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Future Prospects for LNG Demand in Ghana

Energy demand in Africa is forecast to grow quickly in the coming decades, with the IEA suggesting[1] a CAGR of 2 per cent between 2016 and 2040, twice the global average. However, it remains to be seen which fuel in a post-COP21 world will be used to achieve this economic growth. As electricity storage is not yet available (and could be initially expensive), Africa could use more coal, oil and/or gas to generate electricity (nuclear is not an option any longer as it is too expensive). With key lending institutions moving away from investment in coal and oil, this leaves a theoretical gap in the market for gas, which would avoid the need to import expensive energy storage technology. This would also help upstream companies to monetise domestic gas resources where a Final Investment Decision, without domestic demand, could be (permanently) postponed as we have seen in Mozambique in the last few years.

But issues of affordability and security are higher up on any national African political agenda than the problem of carbon reduction (although in large cities, air quality considerations could provide a significant opportunity for gas). The cost of gas and the credit worthiness of African clients[2] are major issues for investors. These two concerns should be looked at jointly: even with very high electricity prices[3], sub-Saharan Africa has never paid more than $8.7/MMBtu (at the wholesale price level) for its gas according to the International Gas Union[4]. Hence only imported gas priced below this maximum level can meet the African challenge. Floating Storage Regasification Units (FSRU) and gas-fired power plants allow companies to test a market and to scale up if successful (or to leave if unsuccessful), although these markets are small and very different to the more established LNG markets. Counterintuitively, LNG is not only better for the climate than oil products, but its use also reduces the risk of theft as a dedicated infrastructure is needed. Could Africa benefit from an LNG market which, according to the consensus, might be oversupplied in the coming years? In his latest publication[5], Jonathan Stern states, "The major challenge to the future of gas will be to ensure that it does not become (and in many low-income countries remain) unaffordable and/or uncompetitive, long before its emissions make it unburnable."[6] This is clearly relevant to the continent of Africa and raises the question of whether LNG can be cheap enough for long enough to have a major impact.

One other key issue is how to identify specific pockets of new demand? As additional demand is still more likely to occur in markets that already consume gas, rather than in markets where gas is not

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[1] In the IEA World Energy Outlook (WEO) 2017 New Policies Scenario.

[2] Most sub-Saharan African countries have a poor sovereign credit rating which severely limits their capacity to borrow from global capital markets.

[3] In slide 14 of the Q3 2016 Golar presentation at http://hugin.info/133076/R/2060701/784759.pdf the average electricity price in Ghana is above the world average of $120/MWh

[4] This record wholesale price was reached in Ghana in 2015, largely based on imported gas from Nigeria.

[5] "Challenges to the Future of Gas: unburnable or unaffordable?" available at https://www.oxfordenergy.org/publications/challenges-future-gas-unburnable-unaffordable/

[6] Stern states that in low-income markets, the price of wholesale gas must be below $6/mmbtu (and ideally closer to $5/mmbtu)

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present in the mix, we initially looked at the Ivory Coast[7] where companies have tested the market using FSRUs and gas-fired power plants. We now turn to an in-depth review of Ghana, another country which is already using gas and where the development of new resources is underpinned by increased local demand. As is the case for the Ivory Coast, the scarcity of data[8] (at the global level) makes analysis more difficult. We have therefore decided to first analyse supply and demand, then consider historical prices before looking at the latest developments in the domestic LNG market, only to conclude that the future of LNG in Ghana is bleak.

Supply and Demand

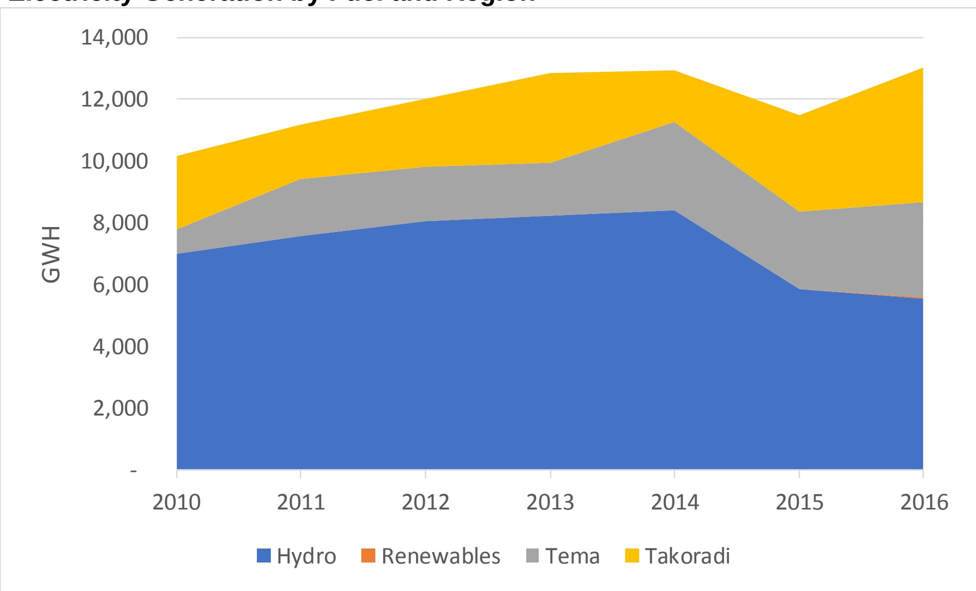
The demand for natural gas in Ghana is totally driven by the power sector. Power generation in the country has been heavily dependent on hydro since the damming of the Volta River, with additional power coming from oil-fired plants. As power generation demand grew, the increased dependence on more expensive oil led to plans being prepared over many years to import gas from resource-rich Nigeria, with the assumption that gas would be much cheaper than oil. This section will consider gas imports, the development of domestic production, and developments in the electricity generation sector which provides the demand for gas.

The Power Sector

The power sector accounts for all gas consumption in Ghana, with plants in both the Takoradi area in the west, where all domestic production is landed, and in the Tema area in the east, which serves Greater Accra. The latter is where all Nigerian gas is now delivered, although in the early years most Nigerian gas was delivered to Takoradi. Gas consumption has always been driven by available supply both from Nigeria and domestic production.

Ghana's power sector is a mixture of hydro and thermal plants, with recently a very small amount of renewables generation[9] added.

Figure 1: Electricity Generation by Fuel and Region



Source: Energy Commission of Ghana

[7] "Can small LNG meet the challenge of empowering Africa?", Oxford Energy Forum – Searching for Natural Gas Demand in the Next Decade – Issue 110 pages 46-47 available at https://www.oxfordenergy.org/publications/oxford-energy-forum-searching-natural-gas-demand-next-decade-issue-110/

[8] The JODI world gas database does not provide any data for those two countries. Pay-data is available from the IEA, but local data is needed to complete the picture.

[9] National Energy Statistics 2007 to 2016, Energy Commission of Ghana.

The thermal plants are split between Tema and Takoradi, and generation from these plants is a mixture of oil- and gas-fired, apart from a very small coal-fired plant in the west which provides power to mines in the region. All the plants, with the exception of the coal plant, can burn either oil or gas, apart from the Sunon Asogli CCGT in Tema, which is gas only. The plants can generally consume light crude oil and some heavy fuel oil, as well as gas.

Hydro generation has declined in recent years because of low reservoir levels which means that not all the turbines can be operated safely. Currently only about half the country's hydro capacity is available, with only one third feasible at the largest dam at Akosombo.

Ghana also has electricity interconnectors with neighbouring countries, principally the Cote d'Ivoire, and in 2016 had net imports of 324 GWh. In previous years, net exports have ranged from 260 GWh to just over 900 GWh. The electricity system suffers from significant technical and commercial losses of around 25 per cent, mostly at the distribution level. These commercial losses are thought largely to reflect theft and illegal connections, which severely impact the financial health of the sector. In addition to these losses the sector also suffers from non-payment issues, with the government sector being a key culprit.

Gas Imports

Natural gas only arrived in Ghana when the West African Gas Pipeline (WAGP) started up at the end of 2008, initially transporting small volumes. The start date of WAGP was meant to be 2006 but the project was considerably delayed, with interruptible gas supplies only starting in late 2008 (when the pipeline was completed but not all the receiving stations or the compressor station in Nigeria were operational). The actual start date, when the contractual commitments were triggered, was not achieved until November 2011.

WAGP is owned and operated by the West African Gas Pipeline Company (WAPCo) Limited, which in turn is owned by Chevron (36.9%), Nigerian National Petroleum Corporation (NNPC) (24.9%), Shell (17.9%), Takoradi Power Company Limited (16.3%), Société Togolaise de Gaz (2%), and Société BenGaz (2%). The pipeline is 678 km long and links into the existing Escravos-Lagos pipeline at the Nigeria Gas Company's (NGC) Itoki Natural Gas Export Terminal and then proceeds to a beachhead in Lagos. From there it moves offshore to Takoradi, in Ghana, with gas delivery laterals from the main line extending to Cotonou (Benin), Lome (Togo), and Tema (Ghana). The pipe was initially supposed to carry a volume of 160 mmscfd and peak over time at a capacity of 470 mmscfd.

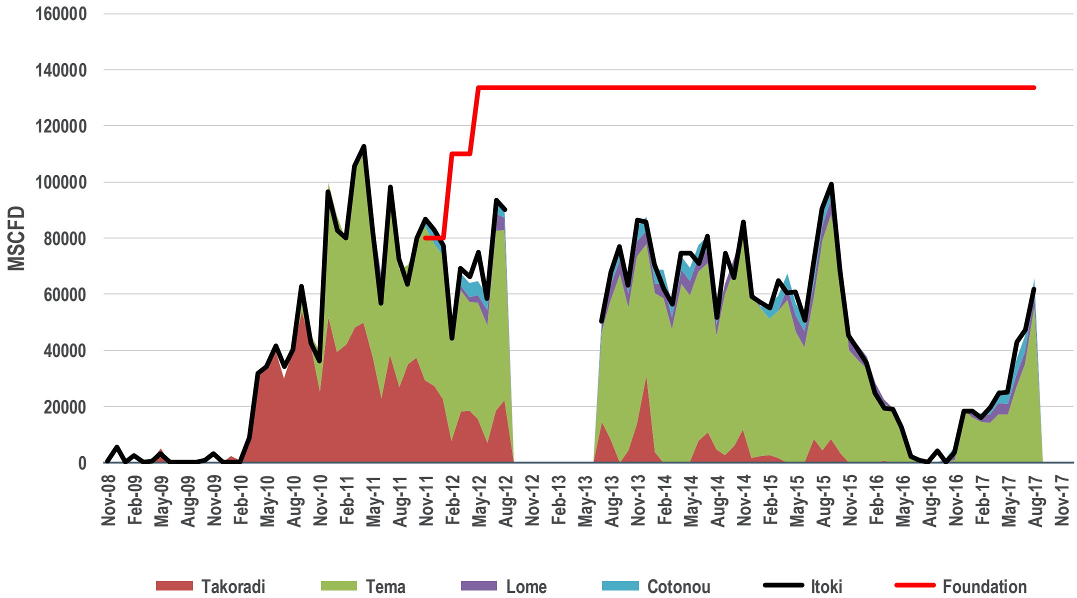
The project was underpinned by a foundation contract of 133.6 mmscfd, of which 123.2 mmscfd was destined for Ghana and 5.2 mmscfd each to Benin and Togo. However, as the chart below shows, the flow of gas has been inconsistent and not met the contractual obligations.

Nigeria has consistently failed to supply gas under the terms of the contract. This has been in part due to vandalism and terrorist action in blowing up the NGC pipelines, partly due to gas supply issues, and also due to Nigeria diverting the gas meant for WAGP to its own power plants. There was also a pipeline breach in August 2012 when pirates hijacked a tanker and dragged an anchor over the pipeline, resulting in long delays while the pipeline was repaired. Because of these continuing issues, the contracts have been operating under *force majeure* effectively since the start date of 2011, with none of the parties concerned showing much willingness to try and enforce the contractual terms.

In August 2014 the VRA (Volta River Authority) – the sole purchaser of gas in Ghana - stopped paying for the gas[10] as it was not receiving payment from the electricity distributors, who in turn were not being paid by most of their customers, principally the Government of Ghana. There is a large debt still outstanding although the VRA has resumed paying its current bills since Q3 2016.

[10] It should be noted that Benin and Togo customers have continued paying.

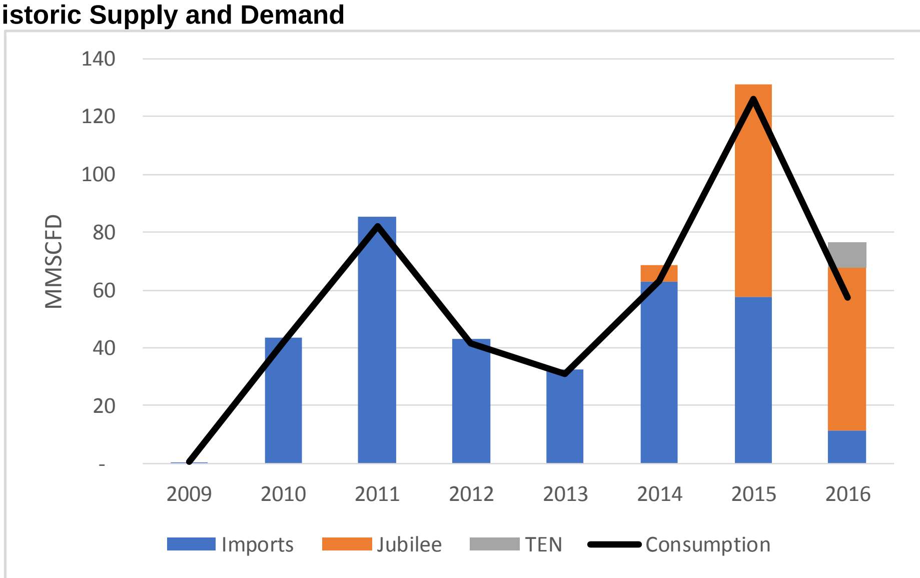
Figure 2: WAGP Gas Flows



Source: WAPCO

Domestic Gas Production

Figure 3: Historic Supply and Demand

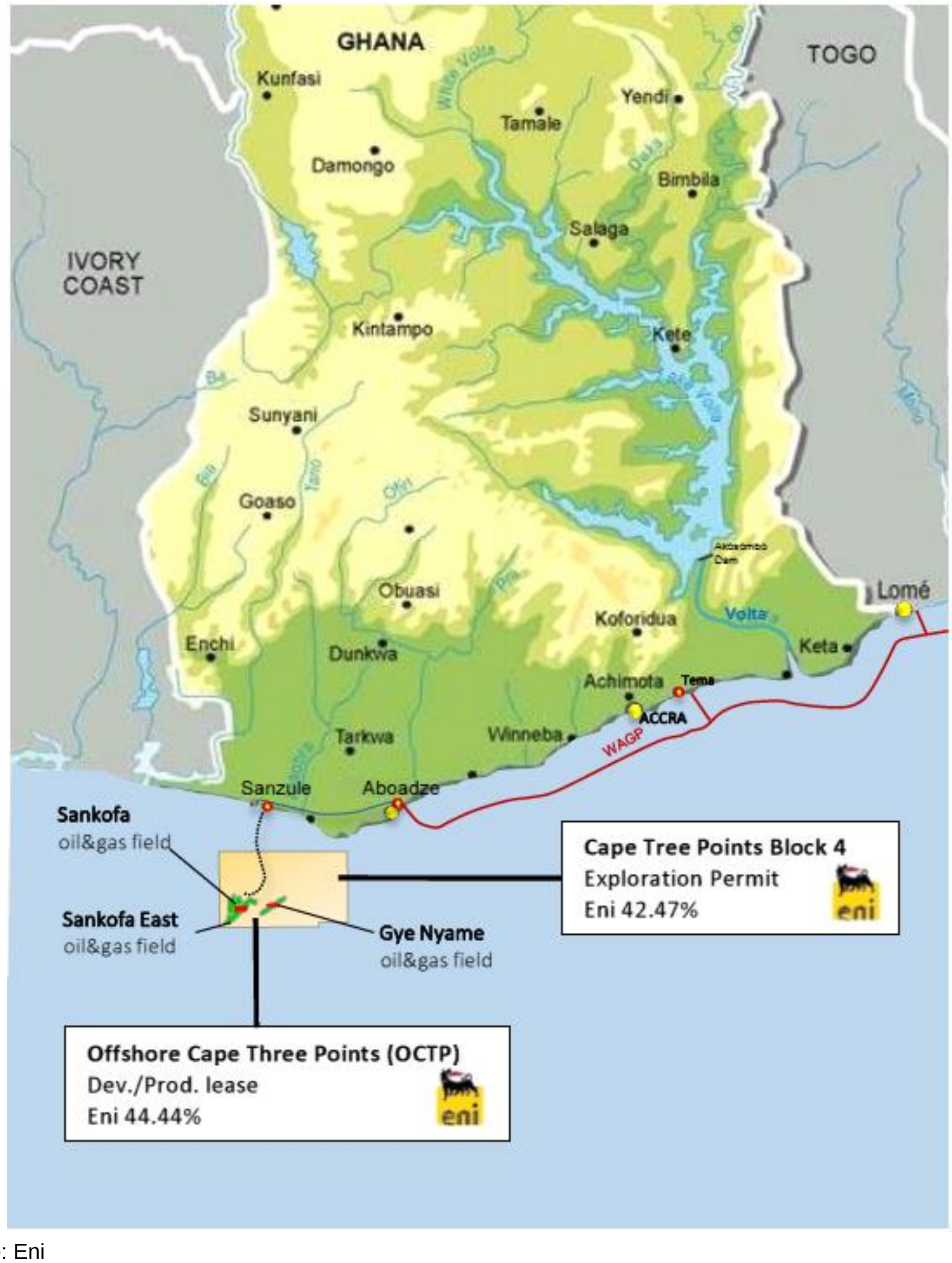


Source: IEA and Energy Commission of Ghana

Domestic gas supply in Ghana is largely under the control of the Ghana National Petroleum Corporation (GNPC), which was established in 1983 to undertake the exploration, development, production, and disposal of petroleum. The corporation is partner in all oil and gas agreements in Ghana and the operator of the Voltaian Basin onshore exploration project. GNPC is also the national gas sector aggregator in Ghana, and aims to supply sufficient fuel to meet Ghana's increasing energy needs.

Domestic production in Ghana began in 2014 with associated gas from the Jubilee field, followed by the TEN field start-up in 2016. Both the Jubilee and TEN fields are operated by Tullow Oil. Jubilee was discovered in 2007 and is an oil field with associated gas. Tullow has a 35.48% share and partners with Kosmos (24.08%), Anadarko (24.08%), GNPC (13.64%), and Petro SA (2.73%). The TEN field is predominantly oil with associated gas but there is also some non-associated gas. The TEN partners are the same as for Jubilee but with different shares: Tullow (47.18%), Kosmos (17%), Anadarko (17%), GNPC (15%), and Petro SA (3.82%).

Figure 4: Ghana Gas Market



Source: Eni

Note: Not to be reproduced or copied without written permission from Eni

Domestic production should be boosted by the development of the Sankofa and Gye Nyame fields, located 60 km off the west coast of Ghana, with the FPSO "John Agyekum Kufuor" which arrived in April 2017 and which was commissioned in July. The project is being developed by a joint venture comprising: Eni[11] (44.44%), which is also the operator; Vitol (35.56%); and GNPC (20%). Additionally, the second phase of the Offshore Cape Three Points (OCTP) project which aims at developing non-associated gas should come into production in the second half of 2018. This gas[12] should produce 1,000 MW of domestic power generation, equivalent to approximately 40 per cent of the country's total installed generation capacity for at least fifteen years.

On the eastern side of the country, there is no domestic production, and future supply to this region is less certain as documented later in this analysis.

Western and Eastern Markets

At the moment, the Ghanaian gas market can be considered as two effectively separate markets, with domestically produced gas unable to flow between the two. The WAGP can deliver gas from Nigeria to both Tema and Takoradi, but there is no connection between the Ghanaian system around Takoradi and the WAGP system which ends at Takoradi, currently to take domestic gas produced in the western area to Tema in the east. In Takoradi, where all domestic gas production is landed, current thermal power generation capacity is 860MW from three plants, which would result in a peak daily gas consumption of around 170 mmscfd[13], if all plants burned gas. In Tema, where all the Nigerian imports are now delivered, the current thermal power generation capacity is around 1,230MW from nine plants, including the gas-only Sunon Asogli plant, which would give a peak daily gas consumption of some 270 mmscfd, if all plants burned gas. However, with the low levels of gas deliveries from Nigeria, almost all these plants are currently having to burn oil when they operate, apart from Sunon Asogli.

The western area is west of Takoradi – see Figure 4 - , where the domestic gas is landed, and the eastern area is around Tema and Accra where the Nigerian gas is delivered. WAGP also has a delivery point at Takoradi and there is currently a project underway to make this an entry point to receive gas from the GNPC system for onward delivery to Tema. This project will also increase the Tema offtake capacity to 240 mmscfd and will be ready in time for the start-up of gas from the big Sankofa or OCTP field in the middle of 2018.

Pricing

Until the start-up of gas from the Jubilee field, Ghana relied on gas imports so the price was effectively the imported gas price from Nigeria through WAGP. The price of this imported gas is governed by the WAGP contract terms and consists of three main elements:

- The contracted wellhead price in Nigeria which consists of a base price which changes partly in relation to the Bonny Light oil price and US inflation.
- The pipeline tariff on the Escravos – Lagos pipeline system (ELPS) which delivers gas from the gas fields to the entry point of WAGP at Itoki.
- The WAGP tariff which is supposedly a 100 per cent capacity charge but in practice, because of the continuous *force majeure* declared by the Nigerian supplier, has been charged on a volumetric basis.

[11] In March 2016, Eni was awarded the operatorship of the exploration license Cape Three Points Block 4.
[12] In 2015, Eni signed a Gas Sale Agreement with the Ghana Authorities, as well as other agreements related to the guarantees for the sale of gas from the OCTP project.
[13] Assumed efficiency of 45 per cent for CCGTs and 33 per cent for OCGTs

There are a few small additional fees and charges to be included to arrive at the delivered gas price. Since the WAGP start date in 2011, the delivered price to Ghana, either at Tema or Takoradi, has usually been in the mid $8/mmbtu range. The WAGP tariff has been increasing over time (currently over $5/mmbtu) while lower oil prices have reduced the wellhead price. At current oil prices, the wellhead price in Nigeria for gas delivered to WAGP is only around half the price that can be achieved by selling the gas in Nigeria to power generators or industry. This incentivises producers to sell the gas in Nigeria rather than send it along the WAGP. Furthermore, potential new buyers for Nigerian gas are inhibited by the high WAGP tariff and the final price they would need to pay.

The Jubilee oil field produces associated gas which was first delivered to the power plants in Takoradi in 2014, when the pipeline and processing plant which was needed to commercialize associated gas entered into service. This associated gas is delivered to the beach, at no cost for the first 200 billion cubic feet (bcf); around a quarter of this total had been delivered by the middle of 2017. The price charged by GNPC to the power plants in Takoradi in 2016 was $8.84/mmbtu, and consisted of: a gas commodity price of $2.90/mmbtu, which is linked to the light crude oil price; a gathering, processing, and transportation fee of $5.28/mmbtu; and a Public Utilities Regulatory Commission (PURC) levy[14] of $0.66/mmbtu. The resulting price for Jubilee gas was suspiciously similar to the final WAGP price. Given the gas is provided for free, the price structure and level suggest that the GNPC is capturing the economic rent through excessive charges. The PURC levy of $0.66/mmbtu, assuming that it is designed to cover the costs of the PURC, also seems excessive, especially when compared with the regulatory fee of $0.06/mmbtu charged on the WAGP[15], and the fact that PURC regulates the electricity sector as well, which has been its main rationale. Once the free gas volume (specifically the first 200 bcf) ends, it is understood that the gas commodity price will be $2.35/mmbtu. This should not, however, affect the final delivered gas price, since the commodity price is already “assumed” to be $2.90.

The TEN oil field, also operated by Tullow, started producing associated gas in 2016. By the end of 2016, Jubilee and TEN had produced just over 50 bcf of gas between them. The TEN field consists of both associated and non-associated gas, with the commodity price for the associated gas being $0.50/mmbtu and the non-associated gas price being $3.00/mmbtu.

Deliveries of non-associated gas from the Sankofa field, part of the Offshore Cape Three Points (OCTP) project, to the Takoradi area are expected to start in mid-2018. The Takoradi offtake point on the WAGP is being reconfigured as an entry point to allow the delivery of this gas to Tema as well as Takoradi. Over a time period of 14 years the Sankofa project is expected to deliver 180 mmscfd, split between the Takoradi and Tema power plants.

A Gas Sales Agreement (GSA)[16] between Eni/Vitol and GNPC has been agreed for an estimated 19-year period (13.5 years of plateau and 5.5 years of expected decline period). The price agreed by the parties is $9.80/mmbtu (2014 money) and the annual quantity is 62 bscf. The contract includes a Take or Pay (ToP) clause that states that the GNPC has to pay for 90 per cent of the agreed quantity of gas whether it is able to take it or not.

The World Bank report 96554-GH states that the gas price formula includes an annual escalation linked to the Henry Hub price and to changes in the US Consumer Price Index as well as a capping mechanism related to the Brent oil price. Also included is an option for GNPC to decrease the gas price by $0.55/mmbtu per $100 million contributed by GNPC to the funding of the gas pipeline.

While the gas price negotiated in the GSA is $9.80/mmbtu, the levelized net economic cost of the gas for Ghana is estimated to be $6.60/mmbtu (2014 money) taking into account direct and indirect

[14] A levy to “fund” the PURC.

[15] The fee of $0.06/mmbtu is paid by the shippers to the transporter and it is then passed on to the regulator – the West African Gas Pipeline Authority – to fund its activities.

[16] World Bank report 96554-GH, page 50.

revenues to the Government of Ghana generated by the project[17]. The price is reduced from $9.80 to $8.20/mmbtu as a result of the royalties and income taxes accruing to the government, and then to $6.60/mmbtu largely reflecting the benefits of GNPC's share of the gas sales revenues combined with their 15 per cent carried interest on the capital costs. It is thought that these "benefits" will be taken into account when setting the final delivered price to end users.

The net $6.60/mmbtu cost is for delivery at the beach. On top of this there is a gathering and processing charge for the GNPC onshore pipeline, which is thought to be around $1.00/mmbtu to deliver the gas to Takoradi, as opposed to the much higher charges levied on the Jubilee gas. To deliver gas through WAGP to Tema, an interim tariff for 2018 has been agreed at around $1.65/mmbtu, in 2017 dollars, although GNPC has agreed to fund the additional work on the WAGP to accommodate this gas and as a result will receive a discounted tariff of $1.50/mmbtu. In total, therefore, the cost of Sankofa gas delivered to Tema is thought to be just over $9/mmbtu – slightly in excess of the current price of Nigerian gas delivered to Tema via the WAGP.

The Table 1 summarises the different prices for delivery at Tema for Nigeria gas and Sankofa. Jubilee and TEN gas is assumed to be delivered at Takoradi so attracting no WAGP transport fee. However, even if they did go to Tema, the delivered price may not change since the high Ghana transport price would most likely be reduced.

Table 1: Gas Price Comparison at Tema

$/MMBTU	Gas From Nigeria		Jubilee	TEN		Sankofa
	2016 H1	2016 H2		Ass'ted	Non-Ass'ted	
Wellhead Price	1.4870	1.2582	2.9000	0.5000	3.0000	6.6000
Nigeria Transport	1.2983	1.2983				
Ghana Transport			5.2800	5.2800	5.2800	1.0000
WAGP Transport	5.0330	5.0330				1.5000
Other Charges	0.3158	0.3673	0.6600	0.6600	0.6600	
Total	**8.1341**	**7.9568**	**8.8400**	**6.4400**	**8.9400**	**9.1000**

Other charges:
WAGP includes the regulatory fee, a pipeline protection zone charge, deliver fee and fuel use
In addition there is a credit support charge which is a fixed fee and is not included in the delivered price. This would have been almost an additional $1.00 in 2016 because of very low volumes but at the contracted volumes level would be less than $0.10.

For Jubilee and TEN other charges are the PURC levy

Source: Energy Commission of Ghana, World Bank, OIES Analysis

With gas from Jubilee, TEN, and Sankofa being priced at the commodity level on a different basis, it remains uncertain what the prices charged to the end user will be, but it seems likely that the commodity prices will be amalgamated and then a single price, which includes gathering, processing, transportation, and other charges, will be charged to the power plants.

The current pricing of gas in Ghana, at least to the end users in the power sector, seems to have coalesced around the $8 - $9/mmbtu range, consistent with the price of gas from Nigeria delivered via the WAGP. At the moment GNPC is generating a large economic rent by selling domestic gas at this price but this will change once Sankofa gas comes on stream in 2018 and also when the "free" Jubilee gas ends. At these price levels, LNG becomes a realistic option, but its uptake depends on whether Ghana actually needs LNG supplies.

[17] World Bank report 96554-GH, page 63.

Ghana's supply and demand balance suggests a potential need for LNG post 2020

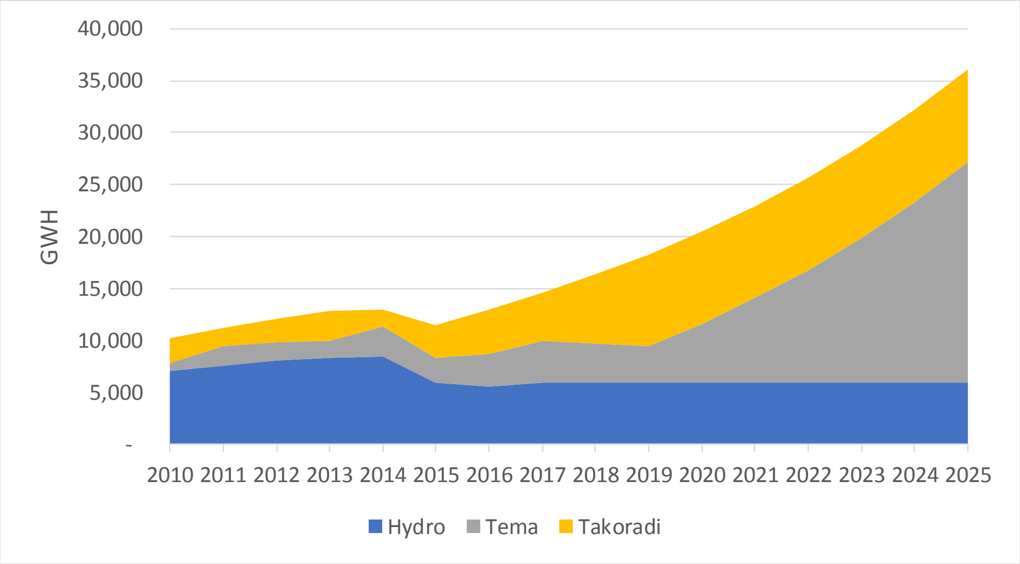
The complexities of the Ghanaian system mean that assessing the prospects for imports of LNG into Ghana is not a straightforward matter. There are many questions which need to be answered over the next ten years, including:

- What will the total power generation demand be in Ghana and will this be affected by reducing electricity transmission and distribution losses?
- How much can hydro contribute in the future?
- If the domestic gas supply feeds the Takoradi power plants, how much will be available to be delivered through WAGP to Tema?
- How much gas will be imported from Nigeria into Tema, bearing in mind that there is a contract for VRA to take 123 mmscfd, but that this is currently in *force majeure* and flows are barely half this rate at the moment?

In a number of unpublished presentations, the Ghanaian government has shown projected power generation demand growing at 12 per cent per annum over the next few years. While some regard this as optimistic, this is a useful benchmark for a base case scenario. In addition to the current 860MW of thermal capacity at Takoradi there is another 630MW committed from both the Karpower Turkish power barge (430MW) and the Amandi CCGT (200MW). The power barge is due to be delivered in the middle of 2018 to coincide with the start-up of the Sankofa field, although this is a very expensive way of adding generating capacity. The Amandi plant may start up in 2019 although this remains uncertain. There is even more new committed capacity at Tema with another 1,025MW from four new plants planned, plus an additional plant at Sunon Asogli. If all these plants at Takoradi and Tema are constructed, then the total thermal capacity capable of burning gas would increase to 3,750MW with a peak daily gas consumption of 780 mmscfd. Together with the existing hydro capacity this is more than enough to meet the government's 12 per cent per annum growth projection.

The chart below is a possible scenario incorporating the 12 per cent per annum projection for power generation demand, assuming that there is little pick up in hydro generation capability and that only the Karpower barge comes on line at Takoradi, not the Amandi plant[18].

Figure 6: Electricity Generation to 2025

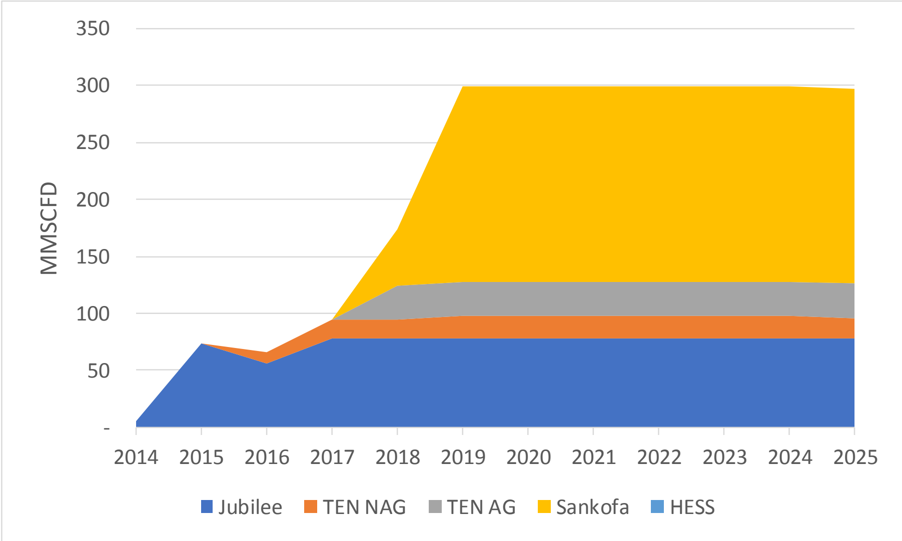


Source: OIES Analysis

[18] The small amount of renewables has been omitted from this chart.

In respect of domestic gas production, the chart below sets out a projection through to 2025 based on field operator assumptions.

Figure 7: Ghana Gas Production to 2025



Source: OIES Analysis

Once Sankofa comes on line, the total domestic production delivered to the Takoradi area is expected to be almost 300 mmscfd. There is also the possibility of a further 50 mmscfd of associated gas from the Hess operated field which is in the Deepwater Tano/Cape Three Points block but this is not expected to materialize until after 2025[19]. As noted earlier, there is a project underway to connect the domestic gas pipeline system, in the Takoradi area, with the WAGP to allow gas to flow from Takoradi to the larger Tema markets, and this is scheduled to start up in the middle of 2018 coinciding with the Sankofa field coming online.

How does this combination of power generation demand and domestic gas production translate into gas flows and imports? If it is assumed that on an annual basis all the gas-fired plants operate on average at a 75 per cent load factor, then Table 2 illustrates a possible base case scenario.

Table 2: Gas Supply Projections

MMSCFD	2018	2019	2020	2021	2022	2023	2024	2025
a Takoradi Supply	174.02	299.02	299.02	299.02	299.02	299.02	299.02	297.02
b Takoradi Demand	159.36	213.60	213.60	213.60	213.60	213.60	213.60	213.60
c Export to Tema (a-b)	14.66	85.42	85.42	85.42	85.42	85.42	85.42	83.42
d Tema Demand	91.79	84.59	137.28	196.28	262.37	336.39	419.29	512.14
e Tema Shortfall (d-c)	77.13	- 0.83	51.86	110.86	176.95	250.97	333.87	428.72
f Nigeria Imports	90.00	90.00	90.00	90.00	90.00	90.00	90.00	90.00
g Available for LNG (e-f)	- 12.87	- 90.83	- 38.14	20.86	86.95	160.97	243.87	338.72

Source: OIES Analysis

It is assumed that the level of Nigerian gas delivered to Tema is set at 90 mmscfd, which is below the 123 mmscfd contract level but above recent levels of 60 mmscfd. Once Sankofa starts up and with only the Karpower barge added to the generation capacity at Takoradi, it is estimated that some 85 mmscfd would be available to flow to Tema from Takoradi and with the assumed 90 mmscfd coming

[19] Hess has a 40% share and its partners are Lukoil (38%), Ghana National Petroleum Company (20%), Fueltrade (2%)

from Nigeria, this obviates the need for LNG imports. Indeed, through to 2020, Ghana is over-supplied with gas. It should be noted that our analysis also assumes that all the thermal plants capable of burning gas will use gas, and that there will be no oil used in Ghana's power generation sector once Sankofa comes on stream. By the early 2020s, however, there is space for LNG imports in increasing quantities as demand from Tema increases.

Clearly, there are any number of possibilities which could alter this scenario significantly. For example, if Ghana recognises that there is a surplus of gas, until 2020 at least, it could generate more electricity for export to neighbouring countries, thus further increasing the demand for gas.

In respect of the outlook for LNG imports, the location of the generating capacity, whether at Takoradi or Tema, is not particularly relevant, since if there was less generation at Takoradi – no Karpower barge for example – there would be more at Tema fed by increased flows on WAGP, following the interconnection with the Ghana system in 2018, from Takoradi to Tema[20].

Assuming domestic production is used in power plants either at Takoradi or Tema, a key variable in assessing the need for LNG is the level of imports from Nigeria. Clearly if they were much lower (60 mmscfd or below) then this could bring forward the time when LNG is required but this is unlikely to be before 2020, in the absence of a material increase in short-term power generation demand. However, despite the apparent lack of requirement for LNG in the short term, the Ghanaian authorities may be pursuing import options for security of supply reasons.

The Ghanaian government seems keen on LNG, but will plans materialise?

As in the Ivory Coast, gas is already being used in Ghana, but here any growth in demand will first be met by new domestic production, with LNG only considered a supplementary source of fuel. Nevertheless, in August 2017 the government of Ghana signed a Memorandum of Understanding (MoU) with Equatorial Guinea for the latter to supply the equivalent of 150 mmscfd of natural gas per day in LNG to Ghana. The MoU also provides for the building and operation of an LNG regasification terminal in Takoradi. Then in September 2017, Gazprom[21] signed a GSA with the GNPC due to commence from 2019 for an initial period of twelve years, providing a second potential source of long-term LNG.

However, if Ghana is to import LNG in any great volume it is clear that suitable infrastructure will need to be built to receive it. Unfortunately, in East Ghana, of the two LNG supply infrastructure options envisaged, one has been significantly delayed and the other may no longer go ahead. The details behind both projects are outlined below, and provide good examples of the difficulties in developing LNG markets in the region.

- The Tema LNG Project is planned to have the scalable ultimate capacity to receive, store, regasify, and deliver 3.4 mtpa utilizing a dedicated FSRU moored off-shore Tema. An associated sub-sea and onshore pipeline will deliver the natural gas to GNPC and its customers onshore. The project, comprising a capital outlay of over $550m, will be implemented on a build-own-operate-transfer basis with the assets transferring to the GNPC after the project's twenty-year term. The idea behind the project is to provide a cheap bridge fuel at a time when WAGP is not providing the required gas for Ghana and where some power generation in East Ghana could move from oil product feedstocks to gas. Höegh LNG signed an FSRU contract with Quantum

[20] The Karpower barge would simply transfer 80 mmscfd of demand from Takoradi to Tema and while this may slightly reduce potential imports from Nigeria, because of the 240 mmscfd offtake capacity at Tema, this would not materially change our conclusion on the need for LNG imports.

[21] http://www.gazprom-mt.com/WhatWeSay/News/Pages/Gazprom-Marketing-and-Trading-Ltd-signs-gas-sales-agreement-with-Ghana-National-Petroleum-Corporation.aspx

Power[22] in December 2016 for the Tema LNG import terminal which will be located close to Accra. The Tema project has an offtake agreement with GNPC for a period of twenty years with a five-year extension option for the charterer and is expected to generate an average annual EBITDA of around $36m. A long-term Time Charter Party Agreement for the FSRU has also been signed with Höegh LNG for FRSU *Höegh Giant* to start being operational in mid-2018 (while used as an LNG carrier in the interim period). In June 2017 the acting head of GNPC said the company was in the market for between 250-500 mmscfd and expected to begin importing LNG early next year, although based on the analysis above these estimates seem wildly optimistic. However, in its H1 2017 results, Höegh stated that, "the project in Ghana remains subject to final governmental approval. As the governmental approval was expected mid-2017 but has not yet been received, the project's timeline could be affected. A positive award will lead to FID and start-up under the FSRU contract 6-12 months following the commencement of the construction work, which includes a pipeline to shore and a spread mooring system to install the FSRU offshore the port of Tema."[23] In its Q3 2017 results, Höegh stated, "The project remains subject to government approval. In the third quarter, the government of Ghana reached an agreement with Gazprom over long-term gas supply, underpinning the country's desire to replace expensive liquid fuels with attractively priced LNG. A positive award will lead to FID pending financial close for the offshore pipeline and spread mooring system to connect the FSRU to the onshore gas grid in eastern Ghana. Start-up under the FSRU contract is expected 9 to 12 months after construction begins"[24]. It seems that as the months pass, the project is further delayed.

- West African Gas Limited (WAGL), comprising Nigeria's state NNPC (60 per cent) and private Sahara Energy (40 per cent), signed a five-year contract with Golar for an FSRU to be moored inside the port of Tema at a new jetty being built by WAGL. On 19 October 2016, WAGL received parliamentary approval for its ten-year gas sales agreement with the government of Ghana, and the FSRU *Golar Tundra* arrived on site in Q3 2016. But according to Golar's Q2 2017 results, "The FSRU *Golar Tundra* remains anchored off the coast of Ghana. WAGL has made no further progress with the construction of supporting land-based infrastructure." Subsequently, in its Q3 2017 results, Golar mentioned that, "the Golar Tundra departed Ghana in September and prepared for service as an LNG carrier"[25], implying that this project will no longer go ahead. This is in fact the best example of a failed attempt to use LNG when prices were low and an FSRU was available. With an FSRU remaining unused for a year, it may be that Ghana has lost all credibility in the eyes of investors for future FSRU options.

Our analysis demonstrates that sub-Saharan African countries which have faced huge difficulties importing foreign gas in the past are still not in a good position to be able to use the FSRU technology that has been an enabler in other parts of the world (Egypt and Pakistan, for example). And with the LNG market now not as relaxed as previously thought by consensus, the FSRU option is likely to be more difficult for other African countries after the failures in Ghana.

[22] Quantum Power is a pan-African energy infrastructure investment platform, currently operating in Ghana, Kenya, Mozambique, Namibia, Nigeria, Rwanda, Senegal, South Africa, and Zambia.
[23] http://hugin.info/143849/R/2128904/813076.pdf
[24] http://hugin.info/143849/R/2150104/825257.pdf
[25] http://www.golarlng.com/investors/press-releases/pr-story.aspx?ResultPageURL=http://cws.huginonline.com/G/133076/PR/201711/2153082.xml

Conclusion

Ghana's drive for gas is aimed at replacing oil as a fuel in the power generation sector, so providing that any gas being offered to consumers - whether domestically produced or imported by pipeline or as LNG – is priced so as to be cheaper than oil, then there should be a market for it. The issue in Ghana and other countries in terms of affordability however, is not just the price of gas compared to oil but whether the electricity market and electricity end users can or will pay for it. The non-payment issue in Ghana and other countries, which starts with the electricity consumers and flows through to the electricity generators and then to the gas suppliers and transporters, may be the key obstacle to growing their gas markets.

Table 3: Way Ahead

	+	-	Solution
People	Need more primary energy to sustain growth	No infrastructure, little money	Focus on local decentralised solar and use gas as a back-up
Energy mix	Move away from coal to renewables	Storage	Gas as a transitional fuel and FSRU for storage
Governments	Skills transfer. LNG could help to kick start domestic gas production	Links with electricity incumbent	Need to demonstrate: a robust simple plan; willingness to enforce payment for gas by government-owned companies
Traditional gas companies	Need to find additional demand	Projects must be profitable and not too small	Can concentrate on power plant with a loan for demand and FSRU for supply (on a market basis)
New entrants	Digital projects need to be small	To be invented	Need to have sunk infrastructure and an anchor customer
Infrastructure companies	Know how to build and operate pipes that are always a geographical monopoly	Needs visibility of future revenues (impossible)	Can build under a turn key contract and operate under a service contract / concession
International organisations	UN 2030 Agenda - Sustainable Development Goal n°7: Affordable and Clean Energy	To kick start projects while being as technology neutral as possible and to leave competition open	Must allow new entrants to compete thanks to new business models that should provide new cheaper solutions to bring energy to people

Source: thierrybros.com

When looking at the options available if Africa wants to boost its energy demand to get its population out of fuel poverty in a post-COP21 world (see table above), modern FSRU solutions offer the quickest, most cost-efficient, and flexible way of importing LNG and deploying this cost-efficient and clean fuel supply infrastructure solution to Africa. Floating import regas terminals could transform the reliability and competitiveness of power generation and gas markets in Africa. But alignment of all parties is needed and it seems to be more difficult in Africa than anywhere else. As seen in Ghana, even an FSRU project needs to be approved by the government, to find customers who are willing to pay and to come in tandem with some additional infrastructure. Alternative solutions to FSRU would either be more polluting (coal and oil) or would take longer or be more expensive (electricity from renewables would need either be intermittent or would have to wait for storage to be affordable), but may still have a role if gas supply options run into political and commercial problems as has been the case in Ghana.

Thanks to digitalisation, the world is changing very quickly with new companies, such as Uber and AirBNB, fiercely competing on price and service levels with old business models (taxis, hotels) while relying on existing infrastructure (roads for Uber, rooms for AirBNB). Could a similar picture be emerging in the energy industry? Current developments in Africa, at least, would suggest not, certainly in the short term. As in OECD countries at the inception of the LNG business, the presence of the national oil company is still required for any project in Africa. Unfortunately those state-owned companies are not known for their ability to fast track decisions and it also seems that a lack of transparency does not help to foster the alignment of the many parties which each have a different agenda. The established companies (NOCs, IOCs and the existing infrastructure) that have so far failed to deliver enough energy in sub-Saharan Africa are not being challenged by new entrants and will therefore continue to fail to provide energy to the African people. In Ghana hopes were raised thanks to the use of FSRU technology, but prospects are being undermined as even the construction of a small piece of infrastructure required to connect the FSRU to the onshore gas grid seems impossible to achieve. Furthermore, it is worth mentioning that markets are efficient only as long as data is available. The lack of data makes the entire gas chain even more vulnerable to the weakest link and without the option to find alternative solutions, as it is impossible to see where this link is.

Timing is also key for import projects. As seen in the Ivory Coast and Ghana, fostering the alignment of all parties takes time. If it takes too long, then Africa could miss the cheap LNG supply wave. If this happens, the future of LNG in Africa could well remain an impossibility as expensive imported gas is not an option for the continent. In this instance, gas demand in Africa will not develop and/or demand will be filled by another hydrocarbon fuel or renewables. Consequently, LNG suppliers should not anticipate growing demand from sub-Saharan Africa. This analysis of the Ghanaian market reinforces Jonathan Stern's conclusions in his latest paper, "Challenges to the Future of Gas: unburnable or unaffordable?" where he emphasizes the many challenges for gas. In Ghana, the future of LNG looks bleak.

The IEA WEO 2017, in its central scenario, expects a 3.5 per cent CAGR for gas in Africa in 2016-2040 (much lower than the 5.8 per cent per annum seen in the period 2000-2016) compared to a worldwide average of 1.6 per cent. Our analysis of Ghana implies this could be possible for gas producing countries but not in countries without any gas resources. We would therefore agree with the IEA's comment that, "Africa's future demand for gas is closely linked to efforts to establish or revive domestic gas markets, notably in Tanzania, Mozambique, Nigeria, Algeria and Egypt"[26]. As for the statement, "LNG-to-power projects are being pursued in Ghana[27], Namibia, Senegal and South Africa to create a domestic gas market, and FSRUs fit well with such projects because they are scalable, fast to deploy and require substantially less (sunk) capital than an onshore terminal or a large cross-border import pipeline project"[28], our analysis of Ghana suggests that this looks more a theoretical concept than relating to any imminent project. With an inability to move from theory to practice, sub-Saharan Africa would have to wait for another disruption (technological or market related) if it hopes to attract foreign gas. Our analysis, in line with the WEO central scenario, concludes that growing demand for gas in Africa in the next decade is going to be more difficult than in the past fifteen years as the countries which are producing gas already have domestic demand,

[26] IEA WEO 2017 p. 341

[27] We would not necessarily agree with the IEA that LNG is being pursued to create a domestic market in Ghana (or South Africa) as there already is one.

[28] IEA WEO 2017 p. 358

while the remainder will find it very difficult to import gas. It also suggests that developing LNG supply projects in Africa could face some significant hurdles if investors were to target other African markets as their main customers. Perhaps the only solution for now to increase gas demand in Africa is for resource-rich countries to make sure that some of the gas is sold domestically to fuel the local economy, which suggests that, as in Ghana, the prospects for LNG imports are relatively poor.