thermal Plants (MMBtu), 2017–2019



Note: The demand of natural gas by the power plants includes their unmet demand, supplied by other fuels due to the lack of natural gas. The authors have used a natural gas conversion rate of 1 Mscf = 1 MMBtu for simplicity, as different rates were found in different documents, ranging from 981 to 1100.

Source: Prepared by the authors.

This gap is covered with the usage of imported, expensive liquid fuels, such as LCO, HFO and diesel. For example, in 2017, the expenses for these fuels reached $339 million. For 2018, the projected cost was $478 million—42% of the total fuel cost (see details in **Exhibit 3**). Indeed, in 2018 the cost of these fuels ranged from $10/MMBtu to $14/MMBtu, while the price of natural gas was around US$7.29/MMBtu Energy Commission (*Energy Outlook*, 2018).

The expected[4] fuel supply for the power sector in 2019 is:

- 80,241,689 MMBtu of natural gas, costing $593 million—therefore, equivalent to $7.4/MMBtu
- 5.3 million barrels of hydrotreated vegetable oil (HVO), with a total cost of US$445 million, which is equivalent to $14.58/MMBtu, almost twice the price of natural gas.

It is important to note that the price of natural gas is also relatively high in Ghana—especially due to the processing and transportation costs (see **Exhibit 4**). According to the recently published Ghana Integrated Power System Master Plan, "as a result of the high costs of fuels, the national average bulk generation cost is about $0.09/kWh, which is the weighted average of the cost of thermal generation of about $0.182/kWh and the cost of hydropower generation of about $.035/kWh." As the share of hydro in the energy mix decreases, and under the current scenario of increasing international oil prices, the overall cost of electricity production in Ghana could increase.

An additional problem related to the usage of these liquid fuels is that the repeated switching from gas to LCO "caused problems with coking inside the burners and nozzles, resulting in unplanned plant outages. At the same time, when gas was available, outages in power plants

[4] Source: "2019 Electricity Supply Plan for the Ghana Power System" (Republic of Ghana 2019).

(because of needed maintenance due to coking issues and financial challenges) led to a situation where sometimes the plants were unable to use the gas when it was available" (Ghana Integrated Power System Master Plan 2018).

The main reasons for the still inconsistent and insufficient supply of natural gas are:

- Deliveries from Nigeria through WAGP are still below the 120 MMscf/d initial contractual level.[5] For 2019 a supply of 60 MMscf/d is expected (Republic of Ghana 2019), although from 2011 to 2018 the average was 38 MMscf/d.
- The domestic natural production site and the domestic gas infrastructure are located in the west and are therefore not aligned with the location of the majority of the power plants in the east. Indeed, the production of non-associated natural gas from the Sankofa field started in October 2018, but the infrastructure bottleneck prevents it from being drained from its production site to the power plants in Tema.
- The natural gas from the Jubilee and TEN fields is associated gas;[6] therefore, the quantities produced have been variable.

This imbalance has created an atypical situation, where:

- Since the commissioning of Sankofa in 2018, the natural gas available in the west is more than the natural gas demand in the region. Indeed, the government is paying approximately $28 million per month to ENI (Sankofa's lead operator), under take-or-pay terms,[7] for approximately 80 MMscf/d that it committed to offtake but that is not being used effectively.[8]
- The power plants in the east continue to suffer gas supply shortages and have to rely on more expensive backup fuels or remain idle and be paid capacity charges.

[5] As summarized by the World Bank, "The West African Gas Pipeline (WAGP), an offshore pipeline built to transport natural gas from Nigeria to Ghana, has been an unreliable source of gas supply. In June 2016, Nigeria suspended gas supplies due to accumulated payables. After Ghana made some payments in early 2017, gas supply restarted based on a pay-as-use basis. Historically, however, severe supply shortages in Nigeria and interruptions in deliveries have compromised Nigeria's contractual ability to supply Ghana with 120 MMscf/d of firm gas. The unreliable gas flows have led to about 700 MW of idle electricity generation capacity, reliance on more expensive liquid fuels, and further deterioration of the financial viability of the power sector" (World Bank 2017).

[6] "Associated gas refers to the natural gas found in association with oil within the reservoir. There are also reservoirs that contain only natural gas and no oil, this gas is termed non-associated gas," https://www.2b1stconsulting.com/natural-gas/ (2B1st Consulting 2012).

[7] "The Government of Ghana, through the GNPC [Ghana Natural Petroleum Company], has agreed to a 90% take-or-pay contract on gas volumes from Sankofa field production. This implies that 90% of Sankofa gas production must be consumed in Ghana, and without any other major gas use, this gas must be used in the power sector," (USAID, Republic of Ghana, Energy Commission, ICF 2018, 91).

[8] The take-or-pay clause of Sankofa's agreement foresees that at least 140 MMscf/d should be offtaken or paid. Currently, around 60 MMscf/d is being used by power plants in the east region. The rest (approximately 80 MMscf/d) is paid for under the take-or-pay clause. See more information at "Ghana Pays $28 Million, not $40 Million for Take-or-Pay Gas Contract- Energy Ministry," Energy News Ghana, January 8, 2019, accessed July 15, 2019, https://energynewsghana.com/2019/01/08/ghana-pays-28-million-not-40-million-for-take-or-pay-gas-contract-energy-ministry/.

The government and its institutions are working to normalize the supply of natural gas. The main measures being taken are:

- Ghana Gas and WAGPCo reached an agreement to allow the usage of the WAGP to transport the gas in the reverse direction, from west (Takoradi/Aboadze) to east (Tema). This would enable another 60 MMscf of dry gas from the Sankofa field to be used by the thermal plants located in the Tema enclave. Works on what is known as the Reverse Gas Flow Project are currently ongoing and are expected to be concluded by August 2019.
- Karpowership, a mobile vessel-power-plant with 460 MW of installed capacity, which usually operates on HVO, will be moved from east to west, switching its fuel supply to run with the natural gas from Sankofa from October 2019 (Republic of Ghana 2019). Works are under development to adapt the natural gas and electricity grid facilities in the new location.
- According to the Electricity Supply Plan for the Ghana Power System (2019), "in addition to the existing supply sources, two liquefied natural gas (LNG) projects are expected to add an additional 430 MMscf/d by 2022." This same plan summarizes the forecasted supply of natural gas by origin, as indicated in Figure 10 below.

Figure 10
Planned Medium-Term (2020–2024) Gas Delivery Profile (MMscf/d)

	2020	2021	2022	2023	2024
Jubilee FV	83	80	83	83	-
Greater Jubilee	-	-	-	-	80
TEN AG	26	26	26	26	26
Sankofa NAG	180	180	180	180	180
Aker	-	-	-	-	-
Takoradi LNG	-	-	180	180	180
Tema LNG	100	250	250	250	250
N-Gas	70	70	70	70	70
Total Gas Supply	**459**	**606**	**789**	**789**	**789**

Source: "2019 Electricity Supply Plan for the Ghana Power System" (Republic of Ghana, 2019).

However, the challenges could persist. The existent domestic reserves of natural gas (under exploration) might not be enough beyond 2023, and there are uncertainties about the amount of gas that could be imported from Nigeria in the future.

7.1. Opportunity – Use of Methanol as a Backup Fuel for Thermal Power Plants

In this scenario of over-dependence of thermal sources, with a limited supply of natural gas, and where the usage of HFO and LCO has a significant impact on the system's costs, we suggest assessing the benefits and the economic feasibility of adopting methanol as a cleaner alternative backup fuel for the thermal power plants.

What is Methanol

Methanol is a liquid fuel that is considered much more environmentally friendly than fuels such a HFO, gasoline, diesel and kerosene. As a synthesized compound, methanol is pure and, unlike diesel and gasoline, it contains no contaminating elements such as sulfur. Sulfur in traditional liquid fuels creates harmful combustion by-products that can be orders of magnitude more damaging to the environment than carbon dioxide. Unburnt hydrocarbons also take significantly longer to break down under sunlight than alcohols such as methanol. Methanol's most substantial drawback is that it has less than half the energy density of traditional liquid fuels. Therefore, it could be necessary to use double the amount of methanol to produce the same amount energy.

As a synthesized fuel, methanol is derived from a chemical process rather than being found like most hydrocarbons. The synthesis of methanol is usually achieved through a catalytic reaction using a feedstock of natural gas. Methanol is directly derived from a traditional hydrocarbon source and consumes energy during its production, but it is still a clean fuel. Given these characteristics, methanol is rarely chosen as a preferred fuel source when natural gas is readily available. As a synthesized chemical, methanol may be subject to different excise taxes than oil-based fuels.

Converting a turbine to run on methanol and achieve the same power output than using natural gas requires an upgrade of its fuel-injection system and fire suppression system, and the creation of methanol loading and storage facilities.

The main downside of methanol is that it has less than half of the energy density of traditional liquid fuels. For example, approximately 1.8 kilograms – 2.05 kilograms of methanol are required to create the same amount of energy as 1 kilogram HFO. Therefore, methanol becomes an attractive option, in terms of costs, when its price is 1.8 – 2 times lower than HVO.

The economics of methanol use need to be assessed on a case-by-case basis as the potential for savings in fuel costs vary according to market prices and the related contracts. Beyond potential savings, using methanol has other important benefits, such as the following:

- Energy security/Diversification: including methanol in the portfolio of backup fuels, in addition to HVO, creates an alternative for eventual problems in the supply of natural gas and HFO/LCO.
- The possibility to select the cheaper fuel at any moment: the conversion maintains the turbine's ability to run on either natural gas, HFO/LCO or methanol, which leaves the option open to run on whichever backup fuel is most economical at the time. Such technical adaptability could prove beneficial in a changing global energy market.
- It is cleaner than HVO: as described in the box above, methanol is more environmentally friendly than oil-based fuels.
- Methanol is less harmful to the operation of the turbines. Light crude oil, heavy fuel oil and diesel can overheat the turbines, reduce their life span and cause unplanned outages but methanol does not have these drawbacks.

An example of a company that successfully converted diesel generators for methanol use is the Israel Electric Corporation.

8. Losses and Revenue Collection Challenges

Technical and commercial losses[9] are another of the biggest challenges the Ghanaian electricity system faces. In 2018, of the 16,246 GWh generated, only 11,656 GWh was finally consumed and sold (registered consumption), resulting in a total loss of 28% (an extremely high percentage if compared with the 8% world average).

Of those losses, transmission losses represented 4.4%, as a result of high loadings in some sections of the grid due to the lack of timely investment to expand and upgrade the system. Around 24% were distribution losses (technical and commercial), mainly caused by the outdated grid (technical losses) and the incidence of fraud or metering problems (commercial losses).

In addition, there is also a significant percentage of unpaid bills from private customers, especially from public and governmental institutions. In 2017, revenue collection rates stood at 93.33% in the case of ECG and 71% in the NEDCo network region (USAID, Republic of Ghana, Energy Commission, ICF 2018).

With the current level of losses and unpaid bills, for each 10 units of electricity produced only 6.7 units are effectively consumed, invoiced and paid for by the end customer. Therefore, to recover the system costs, the final user should pay for 1.5 units per unit of electricity consumed.

The entrance of Power Distribution Ghana (PDG), the new private operator of the electricity distribution network for the southern region, is expected to address some of these challenges. By investing and upgrading the grid, modernizing meters, extending the pre-payment method to most of the customers and adopting better protocols to reduce incidences of fraud and metering errors, PDG is planning to improve the collection rates.

9. Tariffs

The Public Utilities Regulatory Commission (PURC) is in charge of setting and publishing tariffs for electricity in accordance with their tariff setting guidelines, which specify some general principles about the tariff structure. The tariffs set by the PURC are applied nationwide. In the period between the major tariff reviews, the tariffs are adjusted to reflect the evolution of the cost through an automatic tariff adjustment formula, which takes into account factors such as the changes in the energy mix (hydro versus thermal), fuel costs, inflation and the foreign exchange rate.

All residential customers enjoy a lower, subsidized tariff rate (lifeline-tariff) for the first 50 kWh of electricity consumption.

The tariffs in Ghana are relatively high (see **Figure 11**).

[9] Technical losses arise during the transport of the energy from the production site to the end customer (mainly due to the heating of the conductors and transformers). Commercial losses (also called non-technical losses) refer to the energy consumed but not invoiced, normally due to metering problems, invoicing errors or fraud. These energy losses are ultimately a financial loss, as part of the energy produced and paid is lost along the way and cannot be used by the end customers. Although the losses are an inevitable inefficiency of any power system, in the case of Ghana they are significantly high.

Figure 11
Average End-User Tariff Ranges of Ghana and Selected Middle-Income Developing Countries and Regions, 2014–2017

Country/Region	Ghana	South Africa	India	China	South-Eats Asia
US cents/KWh	15 – 19	8 – 10	8 – 9	7 – 8	4 – 7

Source: Table 12 from the Energy Commission (*Energy Outlook*, 2018).

In March 2018 tariffs decreased, but the recently published major tariff review raised them by 11% in July 2019 (Public Utilities Regulatory Commission, 2019).

10. Financial Challenges of the Sector

Even with these relatively high rates, the revenue collection of the sector has not been able to cover the costs of the system, which has generated a chronic debt situation in the electricity sector. In March 2017, the accumulated financial debt was around $2.3 billion (World Bank 2017).

Several structural and operational inefficiencies contributed to a situation of increasing system costs, mainly:

- Emergency procurement of thermal capacity (at high costs)
- High capacity charges being paid for the excess of installed capacity
- Usage of expensive and imported liquid fuels, due to the unreliable supply of natural gas
- Relatively high natural gas prices
- Significant technical and commercial losses in the electricity distribution network

In addition, the revenue collection rate is low, and many customers are still using private diesel gensets due to high tariffs, which decreases their grid-based electricity consumption and the utility revenues.

Beyond the specific measures being implemented to palliate these burdens, the government also implemented, in December 2015, energy levies (through the Energy Sector Levies Act, known as ESLA), which help to repay the debts owed by the utility companies to the IPPs and fuel suppliers and also to recover the costs of rural electrification programs and public lighting. Some energy levies are applied to diesel, gasoline and LPG prices, while others are applied to the electricity bill.[10]

A special purpose vehicle (SPV), E.S.L.A. PLC, was created to issue long-term bonds to resolve the energy sector debts, with the securities backed by part of the levies.

[10] For a detailed view of the energy levies, consult Parliament of the Republic of Ghana. "Energy Sector Levies act, 2015." (Act 899). December 24, 2015, https://www.eslaplc.com/pages/download/Energy_Sector_levies.pdf.

In addition, the implementation of a cash waterfall mechanism was planned—to regulate/manage the cash flow of the power system—aiming for an equitable distribution of the revenues collected by the utilities to all stakeholders in the power sector supply chain.[11]

11. Renewables

The government of Ghana is aware of the potential benefits of introducing more renewables into the energy mix and thereby harnessing the vast natural resources available, as it could help to:

- decrease the costs of electricity production,
- diversify the energy mix,
- improve the reliability of the energy system,
- decrease dependence on imported fossil fuels,
- reduce emissions in the power generation sector,
- and create a local industry and jobs around renewable solutions.

However, the development of the sector remains limited, accounting for only 1.5% of the installed capacity, as shown in Table 3 and detailed in Exhibit 2.2.

The first intent to promote renewable sources at scale came in 2011, with the still-valid Renewable Energy Act 2011 (Act 832), which contains the main regulations and mechanisms to incentivize renewable energies and to obtain the licenses to operate. Among the incentives are a renewable energy feed-in-tariff rate (RE-FiT), a renewable energy purchase obligation (REPO) for distribution companies and bulk customers, and a guaranteed connection to transmission and distribution systems.[12]

However, since then, the evolution of the renewable sector has not been straightforward. The main problems, similar to those that arose when procuring new thermal capacity, were:

- No proper central planning, lack of a definition of institutional responsibilities and overlapping on procurement/offtaker role; in an attempt to develop the renewable power sector, several PPAs and memorandums of understanding (MOU) were signed by different government bodies and state-owned companies with renewable IPPs to build solar and wind projects with high electricity prices and on many occasions with non-transparent procedures and without competitive procurement.
- Incentive mechanisms were not clear: different procurement systems (competitive tendering process, bilateral negotiation, feed-in-tariff) were used to grant a PPA to a project.
- The process, from project to commissioning, was not well-defined, requiring several bilateral negotiations with the government and, consequently, was extremely expensive and time-consuming for the IPPs.

[11] The authors did not find reliable information on the implementation status of this mechanism. It was approved in 2017, but was not operative until at least the end of 2018. Stakeholders interviewed reported that it was planned to be implemented in the beginning of 2019.

[12] Apparently, so far, such incentive mechanisms have not had any practical effect.

As a result, there are more than 40 renewable projects in different phases of the planning and development process. The new government, facing this scenario, decided to review the signed renewable PPAs and MOUs, which are now being renegotiated. Although necessary, this created a situation of uncertainty.

Currently, the government target is to reach 10% of renewable energies in the energy mix by 2030. Initially, this target was stipulated as 2020, but the excess generation capacity and the sector's financial situation imposed a barrier to the adoption of renewable technologies in the short and medium term.

The recently published Renewable Energy Master Plan (REMP) (Ministry of Energy et al. 2019) introduces specific targets—in terms of renewable technologies, installed capacity and periods of installation—from now to 2030 (see Table 4). The aim is to increase the proportion of renewable energy in the electricity mix from 42.5 MW (2015) to 1363.63 MW (2030) and promote local content and local participation in the renewable energy industry (see more details in Exhibit 5).

Table 4
Renewable Energy Master Plan's Target for Renewable Sources in the Electricity Sector (Cumulative)

Tecnology	Unit	Reference (2015)	2020	2025	2030
Solar, utility scale	MW	22.5	152.5	347.5	447.5
Wind energy, utility scale	MW	0	0	275	325
Small/Medium hydropower	MW	-	0.03	80.03	150.03
Wave energy	MW	-	5	5	50
Solid biomass utility-scale	MW	0	0	72	72
Waste-to-energy, utility scale	MW	0.1	0.1	30.1	50.1

Source: "Ghana Renewable Energy Master Plan." (Ministry of Energy et al. 2019).

However, there is still uncertainty regarding the mechanisms to incentivize and contract the future renewable projects. Although the REMP comments on the mechanisms (feed-in-tariff, competitive procurement and utilities purchase obligation), there is no detailed framework to define how these mechanisms—which were already part of the 2011 act—will be brought into practice.

The government is keen on promoting public-private partnership and attracting private investment to this underdeveloped and promising sector. Nevertheless, there are several circumstances still acting as barriers (see Table 5).

Table 5
Barriers to Renewable Energies

General barriers	Specific barriers for renewables
▪ The power sector is deeply indebted—a situation that increases the risk for potential investors, limiting their ability to raise funds in the debt markets. ▪ There is overcapacity of installed generation. ▪ Political risk: although the overall political situation in the country is stable, given the traditional high government involvement in the electricity sector (directly or through its companies), changes in government have been affecting the priorities, strategies and implementation of energy policies. ▪ Land availability is a major constraint. ▪ Limited infrastructure in terms of roads and ports. ▪ Although not a limitation, investors should be aware of local content policies.	▪ Regulatory risk—as the PPAs/deals agreed are being reviewed, which could create a perception of legal uncertainty. ▪ Uncertainty regarding the mechanisms to incentivize and contract the future renewable projects. ▪ Process to go from development to operation is complex and time-consuming. ▪ Several projects are already in the pipeline, which could limit the space for new projects—at least in the short and medium term. ▪ Integration of renewables with the existing grid. One key limiting factor for increased grid integration of variable renewable sources, such as solar PV and wind, is the impact of their intermittency on the national grid.

Source: Prepared by the authors.

The development of a renewable market will depend on the ability of the government and its institutions to create a business environment that can overcome these challenges, reaching a satisfactory agreement for the current renewable projects under renegotiation and creating a stable and clear framework to select future projects in a competitive, scalable and efficient way.

12. Off-Grid Solutions:[13]

a. Mini-Grids

The REMP, published in February 2019, makes it clear that the development of mini-grids is a fundamental step towards universal electrification. In fact, the plan sets a clear target of having 300 mini-grids in operation by 2030, based on renewable energy resources like solar, wind, biomass, biofuel or hydro power, coupled with backup diesel generation or batteries when needed.

On top of the 13 existent mini-grids,[14] the goal is to build 287 new mini-grids—especially in island and lakeside communities with more than 500 inhabitants, in order to serve these unelectrified

[13] Off-grid solutions usually refer to mini- or micro-grids and also to stand-alone solutions.

[14] There were 13 mini-grids in operation in the country, under the following scheme/ownership:

- Seven mini-grids are operated and owned by Black Star Energy Ltd., which apparently is the only company with a commercial license to develop and operate off-grid solar-powered mini-grids in Ghana. They are developing eight additional mini-grids.
- Five mini-grids were developed and built in 2015/2016 by a consortium that won a competitive tendering process (based on price and technical capacity), under a project funded by the World Bank. The consortium operated the mini-grids for two years, and, following the initial agreement, in 2018 the mini-grids were handed over to VRA (a state-owned utility), which is now in charge of the operation/maintenance.

communities in a more cost-efficient way instead of extending the national grid. The implementation schedule foresees:

- 73 new mini- and micro-grids in Cycle I (2019–2020)
- 114 further mini- or micro-grids in Cycle II (2021–2025)
- 100 additional mini- or micro-grids in Cycle III (2026–2030),

At an estimated average cost of $780,000 per mini-grid, the total investment needed could reach up to US$220 million.[15]

Therefore, if such plans are pursued, the mini-grid building market is expected to experience a significant growth in the next 12 years.

However, all the mini-grid development is expected to be public-driven and operated by the current utilities. In fact, the plan states that "a mini-grid policy was approved in January 2016 to mainstream mini-grid electrification into the National Electrification Scheme. Under the policy, mini-grids are public sector led investment with VRA and ECG/NEDCo responsible for generation and distribution, respectively. Customers on mini-grids would enjoy the same pricing policy as those on the main electricity grid under the rural electrification arrangement" (REMP 2019).

They are planned to be financed by creating a special fund, dedicated to mini-grid development and funded by the government of Ghana's budget, loans, grants and the rural electrification levy applied to electricity bills.

Therefore, if the new plan is followed, there are limited opportunities for private companies interested in developing, financing, building and operating the mini-grids. The opportunities for private companies are likely to be limited to the phase of project development and construction or as providers of ancillary services, equipment and maintenance.

That said, a mini-grid regulation is being developed, and although it is expected to follow the public-drive approach, certain debate about the role of the private initiative is still ongoing. Some players are advocating for a more business-oriented model, which would serve to raise funds faster and accelerate the implementation of mini-grids. There is significant opportunity to unlock this market should government policies change.

In the case that the government and policy makers modify the current decision of promoting a mini-grid model with public-sector-led investment and instead decide to promote a model that allows private companies to invest in and operate the mini-grids, another barrier for a commercial mini-grid model would be the current uniform tariff policy, which makes it difficult, if not impossible, to recover the costs from building and operating a mini-grid with the revenues coming solely from the tariffs. Therefore, it will be necessary find a model that fits the uniform tariff policy and, at the same time, provides an economic incentive to private investors and operators.

b. Opportunity: Solar Home Solutions Using the Pay-as-You-Go Business Model

In Ghana, there are stand-alone solar solutions (solar panels powering off-grid households) in the country, serving more than 40,000 households. However, this market could be further developed to attend off-grid households in rural areas in a quick and cost-efficient way using the pay-as-you-go model. The combination of a limited but still considerable number of households

[15] Based on the investment cost foreseen on page 53 of the Renewable Energy Master Plan, an investment of US$56,940,000 is required to build 73 new mini-grids up to 2020.

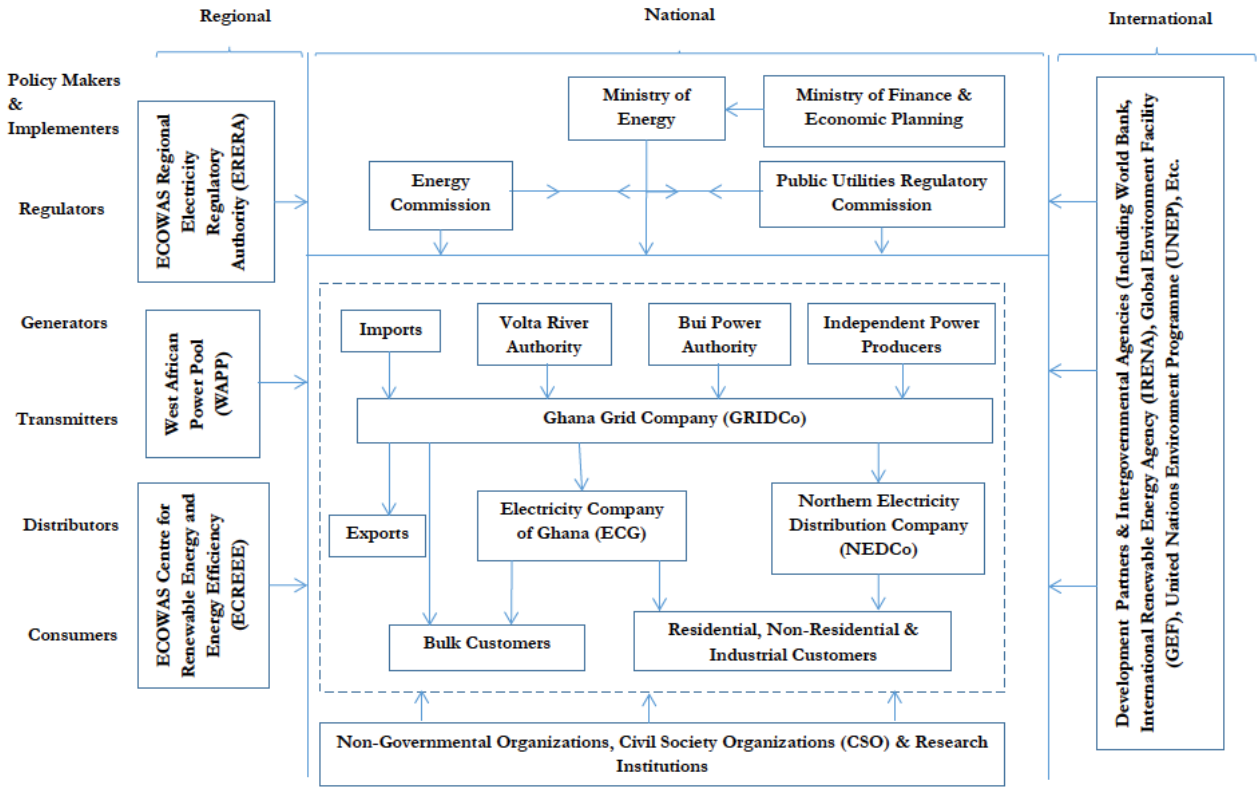
with no electricity and the current administration's pursuit of enhanced electricity access through public-led initiatives creates an interesting opportunity to design a pay-as-you-go program on a national scale.

Through the pay-as-you-go business model, people still living without electricity can lease a small stand-alone photovoltaic system (a kit with a solar panel, a battery and basic appliances such as lamps, a radio and a portable charger). Customers would pay small amounts using mobile money, usually paying less than their current expenditure on torch batteries, diesel generators or kerosene. After a payment period that usually varies from 12 to 36 months, the customer owns the solar kit.

The authors assessed this market and the opportunity in detail in the report "Solar Home Solutions Using a Pay-As-You-Go Model in Ghana: Exploring the Opportunity".

An example of a successful Public Private Partnership is the case of Ignite Power, a company offering solar home solutions through the pay-as-you-go model. By collaborating with the government of Rwanda, Ignite was able to connect more than 100,000 households in two years, at prices well below other solutions in Africa. The company is currently implementing a similar approach in Mozambique and Sierra Leone.

Exhibit 1
Institutional Framework of the Electricity Sector



Source: Kumi, Ebenezer Nyarko. The Electricity Situation in Ghana: Challenges and Opportunities (2017).

Exhibit 2
Installed Electricity Generation Capacity, December 2018

2.1 On Grid (MW)

Plant	Installed capacity (MW)	Dependable capacity (MW)	Owner	Fuel
Hydro				
Akosombo	1,020	900	VRA (state-owned)	Hydro
Kpong	160	140	VRA (state-owned)	Hydro
Bui	400	360	Bui (state-owned)	Hydro
Total	**1,580**	**1,400**		
Thermal				
Takoradi Power Company (TAPCO)	330	300	VRA (state-owned)	Gas/LCO
Takoradi International Company (TICO)	340	320	VRA (state-owned)	Gas/LCO
Tema Thermal 1 Power Plant (TT1PP)	110	100	VRA (state-owned)	Gas/LCO
Cenit Energy Ltd	110	100	IPP	Gas/LCO
Sunon Asogli Power (Ghana) Limited	560	520	IPP	Gas/LCO
Tema Thermal 2 Power Plant (TT2PP)	80	70	VRA (state-owned)	Gas
Kpone Thermal Power Plant	220	200	VRA (state-owned)	Gas/Diesel
Karpowership	470	450	IPP	HFO
Ameri Plant	250	230	IPP	Gas
Trojan*	44	40	IPP	Gas/Diesel
Genser*	22	18	IPP	Gas
AKSA	370	350	IPP	HFO
Cenpower	360	340	IPP	Gas/LCO
Total	**3,266**	**3,038**		
Renewables				
Safi Sana biogas*	0.1	0.1	IPP	Waste
VRA solar*	2.5	2	VRA (state-owned)	Solar
BXC solar*	20	16	IPP	Solar
Mienergy*	20	16	IPP	Solar
Total	**42.6**	**34.1**		
Grand total	**4,888.6**	**4,472.1**		

Note: * Connected at sub-transmission level.

Source: Adapted from Table 3.1 of "National Energy Statistics 2009–2018" (Energy Commission, 2018) and Table 19 of "2019 Electricity Supply Plan for the Ghana Power System" (Republic of Ghana, 2019).

Exhibit 2 (Continued)

2.2 Renewables, Installed Capacity (kW): Off-Grid and On-Grid, 2013–2018

Year	Off-grid		On-grid				Mini-Grid		Total Installed
	Solar	Wind	Dist. SPV	Utility Solar	W2E	Hydro	Solar	Wind	
2013	-	-	494.6	2,500.0	-	-	-	-	2,994.6
2014	1,350.0	-	442.8	-	-	-	-	-	1,792.8
2015	4,002.7	20.0	700.1	20,000.0	100.0	4,000.0	256.0	11.0	29,089.8
2016	1,238.3	-	2,626.3	-	-	-	-	-	3,864.6
2017	677.5	-	4,265.9	-	-	-	58.3		5,001.7
2018*	4.2	-	8,601.7	20,000.0	-	-	-	-	28,605.8
Total	7,272.7	20.0	17,131.4	42,500.0	100.0	4,000.0	314.3	11.0	71,349.3

*Provisional

Note: W2E = waste to energy; Dist. SPV = distributed solar photovoltaic.

Source: Table 3.1 of the "National Energy Statistics 2009–2018" (Energy Commission, 2018).

Exhibit 3

Breakdown of Estimated Fuel Cost for the Power Sector, 2018 and 2019

3.1 Estimated Quantities of Fuel and Cost for the Power Plants for 2018

Type of Fuel	Cost (Million USD)
VRA - LCO	42
VRA - GAS	263
VRA - DFO	32
TOTAL VRA FUEL COST	**336**
IPP - LCO	168
IPP - GAS	260
IPP - HFO	184
IPP - DFO	52
TOTAL IPP FUEL COST	**665**
TOTAL VRA & IPP COST	**1,001**

Source: Table 22 from the "2018 Electricity Supply Plan for the Ghana Power System" (Republic of Ghana, 2018).

3.2 Estimated Quantities of Fuel and Cost for the Power Plants for 2019

Type of Fuel	Cost (Million USD)
VRA - LCO	-
VRA - GAS	278.91
TOTAL VRA FUEL COST	**278.91**
IPP - LCO	
IPP - GAS	314.88
IPP - HFO	445.93
TOTAL IPP FUEL COST	**760.81**
TOTAL VRA & IPP COST	**1,039.72**

Source: Table 30 from the "2019 Electricity Supply Plan for the Ghana Power System" (Republic of Ghana, 2019).

Exhibit 4

Summary of Adjusted, Weighted Average Cost of Gas and Tariffs, 2018

COST TYPE	SOURCE OF GAS SUPPLY US$/mmBTU									AWACOG*
	Jubilee	TEN	HESS	Sankofa 1	Sankofa 2	LNG Takoradi	LN Tema 1	LNG Tema 2	WAPCo	
Commodity Charge	0.50	2.35	2.90	6.78	6.78	5.80	5.85	6.36	2.59	
Gathering Charge / ELPS Charge	1.04	1.12	1.12						1.27	
Processing Charge	1.12	1.12	1.12							
Transmission Service Charge: Transportation to Takoradi	1.12	1.12	1.12	1.12	1.12					
Transportation to Tema	0	0	0	0	0				4.55	
Regulatory Levy	0.40	0.40	0.40	0.40	0.40					
Shipping & Aggregation	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05		
Regasification fee						1.40	1.60	1.38		
Total Delivered Gas Price	4.23	6.16	6.71	8.35	8.35	7.25	7.50	7.79	8.41	**7.29**

Source: Energy Commission (*Energy Outlook, 2018*).

Exhibit 5

Extract from the Renewable Energy Master Plan

Utility Scale Solar Challenges in Adoption of Utility Scale Solar Power Projects

Based on provisional licenses granted by the Energy Commission for solar utility scale projects, it appears investors perceive solar utility projects as the least challenging among the utility scale projects. However, the industry faces a set of unique challenges with regards to funding and grid integration. These challenges include the:

- Variable nature of solar power
- High cost of solar power
- High cost of capital and limited access to long-term financing
- Inadequate reserve margin limits integration of larger utility scale solar plants
- Land requirement (2.5 acres/MWp to 4 acres/MWp) is significant and could compete with other land-use options.

Strategies to Promote Utility Scale Solar Power Systems

In view of the above, the following strategies will be used to promote the utility scale solar market:

- Mobilize funds domestically (e.g., bonds, shares, etc.) to finance major renewable energy projects
- Provide government on-lending facilities to renewable energy investments
- Institutionalize competitive procurement to achieve price reduction in tariffs
- Upgrade the National Interconnected Transmission System to make the grid robust for renewable energy technologies (RET) integration (system control centre, weather forecasting systems, etc.)
- Drive developments onto land that does not compete with other uses
- Encourage contribution of land as equity in RET projects
- Institute reward schemes for outstanding renewable energy projects/initiatives
- Promote mixed use of land for solar power and agriculture
- Incorporate land requirement for renewable energy projects in the national spatial planning
- Encourage take-and-pay power purchase agreements (PPAs) for conventional base load power plants to make the integration of variable RETs technically and financially feasible.

Source: "Ghana Renewable Energy Master Plan." (Ministry of Energy et al. 2019).

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