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International Petroleum Transactions and the Development of Gas-to-Power Markets in West Africa

by T. Oyewunmi

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International Petroleum Transactions and the Development of Gas-to-Power Markets in West Africa

Tade Oyewunmi[*]

1. Introduction

As the emergence of low-carbon and transitional energy markets gain traction globally, the viability and security of gas supply markets are becoming as essential as the need to decarbonise and curb unsustainable practices such as flaring and methane leakages along the value chain. Consuming markets and states will need to foster more competitiveness and a gradual switch from more carbon-intensive energy sources such as coal and diesel oil. In particular, countries in the Sub-Saharan African context that are still in the early stages of developing required infrastructure and regulatory framework are increasingly concerned with reliability of supply from both the upstream exploration and production (E&P) segments, and would also need to address challenges in the institutional and investment climate of their domestic downstream energy sectors.[1] With African energy demand is projected to grow at 3.5% per annum (p.a.) over the next couple of decades, it is interesting to note that the continent has about 488 trillion cubic feet (Tcf) of proven gas reserves and gas production is projected to increase by 110%.[2] Accordingly, projects designed to support production and supplies must be bankable,[3] thus requiring applicable legal, regulatory and contractual frameworks which are designed to enhance timely investment decisions and effectively mitigate post and pre-completion risks.[4]

Compared to more recent trends in which more gas commercialisation and utilisation projects are being considered for domestic electricity, commercial and industrial uses, earlier projects (e.g. in the 1990s to 2000) were mostly developed as a means of creating alternative sources of export and foreign exchange earnings. Within the past decade, about 30% of global oil and gas

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[1] The International Energy Agency (IEA) *Global Gas Security Review 2018: Meeting Challenges in a Fast-Changing Market*, (IEA Publications, 2018) 1-102; Rahmat Poudineh and Tade Oyewunmi, 'Natural gas in Nigeria and Tanzania: can it turn on lights?' in *Oxford Energy Forum Issue 115- Electrifying Africa*, (Oxford Institute for Energy Studies, September 2018) 14-20.

[2] BP Plc, *Energy Outlook 2018: Country and regional insights- Africa* (BP Publications 2018) <www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/energy-outlook/bp-energy-outlook-2018-region-insight-africa.pdf> (accessed 21.05.2018); BP Plc, *Statistical Review of World Energy 2018* (67th Edition, June 2018) 1-53 at 26; Snam, International Gas Union (IGU) and The Boston Consulting Group, *2018 Global Gas Report* (IGU Publications, November 10, 2018) 1-55.

[3] Bankable projects can be regarded as those with sufficient collateral, future cashflow, and high probability of success, that is acceptable to institutional lenders, financiers or stakeholders to the extent confirming an investment decision(s). In other words, considering the overall structure of the project vis-à-vis risks and returns, relevant lenders, sponsors or financiers are willing to support such project. Any risks to the stability of cashflows and reasonable returns, whether due to changes in law, taxation or regulation; or supply and service interruption due to political interference or terrorist action or sabotage of infrastructure, will be crucial.

[4] Tade Oyewunmi, 'The Evolving International Gas Market and Energy Security in Nigeria' in Sola Adesola and Feargal Brennan (eds), *Energy in African Developing Economies: Policy, Management and Sustainability* (Palgrave Macmillan, 2019) 237 at 117-145.

discoveries have been in Sub-Saharan Africa.[5] Countries such as Ghana, which hitherto relied mostly on imports have recently announced oil and gas licensing rounds, while also developing several upstream and midstream gas projects from the Sankofa and Gye Nyame fields in the Offshore Cape Three Points (OCTP) area, as well as the Tweneboah-Enyennra-Ntomee (TEN), projects to augment shortfalls in imports and meet growing demand.[6] Projects such as the West African Gas Pipeline (WAGP) where designed to take gas from producers in Nigeria to fuel power generation utilities in neighbouring Benin, Togo and Ghana. Other commercialisation options from traditional large-scale to small-scale LNG projects, Floating Storage and Regasification Units (FSRU) and Floating Liquefied Natural Gas (FLNG) have equally gained more attention, despite the challenges of affordability of delivered gas, downstream power sector liquidity and creditworthiness, technical and commercial losses, constraints to timely investment decisions have been considerable.[7]

As these issues arise, and projects are being structured to overcome the various challenges, it is important to note that the institutional framework of laws, regulations, policies, licensing and contracts relating to the exploration, production and supply of gas plays an instrumental role in meeting any underlying security of supply, sustainability and competitiveness objectives and creating viable gas markets. By highlighting some developments in Nigeria and Ghana, this paper will examine the spectrum of international petroleum transactions, legal, policy, and risk assessment issues that underpin gas utilisation and commercialisation projects in the West African sub-region.

2. Supplying Gas for Power Generation in West Africa

Ordinarily, domestic gas production enhances a vibrant and less costly gas-to-power industry when the gas reserves are available in commercial quantities, coupled with the required infrastructure, technical know-how and investment capital. In countries with little or no gas reserves, importation becomes an attractive option, mainly when cross-border pipelines or LNG via FSRUs are available. In either case domestic prices, energy policy and economic regulation must support the cost of imported or domestically produced gas and the necessary infrastructure.[8] Natural gas, whether produced from oil-rich reservoirs (i.e. associated gas) or gas only fields (i.e. non-associated gas) is capital-intensive to process, supply or store, albeit,

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[5] Yinka Omorogbe and Tade Oyewunmi, *OGEL Special Issue on "Oil and Gas Law and Policy in West Africa" – Editorial* (OGEL 1 (2017) at <www.ogel.org/article.asp?key=3665#_ftn2> (accessed 05.04.2018)

[6] The World Bank, *'Ghana - Sankofa Gas Project'* (World Bank Group Report 96554, Washington, D.C., 2015) 1-114 available at <http://documents.worldbank.org/curated/en/173561467986250592/Ghana-Sankofa-Gas-Project> (accessed 21.05.2018); Mike Fulwood and Thierry Bros, *Future Prospects for LNG Demand in Ghana* (Oxford Institute for Energy Studies (OIES), Energy Insight: 26, 2018) 1-15. Ghana's first oil and gas licensing round was announced on October 15th, 2018, see <https://www.ghanalr2018.com/>.

[7] Ghana, Côte d'Ivoire etc. have all dabbled into the FSRU option within the past decade, while the Nigerian LNG project remains one of the biggest LNG suppliers globally, other projects such as the Brass LNG and Olokola LNG export projects were mothballed or stalled. See. Tade Oyewunmi, *Regulating Gas Supply to Power Markets: Transnational Approaches to Competitiveness and Security of Supply* (Kluwer Law International, 2018) 323 at 40-43; Yinka Omorogbe, 'Law and Investor Protection in the Nigerian Natural Gas Industry' (1996) 14(2*) Journal of Energy & Natural Resources Law* 179-192; Thierry Bros, *Can small LNG meet the challenge of empowering Africa?* in Oxford Energy Forum-Issue 110, Searching for Natural Gas Demand in the Next Decade, (OIES, August 2017) at 46-47

[8] Tade Oyewunmi, 'Examining the role of regulation in restructuring and development of gas supply markets in the United States and the European Union' (2017) 40(1) *Houston Journal of International Law* 191-296. See also Oyewunmi (n4) on *International Gas Market and Energy Security*; Oyewunmi (n7) on *Regulating Gas Supply to Power Markets.*

efficient for energy and more environmentally-friendly compared to other hydrocarbons.[9] Before investments go into building essential networks of processing facilities and pipelines required to supply demand centres; the economic, security and reliability risks must be critically examined and subject to necessary due diligence evaluations.

Considering the relatively smaller demand sizes of most developing countries in the sub-region on the one hand and the inherent network-bound nature of gas-to-power and economies of scale features on the other hand, compared to the magnitude of natural gas resources required to justify a typically capital-intensive large-scale LNG and transnational pipeline project; there had been some challenges involved in matching gas supply to power demand downstream. However, recent technological advancements pertaining to bespoke smaller-scale gas commercialisation and LNG solutions for power generation has gained traction over the past decade.[10] The potential for downstream power projects- including the applicable legal and regulatory framework- to provide necessary guarantees (i) for the credit requirements of financing arrangements; and (ii) midstream infrastructure required to process and transport gas to where the power generation is needed; means that supplying gas to power at the right scale remains one of the most promising avenues for gas utilisation and developing viable gas markets, reduce gas flaring in producing countries, and support energy security in the sub-region. Additionally, to the extent that other more carbon-intensive hydrocarbons like coal and diesel oil would raise more concerning sustainability issues in a global low-carbon energy mix scenario, the deployment of gas-to-power solutions, together-with decentralised renewable energy projects would likely become increasingly essential for energy policy going forward.[11] The emerging tendencies for financial and lending institutions moving away from investment in coal and oil, as well as more international oil companies (IOCs) looking at more efficient ways to decarbonised operations, leaves a notional gap in the market for gas and more interests in gas commercialisation projects.

2.1. State Participation and Private Sector Operators

The role of the host country and host government (HG) as owners of oil and gas resources *in situ* and administrator through the licensing and regulatory framework respectively, is often made more complicated with the archetypical role granted to national oil and gas corporations in joint ventures or petroleum exploration and production agreements with IOCs and local private operators. In Nigeria for instance, ownership and title in all petroleum (oil and natural

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[9] See US EIA. 'Natural Gas and the Environment – Basics' (January 2016) <www.eia.gov/energyexplained/?page=natural_gas_environment> (accessed 20 March 2016); The Oil and Gas Climate Initiative (OGCI) Report (September 2018) 1-54 <https://oilandgasclimateinitiative.com/wp-content/uploads/2018/09/OGCI_Report_2018.pdf> accessed (01/10/2018). The Burning natural gas for energy results in fewer emissions of air pollutants and carbon dioxide (CO2) per unit of heat produced (less than coal or refined petroleum products). About 117 pounds of CO2 are produced per million MMBtu equivalents of natural gas compared to more than 200 pounds of CO2 per MMBtu of coal and more than 160 pounds per MMBtu of distillate fuel oil. Additionally, the development of CCGT technology means that gas-fired generation becomes relatively more efficient. The decarbonisation of gas networks, elimination of gas flaring and methane leakages would however be essential in the emerging international low-carbon scenario where gas supply will increasingly go hand-in-hand with distributed renewables and electrification of major traditional demand points.

[10] Michael Farina and Brandon Wilson, *Gas to Power: Fast and flexible electricity for rapidly developing countries*, (GE Gas to Power White Paper, August 21, 2015) 1-17 at <www.gereportsafrica.com/post/127212622815/gas-to-power-delivering-fast-and-flexible> (accessed 22 March 2016); United States Agency for International Development (USAID), *Understanding Natural Gas and LNG Options* 243, (Third Volume of Power Africa's 'Understanding' Series, USAID/US Dept. of Energy/US Energy Association, 2016).

[11] Poudineh and Oyewunmi (n1) ibid; Fulwood and Bros (n6) ibid.

gas) resources are vested in the Federal Government,[12] while direct state participation in industry activities is primarily carried out through the Nigerian National Petroleum Corporation (NNPC) and its subsidiaries such as the Nigeria Gas Company Ltd (NGC).[13] The Ministry of Petroleum Resources ('Ministry') oversees policy and regulation in the industry, and headed by the Minister of Petroleum ('Minister') who is empowered by the Petroleum Act to grant oil prospecting licenses (OPL) and oil mining leases (OML) etc.[14] The Ministry's Department of Petroleum Resources (DPR) functions as the industry regulator, while the Minister is also the designated chairman of NNPC's board of directors according to the NNPC Act.[15]

In Ghana, the ownership and title to petroleum resources is vested in the President, to be held in trust for the people,[16] while petroleum E&P activities shall be conducted in areas opened-up by the Minister in charge of petroleum under a licence or petroleum agreement.[17] The primary role of the Ministry of Energy is the formulation of policy, while the government-owned Ghana National Petroleum Corporation (GNPC)[18] is the commercial entity through which the state participates in industry activities, especially in petroleum agreements with IOCs and other private operators.[19] Concerning gas supply, the GNPC acts as an aggregator, while its subsidiary, the Ghana National Gas Company (GNGC) owns the domestic pipeline and operates the gas processing facilities, including the responsibility of developing the downstream distribution system.[20] Note also that the Petroleum Commission is responsible for

[12] See s 44(3) of the Constitution of the Federal Republic of Nigeria 1999 CAP C23 LFN 2004 ("Nigerian Constitution"); s 1 of the Nigerian Petroleum Act 1969 CAP P10 LFN 2004 ("Petroleum Act").

[13] The NGC was created in 1988 as the NNPC's subsidiary responsible for gathering, treatment, transmission and marketing in Nigeria's natural gas and its byproducts domestically and to neighbouring countries. NGC was restructured and renamed in 2016 as the Nigerian Gas Processing & Transportation Company (NGPTC) and the Nigerian Gas Marketing Company (NGMC). See Oyewunmi (n7) on *Regulating Gas Supply to Power Markets,* at 127-140.

[14] Section 2 of the Petroleum Act. An OEL is a non-exclusive right to explore for petroleum; an OPL is an exclusive right to explore and prospect for petroleum; and an OML is an exclusive right to search for, win, work, carry away and dispose of petroleum.

[15] the Nigerian National Petroleum Corporation Act 1977 (NNPC Act) CAP N123 Laws of the Federation of Nigeria 2004. The NNPC itself was originally a merger between the Ministry and the Nigerian National Oil Corporation, which was created in 1971. In addition, the NNPC Act created the Petroleum Inspectorate as a department and integral part of the NNPC. The NNPC's Petroleum Inspectorate was later merged with the Ministry of Petroleum Resources to form the DPR in 1988. The Act provides that any regulatory functions conferred on the Minister by the Oil Pipelines Act or Petroleum Act shall be deemed to have been conferred on the Chief Executive of the DPR. Among other duties, the Act charges the Chief Executive of the DPR with responsibility for issuing licenses and permits for all activities connected with petroleum exploration, exploitation, refining, storage, marketing, transportation and distribution. The Act also charges the NNPC with the duty of participating in every area of the petroleum industry, including exploring, prospecting, working, winning or otherwise acquiring, possessing and disposing of petroleum, as well as, providing and operating pipelines, tanker-ships and other facilities for the conveyance of crude oil, natural gas and their products and derivatives. See sections 5 and 10 of the NNPC Act.

[16] Section 3, Ghanaian Petroleum Exploration and Production Act 2016 (PEPA).

[17] Sections 5, 6 and 7, PEPA 2016.

[18] See the Ghana National Petroleum Corporation Act, 1983 (PNDCL 64).

[19] Based on Sections 10 and 11 of the PEPA, the exploration, development and production of petroleum must be subject to the terms of a petroleum agreement between a body corporate (i.e. a private company), the Republic of Ghana and GNPC, in which the body corporate is essentially a contractor (akin to a typical production sharing contractor, with participating interests as in a typical concession or license). The said petroleum agreement must also provide for an initial 'carried' participating interest of at least 15% for the GNPC, which may be increased subsequently as agreed by parties and the additional participating interests taken-up by the GNPC shall be a 'paying interest' in respect of costs incurred in the conduct of petroleum activities other than exploration costs. The GNPC may also engage in E&P petroleum activities in an opened area which is not yet subject to a petroleum agreement

[20] Ghana Ministry of Petroleum, *Gas Master Plan,* (2016) 1-246 at 10-11, 110-115.

upstream licensing and regulation, while the midstream and downstream licensing and technical regulation is carried out by the Energy Commission and economic regulation is undertaken by the Public Utility Regulatory Commission (PURC) which is designated to be the economic regulator for electricity, gas and water, thus, principally accountable for tariff setting, promotion of competition and complaints handling, which are all essential factors in growing a nascent gas market. The PURC advises the government on gas pricing- commodity prices and sets regulated tariffs for gas processing, transportation and distribution.[21] The Energy Commission licensed the Bulk Oil Storage and Transportation Company which was initially created to operate oil pipelines in Ghana in 2015 as the National Gas Transmission Utility.

The impact of government participation and control in the value chain is also evident in the pricing of gas-to-power and domestic gas utilisation. The IGU's 10-year global price formation and wholesale market survey reveals that within the past decade:

(a) The adoption of gas-on-gas competition (GOG) in pricing constituted the largest share of total world gas supply/consumption at 45%. Predominantly in North America, Europe, the Former Soviet Union and Latin America. The percentage of oil price escalation (OPE) pricing was about 20%. The regulated pricing categories – regulated cost of service (RCS), regulated social and political (RSP) and regulated below cost (RBC) – accounted for about 31%.[22]

(b) The fundamental changes have been the continuous move away from OPE to GOG in Europe, from RBC to RCS, RSP and GOG in Russia, from RSP to RCS and OPE in China and from RBC to RSP in Iran and from RBC to RCS in Egypt and Nigeria. GOG and OPE have also recently benefitted from pricing reforms in India and China respectively.

The trends signify a general move towards reforms and growing inclination towards developing more competitive price regulation and market governance structures globally. Furthermore, there is a race for market share in global markets by the incumbent and upcoming producers and suppliers. It portends keen competition for scarce investment capital by relevant operators and international firms, including NOCs. While there may be socio-political justifications for keeping prices low through 'regulated-pricing' in developing economies and markets, medium to long-term competitiveness and infrastructural developments, security of supply (due to the importance of gas in the energy mix) and sustainability (due to the environmental benefits of switching to less carbon-intensive gas from coal and oil products) would require more efficient market-based pricing, economic or incentive-based regulatory approaches. In an environment where the NOC and its subsidiary (e.g. Nigeria's NNPC and NGC) are expected to be the primary drivers of investments and infrastructural growth in the domestic market; export revenue losses, lack- of competitiveness or commercially insecure local markets could eventually lead to significant energy security and supply sustainability implications. The conclusion of lingering reforms and enhancing the viability and credit-worthiness of operators across the gas-to-power value chain is therefore essential.

[21] Ibid.

[22] The categories of OPE, GOG, Bilateral Monopoly and Netback from Final Product can be broadly described as "market-based" pricing, while the categories of RCS, RSP and RBC can be classified as "regulated" pricing.

2.2. Regulatory and Contractual Issues

The typical gas supply value chain comprises of the (i) upstream exploration and production (E&P); (ii) the midstream gas (processing, storage and transportation); and (iii) downstream (sales and distribution) segments. The upstream producers hold a license to explore and produce gas, which is thereon, gathered through small diameter pipelines (gathering lines) from oil and/or gas fields; the gas molecules then go through the processing facilities to remove water and impurities or by-products such as natural gas liquids (NGLs). The dry gas is then compressed to flow into large transmission pipelines (midstream) and then transported to offtakers such as gas-fired power generators, storage or other distribution centres (downstream).[23]

It is important to understand the legal and contractual nature of property rights acquired by private stakeholders vis-à-vis the state's in international energy investments and projects, especially given the typical roles of the host government as administrator and business partner. There are licenses and arrangements which empowers relevant operators to find, produce, take away, process and sell oil and gas resources, with the promise of reasonable returns. In some cases the underlying objectives of the state vis-à-vis the private operators, multinational corporations and lenders may not be properly synchronised to the extent that would support the development or viability of a project.[24] For instance, the background facts and issues leading to the case *Process and Industrial Developments Limited vs Federal Republic of Nigeria and Ministry of Petroleum Resources*[25] underscores the need for due diligence. In this case, which is still ongoing at the time of writing this paper, Process and Industrial Developments Limited (PIDL) a company incorporated by two Irish nationals in 2006 primarily to execute a natural gas processing project in Nigeria, was to receive "Wet Gas" for free from the Nigerian government and convert it into "Lean Gas" which the government could supply to local power producers. As compensation, PDIL would freely sell the natural gas liquids (NGLs) produced as by-products of the processing. The company commenced feasibility and engineering studies/plans for the project and executed a Gas Supply and Processing Agreement (GSPA) with the Nigerian Ministry of Petroleum (NMP)[26] in 2010. Even though PDIL and NMP agreed to have wet gas delivered by the Nigerian Government from OMLs 123 and 67 operated by Addax Petroleum and ExxonMobil respectively; it is interesting to note that both Addax and ExxonMobil were not parties to the GSPA. Later on, the unwillingness of Addax and ExxonMobil to supply the expected wet gas became a deal-breaker for PDIL and NMP. Thus, PDIL commenced arbitration against Nigeria under the GSPA with three arbitrators appointed. Among other things, the arbitration tribunal issued an award on liability in 2015, deciding that (i) the Nigerian Government was in breach of its obligations under the GSPA to deliver Wet

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[23] Tade Oyewunmi, 'Regulatory and Policy Issues for Natural Gas Supply to Power Markets: examining the energy supply crisis in Nigeria', OGEL 1 (2017) *Special Issue on Oil and Gas Law in West Africa* at </www.ogel.org/article.asp?key=3677> (accessed 15/03/2017); Joel Eisen et al, *Energy, Economics and the Environment, Cases and Materials* (University Casebook Series, 4th edition, Foundation Press, 2015) 1127 at 11-19.

[24] See Oyewunmi (n7) at 14-28.

[25] Case 1:18-cv-00594-CRC at the Washington DC Circuit, 08/27/18

[26] The NMP, headed by the Minister of Petroleum Resources is responsible for administering and governance of the Nigerian petroleum industry, while the NNPC is the government owned corporation through which the state participates in the commercial and technical aspects of the industry through Joint Ventures/Joint Operating Agreements (JV/JOAs), Production Sharing Contracts with international and Nigerian private companies. See the Petroleum Act 1969 CAP P10 Laws of the Federation of Nigeria 2004; NNPC Act CAP N123 Laws of the Federation of Nigeria 2004; Oyewunmi (n7) at 127-146; Oyewunmi (n23) on *Regulatory and Policy Issues for Natural Gas Supply to Power Markets*.

Gas to the facility which was to be built by PDIL; (ii) although the GSPA identifies OMLs 123 and 67 operated by Addax and Exxon as the source gas, the Nigerian Government, as the party to the GSPA, was obliged to and could obtain the Wet Gas from other sources when Addax and Exxon refused to supply PDIL. Regarding damages, a dissenting arbitrator held that damages should be limited to US$250 million; while the two other arbitrators awarded PDIL US$6,597,000,000 plus 7% pre- and post-award interest as compensation for a breach of contract.[27] In 2016, a Federal High Court in Nigeria gave an order setting aside the liability award,[28] while two years later PDIL filed a petition in the US seeking to enforce the award *inter alia* under the Convention on the Recognition and Enforcement of Foreign Arbitral Awards, June 10, 1958 (i.e. the "New York Convention").

Without going into the merits and demerits of the ongoing claims and counterclaims or appeals, the PDIL case is an instructive example on how agreements (bringing all necessary parties to the table), institutional and regulatory framework issues influence and impact on gas commercialisation projects. Fundamental international petroleum transactions - legal, policy, and risk assessment issues – underpin such ventures. Questions such as what determines rights and entitlements to produced oil and gas from concessions in which the government holds participating interests through its NOC subject to applicable laws and contractual provisions such as JV/JOAs with IOCs/independent co-venturers and essentially joint-concession holders? Clearly, while the state has absolute ownership and title to oil and gas *in situ*, the rights to commit to sell or deliver X amounts of produced gas (over and above its participating interest entitlements) to third-party buyers A or B at the price of $Y must be subject to further valid arrangements and agreeable to relevant co-venturers and participating interest holders in the production from the concession, especially since agency or trust relationship is not assumed without such.

2.2.1 Upstream Licensing and Contracts

(a) Hybrid Concessions and Model Petroleum Agreements

Generally, international upstream operations are based on licences and concessions; Joint Ventures/Joint Operating Agreement (JV/JOA); Production Sharing Contracts (PSCs); and Service Contracts (i.e. Risk Service Contract (RSC) and Pure Service Contracts).[29] In recent times, it is more common to find hybrids and/or model agreements reflecting elements of a typical concession and/or royalty system and PSC or JV/JOA adopted in West African and Sub-saharan African countries as opposed to Service Contracts which are more common in South America and Middle Eastern countries. For instance, Ghanaian 2008 OCTP area Petroleum Agreement[30] between (i) ENI Ghana Exploration & Production Limited (ENI) as operator, (ii) Vitol Upstream Ghana Limited (Vitol) and (iii) Ghana National Petroleum Corporation (GNPC); and the 2006 Deepwater Tano Petroleum Agreement between **(i)** Tullow Oil as operator, (ii) Anadarko Petroleum, (iii) Kosmos Energy, (iv) PetroSAGhana Limited and

[27] See Sophia Morris, *Nigeria's Immunity Appeal Of $9B Award Allowed By Judge*, (Law360, November 2, 2018) at <www.law360.com/articles/1098282> (accessed 15.11.2018)
[28] *Minister of Petroleum Resources vs Process and Industrial Developments Limited BVI*, No. FHC/L/CS/264/2016 (Federal High Court, May 24, 2016).
[29] Oyewunmi (Ibid); Mohd Naseem and Saman Naseem, 'World Petroleum Regimes', in Kim Talus (ed) *Research Handbook on International Energy Law* (Edward Elgar, 2014) 149-180.
[30] Participating interests in the acreage is allocated between ENI, Vitol and GNPC as 44.44%, 35.56% and 14% respectively. See Ghana Petroleum Register- Offshore Cape Three Points available at <www.ghanapetroleumregister.com/sankofa> (accessed 12.11.2018).

(v) GNPC) have elements of a concession/royalty system and production sharing.[31] In commercial terms, the Ghanaian hybrid approach represents a tax and royalty-based system with minority state participating interests, unlike in Nigeria where concessions granted as licenses and leases in combination-with JV/JOAs from the 1960s-1980s now have government-owned NNPC having majority stakes.[32]

In Ghana, the OCTP Area operations led to the Sankofa & Gye Nyame fields, while the Deepwater Tano operations led to developments such as the TEN projects which are very key in meeting growing demand in the Ghanaian domestic gas market due to the unreliability and shortfalls in imports via the WAGP from Nigeria.[33] Other forms of model upstream agreements used in the region include Tanzania's Model Production Sharing Agreement 2013 and Mozambique Model Exploration and Production Concession Contract (EPCC) 2016. In Nigeria, JV/JOAs accounts for about 49% of petroleum operations, while PSCs, Sole Risk Concessions and Marginal Field Licenses constitute about 41%, 6% and 4% respectively.[34]

On a general note, licences and concessions granted by a Host Government to a private international or local company confers non-possessory interests in a defined area within the State's territorial jurisdiction, to find, produce, take and dispose-off oil and gas, subject to the payment of taxes, royalties and rents as required by law. Most host governments manage the award of licenses and industry participation through a ministry (e.g. the NMP) and one or more regulatory agencies such as the Department of Petroleum Resources (DPR) in Nigeria.[35] Host governments also acquire participating interests in commercial and operational activities through NOCs such as the NNPC and the GNPC, thereby entering into JV/JOAs or other variants of upstream petroleum production agreements. The Nigerian OPL and OML granted by the Minister of Petroleum is a type of modern concession, upon which a JV/JOA is formed with IOCs such as ExxonMobil, Chevron and Shell.[36] In this context, the interests and liabilities

[31] Participating interests in the acreage is allocated between Tullow (35.48%), Anadarko (24%) Kosmos Energy (24%), PetroSAGhana (2.52%), GNPC (14%). See Ghanaian Petroleum Register- Deepwater Tano at <www.ghanapetroleumregister.com/deepwater-tano> (accessed 12.11.2018).

[32] Yinka Omorogbe, *Oil and Gas Law in Nigeria* (Malthouse Press, 2003).

[33] The OCTP is located about 60 km off Ghana's Western Region coast. The fields have about 770 million barrel of oil equivalent (mboe) in place, of which 500 million barrels of oil and 270 mboe of non-associated gas (about 40 billion cubic meters). The project includes the development of gas fields whose production will be utilized entirely by Ghana's domestic market. A 63 km pipeline transports gas to Sanzule's Onshore Receiving Facilities (ORF), where it is processed and transmitted to Ghana's national grid, supplying approximately 180 million standard cubic feet per day (mmscfd). See Ghana Petroleum Register- Sankofa & Gye Nyame Fields at <www.ghanapetroleumregister.com/sankofa-1> (accessed 12.11.2018)

[34] Oyewunmi (n7) at 133; DPR Nigeria, *2017 Nigerian Oil and Gas Industry Annual Report*, (Department of Petroleum Resources) 1-111 at 29

[35] Tade Oyewunmi, 'Examining the legal and regulatory framework for domestic gas utilization and power generation in Nigeria', (2014) 7(6) Journal of World Energy Law & Business, 538-557.

[36] The NNPC-ExxonMobil JV in which ExxonMobil subsidiary- Mobil Producing Nigeria- is operator has, NNPC with 60% participating interest and ExxonMobil 40% relates to about 4 OMLs, while the NNPC-Chevron JV operated by Chevron with NNPC holding 60% and Chevron holding 40% interests relates to about 8 OMLs. Other JVs include (i) the NNPC (60%), Agip (20%), Phillips Petroleum (20%); (ii) the NNPC (60%) and Total E&P Nigeria Limited (TEPNG) (40%). The Shell-operated JV accounts for more than 40% of Nigeria's total oil production from about eighty fields. The JV is composed of the NNPC (55%), Shell (30%), Elf (10%) and Agip (5%). Over the last couple of years, the IOCs in the Shell-Elf-Agip/NNPC JV have divested their 45% stake in several concessions to various Nigerian independents, see the Energy Mix Report, 'Upstream Assets Divestment In Nigeria: Update, Outlook And Challenges', 1 July 2014, available at <http://energymixreport.com/upstream-assets-divestment-in-nigeria-update-outlook-and-challenges/> (accessed on 11 November 2014). Such divestments have led to the emergence of JVs between Nigerian-owned independents and NNPC or the subsidiary called Nigerian Petroleum Development Company (NPDC) like NNPC and SEPLAT and NPDC and NECONDE JVs.

are typically 'joint' and 'several' and to the extent of their respective participating interests. The JV comprises the participation agreement, which defines the relationship and participating interests of the parties, while the JOA defines the legal and operational relationship of the co-venturers by providing for issues such as the operating committee and operator for the concession, work programme and budget, development or disposition of discovered gas, transfer of participating interests etc.[37] Note that clause 9.3 of the Association of International Petroleum Negotiators (AIPN) Model JOA 2012 which often serves as a benchmark for industry negotiations and arrangements *inter alia* provides for Disposition of Natural Gas as follows:

> The Parties recognise that, in the event of individual disposition of Natural Gas, imbalances may arise with the result being that a Party will temporarily have disposed of more than its Participating Interest share of production of Natural Gas. Accordingly, if Natural Gas is to be produced from an Exploitation Area, the Parties shall, in good faith and no later than the date on which the Development Plan for a Natural Gas project is approved by the Operating Committee, negotiate and conclude the terms of a balancing agreement to cover the disposition of Natural Gas produced under the Contract, regardless of whether all of the Parties have entered into a sales arrangement or sales contract for their respective Entitlement of Natural Gas.

Under Article 15 of the Model Petroleum Agreement (GMPA) used in the Ghanaian 1st Oil and Gas Licensing Round, the special provisions relating the natural gas include:

(a) All gas production by the Contractor in association with the GNPC shall be, subject to applicable law, regulations and the terms of this Article 15;

(b) Contractor shall not flare or vent gas unless permitted under the Petroleum (Exploration and Production) (General) Regulations, 2018. The Contractor shall have the right to use gas produced from the Contract Area in reinjection for pressure maintenance or upstream power generation at no cost;

(c) The Contractor has the right to dispose of its share of gas produced based on the terms of the agreement, provided that priority is given to domestic demand for gas, without adversely affecting an export project. Additionally, the Contractor shall have the right to extract and dispose of liquid hydrocarbons from its share of gas produced.

(d) While associated gas is regarded as the property of the State, the Contractor is advised to come up with a plan for the utilisation for Associated Gas. Where the production, processing, and utilisation of Associated Gas is considered has non-economic, the GNPC shall have the option to off take such Associated Gas (not used for Petroleum Operations or flared) at the outlet flange of the gas-oil separator on the oil production facility, at GNPC's sole risk and for its use. Thereon, GNPC and the Contractor shall work together to develop the appropriate interface between

[37] Tade Oyewunmi, 'Natural Gas Exploration and Production in Nigeria and Mozambique: Legal and Contractual Issues' *OGEL* 1 (2015) 1-25; Ernest E. Smith *et al., International Petroleum Transactions*, (3rd Edition, Rocky Mountain Mineral Law Foundation, 2010) at 526-647.

Natural Gas infrastructure owned by the State (presumably for domestic supply) and the development and production area.

(e) If the Contractor considers that it may be economic to produce Associated Gas for sale, then a commercial assessment of such prospects may be carried out.

(f) The Contractor also has the right to commercialise non-associated gas discovered in the Contract Area. The Parties shall discuss the required contractual arrangements for the disposition of the Natural Gas to potential purchasers, consumers, infrastructure owners and the GNPC, while projects should guarantee a reasonable rate of return and the use of the State's gas infrastructure if available.

Notably, article 15.17 of the GMPA provides thus:

> "Except with respect to specific provisions in this Agreement concerning Natural Gas and different or additional provisions concerning Natural Gas which may be agreed by the Parties in the future, in the event of a Discovery of Natural Gas in the Contract Area which is to be developed and commercially produced, the provisions of this Agreement with respect to interests, rights, and obligations of the Parties regarding Crude Oil shall apply to Natural Gas, with the following necessary changes in points of details: (a) The system for the allocation of Natural Gas among the Parties shall follow the same general format as Article 11.1 provides for Crude Oil, with the exception that the royalty to be delivered to the State on Natural Gas shall be at the rate of [...] percent ([..]%). If the State elects to take its royalty on Natural Gas in cash, the value of such Natural Gas shall be the Natural Gas market price, less transportation, processing, compression, and marketing costs"

The above-highlighted provisions regarding the rights, interests, disposal and utilisation of produced gas are essential for ensuring fair and equitable allocation of resources, especially given the 'joint' and 'several' ownership interests and liabilities principle applicable to petroleum operations in a concession as combined with a JV/JOA or petroleum agreement. Due to the physical features of gas, as well as the typical requirement for huge upfront investments and technical issues for producing, processing or storing or utilisation in re-injection procedure to recover more oil; the quantifying, metering and balancing arrangements are key issues to creating appropriate economic and commercial value for both public and private interest holders, operations and project financiers. Ordinarily, each co-venturer has entitlements equal to their respective participating interests and there is usually a delivery point for allocating such volumes. Furthermore, unless otherwise agreed, no 'agency' or 'trust' relationship is *ipso facto* assumed between the parties regarding the disposition of produced gas.

The other interesting provisions in JOAs and upstream agreements include the allocation of hydrocarbons to parties and principles of natural gas agreement(s) with the host government. Since host governments are normally responsible for regulating and managing domestic gas supply networks through a gas transmission and marketing subsidiary of the NOC,[38] it becomes pertinent to established clear guiding rules between the private and public stakeholders, such as: (i) the right to market and to export all gas entitlements, including the government's share, where necessary or as may be agreed; (ii) to the highest value outlets, whether domestic or

[38] Oyewunmi (n7); Oyewunmi (n35) *Domestic gas utilization and power generation in Nigeria*, supra.

export; (iii) considerations for the level of infrastructural and commercial development of the domestic market; (iv) gas reserves to be produced for their full economic life; and (v) access to infrastructure and pipeline capacity for the purposes of gas processing and transportation at a competitive tariff.

(b) PSCs and Service Contracts

PSCs and Service Contracts are essentially agreements in which the State, through the NOC, holds the concession and appoints a private international and/or local E&P company or a consortium as contractor to carry out upstream operations. Under the PSC arrangement, the parties agree to share produced oil and gas from the defined contract area in predetermined percentages, following the allocation and payment of relevant tax, royalties and fees usually in kind.[39] The contractor bears all the exploration and production risks and is generally in charge of operations and the management of the contract area unless the State party agrees to participate in the venture directly. If no petroleum is found, the contractor typically receives no compensation. The duration of the E&P period, the evaluation and announcement of a commercial discovery, developing a feasible gas utilisation or supply project, and deciding which party will be primarily responsible for marketing as well as balancing issues in cases of multiple interest holders, are some of the key provisions relating to gas supply arrangements which must be synchronised with and delivery, take-or-pay and sales obligations to be established under a GSPA and Gas Transportation Agreement (GTA) midstream and downstream for an integrated gas commercialisation project to be consolidated.[40]

In Nigeria, an OPL holder may submit a feasibility study programme or proposal for gas utilisation within five years of commencement of crude oil production. Although, the Petroleum Act 1969 empowers the Federal Government to take produced gas free of charge or at a price without payment of royalty, as well as to approve the price for domestic gas sales, the actual dealings between the government and upstream operators are consolidated by agreements and based on newer policies such as the National Gas Policy 2017 and regulations such as the recent Flare Gas (Prevention of waste and pollution) Regulations, 2018.[41] The Nigerian 2005 Model PSC provides *among other things* that when the contractor discovers enough gas quantities that could justify commercial development, it shall report same to the NNPC. The contractor then investigates and submits proposals for commercial development while considering local strategic needs to be identified by NNPC. Both the contractor and NNPC would also execute further gas development agreement(s) which shall recognise the former's right to participate in development projects, the right to recover costs and share in profits. The contractor is also obliged to submit a Field Development Programme to the NNPC.

2.2.2 Midstream Arrangements and Contracts

Depending on whether the commercialisation venture is for export via LNG or domestic supply to a power facility, negotiating and concluding midstream arrangements such as LNG Sale and Purchase Agreement (SPA), GSPAs and other forms of sales and purchase agreements are essential in securing the upstream gas producers' commitment to sell and the buyers' obligations to take and pay for specified volumes gas for delivery to, e.g. a gas-fired power utility, LNG or processing facility, subject to a predetermined pricing and/or rate-of-return

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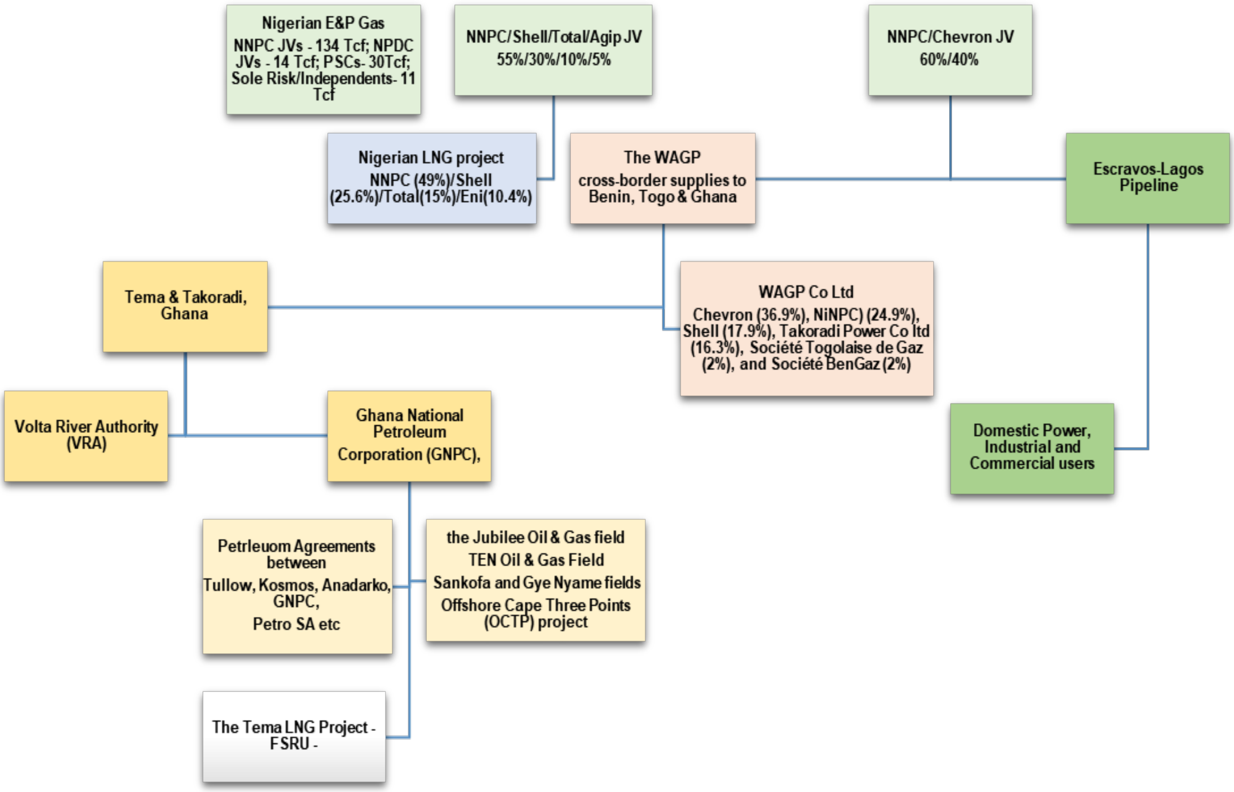
[39] Ernest E. Smith *et al.,* (n37) *International Petroleum Transactions,* at 463-473; Omorogbe (n32).

[40] See further discussion on the 'Gas Supply Value Chain in Oyewunmi (n7) at 14-20; Oyewunmi (n8) *restructuring and development of gas supply markets*.

[41] Oyewunmi (n7) 132-150.

framework. The agreement would typically include conditions precedent for the seller, buyer and transporter as well as determining when such conditions are satisfied and what happens if not satisfied. The conditions would ordinarily include obtaining all necessary approvals and agreements for (i) development, production, and sale of gas by the seller; (ii) purchase, receiving, and use gas acquired by the buyer; and (iii) conveying and delivery of committed volumes by the transporter. Including arrangements for siting, construction and financing, in this regard, representations and warranties as to creditworthiness and authority to perform obligations – e.g. underlying entitlements to dispose or sell contracted gas volumes- are quintessential. A GTA provides for the relevant terms governing the transmission of gas, such as transportation tariffs and ancillary service obligations by the pipeline operator.[42] In both domestic and cross-border (international) supply contexts, these arrangements should be consolidated to before upstream producers, suppliers and their financiers commit to investing in the project as depicted in Figure 1 below highlighting important West African gas production and supply arrangements and projects which will be discussed later in more detail.[43]

Figure 1: A Schematic of Gas Production and Supply Arrangements in West Africa- Nigeria to Ghana



In a cross-border context, the transportation agreement would also outline the transit fees provisions, allocation of risks between suppliers and pipeline owner/operator in cases where third party access is allowed and applicable tariffs for such services.[44] The main commercial and transportation risks to be considered by suppliers and pipeline company are: (i) availability

[42] Oyewunmi (n7) 20-25.
[43] Peter Roberts and Ruchdi Maalouf, 'Contractual Issues in the International Gas Trade: LNG - the key to the Golden Age of Gas' in Kim Talus (ed), *Research Handbook on International Energy Law* (Edward Elgar, 2014) at pp. 329-357
[44] Thomas J. Dimitroff, 'Cross-border oil and gas pipeline risk and sustainable mitigations' (2014) 7(4) *Journal of World Energy Law & Business* 287–339.

of gas volumes from upstream associated and non-associated gas fields, without a functioning, secure or reliable pipeline capacity available; and (ii) availability of required pipeline capacities, even although gas volumes from upstream sources are already committed to other uses or lack of creditworthiness of the consumers/offtakers to pay for volumes and services to be rendered by the pipeline company. In the context of developing West African economies, in which the offtakers and consumers are mostly power utilities with liquidity and affordability constraints as well as state-centred government control, these risks may become more exercabated, therefore requiring further consideration and mitigation strategies. Creditworthiness and financial ability to fulfil obligations under supply arrangements are typically established by a guarantee or standby letter of credit issued by a bank, an on-demand bond issued by a surety corporation, a corporate or government guarantee, or such other financial security as is agreed between parties.

The need for project financing or support from international financial institutions and corporations in meeting the significant upfront costs and capital inputs from project 'pre-completion' to 'post-completion' and through the stages of feasibility studies, front-end engineering, detailed design and construction, to operational phases, underscores the need for thorough due diligence and risk assessment. Contractual clauses and mechanisms such as take-or-pay (ToP), deliver-or-pay, price adjustment and review, and *force majeure* provisions are very instrumental in securing necessary commitments. Although, damages arising from claims of a 'breach' or 'non-performance' against a sovereign may prove complicated as seen in the PDIL's case above and as between sovereigns in a transnational cross-border scenario such as between Nigeria and Ghana in the light of defaults and unreliability issues in the WAGP as will be discussed later, in reality, parties' resort to negotiations, mediation, arbitration and political solutions.

A ToP clause obligates a purchaser to make payment even if it fails to take the negotiated percentage of the quantity of gas that it has committed under the contract to pay for. This type of clause recognises the interest of the producer in seeking to secure guaranteed cash flow to cover *ex ante* costs. These arrangements also protect the purchaser by providing for make-up-rights, by which a buyer that incurs ToP liabilities in one year can recoup those amounts or part of them by taking more gas than the minimum in future years. On the other hand, DoP clauses are designed to protect the buyer's interests in receiving the gas it has already contracted for. They require a seller that fails to supply negotiated amounts to make compensatory payments. There is generally the need to provide for periodic price adjustments to reflect changes in the value of the product over time considering the traditional long-term duration of supply contracts. Parties also seek to reconcile the interests of buyers and sellers over the long-term period of the contract. Some supply agreements also include a 'reasonable endeavours' principle which would require a party to act only in a commercially reasonable manner, and generally does not constitute a firm obligation on such party to perform. Although an obligation of a seller to deliver gas from a predetermined concession or contract area may be counterbalanced with the obligations to get gas from third-party and alternative sources if it becomes 'unreasonable' or impossible to have gas such predetermined concession area due to, e.g. some security, technical or transactional issues.

2.2.3. Transnational and Cross-border Pipeline Considerations

Regarding pipeline projects, most of the challenges relating to a typical domestic gas supply framework applies to the cross-border context, however, in the latter the involvement of two or more governments presupposes the need for bespoke instruments such as- Intergovernmental

Agreements (IGA), Host Government Agreements (HGAs), multilateral treaties establishing *inter alia* a joint, multinational agency as in the WAGP Authority and other project financing and development agreements.[45] An IGA between the host governments across which a cross-border pipeline is constructed and operated would be backed by multilateral and bilateral trade, double taxation and investment agreements. The HGAs and project related agreements would be necessary between the pipeline company and each of the host governments where appropriate, as well as enabling laws domesticating the applicable multilateral treaty within the laws of the participating states as was the case with Nigeria, Togo, Benin and Ghana in the WAGP.[46] Generally, IGAs should provide for issues relating to state-to-state dealings with the project company and transported gas volumes such as the freedom to transit, access, protecting the rights and obligations of upstream and downstream states and investors, exemption of pipeline company from double taxation.[47]

3. Projects, Pipelines and LNG in Nigeria and Ghana

Given the preceding discussion bordering on how contracts, law, regulation and institutional frameworks impact international petroleum transactions and gas commercialisation projects, it is worth highlighting some projects in West Africa, particularly in Nigeria and Ghana, over the past couple of decades. The Nigerian domestic gas pipeline infrastructure mainly comprises two unintegrated pipeline networks of approximately 1,100 kilometres: (i) the Alakiri-Obigbo–Ikot Abasi Pipeline (the Eastern Network), and (ii) the Escravos–Lagos Pipeline System (ELPS) (the Western Network), as well as the dedicated pipeline infrastructure owned by the NLNG company, the NNPC-Shell JV and the NNPC-Chevron JV.[48] The ELPS is the main trunkline connecting gas reserves in the Niger Delta to industrial and power generation plants in the South West of the country and also feeds the West African Gas Pipeline System, to neighbouring Benin, thereafter to Togo and Ghana.

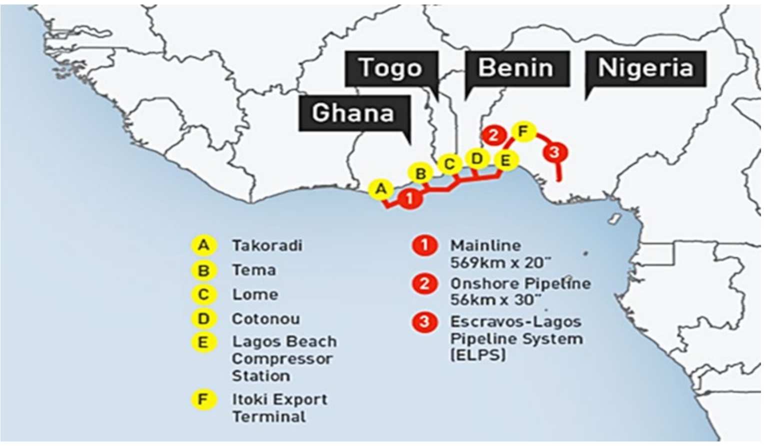


Figure 2: West African Gas Pipeline & Escravos - Lagos Pipeline

For the Nigerian government, gas utilisation projects such as the NNPC-Shell JV's NLNG project, ExxonMobil JV Oso Condensate Project, the Chevron JV GTL Escravos Gas Project

[45] Ibid at 318

[46] See the West African Gas Pipeline Treaty, 31January 2003 ("WAGP Treaty"); Enabling Legislations- (i) Bénin – Régime juridique et fiscal applicable au projet du GAO 2005, (ii) Ghana – West African Gas Pipeline Act, 2004, (iii) Nigeria – West African Gas Pipeline Act, 2005, and (iv) Togo – Régime juridique et fiscal applicable au projet du GAO 2004; WAGP Regulations- (i) Bénin- Réglement du Gazoduc de l'Afrique de l'Ouest, 2005 (ii) Ghana – West African Gas Pipeline Regulations, 2005, (iii) Nigeria – West African Gas Pipeline Regulations 2006, and (iv) Togo- Réglement du Gazoduc de l'Afrique de l'Ouest 2005; and the WAGP Access Code governing access to Transportation Services, 2004 at <www.wagpa.org/project-documentation/> (accessed 15.10.2018)

[47] Dimitroff (n44) supra.

[48] Oyewunmi (n7).

and the WAGP (expected to receive gas from NNPC-Shell JV and NNPC-Chevron JV),[49] were more about boosting state export revenue and foreign exchange earnings. These were less about domestic energy supply security or cutting down on reliance on carbon-intensive petrol and diesel oil mostly used for private power generators due to the epileptic power supply from the national grid. NNPC and its gas transmission and marketing subsidiary, i.e. the NGC (now NGPTC and NGMC) are entrusted with the responsibility of developing the domestic gas supply market as well as operate and manage the main transmission pipelines and network.

3.1. Nigeria's LNG Export Projects

Sponsored by the NNPC-Shell JV, the project company- Nigeria LNG Limited (NLNG) was incorporated in 1989 to produce LNG and NGLs for export. The company's shareholding and equity distribution comprise the Federal Government, represented by NNPC (49%), Shell (25.6%), Total (15%) and Eni (10.4%). It currently has two subsidiaries- Bonny Gas Transport (BGT) Limited and NLNG Ship Management Limited (NSML), signifying the importance of shipping and transportation management for efficient deliveries and marketing.[50] The project is situated on a 2.27 sq.km of mostly reclaimed land in Bonny Island, offshore Rivers State, in the Nigerian Niger Delta and built to receive diversified supplies of Associated and Non-Associated Gas from its upstream JV sponsors. Its assets include six transmission pipeline systems, with four of them located on-shore.[51] The project itself has been in consideration since 1976 and only received a Final Investment Decision (FID) in 1995, following which a turnkey Engineering, Procurement and Construction (EPC) contract was executed to construct the Trains 1 and 2 of the liquefaction plant, the Gas Transmission System and the Residential Area (RA). LNG production commenced in 1999, followed by FIDs for expansion to Train 3, including an NGL and LPG production facilities, which became operational in 2002. Further expansions to Trains 4, 5 and 6 commenced with an FID in 2002 for 4 and 5 and 2004 for 6, while operations and start-up commenced in 2005, 2006 and 2007 respectively, including Train 6 with additional condensate processing, LPG storage and Jetty facilities, giving the entire facility a capacity of producing 22 million tonnes per annum (mtpa) of LNG, and 5 mtpa of NGLs from 3.5 Billion cubic feet per day (Bcf/d) of natural gas intake.[52]

The first shipments from the NLNG facility took place in 1999 to destinations in Europe such as Italy, Spain and Portugal, as the original idea for such export facilities was to ship LNG to the US and Europe.[53] Early interests of companies such as Cove Point Trading of Maryland US, Cabot of Boston, Snam of Italy and Enagas of Spain is led to SPA negotiations. However, the political instability in Nigeria and initial insufficient government support for the project and financing difficulties prompted some of the initial offtakers to abandon the venture. While others joined in, such as British Gas and Enel, sales negotiations took several years for SPAs

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[49] Oyewunmi (n7). The Escravos Gas Project was developed by the NNPC/Chevron JV to process and utilise associated gas. The gas is developed, compressed and piped to a liquid extraction facility where LPG and condensates are removed. The LPG is transported by pipeline to an offshore floating storage and offloading vessel, while the condensate is blended with Escravos crude oil stream and the remaining dry gas is sold to the NGC/NGPTC.

[50] See the NLNG Ltd, *Facts and Figures on NLNG 2018* (July 5, 2018) available at <www.nlng.com/Media-Center/Pages/Fasts-and-Figures.aspx> (accessed 12.11.2018)

[51] Ibid.

[52] Ibid. Plans for building Train 7 that will lift the total production capacity to 30 mtpa of LNG are currently progressing

[53] Oyewunmi (n4) supra on *the Evolving International Gas Market.*

to be agreed.[54] The initial set of long-term SPAs were signed with GdF (France), Enel (Italy) and Enagas (Spain) as offtakers, later joined by Botas (Turkey) on a Delivered ex-ship (DES) basis. Financing negotiations closure was by the end of 2002, and unlike most LNG projects, which are paid for through project finance, the NLNG was financed through the balance sheet of the shareholders sponsoring it.[55] After the trains 1-3, financing of trains 4-6 was done by giving lenders security for the loan over the whole liquefaction project without asset segregation, with a financing structure that is understood to have an unusually high equity share (around 50%).[56]

The contractual, financing and equity arrangements meant that a considerable amount of NLNG's volumes were contracted to offtakers not linked to any specific destination and including some of the project sponsors themselves. Thus, even though about one-fourth of the overall NLNG volumes were sold under contracts intended to serve US and Spain, there was considerable destination flexibility which permitted easier diversions to other demand centres in the wake of a shale gas production boom in the US that meant demand and supply of Nigerian LNG to the US plummeted. The key issues that underpinned the viability of and eventual FIDs in this project centred around the stability of the regulatory environment and the provision of contractual 'safeguards' in respect of incentives and guarantees. The ability to conclude investment and supply negotiations efficiently and with government support was also undeniably critical.

3.1.1. Legal tussles and political solutions?

The NLNG project was established pursuant to the Nigerian LNG (Fiscal Incentives, Guarantees and Assurances) Decree no. 39 of 1990 and amended by Decree no 113 of 1993 (the 'NLNG Act').[57] The NLNG Act *inter alia* provided for- (i) a 10-year tax relief period to the NLNG; (ii) exemptions from all customs duties, levies, charges and imposts of a similar nature; pre-shipment inspection of imports waivers; (iii) no export duties, taxes or other duties, levies, charges or impost of a similar nature shall be payable or imposed on NLNG; (iv) Guarantees, assurances and undertakings shall be in effect throughout the lifespan of the venture; (v) The *Government 'binds itself not to amend the fiscal regime except with the prior written agreement of the shareholders'* and (vi) The Government agrees to ensure that the guarantees shall not be suspended, modified or revoked during the life of the Venture, except with the mutual consent of the Government and shareholders.

Some provisions of the NLNG Act prohibiting any future legislation that might affect the assurances and guarantees granted as a means of 'investment stability' for the project has been contentious and controversial.[58] In *Niger Delta Development Commission (NDDC) v Nigeria Liquefied Natural Gas Company Ltd* FHC/PH/CS/313/2005, The NDDC sued the NLNG and others claiming that according to the NDDC Act 2002, the NLNG is a gas processing company operating in the Niger Delta Area, thus obliged to pay an annual levy of 3% of the NLNG's total annual budget to the NDDC. While the Federal High Court *inter alia* held that the

[54] The IEA, *Global Gas Security Review 2016* (IEA Publications, France, 2016) 1–117 (accessed 25 December 2016).
[55] Ibid.
[56] Ibid at 54.
[57] Now an Act of the National Assembly in referred to as the Nigerian LNG (Fiscal Incentives, Guarantees and Assurances) Act Cap N87 Laws of the Federation of Nigeria 2004
[58] See also Bayo Adaralegbe, 'Stabilizing fiscal regimes in long-term contracts: Recent developments from Nigeria', (2008) 1(3) *Journal of World Energy Law & Business* 239-246.

highlighted provisions of the NLNG Act were unconstitutional only to the extent that it fetters the government's legislative powers to make new laws that could affect the assurances and guarantees made to support the projects FID, the Court of Appeal and Supreme Court upheld the validity of the NLNG Act and refused the NDDC's claim. Notwithstanding, various stakeholders and local groups have called for an amendment of the NLNG Act by the National Assembly (legislature) and especially since it has been more than ten years since the project was commissioned in 1999. The role of the Federal Government as a stakeholder in the project has commercial, economic and socio-pollical ramifications, which has seemingly kept the project's economics and viability insulated from various legal and security risks in reality. With assets worth about US$15.4 billion, the project is arguably one of the most successful commercial ventures in which the government benefits from its share of payments for feed-gas supplied by upstream JV sponsors as well as dividends and company income tax via its shareholding through the NNPC.

Other LNG ventures that have been considered in the recent past include Brass LNG and Olokola LNG (OKLNG). These proposed projects have been awaiting an FID for several years mainly due to questions about the availability of feed-in gas and divestments by the IOCs.[59] For instance, ConocoPhillips withdrew from Brass LNG, while Chevron and BG withdrew from OKLNG amongst other recent divestments from Nigeria. Arguably, the risks relating to the uncertainties and over-politicisation of the future investment climate in the Nigerian oil and gas industry following the protracted process of legal and regulatory reform were also considered too high, as well as the growing desire of the government to channel more resources to domestic supply of gas to power and industries.

3.1.2. More Nigerian Condensates and NGL Projects

The Oso Condensate Project was designed to support Nigerian hydrocarbon exports and foreign exchange earnings from the production of NGLs. The project consists of the commercial development of the condensates from an OML held by the NNPC-Mobil Producing Nigeria (MPN) JV and operated by MPN. Although it was discovered as far back as 1967, it remained undeveloped for over 24 years. The government's push for more gas utilisation and curbing of gas flaring triggered plans for developing the project, while the central financing (both equity and debt) and development arrangements were concluded between 1988 and 1990-92.[60] Equity financing accounted for about 35%, while debt financing for MPN was provided by the International Finance Corporation (IFC), the US Exim Bank, and commercial banks such as Union Bank of Switzerland, Banque Nationale de Paris and Credit Lyonnais. Loans to the NNPC were from the World Bank, the IFC, the Export-Import Bank of the United States, the Export-Import Bank of Japan, the European Investment Bank, and some commercial banks led by Morgan Guaranty Trust Company. The FGN also promulgated the Oso Condensate Project Decree No 15 of 1990, which enabled the NNPC to borrow money in any currency for the project, as well as to pledge any of the funds, revenue and assets received by it for the project.[61] The NNPC also had the power to create escrow

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[59] Oyewunmi (n7); Hakim Darbouche, *Issues in the Pricing of Domestic and Internationally-Traded Gas in MENA and Sub-Saharan Africa* 1–37 (OIES, NG 64, June 2012)

[60] Yinka Omorogbe, 'Law and Investor Protection in the Nigerian Natural Gas Industry' (1996) 14 *Journal of Energy & Natural Resources Law* 179–192.

[61] Ibid. World Bank, *'Nigeria - Oso Condensate Field Development Project'* (Washington, DC: World Bank, 1991), available at <http://documents.worldbank.org/curated/en/834791468291017038/Nigeria-Oso-Condensate-Field-Development-Project> (accessed on 23 September 2015).

accounts outside Nigeria from which the capital and interest on money earned from the project shall be paid. Thus, the decree arguably ensured that payments due to the project creditors are not delayed or otherwise hampered, because of any inefficiencies in the Nigerian legal and administrative framework.

3.1.3. International Financing and government-backed Guarantees for Gas-To-Power Solutions?

Facilities such as the World Bank's Partial Risk Guarantees (PRGs), as well as the support available via the International Bank for Reconstruction and Development (IBRD) and the Nigeria Electricity and Gas Improvement Project (NEGIP) financed by the International Development Association (IDA), have become relevant in the scheme of things.[62] The objectives of the NEGIP includes (i) to improve the availability and reliability of gas supply to increase power generation in existing public sector power plants, and (ii) improve the power network's capacity and efficiency to transmit and distribute quality electricity to the consumers. Its three main components are (i) risk mitigation through PRGs in support of gas supplies to increase power generation from existing public sector power plants; (ii) the enhancement of transmission and distribution infrastructure; (iii) the provision of the logistical support and technical advisory services required to sustain ongoing reforms to the governance and institutions.

According to the NEGIP's January 2017 update, as at December 2016 ', no gas is being supplied to public power plants under the PRG Framework as no IDA Guarantees for gas supply agreements have yet been executed'.[63] Amongst the risks identified under the NEGIP's 'risk-rating' tool, the overall risk profile of the Nigerian domestic gas supply and power sector is substantial. In this regard, political and governance risk is 'high', risks related to sector strategies and policies, which were deemed 'substantial' are now rated 'high', and risks related to the institutional capacity for implementation and sustainability are rated as 'moderate'.[64] These ratings are probably due to unresolved institutional reforms and regulatory challenges to gas commercialisation, supply and utilisation for power, insufficient liquidity and creditworthiness in the power sector, and misalignments between the privatisation and liberalisation of power market vis-à-vis the inconclusive reforms of the domestic gas market, under-investment in power sector's transmission capacity and technical to commercial losses, having a reverse knock-on effect on the ability of about 85% of generation capacities (which is gas-dependent power generation) to be fully operational and afford to pay for gas from upstream suppliers.[65]

There is also the Political Risk Insurance (PRI) package offered through the Multilateral Investment Guarantee Agency (MIGA).[66] In April 2013, the World Bank provided its first PRG

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[62] The World Bank, *'Nigeria Electricity and Gas Improvement Project (NEGIP)'* (P106172, June 2009), available at <http://projects.worldbank.org/P106172/nigeria-electricity-gas-improvement-project-negip?lang=en&tab=overview≥ (accessed on 23 September 2015); World Bank, 'Nigeria Electricity and Gas Improvement Project (NEGIP) : P106172 - Implementation Status Results Report' (4 January 2017), available at <http://documents.worldbank.org/curated/en/308351483543904959/pdf/ISR-Disclosable-P106172-01-04-2017-1483543890787.pdf≥ (accessed on 21 January 2017).

[63] Ibid.

[64] Ibid.

[65] Gail Anderson, 'Nigeria's hunt for gas buyers' Petroleum Economist 19 December 2018 at <www.petroleum-economist.com/articles/midstream-downstream/lng/2018/nigerias-hunt-for-gas-buyers> (accessed 07.01.2018)

[66] See World Bank Press Releases, 'First MIGA Guarantee in Nigeria's Critical Gas Sector Backs Seven Energy's Investment in Midstream Infrastructure' (Washington DC, October 26, 2015) available at

for the sum of USD 145 million in support of a Gas Supply and Aggregation Agreement.[64] The PRGs generally cover risks associated with changes in law and the regulatory/tariff framework and failure to meet contractual payment obligations by the federal government-owned power utilities, while the PRI covers risks such as transfer and convertibility, expropriation, war and civil disturbance, non-honouring of sovereign financial obligations and breach of contract. Apparently, following these financial and investment risk mitigation mechanisms, a few independent gas producers and other private investors have recently ventured into Independent Power Projects (IPPs). For example, SEPLAT (a Nigerian-owned E&P company that acquired some JV/JOA operatorship and upstream participating interests previously held by the NNPC/Shell JV in 2010) recently concluded a GSPA with the Azura-Edo 450 MW IPP.[67] The project is said to be located close to a secure and reliable source of gas and is about one kilometre away from the path of Nigeria's main gas pipeline (i.e. ELPS). The Azura-Edo IPP is a 450MW open cycle gas turbine power station and the first phase of a 2,000MW project. The relevant parties reached financial close on 28 December 2015 and construction started on 5 January 2016. It became fully operational in May 2018. One could contend that the project would not have become a reality without multiple risk mitigation guarantees and the fact that gas supply is based on an index-linked price of US$3/mn Btu rather than the regulated (RCS) price of US$2.50/mn Btu.[68] Following a recent government approval of a sovereign guarantee waiver, the project benefited from the World Bank PRG financing programme and the MIGA for political risk insurance.[69] Other upcoming gas-based projects include the Exxon Mobil Qua-Iboe IPP, the Century Power Okija IPP, and the Geometric OMA IPP.[70]

3.2. The WAGP and Energy Supply in Ghana

About the same time the NLNG project was gaining traction from the late 1990s to 2000s, the WAGP project was being consolidated with the aim of (a) improving the competitiveness of the energy sectors in Ghana, Benin, and Togo through the supply of 'cheaper' and more 'environmentally-friendly' gas from Nigeria; (b) to diversify energy sources in the importing countries and replace solid and liquid fuels used for power generation, industrial and commercial purposes; and (c) fostering regional economic growth and political integration, by supporting the West African electricity market.[71]Article II.1(3) of the WAGP Treaty provides that as defined in the International Project Agreement (IPA),[72] the WAGP shall be a high-pressure gas pipeline, with associated compression and metering stations, interconnection

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<www.miga.org/Lists/Press%20Releases/CustomDisp.aspx?ID=504> (accessed 15 November 2015). According to the press release: 'MIGA is providing a guarantee of $200 million against the risk of expropriation to Seven Energy's wholly-owned subsidiary, Accugas Ltd. The investment has a strong environmental profile, as Seven Energy's operations will reduce gas flaring and displace more-polluting fuels such as diesel and biomass. MIGA's backing of Seven Energy forms part of new generation of jointly developed World Bank Group solutions. In addition to MIGA's insurance, the World Bank supports the country's sector reforms while the IFC itself and an IFC-managed fund have jointly invested in Seven Energy in Nigeria.'

[64] The World Bank, *'World Bank to Help Nigeria Improve Gas Supply and Reliability, and Bring More Electricity to Nigerian Consumers'*, April 2013, available at <www.worldbank.org/en/news/press-release/2013/04/22/world-bank-to-help-nigeria-improve-gas-supply-and-reliability-and-bring-more-electricity-to-nigerian-consumers> (accessed 28 November 2015).

[67] See the Azura FAQs at <www.azurawa.com/index.php/faq/>

[68] Anderson (n65).

[69] See Oyewunmi (n7)

[70] Ibid.

[71] The World Bank, 'West African Gas Pipeline Project: Implementation Completion Report Review' (World Bank Group, No ICRR14706, Washington, D.C. 2005) 1-10; WAGP Treaty.

[72] An IPA was executed between the pipeline company and operator, West African Gas Pipeline Company Limited (WAPCo), and the state parties.

points and laterals to Cotonou (Benin), Lomé (Togo) and Tema (Ghana), together with such extensions and expansions as the State parties shall from time to time agree, which shall link the outlet point of the ELPS in Nigeria to Takoradi in western Ghana and transiting through the territorial waters of the States. Article II.2 makes the WAGP an open access transporter as contemplated under the IPA. The 678 km long pipeline terminates at Ghana's Takoradi Power Stations, with the possibility of being extended to other West African countries such as Cote d'Ivoire.

The WAPG Authority was established under Article III of the WAPG Treaty as an international institution having legal personality and financial autonomy recognised in each State party. It is empowered to (i) monitor compliance with obligations under the IPA, (ii) facilitate the grant, renewal or extension of project authorisations, (iii) negotiate and conclude pipeline development plans, the terms of amendments to the conditions on which pipeline licenses are granted, as well as agree with the pipeline company on the terms of the Access Code in accordance with the IPA. The authority does not set tariffs, as these are regulated by contract and the pipeline access code.

The transactional and regulatory aspects of the project comprised (a) contracts for the design, engineering, construction, ownership, operation and maintenance, oversight, political risk mitigation and guarantees; (b) contracts for (i) the purchase of gas from the upstream producers in Nigeria i.e. the NNPC-Shell JV and NNPC-Chevron JV; and (ii) gas transportation and sales to designated power utilities; and (c) environmental assessments and resettlement action plans.[73] The following cooperate entities were entrusted with the implementation of the project, i.e.

- West African Gas Pipeline Company Limited (WAPCo), the pipeline project company owned by Chevron (36.9%), NNPC (24.9%), Shell (17.9%), Takoradi Power Company Limited (16.3%), Société Togolaise de Gaz (2%), and Société BenGaz (2%). Established to build, own, operate, and transport gas through the WAGP system.
- N-Gas Limited, comprising of NNPC (62.35%), Chevron (20.00%), and Shell (17.65%). The company arranges for the purchase of gas from the producers under long-term GSPAs, which will be transported by NGC and WAPCo, and sold to Ghana's Volta River Authority (VRA)[74] and Communauté Electrique du Bénin (CEB)[75] also on a long-term basis, i.e. 20-year term;
- The NGC (as NNPC's gas transmission and marketing subsidiary) is contracted by N-Gas to transport gas from the upstream sources via the ELPS to a terminal near Lagos, thereafter taken up by WAPco into the WAGP system.

The principal project agreements comprise- (i) the IPA between the four States and WAPCo, providing for the development, financing, construction, ownership, and operation of the WAGP by WAPCo; (ii) the Takoradi GSA between VRA and N-Gas, providing for the sale by N-Gas and purchase by VRA of up to 120 MMscf/day of gas on a take-or-pay and ship-or-pay basis; ((iii) the Takoradi GTA between WAPCo and N-Gas for the gas being sold by N-Gas under

[73] The World Bank, '*IDA provides an innovative partial risk guarantee in support of the West African Gas Pipeline Project (English). Project finance and guarantees notes*' (World Bank Group, No 35903, Washington, D.C. 2005)
[74] The VRA is Ghana's state-owned power generation corporation.
[75] The CEB is an international corporation co-owned by the governments of Bénin and Togo, responsible for developing electricity infrastructure in both countries which are strongly dependent on energy imports from Ghana.

the Takoradi GSA; (iv) the VRA Direct Agreement among VRA, WAPCo, and N-Gas whereby N-Gas assigns to WAPCo (as security for N-Gas's payment obligations to WAPCo under the Takoradi GTA) the component of the VRA termination payment and arrears owing to N-Gas under the Takoradi GSA corresponding to the same component payable to WAPCo by N-Gas under the Takoradi GTA; and (v) the Government Consent and Support Agreement (GCSA) under which Ghana, in compliance with its undertaking under the IPA, irrevocably and unconditionally guarantees to N-Gas and WAPCo the performance obligations of VRA under the Takoradi GSA and the VRA Direct Agreement.

The reliability of supply from Nigeria on a ship-or-pay basis and capacity of foundational buyers to take and pay for delivered gas is critical to the viability of the project, mainly because the VRA and CEB were expected to underwrite the costs of the pipeline system, backed by government guarantees and international project financing arrangements.[76] The initial US$590 million value was designed to be financed through direct equity and shareholder loans to WAPCo, while subsequent expenditures are expected to be funded by cash flow from transport operations. As in a typical long-term supply project with long pay-back time, WAPCo is expected to recover its investments through gas transportation charges under its GTA with N-Gas and other future shippers; NGC recovers any operational and maintenance expenses through transportation charges under its GTAs with N-Gas, while the upstream producers would also recover any project related costs (e.g. upgrading and installing gas gathering systems and treatment facilities upstream of ELPS) through gas sales under GSAs with N-Gas or any other entity that ships gas through WAGP.[77]

While project sponsors and advisers focused more on guaranteeing and mitigating the demand-side risks from Ghana, there was less attention given to evaluating exogenous risk factors and supply-side risks from Nigeria. Thus, project design and effectiveness would, later on, be rigorously tested. The actual total cost of pipeline commissioning ended-up being higher than estimations, as there were construction delays, pipeline ruptures and sabotage and some operational challenges. A 2006 start date ended-up with interruptible gas supplies starting in late 2008 with smaller volumes than expected partly because not all the receiving stations or the compressor station in Nigeria were operational when the pipeline was completed. The actual start date, when the contractual commitments were triggered, was not achieved until November 2011.[78] Also, connections to power plants in Benin, Togo were completed only at the end of 2013. The period between 2009 and 2012 was unfortunately notorious with vandalism and sabotage in the Nigerian Niger Delta, including pipeline rupture by pirates of the coast of Togo in 2012, concurrently, Nigeria was also intensifying efforts to increase gas supply to domestic uses with structural reforms and policies such as the Nigerian Gas Master Plan 2008- domestic gas supply obligations.[79] These complex issues meant that the contracts have been operating under *force majeure* effectively since the start date of 2011, although the current Nigerian government administration has arguably been able to address the insecurity issues in the Niger Delta compared to previous administrations.

Regarding commercial risks, it is noted that between 2014 and 2016, the VRA stopped paying for the gas delivered due to liquidity and financial issues in Ghana's electricity market as it was not receiving payment from the electricity distributors, who in turn were not being paid by most

[76] Ibid.
[77] Ibid.
[78] Fulwood and Bros (n6).
[79] Oyewunmi (n7).

of their customers, principally the Government of Ghana.[80] According to the World Bank's project Implementation Completion Review (ICR), the Partial Risk Guarantee (PRG) framework did not adequately incorporate the implications of parallel developments such as the domestic gas production in Ghana and ongoing sector reforms and policy initiatives in Nigeria.[81] Also, perhaps due to the socio-political complexities and the limited development of the gas market in the consuming countries, the governing institutions have not been able to make any significant strides in finding a solution to the force majeure issue.

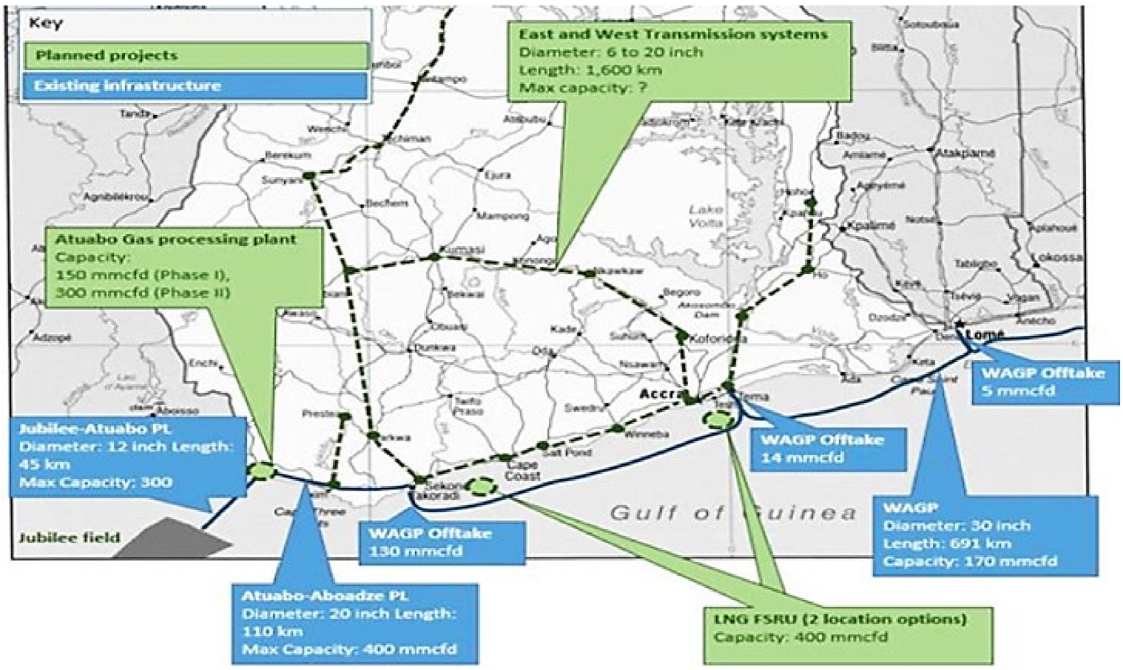
Generally, both cross-border and domestic supply arrangements involving governments comes with political risks, e.g. due to a change in governments or political dispositions or difficulties in government-owned utilities such as the VRA meeting contractual obligations. The World Bank system makes available partial political-risks guarantees to cover payments owing by the Government, e.g. due to termination of the Takoradi GSA with VRA. Thus, private sector participants took up the construction- and operations- related risks, while the public sector took up the payment risks under the GSAs, which are on a ToP basis. Events of *force majeure* are shared among the parties; however, a default by the upstream producers in delivering gas in Nigeria will result in the payment of liquidated damages to the foundation customers, but only about default due to negligence rather than sabotage or accidents. Regardless of the options and possibilities afforded by PRIs or PRGs and other instruments from the international financial institutions, it is still essential to have sufficient liquidity in consuming markets as well as the ability of buyers to take and pay for gas or power along the value chain. In reality, the international lending system depends to a large extent on the government's ability to back the assurances and guarantees which usually leads to other issues such as government's credit ratings in case of default or competing objectives for governmental expenditures.

3.2.1. Production and Supply from Ghana

Given the discoveries of domestic offshore reserves in the Jubilee and TEN fields with about 490 Billion cubic feet (Bcf) and 363 Bcf of associated gas respectively and the Sankofa field with non-associated gas of about 1,107 Bcf, there are now newer projects aiming at domestic production and utilisation in Ghana. This, however, depends on adequate investments for new gas supply infrastructure and the effectiveness of the institutional and regulatory framework in fostering a more competitive domestic market for gas-to-power vis-à-vis imports through the WAGP and LNG sources. Upstream operations following petroleum agreements between GNPC and IOCs led to the discovery of oil in 2007 and domestic gas production in 2014 when the pipeline and processing plant necessary to commercialise associated gas was commissioned to supply power plants in the Takoradi area.[82] Operators of the TEN concession also began production of gas in 2016, while the Sankofa field project began supplies to the Takoradi area in 2018 with a 63-kilometre submarine pipeline transporting gas to onshore receiving facilities where it is processed and transmitted downstream.

[80] Fulwood and Bros (n6) supra.
[81] The World Bank, *'West African Gas Pipeline Project: Implementation Completion Report Review'* (World Bank Group, No ICRR14706, Washington, D.C. posted April 13, 2015).
[82] Fulwood and Bros (n6) supra; Ghana Ministry of Petroleum, *Gas Master Plan,* (2016) 1-246.

Figure 3: Components Ghanaian Western Gas Corridor (as of 2016)[83]



The Takoradi offtake point on the WAGP is being reconfigured as an entry point to allow the delivery domestic offshore gas supplies from Takoradi in the West to augment unreliable supplies in the Tema area in the east where most of the supplies from Nigeria is delivered. The Sankofa project is expected to deliver 180 mmscfd, split between the Takoradi and Tema power plants with a GSA between Eni/Vitol and GNPC for an estimated 19-year period, including a ToP provision which requires GNPC to pay for 90% of the agreed quantity of gas whether it can take it or not.[84]

Some of the most pressing challenges for the viability of the domestic gas-to-power market includes- (a) the VRA's financial difficulties and under-investment in power generation attributable to unreliability in gas imports leading to the use of more expensive light crude oil for thermal power generation, non-cost-reflective electricity tariffs; (b) the state-owned wholesale electricity purchasers - the Electricity Company of Ghana and the Northern Electricity Distribution Company- are also facing major liquidity difficulties and poor creditworthiness as power offtakers; and (c) high technical and non-technical losses and arrears from public sector consumers as with most developing economies in the region.[85] The wholesale gas market is based on bilateral contracts between Nigerian gas suppliers and VRA, while there are steps towards sectorial reforms and a new pricing policy for natural gas to enhance competitiveness.

3.2.3. LNG Options for Ghana

The Sankofa gas project is expected to be in production for almost two decades. However, other fields currently in operation in Ghana are expected to decline rapidly after 2020.[86]

[83] See Ghana Ministry of Petroleum, *Gas Master Plan,* at 88.
[84] Ibid; The World Bank on Sankofa Gas Project (n6) supra.
[85] Ghana Ministry of Petroleum, Gas Master Plan, (2016) 1-246; Bros (n7) at 46-47; Poudineh and Oyewunmi (n1) supra.
[86] World Bank on *Sankofa Gas Project* (n6) supra.

Consequently, since the emerging legal, political and economic issues may continue to make WAGP supplies less reliable than as agreed or the enforcement of performance remains equally complicated in reality; Ghana has been looking into LNG imports for the medium to long-term as demand and the domestic market grows. The Ghanaian government signed a Memorandum of Understanding (MoU) with Equatorial Guinea in August 2017 for about 150 mmscfd of natural gas per day in LNG supplies to Ghana. The MoU also provides for the building and operation of an LNG regasification terminal in Takoradi.[87] Additionally, in September 2017, Russia's Gazprom 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.[88] However, it appears that due to the current market development and institutional issues highlighted earlier, the LNG and FSRU options continue to face significant delays or mothballed. For instance, the Tema LNG Project which includes an FSRU facility to receive, store, regasify LNG and deliver gas on a build-own-operate-transfer basis with the assets transferring to the GNPC after the project's twenty-year term. The West African Gas Limited (NNPC (60%) and Sahara Energy (40%)), signed a five-year contract with Golar for an FSRU to be moored inside the port of Tema, Ghana. Even though a 10-year GSA with the Ghanaian government was approved in October 2016, the project appears to have been stalled, and the Golar Tundra FSRU has since left Ghana.[89]

The issue in Ghana and other developing West African countries regarding affordability is not just the question of 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. This issue underscores the need for contractual and project financing frameworks that can help to fully understand supply and demand side risks and provide effective mitigation tools.

4. Conclusion

To develop more sustainable and secure energy supply industries in the sub-region, more carbon-intensive sources of energy like coal and oil products would have to make room for more environmentally-friendly and potentially cheaper or efficient gas and renewables. In countries with significant gas reserves like Nigeria or those close-enough to such reserves with reserves of their own like Ghana, it is becoming increasingly important to develop more reliable and competitive gas-to-power markets. Host governments playing the roles of resource-owner, business partner with private-sector and financiers as well as the regulator often makes the objectives of developing viable projects, commercial and institutional efficiency as well as better economic regulation, more complicated. Thus, project sponsors, lenders and developers typically have to examine the full spectrum of applicable international petroleum transactions, legal, policy, and risks that are peculiar to gas and energy projects, including liquidity and creditworthiness issues which stems from the end-users of the gas or power produced. Where gaps or real obstacles to a project's development are found in the existing legislation and regulatory framework, such gaps and obstacles can and should be addressed in the formulation of the relevant policy, institutional, transactional and contractual frameworks.

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[87] Fulwood and Bros (n6) supra.
[88] Ibid.
[89] Ibid.