GAS MASTER PLAN

Republic of Ghana

DEVELOPED

BY

MINISTRY OF PETROLEUM

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Abbreviations and acronyms

bcf	Billion cubic feet
BOF	Basic oxygen furnace
BOOT	Build, Own, Operate, Transfer
BOST	Bulk Oil Supply and Transport Company
CEB	Communaute Electrique du Benin (Electricity Company of Benin)
CDB	Chinese Development Bank
CHP	Combined heat and power
CNG	Compressed natural gas
COG	Cost of gas
CREG	Comisión de Regulación de Energía y Gas
DES	Delivered ex ship (LNG)
DMO	Domestic Market Obligation
EBN	Energie Beheer Nederland B.V.
EC	Energy Commission
ECA	Economic Consulting Associates
ECG	Electricity Company of Ghana
EIA	Energy Information Administration
EMRA	Energy Market Regulatory Authority in Turkey
E&P	Exploration and production
EU	European Union
FOB	Free on board
FPSO	Floating productionstorage and operation unit
FSRU	Floating storage and regasification unit (also sometimes FRSU)
G2P	Gas-to-power
GCMC	Ghana Cylinder Manufacturing Company
GMP	Gas Master Plan
GMPM	Gas Master Plan Model
GNGC	Ghana National Gas Company
GNPC	Ghana National Petroleum Company
GoG	Government of Ghana
GTS	Gas Transport Services
HFO	Heavy Fuel Oil
IBP	International best practice
IOC	International oil and gas companies
IPP	Independent power producers
LCO	Light crude oil
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas

MCC	Millennium Challenge Corporation
MENA	Middle East and North Africa
MENR	Ministry of Energy and Natural Resources
MEP	Ministry of Energy and Petroleum
mmbtu	Million British Thermal Units
mmcfd	Million standard cubic feet per day
MMSTB	million stock tank barrels (oil)
MP	Master plan
NEDC	Northern Electricity Distribution Company
NGC	Nigerian Gas Company Limited
NGPP	National Gas Pricing Policy
NGTU	Natural Gas Transmission Utility
NGV	Natural Gas Vehicles
NNPC	Nigeria National Petroleum Company
PC	Petroleum Commission
PPP	Public private partnership
PSA	Production Sharing Agreement
PURC	Public Utility Regulatory Commission
PV	Present value
R/P ratio	Reserves to production ratio
RFO	Residual fuel oil
SOE	State owned enterprise
Tcf	Trillion cubic feet
TEN	The TEN group of fields which includes one gas condensate field (Tweneboa) and two oil fields (Enyenra and Ntomme)
ToR	Terms of Reference
TPA	Third-party access
TPAO	Turkish Petroleum Corporation
TTF	Title Transfer Facility
VALCO	Volta Aluminium Company
VAT	Value Added Tax
VRA	Volta River Authority
WACOG	Weighted average cost of gas
WAGP	West African Gas Pipeline
WAGPA	West African Gas Pipeline Authority
WAPCo	West African Gas Pipeline Company

Executive Summary

Background and Objectives of the Ghana Gas Master Plan

The use of natural gas in Ghana started with imports of gas from Nigeria through the West Africa Gas Pipeline (WAGP) for use in the power generation sector. WAGP supplies have been subject to unreliable supply, major interruptions and consistently below agreed supply volumes. With significant domestic associated and non-associated gas reserves discovered recently, the gas supply dynamic in Ghana has changed. Likely near-term production from the most advanced reserves are concentrated in three large offshore gas fields: the Jubilee field with associated gas reserves estimated at 490 Billion cubic feet (Bcf), the TEN fields with associated gas reserve of 363 Bcf and the Sankofa field with non-associated gas reserves of 1,107 Bcf. In addition, the Mahogany and Teak discoveries with total reserves of 120 Bcf will be developed as part of the Greater Jubilee Full Field.

With the completion of onshore infrastructure, notably a processing plant at Atuabo and pipeline from Atuabo to Aboadze, domestic gas has reached the market. The primary objective of the Gas Master Plan (GMP) is to develop a strategy for infrastructure development priorities that will contribute to the development of Ghana's natural gas resources and security of energy supply. The plan focuses on the medium to long term requirements for Ghana's gas sector..

Methodology

The Master Plan is based on qualitative analyses of the policy, institutional, regulatory aspects and developmental aspirations of Ghana, complemented by lessons from international experience in gas sector development in selected countries. The qualitative analysis is supported by quantitative methodologies underpinning the recommendations for the upstream, midstream and downstream gas sectors. A comprehensive Ghana Gas Master Plan Model (GMPM) has been developed to examine alternate scenarios, covering the following main aspects:

- Estimates of the demand for gas in Ghana up to 2040 on the basis of a power dispatch model and netback prices for the most likely non-power offtakers
- Calculations of the national annual gas supply and demand balance in Ghana, as well as the regional balances
- The weighted average cost of gas resulting from the supply mix
- Determination of the location, capacity, costs and timing of new infrastructure: transmission pipelines and LNG terminals
- The economic value of different gas utilisation scenarios

The GMPM enables different scenarios to be examined and compared.

The scope of this Master Plan is therefore focused on the economic, policy, regulatory and institutional issues. Any investment decisions and activities should however, consider environmental

and social impacts on the development of Ghana. The following subsections summarise the key inputs and recommendations of the plan.

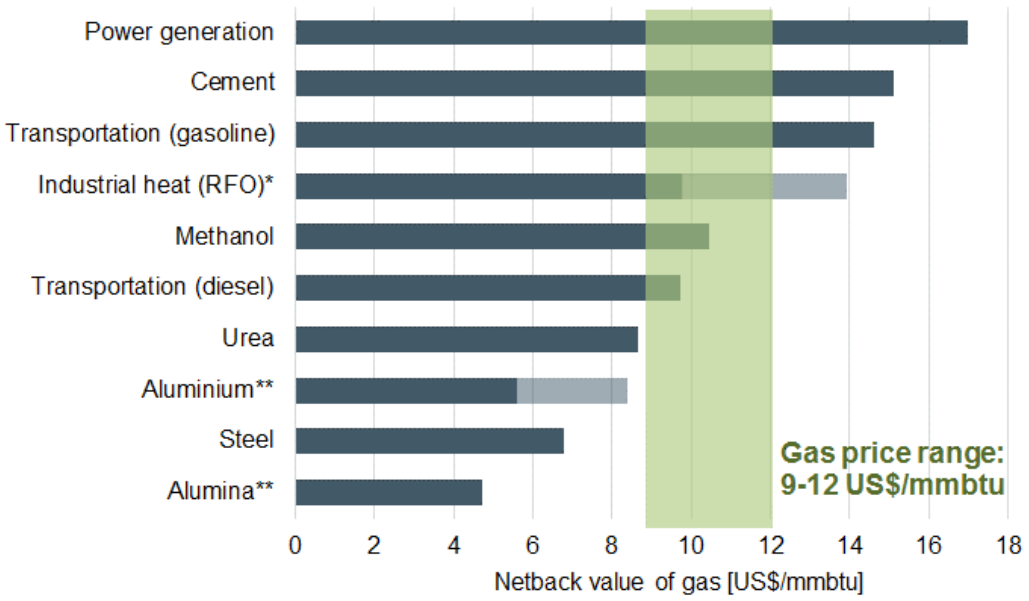
Lessons from International Benchmarking

An extensive review of gas sector development in nine countries provides key lessons of direct relevance for Ghana's medium to long term gas strategy. The countries reviewed are Colombia, Indonesia, Israel, Netherlands, Nigeria, Tanzania, Thailand, Trinidad and Tobago and Turkey. The lessons serve as guiding principles followed in the recommendations of the GMP and include:

- The **power generation sector has been the primary off-taker** at initial stages of gas market development in all countries.
- The regulatory framework to ensure cost reflective pricing and thus **financial viability of entities along the gas to power value chain**, is paramount.
- Gas **transmission networks have been developed by integrated state-owned gas companies** with government and donor financing, on the basis of large loads from power generation or large industrial users.
- Industrial usage has appeared most successful where it has **grown in an incremental fashion**, rather than selecting 'champion' industries through proactive industrial policy.
- **Export** of gas has been important in many countries but is **not relevant to Ghana** at present, due to the size of reserves and potential domestic market

Gas Utilisation Options

Non-power, i.e. mainly industrial uses and demand for gas were assessed based on comparator countries and a detailed netback analysis of the value of gas in various sectors for Ghana. The netback values of a range of possible gas utilisation options are summarised in the diagram below. The netback values together with gas prices provide a measure of economic feasibility of gas use across sectors. For sectors where netback values exceed gas prices, gas use is economically feasible. This is indicated by 3 zones in the figure below: gas uses where the netback value is higher than the green band are clearly economic; the economic attractiveness of uses within the green band range of US$9-12/mmbtu will depend on future gas prices; uses below the green band are unlikely to be economic uses of gas.



The recommended strategy for gas utilisation is given below.

- **Power generation** represents one of the most economically attractive, low-risk and urgent demand sectors for natural gas supplies.
- **Cement/Clinker production represents an economic sector for the use of gas, subject to availability of suitable limestone deposits.**
- Another priority may be gas for **heat demand to low-risk domestic-market focused industrial clusters**, especially in co-generation use, switching from expensive alternatives such as fuel oil.
- Dedicated **CNG vehicle fleets** such as urban buses and taxis offer an attractive potential saving on fuel costs in addition to the environmental benefit.
- **Strategic capital-intensive industries** such as urea, methanol and aluminium are a high risk option due to their high capital investment requirements, requirement for low gas prices, and strong level of competition in globalised markets with volatile prices.
- **Exports** are not a viable option for Ghana at the present, as the reserves are not enough to cover both domestic needs and economically viable levels for LNG exports.

The recommendation to focus on power generation for gas usage is in line with the current gas utilisation strategy of the Government of Ghana (GoG) as per the National Gas Pricing Policy. Additionally, GoG could focus on the transport sector where gas usage is also feasible, although the development of this market for gas is harder to achieve.

Supply Profiles and Cost of Gas

Three supply profiles on the basis of domestic gas reserves and resources, WAGP import volumes and potential LNG imports have been constructed. Domestic reserves are based on the supply of associated gas from the Jubilee gas field, TEN group which includes two oil fields (Enyenra and Ntomme) and one gas condensate field (Tweneboa). A non-associated gas discovery, the Sankofa field, discovered by ENI and associated gas discoveries, the

Mahogany and Teak by Kosmos are also expected to come into production in the near future. There are also likely to be further prospective gas reserves and resources (both non-associated gas and associated) from undrilled structures.

Three supply profiles are projected on the basis of the best available information on currently identified reserves, resources and estimates of future discoveries. The tables below summarises the production volumes of each field.

Field	**Low supply**	**Base supply**	**High supply**
Jubilee*	349	533	639
TEN	287	287	427
Sankofa	1,366	1,366	1,645
MTA*	24	129	173
Hess		177	177
Shallow Tano			193
Other Non-associated gas			1,000
Other Associated gas			1,000
Total	2,026	2,492	4,254

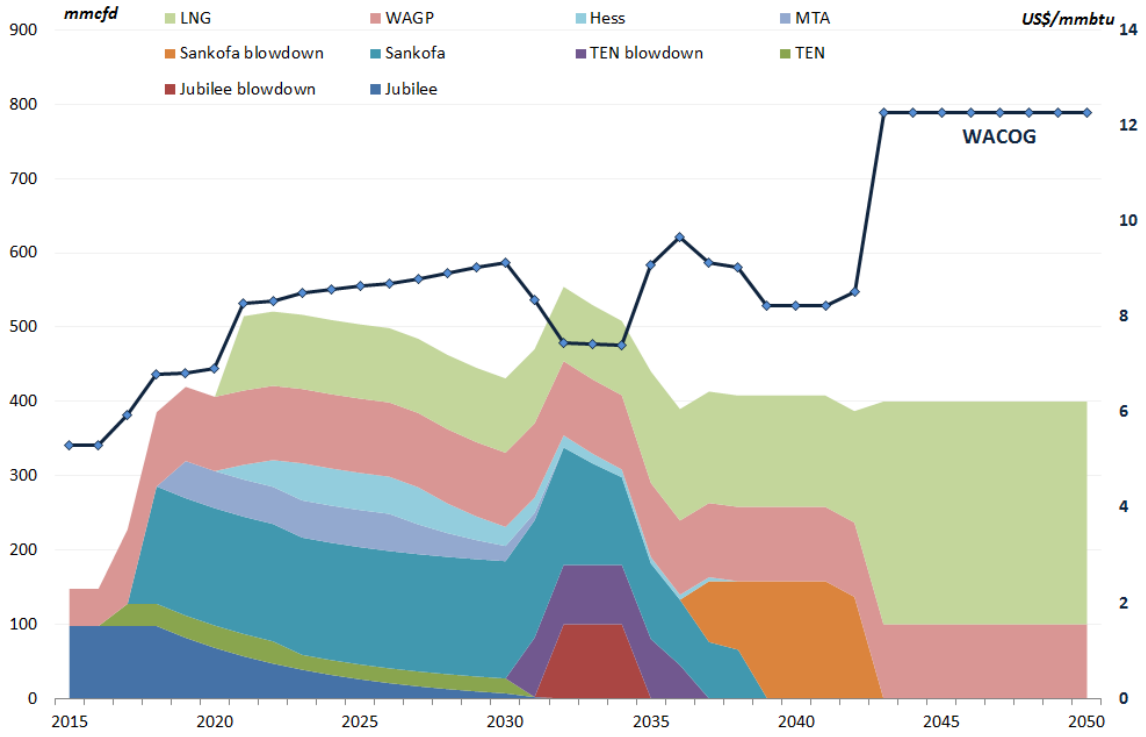
Field	**Production year**	**Daily sales peak**	**Indicative cost**
	earliest	*mmscfd*	*US$/mmbtu*
Jubilee	2015	60-120	2.98 – 4.20
TEN	2017	30-50	2.98 – 4.20
Sankofa*	2018	150-180	8.90
MTA	2019	50-120	4.20
Hess	2021	50	2.98 - 4.20
Shallow Tano	2025	50	2.98 - 4.20
Other Non-associated gas	2020	140	4.20
Other Associated gas	2019	140	2.98

Note: unproven sources are only assumed in the high case

For WAGP, the plan assumes a volume of 50 mmscfd in the low supply forecast over the period 2015-2050; 50 mmscfd rising to 100 mmscfd in 2017 for the base case and 50 mmscfd rising to 170 mmscfd in 2017 in the high case. The cost of WAGP gas is set at a price of US$8.6 /mmbtu. LNG import capacity is assumed at 300 mmscfd at an initial price of US$10.5 /mmbtu.

The graph below shows the supply profile and the resulting weighted average cost of gas (WACOG) for the base case. The plan has also examined the high and low cases. It may be noted that the presented supply volume in the diagram is 'potential' supply. It is therefore not capped by demand levels and is used in conjunction with demand projections in the GMPM to estimate a demand-supply balance in this document.

The changing weighted average cost of gas (WACOG) associated with the above supply profile shows an initial price marginally above US$6/mmbtu. The cost rises steadily towards just above US$12/mmbtu by 2040 when the new supplies come on stream and LNG takes up a larger proportion of supplies. In the high supply case the WACOG may lie in the lower range of US$7-10.5/mmbtu. These gas costs could also reduce a little if oil prices continue their end 2014 low trend..

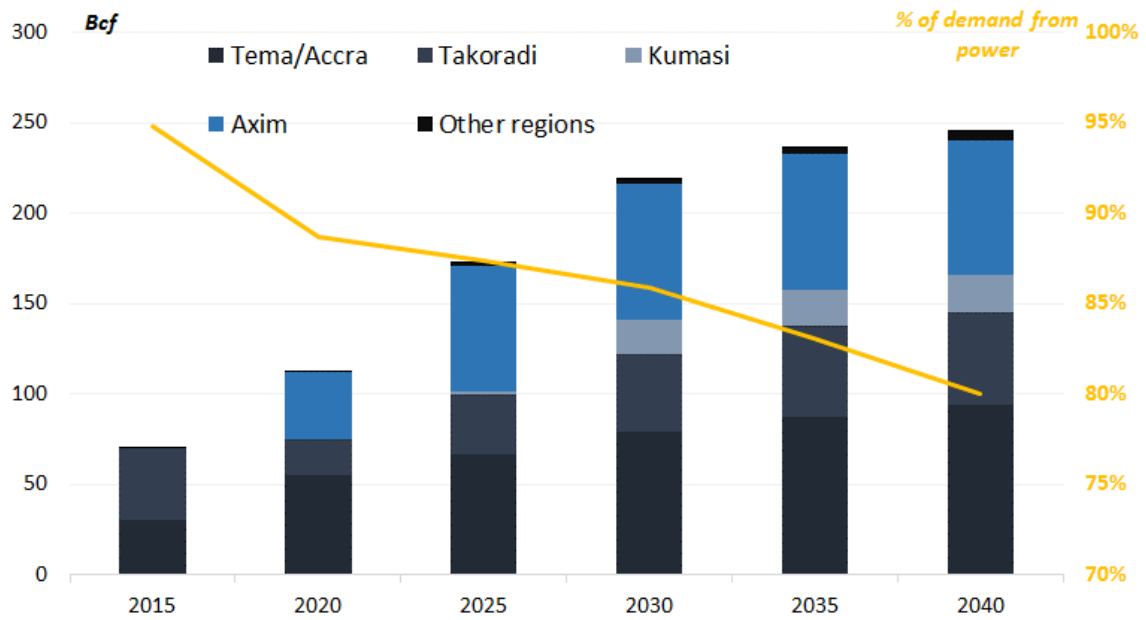


Gas Demand

Gas demand in Ghana will come from three main sectors: power generation, industrial demand and gas use in transport. **The power sector constitutes the largest share of demand exceeding 80% of total demand over the period 2015 to 2040**. Gas to power demand is estimated through a power dispatch model taking into account electricity demand and GoG's power generation plans.

Besides the power sector, a growing number of industries would use gas for industrial process heat, plus a pilot exploration of the use of gas in the transport sector, as a replacement for petrol, diesel and LPG.

For the purpose of infrastructure planning, the analysis also breaks down gas demand into 12 main demand clusters. The diagram and table below illustrate the geographical and sectoral distribution of demand in the base case scenario. Due to the importance of the power sector, **gas demand in Ghana is likely to be concentrated in two areas: Tema/Accra and Takoradi/Axim**.



A1.1 *Bcf*	A1.2 Power demand	A1.3 Industry & transport	A1.4 Total gas demand by region											
A1.5	**A1.6**	**A1.7**	A1.8 *Tema/ Accra*		A1.9 *Takoradi*		A1.10 *Kumasi*		A1.11 *Axim*		A1.12 *Other regions*	
A1.13 2015	A1.14 66	A1.15 4	A1.16	30	A1.17	40	A1.18	-	A1.19	-	A1.20	-
A1.21 2020	A1.22 10	A1.23 13	A1.24	55	A1.25	20	A1.26	-	A1.27	3	A1.28	2
A1.29 2025	A1.30 15	A1.31 22	A1.32	67	A1.33	33	A1.34	1	A1.35	7	A1.36	3
A1.37 2030	A1.38 18	A1.39 31	A1.40	79	A1.41	43	A1.42	19	A1.43	7	A1.44	4
A1.45 2035	A1.46 19	A1.47 40	A1.48	87	A1.49	51	A1.50	19	A1.51	7	A1.52	5
A1.53 2040	A1.54 19	A1.55 49	A1.56	94	A1.57	51	A1.58	20	A1.59	7	A1.60	6

Supply-Demand Balance

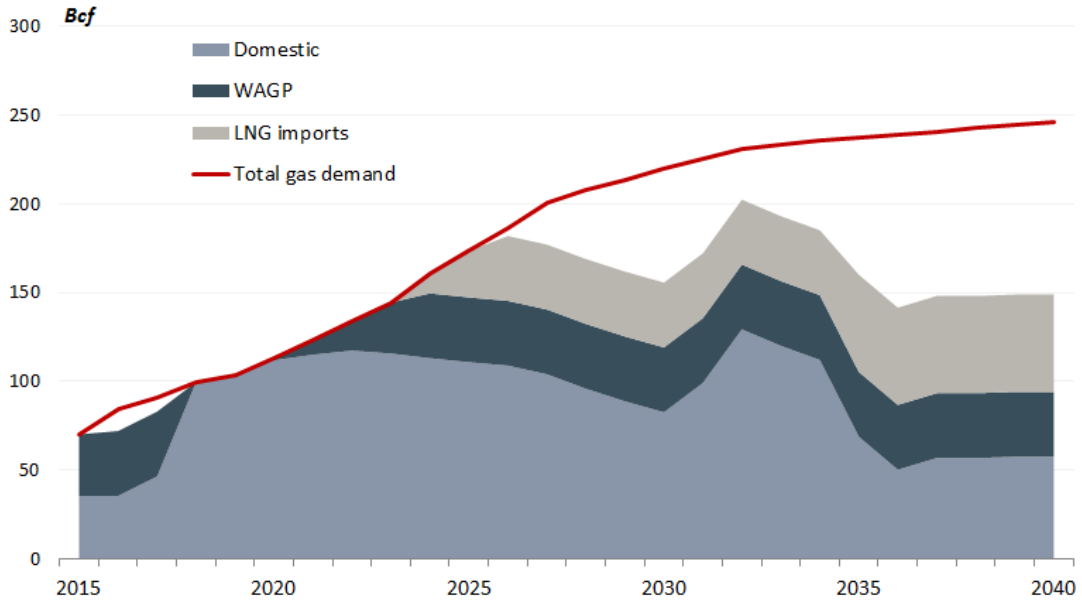
The base case supply-demand balance is shown in the diagram below. The potential supply profile in the diagram is adjusted and capped by the estimated demand volumes.

The domestic resources which will be available from 2017 and onwards are adequate to cover the total demand for gas until 2021 in all simulated cases. In 2021 the LNG terminal in Tema is expected to increase the available capacity in the system.

This assumption is reviewed in our infrastructure plan and discusses the details of a suitable LNG strategy compared to the pre-feasibility study completed by The Millennium Challenge Corporation.

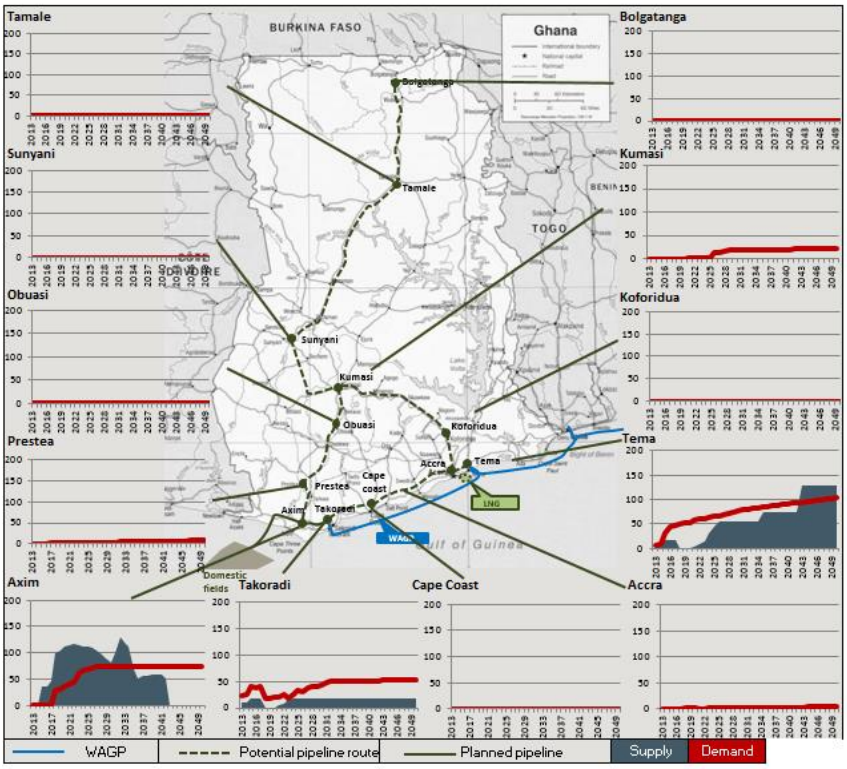
The reserve to production ratio is 72 years in 2015, 20 years in 2020 and 14 years in 2030. The reserves to production ratio decreases exponentially across the years as production rises and reserves fall.

The Natural Gas Policy will address the desired reserves to production ratios for Ghana and mechanisms for increasing reserves and recovery of natural gas to prolong the sector's economic life.



Infrastructure Investment Plan

As noted previously, gas demand is focused on two main demand centres are Takoradi and Tema. Key supply points are Atuabo and Sanzule (for domestic production), Takoradi (for parts of WAGP) and Tema (WAGP and LNG terminal). The map-based presentation of the GMP modelling results below shows the regional supply-demand balances and the possible gas pipeline options assessed. The analysis shows that there is scope for bringing gas from the western parts of the country to satisfy unmet demand levels in the east in the short term. Balancing supply and demand across the regions is the main considerations for the proposed infrastructure plan.



The recommended infrastructure development plan is derived from an analysis of balancing demand and supply of gas across regions, ensuring security of gas supply, minimising the impact on gas transmission tariffs, and maximising the impact on direct economic value. The key recommended points of the gas infrastructure plan can be summarised as:

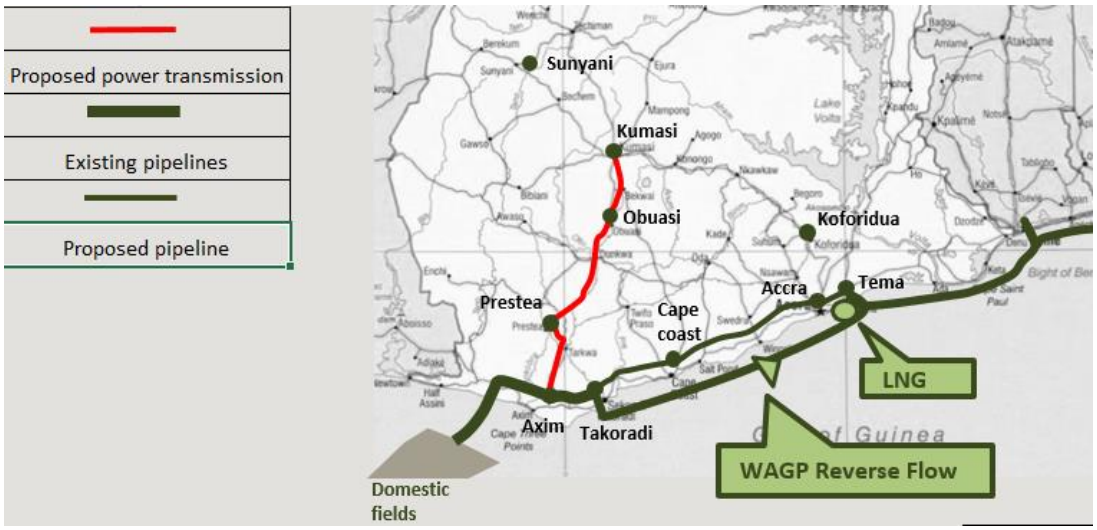
- **To cover the short term demand in Tema (2015-2018) reverse flow capabilities on WAGP should be developed**. The capacity of the pipeline for the reverse flow with the addition of a compressor station could support 100 mmscfd and the assumed capital costs for the compressor station are US$20 million.

- **GoG should develop the onshore gas pipeline connecting Takoradi with Tema** to ensure security of supply, introduce competition on the transportation of gas and develop the gas market along the coastal line for potential customers. The diameter of the pipeline would need to be 20 inch at an investment cost of US$250 million.

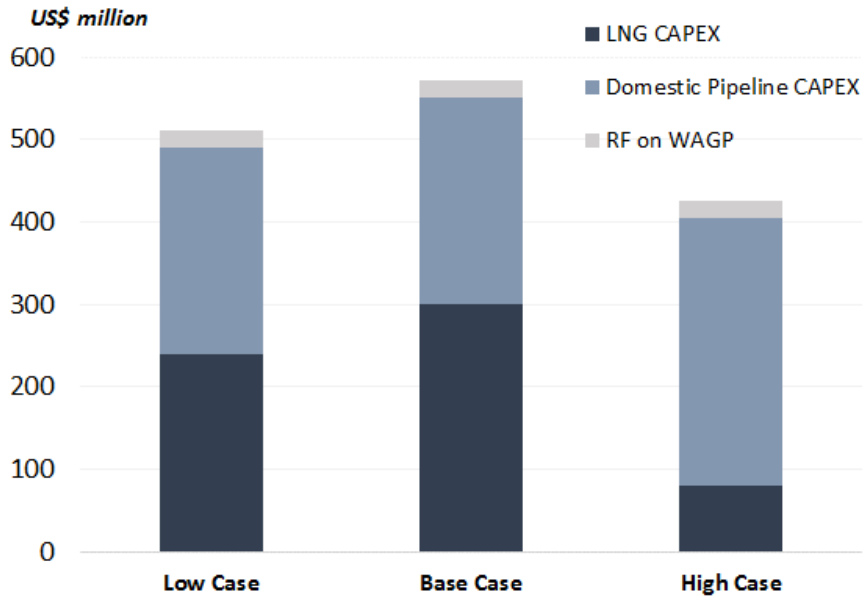
- **To cover immediate short term and long term demand GoG should develop an LNG Terminal in Tema**. A floating regasification unit instead of an onshore terminal would ensure flexibility of use. The terminal and associated infrastructure should be sized on the basis of medium term unmet demand, approximately 270 mmscfd. This would require investment costs of between US$40 million (if no fixed berthing) and US$300 million (with fixed berthing).

- **The model does not indicate the need to develop a gas pipeline to Kumasi and further north for now**. Instead GoG should develop or strengthen the power transmission lines to cover energy demand in those regions.

The map below illustrates the proposed infrastructure plan. **Total investment costs could range from 420 US$ million to 570 US$ million depending on the assumed level of demand and supply**[1].



The breakdown of total investment costs across three supply/demand scenarios is shown in the diagram below. All recommended infrastructure is needed immediately – apart from the LNG terminal in the high supply and high demand case. This highlights the urgency for gas infrastructure investments in Ghana that would ensure balanced gas demand and supply in the country.



The transmission tariff resulting from the proposed infrastructure plan is estimated to range between 0.50 US$/mmbtu to 0.76 US$/mmbtu. Adding this to the weighted average cost of gas, the cost of delivered gas would range between US$5.0 /mmbtu and US$8.6 /mmbtu until 2020; US$6.0 /mmbtu and US$10.7 /mmbtu between 2020 and 2030.

The total economic value in present value terms of the proposed gas infrastructure plan ranges between US$16 and 33 billion. The true economic value of the gasification strategy will be

[1] Note assumption includes a fixed berth LNG assumption, i.e. a high cost LNG regasification option. We have opted to focus on a 'conservative' assumption for gas infrastructure financing providing the upper range of possible investments.

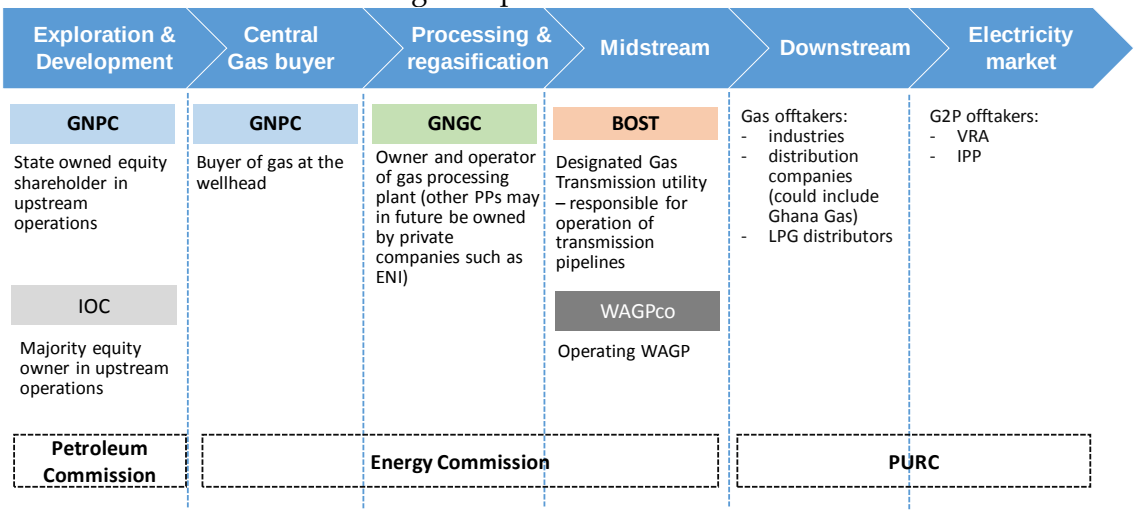
determined by the volumes of domestic supply and consumption. The economic value lost from unmet demand as a result of the recommended infrastructure is relatively small; an LNG import terminal with greater capacity could be developed, though this additional capacity might have a low return.

Institutional Framework

Proposals for the development of the gas sector are covered by a number of policy documents (notably the 2010 Energy Sector Strategy and Development Plan) and various legislative instruments (such as the enabling laws for the regulators and the five legislative instruments pertaining to gas issued by the Energy Commission). The framework is not as complete as it should be, and in due course consideration should be given to **reviewing the Gas Policy in the light of experience and developing a corresponding Gas Sector Act** to make the policy effective.

The institutional structure (prior to recent changes of GNPC being a gas aggregator of and GNGC becoming a subsidiary of GNPC) is summarised in the diagram below. Upstream licensing regulation is the responsibility of the Petroleum Commission, midstream and downstream licensing and technical regulation is the responsibility of the Energy Commission and economic regulation is undertaken by the multi-sector utilities regulator, PURC.

Exploration, production and gas aggregation are the responsibility of GNPC while GNGC owns the pipeline, owns and operates the gas processing plant and has the responsibility of developing the downstream distribution system, initially for industrial gas customers. BOST has been licensed by the Energy Commission as the sole national transporter of natural gas in Ghana. Other players are the international oil companies in the upstream sector, the West African Gas Pipeline Company and the power generation companies (VRA and IPPs) as the ultimate drivers of demand for gas-to-power.



The key roles for implementing the long term infrastructure plan and developing the supply and distribution of gas to the market, as modelled in the scenarios, is split between three segments of the diagram above (processing and regasification, midstream, downstream), two principal bodies (GNGC and BOST) and two regulators (EC and PURC). This is a complex structure and one where **effective coordination of tasks and roles is needed** to

avoid time and cost over-runs. This was the case with the gas processing plant where delays and cost over-runs have affected the development of the sector.

This structure was compared with other countries which have successfully developed their gas sectors and markets, such as Turkey and Trinidad and Tobago, where a more centralised approach to coordination of gas procurement, transmission development and wholesale has proved very successful. The coordination of investment between the upstream, midstream and downstream is complex in a newly evolving gas sector, compounded by the difficulties of having credit-worthy entities to guarantee the gas contracting and infrastructure investment.

Based on international comparators, gas sector development is facilitated by providing a simpler structure more suitable to the nascent state of the gas market in Ghana. **The decision to appoint GNPC as the aggregator of gas and making GNGC a fully owned subsidiary of GNPC will** improve coordination in the sector and facilitate infrastructure investment and financing. The rationale of BOST as the transmission pipeline investor is not clear. Coordination of upstream, midstream and downstream investments would be easier in an integrated structure where a combined entity of GNPC and GNGC could coordinate and finance new investments more effectively.

It is recommended that the roles of the regulating entities should be unified in the downstream gas sector and handled by one institution.

Financing Strategy

GoG has challenges in the provision of additional infrastructure over the coming years. The following issues need to be taken into account in attempting to address this situation:

- **Royalties and tax revenues from the production and sale of gas may help provide securitization** along the gas value chain rather than fully fund specific investments.
- Private sector involvement, likely through **PPP structures needs to be pursued** to provide sufficient funding for all identified infrastructure to be delivered.
- A **BOOT arrangement is suitable for easily identifiable projects** such as an LNG FSRUs and point-to-point pipelines while concession arrangements are better suited for distribution networks.
- Measures to help broaden participation in infrastructure development and speed up implementation include greater use of pre-screening of bidders for their technical and financial capacity and increasing transparency in tendering processes. Bonds and forms of penalties for not meeting schedules/commitments should be used where appropriate.
- Any **government support should focus on risks which are outside the control of developers** and more easily borne by the State.

Pricing Policy

It has been observed that the pricing approach in the Gas Master Plan is inconsistent with the existing National Gas Pricing Policy (NGPP)so **a new pricing policy statement is required**. It should be based on the following principles:

- The financial viability of supply entities is to be assured, through gas price components being cost reflective and yielding adequate rates of return.
- Upstream **commodity prices** are to be negotiated, while the gas price to consumers should be based on the weighted average cost of gas (WACOG), plus a supplier's margin.
- **Processing, transmission and distribution tariffs** are to be transparently regulated by an independent regulatory agency.
- Average rather than marginal costs are to be used for tariff calculations in the short to medium term.

The pricing regulatorshould be responsible for defining the detailed methodology to be used for the gas processing fee, transmission tariff and distribution charges, specifying procedures for periodic price reviews, providing an indexation formula to protect the real value of the prices between major reviews and defining circumstances for exceptional reviews to take place.

Summary of Recommendations for a Coordinated Development of the Gas Sector

Ghana is poised to make effective use of its petroleum and gas resources to raise its development trajectory to a new level. Some recommendations are made in the report on short-term issues, but the focus is on key measures to ensure the medium and long-term development of the gas sector:

- **Policy**: Put the Gas Master Plan into the public domain and make clear GoG's commitment to its core gas allocation prioritisation (power sector and industrial process heat). Following this, the National Gas Policy should be formulated and promulgated.
- **Legislation**: Use the Gas Policy as the basis for developing a comprehensive Gas Sector Act which will support the continuous development of gas in the national interest.
- **Regulation**: Provide a stable regulatory and fiscal framework, including predictable fiscal conditions and gas pricing mechanism, for the upstream, midstream and downstream components of the gas industry.
- **Institutional structure for infrastructure development**: Streamline coordination of infrastructure development along the gas value chain, to reduce risks and improve coordination of infrastructure development.. In particular the responsibility of gas infrastructure planning and asset ownership needs to be clarified for improved coordination. It is recommended that the roles of the regulating entities should be unified in the downstream gas sector and handled by one institution.

- **Pricing**: Review and promulgate a new national gas pricing policy which is consistent with the Gas Master Plan and define the detailed regulatory framework.
- **Capacity-building**: Put resources into capacity-building in each of the competence areas required for gas sector development.
- **Infrastructure:** Enable and support the development of key strategic gas infrastructure, which includes a coastal east-west pipeline, an LNG terminal in Tema and reverse flow arrangements with WAGP.
- **PPPs for gas projects**: Working through the newly defined national PPP framework, be open to flexible PPP arrangements to ensure adequate financing of gas infrastructure investments.
- **Government financial support**: Draw on the *Project Development Facility* to prepare projects to a stage where an efficient competitive bidding process can be launched; use the *Ghana Infrastructure Investment Fund,* rather than a special purpose gas securitisation fund, to provide the public financing component of PPP and JV transactions; provide government guarantees and/or subsidies sparingly, if at all, in the gas sector.
- **Imports***:* Ensure adequate security of supply to attract IPP investments through supplementing domestic supplies with flexible import arrangements (undiminished importance to lower-priced WAGP imports, together with higher-priced regasified LNG from FSRUs). In the future, increase in imports should consider WAGP expansion over LNG.
- **Off-taker viability**: Ensure the financial viability and associated credit-worthiness of power and gas sector entities.
- **Industrial gas users**: Seek out non-power users of gas; follow gas-to-power investments with the development of low pressure distribution networks to provide gas to industrial customers.
- **Transport sector**: Undertake a **pilot** project on the import of compressed natural gas vehicles, as part of public transportation. Subsequently, the Ministries of Transport and Petroleum should collaborate to develop a policy framework for infrastructure and retrofitting of vehicles to use CNG.
- **Increasing reserves**: As the domestic gas market develops, IOCs should be encouraged to maximize the exploitation of existing fields and exploration of new fields to increase reserves. Review future supply-demand balances on a regular basis and re-assess the costs and benefits of introducing a wider spectrum of gas utilisation.

1 INTRODUCTION

This ***Gas Master Plan (GMP) has been*** prepared by the Ministry of Petroleum ***for Ghana***. It is culmination of a process of activities that involved consultancy studies and stakeholder consultations.

The document is the third deliverable following the submission of an Interim Report by Economic Consulting Associates (ECA) of the United Kingdom in May 2014 and the Draft Final Report in September 2014.

1.1 Objective of the Plan

The primary objective of the GMP is to develop a medium to long term strategy for infrastructure development priorities that will contribute to the development of the country's natural gas resources and security of energy supply.

The GMP and related pricing policy options offers guidance for the Government of Ghana (GoG) and other stakeholders within the energy sector by providing the following outputs:

- **Proposed gas allocation plans** across domestic power and industrial sectors and exports (if feasible) on the basis of economic value added and the available supply
- **A medium to long term infrastructure plan** that will ensure security of supply and be in line with the proposed gas allocation plans
- **Recommendation on a suitable gas pricing policy** which ensures upstream production as well as security of demand
- **Recommendation on a suitable institutional framework** to be in line with international best practice and promote development of the sector
- **A review of the regulatory framework** analysing the major points of deficiency for gas sector development.

As a key part of the plan, a model (the Gas Master Plan Model, GMPM) is provided for updating and examining alternate scenarios for the development of the gas sector and its economic impact.

Although the focus is on developing medium to long term plans, the short term bottlenecks of the gas market and gas industry in Ghana, were taken into account. The recommendations are guided by the requirements and needs over the longer term horizon.

1.2 Ghana's Gas Sector – Background and Key Issues

The use of natural gas in Ghana started with imported gas being used in the power generation sector. With severe power shortages in the country, insufficient supply through the West African Gas Pipeline (WAGP) and recent significant non-associated gas discoveries, the development of the gas sector and its integration with the power sector has become a priority for policymakers. The gas industry in Ghana has only recently been established and is characterised by a number of different institutions, agencies and

organisations with overlapping mandates. This is not the most common or proven approach for a nascent gas sector; other countries embarking on developing their gas sector in a major way have followed a more integrated approach, such as Turkey. Lack of expertise and capacity in handling gas issues, uncertainty about institutional responsibilities, and the difficulty of coordination between multiple bodies has meant that the sector has not developed as rapidly as expected.

Supply from WAGP

Gas is currently supplied through the West African Gas Pipeline (WAGP), an offshore gas pipelines connecting Takoradi and Tema in Ghana with Nigerian gas fields. Since the inception of WAGP in 2009, gas flows to Ghana from Nigeria have never reached the fully contracted volume of 123 million standard cubic feet per day (mmscfd). Over recent years, supplies were completely interrupted due to serious damage to the pipeline in 2012. The shortage in gas supplies has resulted in the use of fuel oil in the country's thermal power plants, significantly increasing electricity costs and adding to the financial burden in the power sector and associated public entities. This has heightened the urgency of developing Ghana's significant domestic gas resources.

Domestic Reserves and Resources

With significant recent finds in non-associated gas reserves together with existing associated gas reserves, Ghana has sufficient gas resources to meet its projected demand over the medium term. Domestic proven gas reserves are concentrated in three large offshore gas fields: the Jubilee field with associated gas reserves estimated at 490 Billion cubic feet (Bcf), the TEN fields with associated gas reserve of 363 Bcf and the Sankofa field with non-associated gas reserves of 1,107 Bcf. In addition, the Mahogany and Teak discoveries with total reserves of 120 Bcf will be developed as part of the Greater Jubilee Full Field.

Gas-to-Power Sector Financial Challenges

Due to insufficient gas supply, demand for gas in Ghana is currently constrained. Besides security of supply considerations, gas demand in the power sector is constrained by a lack of investments in gas to power generation capacity. The main reasons for under-investment in gas fired power generation include the following:

- The Volta River Authority (VRA), Ghana's state owned power generation company, is facing major financial difficulties and is not in a position to raise capital for major investments in power generation. Shortages in gas supply have meant that VRA having to rely on expensive light crude oil in its thermal power generation facilities. Without adequate electricity tariff increases, the World Bank projects that VRA is facing imminent financial collapse[2].

- The two state owned wholesale electricity purchasers, the Electricity Company of Ghana (ECG) and the Northern Electricity Distribution Company (NEDCo) are in financial difficulties, bringing their creditworthiness as offtakers of electricity into question. This detracts potential independent power producers (IPP) from investing in the sector. Besides low electricity tariffs, the main reasons for the financial difficulties are high technical and non-technical losses and arrears from public sector consumers. A major reform programme is currently underway at ECG aiming to reduce losses, increase

[2] *Energizing Economic Growth in Ghana*, World Bank June 2013

productivity of the workforce by introducing performance based pay, and streamlining decision-making processes through a new management structure.

- Electricity tariffs for the past few years have been below cost recovery levels resulting, among other things, in the financial difficulties of NEDCo and ECG. More importantly, however, this has sent a negative signal to potential market entrants, the independent power producers about the viability of investments in power generation.

Lack of Market and Price for Gas

As the gas sector was only recently established, no competitive gas market exists. Wholesale gas is traded via bilateral contracts between Nigerian gas suppliers and VRA. A pricing policy for natural gas was agreed by the Government in May 2012 but this has not been finalised..

The LPG market in Ghana is more mature and LPG has been promoted by GoG since 1986. Consequently, a network of LPG filling stations exists in Ghana with most of them concentrated in and around Accra. The objective of the LPG policy was to incentivise residential users to switch away from biomass sources for cooking and heating. With rising fuel prices however, LPG has increasingly been used in the transport and commercial sectors over recent years. This together with a supply shortage of LPG has resulted in GoG policy to reduce subsidies and adjust prices to more cost reflective levels.

Gas Infrastructure

The Western Gas Corridor is a major infrastructure project promoted by Ghana National Gas Company (GNGC) to bring gas from the offshore fields to gas fired power plants in Takoradi. The project has been under development since 2011. Some pipeline components and the gas processing plant were completed in 2014. Infrastructure planning has been slow in Ghana and apart from WAGP and the pipeline components of the Western Gas Corridor no other gas infrastructure currently exists in Ghana.

1.3 Ghana Gas Master Plan Model (GMPM)

The above issues form the backdrop to the Ghana Gas Master Plan. They are all addressed later in this document. At this point, it is opportune to introduce the analytic basis for quantitative aspects of the plan. This is the Ghana Gas Master Plan Model (GMPM) which aims at providing guidance for policy advice for the upstream, midstream and downstream gas sectors, by simulating alternate supply, demand and infrastructure investment scenarios. Its main features are to allow the preparation and analysis of scenarios to:

- estimate the demand for gas in Ghana up to 2040
- calculate the national annual supply demand balance in Ghana up to 2040
- calculate the weighted average cost of gas resulting from the supply mix
- determine the location, capacity, costs and timing of main pipeline routes in the gas transmission networks
- calculate the economic value of gas utilisation scenarios

The main structure of the model is shown in Figure 1 below. The model has three main components:

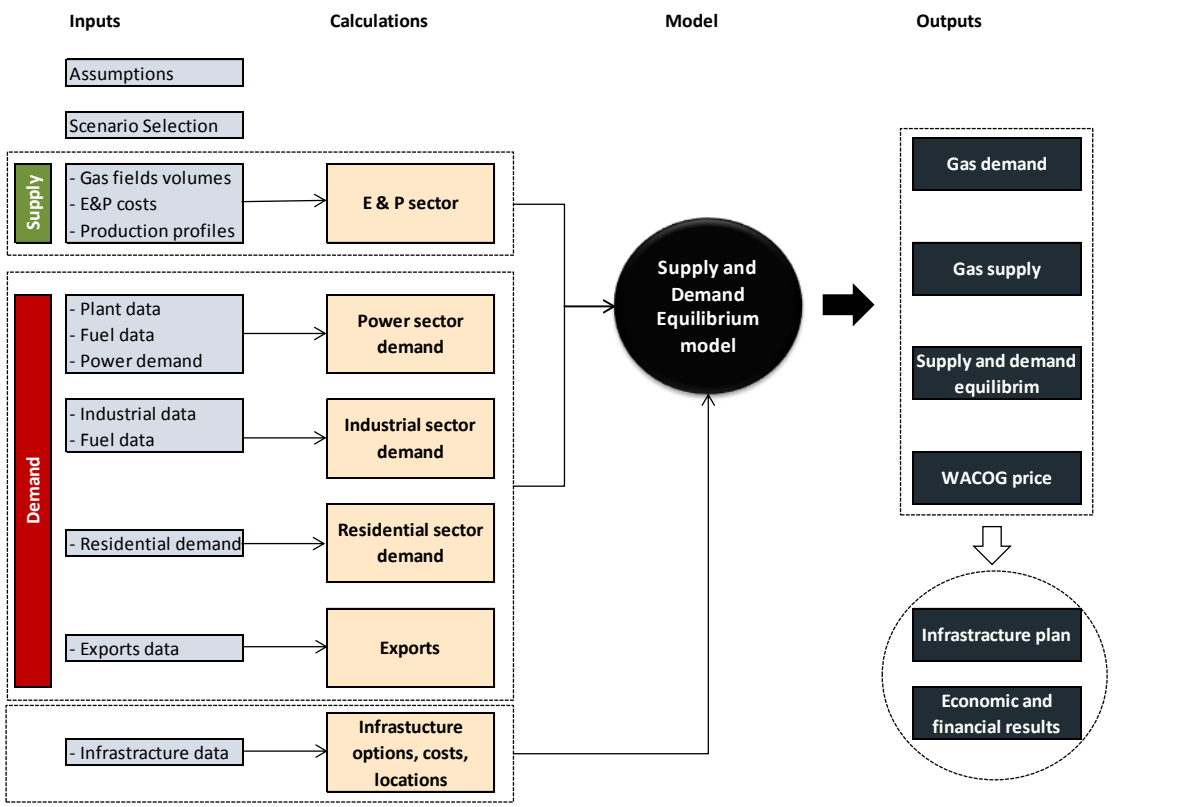
- ***Input data*** – the component where all data, assumptions and scenario parameters are defined by the model user

- ***Calculation*** – the part of the model where demand and supply volumes are calculated on the basis of the inputs and parameters determined in the first component. This also includes an economic analysis of the different utilisation options.

- ***Outputs*** – the component of the model where the key results of GMPM including the gas demand levels, the equilibrated gas supply volumes, the weighted average cost of gas (WACOG) and the infrastructure components are presented.

Within each part there are several sub-sections for the supply, demand, infrastructure and economic gas allocation processes. For the supply and demand components, which represent the largest parts of the GMPM, the sub sections are defined through different industries.

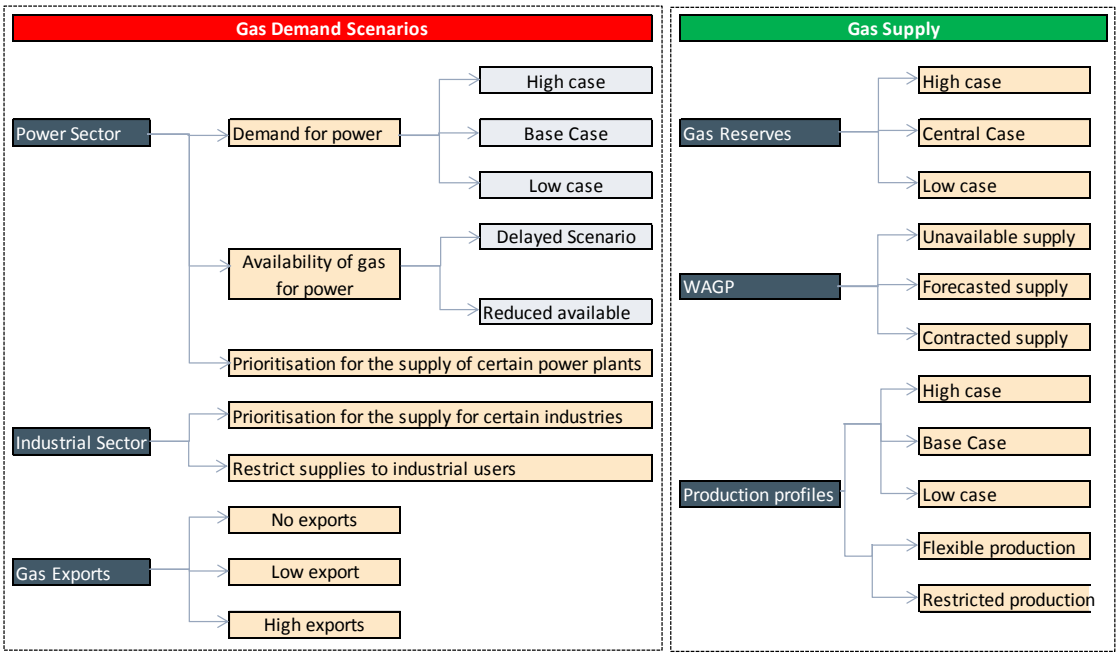
Figure 1: Ghana Master Plan Model Structure



The model brings together all relevant data and projections of the supply and demand for gas in a consistent framework over a nearly three decade planning horizon. Demand is spatially disaggregated, and permits analysis of the pipeline and other infrastructure investment needs required to make full use of the country's gas resources. In addition to gas information, time and economic parameters and various conversion factors are needed. Details of the methodologies used for power demand, netback analysis and infrastructure planning and the assumptions used in the model are provided in Annex A5.

Given the uncertainty over future gas pricing, export commitments, domestic supply volumes, infrastructure development and demand forecasts, the GMPM allows the user to simulate a variety of different scenarios. The different scenarios that can be chosen by the user are summarised in Figure 2.

Figure 2: Modelling Scenarios



The GMPM has two main purposes:

- to facilitate the development of the Gas Master Plan, based on a reasonable and agreed set of scenarios, and to illustrate the results of the scenarios
- to be used by the Ministry for future updating

The second purpose is critical, as the external factors driving gas sector development can change quite fast, including international fuel prices, upstream discoveries, macro-economic factors and their impact on gas demand. This plan presents currently relevant scenarios. The GMPM will allow new scenarios to be analysed as circumstances change.

1.4 Overview of the Report

The remainder of this plan is structured as follows:

- Section 2 discusses gas utilisation priorities, identifying power production and industrial heat as the main sectors to be targeted at the present time
- Section 3 presents estimated gas supply, production and cost scenarios
- Section 4 analyses demand for gas from the power and industrial sectors
- Section 5 discusses gas allocation, presents the supply-demand balance and determines the infrastructure investment requirements

- Section 6 discusses policy, institutional, regulatory and pricing frameworks
- Section 7 presents a summary of the Gas Master Plan and provides recommendations
- Section 8 discusses the gas pricing policy
- Section 9 summarises the main recommendations of the plan

The annexes provide a list of documents consulted, present the international case studies covering comparator countries, and provide details on the methodologies embedded in the Gas Master Plan Model and the data inputs and assumptions used to generate the results, as well as some summary information on related studies.

2 GAS UTILISATION IN POWER AND NON-POWER SECTORS

In order to assess the value of gas in various possible end-user sectors and make recommendations on the policy for allocating gas to potential demand centres, this strategy document reviews previous studies and uses a Netback Analysis to calculate the value of gas in the main sectors, in accordance with international best practice. This section therefore covers:

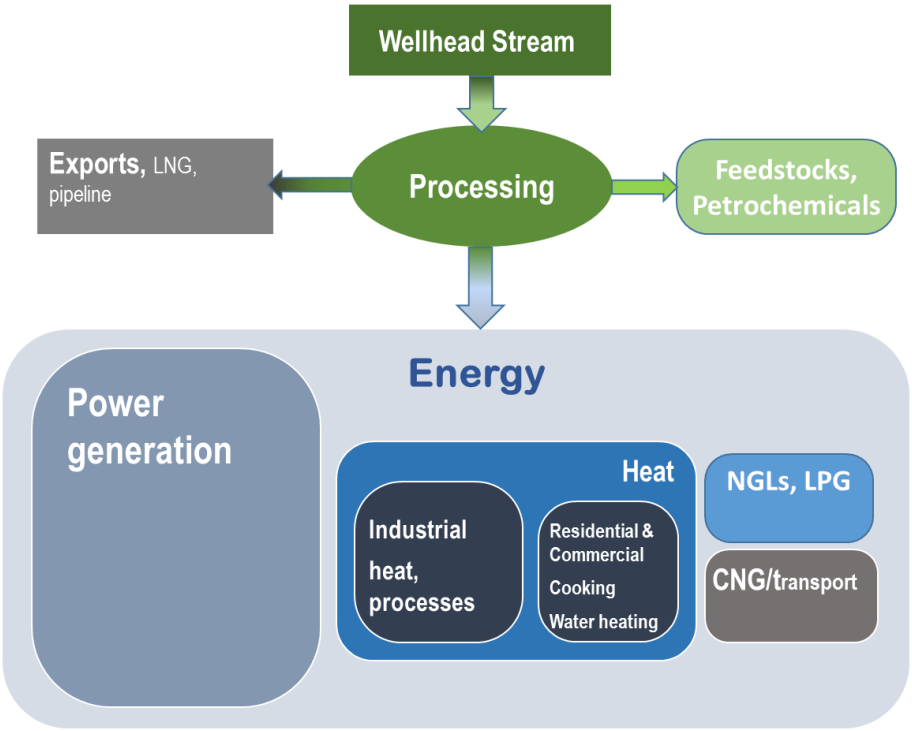
- A review of **previous studies** and assessments of the attractiveness of gas in different sectors
- The use of **netback analysis** to calculate the value of gas in the main sectors
- A review of **international benchmarking** on how these utilisation issues have been addressed in a select group of comparator countries
- A set of **recommended gas utilisation options**.

During processing of raw or wet gas, Natural Gas Liquids (NGLs) including Liquefied Petroleum Gas (LPG) and Condensate are removed from the gas stream and marketed separately. The remaining lean gas is utilised primarily as fuel for power generation, but could also be used as an energy source for industrial heating purposes, cement sector or as a feedstock for certain petrochemicals. The utilisation options for this lean or "dry" gas is the focus of this section of and is sub-divided into:

- Power Generation
- Cement Production
- Industrial Co-Generation
- CNG vehicles
- Petrochemical synthesis
- Residential and commercial heating

A further option is the export of gas via pipeline or as LNG. These options are summarised in **Figure 3**.

Figure 3: Common Gas Utilisation Options



Ghana's gas resource, if properly utilised, could meet the bulk of the country's energy requirements. This Gas Master Plan considers a large range of potential small-scale and large-scale domestic gas utilisation options as identified in **Figure 3**. Such coverage will allow for the possibility of expanding focus sectors if and when additional resources are discovered and supplied at an economically viable cost.

The Plan draws on findings from previous reports on gas utilisation options undertaken for the country, original research and also international experience and related lessons learnt in the development of natural gas sectors.

2.1 Gas Utilisation Options – Previous Studies

The starting point for these analyses are the reports that have already been carried out. The Plan first surveys these sources, before developing its own estimates of potential gas demand in various sectors. Three highly relevant studies have been conducted regarding potential gas utilisation options for the country. These are:

i. *'Advisory Paper – Ghana Sector Gas Master Plan'* prepared for the Ministry of Energy by Nexant in 2010.
ii. *'National Gas Utilization Plan for Ghana'* prepared by the Energy Commission in 2010.
iii. *'Energising Economic Growth in Ghana: Making the Power and Petroleum Sectors Rise to the Challenge'* prepared by the World Bank in 2013.

The World Bank study focused on the power sector, clearly identifying this as the priority area for gas utilisation in Ghana. While reaching a similar conclusion, both the Nexant and the Energy Commission's reports also assessed alternative uses in the industrial, commercial and residential sectors. The non-power uses assessed as possible utilisation options in each report are summarised in **Table 1**.

Table 1: Utilisation Options Considered in Previous Studies

Advisory Paper – Ghana Sector Gas Master Plan	*National Gas Utilization Plan for Ghana*
	Industrial Heat
Fertilizer	Urea
	Ammonia
Methanol	Methanol
	Dimethyl Ether – a derivative of methanol)
Aluminium	
Salt and Chor-Alkali	
Poly-Vinyl Chloride	
Residential and Commericial	Residential and Commercial
CNG for transportation	CNG for transportation

Note: re-ordered to show similarities and differences

The main findings of the three reports are discussed below with the non-power uses - , grouped under the categories presented in **Table 1**.

2.1.1 Power Generation

Power generation has been clearly identified as the priority sector for gas utilisation in all three reports. The World Bank stresses the importance of a well-functioning power sector for enabling economic growth and improving living standards in the developing world.

However the problems which are currently being faced by the power sector are well documented but have so far remained largely unresolved. These include:

- the poor financial health of State Owned enterprises (SOEs);in the power generation and distribution
- the need for new investment in the sector
- the barriers facing potential Independent Power Producers (IPPs) such as weak credit-worthiness of the off-takers and demand for credit enhancement instruments
- a high level of system losses and inadequate revenue collection, resulting in cash shortfalls in the supply chain
- Non-availability of fully cost reflective tariffs, and delays in the application of price indexation to regulated tariffs
.

The last 2-3 year period has seen these long-standing issues become critical, due also to gas supply shortages through the WAGP, forcing thermal generation plants to switch to Light Crude Oil (LCO) and Diesel. This is an expensive pathway; around the world, oil and its

distillates have seen a gradually reducing share in the fuel mix for power generation over the last few decades. Due to the relatively higher cost of oil and diesel as a source of base or mid-merit load, such generation is typically restricted to low utilisation peaking plants.

The World Bank estimated in 2013 that LCO would cost US $17/mmbtu based on crude oil at $100/bbl[3]. That is substantially higher than cost estimates for gas supply either from domestic fields or through WAGP (Section 3 discusses gas supply projections and cost estimates in more detail). The high cost of LCO is cited as the primary cause of the dramatic deterioration in the financial position of VRA. The clear cost advantage of gas against competing fuel sources was also highlighted in both the Nexant and Energy Commission reports as the key drivers of demand for new gas supplies.

2.1.2 Strategic Large-Scale Projects

Certain large industries are extremely energy-intensive, most notably the process of aluminium smelting from alumina. The Volta Aluminium Company (VALCO) was established in the 1960s and has for a long time received electricity at subsidised rates to maintain competitiveness and keep the plant running. Despite now only operating at around 20% of its 200,000 million ton/year capacity, VALCO still uses approximately 3.5% of Ghanaian power supply. The World Bank report calls for the subsidy to be removed, or provided in a transparent manner through general taxation.

Nexant's 2010 report estimated that a maximum price of electricity of between US$44 and US$66/MWh would be required for aluminium production to break even. This compares to the then electricity price of approximately US$300/MWh for large-scale industrial users. Recognising the requirement for cheap electricity as a necessity for aluminium production to be a viable proposition in Ghana, a further report for the Ministry of Energy in 2010 performed by Emos Consulting, which assessed possibilities for '*oil and gas driven aluminium-based industrial development*', cited the wider industrial benefit which could be leveraged from subsidising power for aluminium production, a case which VALCO itself makes strongly.

By linking aluminium smelting to a new alumina refinery served from Ghana's Bauxite mines, an integrated domestic aluminium value chain could be formed. Such a refinery, if viable, would also create substantial demand for heat energy from gas, as discussed below in Section 2.1.4 on industrial heat from gas.

Further industries linked to alumina production which are also energy-intensive through demand for power are the Chlor-Alkali and Poly-Vinyl Chloride (PVC) industries. The development of these industries has been proposed in Ghana and their feasibility was assessed in 2010 by Nexant. Based on requirements for a 400,000 ton/year aluminium smelter, Nexant estimated 23,000 ton/year of sodium hydroxide production and 35,000 ton/year PVC production would add a total demand for 62.9 GWh/year.

2.1.3 Petrochemicals

Gas is a principal feedstock in the production, typically by oil and gas rich nations, of a number of petrochemicals which are traded globally.

The World Bank report did not investigate the attractiveness of prioritising such utilisation options but stated that power sector demand should be satisfied before their consideration. This is a position supported by the Nexant report which provided a netback cost analysis on the viability of gas as feedstock for fertilizer and methanol production.

While regional demand for petrochemicals in Africa is growing rapidly, Nexant stress the importance of both fertilizer and methanol plant to be 'world-scale' in size in order to attract the required investment. Due to limited domestic demand in Ghana this in turn would create dependence on supplying export markets and correspondingly high risk from volatile global prices. Based on an ammonia plant producing around 2,000 tons per day, gas demand of 30 mmbtu/tonne and a forecasted ammonia price ranging from US$200 to $600/tonne, Nexant estimated a maximum average gas price of just US$1.7/mmbtu from 2015 to 2025 would be required for the project to be viable. The volatile price forecast further underlines the high risk associated with such investments.

A similar, albeit slightly more attractive result, was arrived at for methanol production. Based on a world-scale plant producing 5,000 tons per day, gas requirements of 33 mmbtu/ton, and forecasted price trends, Nexant estimate an average gas price of US$4.8/mmbtu would be required from 2015 to 2025 to make such a plant economic.

The Energy Commission's report provides less detail on the viability of petrochemical production, but does note the constraints arising from fertilizer, methanol and Dimethyl Ether's (DME) capital-intensive nature and reliance on export markets.

2.1.4 Industrial Heat

Low pressure pipelines can be established in industrial areas to supply natural gas to factories for heat in industrial processes. In these circumstances, gas will compete with other fuel sources, notably Residual Fuel Oil (RFO) and Liquefied Petroleum Gas (LPG). Where infrastructure for pipeline gas can be provided so as to allow the cost differential to RFO and LPG to be sufficiently attractive to incentivise switching, industrial heating uses may present an additional source of low-risk incremental demand for natural gas. While large petrochemical plants would require government investment or government guarantees, the industrial users make their own investments in their factories. Another issue is the investment required in the distribution network.

Tanzania provides a good example of how the industrial use of gas can proceed in an incremental fashion, once gas was made available onshore in the Dar-es-Salaam area primarily for the power sector. As of 2012:

Industrial gas consumers: 35 industrial consumers are supplied via a 42 km low pressure gas distribution network. Gas comes from the Songo-Songo field and is piped to Dar es Salaam via a 25 km 12" offshore pipeline and a 207 km 16" onshore transmission pipeline, plus a distribution network that consists of 50 kilometres of low pressure pipeline and four pressure reduction stations.

CNG: a compressing station has been established which supplies a few bulk customers (notably the Movenpick Hotel, IMI, Tanpack and Iron & Steel) and a limited but growing number of CNG-powered vehicles.

One lesson for Ghana is that, due to the need for cost-effective distribution networks, the economics of small-scale industrial usage of pipeline gas for heat operates best in clusters close to an upstream supply terminal, processing plant or existing transmission pipeline. For this reason the industrial districts of Tema and Takoradi present the most obvious potential locations where this type of demand may first grow.

The cost advantage may be sufficient to incentivise the development of additional industries which are currently uncompetitive domestically due to the cost of available fuel supply sources for industrial heat. Clear candidates here include steel based on Basic Oxygen Furnace (BOF) approach and clinker production for cement, both commodities for which demand is expected to expand rapidly as Ghana grows towards a middle-income country status. However, clinker production depends on the identification of suitable limestone deposits. For steel there is presently a limited amount of production in Ghana, understood to total approximately 0.6 MT/year, all based on Electric Arc Furnace (EAF) production. This approach is dependent on the provision of energy in the form of electricity. The relative economics of the BOF and EAF approaches will therefore depend in part on the related costs of gas and electricity.

Another value chain that has attracted considerable interest is alumina. Bauxite mining is currently undertaken in Ghana at Awaso in the Western Region. In addition, an estimated 1.5 billion tons of bauxite resources exist in Nyinahin and Akyem. The bauxite could be used to feed an alumina refinery to provide a domestic supply of alumina to aluminium smelting plants. Due to the cost advantages of transporting alumina rather than bauxite, where possible, refining takes place at the bauxite source rather than at the aluminium smelter. While not as energy intensive as aluminium smelting, the Bayer Process for refining bauxite into alumina has substantial demand for heat, averaging in excess of 14 GJ per tonne per annum. The Emos Consulting industrial development report foresees a dual-track approach with alumina supply chains both in the Eastern Corridor for the existing VALCO smelting facilities, and the Western Corridor serving a new Greenfield site.

2.1.5 Residential and Commercial Heating

Residential and commercial use of natural gas demand in Ghana is focused on cooking and water heating, rather than space heating. In recent years there has been a drive in the country to incentivise switching from traditional fuels to LPG and solar water heating in order to meet these demands. According to the LPG Promotion Strategy for Ghana published in 2011 by the Energy Commission, a 40% penetration rate for households had been reached (compared to 6% in 2000).The Government is in the process of revising its LPG policy to increase penetration to 50% by 2020.

For natural gas to become attractive, it would have to offer a cost advantage over LPG, after accounting for the significant capital required to establish urban distribution networks. The principal barrier is that without demand for space heating, average load would be low while capacity requirements for peak periods would remain high, increasing the infrastructure component of the total cost. As a result, Nexant cited the examples of South Africa and Cote d'Ivoire, where such networks have encountered financial difficulties in similar

circumstances and claimed that potential revenues in Ghana would be insufficient to recover costs. This is a position supported, at least in the near to medium-term, of the Energy Commission's report, where they estimated an urban grid for the residential and commercial sectors will not be viable for '10-15 years'. There are also significant theft and safety issues related to gas distribution networks. This Plan therefore does not recommend use of natural gas for domestic purposes a priority in the near to medium term.

2.1.6 Transportation

Natural gas can be used in a pressurised state, known as Compressed Natural Gas (CNG), for transportation as an alternative to petrol and diesel fuels. While CNG's market share is still very small internationally, its use has proved popular in a number of markets where its growth has received targeted support and the cost of standard fuel options is high. This is particularly true among urban taxi and bus transportation fleets in nations for which the transition to CNG has received state assistance.

Environmental benefits and the potential gap between natural gas and petroleum product prices further incentivise CNG growth. The main constraints to CNG's use are the absence of infrastructure (including both compressors, which require reliable electricity supply, and a network of fuelling stations); the capital cost of converting vehicles; poorer performance of vehicles; uncertainty over the future gas-oil price spread; and large storage space requirements. Targeting the conversion of dedicated fleets, rather than a general conversion of all vehicles on a voluntary basis, helps reduce the impact of all these challenges, particularly by allowing for localised refuelling infrastructure to be developed.

Ghana has a sizeable fleet of LPG-fuelled vehicles, a trend that has been driven by the cost saving from cheap LPG, which was subsidised to incentivise residential and commercial use. According to NPA, in 2015 there are 603 LPG fuelling stations, over a third of which were in Accra, with taxi and bus fleets prominent among users. Measures to address the undesired outcome of an effective cross-subsidy from petrol to LPG were proposed in the Promotion Strategy paper, however, the popularity of LPG may help provide a model and natural market for CNG-fuelled vehicles. This Plan recommends that the continuous use of LPG in vehicle and bus fleets should be subjected to safety regulations.

The Nexant report identified the need for supporting regulatory frameworks, fleet sizes greater than 50, favourable inter-fuel taxation, and strong safety standards, as conditions for enabling the sustainable growth of CNG as an alternative transportation fuel in Ghana. These same factors were also highlighted in the Energy Commission's report. This latter report also noted the potential for CNG in the residential and commercial sectors for cooking. However, practical issues regarding energy density, cylinder size, distribution and storage, have so far prevented this from becoming a noteworthy market for CNG in other parts of the world.

2.1.7 Exports

If and when supplies from domestic gas production are able to sufficiently meet local demand, exports might present an option. Such gas exports would likely be in the form of Liquefied Natural Gas (LNG) and would require a liquefaction facility and an export terminal. Once domestic demand is adequately met, particularly for electricity generation,

and sufficient gas becomes available to justify the construction of an LNG liquefaction facility and export terminal. Alternatively, it could be more beneficial to export electricity or any other commodity in high demand instead of gas. The final choice will be based on the expected margin to be gained; the level of risk associated with an investment, and the potential wider economic benefits.

2.1.8 Summary of Previous Reports and Planned Options

Previous studies present a largely consistent line regarding the recommended prioritisation for domestic gas utilisation in the country.

Power sector*:* this presents an immediate source of secure and growing demand with attractive margins at low-risk as existing Open Cycle Gas Turbine (OCGT) plants are ready to convert to Combined Cycle Gas Turbine (CCGT) plants, in addition to new gas-based thermal plants at various stages of development.

Industrial heat: low-risk industrial use is attractive because it can be expanded in an incremental fashion primarily to supply domestic demand.

Initially this is likely to cover localised distribution networks for small industrial clusters around pipeline terminals at Tema, Takoradi, and possibly Prestea. Should suitable limestone deposits be identified, clinker production will also fall into this category.

Steel furnaces lie somewhere between this and higher-risk groups in that plant may be focused on domestic supply and are somewhat less capital intensive than the mega-projects discussed below, but may still face tough competition with cheaper imports.

CNG for transportation is less attractive than the other two categories due to implementation difficulties but could be incrementally rolled-out, with the benefit of releasing LPG and oil products for other uses. Risks would be minimised by making CNG available in the first instance for dedicated taxis and goods transport fleets, with vehicles tuned to operate efficiently on CNG.

Sectors which should not be prioritised for now are:

Residential and commercial: distribution networks are seen either as uneconomic or long-term options.

Mega-industries: whether and when to prioritise and provide targeted support to large, high-risk, strategic industrial sectors that use natural gas either for energy (through power or directly for heat supply) or as feedstock is also in doubt.

These options are capital intensive and either rely on export markets with volatile commodity prices or will face intensive competition from imports. This group includes the aluminium sector and its upstream components of alumina and chor-alkali production, petrochemical production (such as ammonia, urea and methanol), and LNG export.

The following Section 2.2 discusses the results of a quantitative netback pricing analysis into the above options which has been undertaken as part of modelling (described in more detail in Section **Error! Reference source not found.**). Section 2.3 then performs international benchmarking on how these utilization issues have been addressed in a select group of comparator countries which have previously managed the development of a domestic natural gas sector. Section 0 then derives specific utilisation recommendations based on a combination of the above findings, the netback analysis, and key lessons learnt from international experience.

2.2 Netback Analysis of Sectoral Demand

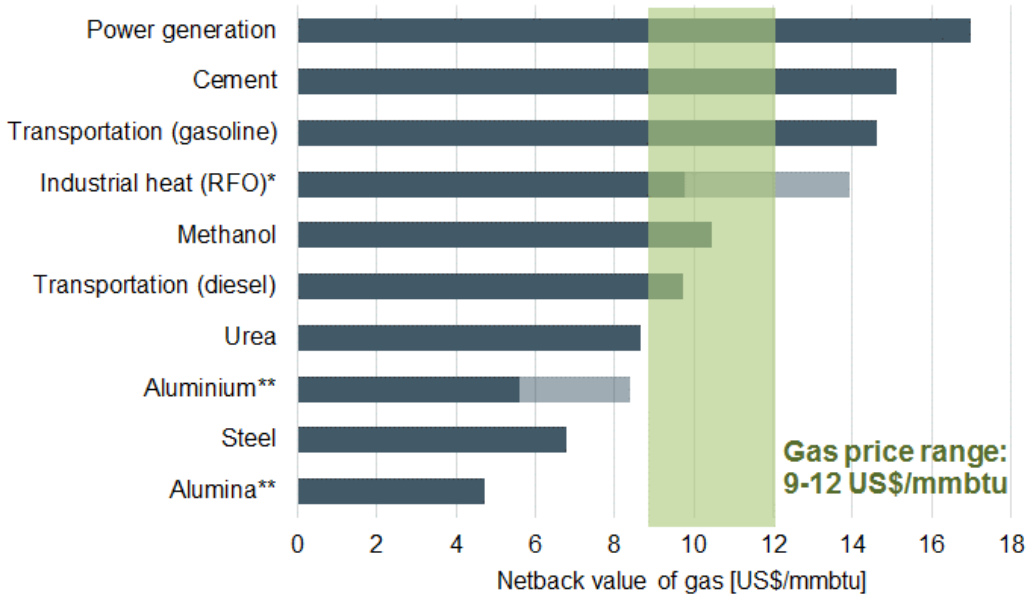
Following the review of previous gas demand studies, netback analysis of the value of gas in each of the main potential consuming sectors was conducted. . This is a key part of the demand modelling process described in Section **Error! Reference source not found.**, where a 'netback' value of gas has been analysed for various industrial utilisation options.

Netback analysis involves taking the current market price of a product (either the domestic price or global price for export-orientated industries with efficient global markets) and subtracting other capital and operation input costs to establish an estimated maximum 'willingness to pay' for fuel supply, in this case, gas. The analysis is carried out for a selection of potentially gas intensive industries.

The sources, figures and calculations which have been used to derive the netback values are discussed in more detail in Section **Error! Reference source not found.**. Sensitivity checks, particularly important for export-orientated industries where viability will be dependent on highly volatile global prices, are also discussed in the following text. The industries selected in the netback analysis have been identified as the major potential gas off-takers.

The main results are summarised in **Figure 4** below, which indicates the value of gas to each end-use, 'benchmarked' against the weighted average cost of gas (WACOG), inclusive of processing costs, plus transmission tariff which in total ranges from approximately US$9/mmbtu to US$12/mmbtu over the Plan's period. The estimates of the WACOG for three scenarios are provided in section 3. Sectors which have a high netback value, especially those with a netback value greater than the benchmark, are those where gas has a high potential value and are likely to be strong candidates for developing as gas consuming sectors

Figure 4: Netback Values in Various Sectors



* The light blue bar for industrial heat indicates the added netback value once the estimated subsidy for Residual Fuel Oil (RFO) is included within results – see below text for further detail

** The calculation of the netback price for aluminium includes gas for both heat and electricity demand through the combined value chain of alumina refining and alumium smelting. The light blue element for aluminium indicates the added netback value derived from using existing smelting facilities at VALCO which are a sunk cost. See below text for further details.

The above preliminary results have been generated based on a 12% discount rate for capital expenditure and can be compared to a delivered gas price of US$8.6/mmbtu in 2014 through the WAGP which could be considered as peg price for domestic gas supplies.

Aside from power generation (not included in the netback analysis), the preliminary results indicate that the most attractive sectors include Cement, CNG for transport, and other incremental sources of small-scale demand for industrial heat. These are addressed below.

2.2.1 Cement

Cement demonstrates an attractive netback value of gas, estimated at approximately **US$15/mmbtu**. This figure is largely a result of the high cost of imported clinker to Ghana, creating a domestic price of cement estimated to be US$153/MT, significantly above the US$70 to US$100/MT observed in the MENA region. A figure of US$120/MT, for instance, would reduce the value of gas to around US$6/mmbtu. Ghana already has a sizeable cement grinding industry and imports all of its clinker.

There are limestone deposits within Ghana at Nauli in the Western Region and Buipe and Daboya in the Northern region, Bongo-Da in the Upper East Region, Oterkpolu in the Eastern Region. The Nauli limestone estimated at over 400 million tonnes, could yield over 1.4 million tonnes clinker per year by means of the dry process, and this would require 12 mmscfd of natural gas. Tests[4] conducted on samples from the limestone deposits have confirmed that the Nauli and Buipe deposits are most suitable for clinker production.

Facts are that for a limestone deposit to be suitable for cement production, according to figures from the industry, the chemical analysis should fit into the range shown in Table 1.

Table 2: Typical chemical for limestone suitable for cement production

Mineral	CaO	SiO_2	Al_2O_3	Fe_2O_3	MgO	Alkalis	Chlorides	SO_4	LOI
%	40.0- 55.0	1.0- 15.0	1.0- 6.0	0.2- 5.0	0.2- 4.0	0.2- 0.1	Trace-0.1	Trace- 0.3	35.0-44.0

(Source: Banerjea, 1985).

According to the Ghana Geological Survey, there are four major limestone deposits in

Ghana, namely; Buipe, Nauli, Oterkpolu and Bongo-Da, with minor deposits occurring at various parts of the country. The four major deposits have the following chemical compositions shown in Table 2:

[4] KNUST and Ghana Geological Survey

Table 3: Chemical composition of limestone major deposits in Ghana

Deposit	Reserves (million tons)	Composition (%)				
		CaO	SiO_2	Al_2O_3	Fe_2O_3	MgO
Nauli	400	48.71-53.32	0.84-4.18	1.54-4.38	1.54-4.30	0.57-1.84
Bongo- Da	6.62	40.00-49.30	9.00-9.30	1.70-3.90	Up to 0.10	1.20-4.20
Oterkpolu	8-10	38.00-38.60	13.27-16.90	2.60-2.59	1.2-2.95	3.07-4.23
Buipe	6.03	48.0	6.20-6.90	2.00-2.80	0.50-0.06	1.00-1.70

2.2.2 CNG for Transport

The estimated netback value of gas to be used for CNG in vehicles provides maximum values of **US$14.6/mmbtu** and **US$9.7/mmbtu** for gasoline and diesel fired vehicles respectively. Gasoline and diesel prices used for the calculations are based on regulated prices as quoted by the National Petroleum Authority[5] (**336 GHp/litre and 327 GHp/litre respectively**) minus the applicable taxes and levies which yielded a net price of 271 GHp/litre for both fuel types. Vehicle performance is based on a mid-range hatchback car. Aside from the cost of alternative fuels, the other significant variable regarding the netback value of gas for CNG is the capital cost of vehicle conversion. International estimates range considerably from around US$1,600 to over US$10,000 for a typical car. A cost of US$6,000 has been used in generating **Figure 4** with a 5 year lifespan.

Sensitivity checks using low and high conversion costs of US$2,000 and US$10,000 were conducted. For gasoline the netback results are US$20.7/mmbtu and US$8.9/mmbtu respectively, while for diesel they yield US$16.0/mmbtu and US$3.7/mmbtu.

The base netback results for CNG are attractive for high mileage taxis using petrol but should be reviewed in conjunction with the other barriers to the technology's take-up as discussed in Section 0, along with an assessment of the relative fiscal terms imposed on each fuel source options. Furthermore the sensitivity of the results to conversion costs and annual mileage indicate the need to confirm assumptions regarding these parameters before making firmer conclusions as to the attractiveness of pilot project. A pilot project study for CNG use in public transportation in Greater Accra region shall therefore have to be carried out to test these results.

2.2.3 Small-Scale Industrial Clusters

Other small-scale demand for energy, especially heat, serving industrial clusters around Tema and Takoradi areas have an estimated netback value of **US$9.8/mmbtu**. This is based on an alternative fuel cost of US$0.47/litre for RFO (derived from the regulated price of 157 GHp/litre net taxes and levies), and a conversion cost at 50 sites of US$45,000 for boilers/furnaces per site with a 10 year repayment period. This result is insensitive to the

[5] http://www.npa.gov.gh/npa_new/Downloads.phpfigures for 14 July 2014

conversion cost with high and low cases of US$60,000 and US$30,000 per site yielding netback values of US$9.2/mmbtu and US$10.5/mmbtu respectively.

The netback results indicate the incremental development of small-scale industrial demand from clusters of operations close to gas supply terminals, is a relatively attractive utilisation option once power sector demand has been met. It should also be noted that these sectors are likely to have significant employment benefits.

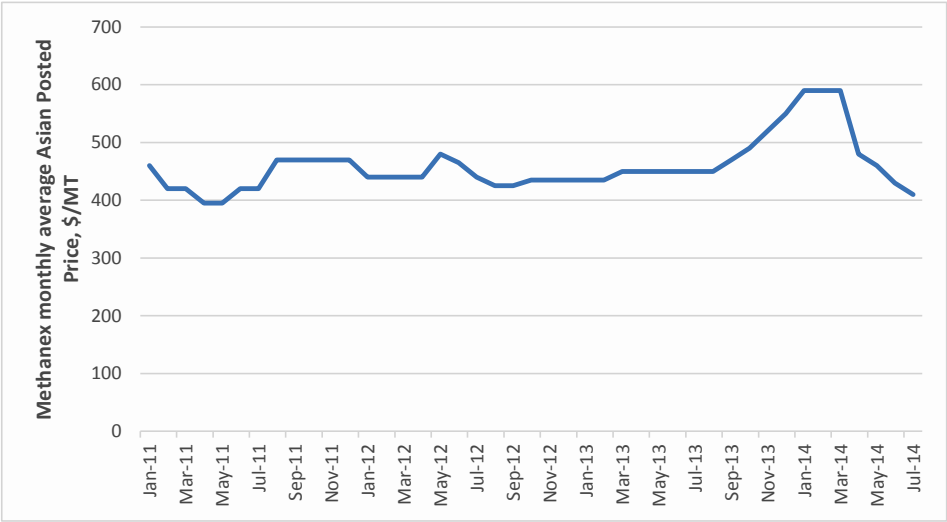
2.2.4 Other Sectors

Other sectors analysed indicate more marginal netback values when compared to the gas cost plus transmission tariff of US$9/mmbtu to US$12/mmbtu. In addition to the tight economics of the base case shown in **Figure 4**, these sectors are also vulnerable to volatile global market prices, either via competition from imports or through a dependence on exports for project viability.

2.2.5 Methanol

Methanol production has been calculated to have an associated maximum netback value for gas of approximately **US$10.5/mmbtu**. While weaker than the sectors discussed above, this remains higher than the initial benchmark gas supply price. The value is based on the construction of a world-scale production plant serving an export market and thus susceptible to global market prices. As shown in **Figure 5**, Methanol prices have been volatile over the last year, showing a marked peak late in 2013 before sliding during the second quarter of 2014.

Figure 5: Historic Methanol Price[6]



An IHS Global Methanol Market Review highlighted a range in production costs globally with producers in the MENA region facing costs of less than US$100/ton, while Chinese gas-based producers represent the international marginal producers at approximately

[6] http://www.methanex.com/products/methanolprice.html

US$350/ton. IHS also predicted broadly flat prices to 2020 before a steady rise to above US$500/tonne by 2030.

Therefore in this analysis the approximate average of the previous 18-month period of Methanex Asian Posted Contract Price has been adopted. This yields a product price of US$480/MT used in the above calculation of our base netback value.

Prices are clearly volatile and uncertain with **Figure 5** showing a price variation ranging between US$400/MT to over US$550/MT. Therefore sensitivity checks have been conducted using this price band, yielding low and high case scenarios for netback gas value of approximately US$8.1/mmbtu and US$12.6/mmbtu respectively. However, analysis of production costs in other nations, suggests that with a production cost of over US$400/MT, Ghana would be at a significant disadvantage with the Middle East and North Africa (MENA) region and North America. As well the country will be in tough competition as a marginal supply source with China and Eastern Europe[7], highlighting the risky nature of investing in such a capital-intensive plant.

> *The netback value analysis of gas for methanol suggests a reasonably attractive utilisation option. However the large capital investment requirements and dependence on an export market where Ghana is at a cost disadvantage compared to many incumbent players, diminishes the attractiveness of methanol as a priority gas utilisation option in Ghana.*

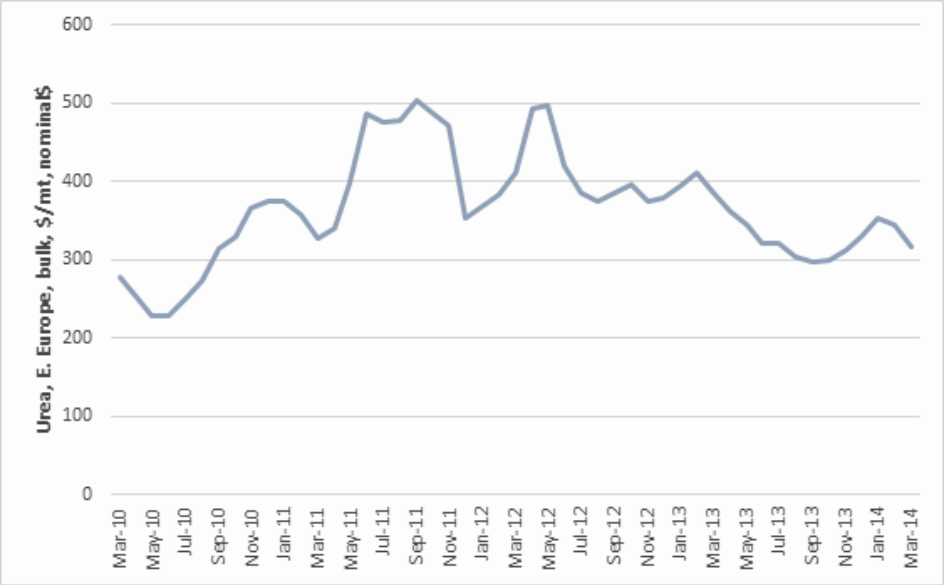
2.2.6 Fertilizer (Ammonia and Urea)

Fertilizer, in the form of ammonia and urea production[8], indicates a reasonable base value of **US$8.7/mmbtu**, but one that is sensitive to changes in global prices which have been highly volatile in recent years. This figure is based on a world-scale plant which would depend on competitiveness in the export market. As shown in **Figure 6**, World Bank data based on Eastern European prices indicates urea prices have varied from US$300/MT to US$500/MT over the course of the last three years.

[7] http://www.ptq.pemex.com/productosyservicios/eventosdescargas/Documents/Foro%20PEMEX%20Petroqu%C3%ADmica/2012/PEMEX_DJohnson.pdf

[8] Ammonia is an input for the production of Urea. As Urea requires CO_2 which is a by-product of the ammonia production, the production of both the Ammonia and Urea must be undertaken at the same site, hence a combined Ammonia-Urea Plant is discussed here.

Figure 6: Historic Urea Price[9]



A 2013 market outlook produced by the CRU Group for global fertilizer markets highlighted the major capacity additions expected between 2013 and 2015[10], predominantly from China and the MENA region. However, Profercy[11] note that the low current urea prices have seen notable delays and cancellations of this new capacity. Given these mixed messages on potential outlook, we have adopted CRU's broadly flat outlook for urea prices to 2017[12] and have taken the average of the previous 18 month period that is US$350/MT. Nevertheless, the same issues as highlighted for Methanol regarding the access of other regions (notably in the MENA or subsidised gas in Trinidad and Tobago) with lower cost of gas supplies than Ghana, confers a significant competitive advantage to their urea producers.

To measure the sensitivity of the above results, the historic US$300/MT to US$500/MT band seen in the World Bank data which would equate to netback gas values of **US$6.4/mmbtu** and **US$15.4/mmbtu** respectively was used. The sensitivity of these figures indicates the high-risk nature of making the very large capital investment required in fertilizer production facilities. For instance, a 660,000 MT/year ammonia plant is estimated to cost US$0.85 billion in capital expenditure.

The potential multiplier effects of increasing the supply of fertilizers such as urea for economic development in Ghana have been cited in support of pursuing investment in the sector. Section 6.2 and Annex A5.366.3 investigates the issue of multiplier effects, estimating that while fertilizer does demonstrate a relatively high multiplier for Ghana, so too does electricity. Therefore no evidence was found to support higher priority being awarded to fertilizer production on this basis.

[9] http://databank.worldbank.org/data/views/reports/tableview.aspx

[10] CRU Group, Global Fertilizer Market Outlook, Commodities Outlook Conference, May 2013

[11] http://www.profercy.com/profercy-studies/the-shale-gas-reality-and-the-urea-outlook-to-2030/

[12] CRU Group, Global Fertilizer Supply/Demand Five-Year Market Outlook (2012-2017)

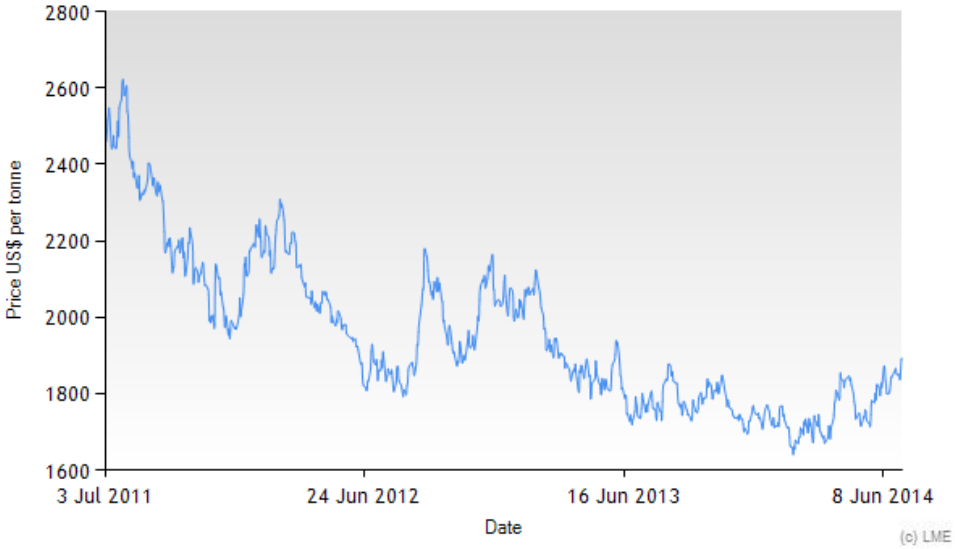
These results therefore suggest fertilizer should not be a priority area for gas utilisation but may present future opportunities as the gas sector matures, particularly if the outlook for urea prices improves.

2.2.7 Alumina and Aluminium

The "Eastern Corridor" industrial development plan proposes a new alumina refinery to supply existing VALCO production. VALCO has a capacity of 200,000 MT/year, 80% of which is currently idle. As noted in Section 0, VALCO currently receives power supply at subsidised rates in order to maintain competitiveness. The netback value provided here for alumina addresses the estimated value of gas for heat supply for such an alumina refinery, irrespective of any losses incurred by VRA/GoG through the subsidisation of power supply to VALCO.

Most alumina is supplied to smelters under bilateral contracts, often at a price per MT of alumina which is a fixed percentage, typically 14-15%, of the final price per tonne of aluminium. **Figure 7** shows the London Metal Exchange prices for aluminium for the 3 year period to June 2014. The aluminium price fell steadily from just under US$2,700/MT to approximately US$1,700/MT by January 2014. Since this date, there are indications of a small recovery with prices in July 2014 standing at approximately US$1,900.

Figure 7: Historic Aluminium Price[13]



HSBC forecast a shift in global supply-demand balance towards a deficit by end 2014 forcing prices above US$2,000/MT before larger surpluses re-emerge during 2016-17, again placing downward pressure on prices. In the light of this historic data and market forecast, this plan takes a base case using an aluminium price of US$2000/MT. Alumina supply per MT at 15% of this aluminium price would then yield a market price of US$300/MT alumina. However a mark-up should be considered for imported alumina which requires shipping costs. It is noted that the September 2014 spot market price FOB Australia was approximately US$280/MT, equating to an import price in China of around US$365/MT. The domestic

[13] http://www.lme.com/en-gb/metals/non-ferrous/aluminium/#tab2

supply price in China at this time was approximately US$400/MT. Therefore our base case for Ghana also assumes an alumina market price of US$400/MT.

Capital expenditure for this case is limited to the alumina refinery, estimated to be US$720 million for a 1 MT per annum plant. Operating costs, exclusive of energy, is about US$200/MT of alumina. A further 150 kWh/MT of electricity is required at industrial electricity rate. Gas consumption estimates is approximately 14 mmbtu/MT for heat during the refining process.

The resulting estimate for the netback value of gas in alumina production is **US$4.7/mmbtu**.

As an indication of the sensitivity of these results to changing market prices, using figures of US$350/MT and US$450/MT respectively yields low and high netback values of US$1.2/mmbtu and US$8.3/mmbtu respectively. The result is also sensitive to the assumed cost of Bauxite which may be close to half of the non-energy operating costs. For instance, a low case for non-energy operating costs of US$150/MT together with the base alumina market price of US$400/MT yields a netback value of US$8.3/mmbtu.

Given the focus on the full alumina value chain in current plans, a second case assessing the netback value of gas inclusive of a dedicated CCGT power plant to supply all electricity requirements (in addition to gas for heat processes) was considered. The same CAPEX and non-energy OPEX values for the alumina refinery as provided above were used. For smelting, two MT of alumina are required per MT of aluminium production and a further US$350/MT has been allocated for other non-energy production costs encountered during the smelting process. This leaves electricity demand for smelting, which is estimated as requiring 16,000 kwh/MT aluminium. This equates to approximately 100 mmbtu of gas input to a dedicated CCGT plant, and provides a maximum netback value of gas of **US$8.4/mmbtu**[14].

For additional smelting facilities, corresponding to the "Western Corridor" of the industrial development plan, a further capital cost of US$4000/MT for new smelting facilities with superior energy efficiency equating to 12,000 KWh/MT electricity demand (approximately74 mmbtu/MT from a dedicated CCGT plant) is assumed. The added costs bring the estimated netback gas value down to **US$5.6/mmbtu**.

> *The netback analysis results therefore suggest that the maximum value of gas supplied to the sector is both low and incurs higher risk than alternative utilisation options.*

2.2.8 Steel

Steel production can be performed either using the Electric Arc Furnace (EAF) approach or the Basic Oxygen Furnace (BOF) approach. The former is a predominantly power driven process and has not been analysed separately to general power generation. Electricity is a fundamental input to the smelting in an EAF and thus cannot be substituted by fuel switching to gas. Using gas as a heat source for the BOF approach and an assumed steel price of US$700/MT, provides an estimated netback value of just **US$6.8/mmbtu**. High and

[14] If the alumina refining energy demands were removed from the calculation and imported alumina at the base case of 400 US$/tonne was included in the O&M costs, then the netback value of gas to electricity for smelting would be 8.6 US $/mmbtu.

low scenarios with steel prices of US$800/MT and US$600/MT yield netback prices of US$9.9/mmbtu and US$3.7/mmbtu respectively.

The netback analysis results for steel via a BOF approach are not promising and indicate a low priority for gas utilisation.

2.3 International Benchmarking

The third approach to assessing attractive sectors for gas is to examine gas utilisation in a range of other countries. Following the above literature review of previous analyses on utilisation options for Ghana, this section discusses how gas has been allocated across different sectors in a selection of comparator countries. Full case studies describing the development of each country's gas sector, institutional structure, regulatory framework and upstream supply are provided in Annex A3.

This section focuses on those findings from the case studies of particular relevance to assessing utilisation options for a newly developed natural gas sector and what lessons they may have for Ghana. The countries included in this review (in alphabetical order) are:

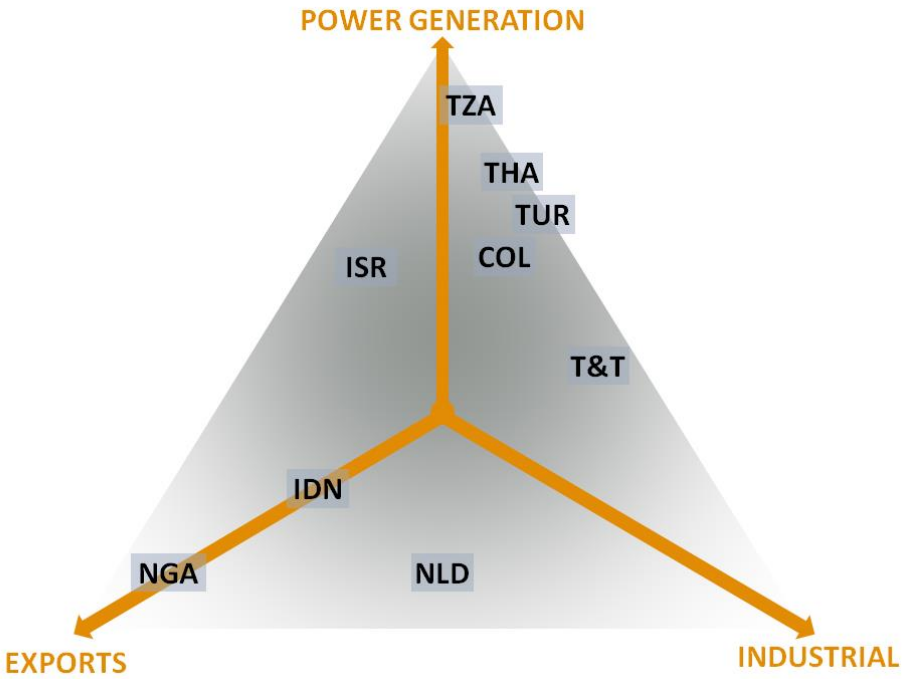
- ***Colombia***
- ***Indonesia***
- ***Israel***
- ***Netherlands***
- ***Nigeria***
- ***Tanzania***
- ***Thailand***
- ***Trinidad and Tobago***
- ***Turkey***

2.3.1 Overview of Utilisation Priorities

Figure 3introduced the main areas of natural gas demand which may be prioritised during the sector's development. The comparator countries selected for this analysis have diverged in their approach to this issue, as shown in **Figure 8**.

The diagram shows that the power generation sector has been the key off-taker during the initial stages of development in all countries except Netherlands, Nigeria and Indonesia.

Figure 8: Initial Sector Prioritisation in Comparator Countries



COL: Colombia	IDN: Indonesia	ISR: Israel
NGA: Nigeria	TZA: Tanzania	NLD: Netherlands
T&T: Trinidad and Tobago	THA: Thailand	TUR: Turkey

It is important to note that priorities are selected by a mixture of government decisions, market forces, timing (relative fuel costs for instance have seen notable changes over time) and other circumstantial conditions. The specific reasons for the success, or not, of gas use in particular sectors within each country is discussed below in Section 2.3.2.

2.3.2 Key Findings from Comparator Countries

The comparator countries analysed have developed their respective natural gas sectors under notably different circumstances. This review discusses the drivers behind establishing which utilisation options took early priority with the objective of drawing out some lessons for Ghana.

Finding 1: The era of development of the gas sector has largely influenced the use of gas at early stages of the gas market

The price differential between different fuel sources has varied considerably with time, as has the availability of technology and prospects for alternatives. This is particularly true in the power sector.

The Netherlands first began expanding its domestic gas production at scale in the 1960s. At this time gas was not a common fuel for power generation internationally due to the availability of cheaper coal and oil and a lack of appropriate infrastructure and technology.

Furthermore nuclear power was expanding rapidly, expected to gradually take over from fossil fuel sources in power generation, and the focus of government energy policy. It was not until after the oil crises of the 1970s, realisation of slower than expected progress in nuclear, and development of more efficient CCGT plants, that gas became a more attractive alternative for electricity.

In Trinidad and Tobago, where the gas was targeted to the power sector as early as the 1950's, significant gas finds coincided with global demand developments of Ammonia in the 1970's, Methanol in the 1980's and LNG in the early 2000's.

Conversely the more recent development of the gas sectors in Colombia, Turkey and (very recently) Tanzania, have taken place in a world where gas for power, when reliably available through pipelines, is a much more financially attractive option than fuel oil for generating electricity.

Similarly the further decoupling of gas and oil prices in the last decade has enhanced the relative attractiveness of CNG for transport when compared to petrol and diesel, as evidenced in the popularity of the technology in Colombia.

Finding 2: A key driver for developing a domestic gas market has been the competitiveness of gas compared to alternative fuel sources

How resource rich a nation is regarding alternative fuel sources for the various utilisation options, has also guided the focus sectors for natural gas in each comparator country. For example, cheap coal for power generation in Indonesia meant the urgency for establishing gas-to-power projects was initially lower than that in other nations, such as Ghana, where the principal alternatives are light crude oil, fuel oil and diesel.

Natural gas is similarly attractive for space heating, water heating and cooking when it can be supplied to the residential and commercial sectors at a cost that is competitive with alternatives such as LPG. This was an early driver in the Netherlands due to its cold climate creating sufficient loads to support the economics of distribution networks and has been a more recent driver of additional demand in Turkey.

The natural development of industrial clusters using gas for heat, or combined heat and power, purposes has also been a feature of a number of the markets reviewed. Rather than occurring through heavy-handed industrial policy, the price differential to existing fuel sources such as RFO and LPG have helped incentivise switching among industries located close to pipelines and terminals. Textile, cement, steel and paper are common demand sources of this kind in comparator countries including Colombia, Indonesia and Tanzania.

Trinidad and Tobago is an example of an actively steered Government industrial policy. However this was due to the saturation of the gas to power market, significant reserves and subsidised prices. Additionally the developments of Methanol and Ammonia plants in Trinidad and Tobago occurred during a time when global competition in these markets was lower and global demand was growing.

Finding 3: The power generation sector has been the prioritised off-taker of gas in the countries with the most recently developed gas markets

Israel, Turkey, Colombia, Thailand and Tanzania are the countries in the presented analysis with the most recently established gas sectors. All have prioritised gas use in the power

generation sector by supporting the development of gas fired power generation, developing gas transmission pipelines and in some cases even provided subsidised gas prices. Besides the competitiveness of gas compared to alternative fuels, this was driven by very similar factors facing Ghana today. These include:

- Small to medium sized domestic gas resources or access to a well-diversified gas supply mix;
- High electricity demand growth and need for additional power generation;
- The political willingness to use gas domestically and develop a gas market;
- Electricity markets that were characterised by significant hydropower resources with new hydro opportunities becoming saturated.

The benefit of prioritising gas for power generation has also been the resulting large and concentrated volume of offtake. This has made the development of gas transmission infrastructure easier and more financially viable.

Finding 4: Key obstacles in developing domestic gas markets over exports have been shown to be pricing issues, credit worthiness of gas or power offtakers and slow infrastructure developments

Two comparator countries developed their gas sectors almost exclusively on exports: Indonesia and Nigeria. In both countries this route was enforced by a mixture of the relative economics, poor domestic infrastructure & regulatory frameworks, and a reliance on International Oil Companies (IOCs) to undertake upstream production. By allowing for an initial focus on exports, IOCs could be incentivised to invest in upstream production with the host governments' attention on the potential fiscal take.

In Indonesia the main source of domestic non-power sector demand, fertilizer, was subsidised putting pressure on gas supply prices and further reducing the attractiveness of serving the domestic sector. More recently a 'carrot and stick' approach to try and build domestic gas use, particularly in the industrial sector, has been initiated by raising regulated prices to increase returns while also implementing a Domestic Market Obligation (DMO) on producers.

In Nigeria, the economic case for the domestic use of gas is much stronger with a desperate need to develop more gas power plants rather than use the expensive fuel oil on which many power plants are currently running on. However, suppliers are hampered by the poor performance of Nigeria's domestic gas and power sectors with below cost regulated tariffs and poor revenue collection rates, leading to a lack of credit-worthiness.

Tanzania and Thailand have indicated the reverse approach to export-led development. Tanzania held early discussion on its gas utilisation master plan focusing on establishing a preference for domestic utilisation options over exports but without underpinning economic analysis. While prioritising gas to power, the poor performance and financial position of the power sector is hampering upstream suppliers, which is a situation Ghana could well be facing, unless the power sector is reformed.

Finding 5: Government subsidies to kick start industrial domestic use have in most cases proven to be neither successful nor sustainable, apart from the transport sector where government support proved vital.

The comparator countries have adopted a different level of proactive industrial policy in directing priority end uses for natural gas, particularly regarding specific strategic large-scale industrial options.

Colombia has developed its gas sector largely without any such policy with the exception of subsidies to CNG transportation. These have helped overcome the initial higher capital spend associated with CNG vehicles which is frequently cited as a key barrier to expanding the technology's market penetration even when long-run economics support switching.

More blunt tools for encouraging domestic industrial demand have been used in Indonesia through its DMO and historically via supplying the fertilizer industry at reduced prices. Nigeria has similarly identified a number of strategic industries claimed to have high economic multiplier effects for future development.

However, in all countries assessed, except the Netherlands and Trinidad and Tobago which developed at a much earlier date, the general power sector has taken priority over such strategic industrial sectors with positive results wherever the regulatory and institutional frameworks have been sufficiently supportive.

Finding 6: The development of a domestic market and the secure demand it provides, encourages continued exploration activity which can result in significant enhancement to proven natural gas resources

Key reforms in the upstream sector of Trinidad and Tobago together with attractive pricing arrangements and favourable fiscal terms have resulted in exploration and production increases in the late 1980's and 1990's. Exploration further accelerated with the Government's strategy to focus on LNG exports, enabling exporters' access to the lucrative global LNG market.

Israel's gas market started with the development of relatively small fields supplying the state-owned power utility, Israel Electric Corporation, ensuring low risk demand by guaranteeing investment through the signature of long term gas purchase contract. The development of this domestic market (also temporarily supported by imports from Egypt which were halted), had a feedback effect on the upstream industry, giving momentum and encouragement to further exploration activity. This resulted in the discovery of large Tamar and Leviathan offshore fields and Israel is expected to soon become a net exporter of gas. By facilitating complementary growth in both the upstream and downstream markets, the risk for new investments in either is lessened helping accelerate that growth.

2.3.3 Lessons for Ghana

The above review demonstrates that although there is no single preferred pathway for gas utilisation in a newly developed market, key lessons can be drawn out that should guide Ghanaian policymakers in developing Ghana's gas sector:

- The power generation sector has been the primary off-taker of gas in all countries where (i) the alternative power generation fuel was fuel oil, (ii) power demand was fast increasing and (iii) hydro power potential was exhausted and insufficient to cover growing domestic demand.

- To ensure the gas-to-power sector's development can keep pace with demand and incentivise necessary investment, the regulatory framework to ensure financial viability exists for all parties is paramount. This applies to both the electricity as well as the gas sector. Cost reflective tariff and pricing, institutional and regulatory certainty, and ensuring gas security of supply have been the main features acting as gas-to-power demand drivers.

- Gas transmission networks have been developed on the basis of large loads from power generation or large industrial users. The development and planning of such a network was typically vested in a state owned gas company. Financing was mainly provided through government or donor support.

- Residential and commercial demand has only been a focus in nations with cold climates which provide an adequate ratio of average to peak loading on urban distribution networks to make their development financially viable. As Ghana does not have such a climate, experience elsewhere would suggest this is not an utilisation priority.

- Industrial usage has appeared most successful where it has grown in incremental fashion rather than via focus on select 'champion' industries through proactive industrial policy. Textile, cement, steel, and paper provide notable supplementary low-risk demand in many markets assessed where economic rationale for gas usage was the main driver. Fertilizer has also been a common demand source but has required subsidy in Indonesia and Trinidad and Tobago.

- Colombia's experience with CNG vehicles demonstrates that with government support, demandgrowth in the transport sector can be strong, although any subsidy should be carefully targeted at specific market barriers or failures (e.g. inability to make initial capital spend, lack of infrastructure, relative level of environmental damage) to ensure market distortions are minimised.

- Lastly a focus on exports has helped incentivise IOCs to invest in upstream production in Indonesia, Nigeria and Trinidad and Tobago. However, the lack of a robust and transparent institutional and regulatory framework coupled with significant price differentials between domestic and international markets has unnecessarily hindered the natural development of domestic demand alongside. The approach of the Netherlands, Colombia and Israel whereby exports are one option considered on their relative economic merit would appear a more sensible model for Ghana to consider. Indeed Israel's experience shows how with limited supply, the early development of a domestic market can help encourage further exploration activity and the potential of greater future finds.

2.4 Recommended Gas Utilisation Options

Based on the above, the recommended strategy for gas use is given below –for the consideration of the Government of Ghana. The strategy is considered to be reasonably robust based on the evidence from the three approaches of assessment: the review of

previous utilisation studies for Ghana's gas, international case studies and the netback analysis are all broadly consistent. The conclusions from these different strands of analysis can be summarised as follows:

- **Power generation** represents one of the most economically attractive, low-risk and urgent demand sectors for natural gas supplies. The financial viability of the sector must be secured in order to incentivise supply and new investment.

- **Cement Clinker production** represents the second most attractive option, subject to suitable location of sufficient limestone deposits for the utilisation of natural gas, where gas pipelines could be economically extended.

- The third priority may be gas for **low-risk domestic-market focused industrial clusters using cogeneration, i.e. combined use of heat and power**, switching from expensive alternatives such as fuel oil. This includes sectors such as the textiles industry and paper industry. Depending on the loads, this demand may be met through an offtake from gas transportation lines (for large offtakes) or local gas distribution networks or via combined heat and power supplying a district heating network.

- Dedicated **CNG vehicle fleets** such as urban buses and taxis offer an attractive potential saving on fuel costs in addition to the environmental benefit. Infrastructure, high capital costs and storage issues present barriers which may be addressed by concentrating on dedicated fleets in specific areas (Accra in the first instance) and providing financial support for conversion cost, possibly recouped through taxation on the CNG supply.

- **Strategic capital-intensive industries** such as urea, methanol and aluminium are a high risk option due to their high capital investment requirements, requirement for low gas prices, and strong level of competition in globalised markets with volatile prices. These are not therefore recommended as priority utilisation areas during the initial stages of Ghana's gas sector development.

- **Residential and commercial** demand for gas through distribution networks is commonly accepted to require space heating demand due to cold climate conditions in order to be economically viable. In the absence of such demand in Ghana and with the widespread use of LPG for cooking, this is not recommended as a priority utilisation area for dry natural gas.

The above recommendations are compared to the prioritization indicated in the Pricing Policy in **Table 4**.

Table 4: Prioritization of Gas Utilisation Options		
Priority	**National Gas Pricing Policy**	**Ghana Gas Master Plan**
1	Power plants	Power plants
2	Fertilizer	Cement Clinker
3	Industrial Heating	Industrial Co-genertaion
4	Other Petrochemicals	CNG Vehicles
5	Others	Methanol, Urea, Alumina

The quantitative support for this Gas Master Plan recommendations for gas utilisation are based on the netback value (or direct economic value), a review of likely risk and other barriers to a sector's development, and assessment of the multiplier results for different infrastructure options discussed in Section 6.3. They do not take into account other environmental and social impact effects which are beyond the scope of this analysis. Nevertheless, it is worth noting that the use of gas for the recommended highest priority – power plants – will replace the much more carbon intensive burning of LCO or proposed coal.

3 SUPPLY AND PRODUCTION PROFILE SCENARIOS

3.1 Overview of Ghana's Upstream Gas Activity

This section establishes plausible scenarios for the supply of natural gas in Ghana. 'Unconstrained' production profiles are developed, meaning the production that could be made available, if required to meet demand. More detailed supply-demand balancing of domestic and imported gas is carried out using the GMPM and reported in Section 5.

Given the relatively early stage of development of upstream activity and the uncertainties on both quantity and timing of recoverable resources, we adopt a scenario approach to future gas production and supply. The scenarios take account of the high level of uncertainty relating to fields not yet in production and the unknown dates when they may enter production (if resources are commercially proven).

The review covers two broad categories of gas supply sources:

- Domestic gas reserves and resources
- Gas imports

Domestic gas reserves are based on the supply of associated gas from the Jubilee field which is developed through a floating production storage and offloading unit (FPSO). Other fields such as the TEN which includes two oil fields (Enyenra and Ntomme) and one gas condensate field (Tweneboa) are being developed. The TEN field is being developed through a separate FPSO.

Additional fields have been discovered by Kosmos in the Jubilee area dubbed the MTA (Mahogany, Teak and Akasa). The Mahogany and Teak are oil and gas condensate fields while Akasa is an oil field. A non-associated gas discovery, the Sankofa field, has been appraised by ENI and committed for development. Furthermore, the Paradise field discovered by Hess is an oil and gas condensate discovery while the Hickory field also by Hess, is a gas condensate discovery. There are also likely to be more resources (both non-associated gas and associated) from undrilled structures.

Apart from gas supply from our indigenous fields, there is gas from Nigeria through the WAGP and potential for LNG imports.

The data used for the domestic gas reserves and resources estimates are taken from a number of sources including:

- Published reserve numbers from operator annual reports
- Information provided by GNPC
- Information from licensed field developers and operators
- Assumptions for potential gas finds

The data for imports is based on:

- Information from WAGP on gas quantities
- Assessment of possible LNG imports

Three scenarios have been prepared based on the above summary of reserves and resources:

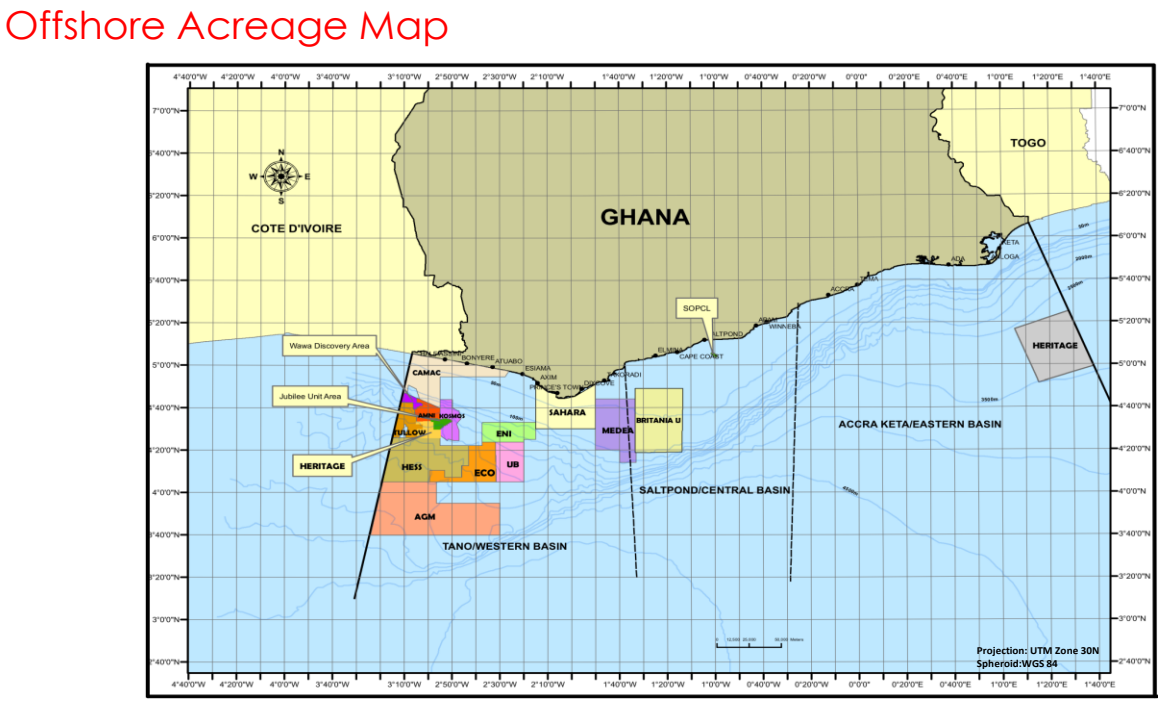
- ***Base supply scenario***
- ***Low supply scenario***
- ***High supply scenario***

The following sections discuss each resource based on current information about the status and development of the fields and prospects.

3.2 Domestic Gas Reserves and Resources

An offshore activity map is shown in **Figure 9**. The most significant feature of the map is the Jubilee oil field located in the western section of Ghana's Exclusive Economic Zone (EEZ), currently in production. A fraction of the associated gas in the production stream is consumed on the FPSO and a portion re-injected for reservoir pressure maintenance while the rest is sent onshore to the Atuabo Gas Processing Plant. The Tullow block which covers the TEN fields is shown to the west of the Jubilee oil field, adjacent to the border with Cote d'Ivoire

Figure 9: Ghana Offshore Activity Map



Source: GNPC, November 2015

To the east of the Jubilee field is the Kosmos Block which contains the MTA fields. These fields would be developed and produced using the Jubilee FPSO. To the south of the Jubilee field is the Hess Block which contains seven separate discoveries. The ENI Block is to the east of the Jubilee field.

The offshore area is generally prospective and has attracted the attention of numerous international oil companies. There are also potentially significant resources onshore in the Voltaian basin, though the exploration and development of these is a long term proposition.

Production profiles and delivered gas costs for the three scenarios are developed by:

- Making assumptions for the production profile of each field
- Assigning each field to one or more of the scenarios depending on our assessment of the probability that the resource will be commercial and developed for production
- Assuming costs for production and transportation in the absence of information.

3.2.1 Greater Jubilee Full Field Development Plan (GJFFDP)

This GJFFDP sets out the integrated development of the Jubilee Field, and the Mahogany and Teak discoveries (together "Greater Jubilee"). Mahogany and Teak will be tied back to and produced through the existing Jubilee Floating Production Storage and Offloading (FPSO) vessel.

Jubilee

Reserves and Production Potential

The Jubilee oil field came into production at the end of 2010. There are significant quantities of gas associated with the oil reserves. The Jubilee oil is light crude with Gas to Oil Ratio (GOR) of about 1,000 standard cubic feet per barrel. This implies that, at the current production rate of 120,000 bopd, an equivalent of 120 mmscfd of gas is being produced.

The field is being developed in phases and further wells are to be drilled. This would increase the oil and gas production and extend the plateau of production profiles.

A gas export forecast has been derived. This assumes that 10 mmscfd of the produced gas is required to fuel the FPSO operations. The low forecast assumes that 30% of the produced gas is re-injected for pressure maintenance. The medium and high forecasts assume that only 20% of the produced gas is required for pressure maintenance. The gas production forecast is shown in Figure 111. The pipeline to shore has a capacity of 220 mmscfd. The production profile below assumes that with the onshore processing facility running at full capacity; re-injection will be substantially reduced and gas to shore will be flowing uninterrupted from 2015.

Blowdown gas (gas re-injected to maintain reservoir pressure) cannot be produced until oil production ceases and is assumed to start in 2032 in the low and base forecasts and 2036 in the high forecast. This blowdown gas production would require the continued use of the FPSO. In order to keep the additional FPSO contract as short as possible it is assumed that

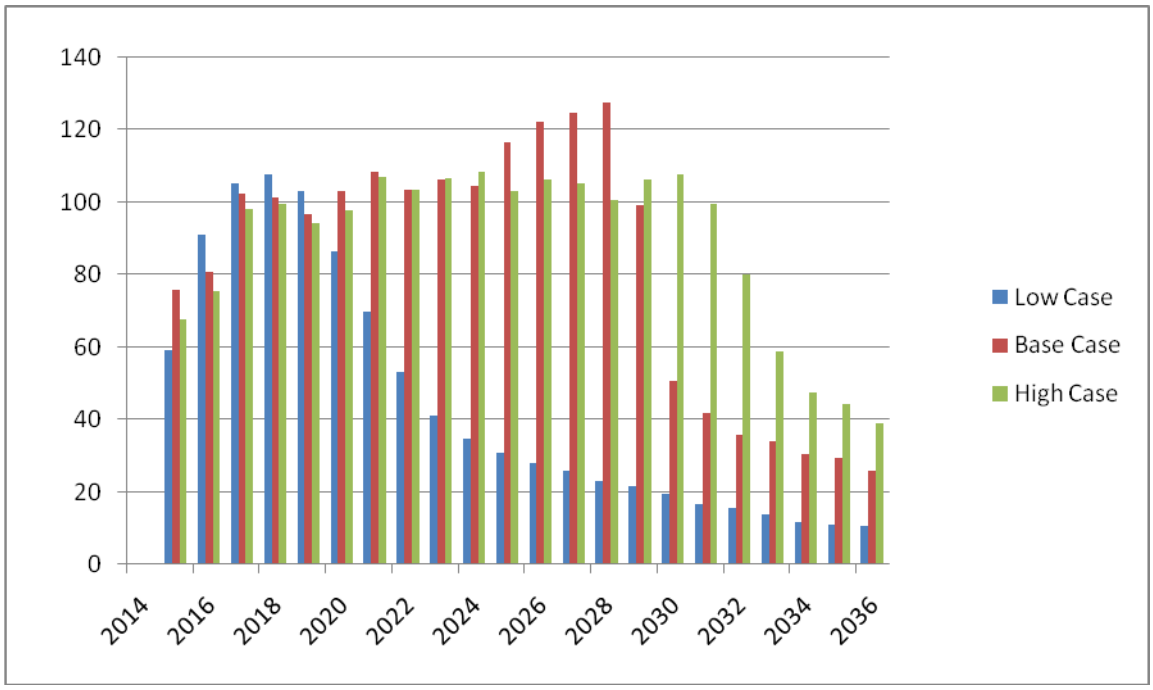
the blowdown gas will be produced as quickly as possible subject only to the maximum capacity of the system.

MTA

The location of the MTA fields is shown in **Figure 14**0. The appraisal programme was completed at the end of 2014. Production from MTA will be routed via the Jubilee production facilities. The gas production profile is shown in **Error! Reference source not found.**1. Due to the limited available information on the MTA field for now, different production profiles are not constructed for the MTA fields. Instead the same production profile is assumed to apply across all scenarios.

Figure 100: The MTA Gas Development Area

Figure 111: Greater Jubilee Full Field Gas Production, *mmscfd*



Source: GNPC

Costs

We assume that the total cost of the facilities required to deliver the Jubilee gas to consumers is US$600 million[15]. The costs are assumed to be US$200 million in 2012, US$300 million in 2013 and US$100 million in 2014. These costs are reflected in the total delivered costs of the Jubilee and TEN fields. Notional transportation and processing tariffs are calculated based on a discount rate of 17%. As GoG will receive revenue from the sales of LPG from the facilities a notional credit of US$0.4/mmbtu is assumed. We also assume that the costs of the transportation and processing facilities will be recovered before the blowdown. The total assumed costs across the three supply scenarios are shown in **Table 5**.

[15] Ahead of final completion of the facilities, the final cost is not known although we understand it may exceed this figure.

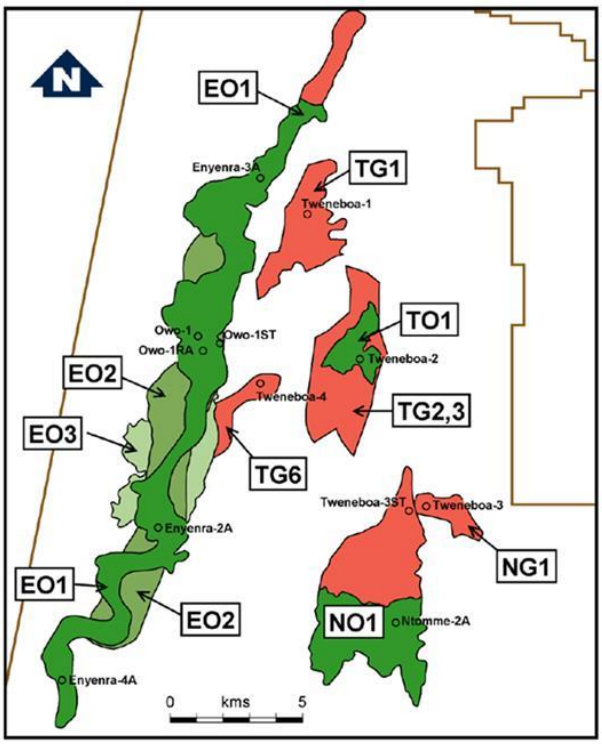
Table 5: Greater Jubilee Full Field Cost Assumptions, *US$/mmbtu*				
Scenario	**Infrastructure**	**Liquid Credit**	**Gas Cost**	**Total**
Low supply scenario				
Jubilee up to 200BCF	4.45	-0.40	0.00	4.05
Jubilee over 200BCF	4.45	-0.40	2.00	6.05
Jubilee blowdown			3.00	3.00
Base supply scenario				
Jubilee up to 200BCF	4.01	-0.40	0.00	3.61
Jubilee over 200BCF	4.01	-0.40	TBD	3.61
Jubilee blowdown			3.00	3.00
High supply scenario				
Jubilee up to 200BCF	3.16	-0.40	0.00	2.76
Jubilee over 200BCF	3.16	-0.40	2.00	4.76
Jubilee blowdown			3.00	3.00

3.2.2 TEN (Associated and Non-Associated)

Reserves and Production Potential

The TEN fields are shown in **Figure 12**2. The main non-associated gas reservoir is the Tweneboa field.

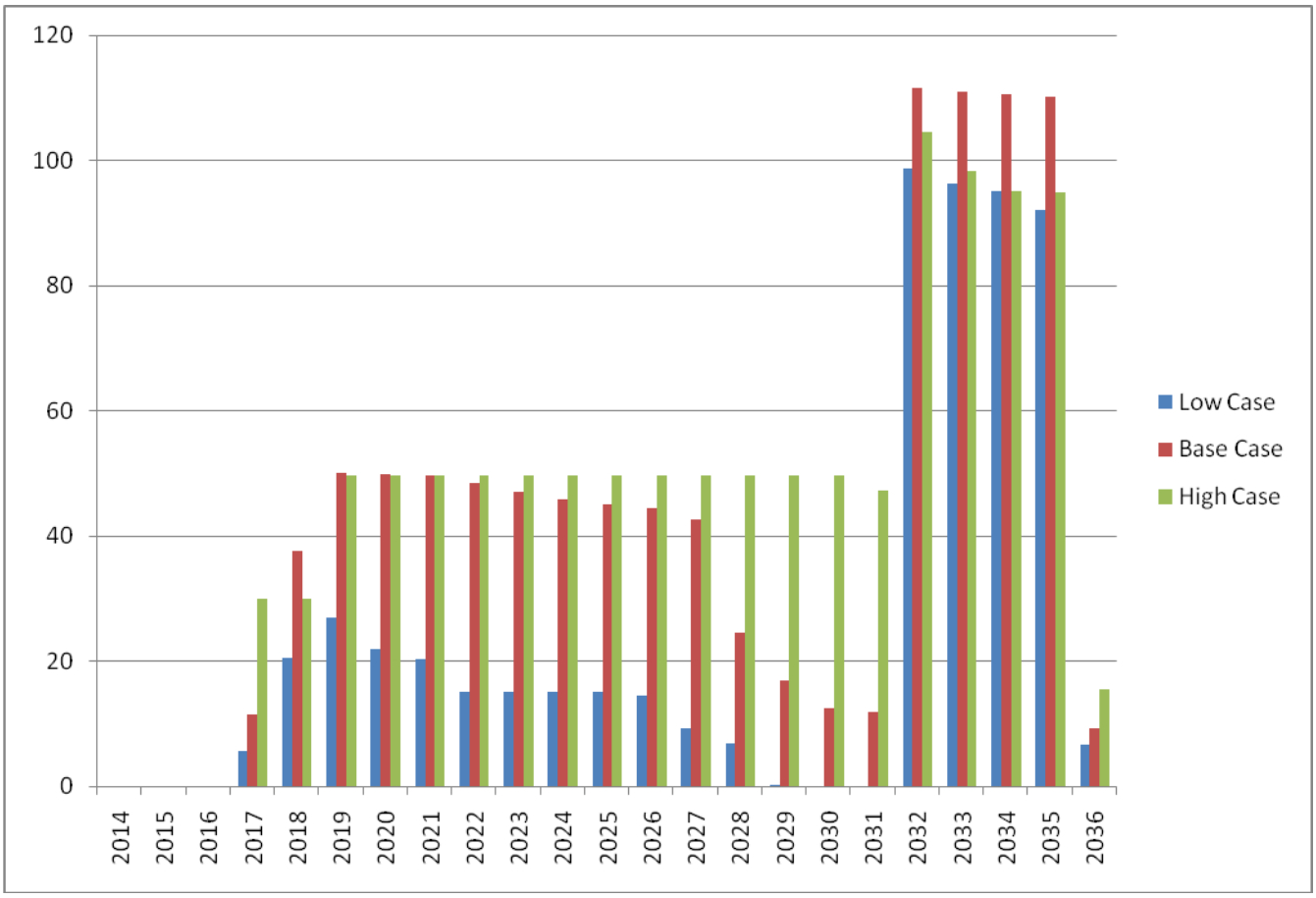
Figure 122: TEN Fields



Note: Oil fields are shown in green and gas fields in red.

The TEN development plan was approved in May 2013 and is expected to commence production in mid-2016. For the purpose of the GMP which is modelled on an annual basis it has been assumed that gas deliveries will begin on 1 January 2017. The oil will be produced through a second FPSO. Gas will be sent through the Jubilee gas pipeline system. **Figure 13**3 shows the assumed gas production profile across the three scenarios.

Figure 133: TEN Gas Production *mmscfd*



Source: GNPC

Costs

The TEN associated gas will be available at US$0.5/mmbtu and the non-associated gas at US$2.9/mmbtu. The cost of the Jubilee transportation and processing infrastructure is added to these commodity costs as shown in **Table 6**.

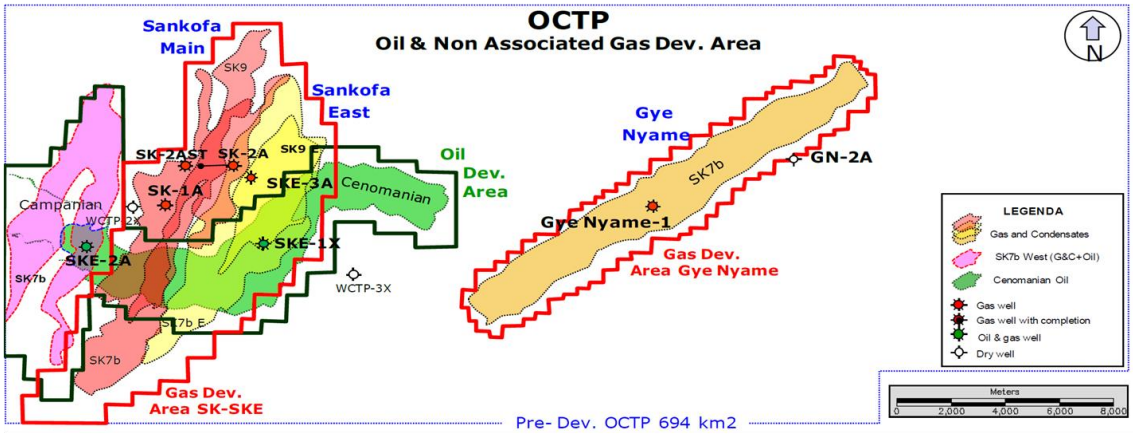
Table 6: TEN Costs *US$/mmbtu*				
Scenario	**Infrastructure**	**Liquid Credit**	**Gas Cost**	**Total**
Low supply scenario				
TEN associated gas	4.45	-0.40	0.50	5.05
TEN non-associated gas	4.45	-0.40	3.00	7.05
TEN blowdown			3.00	3.00
Base supply scenario				
TEN associated gas	4.01	-0.40	0.50	4.61
TEN non-associated gas	4.01	-0.40	3.00	6.61
TEN blowdown			3.00	3.00
High supply scenario				
TEN associated gas	3.16	-0.40	0.50	3.76
TEN non-associated gas	3.16	-0.40	3.00	5.76
TEN blowdown			3.00	3.00

3.2.3 Sankofa and GyeNyame

Resources and Production Potential

Details of these fields which are being developed by ENI are shown in **Figure 14**4. There are two gas development areas. The Sankofa Gas Development area covers the Sankofa and Sankofa East gas fields; the GyeNyame Gas Development area covers the GyeNyame gas field. First gas is expected to be delivered in 2018. After extraction of LPG and condensate a peak gas sales volume of 180 mmscfd is expected.

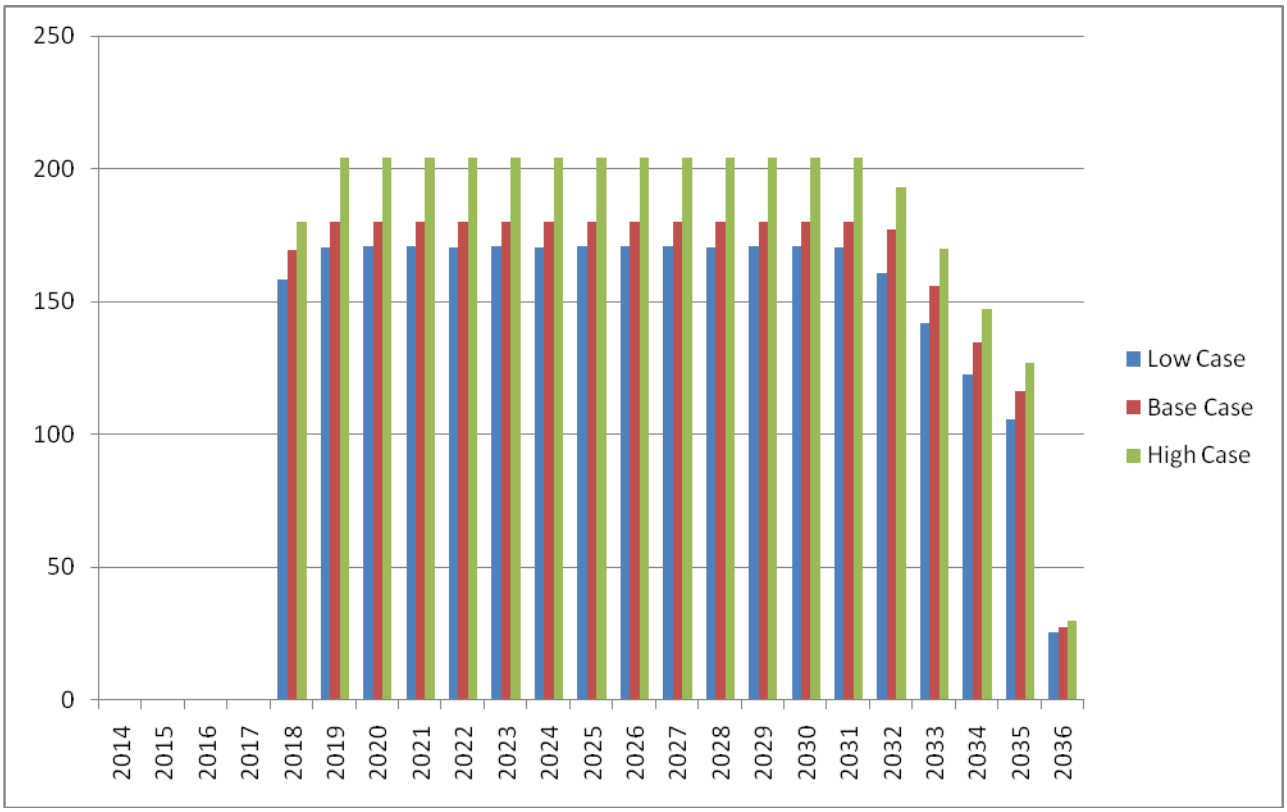
Figure 144: Sankofa and GyeNyame Gas Development Area



Source: ENI

The gas production forecast is shown **Figure 15**5. The associated gas is initially re-injected for pressure maintenance and a blowdown of this gas occurs in 2036.

Figure 155: Sankofa and GyeNyame Gas Production *mmscfd*



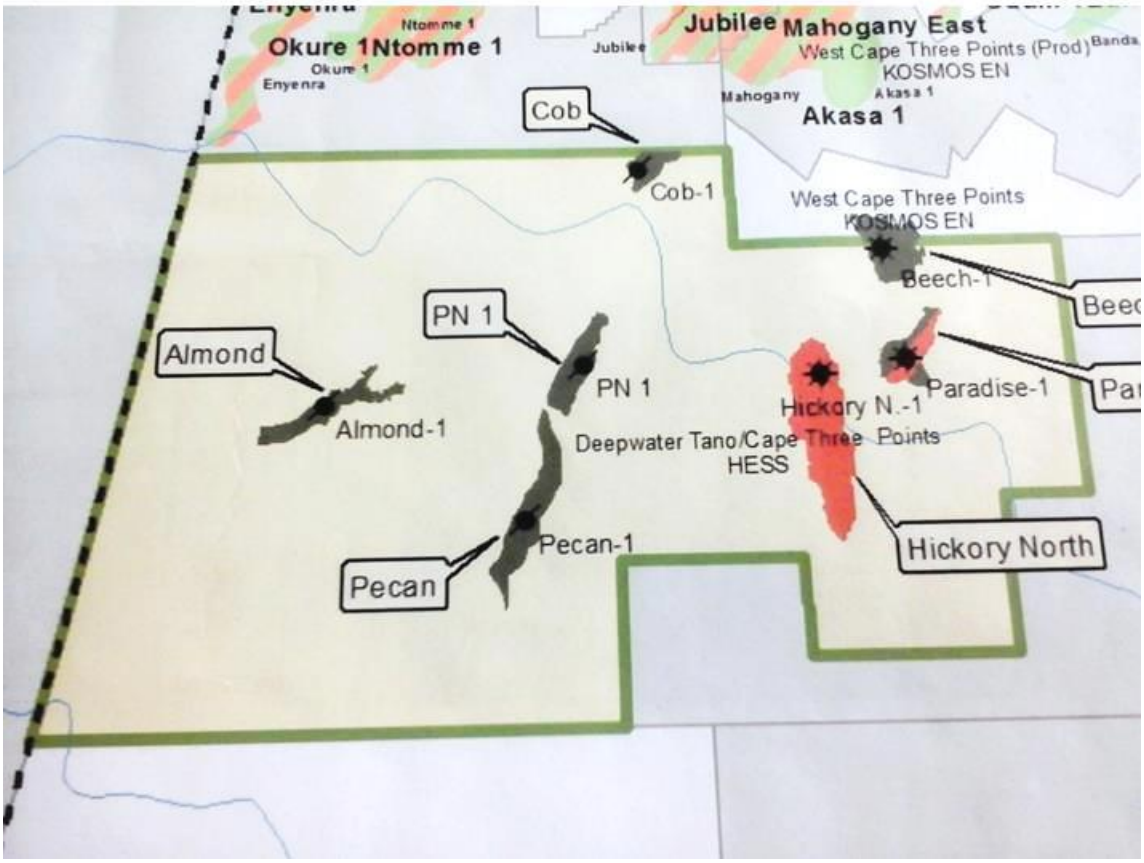
Costs

From the expected production profiles, investment and operating costs in the approved PoD, the delivered gas price to the onshore receiving facility at Sanzule would be US$ 9.8/mmbtu. . The blowdown gas is assumed to be supplied at US$ 3/mmbtu.

3.2.4 Hess

Hess has discovered seven fields in its licence area to the south of the Jubilee field including the Paradise oil and gas condensate field and the Hickory gas condensate fields. The fields' locations with respect to the Jubilee field are shown in **Figure 16**6.

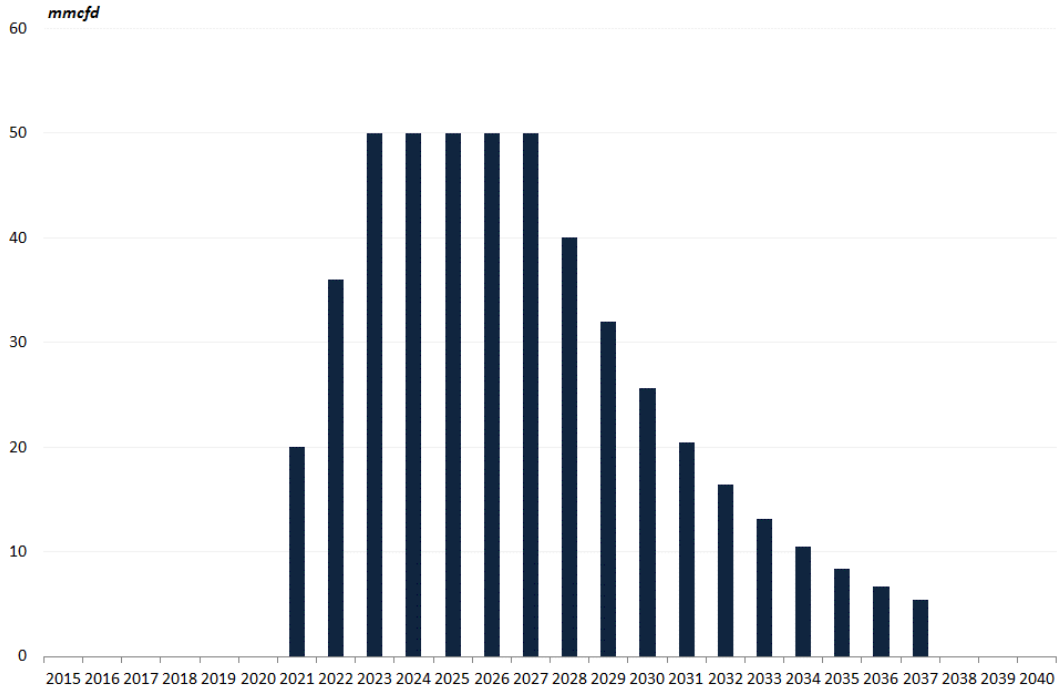
Figure 166: Hess Oil and Gas Fields



No further information is currently available on the Paradise and Hickory fields. For the purposes of this GMP it is assumed that gas would be supplied through a new gas gathering pipeline connected to shore from 2021 for a total supply of 177 Bcf and produced at a plateau rate of 50 mmscfd . The assumed gas production forecast is shown in **Figure 17**7.

Similar to the production and cost profiles of the MTA fields, one profile for each of the three supply scenarios is assumed.

Figure 177: Hess Gas Production Forecast, *mmscfd*



Source: GNPC

Costs

It is assumed that Jubilee gas facilities would have been partially paid for by the time the Hess fields come into production in 2021 and It is assumed that Hess gas would be sold between US$ 2.98 - 4.20/mmbtu.

3.2.5 Shallow Tano Gas

There is currently non-commercial gas in the Shallow Tano Block. However, it is assumed that this will become available under the high supply scenario from 2025. GNPC has estimated a total supply of 193 Bcf, producing at a plateau rate of 50 mmscfd starting 2025. .

Costs

It is envisaged that the Shallow Tano gas would use the existing Jubilee onshore facilities and pipeline which would have already been paid for by the time the field comes onstream. The gas would need a high price to be produced and it is assumed that the contract price would be between US$2.98 -4.20/mmbtu.

3.2.6 Other Associated Gas

There are other undrilled prospects where sufficient information is not yet available. For the purposes of this GMP however, it has been assumed that further associated gas will total 1Tcf in the high supply scenario at a rate of 140 mmscfd over 20 years.

Costs

It is assumed that associated gas will be sold through a new terminal at US$ 2.98/mmbtu.

3.2.7 Other Non-Associated Gas

There are other undrilled prospects where sufficient information is not yet available. For the purposes of this GMP however, it has been assumed that further non-associated gas will total 1Tcf in the high supply scenario at a rate of 140 mmscfd over 20 years.

Costs

It is assumed that this non-associated gas will be sold at the same price as the Sankofa/GyeNyame gas, namely at US$4.2/mmbtu.

3.3 Domestic Gas Supply Scenarios

As noted above, this GMP assumes three supply scenarios, being a Low case, a Base case and a High case. The gas supply volumes for each scenario are summarised in **Table 7** (reserves and resources) and **Table 8** (earliest production year and cost assumptions).

Table 7: Scenarios for Gas Reserves and Resource, *Bcf*

Field	**Low supply**	**Base supply**	**High supply**
Jubilee*	349	533	639
TEN	287	287	427
Sankofa	1,366	1,366	1,645
MTA*	24	129	173
Hess		177	177
Shallow Tano			193
Other Non-associated gas			1,000
Other Associated gas			1,000
Total	2,026	2,492	4,254

* NB: *Estimates from Greater Jubilee Full Field Development Plan, 2015*

To obtain a realistic picture of future production volumes, we include yet-to-find oil and gas fields in our analysis. Exploration in Ghana is continuing at a high level and further discoveries are likely.

However these possible further discoveries have only been taken into account in the high forecast. The timetable for the start of supply for the yet-to-find fields is only indicative.

Table 8: Summary Data for Gas Exports and Pricing Scenarios

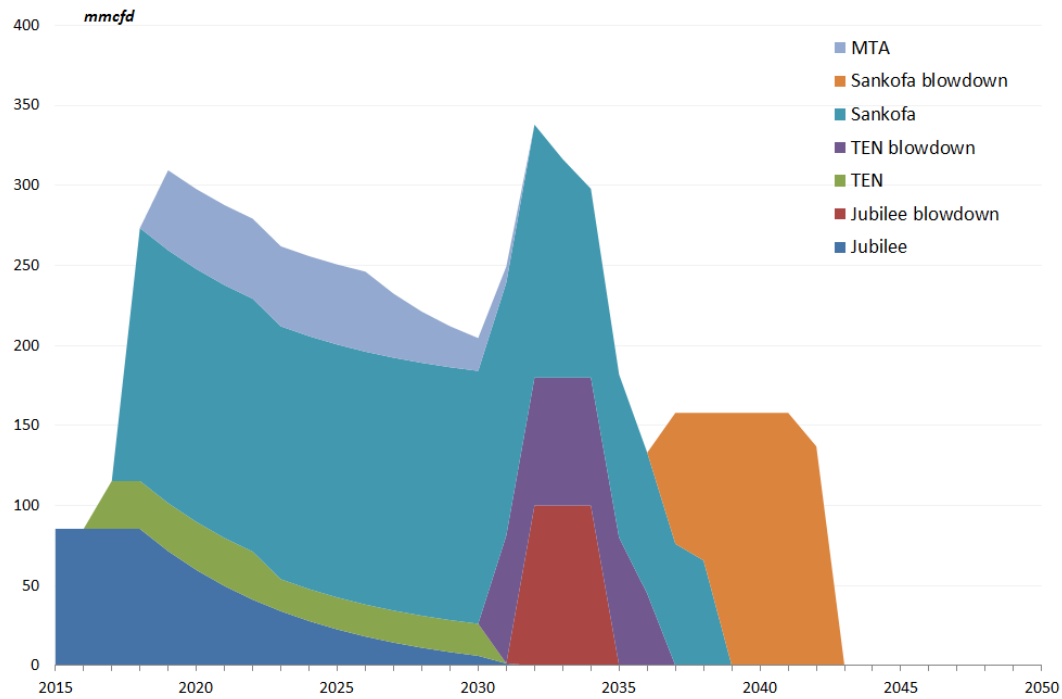
Field	Production year	Daily sales peak	Indicative cost
	earliest	*mmscfd*	*US$/mmbtu*
Jubilee	2015	60-120	2.98 – 4.20
TEN	2017	30-50	2.98 – 4.20
Sankofa*	2018	150-180	8.90
MTA	2019	50-120	4.20
Hess	2021	50	2.98 - 4.20
Shallow Tano	2025	50	2.98 - 4.20
Other Non-associated gas	2020	140	4.20
Other Associated gas	2019	140	2.98

Note: unproven 'Other' sources are only assumed in the high case

** This negotiated price of US$8.98 /mmbtu, by prevailing global gas prices, is excessive*

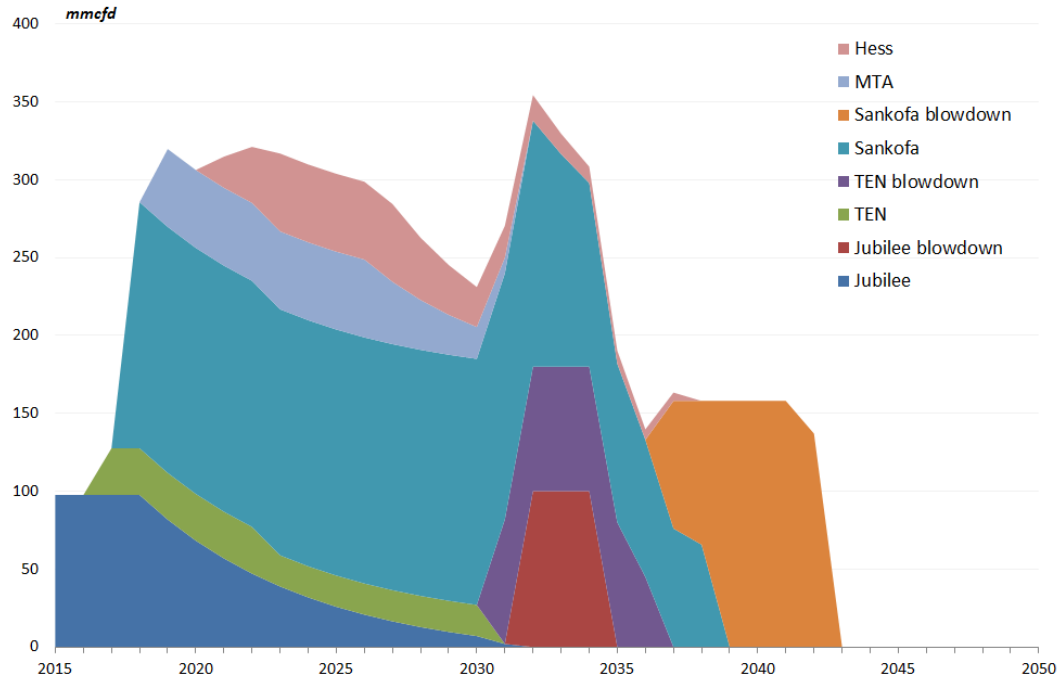
The details of the assumed fields and production in each scenario are shown in the following three figures. The Low supply scenario is shown in **Figure 18**8. This covers associated gas from Jubilee and TEN as well as mostly non-associated gas from Sankofa/GyeNyame.

Figure 188: Low Domestic Gas Supply Scenario



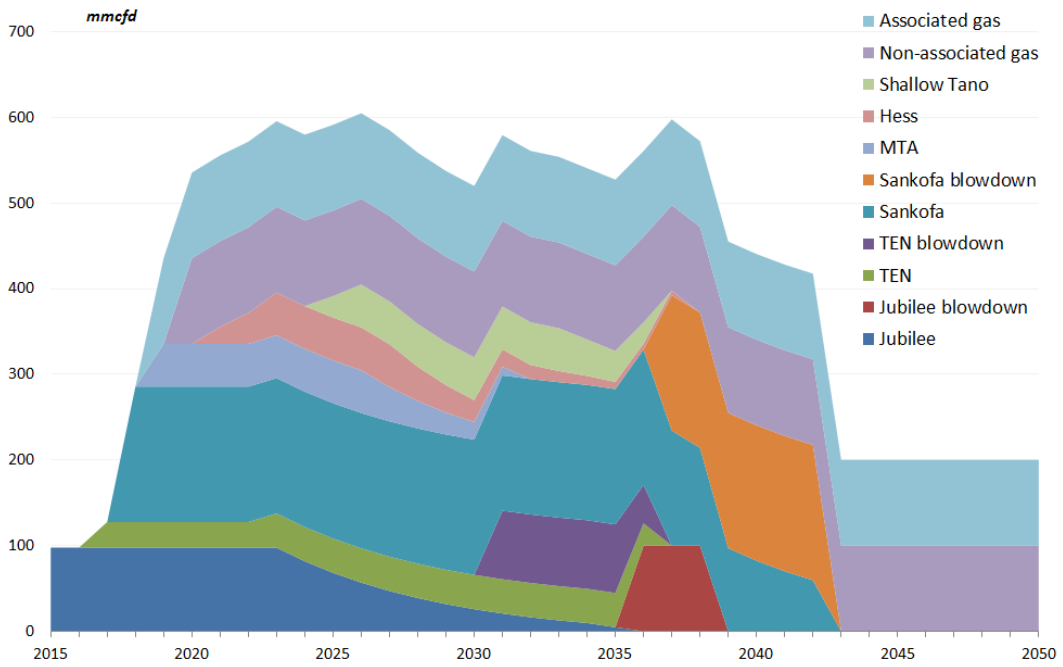
The base supply scenario is shown in **Figure 19**. In addition to the fields shown in the Low scenario, the Hess field production is added, which is the next most likely to come into production. This gives a plateau of just over 310 mmscfd.

Figure 19: Base Domestic Supply Scenario



The High supply scenario is shown in **Figure 20**0. This shows a plateau production level of 500 mmscfd. In addition to the supply shown in the Base scenario, supply from the Shallow Tano discoveries has been added. There has also been an allowance for potential resources of non-associated and associated gas of 1 Tcf each producing at 140 mmscfd over 20 years. This further associated gas is assumed to have an earliest start in 2019 and the non-associated gas in 2020.

Figure 200: High Domestic Supply Scenario



Figures on reserves and production used in producing these charts are subject to changes, as and when updated information is made available.

3.4 Gas Imports

In addition to domestic production, gas is imported through the West Africa Gas Pipeline (WAGP).

3.4.1 West African Gas Pipeline

Current Status and Supply Scenarios

WAGP takes custody of gas from the Western Gas Transmission System in Itoki gas supply hub in Nigeria. Gas supply is generally short in this region but is expected to improve once the connection is made between the Western and Eastern Nigerian gas transmission systems.

WAGP currently has a capacity of 170 mmscfd without additional compression. However, with additional compression, the capacity is 460 mmscfd with a maximum operating pressure of 150 bar. The Volta River Authority (VRA) has contracted a capacity of 123 mmscfd in the system. It should be noted that, to date, WAGP has failed to deliver the contracted quantity consistently. However, it would be possible for VRA to contract additional capacity of 47 mmscfd to bring it up to a total of 170 mmscfd through additional agreements with WAGP.

The delivery failures to date suggest that under-delivery will continue and this provides justification for Ghana to continue to develop its indigenous resources.

A volume of 50 mmscfd in the low supply forecast over the period 2015-2050 is assumed; 50 mmscfd rising to 100 mmscfd in 2017 for the base case and 50 mmscfd rising to 170 mmscfd in 2017 in the high case.

Costs

From discussion with WAGP it is understood that the current price for gas delivered to Tema is US$ 8.6/mmbtu which includes a transportation tariff of US$ 5.02/mmbtu.

3.4.2 LNG

The supply forecasts indicate that LNG imports would be required in the low and base production forecasts as early as 2021 while in the high production forecast LNG imports would not be required until 2039.

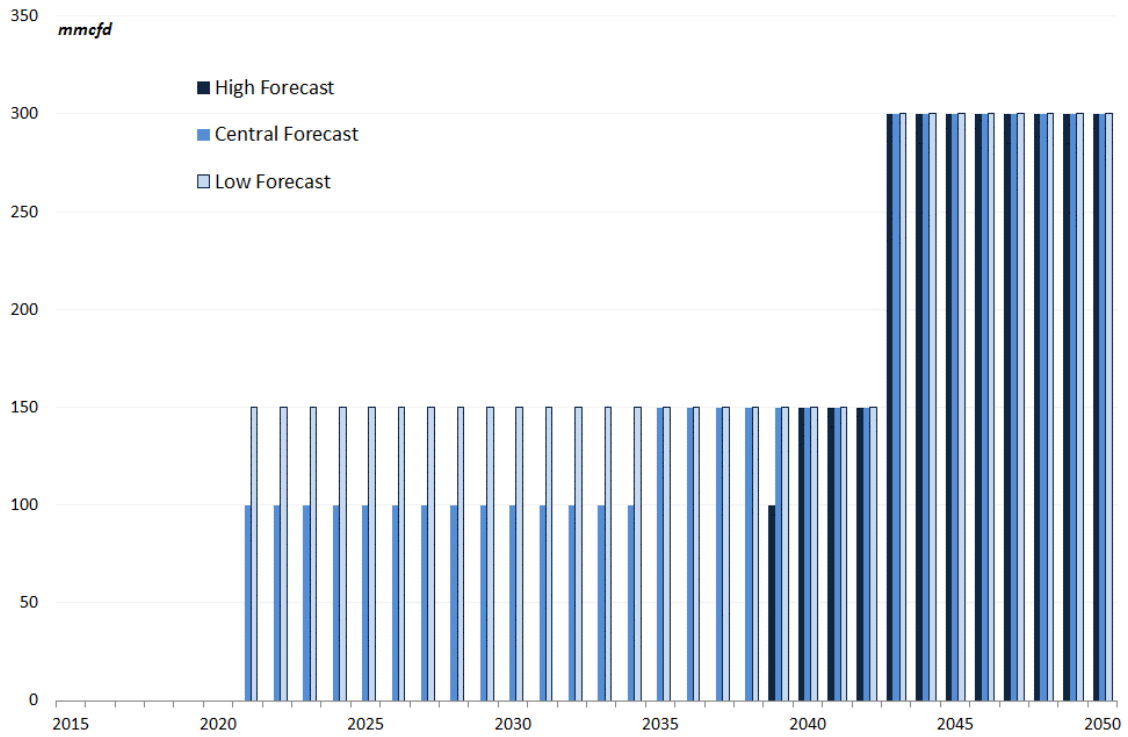
Based on the Demand/Supply projections in Section 5.3.3 an estimated 300 mmscfd of LNG would be required to address the supply shortfall. This is consistent with the recommendations made by the Millennium Challenge Corporation in their pre-feasibility Study of an LNG terminal in Ghana. It is assumed here that an LNG terminal with a capacity of up to 300 mmscfd will be appropriate. This assumption is made to provide an initial gas supply and demand balance. The location, exact capacity and year needed have

been established in the pre-feasibility study (of which the key points are summarised in Annex A4). LNG recommendations are proposed in Section 6 of this Report.

In November 2015, Ministry of Power contracted an equivalent of 120 mmscfd of LNG with West African Gas Limited to be delivered by second quarter of 2016 for an initial 5 year period with the option to extend for a further 5 year period.

Figure 211 shows the LNG import profile assumed for the three supply scenarios.

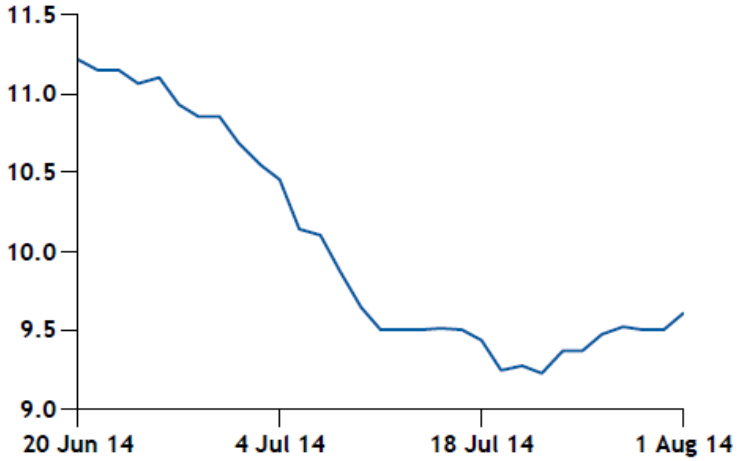
Figure 211: LNG Imports, *mmscfd*



Costs

The costs of the FSRU and associated infrastructure would be close to US$2/mmbtu. The cost of shipping the LNG is assumed to be close to US$1/mmbtu. LNG cost over the period 20 June 2014 to 1 August 2014 ranged from US$11.2/mmbtu to US$ 9.7/mmbtu as shown in **Figure 22**2. An average of US$10.5/mmbtu is used in this GMP.

Figure 22: West Africa LNG Spot Prices, *US$/mmbtu*



Source: Argus

3.5 Total Supply Scenarios and Costs

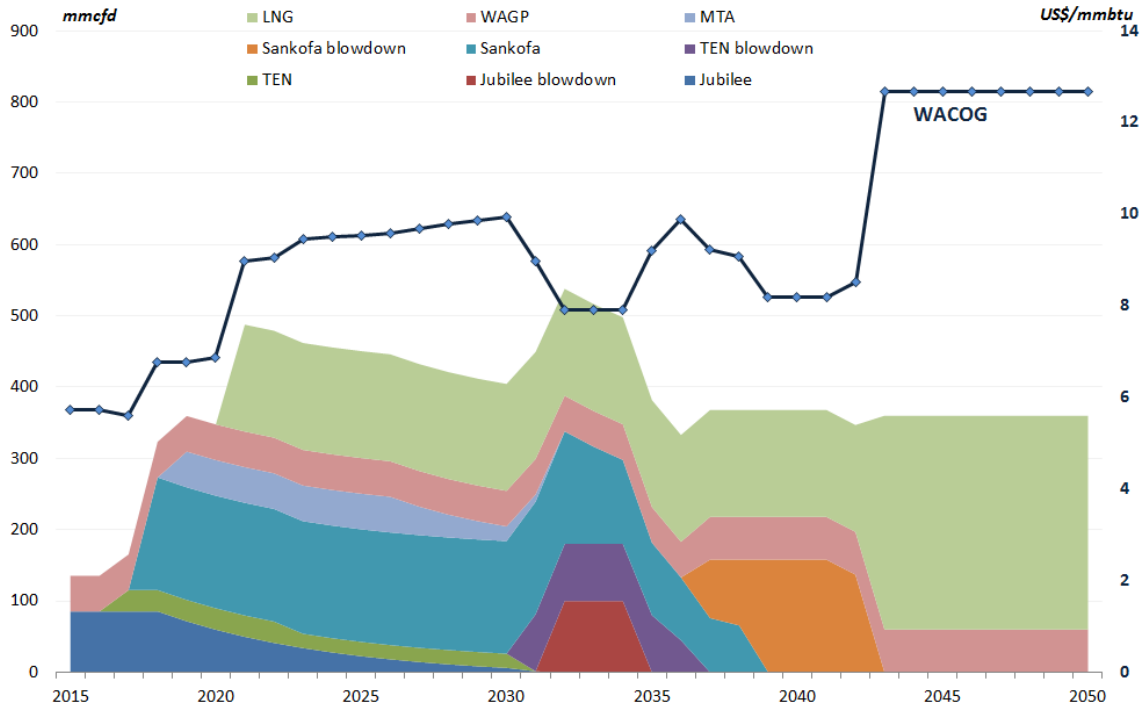
The total supply scenarios combine the domestic production and import options to estimate the maximum supply profiles and the Weighted Average Cost Of supplied Gas (WACOG). Based on a combination of domestic supply and gas imports (both WAGP and LNG) three gas supply forecasts have been developed: Low, Base and High supply scenarios.

3.5.1 Low Supply Scenario

The overall Low supply scenario is shown in Figure 233. The scenario includes both the domestic supplies discussed earlier together with gas from WAGP and LNG. The low domestic supply leads to an early requirement for LNG imports.

The WACOG is also shown in the figure. If WAGP gas was available in larger quantities, it would reduce the WACOG. The dip in the WACOG from 2031 is caused by the introduction of the low cost blow down gas that is produced (Jubilee, TEN and Sankofa) once oil production ceases. This temporarily reduces the WACOG. The long term maximum WACOG is a little over US$12/mmbtu. In the medium term it is in the range US$8-10/mmbtu.

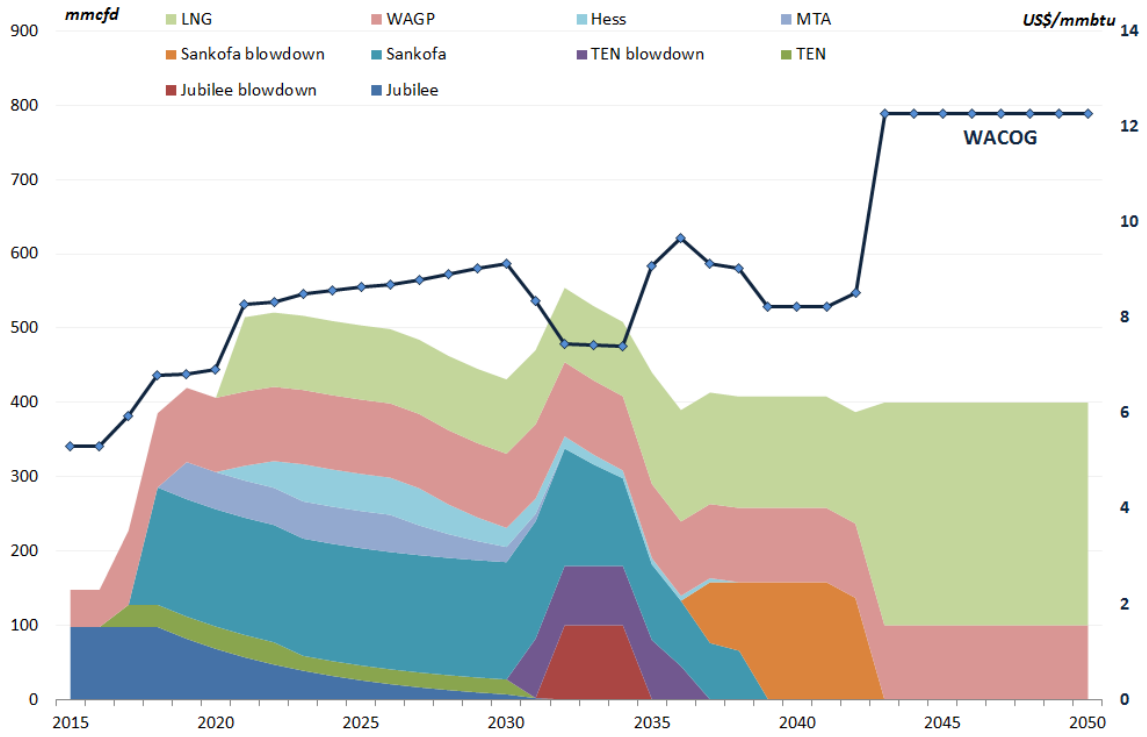
Figure 233: Low Total Supply Scenario



3.5.2 Base Supply Scenario

The total base supply scenario is shown in Figure 244. The weighted average cost of gas is included in the figure. The supply volumes and costs follow a similar pattern as for the low case. It is only the small Hess field that is additional to total supply in this scenario. The long term maximum WACOG is a little under US$12/mmbtu, in the medium term it is in the range US$8-9/mmbtu.

Figure 244: Base Total Supply Scenario

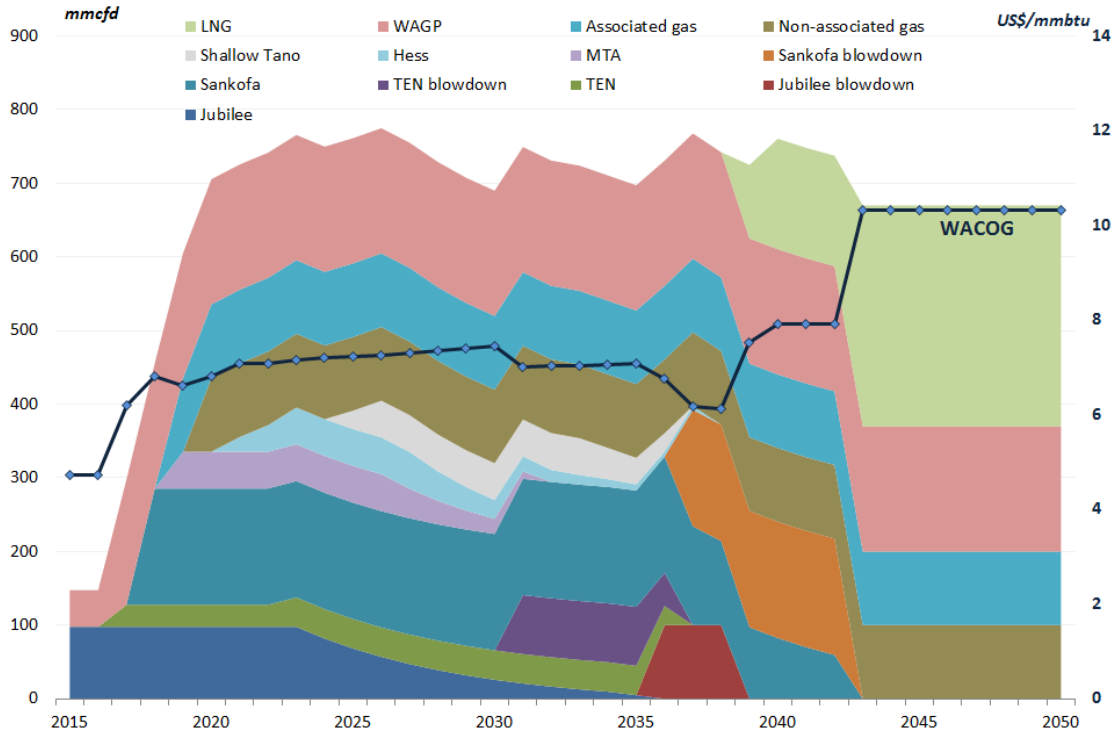


3.5.3 High Supply Scenario

The High supply scenario is shown in Figure 255. The scenario includes both the domestic supplies discussed earlier together with gas from WAGP and LNG. Additional domestic supplies of both associated and non-associated gas have been assumed to be available from increased exploration.

The weighted average supply costs are lower than in the previous two scenarios due to the increased and sustained availability of domestic gas. The introduction of large volumes of domestic supply allows the imports of LNG to be reduced lowering the weighted average cost of gas compared to the Low and Base Supply scenarios. The long term maximum WACOG is a little over US$10/mmbtu. In the medium term it is estimated in the range of US$7-8/mmbtu.

Figure 255: High total supply scenario



4 DEMAND FOR GAS

The potential gas demand is analysed in this section under several scenarios which represent different states of the economy and different states of the gas sector in Ghana. There are in principle three main drivers of gas demand:

- Gas demand from the power sector
- Gas demand from the industrial sector

The demand for gas was assessed through the GMPM by analysing and modelling each sector separately.

The results in this section are reported to 2040. The trends beyond 2040 are similar but since, from section 3, it can be seen that there is a supply gap in all cases after 2040, it is only useful to show the infrastructure options and gas demand balances up to 2040.

4.1 Gas Demand from Power Sector

The current power generation mix in Ghana is 55% hydro energy and 45% thermal energy[16]. Given that hydro power generation is an important element of the power generation and that it depends on water inflows, the dispatching of the power sector should allow for the seasonal variation of hydro power generation. The GMPM accounts for the seasonality of hydro power and determines the merit order of gas in Ghana's power generation fuel mix to calculate the demand for gas. For the dispatching of the power sector, various data series and assumptions were required including the power sector development plan, the technical characteristics of the existing and planned power stations, the fuel costs of the power plants and, assumptions on hydro power generation, renewable energy generators and the demand for power.

Lignite or coal fired power plants are currently being considered in the power sector development plan.

Nuclear power has not been included in the dispatch model although this is proposed by government. This seems a long term project with a high degree of uncertainty and could at the earliest be developed by 2035.

Given the uncertainties over future gas supplies, the development of new power and gas infrastructure and the demand for power, we have considered three alternative scenarios for the power sector:

- **Low case –** assumes that the domestic energy demand will grow at 4% annually. VALCO will be operating with one pot line from 2016 and onwards. The expected annual average energy required for exports to CEB and SONABEL will be about 182MW per annum starting in 2018 and exports to Mali will commence in 2024 with an average load of 50 MW.

[16] Source: GRIDCo, 2013 Supply plan, 2013.

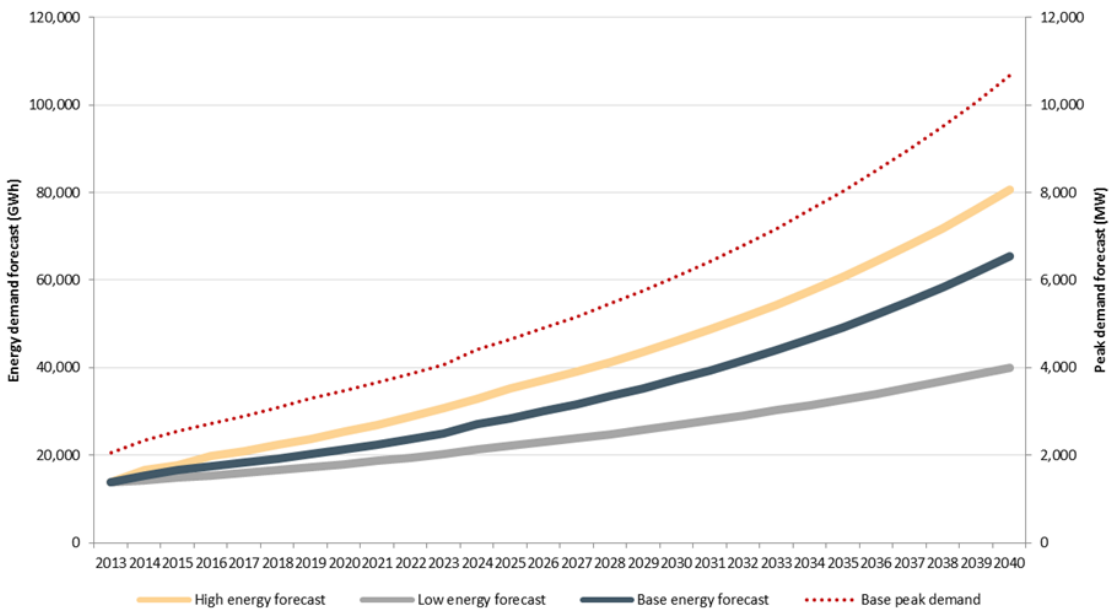
- **Base case** – assumes that the domestic energy demand will grow at 6% annually. VALCO will be operating with two pot lines from 2016 and onwards and three pot lines from 2018. The expected annual average energy required for exports to CEB and SONABEL will be about 228 MW per annum starting in 2018 and exports to Mali will commence in 2024 with an average load of 100 MW.

- **High case** – assumes that the domestic energy demand will grow at 8% annually until 2026 and 6% annually thereafter. VALCO will be operating three pot lines in 2015 and 5 pot lines from 2018 and onwards. The expected annual average energy required for exports to CEB and SONABEL will be about 342 MW per annum starting in 2018 and exports to Mali will commence in 2024 with an average load of 150 MW. New generic power plants are assumed to come on-stream after 2020 to cover the uprising demand and provide the required reserves margin of 18%.

The average energy demand forecast and the peak demand forecast are presented in Figure 29 and were used to generate a typical daily load profile for each year and to calculate the amount of energy required for generation. On the supply side, the available capacities were used to calculate the associated costs of power generation for each power plant.

The assumptions regarding the power sector development plan were analysed in Annex A5.74.1. A power dispatch model was used (within the GMPM) to determine the dispatch of the gas fired plants and the resulting demand for gas.

Figure 26: Power Demand Forecast



Given the demand for power and the set of the generating facilities in each year the power dispatch module of the GMPM calculates the amount of gas that is required. The economic dispatch of the power sector can be summarised in the following 7 steps:

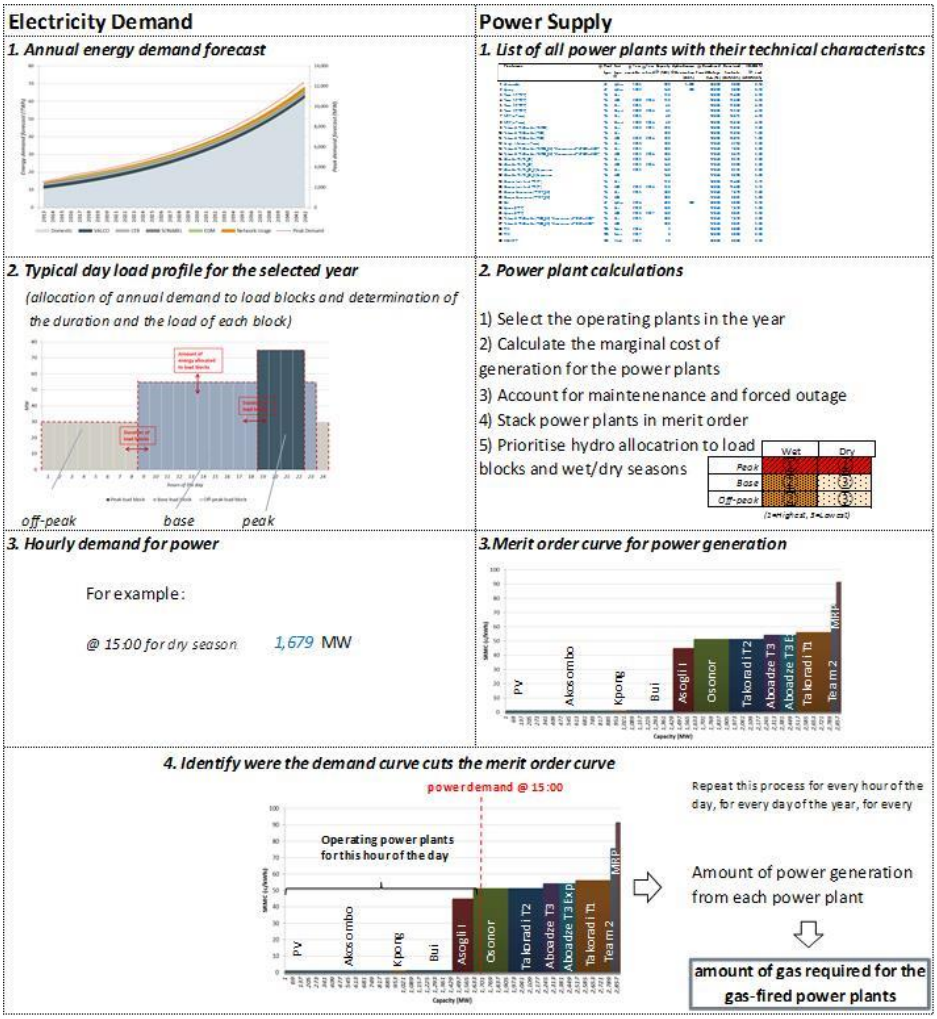
- Step 1: Determine the total annual demand for electricity

- Step 2: Determine the load profile for a typical day
- Step 3: Calculate the available capacity of the power plants hourly
- Step 4: Calculate the total variable costs of the power plants
- Step 5: Rank the available power plants by least cost generation
- Step 6: Superimpose the load profile of a typical day onto the merit order curve to determine the marginal cost of system
- Step 7: Repeat this process for every hour of the year for each year to extrapolate demand on an annual basis up to 2040.

This 7-step process is illustrated schematically in **Figure 27**.

NB: The gas demand was then estimated based on the heating value of the gas and the heat rates of the power generating plants.

Figure 27: Power Sector Dispatch Methodology



The methodology followed to carry out the economic dispatch of the power sector is explained in detail in Annex A5.1. The input data for the inventory of power plants in the country (i.e. power demand forecast, the power plant operating assumption, fuel costs, etc.) is presented in Annex A5.74.1.

For the base case, the annual demand for gas from the power sector is estimated around 182 mmscfd (67 Bcfa) in 2015, 275 mmscfd (100 Bcfa) in 2020 and 519 mmscfd (189 Bcfa) in 2030. It is estimated that the demand for gas will grow by 9.0% per annum in the low case, 10.4 % per annum in the base case and 12.0 % per annum in the high case from 2013 to 2035. This will be driven by the addition of new gas fired power plants, the increasing available gas reserves and production and the increasing demand for power. The initial demand in 2015 is estimated at 260_mmscfd. The peak demand between 2016 and 2035 is estimated at 490 mmscfd (179 Bcfa) in the low case, 539 mmscfd (197 Bcfa) in the base case, and 692 mmscfd (253 Bcfa) in the high case.

The annual demand for gas from the power sector is depicted in Figure 28 and **Table 9**. Detailed tables for the gas demand forecast from the power sector and the regional distribution of this demand are included in the annex A5.366.1.

Figure 28: Power Sector Gas Demand, mmscfd

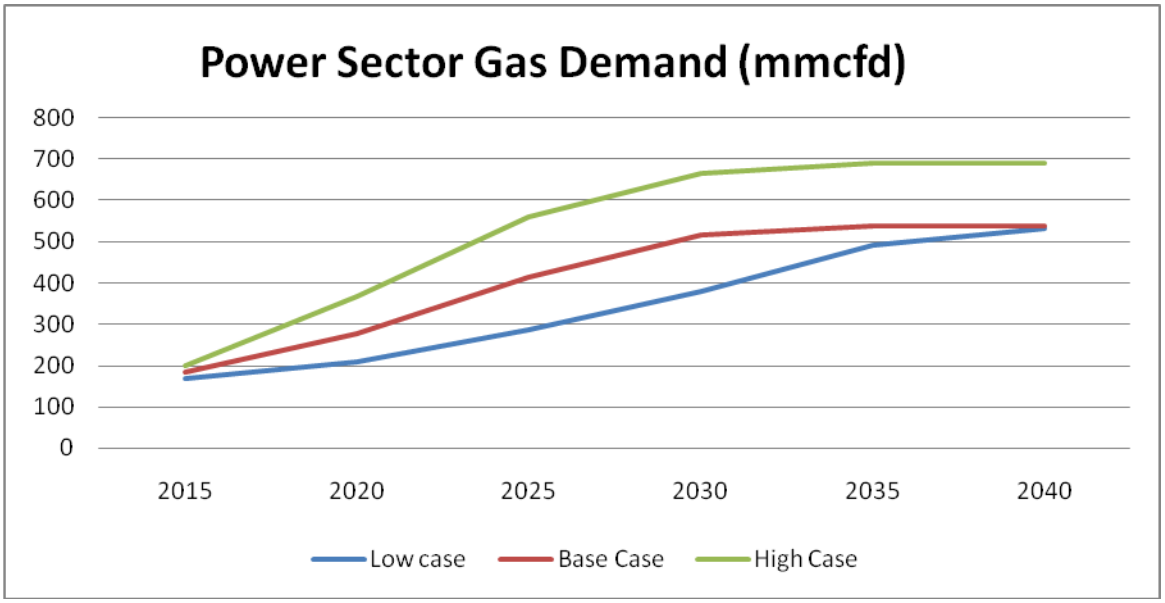


Table 9: Power Sector Gas Demand

Year	Low case scenario *mmscfd*	Base case scenario *mmscfd*	High case scenario *mmscfd*
2015	167.6	182.4	199.5
2020	207.5	274.9	368.2
2025	286.2	415.3	561.9
2030	379.9	516.0	667.5
2035	491.0	539.3	691.5
2040	530.7	539.3	691.5

It is estimated that approximately 34% of the demand will be located in the regions close to Tema, 58% in the regions around Takoradi and 7% in Kumasi (if a pipeline is built from Essiama to Kumasi).

Note that this is a 'template' chart used for all the infrastructure options and demand scenarios, hence the charts for some of the regions are blank when demand there is zero in that scenario or not met.

Additional information regarding the power sector modelling and results, which is the main driver of the demand for gas, is provided within the GMP model. The model calculates the operating costs of the power plants and the marginal cost for power generation, the amount of generation from each power plant, the load factors and the amounts of fuel required on an annual basis.

4.2 Gas Demand from Non-Power Sectors

Demand for gas from the industrial sector has been determined through a 'Netback Analysis'[17] of the maximum value of gas for industrial producers, based on current product prices minus other input costs.

Industries were assessed in line with the utilisation options discussed in Section 2 of this Plan (i.e. a selection of energy-intensive industries which may be of specific interest to policy makers were identified and analysed separately, with smaller industrial clusters using gas as an alternative to RFO/LPG grouped under an additional 'industrial heat' category).

The data required for each industrial sector includes:

- **Estimated product price** based either on domestic market prices (e.g. for cement), or in the case of export oriented industries, the global market prices.
- **Product demand (current)** based on estimates of current use within Ghana from import data and existing domestic production levels.
- **Demand growth in product**, based on a factor related to forecasted GDP growth.
- **Demand from exports** has been selected so as to provide a market equivalent to the minimum production capacity of a world-scale production plant for export orientated products (aluminium and methanol).
- **Capacity build-rate** estimates a single figure per sector to constrain production growth to a given amount. This is in order to both account for the minimum economic size of a single plant and to limit the annual increase in production capacity which can occur.
- **Plant/infrastructure build time** provides a minimum lead time before commissioning of a new plant can occur to allow for design and construction.

[17] In some situations other methodologies besides the Netback analysis may be more useful particularly where the social benefits take precedence over financial considerations

- **Estimated capital cost** of new production plant, or conversion cost for existing plant/vehicles (in the case of CNG for transport). A common discount rate and plant lifespan have been applied to all sectors to unitise capital cost with the exception of CNG vehicles for which a shorter lifespan has been assumed.

- **Estimated operating cost** of a production plant or vehicle.

- **Gas consumption requirements** per unit of product produced (or kilometres driven in the case of vehicles).

Input values currently assumed for the above parameters together with a detailed description of the calculation methodology employed are provided in Annex A4.6.3.

Following the analysis described in Chapter 2 on the netback value of gas in the various utilisation options the power sector demand scenarios is detailed in Section 4.1 above. In the case of the non-power sector detailed in Section 4.2, only gas demand for industrial heat and limited CNG for transport have been incorporated in the demand calculations. Demand for power from the existing aluminium smelting operations at VALCO is already included in the gas demand from the power sector analysis in Section 4.1.

Industrial Demand for gas is calculated for each scenario as the gas consumption requirements per unit output of product multiplied by quantity of product demanded (domestic plus export) for all industries pursued within that scenario.

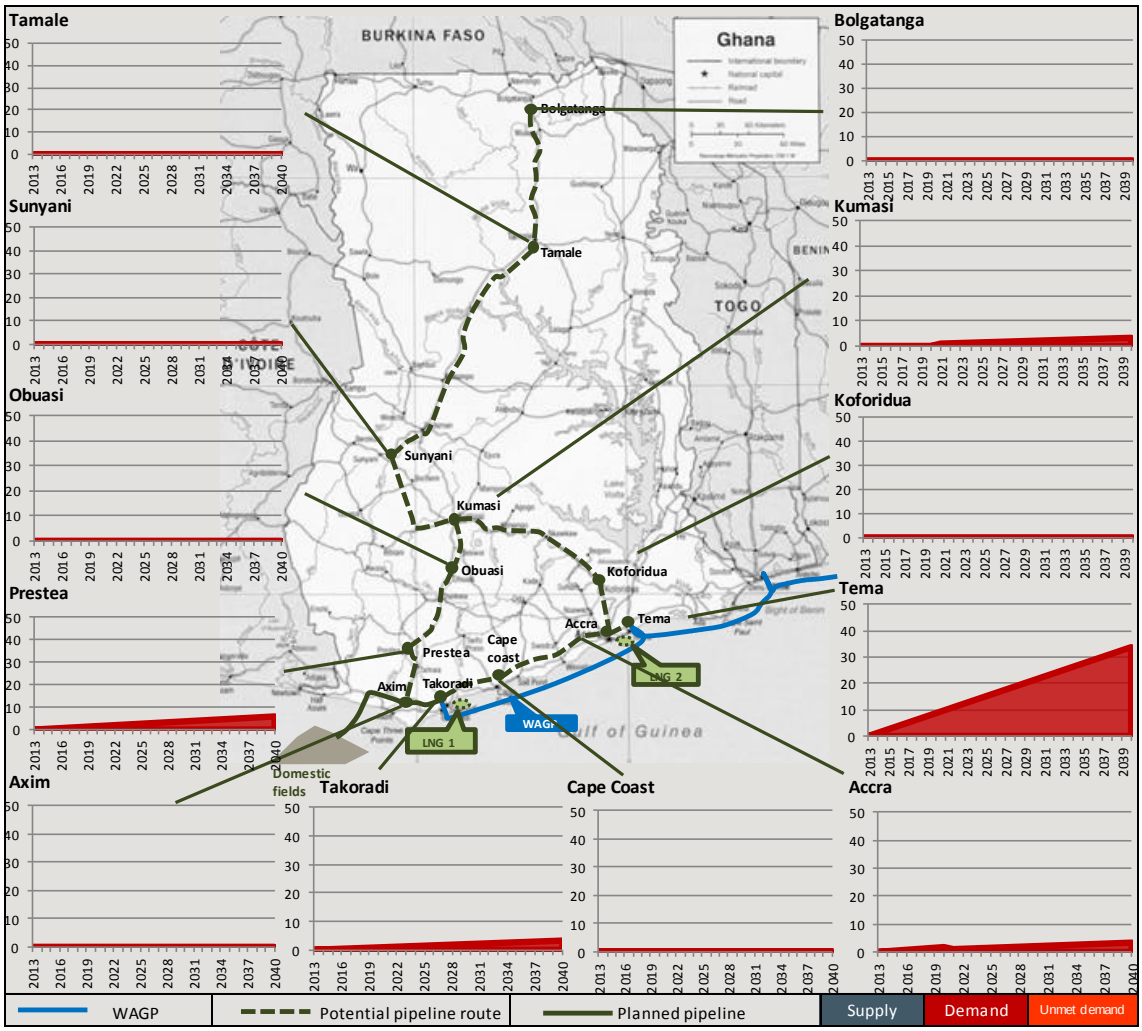
The industrial demand resulting from the use of gas for industrial heat and limited CNG for transport is illustrated in **Table 10** below.

Table 10: Industrial Sector Gas Demand

Year	*mmscfd*
2016	10
2020	35
2025	60
2030	85
2035	110
2040	135

The regional breakdown of the demand for gas for the industrial sector is illustrated in **Figure 29**. The input figures and reasoning for their selection are provided in Annex A4.

Figure 29: Regional Distribution of Gas Demand for Industrial Sector



A sensitivity analysis on industries which were not recommended after the netback analysis was also conducted. The industries taken into consideration were:

- The aluminium industry considering an integrated Alumina-Aluminium supply chain with Bauxite refining and expanded smelting operations
- The urea and methanol industries.

The additional gas demand from the inclusion of these two industries is shown in Table 9

Table 11: Additional Demand from Aluminium, Urea and Methanol Sectors		
Year	**Aluminium** *Bcf per year*	**Petrochemical** *Bcf per year*
2020	30.5	74.3
2025	39.6	83.4
2030	48.8	92.6
2035	74.2	101.7
2040	83.3	110.8

However, it should be noted that the total demand for gas that was taken into consideration for this study's analysis of infrastructure options does not include the additional gas demand described above.

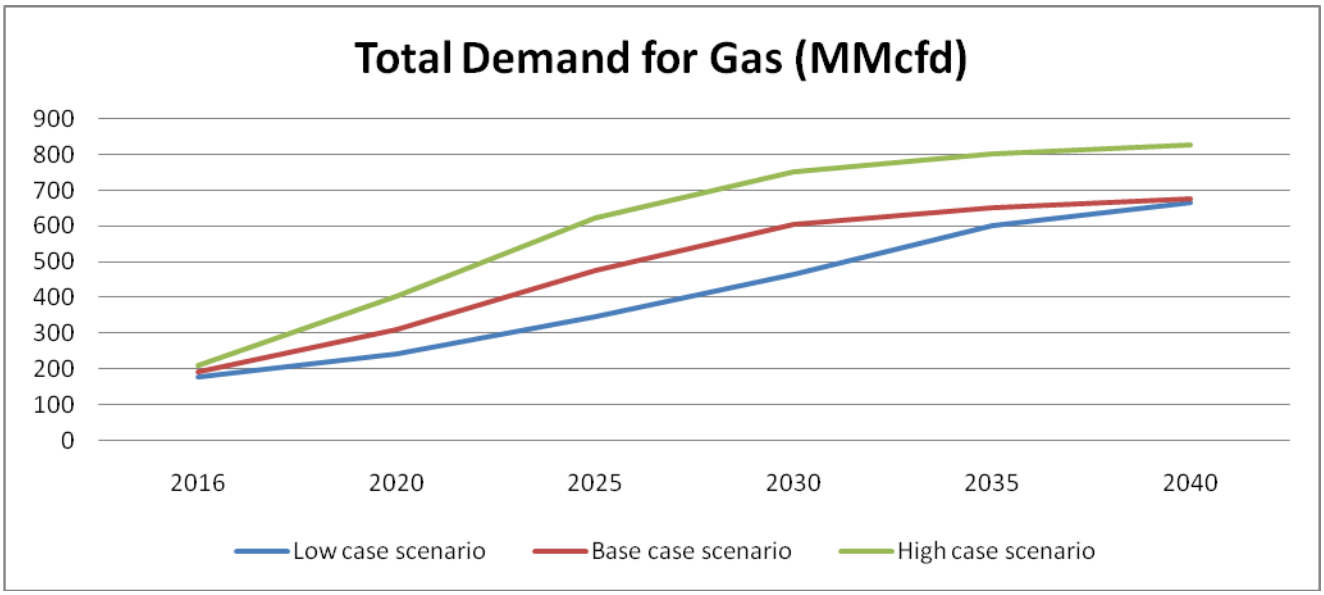
4.3 Exports of Gas

As supply volumes in most years of all scenarios are insufficient to meet domestic demand for power and basic industries and have to be boosted by WAGP and LNG imports, the export of gas from Ghana has not been considered in this Plan. Should the supply situation change in the future, the model has the capability to include export demand as a specific component of overall demand.

4.4 Total Demand for Gas

The total demand for gas, combining the demand from the power sector and the demand from the industrial sector, is depicted in Figure 30 and **Table 12**.

Figure 30: Total Gas Demand, mmscfd



The main driver of the total demand is the power sector contributing approximately 88% to the total demand. The remaining 12% is from the industrial sector. As noted above, exports are not realistic with the current state of the gas sector and therefore they do not contribute to the total gas demand. Each of the low-base-high demand scenarios is made up of the low-base-high demand for gas from the power sector, plus the industrial demand, which is assumed fixed.

Table 12: Total Gas Demand Scenarios, mmscfd

Year	Low case scenario	Base case scenario	High case scenario
2016	178	193	210
2020	242	310	403
2025	346	476	622
2030	465	601	753
2035	601	650	802
2040	666	675	827

5 GAS BALANCE AND SCENARIOS

5.1 Role of Gas in National Development

Ghana has discovered hydrocarbon resources at an opportune time when new sources of energy are required to power the country's economic development. Gas is particularly important in replacing the expensive liquid fuel which is still an important component in the country's power generation mix. Adequate gas supply will facilitate the ongoing electricity grid expansion programme and provide an adequate reserve margin. Power is currently the single largest constraint on Ghana's ambition to achieve sustained high levels of GDP growth to consolidate its middle income status.

The economic significance of the top two uses of gas is as follows:

- **Gas for power generation**
  - *Direct benefits* – substitution of expensive imported liquid fuels with a lower cost domestic gas will give significant cost savings for possible expansion in generation capacity.
  - *Indirect benefits* – GRIDCO estimates the cost of unserved energy at between US$6.5 and US$14.2/kWh dependent on customer class. This very high figure reflects the substantial positive multiplier effects for the economy of provision of power paving the way for higher rates of GDP growth and social development.
- **Gas for industrial process heat**
  - *Direct benefits* – existing industries will be able to substitute cleaner and cheaper natural gas for their current fuel sources which include RFO, HFO and diesel; provision of gas will also lead to an increase in investment in new industries which require process heat.
  - *Indirect benefits* – lowering the cost of production and increasing industrial development will make Ghanaian products more competitive while at the same time increasing employment and incomes, which in turn will have multipliers in the overall economy.

As explained in Section 2, other economically important uses for Ghana's natural gas at this point would be cement production, industrial heating and possibly also CNG vehicles[18].

Spatial development

It is Government policy to have development spread across the country and not just concentrated around Accra and the port cities. The initial gas developments will exacerbate the imbalance.

[18] Though as noted elsewhere the development of CNG is challenging and has failed in a number of other places through inadequate planning and support to implementation

However, once the location of gas fired power stations and industries elsewhere in the country justifies the building of a gas pipeline to the interior, this will create new poles of development. The multiplier effects of gas-related investments along such pipelines will be significant for the regions concerned.

In the event that there are new discoveries at a later stage, the use of gas for large-scale investment projects could be considered. Creating a national aluminium value chain is a case in point . Gas could be used as the energy source for transforming bauxite mined in Ghana into alumina. The alumina would be smelted by VALCO to produce aluminium.

5.2 Supply/Demand Scenarios

The development of the Gas Master Plan assesses the demand, the supply and the inter-linkages between the two under various infrastructure options and scenarios. Given the uncertainty over future gas pricing, domestic supply volumes, export commitments, infrastructure development and the demand forecast, the supply and demand balance is simulated with five scenarios to explore different potential states of the gas sector in Ghana. The aim of the task is to set out a framework of supply, demand and infrastructure options for optimum policy decisions to be made.

For planning purposes and testing the robustness of preferred plans, the analysis distinguishes between '***aligned***' and '***non-aligned***' scenarios. Three aligned scenarios (i.e. where supply, demand and infrastructure choices are aligned to each other) and two non-aligned scenarios are examined:

Aligned scenarios assume that supply and demand projections will align:

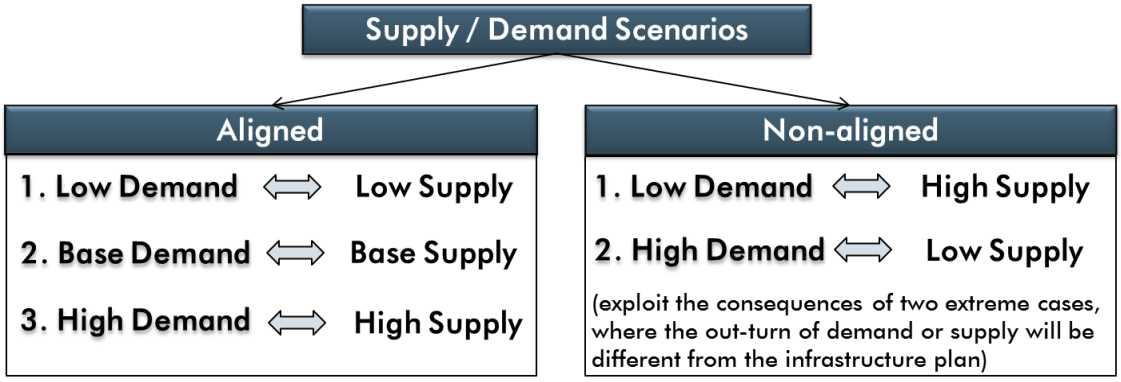
- ***Low case*** – assumes low demand and low supply
- ***Base case*** –assumes base demand and base supply
- ***High case*** –assumes high demand and high supply

Non-aligned scenarios assume that the actual outcome will be different from the planned outcome, i.e. high supply (and high infrastructure development) is expected, on the assumption the demand would also be high, but supply turns out to be low. Or conversely, when demand, supply and infrastructure are planned to be high, demand turns out to be low. There are two non-aligned cases:

- ***Non-aligned case with low demand*** –assumes low demand and high supply
- ***Non-aligned case with high demand*** –assumes high demand and low supply

The assumed scenarios are depicted in Figure 31 below.The state of the gas sector each scenario represents is explained in Figure 97 for the Aligned scenarios and in Figure 98 for the Non-aligned scenarios in the Annex A5.366.1.

Figure 31: Supply and demand scenarios



The aligned scenarios represent more stable states of the gas sector. On the other hand, the non-aligned scenarios exploit the *'bad forecasting'*consequences of two extreme cases combined with infrastructure investments premised on high demand. The Non-aligned cases are premised on an optimistic view being taken at the start, and potentially 'high' infrastructure being undertaken, but with the sector subsequently having to contend with a supply-demand mismatch due to either unexpectedly low demand or low supply. These two cases are designed to test the robustness of either the high infrastructure and supply plan, or the low infrastructure and supply plan. The different infrastructure plans and how they vary across demand/supply scenarios is discussed in Section 6.4.

5.3 Supply/Demand Balance

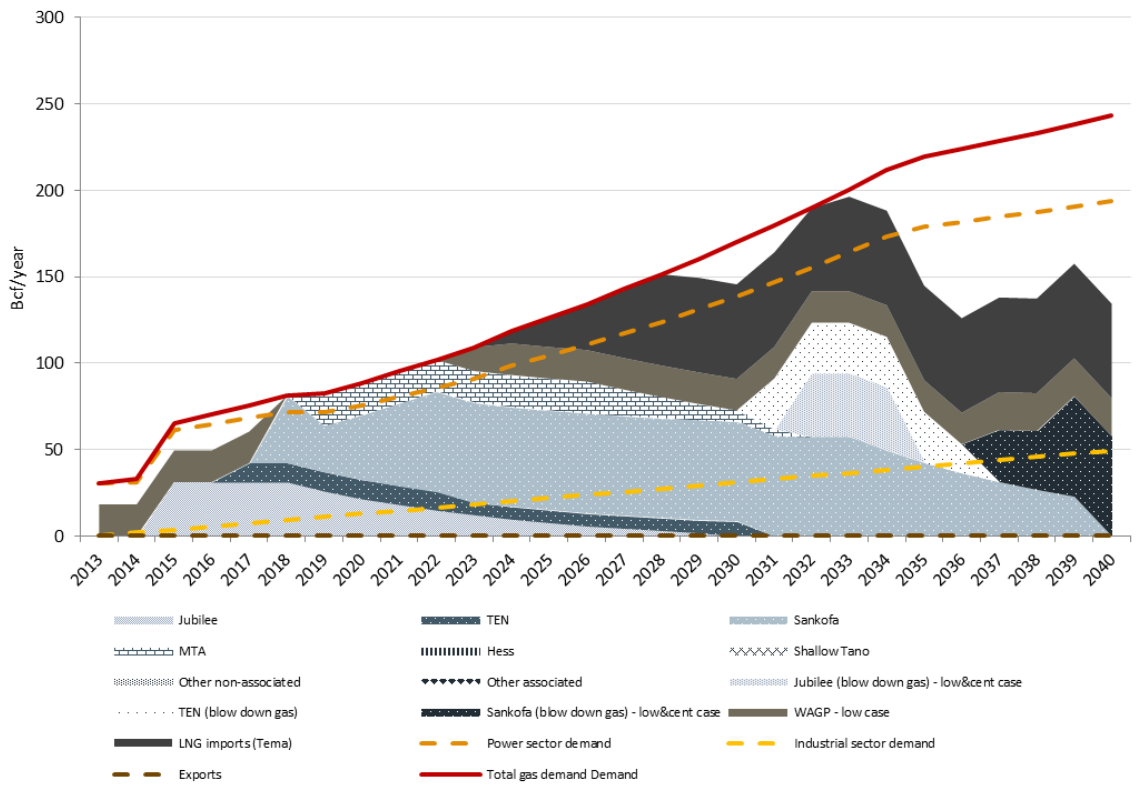
To balance the unconstrained demand with the available gas supply in the GMPM, the available gas supply options are ranked on the basis of the costs of production. The least cost supply option is utilised first. Available supplies within one year are restricted by the maximum available production of each field, the pipeline maximum throughput volumes or the maximum regasification capacity of LNG terminals. The total amount of gas that can be delivered over the years is restricted by the proven reserves of each field. The planning horizon discussed below covers the years between 2013 and 2040.

5.3.1 Low Case: Supply/Demand Balance

In the low case, it is assumed that the gas sector will develop at a lower rate constrained by the available gas supplies and the demand for gas. The supply and demand balance is presented in Figure 32. The shaded areas represent the total supply by source while the demand is shown by lines. The total demand is the red line, whereas the dotted lines represent the split between the power and the industrial sector.

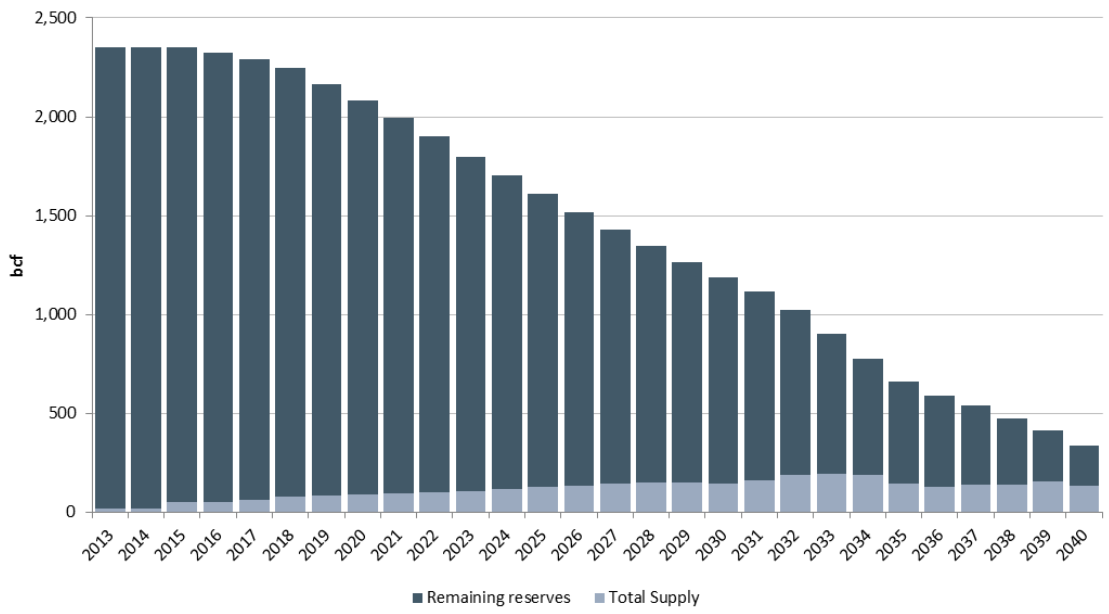
The results show that the WAGP supplies have not been adequate enough to meet the demand for gas for the past two years. The addition of the Jubilee field gas from 2015 will reduce significantly the unmet demand until 2018. From this point until 2026, the additional production from the TEN and the Sankofa fields will still not be sufficient to cover the unmet demand. This is in light of the recent installation of emergency plants which are mostly gas-fired. LNG imports will therefore be required to meet any shortfalls in demand. Meeting this demand from imports would require further investments in import infrastructure.

Figure 32: Low case: Supply/demand balance, *bcf per year*



The rate of the depletion of the domestic gas reserves following the utilisation of gas presented in Figure 32 is depicted in Figure 33 below.

Figure 33: Low case: reserves depletion, *bcf per year*



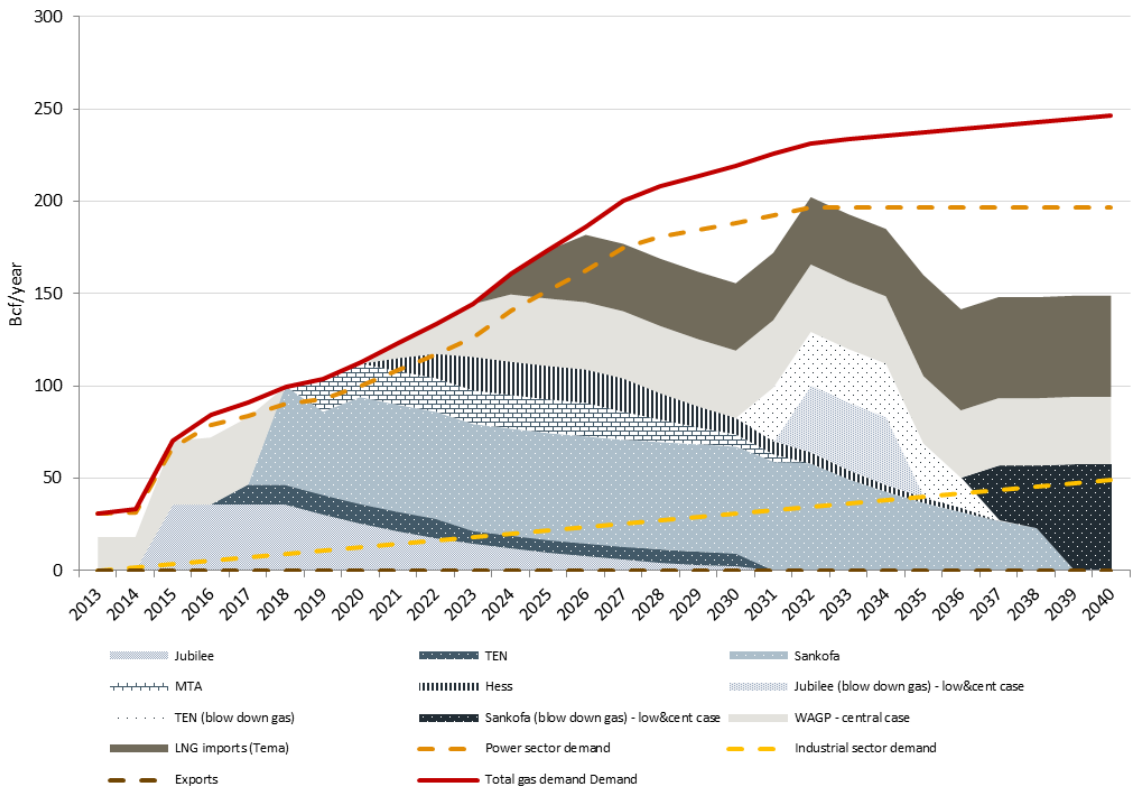
The reserve to production ratio in 2015 is 75 years, in 2020 it is 24 years and in 2030 it is 16 years.

5.3.2 Base Case: Supply/Demand Balance

The base case assumes a more stable development of the gas sector in Ghana, which lies between the low and the high case scenarios. Demand is growing at a faster rate in comparison to the low case scenario, however, gas supplies from the Hess field are also taken into consideration.

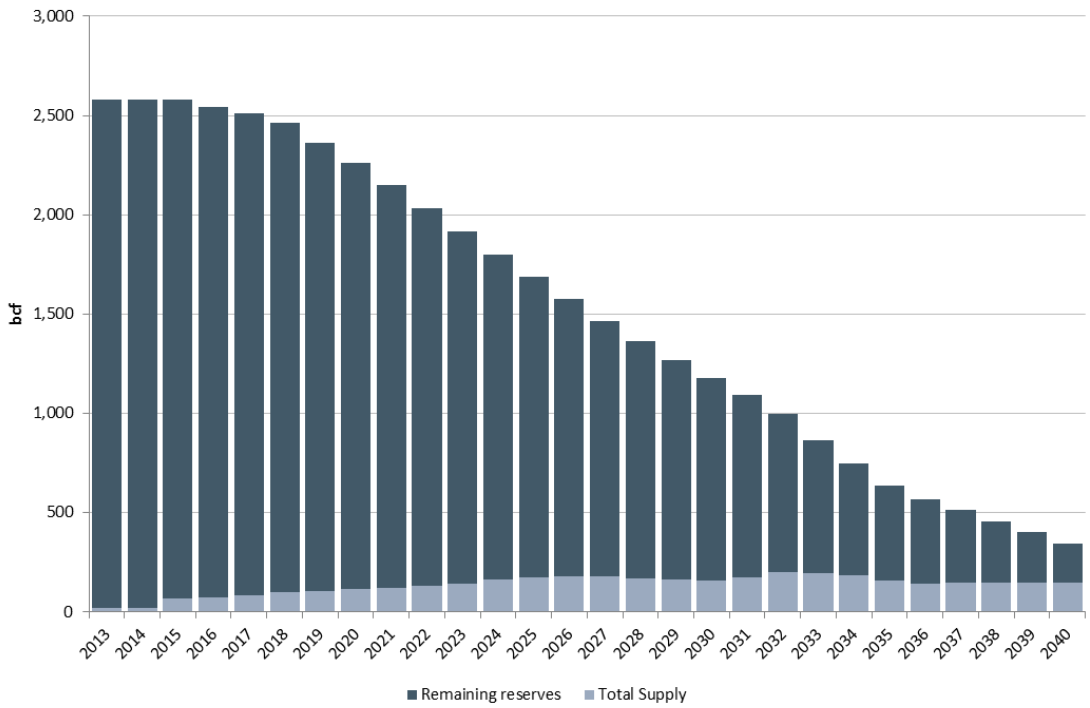
As shown in Figure 34, the available supply is insufficient to cover the total volumes of gas demand until 2018. Thereafter, the combination of the supply from the domestic fields and the WAGP is enough to cover the demand until 2023. The utilisation of the supply from the LNG terminal in Tema may start in 2023.

Figure 34: Base case: Supply/Demand balance, *bcf per year*



The reserve to production ratio is 72 years in 2015, 20 years in 2020 and 14 years in 2030. The reserves to production ratio decreases exponentially across the years as production rises and reserves fall. The depletion of the gas reserves is depicted in Figure 35 below.

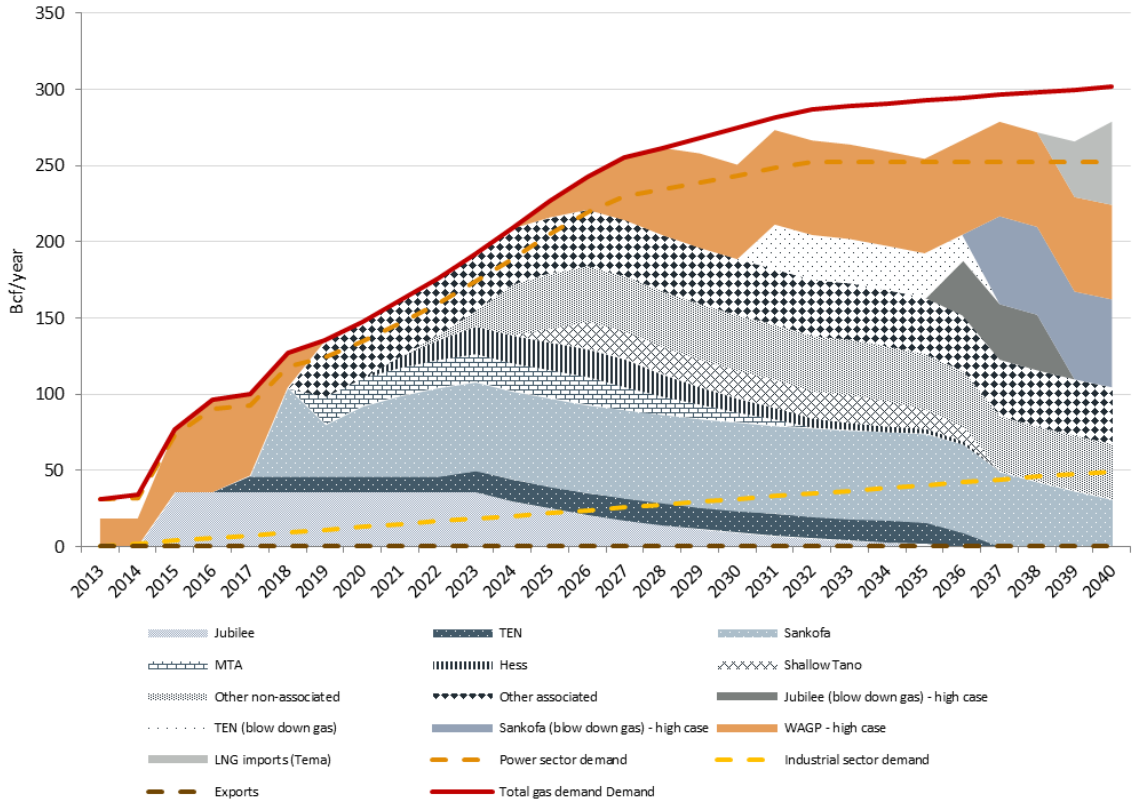
Figure 35: Base case: reserves depletion, *bcf per year*



5.3.3 High Case: Supply/Demand Balance

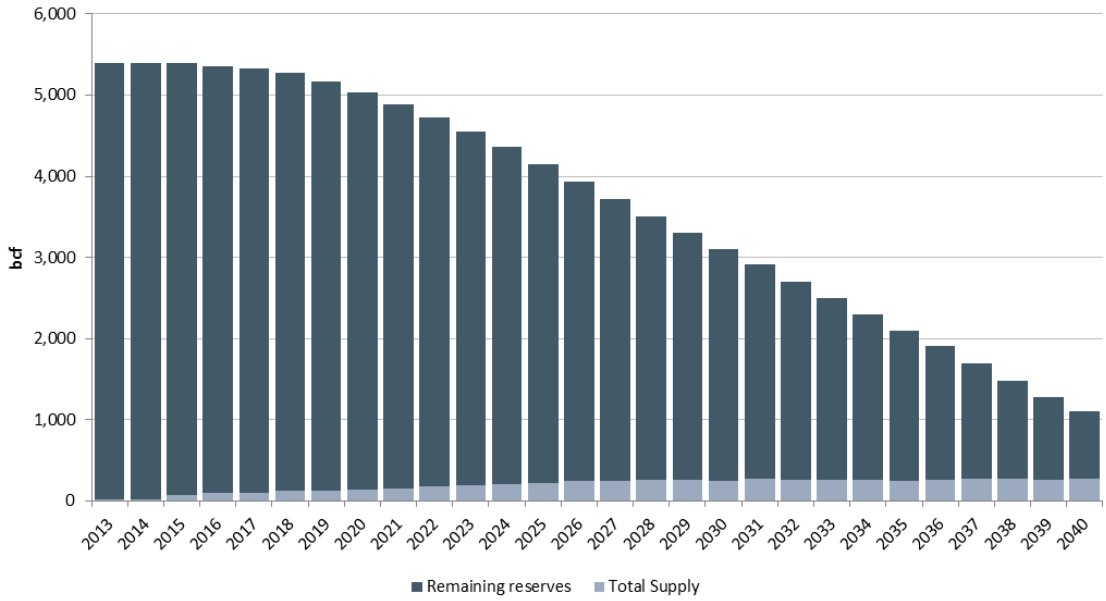
In the high case it is assumed that the gas sector will develop at a high rate with new available supplies and high increase in demand. The supply and demand balance is presented in Figure 36. The results show that the WAGP supplies are not enough to meet the demand for gas in the first two years. From 2015 until 2017 the demand is met from the supply of the Jubilee and the WAGP. In 2017, 2018 and 2019 the additional production from TEN, Sankofa and MTA fields will be sufficient to cover the demand.LNG imports are assumed to be available in 2037. However, the supply from the domestic fields and the WAGP is not enough to cover the demand from 2028.

Figure 36: High case: Supply/Demand balance, *bcf per year*



The rate of the depletion of the domestic gas reserves following the utilisation of gas presented in Figure 36 is depicted in Figure 37 below. The reserve to production ratio is 150 years in 2015, 34 years in 2020 and 16 years in 2030.

Figure 37: High case: reserves depletion, *bcf per year*

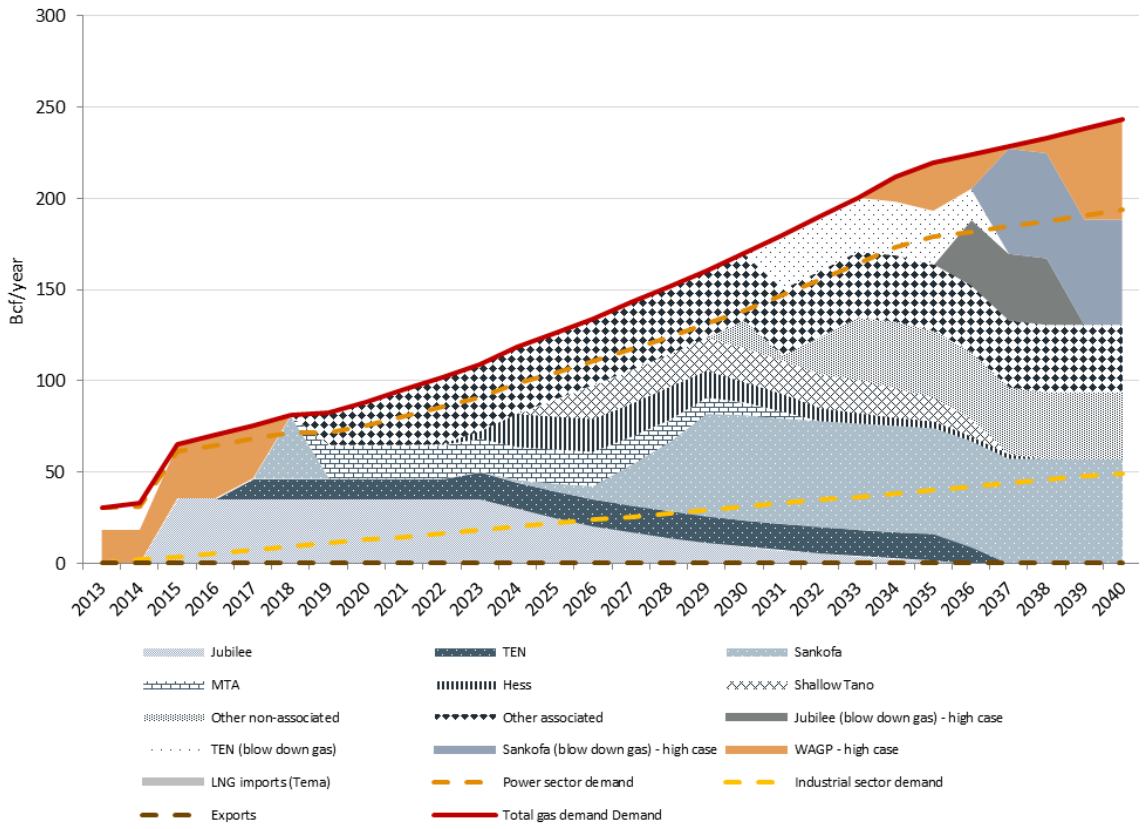


5.3.4 Non-Aligned Case with Low Demand/ High Supply

The non-aligned case with low demand assumes low demand, high supply and high infrastructure development. It is an optimistic view being taken at the start, and 'high' infrastructure being undertaken, but with the sector subsequently having to contend with a lower demand than expected. The supply and demand balance for the non-aligned case with low demand is illustrated in Figure 38 below.

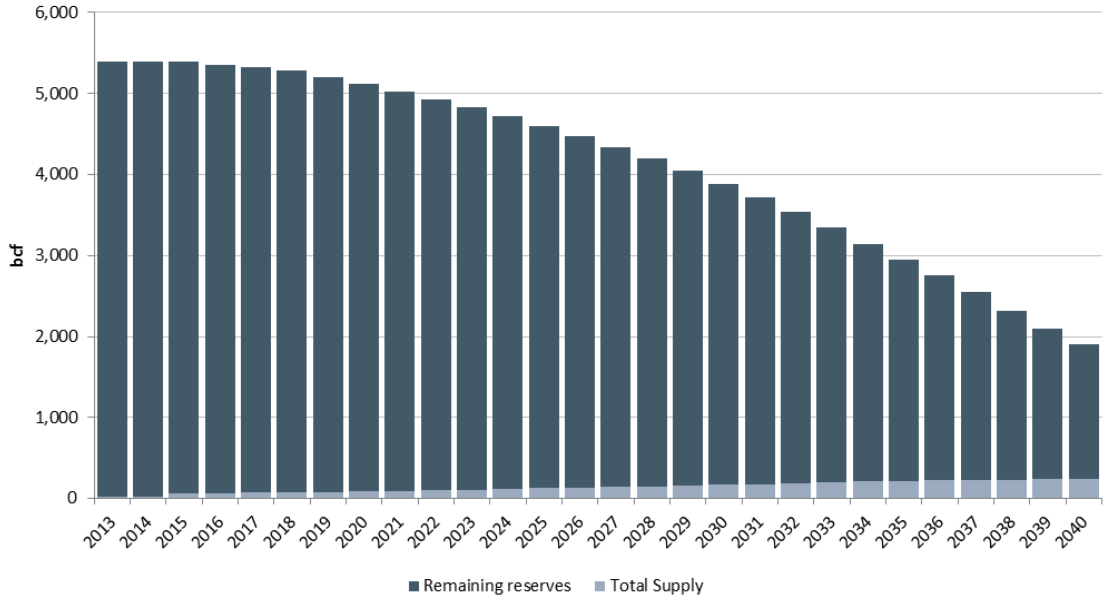
The supply from the WAGP and the domestic fields is not adequate to cover the full amount of gas demand until 2015; thereafter, the demand is totally met. The LNG terminal will be necessary after 2043. Until this year the demand can be supplied from the domestic fields and the WAGP.

Figure 38: Non-aligned case with low demand: Supply/Demand balance, *bcf per year*



The rate of depletion for the reserves is depicted in Figure 39. In this non-aligned case with low demand and high supply the reserves last for a longer period in comparison to the other cases examined. The R/P ratio in 2020 is 58 years and in 2030 close to 23 years.

Figure 39: Non-aligned case with low demand: reserves depletion, *bcf per year*

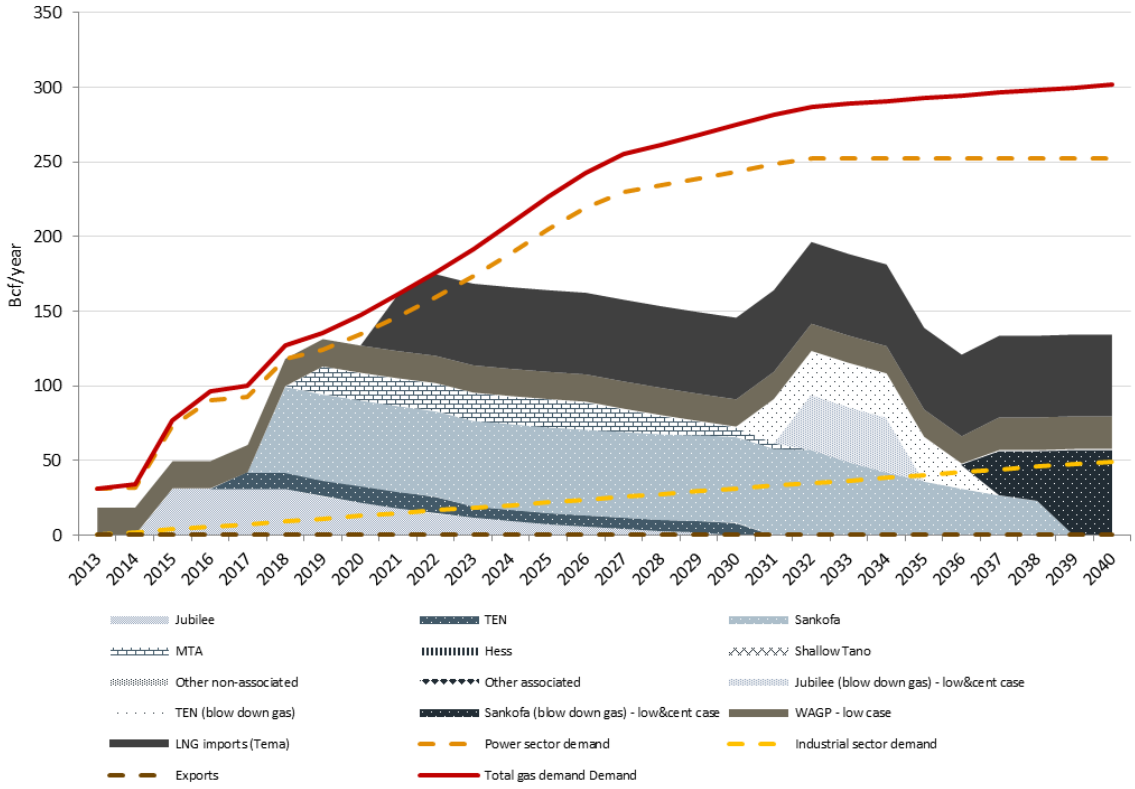


5.3.5 Non-Aligned Case with High Demand/Low Supply

The high demand – low supply case represents a case with an optimistic view being taken at the start, and 'high' infrastructure being undertaken, but with the sector subsequently having to contend with lower supplies than expected. The supply and demand balance for the non-aligned case with high demand is illustrated in Figure 40 below.

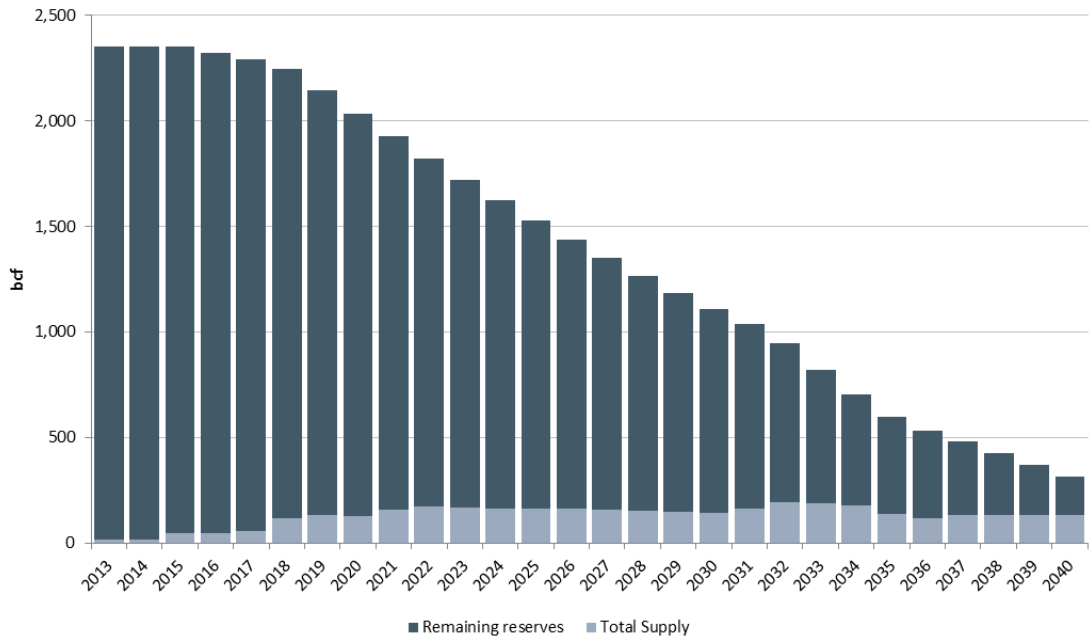
The demand volumes are the same with the high case scenario and the supply that is available is the same as the low case scenario. The available supplies are not enough to meet the demand until 2021, when the LNG terminal will be added to the system. The unmet demand is approximately 30% of the total demand during these years. Additional LNG terminals will be required after 2022 to cover the rising demand and the depleting reserves from the domestic fields.

Figure 40: Non-aligned case with high demand: Supply/Demand balance, *bcf per year*



The reserves to production ratios in this case are very small in comparison to the other cases. The R/P ratio in 2020 is 19 years and in 2030 is 2 years. Reserves are depleted at a faster rate due to the increased demand and the low supplies. The rate of depletion is illustrated in Figure 41 below.

Figure 41: Non-aligned case with high demand: reserves depletion, *bcf per year*



5.3.6 Supply/Demand Balance Comparisons

The following table summarises the supply and demand balance for the aligned and the non-aligned cases from 2013 until 2040 in present value terms. In all simulated cases the supply of the WAGP is not enough to meet the demand from the power sector and the industrial sector in the former years of the study (i.e. between 2013 and 2015). The domestic resources which will be available from 2017 and onwards are adequate to cover the total demand for gas until 2021 in all simulated cases. In 2021 the LNG terminal in Tema is expected to increase the available capacity in the system.

Table 13: Supply/demand balance: summary table (2013-2040)					
A1.61	**A1.62 Low case**	**A1.63 Base case**	**A1.64 High case**	**A1.65 Low demand – High supply**	**A1.66 High demand- Low supply**
A1.67 Max available supply capacity, A1.68 *bcf per year*	A1.69 123	A1.70 202.35	A1.71 283	A1.72 305	A1.73 123
A1.74 Supply from domestic fields, *bcf*	A1.75 752	A1.76 869	A1.77 1,480	A1.78 1,104	A1.79 792
A1.80 Supply from WAGP, *bcf*	A1.81 178	A1.82 301	A1.83 663	A1.84 134	A1.85 220
A1.86 Supply from LNG, *bcf*	A1.87 239	A1.88 156	A1.89 18	A1.90 0	A1.91 305
A1.92 Total supplied demand, *bcf*	A1.93 1,095	A1.94 1,327	A1.95 2,257	A1.96 1,238	A1.97 1,317
A1.98 Unmet demand, *bcf*	A1.99 169	A1.100 219	A1.101 84	A1.102 26	A1.103 603
A1.104 Total demand, *bcf*	A1.105 1,264	A1.106 1,546	A1.107 1,954	A1.108 1,264	A1.109 1,919
A1.110 Years of unmet demand	A1.111 2013-2017, 2029-2040	A1.112 2013-2017, 2026-2040	A1.113 2013-2014, 2029-2040	A1.114 2013-2014	A1.115 2013-2020, 2021-2040
A1.116 First year of LNG requirements	A1.117 2024	A1.118 2024	A1.119 2029	A1.120 >2040	A1.121 2021
A1.122 R/P ratio in 2025 (years)	A1.123 18	A1.124 15	A1.125 19	A1.126 36	A1.127 6
A1.128 Depletion of domestic reserves (year)	A1.129 >2040	A1.130 >2040	A1.131 >2040	A1.132 >2040	A1.133 2043

6 GAS INFRASTRUCTURE

The gas infrastructure plan is derived by addressing the five key policy questions. As a first step, however, the Plan presents the existing gas infrastructure and GoG's current plans for gas infrastructure development.

6.1 Existing Infrastructure and Short Term Plans

The last gas infrastructure plan that proposed gas transmission and distribution infrastructure dates back to 2007[19]. This has become outdated, and therefore been updated in this Gas Master Plan

This GMP provides a road map for Ghana's long term infrastructure development. The following gas infrastructure currently exists in Ghana:

1) The **Western Corridor Gas Infrastructure Development Project (WCGIDP)**,is a project to bring the gas discovered at the Jubilee offshore gas field to the Ghana market. The Project achieved Mechanical Completion in late 2014 and started Commercial Operations in 2015. The WCGIDP infrastructure is composed of the following components :

    i. **Jubilee- Atuabo offshore gas gathering pipeline** – This is a 12 inch diameter, 59 km offshore pipeline from the Jubilee oil& gas field's FPSO to the Atuabo Gas Processing Plant. The pipeline has a deep sea portion of 14km, and shallow water component of 45 km. This pipeline brings raw gas from the Jubilee field for processing onshore at the Atuabo Gas Processing Plant. Completed in 2013, the pipeline is owned and operated by the GNGC.

    ii. **Atuabo Gas Processing Plant –** the plant has a design capacity to process 150 mmscfd of raw gas, into lean gas, and Natural Gas Liquids (LPG and Condensate). The plant has been designed and constructed by SINOPEC International, and is owned and operated by the GNGC. Project construction started in 2012 and the plant achieved mechanical completion in November 2014, and commercial operations in May 2015.

    iii. **Atuabo – Aboadze onshore transmission pipeline** – This is a 20-inch diameter, 110km onshore gas transmission pipeline to bring the lean sales gas from Atuabo to Power plants at Aboadze. This pipeline, completed in 2013, has a design capacity of 400 mmscfd. Currently, the pipeline is owned and operated by the GNGC.

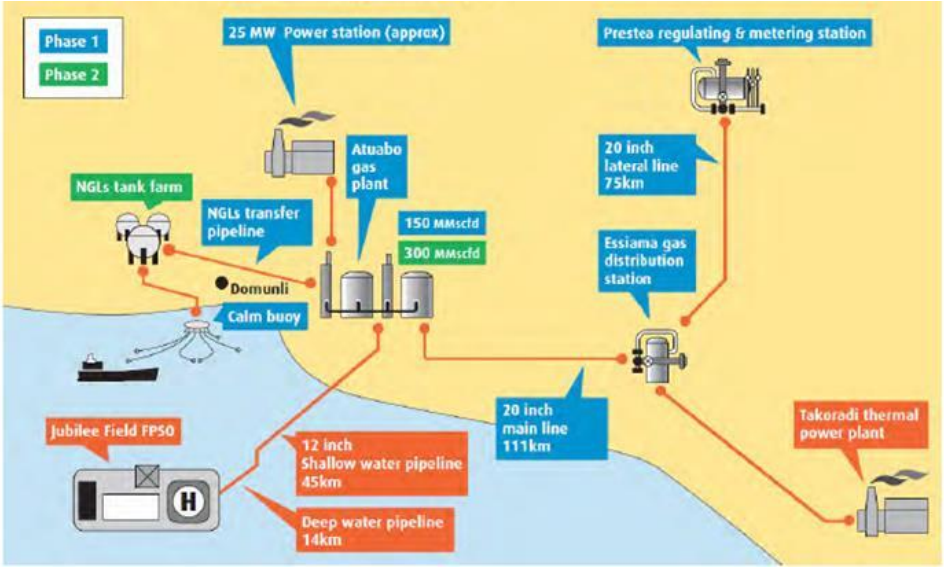
    iv. **Associated gas infrastructure for metering and distribution –** this includes an Initial Station at Atuabo, a Distribution Station at Esiama (the start of the branch line to Prestea) and a regulating and metering station at Takoradi.

[19] *Natural Gas Transmission and Distribution Infrastructure Plan for Ghana*, Energy Commission, August 2007

v. **Esiama-Prestea lateral pipeline, regulating and metering station –** this is a 20 inch diameter 75 km long lateral pipeline connecting Essiama to Prestea.

The Western Corridor Gas Infrastructure project is depicted in **Figure 42** below.

Figure 42: Components of the Western Corridor Gas Infrastructure Project



The Onshore Gas Transmission Pipeline and Metering Systems have been designated as the National Integrated Gas Infrastructure System (NGITS).

- **West African Gas Pipeline (WAGP) –**

The WAGP is a 691 km long offshore pipeline starting from Nigeria and ending in Ghana, with landing points in Cotonou (Benin), Lome (Togo), Tema and Takoradi. The pipeline was completed in 2009, and delivers gas from Nigerian sources. The first segment of the pipeline is onshore in Nigeria with a diameter of 30 inches and the second segment is offshore with a diameter of 20 inches. At full capacity and without compression, the pipeline can deliver 170 mmscfd. The maximum deliverability is 430 mmscfd, requiring additional compression. Contracted capacity for Ghana is 123 mmscfd, however, it should be noted that, to date, WAGP has failed to deliver the contracted quantity consistently. With the development of the WCIDP, the gas demand in the Western Corridor is largely being met by indigenous gas. The flow of Nigerian gas has practically been restricted to Tema, with the Tema-Takoradi section of the WAGP remaining largely unutilised. This has opened the possibility of using this section of the WAGP to reverse flow surplus gas in Western Corridor to feed the Eastern Corridor demand centres. The GoG has already approved the NGITS-WAGP inter-connection project, which shall be completed in 2016.

Proposed LNG regasification terminal –

Due to a potential shortage of gas supply to meet local demands, the GoG is currently considering the development of a regasification facility. With funding from the Millennium Challenge Corporation (MCC), a pre-feasibility study was completed in 2014 to determine the size and location of a potential LNG import terminal. Seven sites were investigated in the study. The sites of Tema and Aboadze scored highly in

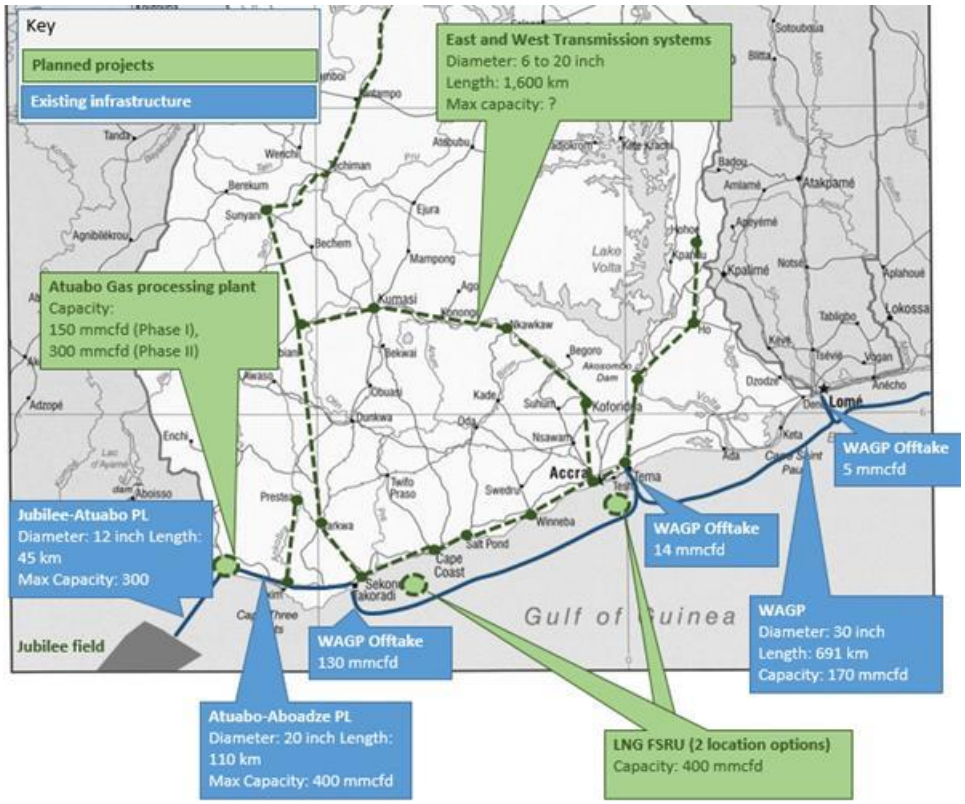
the evaluation process and are considered viable options for location of the facility. The facility investigated in the Report is a Floating Storage and Regasification Unit (FSRU) to ensure lower costs, smaller size and added flexibility as compared with a fixed on-shore facility. The capacity of the regasification terminal was preliminarily established at between 250 and 400 mmscfd in the Report.

Transmission and distribution systems–

As planned in the Energy Commission's Gas Transmission and Distribution Plan 2007, two systems should be developed. Firstly, the NGITS should be expanded from Takoradi to Tema and cover all main population centres in that corridor. Secondly, a distribution network between Tema and Accra would serve all major industrial and commercial offtakers in those regions. The costs were estimated at US$636 million in 2007. These recommendations were based on the assumption of sufficient gas supplies from WAGP. Recent supply interruptions, less than contracted WAGP supply volumes and the discovery of significant domestic reserves, imply that this infrastructure plan is not necessarily applicable anymore. We nevertheless use this as a starting point for our infrastructure recommendations.

The existing and the planned infrastructure components of the gas transmission system in Ghana are presented in **Figure 43** below.

Figure 43: Components of the Western Gas Corridor project under development



Source: ECA and GoG publications

6.2 Approach for Gas Infrastructure Analysis

The review of existing and planned gas infrastructure has already highlighted the possible gasification options available to Ghana. In this sub-section a suitable infrastructure plan is recommended on the basis of the following 4 step approach:

Step 1: assessing regional demand and supply balances and identifying 11 different gas pipeline options.

Step 2: identifying five key policy questions of medium to long term interest for balancing demand and supply across the country.

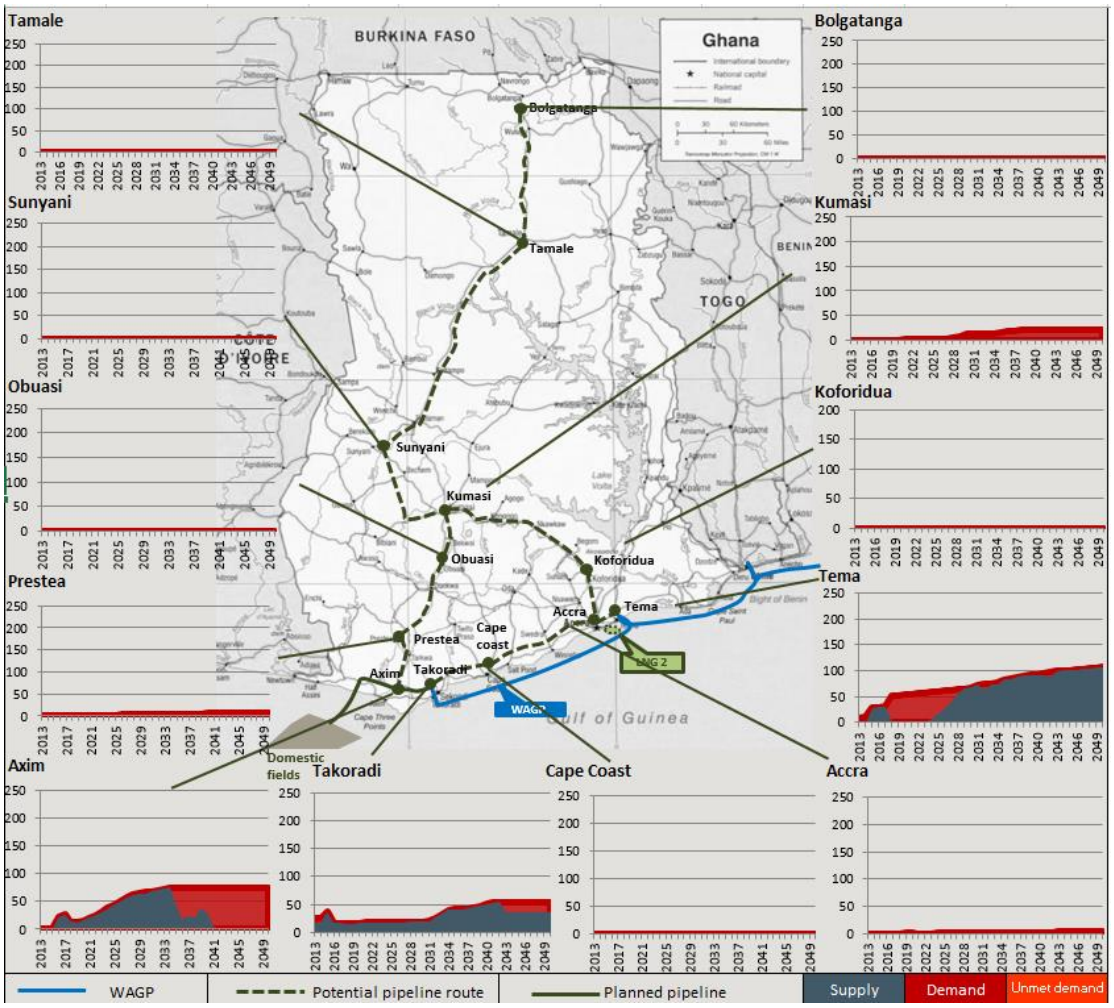
Step 3: assessing, for each policy question, which infrastructure option yields the highest economic value, lowest impact on the cost of delivered gas and provides the highest level of security of supply. This will be done in relation to the five demand and supply scenarios presented in Section 5.

Step 4: on the basis of the results of analysis of each policy question, e the results are combined to recommend on the most feasible infrastructure plan.

6.2.1 Supply/Demand Balances and Key Policy Questions

To analyse the infrastructure plan, the demand and supply volumes were broken down into separate regions representing clusters of demand and supply centres. The twelve identified demand clusters are depicted in **Figure 44** for a Base Case demand and supply scenario. The initial supply flows start from Axim for the domestic fields, from Takoradi and Tema for the WAGP and only from Tema for the LNG terminal[20].

Figure 44: Demand and Supply Clusters



The analysis shows that the majority of demand in the short, medium and long term is clustered around Domunli, Takoradi, Tema and Kumasi. Areas of considerably smaller potential demand but with high potential for industrial offtakes are Accra and Prestea. The map also shows that three supply points exist: Tema (LNG and WAGP), Domunli (domestic gas production) and Takoradi (WAGP).

The key priority of the proposed infrastructure plan is to balance the main supply points with the main demand centres. This will determine the capacity, year of construction and investment requirements.

On the basis of existing plans and supply/demand balances eleven potential pipeline options connecting the demand clusters have been identified. These are also shown in **Figure 44** by a green dotted line. The 11 pipelines considered are:

1. Tema – Accra (30 km)
2. Accra – Cape Coast (130 km)
3. Cape Coast – Takoradi (66 km)
4. Accra – Koforidua (70 km)

5. Koforidua – Kumasi (186 km)
6. Domunli – Prestea (87 km)
7. Prestea – Obuasi (120 km)
8. Obuasi – Kumasi (57 km)
9. Kumasi – Sunyani (140 km)
10. Sunyani – Tamale (304 km)
11. Tamale – Bolgatanga (158 km)

Besides gas pipelines, the following gas infrastructure options are considered in the analysis:

1. a reverse flow on WAGP
2. an LNG regasification terminal located offshore in Tema.

From the existing infrastructure and the assessment of regional supply and demand imbalances, the following questions have been identified to be of major importance for GoG:

- Is an onshore pipeline between Tema and Takoradi preferable to a reverse flow arrangement on WAGP? Or will both be needed?
- Should Kumasi be connected by pipeline to Tema or Takoradi or both?
- Is demand in the north of Ghana high enough to warrant a gas pipeline connection (rather than rely only on power transmission)?
- Should Kumasi be connected by pipeline or power transmission?
- What capacity is needed for an LNG terminal and when will it be needed?

The first question is evidently the most important one in light of the imbalances of demand and supply between the regions of Tema and Takoradi and this is therefore the starting point of the analysis.

6.2.2 Comparators and Scenarios used in the Analysis

Each of the five policy questions has a small number of possible infrastructure options (usually two). The indicators to compare the options and reach a conclusion on the most feasible option are:

- Changes in economic value and unmet demand
- Total investment requirements
- Changes in gas transmission tariffs
- Qualitative factors

The concepts and the methodology for each option are described below.

Economic Value and Unmet Demand

The economic value of gas is determined by the following

> ***Direct economic value*** of supplying the quantities defined under each scenario to each sector based on its netback value for gas
>
> ***Indirect economic value***, using linkage multiplier effects

For a given level of demand, each sector will have a maximum economic value of gas supply equating to the highest price the sector is willing to pay. The netback analysis described in Section 2.2 is used to estimate these maximum values. The economic analysis estimates the added ***direct economic value*** of supplying the quantities defined under each scenario to each sector. It does this:

> Firstly, by assuming domestic supply occurs at the minimum wholesale supply price which is calculated using the gas supply costs in Section 3.5 and the associated infrastructure costs of each scenario.
>
> Secondly, for each gas consuming sector/activity, the difference between the maximum price that activity would pay for gas (represented by its netback value) and the cost of supply (represented by the cost of gas plus the cost of transportation) reflects the surplus economic value.
>
> Thridly, these values are summed over all activities and years (discounted) to give an estimate of the total economic value of the gas for that scenario.
>
> Unmet demand is valued at international LNG prices in the economic valuation.

Doing this for each option and policy question will provide a comparative measure of the relative economic value created by the respective gas allocation policies.

The indirect economic value of gas for each sector can be calculated through a multiplier. However due to a lack of adequate and precise data, the analysis is focused on the direct economic value. A more detailed description is provided on the multiplier effect in Annex A5.366.3.

Total Investment Requirements

The total investment requirements are the sum of CAPEX for the infrastructure options scaled by throughput volume requirements. Details of the assumptions on infrastructure CAPEX are provided in Annex A5.261.1.

Gas Transmission Tariff

The transportation costs are calculated using Discounted Cash Flow (DCF) method and they include:

- the capital costs of the pipeline infrastructure
- the operating cost of the pipelines,
- the cost of the gas losses and

- the costs associated with taxation.

The transportation tariff is assumed to be a uniform tariff for all consumers as discussed in the general principles of gas pricing in Ghana[21]. The infrastructure costs for the calculation of the transportation tariff are analysed for each scenario in section 6.3. The forecasted consumption used for the tariff calculations is presented in the Supply/Demand balance in Section 5.2. Additional levies or other types of additional charges are not included in the calculations. The transportation tariff is calculated assuming a 15% internal rate of return.

Qualitative Factors

For each policy question, a brief description of the major qualitative factors that cannot be captured in economic value, investment costs or transmission tariffs is provided. These will mainly include considerations for security of supply and access to gas offtake along the proposed gas pipeline routes.

Demand/Supply Scenarios used in Infrastructure Analysis

For each policy question, these factors are assessed along five main demand and supply scenarios. These are described in Section 5.2 and include:

Aligned scenarios:

- **Low case –**low demand and low supply
- **Base case –**base demand and base supply
- **High case –**high demand and high supply

Non-aligned scenarios:

- Non-aligned case with low demand –low demand and high supply
- Non-aligned case with high demand –high demand and low supply

6.3 Results of Infrastructure Analysis

This sub-section presents the results of the infrastructure analysis along each of the five key policy questions outlined above.

6.3.1 Onshore Pipeline vs. Reverse Flow on WAGP

The most important short term gas infrastructure question for Ghana is whether to develop an onshore pipeline between Tema and Takoradi. The pipeline would connect the main western supply region of the country with a major existing potential demand region (Tema and Accra). Additionally, possible gas demand along the coast could be met with the development of the pipeline.

[21]USAID, 2014, USAID Technical Assistance to Ghana PURC on Natural Gas Tariff Setting Final report.

The planned pipeline would run parallel to WAGP as shown in **Figure 45**. With the possibility of having reverse flow arrangements on WAGP ensuring gas flows from west to east. The question whether the onshore pipeline, the reverse flow arrangement or both are required, needs to be addressed. To do so, three scenarios are compared:

- Only reverse flow[22] on WAGP – available in short term
- Only onshore pipeline without reverse flow on WAGP – available in medium term
- Both onshore pipeline as well as reverse flow on WAGP – available in short to long term.

Figure 45: Route and Location of Tema - Takoradi Pipeline

As noted above, each of the three scenarios along the main quantitative comparators is assessed:

- Impact on economic value,
- Impact on gas transmission and
- Investment requirements.

The results of the simulations are shown in Table 14 and the lowest cost/highest benefit option under each comparator highlighted. It should be noted that in this section, focus is placed on the question of whether one infrastructure option is required over another. The year of development, capacities and costs are elaborated in more detail in Section 6.4.

[22] This option is currently being pursued

Table 14: Onshore vs. WAGP Reverse Flow Results									
D/S Scenarios	**Economic value** *US$ billion*			**Gas transmission tariff** *US$/mmbtu*			**CAPEX** *US$ million*		
	RF	**Onshore**	**RF & Onshore**	**RF**	**Onshore**	**RF & Onshore**	**RF**	**Onshore**	**RF & Onshore**
Aligned Low	15.9	16.3	16.3	0.87	0.76	0.76	20	299	319
Aligned Base	20.7	21.1	21.1	0.69	0.60	0.60	20	299	319
Aligned High	32.5	33.0	33.0	0.58	0.50	0.50	20	326	346
Non-aligned LowD	23.3	23.2	23.2	0.58	0.75	0.75	20	326	346
Non-aligned HighD	19.2	18.9	18.9	0.58	0.66	0.66	20	326	346

Besides the CAPEX and economic value assumptions outlined in different parts of this document. It is assumed that:

- Compressor costs of a reverse flow arrangement would be about US$20 million. It is difficult to know the precise costs without the technical parameters of WAGP, so a standard cost of compression is assumed. Further details for the compressors capital costs are included in Annex A5.261.1.

- The transmission tariff for reverse flow is currently set at a level of US$4.17/mmbtu reflecting the cost for the transportation of gas from Nigeria to Ghana. It is unlikely that the tariff would remain that high for a reverse flow arrangement. The reverse flow would use only a section of the WAGP from Tema to Takoradi and would require a compressor station.

It is expected that a potential gas off-taker would be willing to pay a tariff for the reverse flow on the WAGP within the range of the gas postage tariff in Ghana. With a credible alternative pipeline connection between Tema and Takoradi, the tariff cannot vary significantly from the postage tariff. It should be noted that, until the construction of a dedicated onshore pipeline from Takoradi to Tema, the WAGP will be in an advantageous position to negotiate a higher tariff for the reverse flow on the WAGP. For the scenario where the supply to Tema is available only from the reverse flow on the WAGP, it is assumed that the tariff will be 15% higher in comparison to the postage tariff including only the dedicated onshore pipeline. For the scenario which includes both the onshore pipeline and the reverse flow on the WAGP, it is assumed that the postage tariff will apply. The split of the revenues from the postage tariff will have to be negotiated between the TSO and the WAGP.

The results in the table are split between the three scenarios outlined above:

(i) the onshore arrangement

(ii) the reverse flow arrangement

(iii) both the onshore and reverse flow arrangement

The onshore pipeline and the combined scenario of onshore pipeline and reverse flow arrangement each results in the highest economic value and lowest transmission tariffs in

the aligned supply/demand cases. For the non-aligned cases, the reverse flow arrangement seems to have the smallest impact on transmission tariffs and the greatest impact on economic value (although minimal). The lowest CAPEX numbers are, as expected, for the reverse flow arrangement.

The combined reverse flow and onshore arrangements result in the same economic value and the same transmission tariff as the onshore section on its own. While the CAPEX is highest for this option, it is still considered the best available investment option. This is also due to factors that cannot be captured in the quantitative analysis. These factors include:

- **Reverse flow on WAGP is a short term measure** to alleviate the immediate supply concerns in Tema. This option could be available as early as 2016, which is considerably earlier than a realistic commissioning date of any regasification terminal in Tema or an onshore gas pipeline. Hence, reverse flow on WAGP is the most feasible short term option to supply eastern demand centres.

- **Reverse flow on WAGP requires very low investment costs**. This together with the current underutilisation of WAGP and subsequent interest of WAGP developers to allow for more gas would make this project feasible and quickly implementable.

- **Developing the onshore pipeline would ensure security of supply** in the medium to long term. As recent events have shown, WAGP can get damaged, interrupted or blocked for various reasons outside of Ghana's control. Having an alternative supply route in the medium term to supply demand-centres in the east is therefore crucial. Assuming an interruption on the WAGP of 1 year for a volume of 75 mmscfd, the loss in economic value would be close to US$240 million. This compares to an additional investment of close to US$50 million if only the onshore pipeline were to be developed.

- Developing the onshore pipeline simultaneously with the reverse flow option would apply **competitive pressure on the WAGP** developers to offer a more competitive transmission tariff, instead of the current very high US$4.15/mmbtu.

- Developing the onshore pipeline would enable the **delivery of gas to potential customers** along the coast line, which is the main reason for the scenarios having the highest economic value in **Table 14**.

The security of supply benefits considerably outweigh the relatively high CAPEX associated with developing both supply options.

The results show that both the reverse flow as well as the onshore pipeline is needed. While the WAGP reverse flow arrangement will alleviate short term supply concerns in the eastern demand regions, the onshore pipeline provides (i) medium to long term security of supply, (ii) competitive pressure on WAGP to offer lower transmission tariffs, and (iii) supply to off-takers along the coast. The result of this strategy might be a US$20 million higher initial investment costs, but a secure supply route and therefore higher potential of gasification of the country.

6.3.2 Kumasi Gas Connection

In light of the results from Section 6.3.1, there are two pipeline options to connect the town of Kumasi, the major demand centre in central Ghana: (i) a western connection from Accra via Koforidua to Kumasi (256 km), and (ii) an eastern connection from Essiama via Prestea and Obuasi to Kumasi (135 km).

To investigate which connection has the least cost and the highest economic value, three scenarios were assessed:

Option 1: Connection of Kumasi to Accra

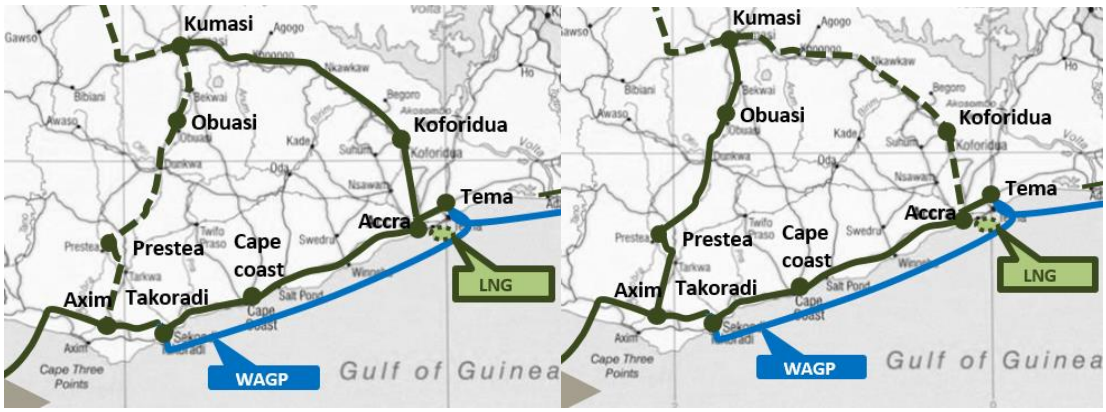
Option 2: Connection of Kumasi to Essiama

Option 3: Connection of Kumasi with both Accra and Essiama

Option 1 and Option 2 are shown in **Figure 46**.

Figure 46: Two Scenarios to Connect Kumasi

Option 1: Accra-Kumasi *Option 2: Axim-Kumasi*



The results of the analysis and the impact for each of the three options are shown in **Table 15**. The comparison across the three scenarios is done along the same three measures as previously, i.e. economic value, gas transmission tariffs and investment costs.

Table 15: Kumasi Gas Connection									
D/S Scenarios	**Economic value** *US$ billion*			**Gas transmission tariff** *US$/mmbtu*			**CAPEX** *US$ million*		
	Accra (Option 1)	**Essiama**(Option 2)	**Accra& Essiama**	**Accra** (Option 1)	**Essiama**(Option 2)	**Accra & Essiama**	**Accra** (Option 1)	**Essiama**(Option 2)	**Accra & Essiama**
Aligned Low	16.0	16.2	15.8	0.95	0.95	1.15	379	392	472
Aligned Base	20.7	20.9	20.4	0.76	0.76	0.92	379	392	742
Aligned High	33.2	33.4	32.9	0.64	0.64	0.78	420	434	528
Non-aligned LowD	23.5	24.0	23.4	0.94	0.94	1.14	420	434	528
Non-aligned HighD	18.4	18.5	18.0	0.85	0.85	1.04	420	434	528

The results show that the individual segments between **Essiama** and Tema yield higher economic benefits, result in lower transmission costs and require lower investment costs than the combination of both. Unlike in the analysis on reverse flow or onshore pipeline between Tema and Takoradi, the combined option here (Option 3) is not the preferred option. This is for the following reasons:

- The impact on gas transmission tariffs for both pipelines is significant and could have reduced downstream demand. The benefits are uncertain, as potential demand along these routes would be small. This would not warrant the construction of two northern pipeline connections.

- Security of supply benefits of developing both pipelines is not significant. With the development of the onshore pipeline between Tema and Takoradi and the reverse flow agreement on WAGP, Takoradi/Essiama as well as Tema/Accra will have two supply points: WAGP and domestic sources. Developing both pipelines to Kumasi would therefore not 'open up' a new supply route or source to Kumasi. One pipeline would be sufficient to provide Kumasi with access to diversified supply sources. Both pipelines are only needed to provide security of supply to Kumasi if one of the pipelines is interrupted.

- Potential demand levels along the pipeline routes are relatively small compared to the significant capital costs of the pipelines. There is therefore no immediately clear reason for developing the pipelines for other reasons than supplying gas to Kumasi.

Of the two individual segments the Essiama connection is marginally more attractive than the Accra connection. Although, the connection is longer and therefore would require higher capital costs, it is a preferred option for gasification purposes. Potential demand for gas is higher and more clustered in Prestea and Obuasi than in Koforidua. The final investment decision would however depend on a more detailed feasibility study of the terrain and the associated costs.

It is important to note that the impact on final gas prices of developing the Essiama-Kumasi connection is significant. At a transmission tariff of between US$0.64 /mmbtu and US$0.95 /mmbtu, the delivered gas price would be high and could choke off part of potential

demand. A comparison is made in Section 6.3.4 on the feasibility of gas based electricity generation in Kumasi as opposed to supply of electricity to Kumasi from the coast via transmission lines.

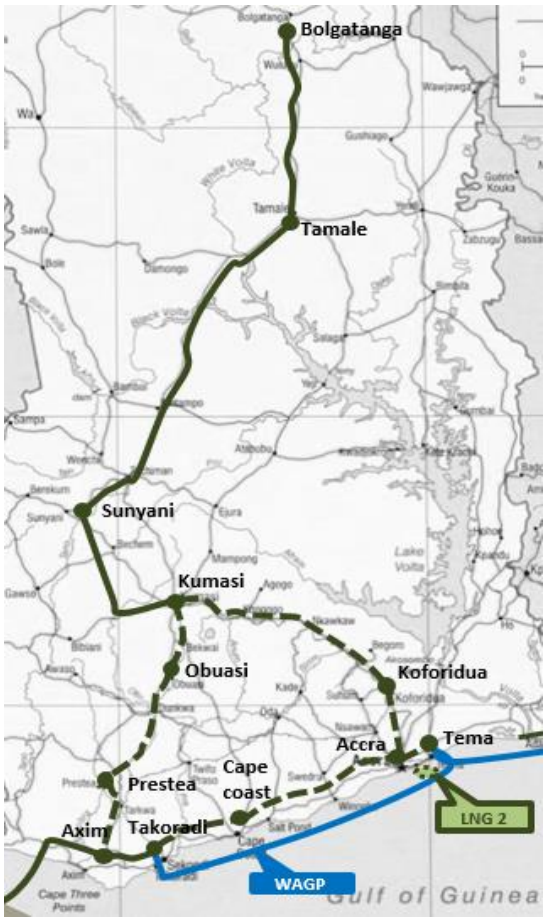
6.3.3 Gas Connections to Northern Ghana

The analysis has so far shown that the country needs an onshore pipeline connecting Tema to Takoradi, a reverse flow arrangement on WAGP and potentially a pipeline connecting Prestea to Kumasi. The last pipeline section is however costly and an assessment is made in the next sub section, whether this could be replaced by a power transmission line.

An interesting follow-on question from the gas pipeline connection to Kumasi is whether a further northbound connection is viable. Following major urban centres and past transmission expansion plans, connections from Kumasi via Sunyani and Tamale to Bolgatanga are considered. These are in effect three pipeline segments with a length of 140 km (Kumasi-Sunyani), 304 km (Sunyani-Tamale) and 158 km (Tamale-Bolgatanga) totalling about 600 km. The considered pipeline route is shown in Figure 47.

Assuming an 18 inch diameter, this would come at an investment cost of US$650 million. This is a significant investment. Given that gas demand in the northern regions, at least, until 2030 is expected to be negligible due to very low industrial activity, lack of planned power generation and major petrochemical or heavy industry plants mean that potential gas demand in the region would be small. This would not be a cost effective proposition at least for now.

Figure 47: Pipeline Route Northward from Kumasi



Very low throughput volume and high capital cost mean that the postage stamp transmission tariff in a scenario where the connections Tema-Takoradi, Prestea-Kumasi and Kumasi-Bolgatanga are developed would rise to US$2.2 /mmbtu from US$0.8/mmbtu without the northern connection... Note that this is the lifetime transmission tariff, i.e. a cost recovery tariff over the life of the pipeline and therefore likely to be an underestimate of the true initial tariff paid. To attract investors to gas transmission projects, tariffs are likely to be considerably higher at early stages of operation to recover the initial high financing requirements of these projects. . Only if gas fired power generation plants or large scale industrial plants requiring gas as a heating source (additional to those already planned in the rest of the country) are developed along the route, might the economics of the pipeline be improved.

6.3.4 Gas Pipeline vs. Power Transmission for the Power Sector

This sub-section addresses the question of whether gas pipelines are needed beyond the minimum coastal sites or whether the electricity transmission grid should be strengthened instead of developing the gas pipelines. The focus here is on the merits of power versus gas transmission for the two recommended gas pipeline segments:

Takoradi – Tema pipeline

Prestea – Kumasi pipeline

The Takoradi-Tema gas pipeline has been recommended above for its security of gas supply benefits to the east and the ability to meet gas demand along the coast. With the significant existing gas demand from power plants in Tema, a secure *gas supply* is needed. If this is not the case, the existing power plants would either be idle or run on expensive fuel oil. It is therefore clear that a gas pipeline between Tema and Takoradi cannot be replaced by power lines if the power plants located in Tema are to be operational.

The argument is less clear for the Prestea-Kumasi pipeline section. The recommendations for this pipeline section were based on small demand volumes and no existing anchor load, i.e. no existing gas fired power plants. This means that there is no sufficient existing capacity to warrant a gas pipeline construction. Hence, there is no direct reason for excluding the possibility of having a power transmission line instead of a gas pipeline. On the contrary, the demand volumes in Kumasi, are projected to be low (a maximum of 27 Bcf up to 2030) bringing into question the development of a costly gas pipeline. Hence the focus of analysis in this section is on the question: *Is a power transmission line or gas pipeline more economically viable between Prestea and Kumasi?*

To compare the economics of gas pipelines and transmission lines, the per-unit transmission tariff for each option was calculated. This is done on the basis of a 30 year discounted cash flow method. The tariffs for a base demand throughput as outlined in Section 5 were compared and the tariffs for newly built pipelines and transmission lines were also compared. Other assumptions made in this analysis are shown in **Table 16**.

Table 16: Inputs Used for Gas vs. Power Transmission

	Gas transmission tariffs	Power transmission tariffs
Rate of return	15%	15%
Size	12 inches	600 MW (single 220V line)
Length	264 km	264 km
CAPEX	US$64,300 /inch/km[23]	US$138,000 /km
OPEX	3% of CAPEX per year	3% of CAPEX per year
Loss rate	1.5%	4%
Throughput	Base demand in Kumasi and Prestea	Base demand in Kumasi and Prestea
Life	30 years	30 years
Tariff	**US$36.1 /MWh**	**US$8.0 /MWh**

Source: ECA analysis

The assumptions above result in a considerably lower CAPEX for power lines (around US$39 million) than for gas pipelines (around US$178 million). The higher losses on the power lines do not offset the higher CAPEX and the results show that power transmission is overwhelmingly more economic than gas pipelines for this section. At 22% of the costs of gas transmission, electricity transmission is a far more viable option than gas pipeline.

The analysis above compares electricity transmission and gas transmission for this particular segment only. In reality, the costs of the gas and transmission lines would be absorbed into a postage stamp tariff and thereby not be as high as shown in the table above. For gas this

[23] US$ per inch of inner diameter and kilometre of pipeline length

would still result in more than a doubling of the gas transmission tariff (compared to only developing the onshore gas pipeline) from US$0.60 to 1.46 /mmbtu.

6.3.5 LNG Terminal: Location, Capacity and Date

The location of the LNG terminal is assumed to be in Tema. A technical pre-feasibility for seven different locations was completed in a study by CH2MHill for the Millennium Challenge Corporation published in July 2014.The key points and results of the study are summarised in the Annex. On the basis of a variety of different technical criteria the study recommends Aboadze as a location for a 250 mmscfd FSRU at a CAPEX of around US$40 million and an OPEX of US$72 million /year.

On the basis of the supply and demand analysis presented above, however, only one terminal to be located in Tema is assumed for the following reasons:

Demand in Tema is currently unmet due to low gas supplies through WAGP. With growing demand in Tema and the Accra region an FSRU could provide the necessary security of supply in the short to medium term. This is point is buttressed by the recent generation capacity additions (gas fired thermal plants) in response to the ongoing acute load shedding.

All short to medium term **gas supplies are located in the western region** of Ghana and gas infrastructure linking producing fields with western gas demand regions are already or nearly completed. An FSRU in that region is therefore unlikely to be needed.

As described above, a reverse flow arrangement and an onshore pipeline connecting Tema and Takoradi is needed; however, potential delays in the **development of these supply options for eastern Ghana** would result in further unmet demand in Tema and Accra.

With the proximity of domestic gas fields and WAGP, the **western region already has two supply options in the short to medium term**. Adding a third through the development of an FSRU, while eastern regions suffer from unmet demand seems sub-optimal.

These points clarify that one terminal located in Tema will be sufficient in the medium term for Ghana. The immediate question for policymakers now is: *when is the terminal needed and what capacity is needed for the LNG terminal?*

This question is presented and discussed in the CH2MHill LNG pre-feasibility study. However, the results from the analysis here are provided for comparative purposes.

Unlike the other policy questions, this one is not a binary question, where only a small number of options are assessed and compared. The approach to this question is done differently. Three distinct phases of LNG development are considered to see how LNG capacity requirements change over these time periods. This helps to draw out a capacity profile for LNG over time and identify the capacity requirements going forward. The three distinct time periods considered are:

- ***Short term*** – the immediate need for LNG given existing infrastructure, ie period 2014-2020

- ***Medium term*** – the medium term need for LNG given proposed infrastructure above, ie period 2020-2030

- ***Long term*** – the long term perspective for LNG requirements in light of demand projections, ie period 2030-2040.

To assess the LNG needs, the supply/demand balances in each of the phases presented above are compared. The main results are shown in **Error! Reference source not found.**.

Table 17: LNG terminal needs

D/S Scenarios	**Years LNG is needed**			**Maximum capacity (*mmcfd)***		
	Short term	**Medium term**	**Long term**	**Short term**	**Medium term**	**Long term**
Aligned Low	2015-2017	2024 -		60	220	450
Aligned Base	2015-2018	2025 -		40	275	425
Aligned High	*n.a.*	2029 -		45	70	210
Non-aligned LowD	*n.a*			*n.a*		
Non-aligned HighD	2015 -			140	410	620

The results show that LNG requirements for Ghana are needed immediately to cover short term needs until 2018 and then from 2024 onwards when significantly higher capacities will be needed. Focusing on the short and medium term, this means that there are two possible LNG strategies that GoG could follow:

Option 1: develop a small scale floating flexible terminal (100 mmscfd capacity) for short term requirements and develop a bigger unit when needed in 2024. This option would require relatively low initial CAPEX, could be done quickly thereby covering the short term demand squeeze, and could be designed flexibly, i.e. on the basis of short term leasing contract.

Option 2: Develop a larger floating terminal (280 mmscfd) from the start taking into account capacity needs in 2030. This would take advantage of the economies of scale of developing a larger terminal. The risks here are mainly the underutilisation of the terminal over the period 2018-2024, slightly higher initial CAPEX than in Option 1 (although), potentially longer time to develop.

<u>In light of the high likelihood of unmet demand in the medium term, option 2 – development of a large terminal - is the preferred LNG development option.</u> The results from the non-aligned cases of high demand reinforce this conclusion.

To counter the risk of underutilisation over the period 2018-2024, GoG should ensure a flexible leasing arrangement for the terminal. This means negotiating the leasing contract of a floating regasification unit initially for a short time period (5 years could be the minimum leasing contract). Once the contract expires, supply demand balances can be re-assessed and

the need of the LNG terminal re-evaluated. In summary, the recommendation is in close to although not identical to the recommendation by CH2MHill and includes:

- Only develop one terminal in Tema;
- Develop a floating regasification unit instead of an onshore terminal to ensure flexibility of use;
- Develop an LNG terminal to cover the short term demand gaps - up to 2018 until Sankofa field comes on stream;
- Develop the terminal's capacity on the basis of medium term demand (i.e. 2030) resulting in a capacity of up to 280 mmscfd according to the projections;
- Ensure the leasing arrangements for the unit are set at a minimum possible contract length to allow the terminal to be used elsewhere if not needed in Ghana over period 2018-2024.

Details on the capital costs of the terminal are provided in the next section.

6.4 Gas Infrastructure Development Plan

Based on the recommendations made in each of the previous sub-sections, a complete gas infrastructure plan for the country is presented here for the aligned supply/demand cases only, i.e. low demand and supply, base demand and supply and high demand and supply. Table 18 shows how the proposed infrastructure capacity, CAPEX and earliest year needed changes across the three demand scenarios.

The capital cost assumptions for the pipelines are outlined in Annex A5.6. The capital cost of the proposed LNG terminal is difficult to assess without knowing the type of floating storage and regasification unit that will be developed (Multi-Point Mooring facility or a Fixed Breakwater and berthing facility). The higher range of the cost data proposed in the LNG pre-feasibility study and recently completed projects were used to calculate the CAPEX. Details on the CAPEX assumption of regasification are in Annex A5.6. As noted above, the compression costs are assumed to be US$20 million.

Table 18: Infrastructure Development Plan

D/S Scenarios	**Capacity** *Mmscf/d*			**PV of CAPEX** *US$ million*			**Year needed**		
	Low	**Base**	**High**	**Low**	**Base**	**High**	**Low**	**Base**	**High**
RF on WAGP	100	100	100	20	20	20	2016	2016	2016
Takoradi-Cape Coast PL	264	264	329	39	39	43	2016	2016	2016
Cape Coast-Accra PL	264	264	329	172	172	187	2016	2016	2016
Accra – Tema PL	264	264	329	40	40	95	2016	2016	2016
Tema LNG terminal	220	275	70	240	300	80	2016	2016	2029
Total				**511**	**570**	**425**			

The results show that all recommended infrastructure is needed immediately – apart from the LNG terminal in the high supply and high demand case. This highlights the urgency for gas infrastructure investments in Ghana that would ensure balanced gas demand and supply in the country.

The infrastructure plan of the Base Case scenario is recommended for the following reasons:

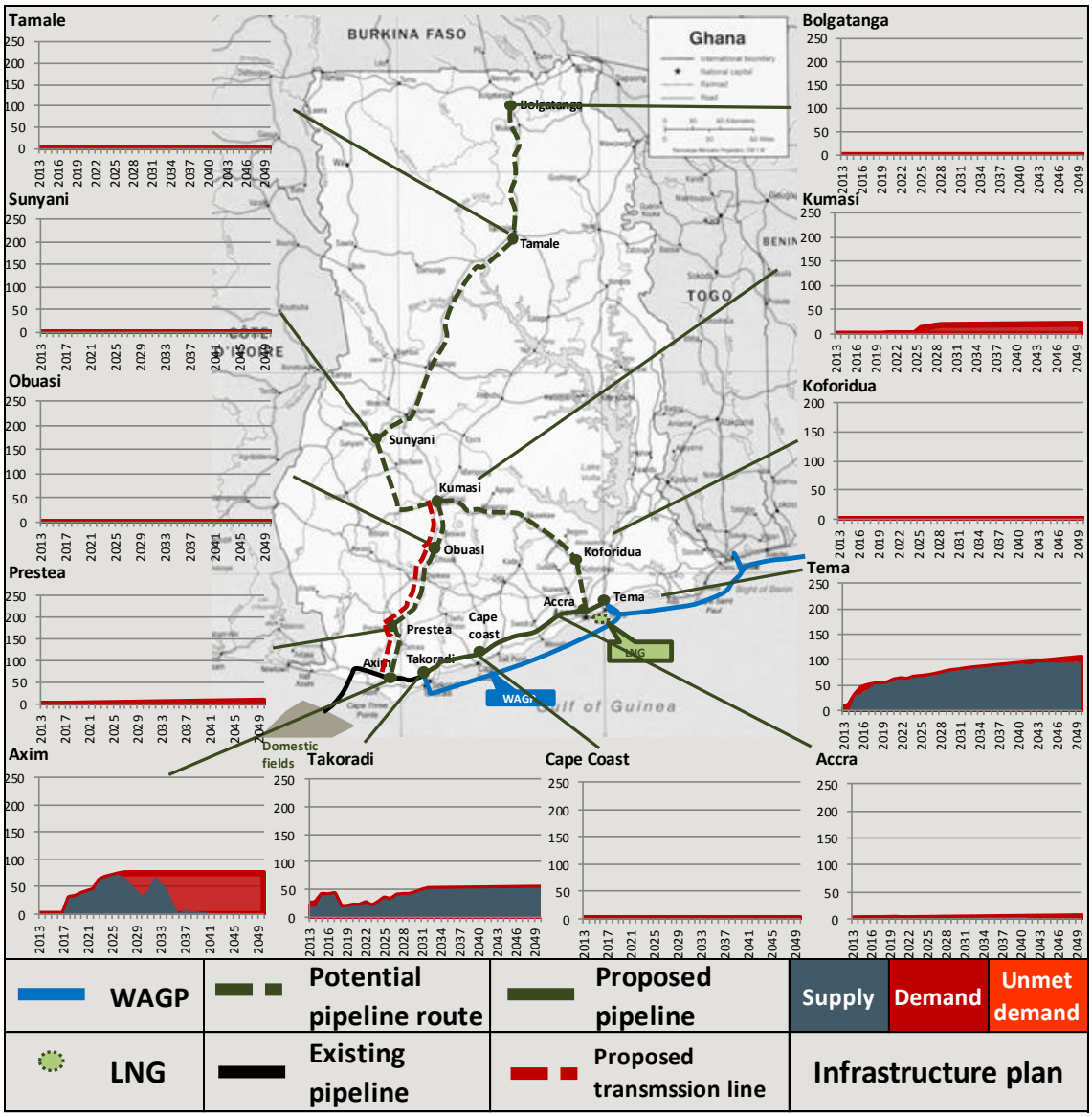
- The Base case scenario is the most likely scenario of all three scenarios constructed.
- The capacity and investments needed between the Base Case and Low Case are almost identical (apart from the LNG terminal).
- In case the high case scenario does indeed occur, the downside impact on economic value and transmission tariff is negligible. The results of the non-aligned cases in the previous sections show this point.

The key points of the recommended gas infrastructure plan can be summarised as:

- **To cover the short term demand in Tema (2016-2018) GoG should develop the reverse flow on the WAGP**. The capacity of the pipeline for the reverse flow with the addition of a compressor station could support 100 mmscfd and the assumed capital costs for the compressor station are US$20 million.
- **GoG should develop the onshore gas pipeline connecting Takoradi with Tema** to ensure security of supply, introduce competition on the transportation of gas and develop the gas market along the coastal line for potential customers. The capacity of the pipelines should be 250 Mmscfd, which under normal pressure conditions would correspond to an inner diameter of 20 inch. The required investment costs would be US$250 million. Once in place, the onshore pipeline would be the main pipeline to be utilised and the transmission tariffs on WAGP could be very low.
- **To cover the short term and the long term demand GoG should develop an LNG Terminal in Tema**. A floating regasification unit instead of an onshore terminal would ensure flexibility of use. The terminal and associated infrastructure should be sized on the basis of medium term unmet demand, approximately 270 mmscfd. This would require investment costs of between US$40 million (if no fixed berthing) and US$300 million (with fixed berthing). To ensure low levels of underutilisation, leasing arrangements should be as flexible and short term as possible.
- **There is no urgency to develop a gas pipeline to Kumasi and further north for now**. Instead GoG should develop or strengthen the power transmission lines to cover energy demand in those regions. The final investment decision will however be linked to the power sector development plan and the importance put on developing gas fired power plants in Kumasi.

A map of the resulting infrastructure plan is shown in **Figure 48**.

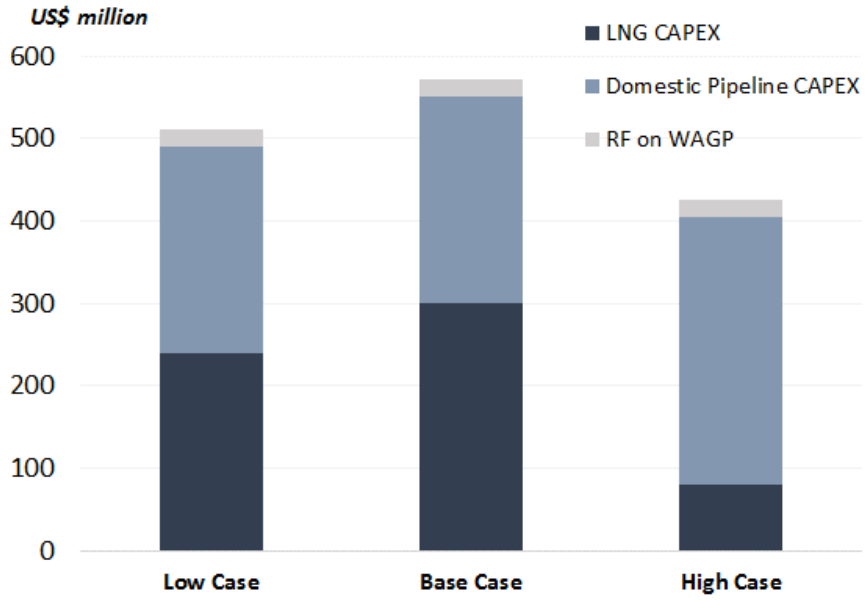
Figure 48: Infrastructure Plan



6.4.1 Total Investment Costs

The total investment costs for new infrastructure deployment between Takoradi and Tema range from US$425 million to US$570 million. As noted above, all investments are needed urgently to ensure security of supply in the short to medium term, particularly in Tema. The precise investment schedule will depend on the financing arrangements, final investment decision and construction periods. The investment requirements are presented in Figure 49 below as total investment costs using 2016 as base year..

Figure 49: Investment Cost for Infrastructure in 2016



The analyses show that the financing requirements for GoG would be US$570 million to ensure gasification and security of supply of the main demand centres. Note that a fixed berthing LNG terminal is assumed, making the LNG cost an 'upper end' estimation. Completely floating terminals could be as low as US$40 million. This would bring down the total CAPEX requirements in the Base Case scenario down to US$310 million.

Interestingly, the high case requires lower investment costs than all other cases. This is mainly due to the considerably lower LNG capacity requirements. As higher volume of domestic supply is available, higher capacity of the LNG terminal is not required to ensure security of supply in the medium to long term. However, as the domestic supply volumes get higher, the inner diameter of the pipelines would have to be increased from 22 inches in the low and base case to 24 inches in the high case.

The capital costs presented here exclude the costs of electricity transmission. Without making a detailed analysis of the existing power transmission system, the exact costs are difficult to estimate. The initial estimates suggest costs of close to US$40 million.

6.4.2 Cost of Delivered Gas

The cost of delivered gas is composed of:

- the weighted average cost of domestic and imported gas supply and
- the transportation cost calculated from the estimated pipeline infrastructure costs and the forecasted consumption.

The estimated cost of gas for each of the supply sources is analysed in Section 3. The transportation cost methodology is described in Section 6.2.2 and is calculated using the DCF methodology including:

(i) capital costs of the pipeline infrastructure,

(ii) operating cost of the pipelines,

(iii) cost of gas losses and

(iv) costs of the corporate income tax.

The transportation tariff is assumed to be uniform for all consumers as discussed in the general principles of gas pricing in Ghana[24]. The infrastructure costs for the calculation of the transportation tariff are analysed in the previous section.

Table 14 summarises the unit pipeline cost under each scenario based on the net present value of all required investment and operational costs from future years to 2040. The regasification costs calculated on the basis of CAPEX and OPEX parameters have been included within the LNG supply price.

Table 19: Transmission Tariffs for Recommended Investment Plan

Scenario	Transportation unit costs *US$/mmbtu*
Aligned Low	0.76
Aligned Base	0.60
Aligned High	0.50
Non-aligned Low	0.75
Non-aligned High	0.66

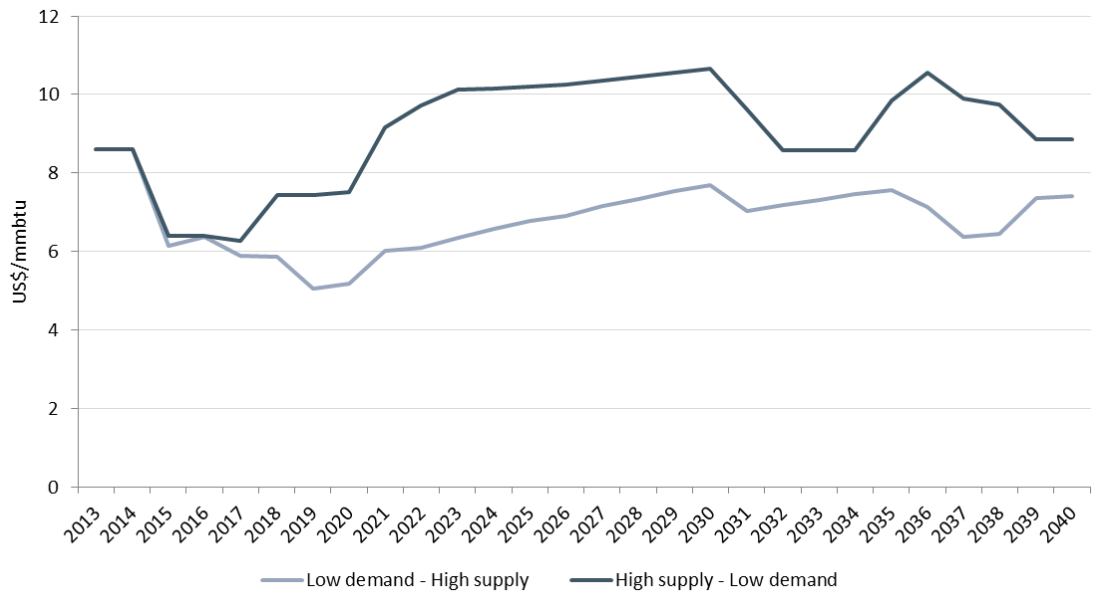
The cost of delivered gas for the aligned cases is depicted in Figure 50 and for the non-aligned cases in Figure 51 for the recommended infrastructure scenario. The results show that the cost of delivered gas ranges from US$5.05 /mmbtu to US$8.6 /mmbtu until 2020 and US$6.03 /mmbtu to US$10.74 /mmbtu from 2020 to 2030. The increased utilisation of gas from LNG imports in the medium to long term accounts for the increased cost of delivered gas during this period.

The significant drop in the cost of delivered gas across all scenarios from 2030 to 2035 is due to the blowdown gas from Sankofa. This would inject large volumes of very low cost gas into the gas supply mix resulting in significant drop in the delivered cost of gas over the period. Once this blowdown gas is depleted, LNG imports will again be the 'marginal' gas supply option raising prices to higher levels.

[24]USAID, 2014, USAID Technical Assistance to Ghana PURC on Natural Gas Tariff Setting Final report.

Figure 50: Cost of Delivered Gas – Aligned Scenarios *US$/mmbtu*

Figure 51: Cost of Delivered Gas – Non-Aligned Scenario *US$/mmbtu*



6.4.3 Economic Value and Unmet Demand

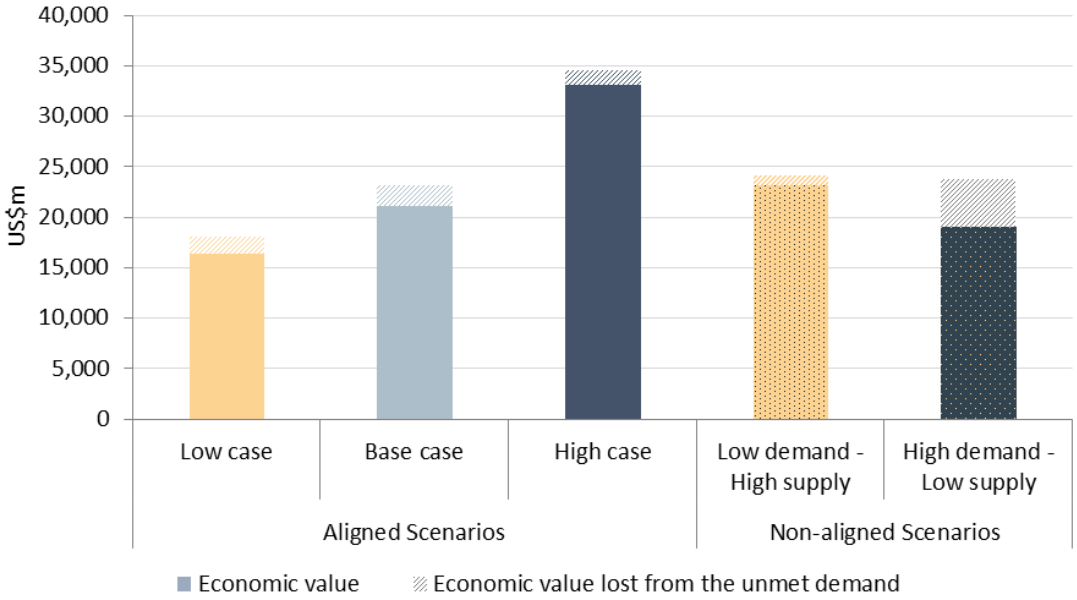
The economic value of the proposed infrastructure plan presented here shows the lost economic value due to unmet demand in present value terms for each supply/demand scenario and the recommended infrastructure plan. The results demonstrate that:

- The total economic value in present value terms of the proposed gas infrastructure plan ranges between US$16 and US$33 billion. The final economic value of the gasification strategy will be determined by the volumes of domestic supply and consumption.

- The non-aligned scenarios reveal that overestimating the capacity of gas infrastructure results in a very small reduction in economic value. This underlines the recommendation of using the base case infrastructure plan instead of the low case or high case plan.

Within the aligned scenarios the economic value for the high case is the highest and is close to double that of the low case.

Figure 52: Direct Economic Value by Scenario



7 INSTITUTIONAL, REGULATORY AND FINANCING FRAMEWORKS

This section covers the non-technical aspects of the Gas Master Plan. Experience in other countries has indicated that a strong policy framework, implemented through effective institutional and regulatory arrangements, is vital for the national development potential of newly discovered gas resources to be realised.

This section starts by outlining the present policy and legal framework, and then discusses institutional arrangements, regulation and financing. The most controversial area is the institutional structure which has been extensively debated publiclyin recent times. The best solution to develop the transmission and distribution system and related infrastructure most effectively and economically is to make GNPC a temporary monopolist in the gas sector responsible for aggregation, ownership and operatorship. However this section also describes a solution that is closer to the present institutional structure whereby the aggregation, ownership and operatorship are handled by different entities. The latter is more complex –hence riskier than it should be at this early stage in the development of the gas sector.

7.1 Policy and Legal Framework

Several policy documents have been published by GoG outlining the major policies for Ghana's gas sector development. Below are the key policy documents, providing the envisaged direction GoG intends to develop the gas sector. As the upstream gas sector development is not the main focus of this plan, the focus here is on midstream and the downstream policy documentation[25]. The gas infrastructure plans are covered in section 6.4.

Energy Sector Strategy and Development Plan, 2010

The Energy Sector Strategy published by the Ministry of Energy in 2010 sets out the main objectives of the energy sector including the gas sector. The strategy proposes the following:

- Achieving gas-based generation for at least 50% of thermal power plant production by 2015
- Prohibiting the flaring or venting of natural gas produced within Ghana to maximise the utilisation of natural gas reserves of the country
- Discouraging re-injection of natural gas unless it results in increased benefits to the associated operations
- Developing a viable domestic petrochemical industry based on natural gas
- Intensifying exploration, development, production and utilisation of Ghana's oil and gas prospects
- Ensuring the exploration of the onshore Volta gas Basin

[25] Most notably we exclude here the Petroleum Act of 1985 and the Fundamental Petroleum Policy, 2009

- Maximising the participation of Ghanaians in the exploration, development, production and utilisation of oil and gas
- Increase LPG consumption across the residential sector to 50% by 2015. This will be achieved through the development of LPG infrastructure and pricing incentives to encourage distributors to expand their operations to especially the rural and deprived areas. The following measures will be implemented in that regard:

    - Speed up the establishment of a natural gas processing plant to produce LPG from the associated gas to be produced from the Jubilee Oil and Gas Field

    - Re-capitalise the Ghana Cylinder Manufacturing Company (GCMC) to expand production capacity. The production of cylinders will focus on small sized cylinders that will be affordable to households in rural communities

    - Construct LPG Storage and supply infrastructure in all regional and district capitals in the long term. In the medium term, it is intended to develop district capital LPG infrastructure

    - Increase the LPG distribution margin

The Energy Commission Act 1997,Act 541 and Gas Regulations

Not a policy document per se, the Energy Commission Act nevertheless sets out the main guidelines for market structure and functioning. One of the key clauses is Section 23, which is entitled 'Interconnected transmission systems and transmission licence'. This applies to both electricity and natural gas sectors. The generation and distribution/supply components are to be competitive, while transmission is to be subject to the issuance of an exclusive licence.

In fulfilment of the requirements of this Act, the Energy Commission in January 2015 licensed BOST to operate the national interconnected natural gas transmission infrastructure to connect all gas supply sources in the country. BOST is the unique Natural Gas Transmission Utility (NGTU) as provided for in the Act and associated rules and regulations (see below). BOST is required to install and operate a non-discriminatory open access national natural gas transmission pipeline system that transports natural gas to distribution centres and bulk customers.

The Energy Commission has promulgated a number of rules and regulations pertaining to natural gas:

- LI 1911 (2007) Natural Gas Distribution and Sale (Technical and Operational) Rules
- LI 1912 (2007) Natural Gas Distribution and Sale (Standards of Performance) Regulations
- LI 1913 (2008) Natural Gas Transmission Utility (Technical and Operational) Rules
- LI 1936 (2008) Natural Gas Transmission Utility (Standards of Performance) Regulations

Clause 3 of LI 1913 makes clear that the NGTU has the responsibility to "install and operate a national natural gas transmission pipeline system that transports natural gas to distribution companies, storage facilities and bulk customers".

Gas Pricing Policy, 2012

The National Gas Pricing Policy was published by the then Ministry of Energy and Petroleum (MoEP) in May 2012 that sets out the gas pricing principles.. The document envisages import parity pricing for gas, resulting in surplus revenue being accumulated in a Gas Rent Fund, which would, *inter alia,* be used to cross-subsidise fertilisers and other strategic sectors.

LPG promotion Strategy (Advisory Paper), 2011

The LPG promotion Strategy is only an advisory paper and therefore only includes recommendations to implement the policy objectives of GoG which consist of (i) increasing LPG penetration to 50% on average in the household, informal business and educational institution sectors by the end of 2015 and (ii) ensuring reliable supply of LPG. Besides the measures outlined in the Energy sector Development Strategy, the advisory paper of the Energy Commission recommends the following interventions:

- **Pricing** - LPG consumption has traditionally been subsidised through cross subsidies from diesel and petrol consumption. With increased switching from petrol or diesel to LPG, GoG (i) foregoes revenue through levies and margin on petrol and diesel and (ii) pays higher subsidies on LPG. Besides alleviating the budgetary pressures for GoG, increasing the margins along the LPG value chain will also increasingly attract private sector investors ensuring supply of LPG. This process is already underway with recent major LPG price adjustments.

- **Increasing LPG supply and delivery infrastructure** – To avoid consumers switching back to wood fuel as a result of higher prices, the availability and production of LPG should be incentivised. Especially to ensure access to LPG in LPG-deprived areas, there must be a deliberate policy intervention by GoG. Specific recommendations include:

    - Contractual arrangements for the financing and operation of domestic natural gas processing facility should be expedited;

    - The use of LPG that would be produced from local gas processing in the domestic market should be given priority over exports;

    - Tax incentives should be provided for investors who invest in LPG filling stations in district capitals and rural areas for a period;

    - Government may provide support to the municipal and district assemblies to install filling stations which may be operated by the private sector under an operation and maintenance agreement.

- **Regulatory measures** – To limit the usage of LPG in the transport sector, existing legislation restricting usage of LPG in transport should be applied. LI 1592 restricts LPG to be used in vehicles only with an LPG tank installation certification. The cost of this certification and issuance is determined to be equivalent to the price differential between LPG and petrol or diesel in energy

terms.

Policy and Legislative Gaps

To consolidate the framework for gas sector development, it is recommended to have a comprehensive legal framework for the gas sector. This can follow after immediate priorities are handled through promulgating regulations on issues such as third party access, pipeline ownership and tariff structures. Once the sector is operational, consideration shall be given to reformulating the Gas Policy in light of experience and developing a comprehensive Gas Sector Act to make the policy effective.

What is presently required is capacity building to ensure agencies and institutions have the requisite knowledge and skills to develop the needed regulations, standards and codes for the effective management and regulation of the gas industry, and subsequently to formulate the Gas Act.

7.2 Institutional and Regulatory Framework

There has been and continues to be lack of clarity about some aspects of the institutional structure for Ghana's gas sector. Roles and responsibilities are defined in legislation and through the regulatory decisions which have been made, but the legislative intentions have not been consistently fulfilled in practice.

Whatever decisions are made by GoG on the institutional structure for the gas sector, there is a significant capacity gap at the present time. None of the institutions described in this section have adequate skills to undertake some of the crucial functions which need to be fulfilled.

7.2.1 Current Gas Sector Institutions

Prior to the discovery of the country's gas resources, the sole natural gas entity was a multi-national entity, the ***West African Gas Pipeline Company*** (WAPCo). Although not a Ghanaian entity and not a part of the natural gas interconnected transmission system (NGITS) of Ghana, WAGP could potentially play a crucial role in the bi-directional transport of gas between the east and the west. , For this reason, it has been considered closely in the infrastructure analysis of this study.

Ghana's natural gas sector is dominated by three state owned entities. These fall under the Ministry of Petroleum (MoPet), which formulates policy and passes legislation for running and managing the sector. The three entities are:

Ghana National Petroleum Corporation (GNPC) – Established in 1985, GNPC is the national upstream company responsible for exploration, development and production of oil and gas. It currently holds between 15 and 20% equity interest in upstream oil and gas operations being conducted by the international oil and gas companies (IOC). ***Ghana National Gas Company*** (GNGC) – GNGC (also referred to as '**Ghana Gas'**) was established in 2011 with the responsibility of gathering, processing, transporting and wholesaling gas. Ghana Gas owns and operates the Western Corridor Gas Infrastructure including the Atuabo Gas

Processing Plant, offshore gathering pipeline and the Atuabo-Aboadze gas pipeline..

The Bulk Oil Storage and Transportation Company (BOST) – Traditionally responsible only for the operation of oil pipelines in Ghana, BOST was licensed by the Energy Commission in 2015 as the National Gas Transmission Utility (NGTU).

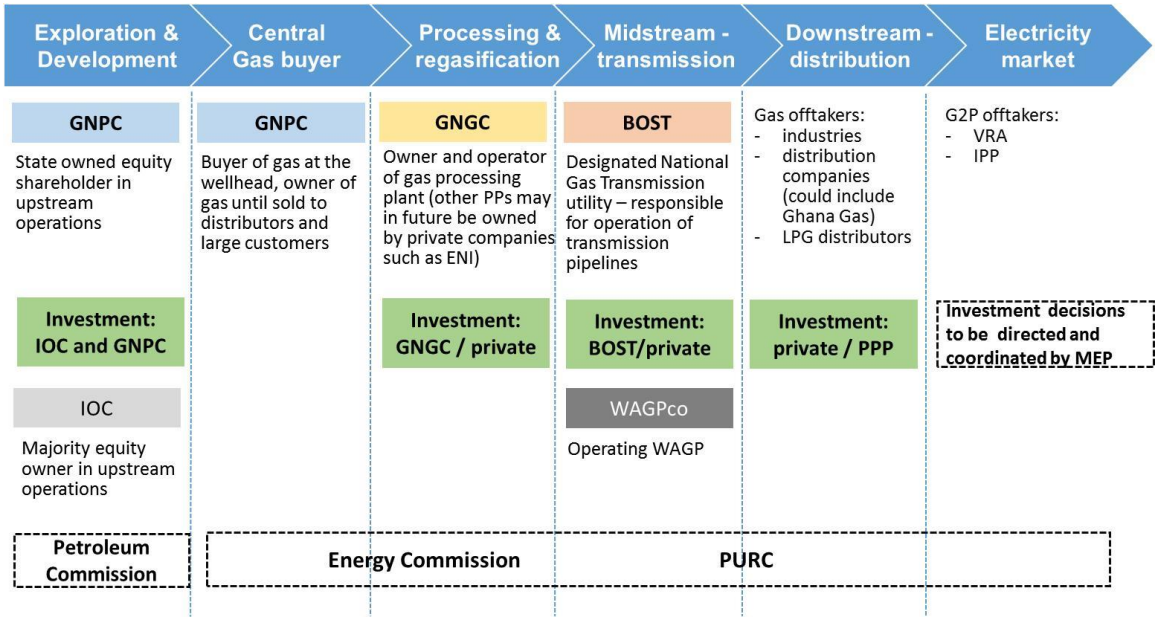
On the surface, this structure is quite comprehensive, but an important impediment is that there are numerous entities for a nascent gas sector with unclear boundaries and limited experience in the gas sector. Furthermore, functions which have been allocated to one entity are in practice being carried out by another:

GNGC has developed, owns and operates the Atuabo-Aboadze pipeline, despite BOST being issued the NGTU licence. This anomaly needs to be addressed. GNPC has been designated by GoG as the sole counterparty for gas purchase agreements with upstream gas producers. This is inconsistent with the initial mandate of GNGC.

In countries with developing natural gas sector, clearly defined institutional boundaries could be difficult to achieve. In view of this, a re-thinking of the institutional structure is suggested in the next section.

Figure 53 provides a summary overview of the involvement of agencies and organisations across the gas value chain.

Figure 53: Institutional Structure Along the Value Chain



Proposed Institutional Framework for Ghana

It is recommended that the approach adopted in Turkey, which involved the petroleum pipeline company Botaş, a subsidiary of the state petroleum corporation Türkiye Petrolleri

Anonim Ortaklığı, being the sole developer and operator of Turkey's gas transmission and distribution infrastructure, is also appropriate for Ghana's gas sector, at least at this early stage of development. Botaş acted as gas aggregator and wholesaler, was the entity that invested in and operated an expanding national transmission and distribution pipeline system.

In Ghana's case, this role can be divided between GNPC and GNGC, whereby GNPC will be the aggregator and wholesaler of the gas and GNGC, as the wholly owned subsidiary of the GNPC, will be the owner and operator of the infrastructure.

With the development of the industry, an LDC may be required to develop the infrastructure and retail the gas to the various end users.

Distribution licences are yet to be called for and issued by the Energy Commission. The plan is for private entities to bid for distribution licences.

As the sector matures, the GoG may consider unbundling the services along the gas sector value chain.

7.3 Regulatory Institutions

Regulatory responsibilities between regulatory agencies are also not clearly defined and delineated. The key agencies responsible for regulating the sector are:

- ***Petroleum Commission*** (PC) – The PC is the technical upstream gas regulator and as such issues exploration and production licences, reviews the petroleum development plans and enforces the technical requirements for upstream oil and gas operators.

- ***Energy Commission*** (EC) – The EC is the technical midstream and downstream gas regulator, with responsibilities in issuing licenses for processing, transportation and distribution activities, drafting and implementing of all technical regulations in midstream and downstream operations and providing advice to MoPet on energy policy.

- ***The Public Utilities Regulatory Commission*** (PURC) –PURC is the economic regulator for electricity, gas and water. It is primarily responsible for tariff setting, promotion of competition and complaints handling. In respect of gas pricing, PURC is to advise the Government on commodity prices and set regulated tariffs for gas processing, transportation and distribution.

- ***National Petroleum Authority (NPA)***-The NPA was established by National Petroleum Authority Act, 2005 (Act 691) to regulate and monitor activities in the downstream petroleum industry; to establish a petroleum pricing formula; and provide for other related purposes.

- ***Environmental Protection Agency (EPA)*** – In Ghana, environmental aspects of the petroleum and gas sectors is covered by a number of legal instruments, including the Petroleum Law, the Environmental Protection Agency Act, the Environmental Assessment Regulation LI 1652, and Ghana National Petroleum Corporation Law. The primary regulatory institution establish*ed to ensure environmental protection in Ghana is the Environmental Protection Agency,* (EPA), created under the EPA Act, 1994 (Act 490). Oil

*and gas were only discovered later and EPA has formu*lated specific policies to address environmental aspects, such as the *Guidelines on Environmental Assessment and Management of Offshore oil and Gas Development* which were promulgated in 2011. As made clear in *Ghana Shared Growth and Development Agenda 2010-2013*, EPA is committed to ensuring that all aspects of natural gas development are consistent with international standards of environmental sustainability.

Besides the above four national regulators, it is also worth mentioning the role of the ***West African Gas Pipeline Authority*** (WAGPA). WAGPA is the authority responsible for monitoring the operation of WAGP and setting its tariffs. The stakeholders of WAGPA are the four participating states (Nigeria, Benin, Ghana, and Togo) and the private stakeholders of WAPCo. The potential future integration of WAGP with the Ghanaian gas transmission network could result in regulatory uncertainty including questions of responsibilities on tariff setting, treatment of asset value of WAGP and technical standards to be met by WAGP.

It is recommended that the roles of the regulating entities should be unified in the downstream gas sector and handled by one institution.

7.3 Financing Structures

The institutional framework is complemented by an overview of the financing challenges for gas sector development. This section outlines the different financing structures that could be applied in gas infrastructure development. It is highlighted here the possible sources of funding, PPP structures and financial support mechanisms. A key aspect of infrastructure financing is the securitisation of the assets. For large scale gas infrastructure investments, this will realistically mainly be provided by the state. Our focus is therefore on PPP structures and its possible roles within different parts of the value chain. While the financing structures and securitisation options will have a small bearing on the total investment costs, the impact on the delivered cost of gas will be small.

The USAID-supported Ghana Natural Gas Sector Short Term Action Plan and ongoing Power Africa Transaction and Reforms Program will provide more details on securitisation and financing strategies.

7.3.1. Sourcing for Funding

Before discussing the PPP options best suited for Ghana, it is worth briefly reviewing the potential financing sources for mid and downstream infrastructure, their capacity for providing that finance, and their risk considerations in doing so. A table of funding sources for project equity and debt, together with the typical drivers for investment and international examples is provided in Annex A6. Many of the entities discussed are fully global and their investment capital is sought from across the world (in the case of private equity and institutional investors, competition for funds stretches into other infrastructure sectors and beyond). The challenge for Ghana is providing sufficiently attractive conditions to compete for these funds without at the same time compromising the economic benefit to be derived from a project's development by creating market distortions. This can be done by using carefully structured PPP approaches, with selected incentive mechanisms designed to reduce risk areas.

Public sector financing of infrastructure projects in Ghana is likely to come either directly from the GoG or from one of Ghana's SOEs working in the energy sector. If all infrastructure is to be funded by public entities, then their capacity for doing so becomes a critical issue. Below, the financial capacity of the GoG and SOEs for undertaking the identified projects is briefly reviewed.

Direct Government Funding

The World Bank estimated in 2011 that Ghana spends approximately US$1.2 billion per annum on infrastructure (approximately 7.5% of GDP). Of this around US$0.7 billion comes from the public sector, meeting all O&M needs (approximately US$0.5 billion per year) and around 30% of capital expenditure (approximately US$0.2 billion out of US$0.7 billion total spend).

This level of financing is insufficient to address all the challenges facing Ghana's infrastructure sectors. Even with efficiency gains and regulatory improvements, the World Bank identified a remaining annual funding gap, not inclusive of any gas sector infrastructure upstream from power generation, of around US$0.4 billion. This is primarily related to the power and water sectors. Increased revenues from upstream production of oil and gas may help bridge this gap but the numerous demands on public sector funding are clear. Recognising this deficit, the GoG introduced a National Public-Private Partnership (PPP) Policy in 2011 aimed at leveraging private sector funding for infrastructure (see Section 0 below).

The GMPM described in Section 6 estimated government revenues from gas production reaching up to US$0.8 billion in the Base Case between the years 2019 and 2020 when infrastructure spend peaks. The Ghana Natural Gas Sector Short-Term Plan foresees upstream royalties being used to create a securitization fund for the gas chain, including power sector projects. Given the large demands for infrastructure funds across the gas and power sectors and the difficult borrowing position for the GoG, this would seem a more sensible use of funds than fully funding specific projects.

State-Owned Enterprises

The state-owned enterprises involved in the midstream energy sector in Ghana were introduced in Section 0. These are GNPC, which we assume in Section **Error! Reference source not found.** will be the owner of gas from wellhead to end user, GNGC which owns and is the licenced operator for the gas processing plant at Atuabo, and owns & operates the Atuabo-Aboadze pipeline, BOST which is the licenced national transporter of gas, and VRA which owns and operates power plants and holds a stake in the WAGP Company. Of these entities, GNPC is in our view the entity best placed to finance and develop transmission pipelines, but the legal and licencing framework points to this being undertaken by BOST.

Private Sector

The potential pool of private sector finance is wide, but the private sector's choices of where to invest are global. Therefore it would be inappropriate to attempt to identify financial capacity of individual entities for investing in midstream gas infrastructure in Ghana. Rather this sub-section reviews the potential role a private sector player may take and what drivers and considerations they will have in making an investment.

A private sector sponsor for a gas pipeline or other midstream facility may be an upstream supplier of natural gas, a downstream buyer, or an independent operational entity for both the upstream and downstream. The drivers for each form of sponsor vary, along with key revenue risk factors and the contract form to mitigate for such risks, as summarised in **Table 20**.

Table 20: Summary of Business Model Characteristics

	Typical driver for investment	Key market risk and mitigation methodology
Upstream Promoter	Develop export market for new fields	Off-take risk secured through some form of take-or-pay contract
Midstream Promoter	Financial return on investment	Ship-or-pay agreements with shippers
Downstream Promoter	Improve and secure supply	Product available for purchase at reasonable price, secured through long-term supply-or-pay contract

Major pipeline constructions are generally undertaken by a consortium of entities and therefore the final approach could be some amalgamation of the above approaches, as in the case of the WAGP.

It is possible that the drivers in **Table 20** are sufficient for incentivising project development from the private sector without government direction (e.g. in the selection and tendering of specific projects). Australia provides an example of a fully privatised transmission and distribution pipeline network scenario. However, there are a number of reasons why in a country such as Ghana, some form of government direction may be preferable or required. For example, it may be desirable to ensure that any given project is coordinated with broader plans for network development. A project may be economically desirable from a full socio-economic perspective but financially not viable for a private sector company, or the overriding licensing and permitting regulatory framework may be overly onerous for an outside party to negotiate. For these reasons some form of PPP – at least in the sense of government selection, feasibility work and tendering of specific projects - may be used.

Under any approach, raising finance is a key issue. The first decision is whether the project itself is fully equity-financed (or at least any debt incurred is corporate debt secured against the sponsor's wider assets) or a degree of project financing is used with no, or limited, debt recourse for lenders. A project finance approach will require detailed scrutiny from lenders who will wish to ensure risks are mitigated and minimised to a low level regarding future returns. For this reason, international pipeline projects which have been constructed in more politically challenging environments, have tended to have a high level of equity relative to debt[26]. A well designed PPP programme, together with appropriate targeted incentives, can contribute to reducing risk and enabling a project financing approach to be utilised with a greater level of debt leverage.

[26] Energy Resource Management (2008), "Assessment of the range of potential funds and funding mechanisms for CO_2 transportation networks"

7.3.2 Public-Private Partnership Structures

Implementation Forms and Options

There is no commonly agreed definition on what constitutes a PPP, with interpretations encompassing everything from narrow service contracts to full divestments in their potential scope. This study will concentrate on those options of greatest relevance to type of projects under consideration; i.e. green-field (namely pre-construction) large-scale gas infrastructure covering gas processing, transmission and distribution pipelines and LNG liquefaction and re-gasification facilities. Relevant structures for discussion are the concession, the Build-Own-Operate-Transfer (BOOT) model and a full JV partnership model between the public and private sectors. An introduction to each along with international examples of their adoption in the gas sector is provided in Annex A6.

Private sector financing of gas infrastructure is well established internationally. Due to their capital intensive nature, pipeline and other midstream facility (e.g. processing plant or LNG terminal) developments are typically undertaken by well capitalized international oil and gas majors or national oil and gas companies. These entities, often in partnership or consortia, have the ability to raise the huge financing required by such projects. They are also most likely to be involved in an exporter-led upstream business model, reflecting the commercial drive to create export routes and new markets for production fields. Ghana has a number of highly active international oil and gas companies working on upstream exploration and production which may be enticed into investment in midstream facilities. However, other financing sources are also possible.

If the private sector cannot be expected to deliver adequate or appropriate development independently, then some form of PPP may be suitable. Selecting an appropriate PPP structure for development will depend on the type of infrastructure in question. Where a single, easily identifiable project is being considered such as an LNG processing plant or a point-to-point pipeline then a form of BOOT structure, with appropriate incentives, is likely to be the most viable option. A JV with the public sector (government as opposed to an SOE) as a directly involved equity party should be considered where the project drivers are heavily weighted towards socio-economic goals that are not easily achieved under a standard revenue mechanism. Where a collection of assets (either new or existing and in need of expansion and refurbishment) is under consideration, then a full concession may be most appropriate. The concession contract and the regulatory framework should be carefully structured to ensure monopolistic conditions are controlled and there are adequate incentives for the concessionaire to undertake necessary investments throughout the concession lifetime.

Current Situation for PPPs in Ghana

In June 2011, Ghana adopted its National Policy on PPPs to provide the initial framework for better organisation of PPPs in Ghana. The policy relates to the range of PPP options where there is significant risk transfer from the public sector to the private sector, but short of full divestiture. The policy is based on a number of key principles, foremost of which are best value for money, appropriate risk allocation and ability to pay by all parties. Ensuring a competitive tender process wherever feasible is also stipulated.

Pursuant to this policy, in May 2013, the GoG published a revised draft Ghana Public Private Partnership Bill to provide the legal basis for the PPP process. The draft bill reiterates the importance of appropriate risk allocation with the party best able to bear it and use of competitive and transparent selection processes. Section 35 of the draft bill outlines the criteria for qualifying projects for a PPP process. The list includes the National Development Plan and National Infrastructure Plan as well as allowing for a list of Strategic National Projects approved from time to time by Cabinet or by the responsible Ministry. This last item provides scope for important infrastructure projects such as those identified within the GMP which are not contained in the other development plans.

Part 4 of the bill relates to tender procedures, providing for a market sounding, EoI and (where appropriate) two-leg proposal stages. Such a process enables the contracting authority to ensure only pre-qualified bidders who meet certain minimum financial and technical standards are permitted, guarding against the risk of non-delivery. As a further deterrent against failure to deliver, Section 69 allows for bid securities to be required.

Enhancing Competition

An additional method of raising the quality of winning bids is to implement a multi-criteria award system, where price is only one component, and other factors are taken into account, such as plan scheduling, bidder experience, track record and quality of business plans. Such an approach provides the buyer with a more subtle balance of risk and reward between bidder qualities than the in-or-out nature of a pre-qualification round, followed by a price only auction. Interviews can also form part of this process.

The draft bill allows for this form of tender structure to be applied in Ghana. However, the model has been criticised for lacking transparency and providing bias towards the incumbent, so is not recommended where this could create difficulty in attracting a wide pool of interested parties[27].

Competition is absolutely vital for a successful tender process. Many potential investors in major gas infrastructure projects are highly experienced players in international gas markets and therefore Ghana must compete for their capital with other investment destinations. In addition to offering a financially viable opportunity, there are a number of further ways Ghana can maximise the number of credible bidders in what is for them a new market, including:

- Ensuring the opportunity is well publicised, with advance notice via commonly used, public tender publication channels
- Producing a detailed project investment prospectus prior to formal tender as part of a dialogue with potential investors
- Holding information meetings, including a hearing round following issue of draft tender materials for comment and refinement

[27] See for example: Maurer, L. and Barroso L. (2011), "Electricity Auctions: An overview of efficient practices", World Bank Study available at: http://www.ifc.org/wps/wcm/connect/8a92fa004aabaa73977bd79e0dc67fc6/Electricity+and+Demand+Side+Auctions.pdf?MOD=AJPERES

- Providing a clear roadmap for the future development of the sector, indicating further tender opportunities of a similar nature, thus incentivising investors to take a strategic position in the market

- Performing pre-development work where uncertainty over conditions and technical viability can vastly increase risk for bidders.

A further aspect that can count against non-incumbent bidders is inflexible conditions on the winning bid. While protecting against project delays and non-delivery is important (as discussed below), unreasonably strict timetables and hefty penalties can present too high a risk for a new player less familiar with local processes.

A final point to note is that the greater the complexity in the permitting and licensing regime, the greater the disadvantage will be of not having existing relationships and experience of negotiating that process. This will again present a disincentive to new players from entering the Ghanaian gas infrastructure market. Simplifying this process and minimising the number of administrative counter-parties will therefore help encourage further competition to tender opportunities.

7.3.3 Financial Support Mechanisms

Financial incentive mechanisms for infrastructure projects can come in the form of direct financial subsidy or indirect support through undertaking activities on a developer's behalf, streamlining processes or providing credit support through loan guarantees and related instruments. Subsidies can also be considered, these being targeted at capital expenditure, operational expenditure (including loan repayments and tax levies) or revenue support. A description of the various options and appropriate use thereof is provided in Annex A6.

The National PPP Policy outlined three instruments for supporting project preparation and financial viability:

- **Infrastructure Finance Facility** (now termed "**Ghana Infrastructure Fund**") – announced in the 2014 budget statement, the establishment of this fund is intended to provide financing via bonds to strategic projects including PPPs by perusing independent credit ratings on international markets and lending at commercial rates. The fund is proposed to be initially sourced from VAT receipts and oil revenues.

- **Project Development Facility (PDF)** – to enable **upstream investment app**raisal, value for money assessments and other feasibility and safeguard studies.

- **Viability Gap Scheme – proposed to** support pr**ojects with direct capita**l investment or grants which are economically justified (on socio-economic ground**s) but not financial**ly viable in the private sector.

- **In addition to the above proposals,** as noted **in Section** 0, the Ghana Natural Gas Sector Short Term Action Plan also proposes **a fund to be drawn f**rom gas revenues to help provide securitization for the gas chain.

7.4 Conclusions

The following conclusions and recommendations can be drawn from the above discussion on possible financing structures:

- The GoG is faced with substantial challenges in the provision of new infrastructure in the coming years and is therefore unlikely to be able to meet all investments required under the GMP.

- Royalties and tax from the production and sale of gas may help provide securitization along the gas chain rather than fully fund specific investments.

- Private sector involvement through PPP structures are needed to provide sufficient funding for all identified infrastructure to be delivered.

- A BOOT arrangement is most suitable for easily identifiable projects such as an LNG FSRUs and point-to-point pipelines while concession arrangements are better suited for distribution networks.

- Any government support should focus on risks which are outside the control of developers and more easily borne by the State. Most important is undertaking early stage development work and securing land prior to project tender.

8 GAS PRICING POLICY

8.1 Existing Pricing Policy

The Natural Gas Pricing Policy (NGPP) was published by the then Ministry of Energy and Petroleum (MoEP) in May 2012 and sets out the gas pricing principles.

The 2012 document envisaged import parity pricing for gas, resulting in expected surplus revenue being accumulated in a Gas Rent Fund. This would *inter alia* be used to resolve investment deficits in the power sector, and, when resources permit, cross-subsidise the fertiliser industry and other strategic sectors.

This section briefly summarises the key features of the NGPP and discusses the differences, along with the recommendations of this Master Plan.

8.1.1 Main Features

The 2012 Natural Gas Pricing Policy published by the MoEP, outlines the following policy objectives:

1. **To secure the commercialization of Ghana's gas reserves**, and ensure economic viability for all parties along the gas value chain with adequate incentives for investment;

2. **To ensure sustained and secure availability of gas,** leading to the provision of secure power supplies for Ghana and supported by a stable and predictable commercial framework;

3. **To insulate Government from the adverse effects of providing subsidies,** by developing a pricing policy that insulates Government from pressure to intervene in the actual price paid by users of gas;

4. **To promote environmental responsibility,** by discouraging environmentally damaging actions, such as flaring;

5. **To provide a source of funding to support Energy Policy commitments,** by maximising the potential rent between the minimum viable gas purchase price and maximum achievable gas sales price to support established energy policy commitments;

6. **To facilitate the development of strategic sectors,** notably the production of ammonia, by providing for differentiated pricing to make such a plant viable without distorting the market for gas.

In support of the above objectives, the NGPP gives guidance regarding establishing the gas purchase price, the gas sales price, the transportation tariff and the rent allocation which arises from the application of objective 5 in the above list. The main features are:

- **Regarding the gas purchase price:**

- Associated gas shall be purchased at no more than US$1 per mmbtu plus the 'aggregation tariff'[28];
- Non-associated gas for domestic utilization shall be purchased at no more than the weighted average import price; and
- Associated and non-associated gas shall be purchased at a level that covers costs and ensures an appropriate rate of return on capital invested.

- **Regarding the gas sales price:**
  - All natural gas shall be sold at no less than import parity prices (as determined by the GoG and PURC) to all users;
  - Above this value, gas customers shall be free to negotiate prices with the gas aggregator;
  - Commodity prices and transportation variable charges shall receive full cost pass-through into variable energy costs and end user tariffs; and
  - Contracts shall be reviewed bi-annually to reflect inflation and US$/cedi exchange rate movements.

- **Regarding rent allocation:**
  - Price discrimination will not occur directly but rather subsidies to 'Strategic Sectors' will be provided through a Gas Rent Fund (GRF) derived from sales revenue;
  - Minimum rebate or subsidy to Strategic Sectors should consider the netback price as advised by PURC and approved by the GoG;
  - The effective price for Strategic Sectors should be not less than the average cost of gas supply from all sources;
  - Rent accruing from the power sector shall be allocated in its entirety to the electricity sector; and
  - A small percentage of the rent may be used to fund the extension of natural gas infrastructure to communities where there is no existing market incentives to do so.

In addition to the above principles for pricing structure, the NGPP also stressed the importance of transparency with the publication, including pricing, of both commodity and transportation services.

[28] While identified in the sub-heading for Section 4.4.5 of the NGPP, no guidance is provided in the text regarding any 'Aggregation Tariff' payable to the gas aggregator (assumed in the NGPP to be GNGC but since declared as GNPC)

8.1.2 GMP Pricing Proposals Compared to the NGPP

Policy Objectives 1 to 4 from section 8.1.1 are largely followed in the GMP approach and the recommendations in section 8.2 will reinforce them. However, the approach does not consider in much detail the wider policy issues covered by Policy Objectives 5 and 6. The concerns with the NGPP are elaborated as follows:

Unregulated commodity charges resulting in monopolistic pricing features

The objective to maximise the potential rent from the envelope that exists between minimum viable purchase price and maximum achievable sales price, is reflected in the condition that gas customers are "free to negotiate with the aggregator, a price for available gas that shall be equal to or greater than the import parity price". This suggests the aggregator's sales prices be unregulated and thus confers monopoly pricing power to such gas sales. The economic value of utilising gas for the final customers could be limited, hindering the development of these sectors and constraining future demand increases below that which is optimal for the economic development of Ghana. This is a concern for all sectors, particularly the power sector.

Regulated gas purchase prices jeopardizing future domestic production

The existing NGPP suggests that upstream gas purchase prices be regulated, i.e. the price paid by the gas aggregator to upstream producers be controlled. Upstream gas price negotiations should ideally be independent of domestic gas pricing norms, except that the aggregator may refuse to sign a contract if the price offered is not compatible with policy objectives.

Costs of gas production can vary enormously between fields depending on a range of factors, as well as the difference between associated and non-associated gas. Prices are normally negotiated bilaterally between the gas aggregator and the upstream producer and formalised in Production Sharing Agreements (PSA)[29] or Gas Sales Agreements (GSA). These negotiations can be guided by a variety of factors on the government's side (e.g. import price considerations, cost recovery of upstream producers, netback analyses, financial health of aggregate buyer, etc). However these should not be formalized in the pricing policy or gas price regulations as field characteristics and circumstances vary over time. Upstream exploration might be discouraged by the implied political risk and future domestic gas production would thereby be jeopardized.

Rent allocation across consumer groups not based on costs

While it may be appropriate to use a proportion of the achievable rent from gas sales to support energy policy objectives, notably via securitization of the gas chain, the magnitude of such rent should be balanced against the development of end-user industries consistent with the stated objective that energy pricing "is efficient and competitive". The objectives of maximising rent and maximising the economic value creation by the gas using sectors need to be carefully balanced.

Prioritizing 'Strategic Sectors' to the detriment of wider inclusive economic development

[29] It is understood that current PSAs for oil production do not include terms for the associated gas

The approach in the NGPP of, in effect, cross-subsidising by charging some gas users at higher prices in order to provide resources to pursue certain industrial policy objectives, would be hard to implement effectively. It is likely over time to become inconsistent with GoG's intention to use Ghana's gas resources to bring about widespread, inclusive national development. Allowing all users to purchase gas at the lowest sustainable price that balances supply and demand is a more assured way of maximising the national development impact[30].

Fertilizer industry as 'Strategic sector' not based on economic justification

The NGPP highlights the development multiplier potential of the fertilizer sector as justification for its prioritization as a 'Strategic Sector'. However, given that even larger development impact multipliers also apply in the power sector and some other sectors, the lowest price requirement applies particularly to the electricity industry. Furthermore the proposition in the NGPP that rent accruing from the power sector be *"allocated in its entirety to the electricity sector"* raises the question from where the funding for any subsidy to Strategic Sectors will be derived.

The demand modelling demonstrates that the vast majority of demand, and thus revenue, is expected from the power sector, while only small quantities are expected to be demanded from other industrial heat sources. On their own these are unlikely to be able to support an ammonia plant or similar large-scale capital-intensive initiative characterised as a Strategic Sector.

Difficulty of prescribing an associated gas price

No justification is provided in the NGPP for the proposed purchase price of associated gas at US$1 per mmbtu (plus the 'aggregation tariff'). This also appears to be in conflict with the criterion that the price should reflect the cost of production plus an appropriate return. Costs of associated gas production are hard to determine, given that it is joint production with oil and each field has different circumstances. In the case of Jubilee, the first 200 Bcf is being given at zero price as an incentive to develop the facilities to take the gas and avoid damaging oil production.

Import parity price ill-defined, with risks of high and volatile prices, creating uncertainty in the market

It is envisaged in the NGPP that the 'Aggregation Tariff' will ensure import price parity for gas sales in Ghana. Several complications arise from this approach. Firstly, there is no rationale in the GMP or the policy objectives for imposing the condition that gas shall be sold at greater than import parity. Secondly, the import parity price, being ill-defined, might be both volatile and higher than a weighted average cost of gas (WACOG) price. This could slow down the penetration of gas in Ghana's energy mix and postpone the national benefits of gas utilisation.

8.2 Features of Proposed GMP Pricing Policy

The existing natural gas pricing policy appears to have certain gaps and insufficiently defined components. This section of the Report summarises firstly, key principles used to

[30] Subsidies may be given to strategic sectors in other ways more effectively.

guide the development of a revised pricing policy; and secondly, outlines recommendations for each pricing component in the gas value chain.

8.2.1 Guiding Principles used for Proposed Pricing Policy

The following principles have been used to frame the revised pricing policy proposals:

- **The gas pricing regime should ensure the financial security of (i) the gas aggregator and (ii) the gas infrastructure investment body** *(in line with Policy Objective 1, 2 and 3 of existing pricing policy)* **–**To ensure upstream investments and a stable commercial framework, the key Government entities along the gas value chain need to be financially secure.

    - Firstly, the gas aggregator needs to at least have sufficient revenue to cover its gas purchases. Without it domestic supplies, upstream investments and public finances are put at risk. Securitisation of long term gas purchase contracts would at a minimum require full recovery of gas purchase costs through the selling prices.

    - Secondly, the gas infrastructure investment body needs to have sufficiently high revenue levels to recover its investments and the cost of financing.

- **Gas commodity purchase prices will be determined by negotiated PSAs/GSAs and not by domestic pricing policy considerations** *(Policy Objective 1 and 2)* **other than the ability to refuse to purchase gas if no price agreement is reached (also subject to the terms of the PSAs) –** In other words, the upstream gas price from each source of supply will be determined bilaterally on the basis of contractual agreements between the gas aggregator and upstream operators.[31]

- For associated gas, cost recovery should be allowed to encourage investment in platform infrastructure, a Debt/Equity ratio of 3:1 is recommended for investment in platform infrastructure. In effect, cost recovery for handling gas up to the flange of the production platform should be allowed in the pricing mechanism[32][33].

- **All gas sales price components should be regulated transparently** *(Policy Objective 1 and 2)* **–** The gas value chain in Ghana will be inherently monopolistic in character, at least for the early stages of sector and infrastructure development. There will initially be a single processing plant and pipeline system, and gas users in Ghana will buy gas from the aggregator. To enable private sector participation, facilitate downstream

[31]These prices will not be regulated or determined in the pricing policy, but instead should be negotiated by GNPC on a case by case basis. GNPC can use benchmark prices to guide these negotiations. These benchmark prices can be determined among other things by cost of production, type of gas, volume of supply or international benchmark prices. A detailed discussion of these benchmark prices is provided in the February 2014 published Report '*USAID Technical Assistance to Ghana PURC on Natural Gas Tariff Setting'*. Note that upstream operators are more likely to refer to opportunity or avoided costs approach, ie the price that would have to be paid for the next more expensive source of supply, if the negotiating operator's supply offer was withdrawn.

[32] Even though this is recommended for now, it could be negotiated as economic parameters change.

[33] For associated gas, the price should be negotiated between the supplier and aggregator subject to a maximum cap of US$1/mmbtu

and upstream investments and provide a consistent commercial framework of operation, price regulation has to be done transparently. As noted above, only gas purchase prices, i.e. the price charged by upstream producers to the aggregator, will not be regulated but determined through bilateral contract negotiations.

- **Average cost instead of marginal cost principles shall be used to determine tariffs in the short to medium term** *(Policy Objective 3)* **–** In new and developing gas markets, prices can be set on the 'second best' basis of average costs and not marginal costs.
- Gas delivered to the end user should be based on a weighted average cost of gas from different sources.

  - **All gas price components should be cost reflective and yield an adequate level of return** *(Policy Objective 1 and 3)* **–** To ensure financial stability for the key entities along the gas value chain and provide incentives for investment**,** all tariff components should recover costs fully, plus an adequate level of return.The components are the gas commodity charge (price paid by consumers to the aggregator for gas supply), processing charge, transmission tariff and distribution tariff.

  - **The commodity charge approach should be based on the weighted average cost of gas (WACOG),**i.e. the average purchase gas price for the aggregator, weighted by the volumes of gas from different sources, plus a small margin to cover the aggregator's costs and risk. However, given the large price variations between different gas streams (Domestic, WAGP and LNG) consideration needs to be given to the way WACOG is calculated and which gas streams are included (see below). It is however recommended that Jubilee foundation gas volumes should be excluded from WACOG calculation, to provide a financial reserve.

  - **Gas gathering, transmission and distribution prices should be set and updated by an independent regulator** *(Policy Objective 1)* **–** Prices should be set according to a predetermined regulatory methodology with regular tariff reviews implemented by the independent regulator. Hence a strong regulatory framework and regulator with adequate capabilities and enforcement mechanisms must be in place.

  - **Cost of gas supply should be the only driver for price differentials across consumer groups** *(Policy Objective 4)* – Gas price differences across consumer categories (e.g. industrial users, households, power sector, etc) should be based solely on cost differentials of gas supply. For example, bulk gas buyers (e.g. the base load power generation sector) connected to the transmission system, will incur lower costs than smaller users with a daily or seasonal load profile. Within consumer categories, gas prices should not vary unless there is strong cost-based justification, which would normally be related to the shape of the load profile and the predictability of the average level of demand.

8.2.2 Key Components of Gas Price Formulation

This section provides brief details on the six key components of the proposed gas pricing regime. The proposals outlined here provide a summary of the key proposed principles and are suggested as a basis for subsequent detailed formulation of the pricing rules.

The following components of the final price to gas consumers need to be determined:

- gas commodity price
- gas pipeline tariff
    - gas gathering
    - gas transmission
    - gas distribution (applying only to retail customers)
- gas processing fee
- levies, margins and taxes (where applicable)

The established guiding principles set out in Section 8.2.1 are to be applied to each of these components together with international regulatory principles for the gathering, processing, transmission and distribution components. The pricing regulator will be responsible for defining the detailed methodology to be used for the downstream infrastructure related components, specifying procedures for periodic price reviews, providing an indexation formula to protect the real value of the prices between major reviews and defining circumstances for exceptional reviews to take place.

Gas Commodity Price

In line with the guiding principles of cost reflectivity of tariffs, the commodity price in the short to medium term is proposed to be calculated as the weighted average cost of gas (the WACOG price). The aggregator of domestic gas will have long term contractual arrangements with each of the producers, and will also import gas when necessary to supplement domestic supplies. The average cost, weighted by the volumes from the different sources, plus a small margin to cover the costs and risks of aggregating and supplying gas, is what should define the commodity gas price for the gas aggregator. The WACOG could be set by the Regulator . The periodicity of adjustment should be quarterly.

Average cost pricing, implemented in the form of a WACOG is recommended as the most suitable at this stage of the development of Ghana's gas sector.

Implementing WACOG

The WACOG is recommended in Ghana because of the current specific circumstances, where the immediate streams of gas have different prices and volumes, e.g. between domestic gas, WAGP and possible future LNG imports.

Given these features, it is recommended to keep Jubilee Foundation gas out of the 'pool' of supply sources that go into the WACOG calculation.

The justification for this is illustrated in the figures below, which highlight the short term volatility of WACOG in the medium term (the next 5 years) if Jubilee gas would be a constituent of WACOG. The examples are derived by simulating some variations in the availability of gas from each source, reflecting their past behaviour or expected characteristics, e.g. for WAGP and for Jubilee as associated gas is also dependent on processing facilities.

The figures are created by simulating the availability of gas to meet demand in each quarterly period (assumed to be the pricing period for WACOG), based on assumed variability in the availability of each source of supply. The difference between Example 1

(**Figure 54**) and Example 2 (**Figure 55**) is due to the random simulation of changes in available supply including the new sources that are expected later in the 5 year period.

Apart from the differences between the three demand/supply cases (low, base and high), the volatility of WACOG in successive 3 month periods is mainly caused by the variation in the total supply mix. Price fluctuations of US$0.5/mmbtu up and down in successive 3 month periods (e.g. as can be seen in 2017 for the base case), or very large jumps in successive periods (as seen in last 2 quarters of 2017), are likely to be unacceptable.

Figure 54: Volatility of WACOG Prices including Jubilee Gas, example 1

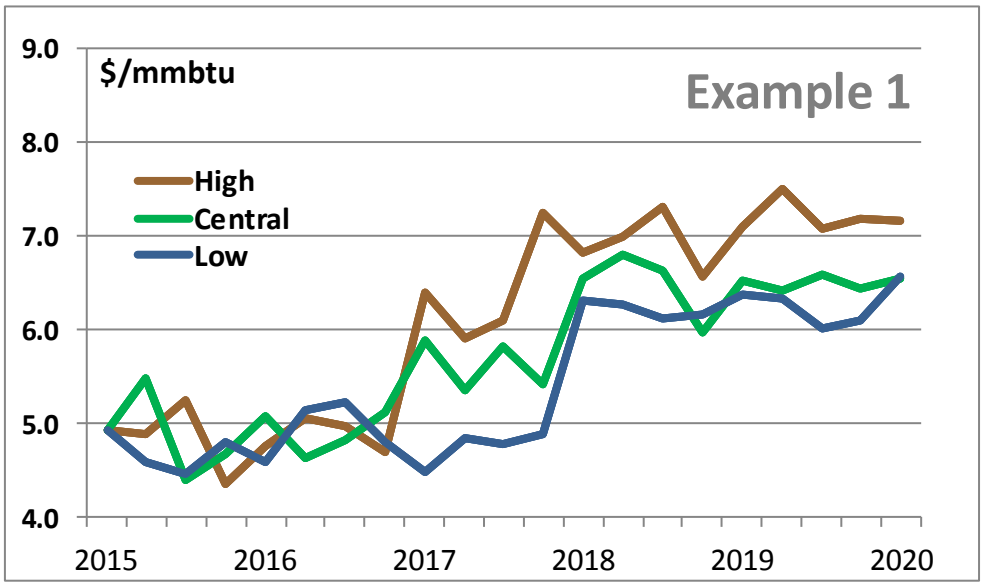
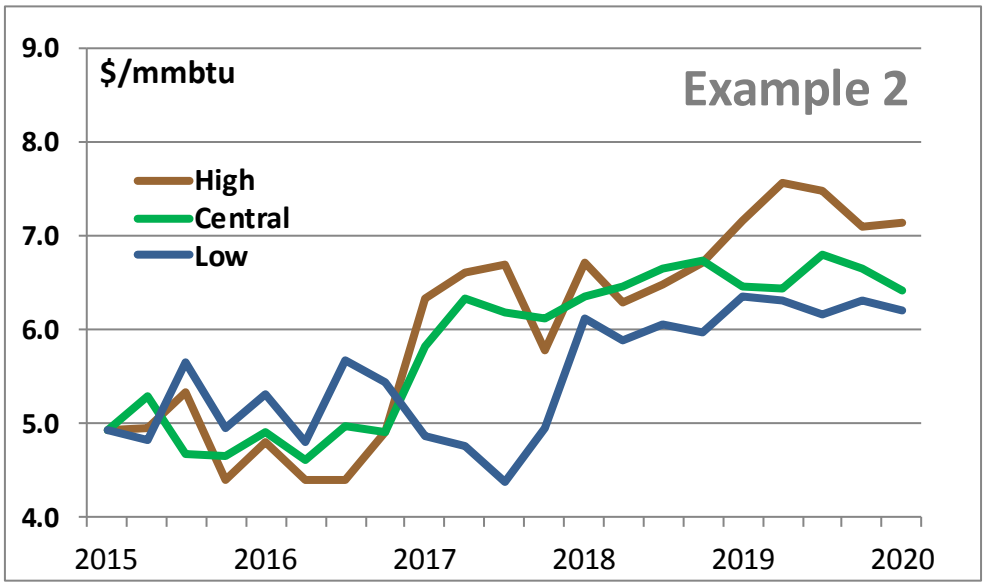


Figure 55: Volatility of WACOG Prices including Jubilee Gas, example 2

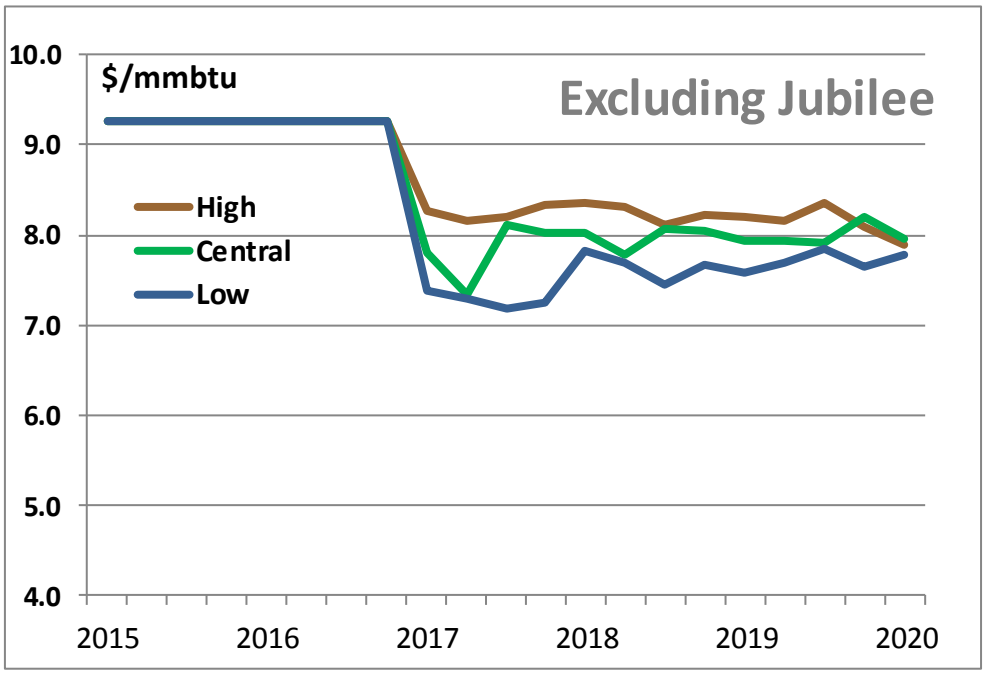


If Jubilee foundation gas is excluded from WACOG, the volatility of the calculated WACOG price will be reduced as the prices of the other supply sources are closer to each other. This is simulated in **Figure 56**. Looking first at the period after 2017, the fluctuation in WACOG is

reduced compared to the previous figures. It would be possible to set a smooth path provided the aggregator had the financial capability to absorb some of the fluctuation in the short term (while recovering it all in the medium term).

The period before 2017 is determined by the WAGP price under existing contracts. The financial effects of this may be offset by providing some Jubilee gas at a low price, noting that some of the rent in the Jubilee gas compared to future gas supply may be directed towards the Rent Fund.

Figure 56: WACOG Prices excluding Jubilee Gas



In summary, the preferred approach is an implementation of WACOG based on a pooling of the costs of all supply sources except Jubilee. It is recommended that the WACOG is calculated on a quarterly basis.

Gas Processing Fee

The second component to be regulated and reviewed by the Regulator should be the gas processing fee, as initially, the Processor will have a monopoly.

The fee should at a minimum cover the direct operational and maintenance (O&M) costs of the processing plant, and the debt service charges associated with its construction.

Gas Pipeline Tariff

Pipeline transportation comprises the gathering, transmission and distribution.

The pipeline tariff basically has two components_- capacity reservation charge and demand charge. The capacity reservation charge is normally fixed, while the demand charge varies with the transported volume.

The regulation of the pipeline tariff should follow the same principles as the gas processing fee.. There is detailed discussion of gas transmission tariff-setting for Ghana in the recent study funded by USAID[34]. The study recommends a cost recovery based postage stamp pricing principle.

In light of the recommendation to calculate the WACOG to determine the commodity price, it is also recommended to use the WACOG to guide the transportation service charges in Ghana instead of an arbitrary index of international netback prices.

The gas distribution charge will apply only to retail customers purchasing gas through an intermediary (such as a Local Distribution Company), rather than directly from the Gas Aggregator. At a suitable time, the concerned regulatory body will call for applications for distribution licences, covering development and operation of city gate stations and a distribution grid. The associated capital and O&M costs need to be presented to the Regulator for a charge to be set for the use of the distribution system. Similar to the commodity, gathering, transmission and processing charges, gas distribution tariffs will have to be cost reflective and provide an adequate rate of return to the developers and operators of the infrastructure.

Connection Charging Principles

For transmission and distribution, connection charges can be based on either shallow (costs of only direct connection to a nearby pipeline) or deep (costs of all incremental pipeline investments including reinforcement to the existing system) charging principles. Shallow charging enables more potential customers to request connection but loads additional costs onto the network provider. Deep charging can result in large and inequitable charges being loaded onto a consumer who happens to request connection that triggers the need for incremental investment. It is proposed that shallow pricing is adopted as being fair across consumer groups, though successful approaches from other countries developing new markets, such as Turkey[35], may be considered.

Levies

In addition to the direct charges identified above, the final price to the gas consumer will need to be augmented by various levies. Levies that are already provided for in the legislation are those required to finance the regulatory institutions. Other levies may also be warranted.

8.3 Implementation of Recommended Pricing Policy Principles

The proposed guiding principles and key features to be determined in the pricing policy need to be expanded in more detail to develop into an implementable gas pricing policy.

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[35] In Turkey, if the network company refuses connection on the grounds that connection costs are not covered by the connection fee, the customer may build the connection at their own cost and recover it through a reduction in future network tariff charges.

This will require both clear specification of the pricing system and its regulation, as well as ability of the pricing regime to be implemented by all concerned entities.

In addition to rewriting and promulgating a new gas pricing policy which is consistent with the Gas Master Plan, the detailed regulatory framework needs to be defined (methodology for price setting, application and review process, regulatory information requirements, etc) and the Regulator strengthened to take on gas, which is a new sector for the Regulatory body. Annex A7 provides some detail on the main areas where implementation steps are needed.

9 RECOMMENDATIONS ON KEY ISSUES

Ghana is poised to make effective use of its petroleum and gas resources to raise its development trajectory to a new level. Some recommendations are made in this report on short-term issues, but the focus is on key measures to ensure the medium and long-term development of the gas sector:

- **Policy**: Finalise and approve the Gas Master Plan and make clear GoG's commitment to its core gas allocation prioritisation (power sector and industrial process heat) and issue a National Gas Policy. **Legislation**: Use the new Gas Policy as the basis for developing a comprehensive Gas Sector Act which will support the continuous development of gas in the national interest.

- **Regulation**: Provide a stable regulatory and fiscal framework, including predictable fiscal conditions and gas prices, for the upstream, midstream and downstream components of the gas industry.

- **Institutional structure for infrastructure development**: Streamline coordination of infrastructure development along the gas value chain, to reduce risks and improve coordination of infrastructure development. Designate GNPC as the Gas Sector Aggregator, which would become a temporary monopoly in the short run. In particular the responsibility of gas infrastructure planning and asset ownership needs to be clarified for improved coordination.

- **Pricing**: Review and promulgate a new national gas pricing policy which is consistent with the Gas Master Plan and define the detailed regulatory framework.

- **Capacity-building**: Put resources into capacity-building in each of the competence areas required for the gas sector.

- **Infrastructure:** Enable and support the development of key strategic gas infrastructure, which includes, reverse flow arrangements with WAGP, coastal east-west pipeline and LNG terminal in Tema.

- **PPPs for gas projects**: Working through the newly defined national PPP framework, be open to flexible PPP arrangements to ensure adequate financing of gas infrastructure investments.

- **Government financial support**: Draw on the *Project Development Facility* to prepare projects to a stage where an efficient competitive bidding process can be launched; use the *Ghana Infrastructure Fund* (rather than a special purpose gas securitisation fund) to provide the public financing component of PPP and JV transactions. Provide government guarantees and/or subsidies sparingly, if at all, in the gas sector.

- **Imports***:* Ensure adequate security of supply to attract IPP investments through supplementing domestic supplies with flexible import arrangements (undiminished importance to WAGP imports, together with LNG).

- **Off-taker viability**: Ensure the financial viability and associated credit-worthiness of power and gas sector entities.

- **Industrial gas users**: Develop low pressure distribution networks in industrial areas and encourage them to switch to gas.

- **Transport sector**: Undertake a **pilot** project on the import of compressed natural gas vehicles, as part of public transportation. Subsequently, the Ministries of Transport and Petroleum should collaborate to develop a policy framework for infrastructure and retrofitting of vehicles to use CNG.

- **Increasing reserves**: As the domestic gas market develops, IOCs should be encouraged to maximize the exploitation of existing fields and exploration of new fields to increase reserves. Review future supply-demand balances on a regular basis and re-assess the costs and benefits of introducing a wider spectrum of gas utilisation.

ANNEXES

A2 Documents reviewed

Natural Gas Infrastructure Plan for Ghana – 2007-2012

CH2M Hill (LNG options) Draft Report

Natural Gas Pricing Policy

Transmission pricing methodology

Natural Gas Utilization Plan for Ghana – *2009-2012*

LPG promotion Strategy- *2010*

Updated Natural Gas Utilization Plan

Grid Co Power Development Plan

Official documentation and maps of upstream reserves

Fundamental Petroleum policy for Ghana – *2008*

Energy Sector Strategy and Development Plan *(2010)*

Local Content and Local Participation in Petroleum Activities – Policy Framework *(2009)*

Advisory Paper on Ghana Gas Sector Development Plan *(Nexant 2010)*

Ghana Natural Gas Sector Short Term Action Plan *(Nexant 2014)*

Strategic and Environmental Assessment on the oil and gas sector

A3 International case studies

This annex providessummarised accounts of the experience of seven countries in developing their national gas markets after discovery of domestic gas resources. The objective of the case studies is to identify the key lessons to be learned for Ghana from past experiences in developing domestic gas markets.

The countries studied were selected to illustrate different aspects of the situation in Ghana: newly found gas resources, lack of a developed domestic gas market, economic situation and growth opportunities, import substitution, export options (for gas and energy intensive products). Our review highlights both successful as well as less successful gas policy and market development trajectories. The countries included in our assessment are (in alphabetical order):

Colombia

Indonesia

Israel

The Netherlands

Nigeria

Tanzania

Thailand

Turkey

A3.1 Colombia

A3.1.1 Summary lessons learned

The Colombian gas sector is of interest to Ghana due to the medium size of its natural reserves, which are mostly associated gas. As such, the gas market was developed on the back of increased oil production. The following list summarises the key lessons relevant to the Ghanaian market:

Gas was initially targeted for power generation to replace fuel oil and complement hydro power generation. Also industrial users were targeted, but no specific sector was prioritised. Instead the gasification strategy was driven by geographic considerations. The location of gas reserves off the Caribbean coast meant that users across all industries in the two largest cities along the coast were targeted. In 1986, upon the discovery of large onshore reserves located close to the capital, the Government decided to make access to gas in the industrial and residential sectors a key priority.

Key factors that contributed to the increased gasification of the country and of the residential sectors were firstly, **a cross subsidised pricing policy** where commercial, industrial and wealthy residential users paid a premium on gas used for subsidising gas consumption for lower income users. Secondly, the **development of a regional gas pipeline plan subsidised by the government**. The development of gas transmission system were done by prioritising urban clusters and regions deemed economically sufficiently solid to affordnatural gas. Institutional responsibility for the development of the pipeline network was given to one state owned entity, which owned, operated and developed the network.

The development of Natural Gas Vehicles (NGV) has been particularly successful in Colombia due to a mix of preferential tax treatment, subsidies to facilities provided for conversion and supply of Compressed Natural Gas (CNG), and increased taxes on the conventional fuels, which made NGV more competitive vis-à-vis liquid fuels.

Colombia has been very successful in attracting private investment across all segments of its gas industry. This has reduced the level of public funds needed to develop the industry and lead to an efficient operation of the industry. In the upstream segment this was ensured through an independent licensing authority. The former state company Ecopetrol is still a major player in the industry but does not benefit favourable treatment over other companies. In the downstream sector the success has been through a major privatisation programme. Gas transmission is under private ownership as is much of the gas distribution industry.

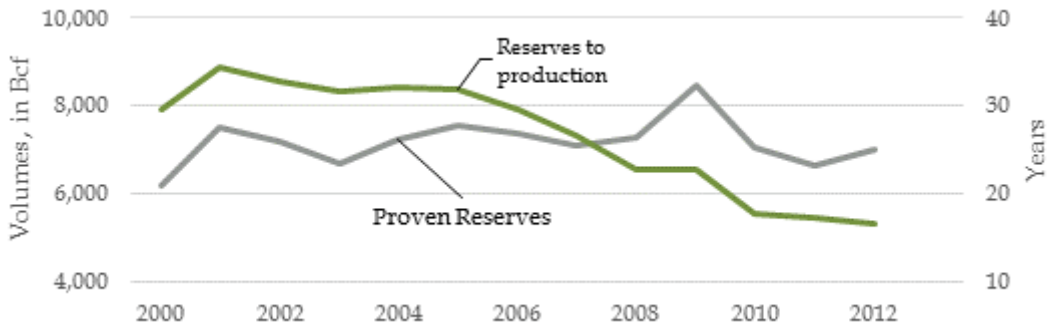
A3.1.2 Overview of gas sector

The initial development of the natural gas sector in Colombia took place in the 1970s after the discovery of the Santander oil field with associated gas and immediate prohibition of gas flaring. Subsequently, the discoveries of the Caño Limón and Cusiana/Cupiagua fields in the 1980s resulted in a significant increase in oil production. Gas sector development was effectively driven by associated gas and as a consequence of the rapid growth in oil production.

Supply and demand overview

Colombia's gas production started in 1970 and historically gas was only used domestically. Proven natural gas reserves are considered to be of medium size, estimated at approximately 5.5 Tcf. The country is self-sufficient and has started exporting gas to neighbouring Venezuela in 2005. Figure 57 shows the annual production (left axis) and the reserves-to-production ratio on the right axis.

Figure 57 Colombia gas reserves and production



Source: Ecopetrol and ANH

Most of the associated gas is re-injected for enhanced oil recovery (56% of all associated gas). Only a small share of gas extracted is vented and flared (2% in 2011). In 2012, 16% of the 440 bcf produced were exported to Venezuela, leaving 360 bcf for the domestic market.

A3.1.3 Gas utilisation

The gas utilisation strategy followed in Colombia was mainly driven by geographical factors. The two largest cities along the Caribbean coast, close to the associated gas reserves, were connected to deliver gas to the power generation sector and any large possible industrial offtaker. No specific preferred allocation among industrial users was followed and gas was used in glass manufacturing, mining, food production, iron and steel, the paper and pulp industry, cement and textile manufacturing.[36]

Although some residential users were connected to the grid in the Caribbean region, domestic usage only became a clear government policy in 1986, when new reserves were discovered onshore close to the capital city Bogota. The *Massive Use of Natural Gas Plan* was used as the main gas allocation document setting out gas usage for residential, commercial, transport and any other industrial sectors.

As part of the gas utilisation plans, the Colombian government subsidised the roll out of a regional gas pipeline project connecting major cities as well as more rural areas. This was done through state owned Promigas. Today, the transmission network is extensive and covers most of the populated areas of the country. The largest users of gas today are:

Industrial sector - as noted above, industry has historically been a key driver of gas consumption in Colombia, accounting to close to 31% of total consumption. No particular industry was explicitly targeted, but instead regional considerations initially

[36] Ecopetrol, 2014.

lead to gasification of industrial users. Later, economic assessments of certain regions were made to prioritise regions and pertaining industries that were able to afford gas.

Power generation - although gas is only the second energy source for power production, since power is mainly sourced from hydropower, it has become a key consumer since the Colombian gas market was developed. It accounts for approximately 24% of all consumption.In recent years, weather-related events have given rise to hydroelectric shortages, which have pushed the government to design policies that will increase power generation from natural gas.

Residential customers **-** residential consumption has increased significantly due to the stepping up of efforts to connect more consumers since 2010. Also, the introduction of a cross-subsidies have helped this development. Residential gas consumption accounts for 21%.

Refinery **-**the use of gas as raw material to produce urea, alcohols and other products, despite not being a key driver at the initial stages, has risen significantly. Its consumption accounts for 14%.

NGV **-** the use of natural gas as a vehicular fuel was only introduced in the 2006-2010 National Development Plan which set a target for natural gas fuelled vehicles in Colombia and introduced two support schemes, described below. In 2011, gas consumption in this sector accounted for 9% of all utilisation.

The abovementioned National Development Plan set a goal of 40,000 vehicles converted during the period. However, this target was quickly surpassed: in 2005, the market in Colombia made a breakthrough by converting 40,000 vehicles thanks to a conversion support scheme introduced which provides a subsidy of US$200-500 per vehicle converted. By 2010, Colombia had grown to become the seventh market for vehicular gas in the world, having converted a total of 324,515 vehicles.[37]

In addition, the Colombian Ministry of Mines and Energy, aiming to replace liquid fuels such as gasoline and diesel for transportation, promoted the development of a programme for adopting natural gas as an alternative fuel. Another key factor to the success of gas in the transport sector was accomplished by the introduction of a Value Added Tax (VAT) exemption for the purchase of parts and equipment for gas service stations as well as gas vehicle conversion kits. In parallel, existing subsidies for liquid and the periodic increases in the price of these fuels during the short and medium term, proved that natural gas was a more competitive fuel for transport.

Exports

Initially, exports were not part of the Colombian gas development strategy. Exports have only recently been enabled by the Colombian government, under pressure from companies which operate in the country. Since then gas exports have been permitted as long as production capacity exceeds total current demand. As a consequence, gas production was increased in 2007 to begin exports to neighbouring Venezuela through a 225 km pipeline. Ecopetrol, Chevron and Venezuelan PDVSA signed a contract under which Colombia would be the exporter in the short-term and the flow of gas would be reversed in 2012. A recent development is the plan to build a Floating Liquefaction Storage and Re-gasification Unit (FLSRU) on the Caribbean coast allowing Colombia to export gas in the form of LNG. It will

[37] Colombian Ministry of Mines and Energy, 2014

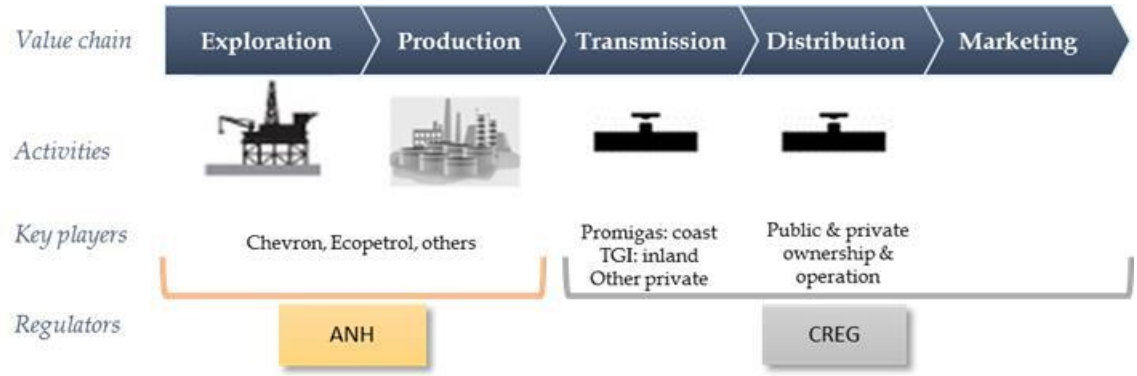
have the capacity to liquefy up to 70 mmcfd of gas sourced from La Creciente field to be exported. The system is expected to start operation in 2015.

Institutional structure

At the time the Colombian gas market was initially developed, the tendency in Latin America was for public and vertically-integrated monopolies to operate in the infrastructure sectors. Accordingly, Colombia established Ecopetrol, a state-owned monopoly company to manage all operations in the oil and gas sectors. The first Gas Master Plan (1986) aimed to use gas to replace more expensive energy sources, ie liquid fuels, across all sectors. In 1993, a new Gas Master Plan was approved by decree, establishing that Ecogas would build and operate, mostly under Build, Own, Operate, Transfer (BOOT) contracts, the transport network to connect the gas fields to Colombia's demand centres.

In the early 2000s, Colombia, following the regional trend, opened its energy markets up for international investment. This led to the restructuring of the sector. The Ministry of Mines and Energy is now responsible for the energy sector overall. Its responsibilities include the adoption of the Colombian government's policies on hydrocarbon exploration and production and the technical regulation and oversight of upstream activities. Figure 58 illustrates they key market actors in Colombia's gas sector.

Figure 58 Key players and regulation of the Colombian gas value chain



The ***Agencia Nacional de Hidrocarburos (ANH)***[38]manages Colombia's hydrocarbon resources. It was established in 2003 and given the mandate to revitalise the Colombian oil and gas sector. The regulator, which oversees the upstream market, has been successful at attracting foreign investors by designing an attractive fiscal regime which encouraged new entry. The number of exploration and development wells grew from 13 to 98 in seven years, between 2001 and 2008.

The ***Comisión de Regulación de Energía y Gas (CREG)***[39] was created in 1994. It acts as the regulator of the mid- and downstream markets from transmission to the commercialisation of natural gas in Colombia. As such, it regulates the tariff regime, quality and competition on these sub-markets for all firm involved, whether public or private.

[38] National Hydrocarbons Agency

[39]Regulatory Commission for Energy and Gas

Ecopetrol is a state-owned enterprise which enjoyed a monopolistic position in the exploitation and extraction of oil and gas. Since the creation of the ANH, Ecopetrol has no regulatory powers. It maintained all its operations and association contracts signed before 2003. Since then, private entities wishing to conduct E&P activities in Colombia no longer need to partner up with Ecopetrol.

Gas transmission is under private ownership as is much of the gas distribution industry. The key players in the transmission business are Promigas which owns and operates the network on the Atlantic and Caribbean coasts. Transportadora de Gas del Interior (TGI), an enterprise created from Ecogas' shares (the former state-owned monopolist). Ecogas was established in 1997 as an autonomous state-owned enterprise whose mission was to develop the gas pipeline network in the country. In this way, by separating the ownership and operation of the transport network from gas producers, distributors and marketers of gas, open access was guaranteed on the network. Ecogas was privatised in 2006, into the now TGI. The latter currently owns and operates the gas transmission network inland.

A3.1.4 Upstream issues

The original monopolistic position enjoyed by Ecopetrol before the opening of the market in 2000 led to the under-exploitation and underdevelopment of new oil and gas reserves. No new wells were discovered during the 1990s. In time, a consensus was initiated which put the rationale for the monopolistic structure under scrutiny. In the early 2000s, Colombia, as well as its neighbours Brazil and Peru, opened their energy markets to international investment, and state-owned enterprises were transformed into entities which operate according to the standards and practices of the private sector. With the establishment of the ANH as an autonomous regulator, Ecopetrol's regulatory functions were eliminated. Nevertheless, Ecopetrol is still a major player in the industry although it is not provided with any competitive advantages.

Since then, Colombia developed its gas market on the basis of joint initiatives between the government and private companies. At present, the largest producer of natural gas is Chevron, in partnership with Ecopetrol.

In recent years, a key concern is that domestic gas production is projected to fall short of meeting demand in the close future. A new plan to increase gas production was published in 2011. It considers the development of shale gas and coal bed methane gas fields. Increasing production has become a priority in order to meet increasing demand from the power sector.

A3.1.5 Downstream issues

Key to successful gasification was the definition of an appropriate regulatory framework, the regional gas pipeline program, a clear long term energy policy, and the commercial efforts of companies in the sector. Competition in the downstream segments was introduced in the 1990s. Since then many private companies have been licensed to operate, six of them have been granted exclusive distribution zones, while the rest operate under non-exclusivity. Prices are regulated and calculated by CREG on a cost-reflective basis, and set for five years.

Moreover, wholesale prices for Colombian gas are set depending on the field they are sourced from. CREG Regulation 119 of 2005 established that prices are regulated for gas originating from the Gas Guajira y Gas Opón fields. The price of gas from all other fields is not regulated.

A3.2 Israel

A3.2.1 Summary lessons learned

Israel's gas market has been developed from scratch in the last 10 years. As a young market, this case study offers important lessons for Ghana:

Initial gas field discoveries prompted the development of a domestic gas market through the displacement of oil for power generation. The key offtaker was the state owned power company, the Israel Electric Corporation (IEC). A newly established dedicated transmission pipeline company,Israel Natural Gas Lines, was given the initial mandate to develop the necessary gas transmission infrastructure.

Given its rapid success, limited domestic production of gas was complemented with imports via a pipeline from Egypt. However, the latter proved unreliable, prompting a situation of supply insecurity in Israel, due to its dependence on a single, inflexible import source.

The government decided to solve the country's short-term shortage of gas supply by investing in more flexible import infrastructure: a floating LNG terminal. This solution was intended to provide Israel with sufficient gas until its newly discovered large-scale fields start production.

The Israeli experience shows that continuing exploration in offshore fields can result in significant enhancement to proven national resources. However, such exploration is only likely to be undertaken once the domestic gas sector has been established. That is, when there is evidence of demand for gas, and an institutional, regulatory and pricing regime which makes supply profitable.

The following key lessons can be noted from Israel's national gas sector policy,which is clear and transparent, providing appropriate incentives for operators:

Israel designed a long-term plan for the development of its gas sector, based on utilisation by large power offtakers, thereby ensuring low risk demand forecasts by guaranteeing investment through the signature of a long term gas purchase contract.

The policy gives upstream operators strong incentives for continuous exploration and production, in the form of an advantageous fiscal and licensing regime, together with a clear export policy.

Israel is committed to making natural gas its primary energy source and specifically to reduce the use of liquid fuels. The country's policy is to allow every gas consumer, small or large, to have access to gas by developing the country's transmission and distribution network.

Additionally, the country's strong policy for gas development relies on the high level of creditworthiness of its offtakers.

Transmission tariffs are regulated while gas commodity prices are left to be determined by sellers and buyers.

The mandate given for transmission development has resulted in adequate transmission pipeline development. The country is divided into six distribution areas, with competitive bidding being required for the exclusive licences in each area.

A3.2.2 Overview of gas sector

Israel introduced natural gas to its energy mix in 2004 following the discoveries of natural gas resources in the country between 1999 and 2001. The relatively small sized fields, estimated at 1.47 Tcf in 2001, began to be exploited by Yam Thetis, a partnership between Israeli and US firms. At the time, gas wasonly used for power generation and later also became available to large industrial users.

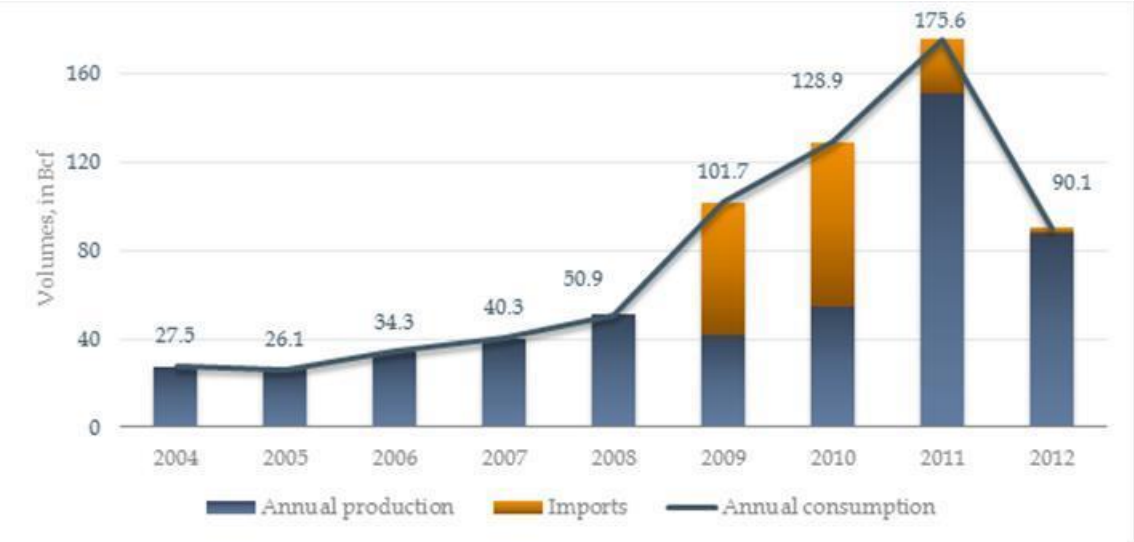
Initially, the only offtaker was Israel Electric Corporation (IEC), the state-owned integrated utility. By building CCGT power plants, IEC became, and still is today, the main gas offtaker serving as a guarantor for gas supply contracts as well as the financing of the transmission network. Consequently, gas demand experienced rapid growth due to the displacement of oil with gas for power generation. However, due to the limited size of the original discoveries, Israel began importing natural gas in order to satisfy the country's increasing demand.

Imports were via the Arish-Ashkelon pipelinefrom Egypt. (See Figure 59) The construction of the pipeline was agreed under a Memorandum of Understanding between the two governments in 2005. At the same time, a gas purchase agreement was signed between the Israel Electric Corporation and EMG, a joint venture between Egyptian and Israeli companies. The purchase agreement was a 20-year supply contract for the import of 246 bcf of natural gas per year into Israel. However, these volumes were never reached, because soon after the start of the agreement, Egyptian supplies proved to be unreliable due to Egyptian terrorist attacks on the pipeline and later gas supply shortages in Egypt itself. As a result, the maximum annual volume of gas imported peaked at 74 bcf in 2010 and has only fallen since (See Figure 60). Consequently, Israel fell into a security of supply crisis in 2012.

Figure 59Israel's pipeline network

Source: Israel Natural Gas Lines

Figure 60Israel's natural gas production, consumption and imports

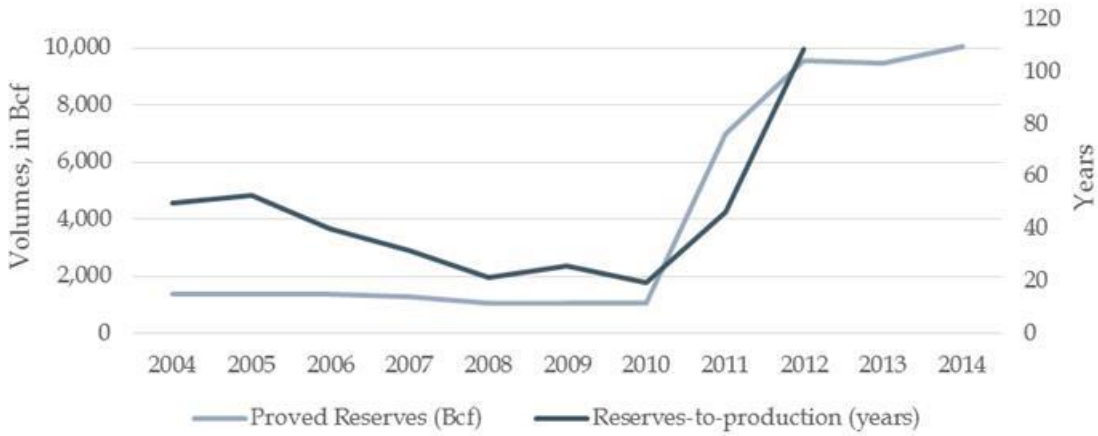


Source: US EIA, 2014

The introduction of imports formally established the existence of a domestic market for gas and this sparked new exploration activities by upstream gas operators. These led to the recent discoveries of large natural gas resources from the Tamar and Leviathan offshore fields. The discoveries came as a solution to the long-term supply problem given their large size, raising the country's gas reserves to 10.1 Tcf in 2014. Once both fields are in production, they are expected to turn Israelinto a net exporter of natural gas within the next decade.

Figure 61 illustrates the trends in reserves and gas production in Israel. The fall in the reserves-to-production ratio until 2010 shows the depletion of the smaller fields initially discovered, while the steep rise in both the ratio and the volume of proved reserves illustrates the discovery of the two large offshore fields.[40]

Figure 61 Natural gas reserves in Israel



Source: US EIA, 2014

[40] Production data is only available until 2012.

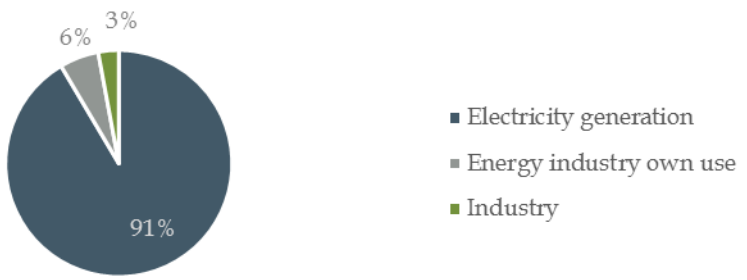
In order to solve the supply crisis in the short term, Israel decided to commission the country's first LNG regasification terminal. This is further discussed in Section A3.2.5 (Upstream issues) below.

Additionally, another strategy adopted by the government to develop the national gas market was to establish Israel Natural Gas Lines (INGL), an independent gas transmission company, with the task of building the transmission systems and to encourage existing and new firms to become consumers of gas.

A3.2.3 Gas utilisation

Natural gas consumption reached 176 bcf in 2011, of which more than 90% was assigned to electricity generation. The main users wereIEC and large industrial users.Figure 72 below shows the use of gas across different activities and sectors.

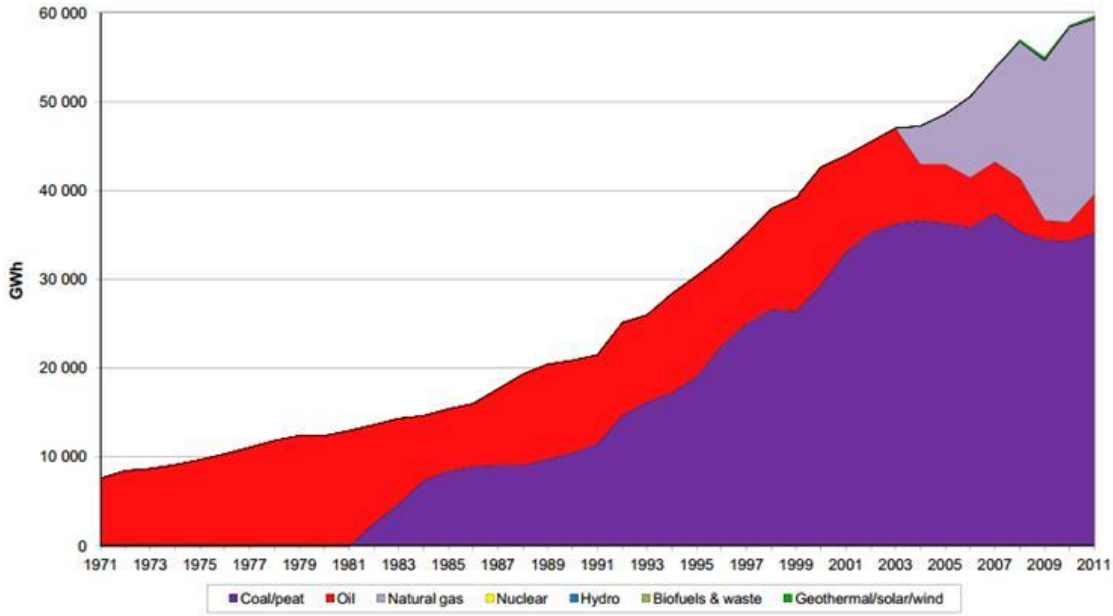
Figure 62Gas utilisation in Israel, by sector/activity



Source: ECA based on IEA, 2011

Fast growth in natural gas demand is expected to continue in the medium and long term, growingup to 635 bcf by 2030, 85% of which is expected to be used by the power sector and industrial users. This is consistent with the replacement of oil as a fuel for power generation with natural gas that commenced in 2004. This is illustrated in Figure 63.

Figure 63 Evolution of Israel's power generation mix, by fuel



Source: IEA, 2014

Additionally, it is the government's intention to invest in developing a distribution network that will reach future small consumers of natural gas. This point is discussed in Section A3.2.6 (Downstream issues) below.

With respect to exports, Israel's government and some of the country's gas supply companies have started negotiations to supply the Palestinian Authority, two Jordanian firms and Lebanon with gas as soon as production from the Tamar and Leviathan offshore fields begins. The newly developed export strategy will be carried out via pipelines to be built connecting Israel's transmission network to the other countries' networks. Furthermore, it is expected that Israel will also start exporting to Turkey in the near future.

A3.2.4 Institutional structure

Energy sector policy, specifically policy on natural gas, falls under the remit of the **Ministry of Energy and Water Resources**. Its policy is to continue to grow gas demand as Israel's economy shifts to one in which gas is the primary energy source. For this reason, security of gas supply is a critical policy issue. It is further discussed below under Section A3.2.5 (Upstream issues).

It is also the Ministry which issues licences and supervises the investment and operation of gas infrastructure in the country. The first supply license was granted to Yam Thetis in 2002 for the sale of gas from the national gas fields being exploited. In December 2006, the ministry granted a licence to EMG for the construction and operation of the gas pipeline to Egypt.

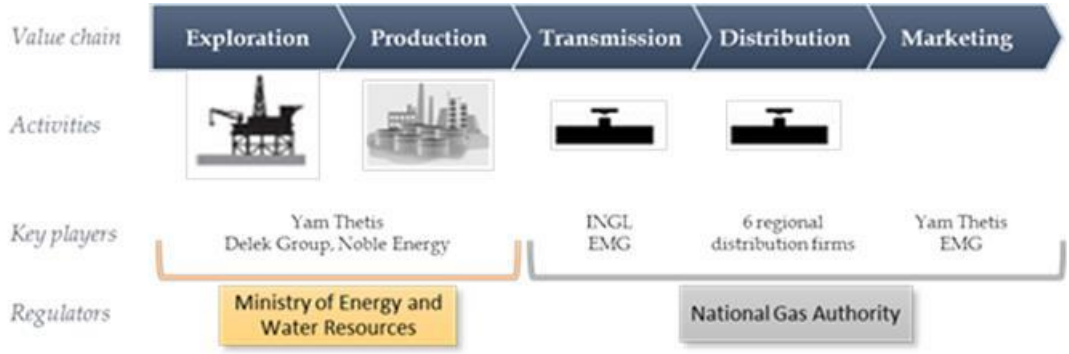
The**Natural Gas Authority** is the regulator of the Israeli gas market. The authority has adopted an open access approach whereby it ensures that there is no discrimination in connecting gas consumers to the gas grid. To this end, the regulator supervises transmission and distribution activities, recommending tariffs for the two, which are approved by the

Natural Gas Authority Council. Natural gas commodity prices are unregulated and left to the market to be set.

According to its mandate, the Natural Gas Authority is responsible for developing the national master plans for gas transmission. It also regulates land access and approves and supervises licensees.

Figure 64 summaries the key players and institutional entities.

Figure 64 Key players and regulation of the Israeli gas value chain



Source: ECA

A3.2.5 Upstream issues

As previously mentioned, in 2012 Israel began experiencing interruptions in the gas supply coming from Egypt and simultaneously faced a near-depletion of its operating gas field. As a result, domestic gas production fell from 150 bcf in 2011 to 88 bcf in 2012, accompanied by a sharp drop in annual consumption due to lack of supply. A critical consequence was suffered by the IEC, which had to turn to alternative and more expensive fuels, such as coal and diesel, which led to higher electricity prices.

In this context of short-term scarcity, Israel decided to pursue a flexible LNG import option and develop its first and only LNG floating regasification terminal, known as Hadera. The basic objectives were twofold:

to solve the temporary shortage until Israel could benefit from its large offshore resources, in particular gas from the Tamar and Leviathan fields[41].

to provide adequate natural gas reserve capacity, strengthening the country's energy independence and security of supply on a long-term basis.

The Hadera terminal is located in the north of Israel, in the Mediterranean Coastal Plain, approximately 45 km from the major cities of Tel Aviv and Haifa. It is owned by INGL, the state-owned transmission company. The first cargo arrived in January 2013 from Trinidad and Tobago.

[41] Output on the Tamar field begun in 2013 while output in the Leviathan field is expected to start in 2017.

As with natural gas originating from other sources (fields or pipeline), the imported LNG is mainly used for power generation. Israel's electricity mix is increasingly oriented towards natural gas as the primary energy source.

A3.2.6 Downstream issues

It is the Ministry's policy for the sector to further develop gas demand to include smaller scale consumers, such as the residential and commercial sectors, as well as small industrial players.

To this end, under a ministerial directive, the country was divided into 6 distribution regions and exclusive distribution licenses are to be awarded to a single distribution company in each region. The 6 distribution licenses will be granted under public tender for a period of 20 to 25 years. So far, three licenses have been awarded while the remaining three are in process.Licensees are responsible for the construction, operation and maintenance of the distribution network.

Another issue faced in the downstream market is that, at present, gas marketing is done by means of bilateral contracts between customers and suppliers. This is possible because all consumers are large industrial players, including power generators. However, once access will be provided to smaller consumers, by means of an extended distribution grid, the Ministry and regulator will have to decide how to regulate the supply and retail markets or if they are to be left open to competition. The latter option is foreseen in the sector's policy which has included an open access component since its creation.

A3.3 Indonesia

Although gas reserves in Indonesia are significantly larger than those in Ghana, it makes for an interesting case study. The country's gas resources are mostly non-associated gas (86%). Indonesian gas was initially exclusively targeted for exports. Currently, Indonesia exports around 50% of its natural gas production and is the largest LNG exporter in the Asia-Pacific region. However with growing domestic energy needs, the Government is struggling to find an adequate pricing policy that incentivises upstream production and ensures domestic demand is met. Furthermore, the institutional structure of the gas sector is characterised by many institutions and agencies with overlapping responsibilities and ill-defined roles. The country therefore provides some lessons learned of mismanagement of certain aspects of the gas sector.

A3.3.1 Summary lessons learned

The key points that can be highlighted from the Indonesian case study, which should be borne in mind as past experiences when developing the Ghanaian gas market include:

The Indonesian domestic market is highly dependent on government support and subsidies. Industrial use of gas will continue to increase given that domestic gas prices are kept low, making it competitive with other fuel alternatives. However, the low domestic prices coupled with domestic market obligations discourage the development of new fields as investors are deterred by low domestic prices.

Indonesia developed its gas market with a strong focus on gas exports, having pioneered the first LNG export project in Asia. However, the introduction of a Domestic Market Obligation has forced producers to utilise LNG export capacity to reach domestic demand centres (located far away from production sites). The historical reliance on International Oil Companies (IOC) to develop LNG projects makes this shift difficult, as they are generally unwilling to sell to the domestic market.

Government policy objective has been to encourage the use of gas by industry, which is seen as promoting domestic economic development. The main driver of gas market development has been the fertilizer sector. The government has supported this by keeping gas prices low, which meant limited supply and lack of incentives for upstream exploration and development. Government is now raising prices to make the domestic market more attractive to suppliers while, at the same time, increasing supply by enforcing the Domestic Market Obligation (DMO) for new gas production and allowing existing LNG export contracts to expire.

Gas infrastructure development has stalled and not followed a long term, strategic development plan. There is a transmission pipeline master plan, but this is ineffective due to the legally-mandated requirement to tender projects, a lack of coordination between the pipeline plan and supply availability and limited investment resources. Instead, it seems that domestic supplies will increasingly come through LNG from the main liquefaction terminals in Indonesia shipped to FSRUs in Java.

There is no clear industry structure, no definition of market operations, inadequate coordination of Codes of Practice and no clarity in the roles and responsibilities of the various players or participants which can, therefore, overlap and contradict one another. This has resulted in lost opportunities and significant delays in essential infrastructure

developments which have, on occasion, cost very large sums of money during the resolution of the problem.

A3.3.2 Overview of gas sector

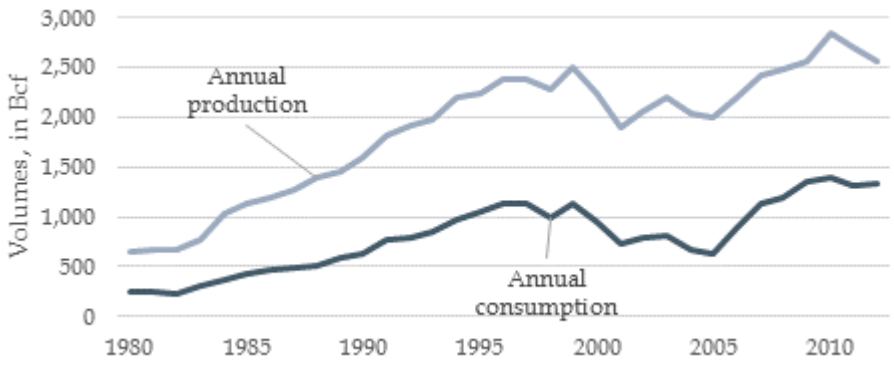
Supply and demand overview

Indonesia's gas exploration and production started slowly in the late 1950s. However, production was only increased significantly in the late 1970s driven mostly by exports. The Indonesian Gas Industry developed initially to create sufficient market to enable the development of the new gas discoveries. Since these discoveries were largely in the more remote parts of this vast country, this often meant that export markets were chosen rather than domestic utilisation. The higher export prices and the high potential cost of a domestic gas infrastructure also encouraged this choice.

Consequently, Indonesia decided to pioneer with Asian LNG exports, a model applied for later projects as well. Important factors driving the continuous focus on LNG for exports have been the low domestic gas prices, the distance of fields from the main domestic market centres and concerns over the willingness and ability of Indonesian state-owned enterprises to pay their bills. The Government had to accept this, as it lacked the resources and skills to develop LNG projects itself and has therefore become reliant on IOCs to do so. Additionally, a pipeline was built in the 1980s to export gas to Singapore and Malaysia.

Figure 65 shows the evolution of domestic natural gas production and consumption for Indonesia. The positive difference between production and consumption shown on the graph illustrates how the country's strategy for the gas sector has historically been to focus on exports.

Figure 65 Natural gas production and consumption in Indonesia



Source: US EIA, 2014

Domestic gas consumption only started growing significantly in the 1980s. Domestic utilisation, as is common worldwide, was based initially on large consumers especially power generators, fertiliser plants, etc. and these were often in close proximity to the points of supply. Pipeline systems have developed to connect the larger consumers, some as dedicated pipelines specifically for one customer and others with some limited access for market players other than the pipeline developer.

Since 1990, domestic consumption has risen due to increased consumption together with the replacement of petroleum products in the industrial sector. Domestic gas prices have been kept low compared to international prices, with the objective of providing greater incentives for industries and later for commercial and household customers to speed up the displacement of oil as a fuel.

In 2010, the Government introduced the priority allocation of gas resources for domestic use, known as a Domestic Market Obligation (DMO). This was in line with the government's policy of increasing emphasis on resource nationalism which also led to the introduction of DMOs in the Indonesian oil and coal sectors. The gas market DMO was introduced in 2010 and identifies the following activities and sectors as priority users:

Oil and gas production increment

Fertiliser industries

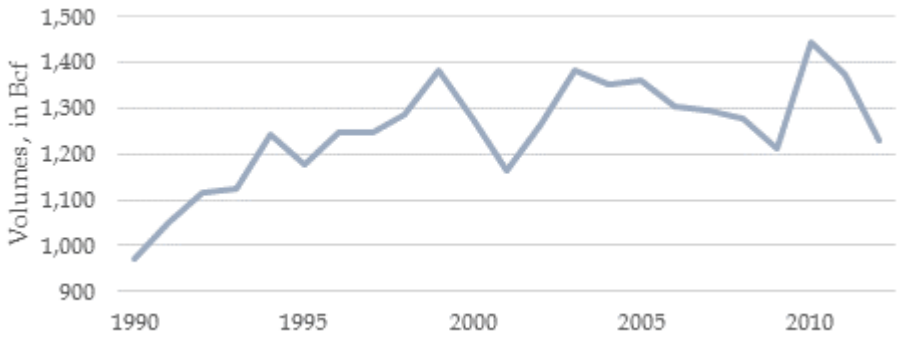
Electricity generation

Other industries

A key issue that arose since the introduction of the DMO relates to the country's complex geography: most of Indonesia's gas reserves are located in East Kalimantan while the demand centres are in West and Central Java. In order to meet the DMO, gas producers have begun diverting liquefied gas from exports to the domestic market. This liquefied gas is then delivered via FSRUs into Java. In this case, in Indonesia LNG has become a means of internal gas transport in the absence of pipelines and presence of existing liquefaction capacity. What is more, new LNG projects are required to meet a DMO. Pertamina and PLN (Indonesia's state electricity firm) have announced plans to develop eight LNG receiving mini terminals by 2015. These terminals will be scattered throughout the eastern region of the island nation and the gas supplied from them is intended to replace oil fuel at three electricity generation plants.

As a consequence of domestic demand increasing as the country developed economically, exports have fluctuated over the years. Figure 66 shows how the introduction of the DMO policy in 2010 caused exports to fall sharply.

Figure 66 Evolution of natural gas exports from Indonesia



Source: US EIA, 2014

Combining the DMO and the declining gas production, Indonesia has had difficulties in meeting its LNG export contract obligations. Some of the renewed LNG export contracts have reduced volumes diverting the volumes for domestic use instead.

A3.3.3 Gas utilisation

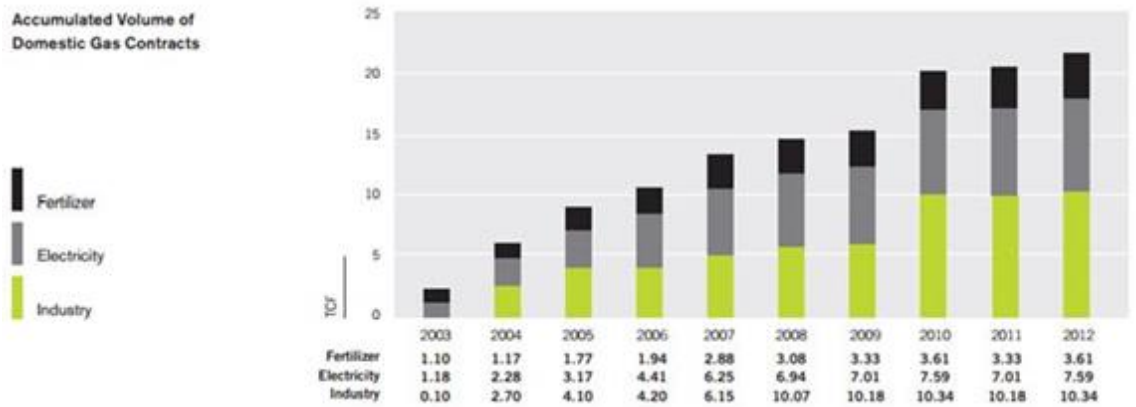
Historically, the key gas consuming sectors were the fertiliser industry and power generation. Since 2004, industry has also become a key consumer of domestic gas.

The Government's pricing policies have historically held gas prices for the fertiliser and industry in general low by negotiating low prices with gas producers. As Indonesia subsidises fertilisers, keeping gas prices low has been a priority since higher gas prices would translate into higher subsidies. There have been moves to increase prices recently which has led to protests from many industrial customers.

Gas demand for electricity generation depends on the price and availability of other fuel options. The availability of cheap coal has reduced gas demand for electricity generation, as it provides a more economical option for electricity generation. However, the availability of gas has also had an impact on the demand for gas for electricity generation with the key issue being that investment into construction of new pipelines hasn't take place, thus hindering the delivery of gas to power stations, leaving at least one running on oil at very high cost.

Figure 67shows the development of the three main sectors consuming Indonesian gas.

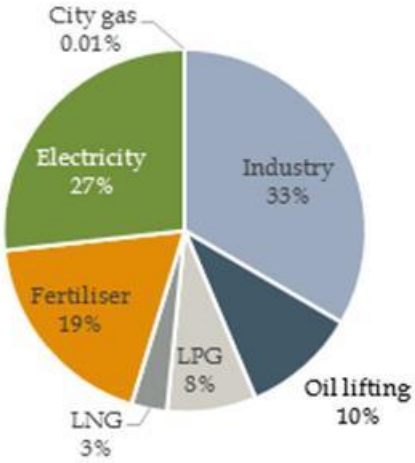
Figure 67 Volume of domestic gas contract in Indonesia



Source: SKK Migas, 2012

Figure 68illustrates domestic gas utilisation at present. LNG and LPG uses illustrated in the figure are solely for domestic transportation of resources, and in the case of the former, mainly utilised for power generation.

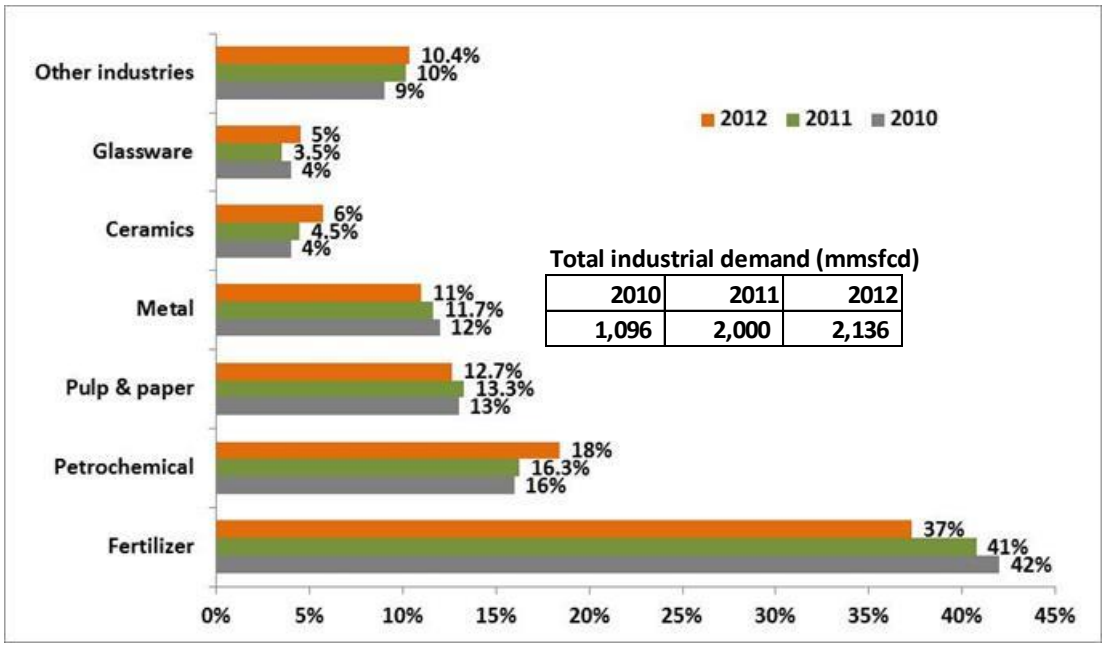
Figure 68 Gas utilisation in Indonesia, by sector



Source: SKK Midas, 2012

In the case of industrial demand, the industries with the largest consumption, after the fertiliser production, are at present the petrochemical sector, pulp and paper production, and the metal sector. Figure 69 shows the breakdown of industrial gas demand in 2010, 2011 and 2012.

Figure 69 Breakdown of Industrial Gas Demand in 2010-2012



Source: Forum Industri Pengguna Gas Bumi (FIPGB)

A3.3.4 Institutional structure

The hydrocarbon industries in Indonesia is overseen by the ***Ministry of Energy and Mineral Resources (MEMR)*** which is responsible for policy, planning and has ultimate responsibility for the award of PSCs. Within MEMR, the ***Directorate-General of Oil and Gas (DG MIGAS)*** is responsible for developing policies in the oil and gas industries and for offering new acreage through bidding rounds.

PGN, a state-owned transmission and distribution company, is the dominant owner and operator of transmission pipelines. Tenders for other companies to build six transmission pipelines were launched in 2006, but none have yet started construction despite frequent claims that this is imminent. The main barrier appears to be a lack of upstream gas supplies to be shipped through the new pipelines.

Pertamina represented the government's interests in the oil and gas industries as both operator and regulator, including signing and supervising PSCs. The 2001 Oil and Gas Law removed Pertamina's regulatory responsibilities and, in 2003, Pertamina was transformed from a state-owned enterprise into a limited liability company under corporation law in which all shares are held by the state[42].

Pertamina participates in a number of PSCs as an operator or partner and is investing in oil and gas infrastructure including LNG receiving terminals. Larger transmission-connected customers, such as the electricity utility, PLN, buy directly from producers who ship gas through PGN's pipelines. Smaller customers are supplied through distribution networks owned by PGN and Pertamina.

Market reforms were introduced in 2001 with the Oil and Gas Law No.22/2001. The upstream gas industry was liberalised, with acreage awarded through competitive bidding and the successful tenderer entering into a PSC with government. Consistent with the law, two regulatory agencies were created:

BP MIGAS was established in 2002 as the upstream regulator with responsibility for monitoring the operation of PSCs, including those operated by Pertamina, evaluating and approving plans for development and work programmes and budgets.

BPHMIGAS assumed Pertamina's downstream regulatory powers in the oil and gas industry. It is responsible for licensing business activities in refining, storage, transport and distribution of gas and petroleum products, supervising these activities and setting gas transmission tariffs and retail tariffs for households and smaller commercial customers. BPH MIGAS regulates the price of approximately 27% of gas sold to users in Indonesia

Figure 70presents the different segments of the gas value chain, key players in each of these and their regulators.

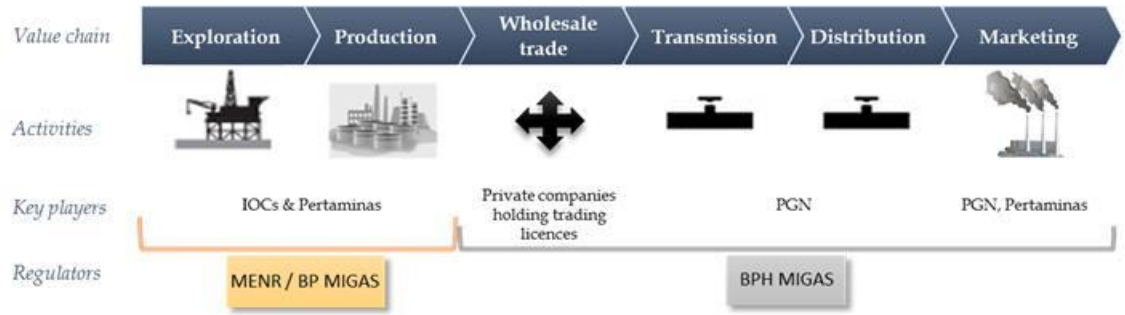
A key problem of the Indonesia institutional structure is that although there are government agencies looking after upstream supply, pipelines and demand, there is no coordination between them. In other words, no one organisation appears to have a clear mandate to coordinate the strategic requirements of the industry which should be to ensure that appropriate gas demand can be met by transporting gas from supply sources to the point of consumption and for the duration in time that such demand exists.

Indonesia has a transmission plan, which even provides for open access arrangements, but it is not followed due to difficulties in coordination and the requirement to tender major projects. Development decisions seem to be taken based on an individual company's views of what they consider to be appropriate. Therefore projects are conceived and planned without any obvious consideration of an overall understanding of what the industry needs for the foreseeable future. Consequently, the current transmission pipeline system is not

[42]The Ministry of State-Owned Enterprises is responsible for exercising the role of shareholder on behalf of the government.

integrated which makes development very difficult and creates serious problems for load management and, more importantly security of supply, particularly for new industrial, commercial and residential developments.

Figure 70 Value chain of the Indonesian gas sector and its regulation



For obvious reasons, pipelines are generally built initially to link a source of supply to a large long term user such as a power station or fertiliser plant. Because there is no coordination or strategic plan, such pipelines rarely provide any significant additional capacity to enable other users to connect in the future. This despite some pipelines being designated open access by the developers/regulators.

A3.3.5 Upstream issues

The price paid by gas producers for the raw gas is primarily the share of gas allocated to Government through the PSC together with special petroleum taxes and royalties. PSCs were negotiated and signed by BP MIGAS, on behalf of the state, between its establishment in 2001 and its recent dissolution. Before this, Pertamina had the same role. It is unclear who will undertake this role in future.

Petroleum sector taxation is governed by Indonesia's tax authorities. The latest Regulation No. 79, issued in December 2010 (GR 79/2010), provides rules on cost recovery claims and Indonesian tax relating to the oil and gas industry.

A3.3.6 Downstream issues

Prices for sales of gas to final customers are governed by MEMR's Regulation No. 19 of 2009 which states that:

- Gas prices for 'general' users are unregulated but should use a cost-based approach
- Gas prices for special users to be determined by MEMR
- Gas prices for residential and smaller commercial users are to be regulated by BPH MIGAS

BPH MIGAS Regulation No. 3 sets out how regulated tariffs are established. Customers are divided into four categories with different prices. The starting basic price used for regulated end user tariffs is the existing tariff for the region[43], which is indexed to Indonesian consumer price index. The BPH MIGAS regulation fails to explain how a basic price is set for new areas or how the basic price is adjusted if PGN's gas purchase prices increase faster than the rate of inflation. However, sellers are allowed to propose tariff adjustments to BPH MIGAS if their costs change.

The price paid for gas that is used by operators to meet their DMOs is governed by the agreements negotiated with BP MIGAS. Usually, the contractor is compensated by BP MIGAS at the prevailing market price for the initial five years of commercial production.

[43]PGN differentiates its prices by region, reflecting different gas purchase costs in each region.

A3.4 The Netherlands

A3.4.1 Summary lessons learned

The discovery of large gas resources in the Netherlands coupled with the rapid development of a gas market makes for an insightful case to review. A policy of setting gas prices on the basis of alternative fuels initially and pegged to international prices subsequently has been a key success factor of developing smaller, more expensive, but economically attractive gas fields. Additionally, this opened the gas market to international gas supply sources, resulting in a situation today where gas is both exported and imported. The Government has extracted revenues from the gas sector through an efficient fiscal regime and has generally used these revenues to re-invest them in domestic consumption. This was particularly important at the early stages of significant gas production (during the 1960's) to alleviate the effect of the so-called 'Dutch disease', a lack of competitiveness from the manufacturing sector resulting from the appreciation of the local currency. The key lessons for successful gas sector development are listed below:

The Netherlands has maximised its gas production potential through the application of the *'Small Fields Policy'* which has encouraged the development of smaller less accessible fields. The policy provides for a guaranteed offtake for small field developers and guaranteed transport through the national gas transport network.

Anadequate gas pricing policy from the start ensured that gas was attractive to both upstream producers as well as consumers. The *'Market Value'* approach introduced in 1958 ensured that consumers would not pay more or less for gas than for alternative fuels, which was mainly fuel oil. It gave upstream operators significant revenues and enabled the development of a gas market. The link between oil and gas was weakened during the oil crisis in the 1970s and abolished in the 1990's with the creation of a competitive gas market.

Gas was initially not targeted for the power sector, as nuclear power was seen as the future power generation source. Instead large industrial users (manufacturing, chemical, metallurgical and ceramic industries) and households were considered the main recipient of gas resources. Gas was initially only used in the power generation sector to make use of the reserves before gas was (wrongfully) expected to be by nuclear power. The trend of gas usage in the power generation sector was accelerated by the oil crisis in the 1970's. With the subsequently identified risks in nuclear power and associated high costs, gas was increasingly used in power generation and today the power sector accounts for the largest gas offtaker.

Targeting smaller, more scattered consumers initially meant that gas distribution and transmission network were developed at great speed in the 1960's. The Dutch state, through Gasunie - a 50/50 private public partnershipwith Shell and Exxon -played a key role in the development of domestic gas transmission networks. Distribution networks were developed by municipalities but with premium payments from Gasunie. Today distribution networks are private and the sector is unbundled.

A stable fiscal and regulatory environment combined with fit for purpose tax incentives have made the Netherlands an attractive country for Exploration and Development investment. Guaranteed offtake prices and volumes from the national petroleum

company in the 1970's created even further incentives for upstream producers to develop smaller fields.

A3.4.2 Overview of gas sector

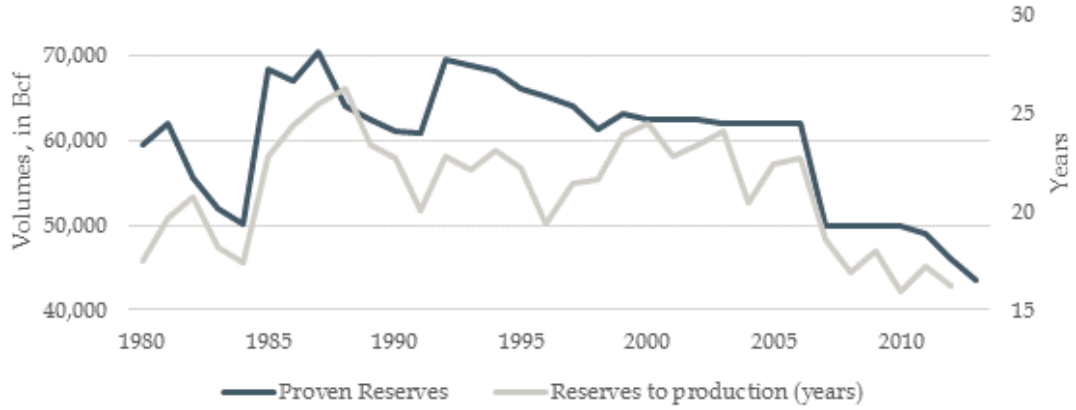
After the discovery and development of the largest gas fields in continental Europe (the Groningen field) in the early 1960s, the Netherlands became one of the biggest gas producing countries in Europe. Today, the country is the largest gas exporter of the European Union. With 70,000 people employed in the sector and revenues in 2011 amounting to €12 billion, natural gas plays an important role as a source of public revenues, employment, and source of energy supply.

Supply & demand overview

Dutch provennatural gas reserves are estimated at 43.4 Tcf, accounting for approximately 29% of all European natural gas reserves. In addition, non-traditional gas reserves are also expected to be significant with approximately 17 Tcf of recoverable shale gas reserves. Nevertheless, according to the Dutch government, their reserves have passed their peaking point and the country foresees becoming a net importer around 2025.

Although domestic gas production at 2.8 Tcf could easily cover the national gas requirements (1.6 Tcf), only 60% of the Dutch natural gas requirements in 2012 were met through domestic production and 0.9 Tcf were imported. The difference was exported to other European countries via interconnections with the UK, Germany and Belgium. The figure below illustrates the expected speed of depletion of Dutch gas resources by means of the reserves-to-production ratio which stood at 16.2 years in 2012.

Figure 71 Netherlands Gas Reserves Production



Source: US EIA, 2014

Foreseeing that the country will become a net importer of gas by 2025, the Government has planned for the country to become a trading point of gas for Northern Europe. The role envisaged implies that the Netherlands would become a point of transit, storage and tradefor the regional gas market.

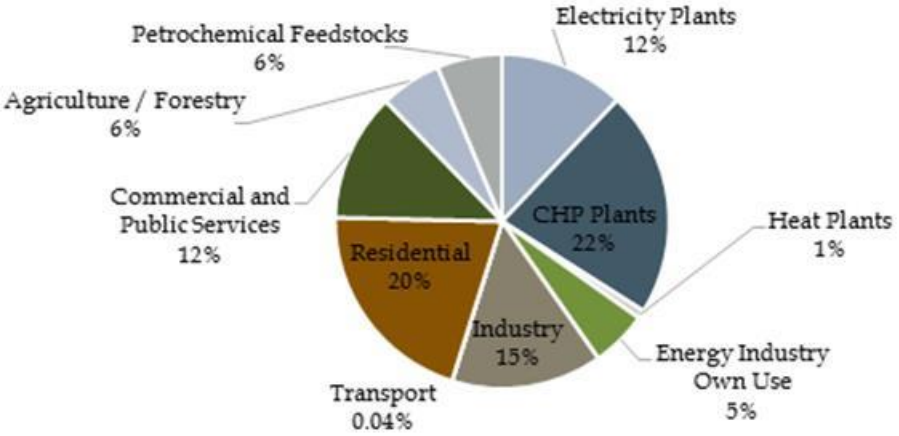
A3.4.3 Gas utilisation

Upon its discovery, gas was not initially destined for power generation. Instead, it was thought to replace fuels in the manufacturing industry, as well as the chemical, metallurgical and ceramic industries. This was motivated by the ability to pay from these 'premium' industries, but also because nuclear power was seen as the main power generation source of the future. This policy objective accelerated the development of gas transmission and distribution infrastructure in the country.

Gas usage in the power sector was the result of expectations that gas had no role to play in future power generation (with the rise of nuclear power), so the country was to make the most of its resources while it could. Initial gas usage restrictions in the power sector were lifted in the late 1960's, gradually replacing oil fired power generation. The oil crisis in the 1970's, and the resulting slight decoupling of oil and gas prices, accelerated the usage of gas in the power sector. Today, gas is the most important energy source for power generation, making up 65% of the Dutch power generation mix.

Combined heat and power (CHP) plants as well as power plants make up the majority of gas consumption representing 35% of total gas consumption. The remaining gas consumption in the Netherlands is made up by the industrial sector (26% of gas consumption), residential sectors (20%), and commercial and public services sectors (18%). The breakdown is shown in Figure 72.

Figure 72Gas utilisation in The Netherlands, by sector/activity



Source: ECA based on IEA, 2011

Exports/Imports

The Netherlands has been a net exporter of natural gas since the discovery of its first gas field. Today, the Netherlands produce close to 2.8 Tcf of which 1.3 Tcf are exported to Germany, France and the UK. 0.5 Tcf are imported mainly from Norway, Russia and the UK. All gas trade in the Netherlands is done via pipeline with interconnections with the German, Norwegian, Belgian and UK networks which are operated by Gasunie Transport Services. The entry and exit licences are granted on an individual basis, without the need to report the specific transport route for the gas. In this way, the system is more accessible, which facilitates the trading of gas in the integrated European market.

Residential and commercial uses

High population density in the Netherlands has led to a high degree of residential gas connection, with 96% of households connected to gas supplies in 2010.[44]The early development of transmission and distribution networks in the country has contributed to the rapid increase of gas utilisation in the residential and commercial sectors. The residential and commercial markets in the Netherlands are underpinned by a high demand for gas fired heating: the main use for the fuel was heating (79%), followed first by water heating (19%) and lastly by cooking (2%).[45]

A3.4.4 Institutional structure

The gas market in the Netherlands is divided into upstream gas exploration activities, gas trading, transmission, distribution and supply. Since 2004, these operations have been legally unbundled and since 2009 financially unbundled. The gas sectors is however still characterised by a high degree of state ownership. Today, the following organisations and companies play a major role in the Dutch gas industry:

Energie Beheer Nederland B.V. (EBN), is a fully state owned petroleum company, and represents the commercial interest of the Netherlands in upstream petroleum activities. By Law,EBN is the joint venture partner of any private company in the gas production sector andholds a 40% share of gas produced.

Gasunieis the state owned gas transmission system owner and operator. It is responsible for the management, operation and development of the gas transmission system. Its subsidiary ***Gas Transport Services*** (GTS) is designated as the TSO under EU legislation.

GasTerra is by far the largest gas trader of natural gas in the Netherlands marketing 75% of gas in the Netherlands including importsfrom Russia, Germany and Norway. Its core activity consists of trading all gas from the Groningen gas field and selling the produced gas to downstream companies. GasTerra's shareholders are the Dutch States (50%), Shell (25%) and Esso (25%).

The ***distribution gas market*** comprises 16 registered regional network operators, the majority of which are state owned (51%), and the rest privately owned (49%). The 16 regional gas networks are operated by 12 regional network operators. In most cases these operators are held by the original energy distribution companies, which in turn are held by regional authorities. Third party access to these networks is free

The ***supply segment*** of the gas sector in the Netherlands is fully private. There are approximately thirty parties currently involved in this market, but Essent, Eneco, Nuon and Delta together represent 85% of retail market share and are the dominant players.

Parties may trade gas at the ***Title Transfer Facility (TTF)***, the virtual trading point of the Netherlands, in order to manage their individual gas balances and portfolios. Contracts traded on TTF are defined using a day as the basic unit of time, with a flat delivery profile within the day.

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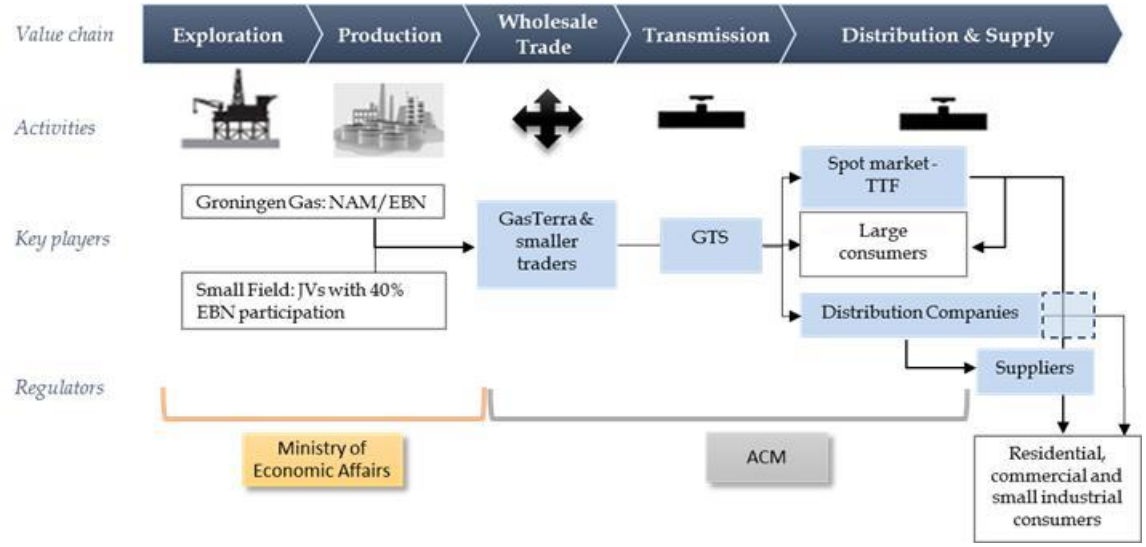
[44] IEA, 2012

[45]Dutch Ministry of Economic Affairs, 2012

The regulation of all energy markets has fallen under the scope of the Energy Department atthe ***Autoriteit Cosument en Markt***[46] (ACM) which is an independent entity responsible for competition and regulation across the economy. The Ministry of Economic Affairs provides policy guidance to the sector and is responsible for granting E&P licences under the Mining Act. When evaluating a licence, the ministry seeks advice from EBN, the Mining Advisory Council, among others. Gas retailers also need to request a licence to supply gas, but to ACM.All players across the value chain are illustrated in Figure 73.

Figure 73 Key players and regulation of the Dutch gas value chain



A3.4.5 Upstream issues

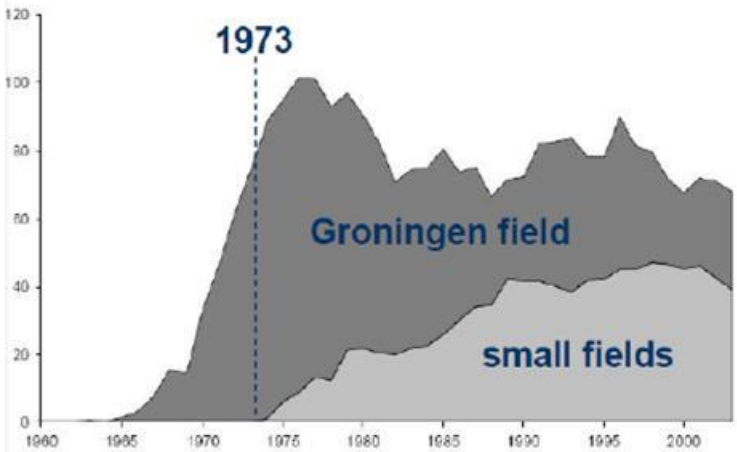
Government revenues from upstream activities are collected via three tax mechanisms. The fiscal regime that applies to natural gas production is a combination of a state profit share levy, a surface rental tax, and a royalty.

Under the false impression that nuclear power would become the dominant source of energy generation, gas was initially not used for power generation but instead exported, without worrying about the depletion of gas reserves. However, in 1974, when it was clear that energy generation could not depend on nuclear energy alone and rising oil prices, the small fields' policy was adopted in order to increase the life of the Groningen gas field and domestic production for as long as possible. Under the policy, Gasunie was obliged to buy gas from any producer of a small gas field at a high load factor at a reasonable price related to the market value of gas and producers were obliged to sell the gas to Gasunie. Since 1996, the producers' obligation changed into an option.

Smaller fields were earmarked for exports and the Groningen field has kept as a swing producer to account for any seasonal fluctuations on the Dutch market. As a result, only a third of the domestic gas consumption now comes from the Groningen field. Figure 74 shows the evolution of gas production from the Groningen field and small gas fields in the Netherlands.

[46]Authority for Consumers and Markets, formerly the Netherlands Competition Authority

Figure 74Gas production as a result of the Small Fields policy, *Bcm/year*



Source: 'Robert van der Geest, A route Planner for Gas Transport through the Netherlands'

A3.4.6 Downstream issues

The Dutch wholesale market is organised around a single trading entity, GasTerra which purchases all gas produced by NAM from the Groningen field. In addition GasTerra has the obligation to purchase any gas extracted from small fields. GasTerra then sells gas to Dutch customers, mostly supply companies, and foreign purchases.

The retail market is fully liberalised in the Netherlands meaning that consumers from all consumer groups are free to choose and switch gas providers. Although gas consumers in the Netherlands have one of the largest switching rates in the European Union (EU), only 8% actually switch. This shows that the retail segment remains highly concentrated around a couple of dominant suppliers.

End user gas prices in the Netherlands are not regulated per se, but retailers are under 'price surveillance'. Energy retailers are bound by law to submit all prices to ACM to check whether these prices are reasonable. ACM checks the reasonableness of tariffs based on an undisclosed model which contains wholesale prices, operational and capital expenses and a certain reasonable margin. If the price of a retailer is deemed excessively high, ACM has the authority to force that retailer to lower its proposed end user tariffs.

Consequently, the price faced by the end consumer in the Netherlands is made up of the gas price charged by producers to GasTerra and other traders (wellhead price), the transmission tariff, the distribution tariff, and supply charge.

A3.5 Nigeria

Nigeria is a close neighbour of Ghana, though considerably larger demographically and in terms of its gas resources. It is a highly relevant case to study given its key role for Ghana's

gas supply and through the West Africa Gas Pipeline (WAGP) and its failure in maximising the economic potential of its gas resources.

A3.5.1 Summary lessons learned

Nigeria has not managed to utilise its abundant natural gas resource to kick start its power sector or any other significant industrial activity. This is due to the following key reasons:

Oil rather than gas production has traditionally been the Governments energy priority. Nigeria's resources are largely associated gas. Oil production has higher value and thereby greater priority for policymakers. Consequently, it is difficult to schedule the production of gas in a way that satisfies the needs of gas consumers. For Nigeria, this has meant that large volumes of associated gas are either flared or vented.

Inadequate policies, weak institutions and a lack of investment in infrastructure have stalled gas sector development. While the technical constraints of associated gas are outside the control of the Nigerian Government, the policy and institutional framework to ensure gas is brought to market and used as a catalyst for economic development is within their control. Inadequately defined gas policies, insufficient investment in gas to power generation infrastructure, regulatory and institutional uncertainty and a lack of gas transportation infrastructure has meant that the contribution of gas to the national economy is far below its potential.

A policy targeted almost exclusively at gas exports has been one of the key reasons for a slow development of the domestic gas market. Nigeria hasa desperate need for gas-fired electricity power generation[47] and the 2008 Gas Sector Master Plan identified a large potential industrial demand for natural gas, suggesting that supply side factors are constraining the development of the gas sector.

Private companies have been reluctant to invest in gas gathering and processing infrastructure and gas-fired power generation because of:

- low gas prices to end users,
- high non-payment risks because retail electricity tariffs are set below cost-recovery levels and poor collection rates making the electricity sector un-creditworthy,
- lack of access to gas transportation and processing infrastructure and monopoly control over gas transmission by national utility company, and
- the reluctance of Government to acknowledge the costs and risks incurred by operators in collecting and processing gas by offering adequate prices.

While the situation in Ghana is different, there are some warning signs that strike a resemblance to Nigeria. In particular, the current high usage of fuel oil in power generation, severe supply (gas transport infrastructure) constraints, power shortages in the country and the real risk of flaring and venting at Jubilee bear a striking resemblance to some of the key issues affecting the slow development of Nigeria's gas sector.

[47]The Roadmap on Power Sector Reform, issued in August 2010

A3.5.2 Overview of gas sector

Nigeria ranks ninth in terms of proven natural gas reserves worldwide, and the largest in Africa, with reserves estimated at 182 Tcfin 2013, according to IEA. Most of these reserves are located in the Niger Delta. Despite the significant size of reserves, Nigeria only produced about 1.2 Tcf of dry natural gas in 2012, ranking it 25th as a world's gas producer. Its gas flaring volumes stood at close to 0.3 Tcf in 2012.

Figure 75shows the development of Nigeria's gas reserves and production over time. Nigeria's proved gas reserves have increased over time. The drivers of increased gas production over the last twenty years was the commencement of LNG exports in the late 1990s. This together with the large volumes of flared and vented gas by the oil industry has resulted in a decline in reserves to production ratio.

Figure 75 Nigeria gas reserves and production

Source: US EIA, 2014

A3.5.3 Gas utilisation

As noted previously, a large share of Nigeria's gas is lost due to gas flaring.
Table 21summarises statistics published by Nigeria National Petroleum Company (NNPC) showing that only 77% of all gas produced in Nigeria in 2012 was utilised productively, while the remaining 23% was flared.[48]34% of total production was sold domestically and exported by pipeline, 18% was re-injected for enhanced oil recovery and 13 % was used for LNG exports.

[48]Gas flaring in Nigeria is presented in more detail in Section A3.29.2.

Table 21Nigeria gas production, flaring and utilisation, 2012

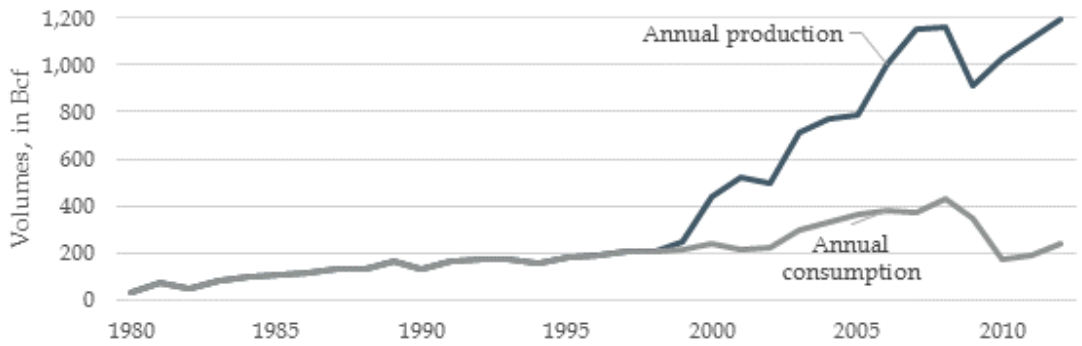
Annual Gas Production			**1.2 Tcf**
Gas Flared			**23%**
Gas Utilised			**77%**
A A3.7	Sold	A3.8	34%
A A3.10	Re-injected	A3.11	18%
A A3.13	LNG	A3.14	13%
A A3.16	Fuel	A3.17	4%
A A3.19	Lift	A3.20	3%
A A3.22	Sold to NGC	A3.23	3%
A A3.25	LPG/NGL	A3.26	2%
A A3.28	Petrochemical	A3.29	1%

Source: ECA elaboration based on NNPC Annual Statistics Bulletin, 2012

Domestically, gas is used in the power generation sector, fertiliser industry, cement industry, steel sector, and in gas distribution networks supplying small industrial users. Around 60% of this gas is sold for power generation. The small distribution networks represent less than 5% of the total gas sold.This is because the existing transmission network only covers a small part of the country and the two main networks are in the south of the country and are currently separate from each other. The eastern network links with the West African Gas Pipeline (WAGP) and will export gas to Ghana, Togo and Benin.

Nigeria started exporting natural gas in the late 1990s and exports have grown steadily since then. Figure 76 shows the difference in production and consumption highlighting the large volumes of gas exported.

Figure 76 Nigeria gas consumption and production, *bcf*



Source: US EIA, 2014

The country is a key player in the international gas market, exporting 9% of all LNG traded internationally. The largest recipients of Nigerian LNG were Japan, Spain and France.

A3.29.1 Institutional structure

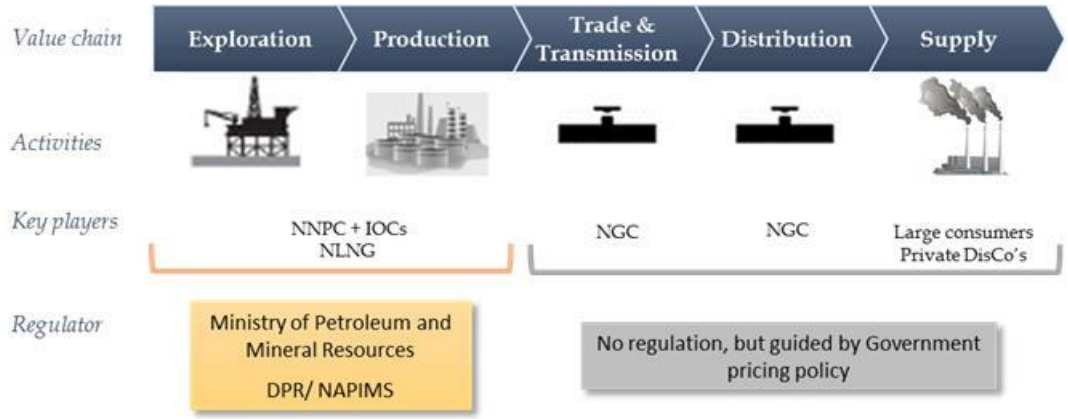
The gas sector in Nigeria is dominated by the state-owned oil company, the***Nigeria National Petroleum Corporation (NNPC)***as the operator and self-regulator in the market. NNPC was established in 1977 through the merger of the Nigerian National Oil Corporation (NNOC) and the Ministry of Petroleum Resources under Decree No. 33. As a fully vertically integrated state-owned oil corporation it participates commercially in the Nigerian oil and gas sector and self-regulates itself.At present, NNPC has six directorates concerned with each part of the oil value chain. It consists of 23 divisions and 19 subsidiaries.

NNPC is active throughout the oil value chain, from exploration to refining, petrochemicals and the transportation of products and marketing. NNPC's exploration and production activities are carried out through joint ventures (JVs) with IOCs active in the Nigerian upstream oil and gas business. The IOCs with the largest contracts are Shell, ExxonMobil, Chevron and Total. The organisation of the gas value chain and key players is illustrated in Figure 77 below.

The ***Nigerian Gas Company Limited (NGC)*** was established in 1988 as one of NNPC's subsidiaries. It is responsible for the development of an integrated national and regional gas pipeline network and with natural gas exports through the WAGP.

Nigeria LNG Limited (NLNG) is a subsidiary of NNPC created in 1989 which focuses solely on the production of LNG for export. NLNG is a consortium established together by NNPC as majority stakeholder together with Shell, Total and ENI. The consortium owns and operates six liquefaction facilities with an annual capacity of 22 million tonnes of LNG and 4 million tonnes of LPG. Its subsidiary, Bonny Gas Transport Limited (BGT) provides transport services for NLNG.

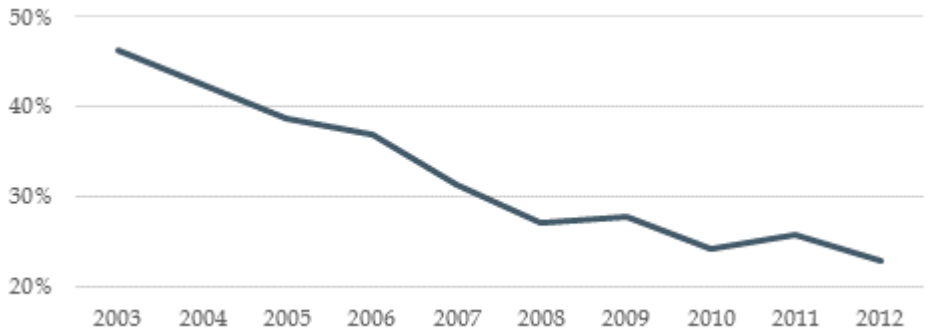
Figure 77 Key players and regulation of the Colombian gas value chain



A3.29.2 Upstream issues

Natural gas discoveries in Nigeria have long been related to oil exploration in the Niger Delta and are thus mostly associated gas. As a consequence it has been common practice in Nigeria to flare gas.The evolution of the relative amount of flaring is shown in Figure 78.

Figure 78 Evolution of gas flaring volumes in Nigeria, *% of production*



Source: ECA elaboration from NNPC Annual Statistical Bulletin, 2012

As shown in Figure 78, gas flaring-to-production ratio has fallen from a very high level, to close to 20%, which is still very high Nigeria is the second largest gas flaring country after Russia, and is responsible for 10% of the volume flared globally. The flaring of gas has cost the Nigerian state approximately US$1.8 billion in revenues per year, according to Nigeria's Department of Petroleum Resources.[49]

Attempts at gas flaring reduction have been made over the past three decades beginning with legislation introduced in 1979which imposed a mandatory requirement on oil companies. Accompanying legislation and decrees also introduced incentives for investments in gas utilisation infrastructure and set a deadline of 1984 to end routine flaring, which was not met. More recent targets for eliminating flaring by 2004, 2007, 2008 and 2010 all passed without success. The latest target was December 2012 with fines imposed on operators who did not comply. However private operators refused to pay the prescribed fines, blaming the situation on the lack of infrastructure and security situation in the Niger Delta.

A3.29.3 Downstream issues

In February 2008, the Government of Nigeria approved a new gas policy and gas pricing regime. The Pricing Policy was designed to encourage the development of local industries and promote economic development, but there was a risk that it would provide cheap gas to private firms who would then simply develop energy intensive products and earn substantial profits by exporting gas embedded in these products. It therefore introduced the concept of 'saturation'. In the event, for example, that the power sector expanded gas-fired generation to fully satisfy the domestic electricity market and then began to export electricity using cheap gas, the Policy recognised the need to then switch pricing for power generation to a netback basis.

The Pricing Policy forms the basis for pricing of gas to producers and end users. The policy grouped Nigerian demand into three groupings to reflect different strategic benefits to the country:

Strategic Domestic Sector – This refers to users that have a significant direct multiplier effect on the economy (ie, spurring rapid economic growth) and is primarily targeted at the

[49] http://www.vanguardngr.com/2013/07/nigeria-loses-1-789bn-daily-to-gas-flaring/

power sector though the Minister is given the discretion to designate other groups of user deemed to be strategic.

Strategic Industrial Sector – This refers to industries that utilise gas as a feedstock in the production of products with a significant non-gas Nigerian content that are primarily destined for export or in some cases, consumed locally. This is designed to encourage industrialisation and job creation. This group include methanol, GTL and fertiliser. For this sector, the strategic intent in pricing is to ensure that feedgas price is affordable and predictable in order to ensure competitiveness of the products in international markets.

Commercial Sectors – This refers to sectors that use gas as a fuel. This is targeted at normal, mature users of fuel that would otherwise use competing fuel such as light fuel oil. Typical users in this category include cement and manufacturing industries. Prices to users in this category are intended to allow the gas sector to make profits from the sale of gas.

A3.30 Tanzania

Tanzania's gas sector can be classified into two distinct phases: the first, moderate volumes and production from on-shore and near-shore shallow wells, and the second, the potential development of much larger off-shore deep wells. Having first been discovered in around 1974, the wells were capped and not opened until the early 1990s when the Songo-Songo extraction, transportation and gas-to-power project was first conceived, although this did not commence production until after 2000.

From the outset, power generation has been the primary sector for domestic gas consumption, and remains so today. Gas is supplied via a pipeline from the southern coastal parts of the country to Dar es Salaam. To date, there has been limited use in other sectors, with some gas transported to a cement plant north of Dar es Salaam, around 50 industrial consumers in Dar es Salaam, and some use in vehicles.

With the prospect of large volumes of gas becoming available from off-shore wells, Tanzania is reviewing the entire sector, focusing on the roles of the government and private sector, and the legislative and regulatory frameworks to support this. Tanzania anticipates large expansion of its gas-to-power sector, and is promoting the prioritisation of domestic gas use through its National Natural Gas Policy (2013), although exactly how this will play out will only become clear once it publishes its National Gas Utilisation Master Plan which is currently under development.

A3.30.1 Summary lessons learned

Given the lack of development of a large gas sector, the key lessons learned are from challenges observed in the existing smaller sector, and in perceptions on the development of the larger sector:

Consumption for power relies on a strong power sector, however the sector is a chronic underperformer. This is due to a lack of political will to ensure its financial stability and a poor track record of transparent and stable negotiation of PPAs with IPPs. This has meant gas suppliers and power suppliers using gas have faced non-payment on their accounts, and further investments have been delayed.

Low pressure gas distribution networks, developed on the back of gas for electricity generation, have been beneficial both for gas producers (much higher prices than the contract prices for power) and for industries able to replace lower cost (and cleaner) gas for high cost liquid fuels. As shown in the map in Section *, industrial gas use has grown progressively, with new industries using gas as well as established industries substituting gas.

Weaknesses in government capacity to implement projects cause delays. The Tanzanian government has struggled to cover all aspects of project development, focusing more on infrastructure development with inadequate attention given to commercial negotiations and economic stability. At present, delays in pricing negotiations may delay the start of generation from a new gas-to-power plant when the plant and pipeline supplying it with gas should be completed close to schedule.

Independence in framework development can miss crucial blind spots. The government, through the Ministry of Energy and Minerals, wishes to develop its new gas frameworks (eg policy, legislation and institutional reform) itself, but an acknowledged lack of experience in developing such frameworks is contrasted with a reluctance to engage external assistance. This appears to be leading to imbalanced development and a challenge for external parties in knowing how support could best be offered. In particular, a lack of appreciation for the commercial skills necessary for extraction negotiations is not giving confidence in the ability of the government to develop its resources in the way most beneficial to Tanzanians.

Lack of a single gas sector development body and poor coordination between relevant stakeholders. Commercial stakeholders have expressed concern at the ability to identify the relevant party(ies) with whom to engage and negotiate for the many steps necessary to complete before they are able to make their final investment decisions. While the concern has been raised by commercial stakeholders, the challenge can relate to all other stakeholders, including other government stakeholders and civil society organisations.

Focus on domestic consumption without supporting economic analysis. The energy policy and early discussions on the gas utilisation master plan have indicated a preference for domestic consumption of natural gas over exports where possible, including household consumption and the development of new industries. To date, economic analysis to support this position has not been forthcoming – such decisions should be supported with economic analysis.

A3.30.2 Overview of gas sector

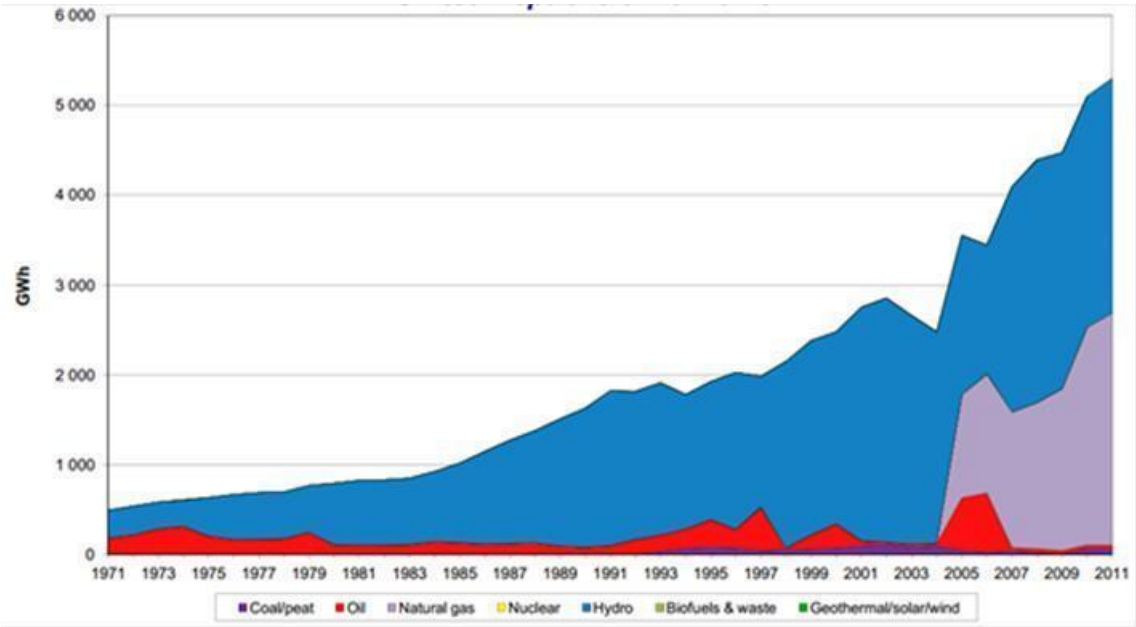
Supply and demand overview

Since gas was first produced in Tanzania in 2000, gas was fully used for domestic consumption. By international standards, Tanzania's gas production and consumption volumes to date have not been large. According to the International Energy Agency, Tanzania's production stood at 4.2 bcf per annum in 2004 and has grown to reach approximately 20 bcf in 2009 with the speed of production increasing to reach 32.8 bcf in 2012.

Gas is currently utilised mostly as a fuel for power generation (86%). The remaining volume is consumed in the industrial sector. This is primarily by a large cement plant north of Dar es Salaam and around 50 businesses in Dar es Salaam. A very small share is consumed by vehicles operating in Dar es Salaam. Gas power currently makes up around half of Tanzania's power generation, although this is set to increase once the new pipeline from Mtwara to Dar es Salaam is completed, and gas is supplied to an existing Heavy Fuel Oil (HFO) plant (which will switch to gas), and the development of the new Kinyerezi 1 gas plant.

Since the commencement of gas production in Tanzania, Figure 79 shows how the country rapidly became largely dependent on gas for power generation since 2004.

Figure 79 Power generation fuel mix in Tanzania



Source: ECA elaboration from NNPC Annual Statistical Bulletin, 2012

A3.30.3 Institutional structure

The institutional structure of Tanzania's gas sector is currently unclear, and is also under review as part of the development of the framework for expanding its gas sector. The sector is ultimately overseen by the ***Ministry of Energy and Minerals*** (MEM) with its policy function. Many of the operational functions in the sector, including managing exploration licensing and making investments on behalf of the government, are held by the ***Tanzania Petroleum Development Corporation*** (TPDC). MEM is also currently the regulator of upstream activities, although the division of tasks between MEM and TPDC is not altogether clear.

Mid-stream and down-stream regulation of the gas sector is managed by the ***Energy and Water Utilities Regulatory Authority*** (EWURA). As its name suggests, EWURA is also the primary regulator of the electricity and water sectors. The future location of the regulatory function for the gas sector is under review as the government is currently considering to split EWURA into two (or more) regulators focusing on energy and water individually. Conflicting views have been given by government stakeholders, principally that a new independent gas regulator will be established, or that all regulatory functions will reside with EWURA.

Regulatory and legislative frameworks

MEM began drafting the ***National Natural Gas Policy*** (NGP) in 2012, with a first draft presented for discussion in late 2012. This first draft was not received particularly well by stakeholders, and revisions made to this resulted in a stronger revised draft. The revised draft contained more detail in many areas, including many of the specific objectives of the NGP. In particular, there are clearer references to the role of a National Oil and Gas Company though it is unclear how this will interact with the incumbent TPDC. The policy

was finally accepted and endorsed in October 2013, although there are many stakeholders who still believe it falls short of what is required to give sufficient guidance to the sector development. To assist readability, the NGP could include a timeframe of when proposed future policies may come into action, how natural gas could affect existing and planned local industries, environmental and social impacts, and have an executive summary and conclusion.

One issue of contention is the Policy's promotion of domestic consumption of natural gas in forms that may not be economically optimal, and where the export of gas and resulting revenue reallocation to other parts of the economy may lead to higher economic returns for Tanzania. On the other hand, the NGP states that:

> *The Government envisages to establish an appropriate pricing mechanism to be based on a set of key principles, including cost reflectivity, prudently incurred costs, reliability and quality of service; fair return on invested capital, and capacity allocation to the most valued use.*

Following the preparation of the NGP, MEM is leading the drafting of the **Natural Gas Act** on behalf of the Government of Tanzania, with the content to be based on the NGP. The Draft Act is currently being circulated within the Government and its institutions.

The **National Gas Utilisation Master Plan** (NGUMP) is currently being drafted with assistance of expert consultants. The NGUMP will provide greater detail on the development of the natural gas sector, including domestic utilisation and local content development. Further content of this is not yet known, but is expected to align with the direction of the NGP. However we do not believe that the NGUMP will address upstream gas issues.

A3.30.4 Upstream issues

Following the large-scale off-shore discoveries, TPDC has reviewed its model PSA (MPSA), with the most recent version released in 2013. The 2013 MPSA is generally more prescriptive than its predecessors and represents a significant tightening of the fiscal and other terms, and some industry analysts have suggested that the government share of profits under the new PSA might be as high as 94% in some cases. However, gas exploration companies have expressed concerns that TPDC and MEM have been particularly slow in developing or coordinating the next level of detailed contracts that are necessary for exploration companies to reach final investment decisions.

The 2013 MPSA provide a minimum equity entitlement for the government (via TPDC) of 25%, with a carry arrangement on favourable terms. Older PSAs provide much lower equity entitlements, mostly in the range of 10-15%. Annual license rentals are significantly higher under the 2013 MPSAs, and it is the first to include a signature bonus (US$2.5 million) and production bonus (not less than US$5 million). Royalties are paid out of gross-production at 7.5% (formerly 5%). The MPSA also includes an 'Additional Profits Tax' based on an R-factor calculation; this is in the contracts only and not enshrined in the tax laws.

Although Tanzania has had modest hydrocarbon production since 2004, the tax framework of law and practice is not well developed. There are few specific rules in the Income Tax Act to deal with upstream projects so there is nothing to cover situations like farm-in agreements, development carries, or other sorts of M&A activities. There are also no specific rules to cover the treatment of decommissioning costs for offshore projects, and although

losses may be carried forward indefinitely, there is no loss carry-back. Exploration and development capital cost is eligible for tax depreciation at the rate of 20% per annum on a straight-line basis.

A PSA contractor will be subject to income tax on sales of profit oil or gas and cost recovery oil or gas with deductions as set out in the Income Tax Act. This calculation is entirely separate from the production sharing formula in the Production Sharing Agreement (PSA) and any income tax payable is due from the contractors' share (ie it is not carved out of the state share). The contractor and its sub-contractors are entitled to relief from import taxes on goods to be used in Petroleum Operations.

A3.30.5 Downstream issues

Tanzania has very little downstream gas consumption. Pricing is based on bilateral contracts, and while the Natural Gas Policy expresses a desire for gas to be priced on market principles, negotiations have been very slow, with the government exhibiting a lack of trust in the market pricing approach.

As highlighted in the summary section, the most significant challenge to downstream use of gas has been in its link with the power sector. Tanzania's power sector, and primarily its vertically-integrated state-owned utility TANESCO, has been a poor performer over many years. While the government has publicly expressed an intention to allow TANESCO to collect sufficient revenue to cover all of its operating costs, with prices set at cost-reflective levels, it has regularly stepped in to tariff reviews to prevent large increases. As a result, it has needed to cover TANESCO's operating losses with subsidies, although these have not always been delivered. Today, TANESCO has arrears of over US$400 million, with about half of these to power companies including Songas, the supplier using gas from the Songo Songo field in the south of the country.

Tanzania has ambitions for domestic use of gas and this is expected to be a key element of the NGUMP once it is released. Until we see this document, we are not able to comment on the merits of this proposed approach, but it is our preliminary view that domestic consumption outside the power sector may only be economic in a small selection of instances, and promoting activities beyond this will erode Tanzania's economic value of its resources.

Gas transportation is currently handled through a single existing pipeline built and managed by Songas. This is a key part of Songas' vertically-integrated gas extraction, transportation and gas-to-power business, although the pipeline is also used to transport gas from other wells and to other facilities. A second and larger 36 inch pipeline is currently being built (due for completion in late 2014) with support from the China Exim Bank, following a similar route to Songas' pipeline. The procurement and feasibility of this pipeline are unclear – it may be much too large for existing on-shore and shallow gas reserves, but not large enough for the larger off-shore reserves that are yet to be developed.

A3.31 Thailand

A3.31.1 Summary lessons learned

The Thai case study provides a good example of a purely domestic-driven gas market development strategy. Thai natural gas resources have been used domestically to drive economic growth. Despite the success of such a strategy, the country now faces new challenges related to the over-dependence on gas as the dominant energy resource. Below, a list of key lessons summarises this case study:

The Thai government saw the gas resource as a means to develop the national economy and thus successfully built a domestic gas industry instead of choosing an export strategy to develop the market. **Originally, the key drivers of gas demand were power generation as well as the petrochemical and gas separation industries.**

The government introduced a subsidy scheme for the integration of CNG in the transport industry and pushed for a large scale conversion of taxis into NGV. However, after conversion took place, NGV prices started to rise, threatening the sustainability of the investments already done and the use of NGV as a whole.

Thailand's reliance on gas to develop its domestic power market has now led to a high dependence on gas imports. Efforts to diversify the energy mix have been blocked due to bad experiences in developing other sources of power generation both at home and abroad.

Despite the government's success in developing a domestic gas market, the sector still depends on subsidy payments to achieve social policy objectives. The market remains attractive to investors, however, as government does commit and generally does pay subsidies to cover losses due to government policies (irrespective of whether these make sense from a wider economic perspective).

Originally, the country's energy markets were characterised by a lack of a clear institutional structure. **More recently, the sector underwent important reforms to its institutional structure, however, there is now a significant overlap in the responsibilities of older institutions and newly created ones.**

A3.31.2 Overview of gas sector

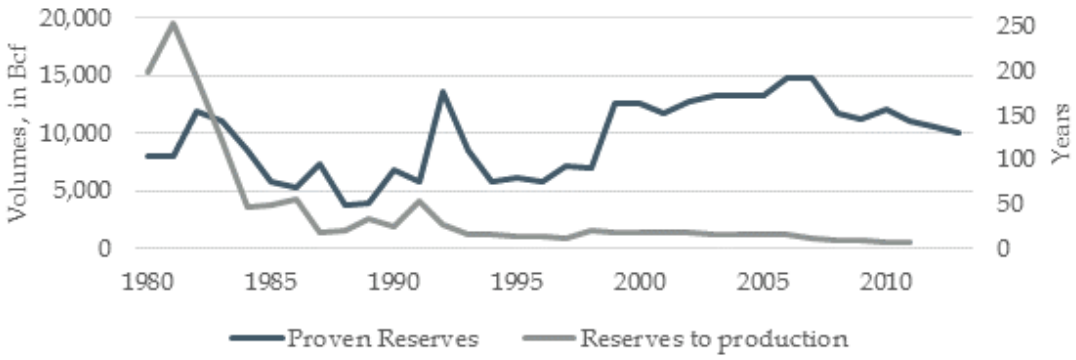
Gas production from the Gulf of Thailand began in the 1970s. The Thai government encouraged the use of gas to develop a domestic petrochemical industry and to substitute for oil in power generation (following the oil shocks of the 1970s). Gas was identified as a resource to drive the country's economic development and no consideration was given to exports.

The domestic market was easily developed in large parts due to the geography of the Gulf of Thailand which allowed for easy construction of pipelines to connect Thailand's offshore fields with the country's main demand centres located close to the coast.

Supply and demand overview

Thailand's proven natural gas reserves stood at 10.6 Tcf in 2013and are found in the Gulf of Siam and the Andaman Sea. Despite all gas production channelled to the domestic market, Thai supply has not able to keep up with the surge in demand prompted by escalating global petroleum prices and government subsidies for the use of natural gas for vehicles (NGV) and home cooking. The result has been a general decline of the resource stock over the last few years. This is illustrated in the sharp fall of the reserves-to production ratio on Figure 80, which stood at seven years in 2012.

Figure 80 Thailand Gas Reserves and Production

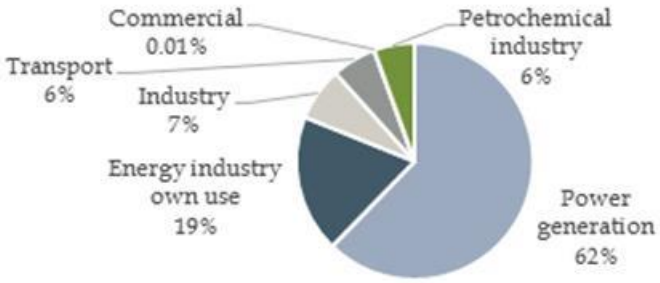


Source: US EIA, 2014

Since its initial development, the role of gas in the Thai economy has grown significantly. The reliance on gas was originally seen as a positive. However, since the 1990s, Thailand has become increasingly concerned about this reliance and the implications for supply security (as imports start) and exposure to oil prices (through the oil-indexation of gas).

The majority of gas is used in the power sector. The International Energy Agency (IEA) reported that in 2011, 62% of domestic gas consumption occurred in the power sector(See Figure 81).The national power company, EGAT, is the largest consumer of natural gas in Thailand with its group of electricity generating plants accounting for more than half of Thailand's total natural gas consumption. EGAT's power plants are linked to all commercial offshore gas fields via pipelines to facilitate supply.

Figure 81 Gas utilisation in Thailand, by sector



Source: ECA based on IEA, 2011

Additionally, 19% isutilised in the Thai energy industry, for example in gas separation plants operated by the national oil and gas company, PTT. Other than the power sector, gas is primarily used for petrochemicals. There is limited industrial demand and a small but rapidly growing NGV market.

The Government of Thailand started promoting the use of natural gas as a fuel for transportation in 2004 as one of a number of oil-substitution measures adopted by the government during the early 2000s as a means of reducing oil imports. Promotion took the form of retail price controls. NGV use was heavily subsidised and PTT was also mandated to build a network of filling stations. As use expanded, this has become unsustainable but increasing CNG prices has led to strong opposition particularly from taxis who were largely encouraged to convert. While prices have increased to 10.5 Bt/kg, the increases have stopped there which still leaves them below PTT's estimate of the cost-recovering price level of 12 Bt/kg.

Institutional structure

Decision-making authority in the Thai power sector is complex and involves the Cabinet, the Office of the Prime Minister, various ministries, government agencies, regulatory bodies and state enterprises. Authorities and responsibilities defined by law or regulation are also frequently not reflected in reality, further obscuring the picture.

This is partly due to the way the industry has evolved. In particular, until relatively recently, there was no individual ministry responsible for energy. Instead, policy was set by a committee under the Prime Minister's office while various other ministries were involved in overseeing individual state enterprises engaged in the sector. There has also been a tendency to establish new agencies to address specific issues, resulting in a large number of entities with unclear and often overlapping responsibilities.

In the absence of a Ministry of Energy, the Government of Thailand established the ***National Energy Policy Committee (NEPC)*** in 1992, to coordinate the various agencies involved in the energy sector and to drive sector reform. At that time, emphasis was placed on increasing competition and the role of private investment in the energy sector. The Committee is served by a secretariat, the ***National Energy Policy Office (NEPO)***.

In 2002, a new ***Ministry of Energy (MOEN)*** was established. NEPO was subsumed into the MOEN and became the ***Energy Policy and Planning Office (EPPO)***, continuing to act as Secretariat to NEPC but with its effective powers greatly reduced. The Minister of Energy is now a member of the NEPC.

There are two key market players in the Thai gas industry: PTT on the supply side and EGATon the demand side.Both are majority state-owned, with the Ministry of Finance holding 51% ownership and the rest of PTT's equity shares are listed on the stock market.

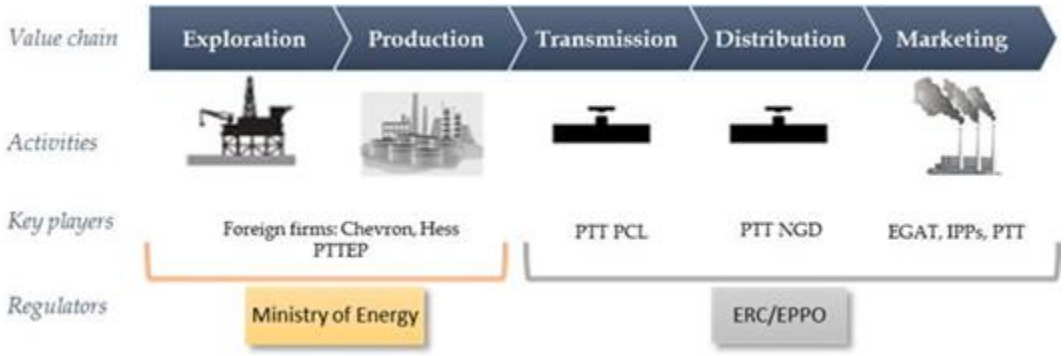
Petroleum Authority of Thailand (PTT)is the national oil company. It has gradually expanded its upstream role to become an operator, including internationally, in its own right due to a policy of indigenisation and technology transfer. In the gas industry, it held a monopoly until the 2007 Energy Industry Act and was responsible for pipelines and wholesale supply (distribution is by joint venture concessions). It also owns and operate the petrochemical industry (through a mix of its own plants and those of subsidiaries and affiliates).

Although PTT was corporatized and listed in 2001, it remains majority state-owned and is considered a state enterprise. The Board of Directors is comprised of government appointees. It is also subject to controls such as a requirement for Cabinet approval of major infrastructure projects and is expected to comply with government policy directions. Through its subsidiaries, it operates at all stages of the gas supply chain, as shown in Figure 82).

The ***Electricity Generating Authority of Thailand (EGAT)*** was established in 1969, it is an integrated generation, transmission and system operation utility. Originally holding a monopoly over generation, since 1994 it has sourced power from a combination of its own power plants, from private producers However, EGAT continues to own a large part (46%) of the existing generating capacity.

EGAT purchases gas from PTT under a Master Gas Sales Agreement which covers all gas purchased by EGAT for its own use and sales to IPPs. The agreement is on a take-or-pay basis. This effectively protects PTT from market risk for these sales. Sales to small power producers (introduced in the 1990s) and to distribution concessionaires are outside the master agreement and under direct contracts for shorter terms.

Figure 82 Value chain of the Thai gas sector and its regulation



In 2007, the government passed the Energy Industry Act which established an independent regulator, the ***Energy Regulatory Commission (ERC)*** which oversees the Thai energy industry, defined as 'the electricity industry, the natural gas industry or the energy network system business'. Accordingly, ERC is responsible for the regulation of gas transmission and storage, the transformation of natural gas from liquid to gas, and the wholesale or retail sale of natural gas via a natural gas distribution system. The ERC is an autonomous agency that reports to the Minister of Energy but not through the MOEN officials and is not part of the Ministry. The Minister of Energy still plays an important role in the market with their responsibilities focusing on sector planning.

There remains overlap in regulatory responsibilities between ERC and EPPO, particularly on the definition of regulatory policy, although the ERC is exerting growing authority (in part because of its taking many of EPPO's staff, thus increasing its capacity relative to that of EPPO).

The Energy Industry Act also created a right of third party access to gas transmission and to the LNG terminal, to be overseen by ERC. As yet, this has not been implemented and PTT remains the only gas buyer and wholesaler. PTT also continues to own and operate the gas transmission network and, through its subsidiary, PTT LNG, owns and operates the LNG terminal.

A3.31.3 Upstream issues

As previously mentioned, the most important upstream issue that Thailand faces is security of gas supply as its own resources are depleted and its economy becomes increasingly dependent on gas imports.

The Government has attempted to address this by trying to reduce the share of natural gas in the country's generation mix. However, despite its efforts, the Government's attempts to diversify have been largely blocked. Following an unsuccessful hydro project (Pak Mun) in the early 1990s, it is generally accepted that no new large-scale hydro will be constructed in Thailand. The state electricity generating utility, EGAT, has been pushing to increase the use of coal and nuclear power for generation but this has been very difficult due to strong opposition on environmental and safety grounds following the experience of pollution from EGAT's large Mae Moh lignite power plant and the recent Fukushima disaster. There is a lot of interest in renewable energy sources but their contribution is limited and likely to remain so due to government concerns over the cost implications, which have led to technology quantity caps being applied.

A3.31.4 Downstream issues

Gas prices in Thailand are indexed to oil prices and gas is sold through a 'pooling' system. Originally, PTT applied three gas pools for pricing purposes, which were later reduced to two pools. The first is comprised of Gulf of Thailand gas up to the quantities required to meet demand from petrochemicals. The second is the remaining Gulf gas plus imports. Sales from each pool are priced at the weighted average cost of gas in the pool plus a margin. The margin is higher for SPPs and distribution concessionaires as PTT considers its risks on these sales are higher. Previously, SPPs were also supplied from a third, highest-cost pool, before this was merged with the EGAT and IPP pool. Sales by distribution concessionaires to industrial customers are linked to the cost of alternative fuels.

There are a number of benefits to pooling prices, the most significant of which are that it:

Permits the absorption of new, costlier supplies (such as LNG) while simultaneously dampening the price impact across users.

Allows domestic gas prices to rise gradually to international levels as the share of imports increases.

Ensures that gas procurement costs are fully recovered and that users (for any given pool and sector) face a common price – this minimises cross-subsidies within a sector or between the sectors forming the pool.

Nevertheless, there are also disadvantages to pooling arrangements. For example, producers effectively receive a dual guarantee regarding the price for their gas and the absorption of their produced volumes in the pool, thereby dampening incentives to compete on marginal prices and pursue efficiencies and technological improvements.

A3.32 Trinidad and Tobago

A3.32.1 Summary lessons learned

Trinidad and Tobago (T&T) is a long established gas market and its gas utilisation strategy since 1960 had three distinct phases of development. First, gas to power was prioritised (1960's 1970's). Second, gas was used for Ammonia and Methanol production (1980's and 1990's). Third gas was used for LNG export (2000's). The gas sector development in T&T has been very successful due to the following factors:

The power generation sector was the key driver for early gas demand development in T&T. The main factors contributing to this were the development of state funded gas fired power generation in the 1950's and 1960's

A vertically integrated state owned national gas company has enabled the development and coordination of the gas sector. The National Gas Company (NGC) purchases, compresses, transports, sells and distributes natural gas in T&T. The vertical integration and state ownership has led to a coordinated approach in developing the gas industry.

Small domestic power market compared to gas reserves enabled development of large industrial use (Ammonia and Methanol). The quick saturation of the power markettriggered the Government to seek out alternative uses in the 1970's and 1980's. LNG projects were annulled due to financial considerations and Ammonia and Methanol were considered key strategic sectors.

Gas has mainly been used for LNG export since 2000. Significant reserves, a saturated domestic market and maximised potential for large scale industrial use has resulted in the government to look for alternative uses for gas in the 2000's. The booming LNG market was chosen as a key strategic policy priority.

Preferentialgas price mechanisms were the key competitive advantage for T&T to export fertiliser and Methanol products. Gas prices for these sectors are based on international price movements of the products, ensuring competitiveness of the industry. The preferential prices together with fiscal incentives, access to main infrastructure and the proximity to the US (largest importer of T&T Methanol and fertiliser products) provided a solid foundation for these sectors to develop in 1980's and 1990's.

Higher exploration activities due to major sector reforms. This included state involvement in upstream operations, fiscal incentives for upstream operators, LNG export focus with a pre-determined offtaker, and domestic gas pricing reforms.

A clear strategy of gas utilisation at different stages of development backed by strong political support. This enabled an integrated gas policy and supported subsidies in gas infrastructure, investment in power generation and development of downstream infrastructure.

A3.32.2 Overview of the gas sector

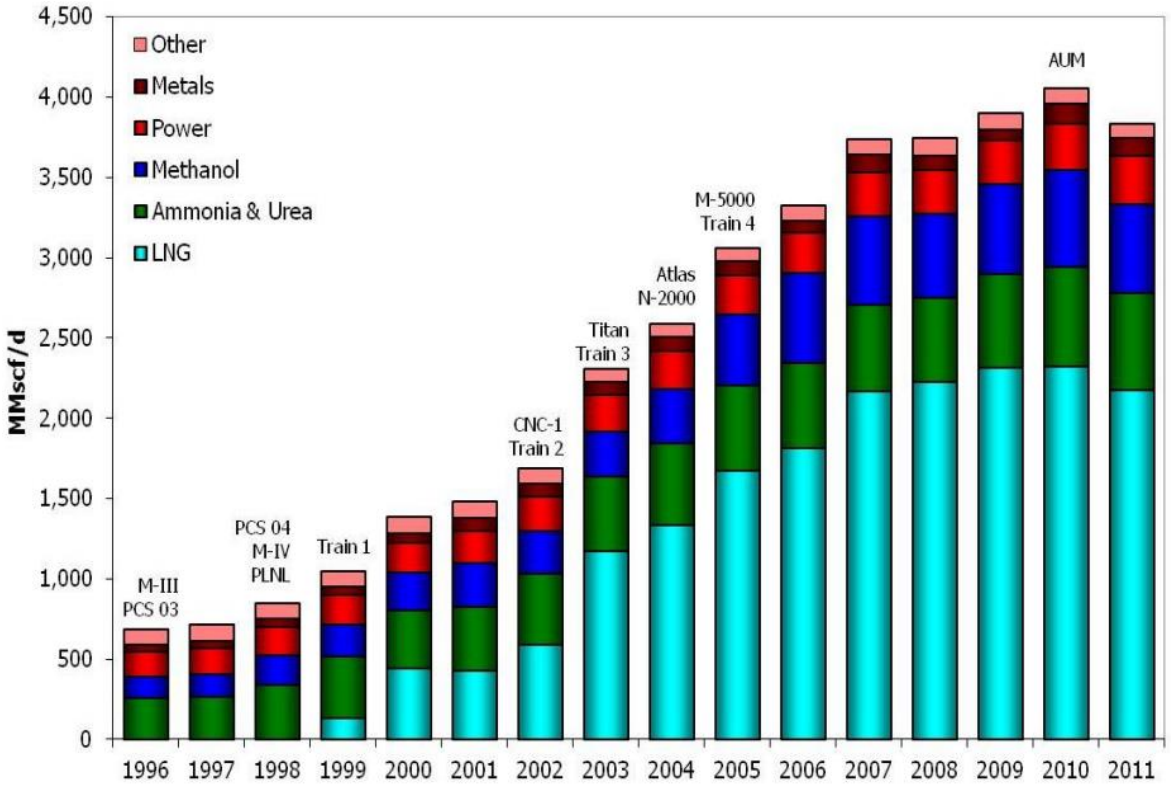
Trinidad and Tobago (T&T) is the world's sixth largest exporter of LNG exporting as much as 680 bcf in 2013. As of January 2013 the proven reserves of natural gas amounted to 13.3 trillion cubic feet (Tcf). Initially used for domestic consumption and in particular the fertilizer and petrochemical industry, natural gas has been exported since 2000. Large finds

in the 1990's and more established use of LNG accelerated this development and today close to 50% of domestic production is exported with the rest being used domestically. Since 2008 production has reached a plateau and remained closed to that level until 2013, with the main reasons being a general global economic slowdown and increased shale gas production in the US.

Supply and demand overview

The breakdown of demand by sectors over the last 20 years is shown in Figure 86. The figure shows the importance gas utilisation for the fertilizer, Methaonl and power generation sectors at early stages of development. The key driver over the last 25 years however has been LNG exports. Today, LNG exports make up the large part of domestic production (around 55%), followed by Methanol production and fertiliser plants (15% each) and power generation (7%).

Figure 83 Development of natural gas consumption Trinidad and Tobago, by sector

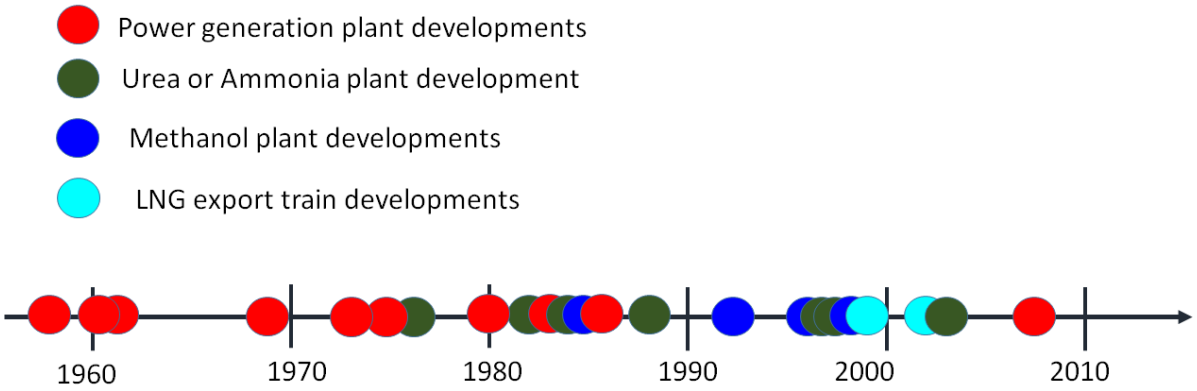


Source: Office of Strategy Management, 2013

Due to the relatively small size of the electricity sector in Trinidad and Tobago, power generation has not been an important driver for demand development in recent years. Instead methanol and fertiliser production have driven the demand levels. At the start of the gas market in Trinidad however the power sector was key in developing the market. The first Ammonia plant was only developed in 1977 while the first power plants were develop din the mid 1950's and 1960's. However with limited growth potential of power demand and significant gas reserves, fertiliser production (Ammonia and Urea) was targeted and in the 1980's and 1990's Methanol facilities were developed before LNG export train were developedFigure 84shows the dates of development of the major gas offtakers.Today the

main offtekars of gas are: 10 Ammonia plants, 4 power generation plants, 7 Methanol plants, 1 Urea plant, 1 Natural Gas Liquids processing facility and 4 LNG trains.

Figure 84 Timeline of gas offtaker plant developments, Trinidad and Tobago



Source: Powergen, Ministry of Energy, CEPAL/GTZ

It is evident from the analysis above that the power sector was the main driver to get the sector initially off the ground. Today, power generation constitutes 99.9% of power generation. This confirms that gas has been utilised at its full potential in the electricity generation sector. In lack of other suitable alternatives – industrial production in Trinidad and Tobago is low – fertiliser production and later on Methanol production was selected as a main gas offtaking industry. This has proven successful with T&T being the world's largest exporter of Ammonia and the second largest exporter of Methanol.

The main reasons for the success of the ammonia and Urea sectors in T&T have been low gas prices compared to gas prices in its main fertiliser offtaker, the US. However with increased shale gas production in the US and falling gas prices domestic Ammonia production is increasing thereby applying competitive pressures on T&T's Ammonia production. Consequently, production levels have plateaued and are even falling.

The success of Methanol in production in T&T is also due to the very low gas prices in the country. At currently US$3.9/mmbtu, gas prices are low compared to the global average. This enables T&T to compete with Saudi Arabia, Iran and Venezuela in Methanol production.

Supply

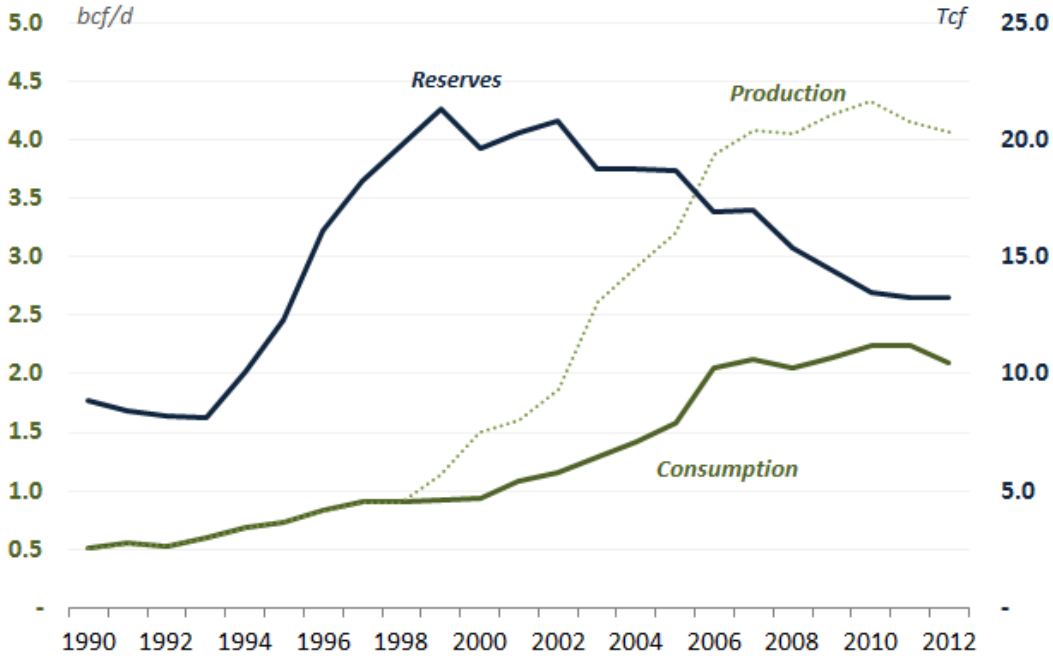
T&T's gas reserves have been declining rapidly since the early 2000's due to high levels of production for LNG exports. Today gas reserves are close to 13 Tcf. At an annual production rate of close to 1.5 Tcf, the gas to production ratio is only 8.6 years. Figure 87 shows the development of reserves, production and gas consumption over the last 25 years. Reserves increased significantly over the period 1994 to 1998. This was largely due to reforms made in the early 1990's to facilitate hydrocarbon exploration. In particular the following steps were taken by the Government:

Undertake seismic surveys on sections of the open areas of the Exclusive Economic Zone and sell the information to potential investors intended to facilitate the offer of additional acreage. The blocks were aggressively marketed by the Government with success.

The offers for the blocks were characterised by flexibility in the licensing arrangement flexibility ie the choice of concession or production sharing contracts.

Fiscal incentives were offered to encourage exploration of deeper horizons.

Figure 85Gas production, consumption and proven reserves, Trinidad & Tobago



Source: US EIA, 2014

Specific to natural gas production, the policy objective in the early 1990's was to encourage producers to develop reserves and bring them to the market. The state owned electric utility, Trinidad and Tobago Electricity Commission (T & TEC), would receive a preferential price. The domestic gas to power market was however so small compared to the potential reserves that this had no impact on exploration and production activity. Additionally T & TEC was required to introduce tariff reform and gas efficient technology in power generation.

The decision in the to export LNG in the mid 1990's and an active policy of gas transmission development domestically lead to further exploration and production in the country and resulted in an increase in reserves. Reserves have however been falling since their peak in 2000 and while the commercial arrangements are still attractive, it seems like the conventional gas resources in T&T have been exploited.

A3.32.3 Institutional structure

The National Gas Company of Trinidad and Tobago (NGC) was established as a fully government-owned state-run company in 1975. It is a vertically integrated company involved along the entire gas value chain and operates in the midstream of Trinidad & Tobago's gas industry. It also has part ownership in upstream operations but its major operational role covers purchasing, compressing, transporting, selling and distributing natural gas.

The NGC is the sole buyer and seller of gas in T&T and purchases the remaining of natural gas that is not exported in the form of LNG to market it to the domestic electricity utility, the petrochemical industries and other consumers. The financial security of NGC as a sole buyer was ensured through long term cost plus pricing arrangements with industrial users until the 2000's.

The NGC was reformed in the early 1990's and was mandated to participate in upstream gas ventures to enhance its value and made the local distributor of gas subject to economic feasibility. As part of these reforms NGC was also assigned a more prominent role in the country's energy affairs ensuring clear coordination along the entire gas value chain and policy. In addition NGC was supposed to:

evaluate all proposals for gas based energy projects the Government is considering;

monitor and guide gas sector projects to implementation;

advise the Government on appropriate incentives to stimulate downstream development and apply approved incentives;

A3.32.4 Downstream issues

As noted above the main offtakers of gas domestically are the power generators, Ammonia and Urea producers, Methanol producers, small industrial users and LNG export trains. The NGC has a flexible pricing arrangement meaning that it sets prices for each offtaker industry separately:

Prices to LNG trains are based on the netback prices of the respective delivery market. Hence the domestic gas price for LNG exporters is set as the FOB price less the costs along the value chain, ie processing fee to plant, plant margin and pipeline tariff.

For industrial users and the petrochemical industry, prices are set on the basis of the product prices. Hence wholesale gas prices change in step with final product prices thereby ensuring the competitiveness of domestic Ammonia and methanol production.

The pricing arrangements for the local industry exposes GNC to considerable risk, as it has to bear the costs of buying from gas producers at cost-plus based prices but selling at prices reflective of final product prices of Methanol, Ammonia and other industries. With increased competition of low cost gas countries on international markets, GNC has incurred losses. GNC was particularly exposed during the financial crisis when Ammonia and methanol prices fell resulting in lower gas purchase prices from large industrial offtakers.

A3.33 Turkey

A3.33.1 Summary lessons learned

Turkey is an interesting case study to analyse due to its rapid growth in gas consumption over the past 30 years. Despite not having significant domestic gas reserves, the gas market was developed over a short period of time. This was due to the following factors:

The power generation sector was the key driver for early gas demand development in Turkey. The main factors contributing to this were the development of state funded gas fired power generation, a government policy objective for gasification and rapid electricity demand growth.

A clear political commitment for gasification of the country drove gas policy and supported subsidies in gas infrastructure, investment in power generation and development of distribution grids.

Turkey's geographical location gave it easy access to a diversified range of gas sources. Consequently, long-term gas import contracts were signed with Russia, Azerbaijan and Iran.

Residential and commercial sectors have driven demand over the period 2004-2012. Gas demand grew largely thanks to the role of distribution companies in developing the grids connecting 90% of Turkey's population. Gas transmission was developed by the state owned gas utility BOTAS under the premise of gasification of the country.

The gradual liberalisation and privatisation of the gas sector aims to ensure private sector participation along the entire value chain of gas, enabling downstream investments, competition on wholesale markets and trimmed market power of former state owned monopolist BOTAS.This has reduced the need for public funding in infrastructure development of the sector.

Pricing remains a difficult issue, as import contracts are expensive and retail gas tariffs are not reflective of these prices. These subsidies are creating a budgetary burden for the Government resulting in policies that aim to reduce gas consumption in power generation.

A3.33.2 Overview of the gas sector

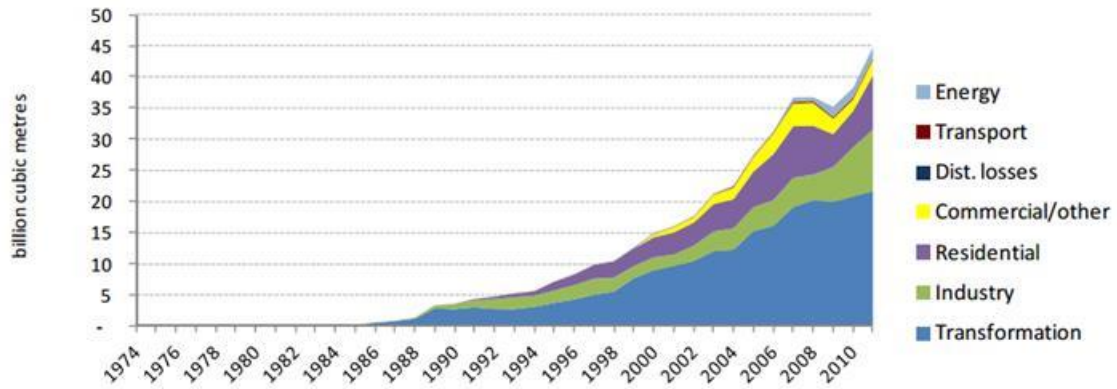
Despite having relatively small volumes of domestic gas reserves (1.2 Tcf in 1990), Turkey developed its gas market rapidly over the last 30 years from no consumption in 1985 to a level of 1.6 Tcf per year in 2012. The main drivers for gas demand until the late 1990's were the increased usage of gas in the power generation sector, the expansion of Turkey's gas transmission and distribution network and usage of gas in industry. Between 2000 and 2012 demand grew rapidly at an average annual rate of 15%. This was mainly due to gasification of the power generation sector but also to the increased usage of gas for residential and commercial use. As a result of high demand and low domestic reserves, Turkey's gas imports dependency has grown and the county is today 98% dependent on imports through

a highly diversified supply mix from Russia, Iran and Azerbaijan, as well as the global LNG market.

Supply and demand overview

The breakdown of demand by sectors over the last 30 years is shown in Figure 86. The figure shows the importance gas utilisation in the power generation sector ('Transformation') for the development of the market in Turkey since its inception but in particular over the period 2000 to 2008. However, industrial, residential and commercial sectors have also seen significant increases in demand since the mid 2000's. Today, the power generation sector accounts for 48% of total gas demand, the industrial sector for 21%, the residential sector for 20% and the commercial sector for 5%.

Figure 86 Development of natural gas consumption in Turkey, by sector



Source: IEA, 2013

Power generation has been the key contributing factor at initial stages of gas market development. The key drivers for the introduction of gas in the power generation sector were:

The low price for Russian gas when imports were introduced contributed to the increase in gas demand from the power sector. However, recent increases in this price have led the government to consider alternative fuels.

Turkey's access to diversified gas supply sources provided for alternative energy sources for power production.

Rapidly increasing electricity demand due to population growth and industrial development.

The electricity sector was originally used to drive state-led economic development. This implied that state-owned electricity generation was utilised as an elongated arm to drive government policy.

In later years, as hydropower generation became less reliable with long and repeated draught periods, flexibility was required to generate power from other sources.

The high utilisation of gas in the power generation mix has resulted in an increase in the penetration of gas in the power generation from 5% in 1990 to 45% in 2012. However current policy objectives are to curb the importance of gas in power generation sectors due to security of supply considerations, the increase cost of imported gas and the country's

dependence on certain gas-supplying countries. The current target is to reduce gas-to-power generation capacity from 31% in 2011 to 24% in 2030.

Industrial sector demand also constituted a significant volume of gas demand at the beginning of gas market development in Turkey. Historically, one of the main industrial consumers of gas is the fertiliser sector. Until 1996, the industry accounted for approximately half of all industrial gas consumption. The main players in fertiliser production are İGSAŞ (Istanbul Fertilizer Industry, Inc.) and TÜGSAŞ (Turkish Fertilizer Industry Co.), both of which have been connected to the gas transport network since the late 1980s. A more recent driver of demand from industry are gas-fuelled cogeneration systems for industrial activity. The following table presents the top six industrial activities according to their 2011 gas consumption:

Table 22Six largest Turkish industries by gas consumption, 2011

Industrial activity		% of annual consumption in industry	
A3.34	**Organised industrial sites**	A3.35	29.3%
A3.36	**Non-metallic minerals**	A3.37	11.8%
A3.38	**Iron & steel**	A3.39	8.8%
A3.40	**Chemistry &petrochemistry**	A3.41	8.6%
A3.42	**Food & beverages**	A3.43	7.6%
A3.44	**Fertilisers**	A3.45	7.0%

Source: EMRA, 2011

The residential sector also contributed to the growth in gas demand, albeit at later stages of market development. The key drivers of the growth in residential and commercial demand was the connection of the major urban cities to gas distribution grids, both for district heating and household consumption. In the case of district heating, Energy Market Regulatory Authority (EMRA) successfully implemented an auction mechanism which granted gas distribution licences for this purpose. The growth in the urban populations and the ongoing modernisation of main Turkish cities meant that uptake in the residential and commercial sector was high. Today, only 10% of the population is not connected to the grid.

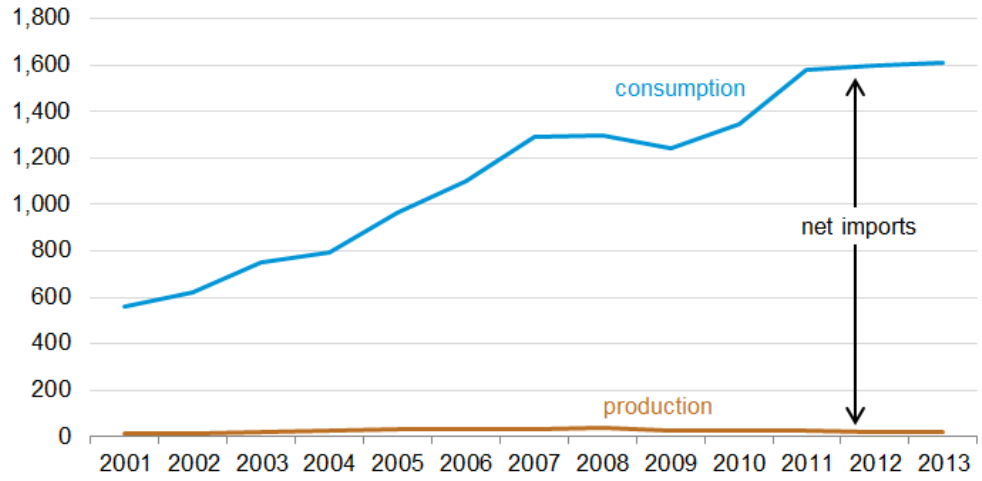
Supply

Turkey's natural gas reserves have not been sufficient to meet its increasing domestic demand and they are expected to be depleted over the next decade (reserve-to-production ratio in 2012 was 9.8 years). Consequently, the gap between consumption and production (Figure 87) has been met with imports. As of 2012, 95% of gas consumed was covered by imports. Turkey's geographical location together with regasification terminals gives it a strategic advance for obtaining gas from a diversified mix of supply sources. However imports are still mainly supplied from Russia (58% of imports) with Iran (18% of imports), Algerian LNG (10% of imports) and Nigerian, Qatari and Egyptian LNG (8% of imports) making up the rest.

The heavy dependence on gas imports and, in particular, reliance on Russian gas imports has prompted the Government to follow policiesto reduce the importance of gas in the power generation mix and to look for alternative supply routes. Most notably, the

development of new regasification terminals and connections to Caspian gas sources are currently being assessed.

Figure 87Annual gas production, consumption and imports in Turkey, *bcf*



Source: US EIA, 2014

A3.45.1 Institutional structure

The 2001 Natural Gas Market Law was instrumental in setting up the legal and institutional foundations of Turkey's gas market. The ***Ministry of Energy and Natural Resources*** (MENR) was mandated to liberalise the Turkish natural gas market following the promulgation of the Natural Gas Market Law in 2001. The Law allowed for gradual privatisation of all parts of the gas value chain. The driving principle was to attract private sector investment, reduce the burden of state ownership on the budget deficit and ensure security of supply. The Law also set out the main legal basis for regulating the key parts of the gas value chain[50].

The Law further established the ***Energy Market Regulatory Authority*** (EMRA), which was responsible for overseeing the privatisation process. As a consequence of liberalisation, the number of foreign and Turkish private market players in all segments of the gas supply chain increased significantly. This was also helped by third-party access (TPA) provisions on the gas transport network granted in 2004. Such liberalisation was further developed as the BOTAŞ' monopoly on the wholesale market was lifted in 2007 allowing other parties to participate in the wholesale trade of gas.

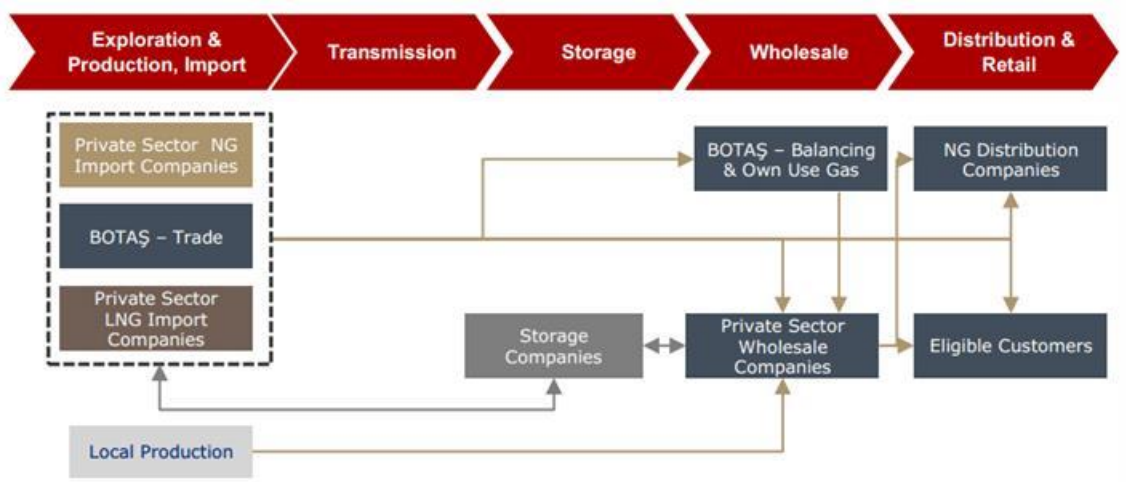
The ***General Directorate for Petroleum Affairs*** (GDPA) is responsible for issuing E&P licences thus overseeing the upstream segment. The ***Turkish Petroleum Corporation*** (TPAO) is still the largest player in the upstream segment. It operates natural gas fields in the Thrace Basin and in the West Black Sea offshore. Gas produced in the Thrace Basin has been sold directly to local consumers, as there is no access to the national transmission network. TPAO also conducts operation jointly with Shell and Exxon for the exploration of shale gas resources in the Mediterranean.

[50]These include regulation of contracted and un-contracted imported gas volumes, domestic production, the wholesale market, open-access in transmission, LNG and storage, third-party access, distribution and its privatisation, retail markets, construction services

BOTAŞ is the former state-owned monopolist operating along the entire gas value chain. Following liberalisation and privatisation of the sector, BOTAŞ is to be split in three separate legal entities handling import, transport and distribution and storage by 2015. The company remains the owner and operator of the Turkish transmission network. Since the market has been liberalised, the transmission business is also opened up to private investment and construction of pipelines. However, up to date, no such third party activities has taken place.

BOTAŞ remains the largest importer of gas having ongoing contracts with Russia, Iran, Azerbaijan, Algeria and Nigeria. Since liberalisation of the market commenced, BOTAŞ is required to reduce its market share to 50% of import contracts. With this measure, MENR aims to partially reduce the import risks imposed on the Turkish gas market by BOTAŞ' signature of take-or-pay contracts for imports from Russia, Azerbaijan and Iran[51]. In addition, the high price of gas supply from abroad has to be subsidised by the Turkish state, directly and through BOTAŞ, imposing a further financial burden. For the reasons above, the government's intention to liberalise the market and forcing BOTAŞ' to transfer some of its import contracts to private entities in order to reduce its share of the market is to reduce import prices through the creation of competition on the market. Despite these efforts, the Natural Gas Market Law No. 4646 still forbids pipeline imports by private operators from countries with which BOTAŞ has existing contracts. The only way is through the transfer of contracts from BOTAŞ to private operators.Figure 88 summarises the key entities involved at different stages of the gas value chain in Turkey.

Figure 88 Value chain of the Turkish gas sector



Source: Investment Support and Promotion Agency of Turkey, 2013

The wholesale trade of gas in Turkey is conducted on a day ahead gas market where only licensed import and wholesale companies are allowed to conduct wholesale activities. There are currently 42 licensed firms. Wholesalers are not allowed to engage in transmission and distribution. Another restriction on wholesalers is that their volumes are limited to 20% of projected national consumption. Wholesalers also have to hold storage capacity to respond to peak demand. Domestic producers and importers are allowed to sell their volumes to distribution companies directly. There were 63 licensed distribution companies in 2012. These firms may only purchase up to 50% of its volumes from a single supplier.

[51]This risk arises due to the network's lack of ability to transport all the capacity contracted for.

A3.45.2 Downstream issues

A key characteristic of the Turkish domestic gas market is the separation of customers into eligible and non-eligible customers. Gas users categorised under the former may purchase directly from importers, wholesale gas traders and gas distribution companies, while the latter user category may only buy gas from licenced gas distribution companies.

Before the recent gas sector reforms, ie reforms undertaken to comply with EU regulations, standards, etc., gas prices in Turkey were determined by BOTAŞ with indirect guidance from the government according to socio-economic policy. Gas prices were determined following different methodologies:

Electricity generation and fertiliser plants - prices were linked to international oil prices and revised every three months. Prices for TEAS were lower than for private generators, reflecting that TEAS contracts were interruptible. Prices for these consumers were confidential.

Gas distribution companies -prices were cost-reflective and affected by exchange rates. These prices were made publicly available. Since 2002, distribution tariffs were capped by MENR at 30% of BOTAŞ supply price.

BOTAŞ gas supply - prices were set under long-term contracts, typically linked to oil prices. These prices are confidential.

Wholesale tariffs - following the passing of the Gas Market Law in 2001, wholesale gas prices are to be negotiated between parties under a framework developed by EMRA. Since 2008, BOTAŞ' wholesale gas prices for eligible consumers and distribution firms were set under the Cost-Based Pricing Mechanism for State-Owned Enterprises. Under the mechanism, prices were updated on a monthly basis to account for changes in import prices and exchange rate fluctuations. More recently BOTAŞ was exempted from the mechanism. Currently, the prices charged to distribution companies and eligible consumers, including gas-fired IPPs, are subsidised prices, while prices charged to generators in the Build-Operate and Build-Operate-Transfer schemes and state-owned power plants are not subsidised. This results on the cross-subsidisation of gas prices between consumer groups.

Retail tariffs - since 2001, retail prices are determined by licensees on a gas cost plus operating cost basis taking inflation into account. They are approved by EMRA.

A4 Summary of LNG pre-feasibility study

Executive Summary and key recommendations from the study GHANA LIQUID NATURAL GAS STUDIES AND DESIGN SCREENING REPORT, March 2014, CH2MHILL, Millennium Challenge Corporation

Key conclusions from the Phase 1 screening studies are as follows:

Situation Assessment

A range of gas demand scenarios were considered by Gas Strategies taking into account future supply scenarios from WAGP and indigenous offshore sources. This identified significant uncertainty in gas demand.

Current gas supply to Ghana is via the West African Gas Pipeline (WAGP). The contracted volume is 120 MMscfd, but this has not been achieved to date with average volumes closer to 60 MMscfd. The shortfall in fuel for power generation is made up by import of light crude oil via SPMs located at Aboadze and Tema.

There has been significant investment in the Western Corridor infrastructure project (believed to be in the order of $850 million) which will import gas from the Jubilee field via a subsea pipeline at Atuabo to a gas processing plant. Natural gas will then be transported via pipeline to the power plants at Aboadze.

This project is not yet operational and first gas for power generation is currently estimated to be available in the fourth quarter of 2014. Other offshore gas reserves have been identified and these are anticipated to come on stream from 2016 onwards.

A range of demand scenarios were assessed, based on proposed power plants and also industrial users. These demands are currently focused around Tema and Aboadze, and future power plant development continues to be focused in these areas but with additional power plant proposals at Domunli and Esiama.

The supply and demand assessment indicates a base case demand for additional gas of approximately 250 MMscfd out to 2025. There is considerable uncertainty associated with this estimate, primarily due to uncertainties in timing of new power plant developments and in the timing and volume of indigenous gas supplies and of volumes via the WAGP. Thus demand may be greater than this. There is also a possibility that demand could be less if power plant projects are delayed, WAGP contract volumes are delivered and indigenous supplies are greater than estimated in the base case. Upper and lower cases are given in Appendix A.

Project Screening

Screening of the sites was undertaken, evaluating them against a range of criteria that included location, operations, environmental and social impacts and cost. This included appraisal of proximity to demand and to gas and port infrastructure.

The options considered in the screening included offshore moorings at Domunli, Atuabo, Esiama, Aboadze and Tema and fixed sheltered berth options at the ports of Sekondi and Takoradi. The fixed berth options were found to be significantly more expensive and also presented significant challenges onshore in terms of connecting to the onshore gas distribution networks due to the distance to the pipeline and density of population in the area.

The screening identified Aboadze as the preferred site for the FSRU facility. Aboadze has the advantages of being close to demand, close to the Western Corridor pipeline for transfer of gas to future projects to the west and also connection to the WAGP as a potential means of supplying gas to Tema by reverse flow, though this will require further study and discussion with WAGP. It is also close to the ports of Sekondi and Takoradi which can provide marine operations support including tugs and other services.

Tema, Atuabo and Esiama all present viable alternatives though it is noted that Atuabo and Esiama are further from existing port facilities that provide tugs and other marine support services.

The screening included a sensitivity assessment of the impact of the Atuabo free port that has just been approved. If this were operational by the time the FSRU started up then this would bring some advantage to the most westerly sites considered (Atuabo, Esiama and Domunli) as marine support facilities would be available.

Indicative Costs

Preliminary cost estimates indicate capital costs for the offshore mooring in the order of US$30-40 million, fixed berth / breakwater options are in the region of US$195-270 million. This includes the FSRU berth/mooring and subsea/onshore pipeline to a tie-in point onshore.

Operational costs are estimated at US$72 million/year, including FSRU leasing over a 10 year period.

Environmental and Social Review

The site options with offshore moorings were found to have similar environmental impacts with the single most important issue being the impacts associated with the chilled water discharge from the regasification process. The full impact of the chilled water discharge is expected to be fairly localized around the FSRU, the full extent of which will be determined through thermal plume modelling conducted as part of Phase II.

The two sites utilizing fixed berth technology, Takoradi and Sekondi were found to have greater environmental impacts because of their location near to the shoreline and sensitive habitats. The sites utilizing the fixed berth technology are expected to have somewhat greater impacts associated with their discharge of chilled water into shallower waters near shore.

Socioeconomic impacts associated with construction and operation of the sites with offshore moorings will all be minimal because of the distance between the mooring sites and the coastline and because construction activities, including the housing of workers, will be done from ships and floating work platforms.

The two sites utilizing fixed berth technology will have additional socioeconomic impacts because of the need for quarrying and transportation of rock for construction of the breakwaters and housing of construction workers on shore within the existing population.

All site options will require an exclusion zone around the FSRU that will have a small impact on artisanal fishing.

The onshore natural gas pipelines associated with the various site options have differing lengths and different impact levels depending upon the characteristics of the areas crossed. In general, socioeconomic impacts associated with the offshore mooring options

were found to be less than those associated with the fixed berth options because of the length of the onshore pipelines and density of residential and commercial development in the Takoradi and Sekondi areas.

Recommendations

Aboadze is recommended as the preferred site for location of the FSRU. It is recommended that this site is taken forward for further study. This should include, but not be limited to, gathering site specific data, detailed assessment of the onshore infrastructure and potential tie-in to the Western Corridor pipeline, detailed assessment of the mooring configuration and further evaluation of the feasibility of transport of gas to Tema via the WAGP both from a technical and commercial standpoint.

It is noted that the studies to date have not identified any specific technical issues regarding feasibility of an offshore mooring. The options proposed at Takoradi and Sekondi present challenges from an onshore perspective in terms of routing the pipeline through the town, as well as being significantly more expensive.

A5 Ghana Gas Master Plan Model

The development of the gas Master Plan requires assessing and balancing many uncertainties: demand, supply, infrastructure, prices etc. A scenario-based modelling tool is essential to allow scenarios to be systematically examined and tested. The Ghana Gas Master Plan Model (GMPM)aims to provideguidance for policy advice for the upstream, midstream and downstream gas sectors. Its main features are therefore to:

estimate the demand for gas in Ghana up to 2050

calculate the national annual supply demand balance in Ghana up to 2050

calculate the weighted average cost of gas resulting from the supply mix

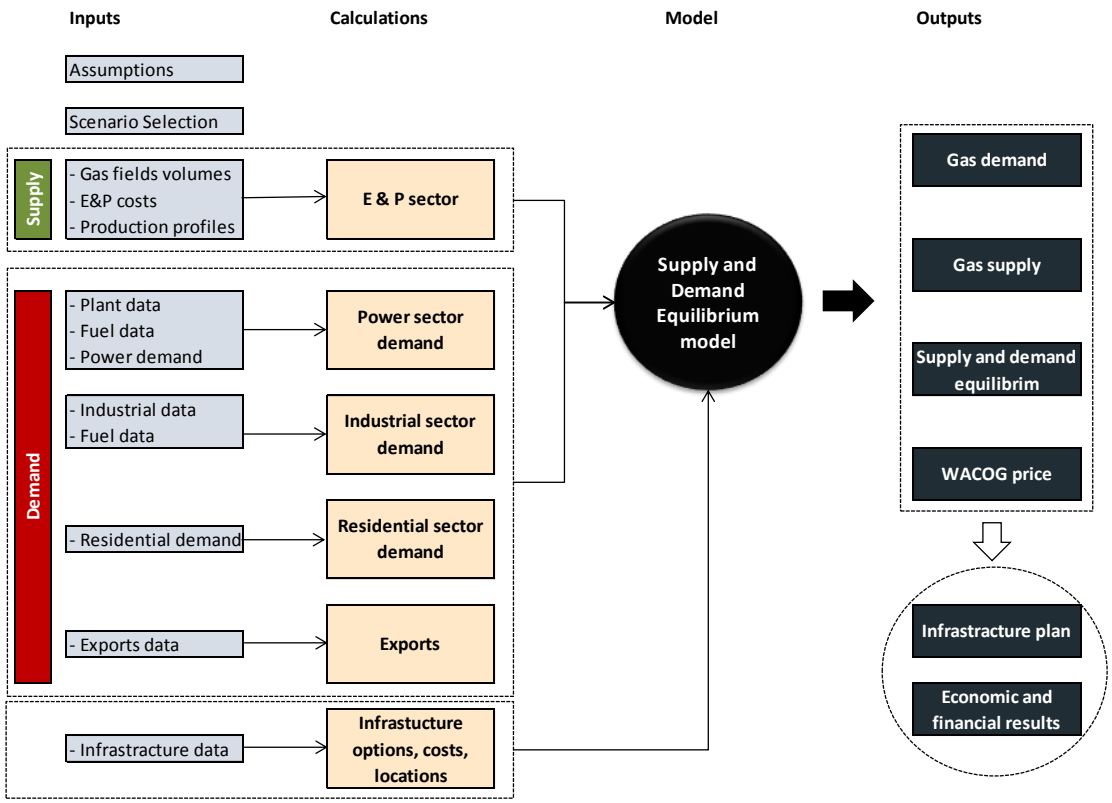
determine a gas infrastructure plan

calculate the financial revenues from the gas sector for the government

calculate the economic value of gas utilisation scenarios

The main structure of the model is shown in Figure 89 below.

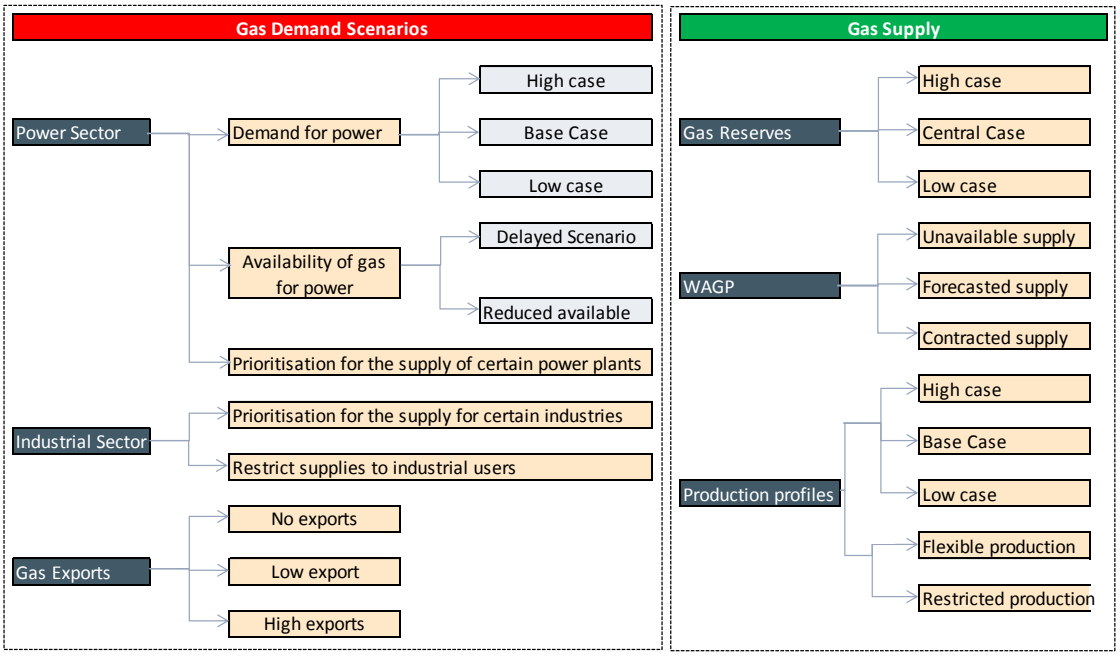
Figure 89Ghana Gas Master Plan Model structure



Given the uncertainty over future gas pricing, export commitments, domestic supply volumes, infrastructure development and demand forecasts, the GMPM allows the user to

simulate a variety of different scenarios. The different scenarios, that can be chosen by the user are summarised in Figure 90.

Figure 90Modelling scenarios



A5.1 Power sector dispatch modelling

The approach of the power sector dispatch module is to determine the amount of gas that is required for the operation of gas power plants. Therefore, it is necessary to model the power sector and proceed with a simplified economic dispatch to determine the operating times of gas fired units, ie their load factors. This approach will determine the amount of gas demand that can be expected from gas fired power plants over the period 2014 to 2040. For the economic dispatch of the sector it is necessary to model the power demand, the power supply and the intersection of the two. A schematic approach of the methodology we will use is presented in Figure 91 below.

The economic dispatch of the power sector uses a simplified hourly least cost dispatch and can be summarised in the following 7 steps:

Step 1: Determine the total annual demand for energy (including exports/imports)

Step 2: Determine the load profile for a typical day

Step 3: Calculate the available capacity of the power plants in each hour of the day

Step 4: Calculate the total variable costs of the power plants for the production of the available amount of power

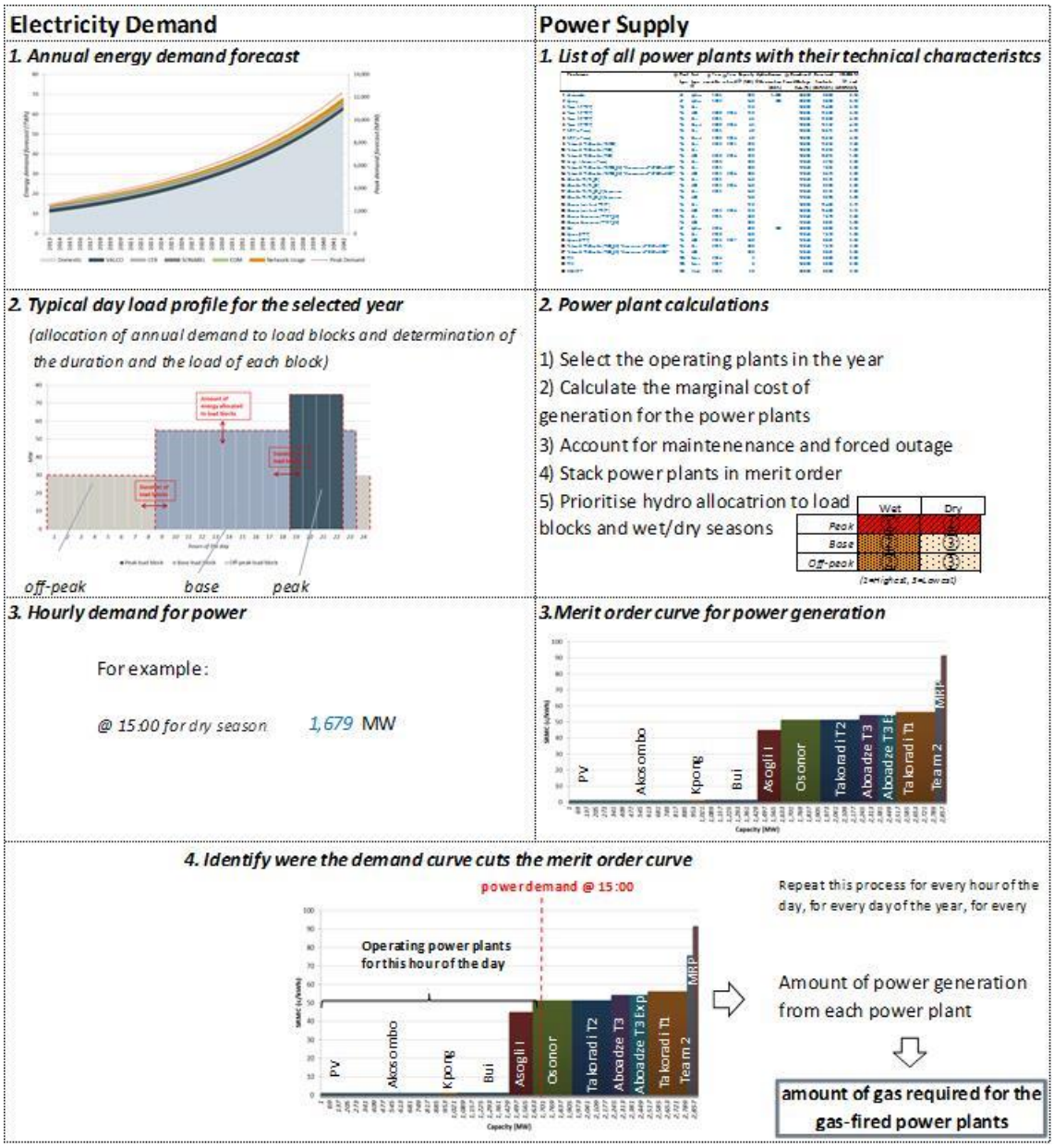
Step 5: Rank the available power plants by least cost and calculate the cumulative capacity (merit order curve)

Step 6: Superimpose the load profile of a typical day onto the merit order curve to determine the marginal cost of system in each hour and the amount of energy generated from each power plant

Step 7: Repeat this process for every hour of the year for each year to extrapolate demand on an annual basis up to 2040.

This 7-step process is illustrated schematically in Figure 91. The main steps are briefly described in the subsequent sub-sections.

Figure 91Power sector dispatch methodology

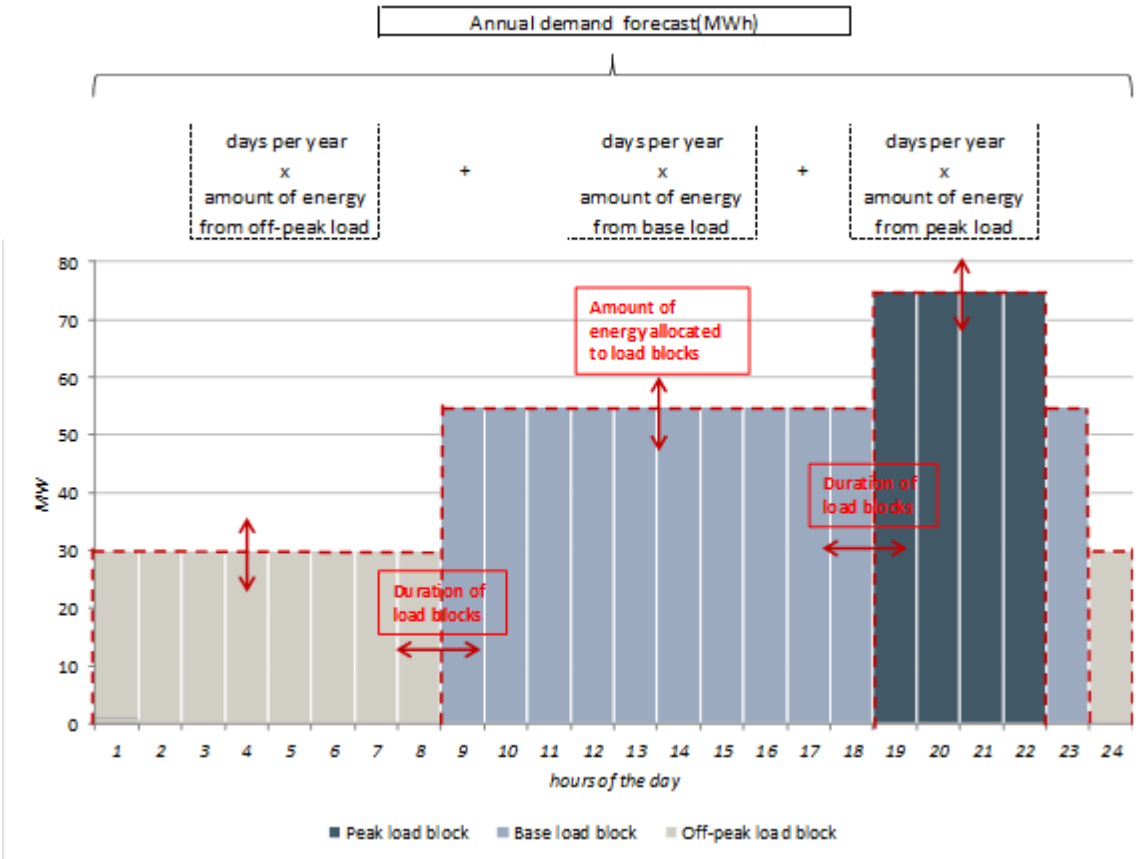


For the power demand modelling the total amount of generation required for each year is an input to GMPM. The GMPM dispatch module estimates the loads of power plants on an hourly basis. Hence the annual demand projection is broken down in three load blocks for a typical day. The amount of energy allocated to each load block is determined by the annual

load factor. The duration of each load block is determined by generic load blocks based on average typical daily load curves for Ghana.

Higher load factors will result in a lower ratio of energy being allocated to the peak and lower load factors will result in a higher ratio of energy being allocated to the peak. The resulting daily load curve should represent the typical average daily load of the year. The methodology for the allocation of the annual load to daily load blocks is shown in Figure 92.

Figure 92Approach for daily dispatch (illustrative)



Given that dispatch represents the generation required, imports and exports must be incorporated into the demand forecast and the load blocks to ensure proper generation. By not including exchanges, generation will be overestimated in the case of imports and underestimated in the case of exports. Imports and exports are incorporated as net demand such that the block becomes based on domestic demand plus exports minus imports.

The supply side of the dispatch curve is determined through the assumed power plants operational in each year. The operational power plants are ordered by variable costs ('merit order'). To stack the power plants in merit order it is necessary to calculate the total variable costs of each plant for the running year. The calculation of the total variable costs takes into account the variable Operational and Maintenance (O&M) costs of each plant, the fuel costs using the heat rate of the power plant, and the emissions cost using the emissions factor of each power plant. The model also allows for periods where power plants are not operational due to maintenance activities or due to unforced outages.

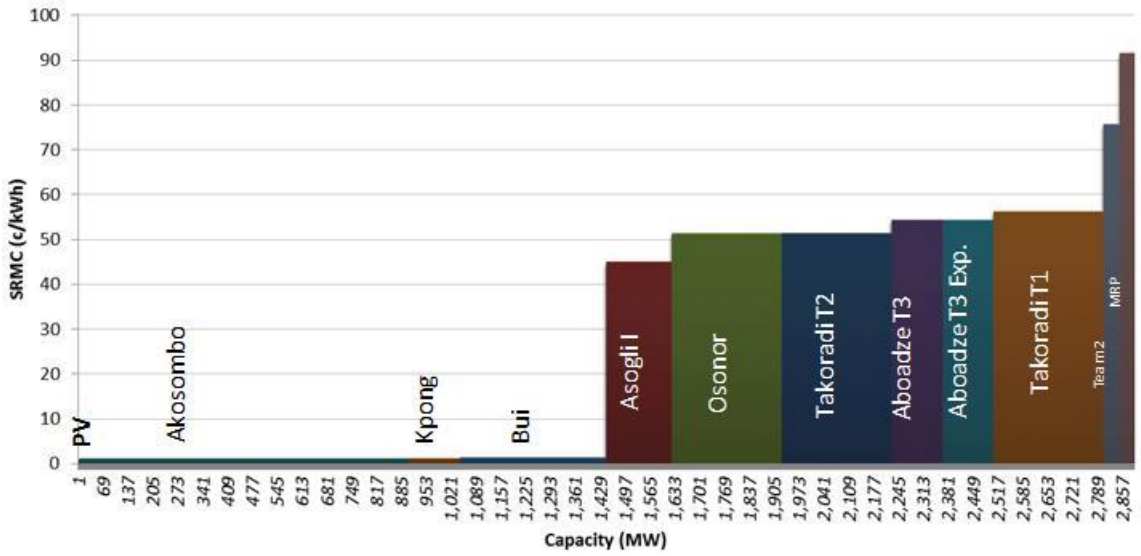
The hydro power plants are modelled in a different manner in comparison to the thermal power plants. The average amount of generation that is available in each year is determined

from the historic amount of generation from each power plant for the past 20 years. The model allows for seasonality in respect to the hydro power plants and splits the year in a wet and a dry season.

The annual average amount of generation calculated from historic capacity factors is split in each load block (peak, base, off-peak) and in the wet and the dry seasons. Firstly, the available amount of hydro generation will be allocated in the peak daily load blocks across the year. The remaining amount will be used for the base and the off-peak daily load block in the wet season. What is left will be allocated in the base and the off-peak daily load block in the dry season. The priorities for the allocation of hydro generation are depicted in Figure 93 above. The power generation from other renewable energy sources (ie wind and PV) is assumed to follow a flat load profile. The amount of generation from these sources is estimated using typical capacity factors for wind and photovoltaic power plants for Ghana[52].

This approach allows us to rank all power plants on an hourly basis and identify exactly at what merit level gas fired power plants come into the dispatch. An illustration of the merit order curve in 2015 is depicted in the following graph.

Figure 932015 merit order curve



The demand curve is then superimposed onto the hourly merit order curve to identify the marginal power plant. Thus the operating plants for each hour of the year are identified. Then, by adding up the generating amount of each power plant for every hour of the year we get the amount of generation for each power plant over a year. Using the heat rate of the gas power plants we can determine the amount of gas required to produce the calculated amount of power. The above process is repeated for every hour of planning horizon of the study.

An illustration of the hourly load from each power plant on a typical day during the dry season in 2020 is depicted in Figure 94 below.

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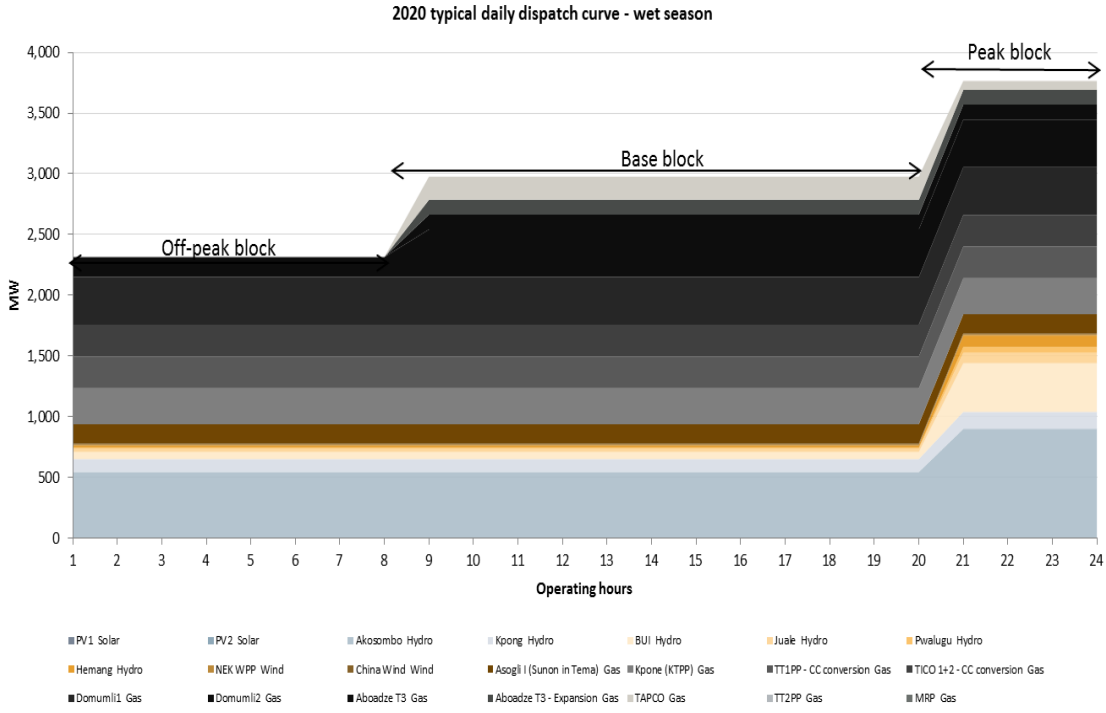
52 *Feasibility Study of Wind Energy Utilization along the Coast of Ghana,Francis Nkrumah, 2002; Design and Analysis of a 1MW Grid-Connected Solar PV System in Ghana, Ebenezer Nyarko Kumi, The Energy Center Kwame Nkrumah University of Science and Technology Kumasi-Ghana, 2013.*

Figure 94Power plants load on a typical day in 2020



A5.2 Industrial sector netback analysis

The objective of the industrial sector netback analysis is to generate a demand profile for each year of analysis against an assumed gas price for that year. Then the calculated weighted average cost of gas is superimposed onto the demand profile to determine the potential demand for gas from the industrial sector.

As detailed in the discussion on inputs in SectionA5.6, a constant demand level is estimated per industry which is applicable if the calculated supply price for gas is less than the relevant netback value. While in reality demand for each product may be expected to vary with price, this approach is considered adequate given; (a) the uncertainties associated with demand forecasting for quantity; and (b) the need for large, lumpy capital investments for a number of the industrial sectors considered.

Demand values are calculated based on the following process:

Step 1:Estimate demand for production - Estimated domestic demand for a commodity for a given year is added to the export potential to give a total demand for the production of a product.

Step 2: Estimate production capacity - If this total demand is higher than the existing production capacity for the previous year this creates a desire for additional production capacity to be constructed. Such additional capacity is modelled as coming online when total demand rises a predefined level above the production capacity of existing plant. This level is set to both reflect the lumpy nature of capital investment in large-scale plant and to limit build-rate beyond what is likely practical.

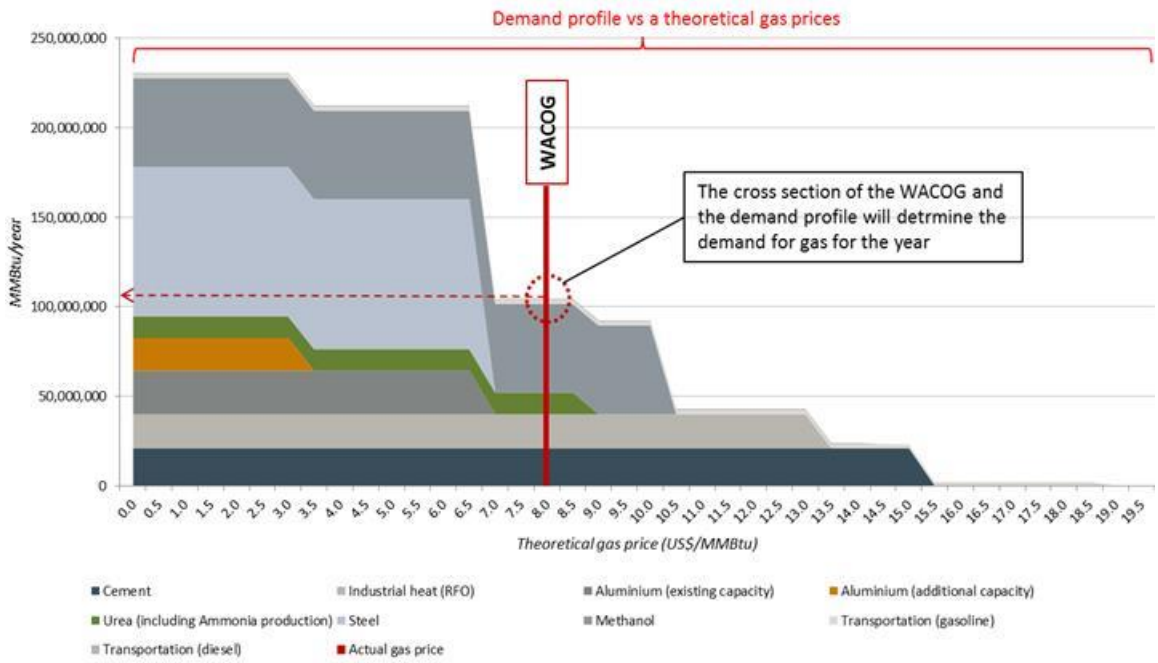
Step 3: Estimate time constraints - In the first years of analysis, plant (or vehicles in the case of CNG) will only come online following the minimum lead time, predefined for each industrial sector, to reflect development and construction. This effect is only imposed from the initial year of analysis as forecasting for future demand may mitigate for the lag in later years.

Step 4: Estimate gas demand profile - Total demand for product from domestic production capacity is then multiplied by the gas consumption requirements per unit production to generate a demand for natural gas from industry. For a given year, this demand is also plotted as a demand profile by sector against the theoretical gas supply price as demonstrated in Figure 95.

Step 5: Estimate gas demand - The gas demand profile is superimposed onto the weighted average cost of gas to determine the demand for gas in a given year.

The metrology described above is depicted on Figure 95 below for a given year. This process is repeated on an annual basis to determine the demand for gas from the industrial sector per annum.

Figure 95Industrial netback value and demand profile (illustrative)



A5.3 Modelling the supply and demand gas balance

This part of the model brings together the assessments of gas demand at cost based prices and available supplies to produce projected supply and demand balances on a regional basis under different scenarios for exploration, development, production and demand. The aim of the task is to set out a framework for the scenarios for supply/demand balancing that will be examined in the GDMP model and, in turn, used to assess the infrastructure options for balancing supply and demand on a regional basis.

The available gas supply options are ranked on the basis of the costs of production. The least cost supply option will be utilised. Available supplies within one year are restricted by the production profiles of each field or the pipelines maximum throughput volumes. The total amount of gas that can be delivered along the years is restricted by the proven reserves of each field. The process is summarised in Figure 96.

Figure 96Supply and demand balance methodology

Step 1: List the E&P costs, 1P reserves and annual supply volumes for each supply option for every year.

A. Costs of available gas supplies

	ENI Sank.	Jubilee	...	WAGP	LNG
2013	x1	y1	...	z1	p1
2014	x2	y2	...	z2	p2
2015	x3	y3	...	z3	p3
...	...	...	...	...	...

B. Amount of available gas reserves *(1P reserves)*

	ENI Sank.	Jubilee	...	WAGP	LNG
2013	X1	Y1	...	Z1	P1
2014	X2	Y2	...	Z2	P2
2015	X3	Y3	...	Z3	P3
...	...	...	...	...	...

C. Amount of annual maximum supply volumes

	ENI Sank.	Jubilee	...	WAGP	LNG
2013	XX1	YY1	...	ZZ1	PP1
2014	XX2	YY2	...	ZZ2	PP2
2015	XX3	YY3	...	ZZ3	PP3
...	...	...	...	...	...

Step 2: Rank the data of each field by least cost

A. Rank of available gas supplies by cost

	Jubilee	ENI Sank.	...	WAGP	LNG
2013	2	1	...	3	4
2014	2	1	...	3	4
2015	2	1	...	3	4
...	...	...	...	...	...

** Supply options can be also prioritised irrespspective of the costs by the user*

B. Amount of available gas reserves by ranked option

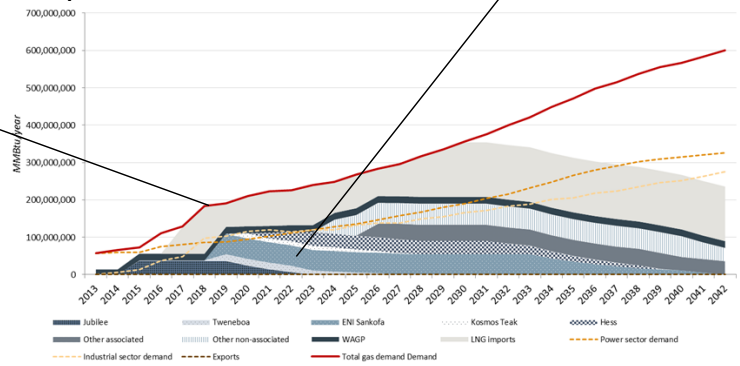
Rank	1	2	3	...	
	Jubilee	ENI Sank.	...	WAGP	LNG
2013	Y1	X1	...	Z1	P1
2014	Y2	X2	...	Z2	P2
2015	Y3	X3	...	Z3	P3
...	...	...	...	...	...

C. Amount of annual maximum supply volumes by rank

Rank	1	2	3	...	
	Jubilee	ENI Sank.	...	WAGP	LNG
2013	YY1	XX1	...	ZZ1	PP1
2014	YY2	XX2	...	ZZ2	PP2
2015	YY3	XX3	...	ZZ3	PP3
...	...	...	...	...	...

Step 3: Match the supply and demand volumes for every year, starting the supply from the least cost option until the resources are depleated.

	Demand
2013	A1
2014	A2
2015	A3
...	...



The supply and demand balance of the gas sector was simulated for five scenarios as it was described in Section 5.2. The state of the gas sector that each simulated scenario represents is depicted in Figure 97 for the Aligned scenarios and in Figure 98 for the Non-aligned scenarios.

Figure 97 Aligned scenarios

Aligned scenarios	Gas Demand Scenarios				Gas Supply Scenarios		
	Power Sector	Industrial Sector	Gas Exports		Gas Reserves	WAGP	LNG imports
Low case scenario	Low case	Non-strategic	No exports	⇔	Low gas reserves	Low available supply	Two LNG terminals
	- Low demand for power - Low power exports - VALCO (2 pot lines)	- Restrict supplies to unprofitable industries. - Supply: Industrial heat (RFO), transportation					- Two LNG terminals located in Tema and Takoradi. Regas capacity: 55 bcf per year each.
Base case scenario	Base case	Non-strategic	No exports	⇔	Central gas reserves	Base available supply	Two LNG terminals
	- Base demand for power - Base power exports - VALCO (3 pot lines)	- Restrict supplies to unprofitable industries. - Supply: Industrial heat (RFO), transportation					- Two LNG terminals located in Tema and Takoradi. Regas capacity: 55 bcf per year each.
High case scenario	High case	Non-strategic	No exports	⇔	High gas reserves	High available supply	Two LNG terminals
	- High demand for power - High power exports - VALCO (4 pot lines)	- Restrict supplies to unprofitable industries. - Supply: Industrial heat (RFO), transportation					- Two LNG terminals located in Tema and Takoradi. Regas capacity: 55 bcf per year each.

Figure 98Non-aligned scenarios

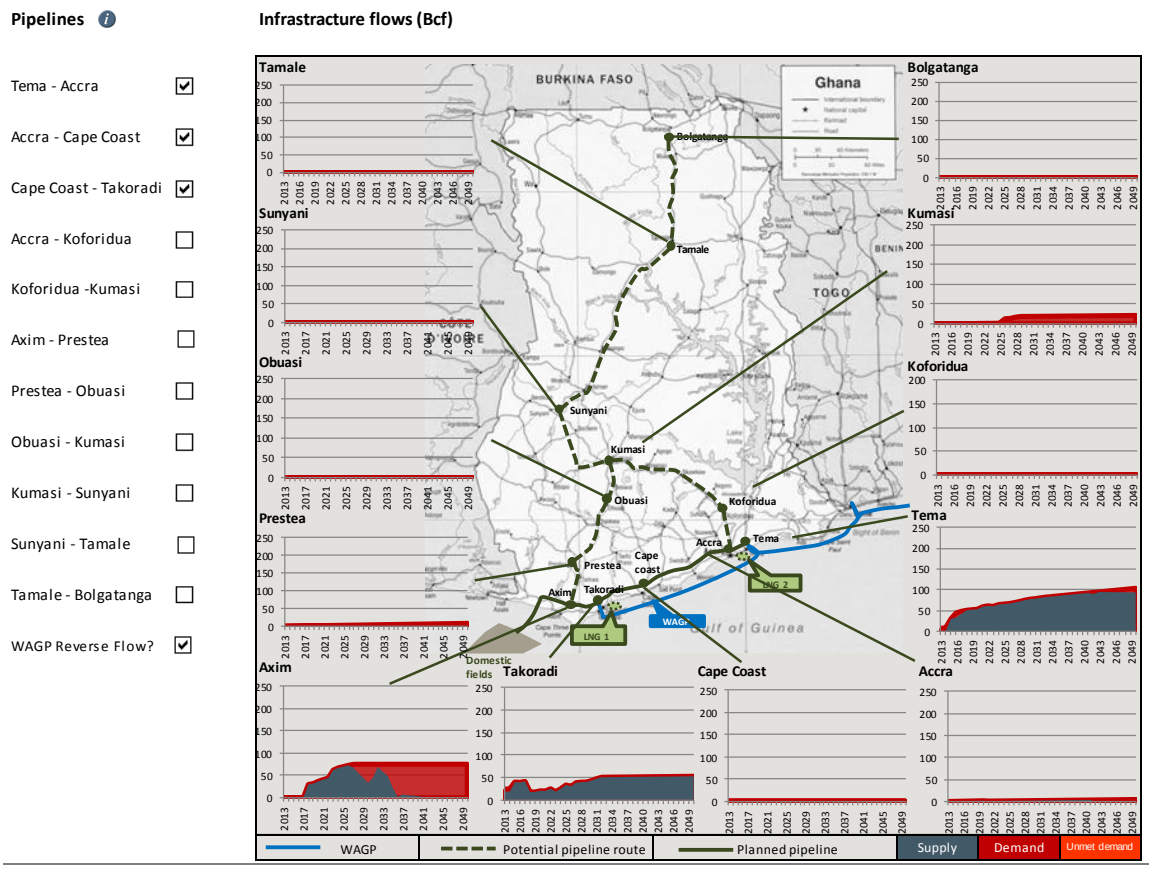
Non-aligned scenarios	Gas Demand Scenarios				Gas Supply Scenarios		
	Power Sector	Industrial Sector	Gas Exports		Gas Reserves	WAGP	LNG imports
Low demand - High Supply - High infrastructure	Low case	Non-strategic	No exports	⇔	High gas reserves	High available supply	Two LNG terminals
	- Low demand for power - Low power exports - VALCO (2 pot lines)	- Restrict supplies to unprofitable industries. - Supply: Industrial heat (RFO), transportation					- Two LNG terminals located in Tema and Takoradi. Regas capacity: 55 bcf per year each.
High demand - Low Supply - High infrastructure	High case	Non-strategic	No exports	⇔	Low gas reserves	Low available supply	Two LNG terminals
	- High demand for power - High power exports - VALCO (4 pot lines)	- Restrict supplies to unprofitable industries. - Supply: Industrial heat (RFO), transportation					- Two LNG terminals located in Tema and Takoradi. Regas capacity: 55 bcf per year each.

A5.4 Gas transmission infrastructure planning

The GMPM also has a gas transportation infrastructure component, which is run to examine feasible pipeline infrastructures after the supply, demand and weighted average cost of gas calculations. The results of the supply and demand analysis feed into the infrastructure component of the model.

In a first step, we break down demand and supply volumes into separate regions (12) representing clusters of demand centres. This is done on the basis of Ghana's largest population centres. In a second step, we estimate gas to power, industrial and residential demand for each of the 12 urban clusters identified. The clusters we will use are shown in the map in Figure 99. The approach we will follow to identify demand for each cluster is to use the location of the power plants and large industrial users and allocate them to each cluster. The user is able to include or exclude pipelines and see the impact on the supply and demand volumes by region, on the transportation tariff and on the infrastructure costs.

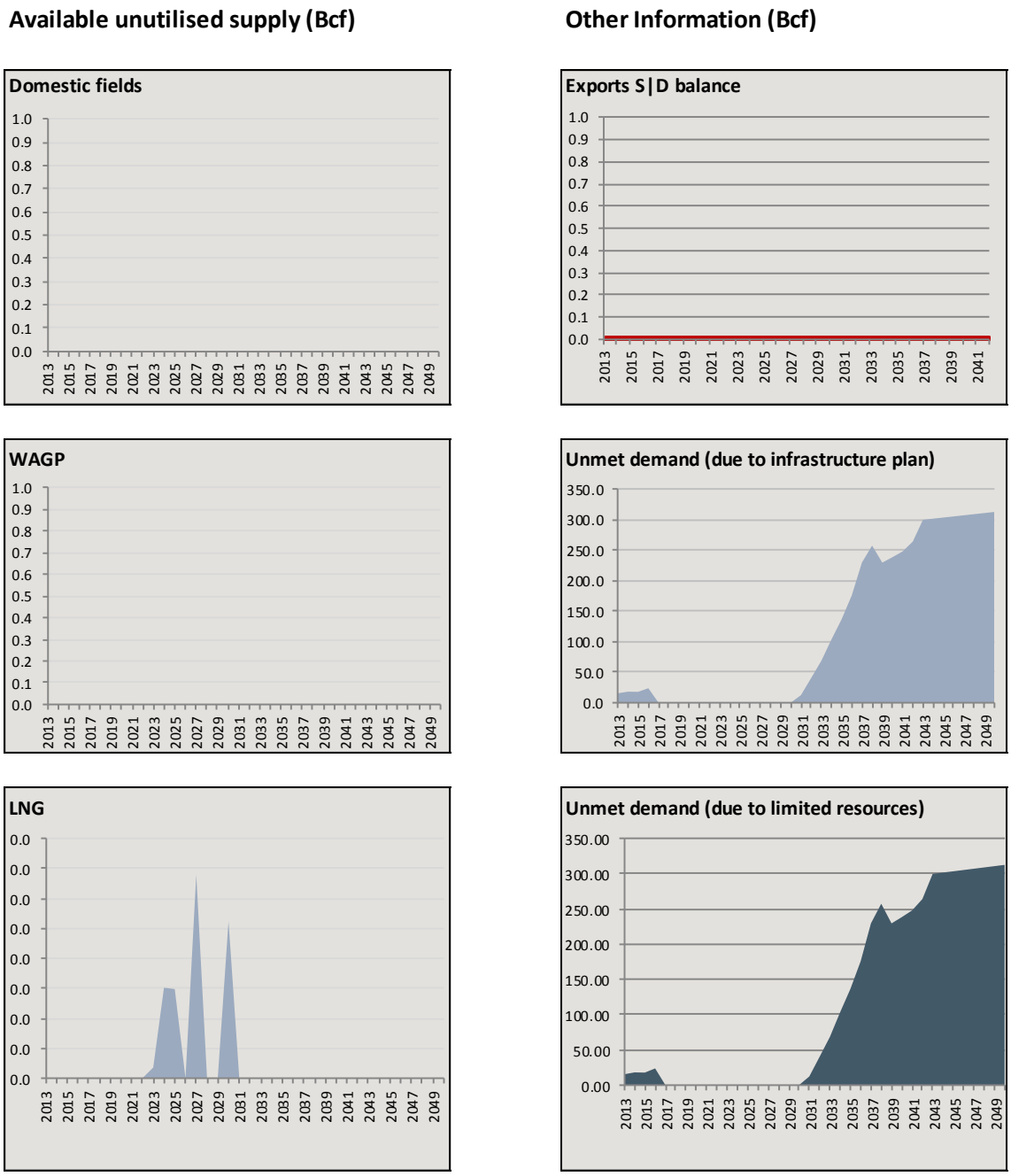
Figure 99Presentation of supply/demand balance for demand clusters



Supply volumes will be estimated on the basis of estimated delivered volumes at each location. The user has the ability to prioritise the supply for certain region if the available supply is not enough to cover the total demand for gas. This will provide a supply demand balance for each of the twelve main urban clusters. The map above shows what the unmet demand levels and excess supply levels in each region for each year could look like.

To obtain a suitable gas transmission infrastructure plan, the main demand and supply centres are connected by pipelines approximately following the routes of existing and proposed transmission plans. The list of possible pipeline options included in our analysis is shown in Figure 99. From this list, any scenario will be based on a selection in order to analyse the resulting supply demand balances at each location. The user is able to include or exclude pipelines and see the impact on the supply and demand volumes by region, on the transportation tariff and on the infrastructure costs.Additional information that will help the user determine the infrastructure plan is also included in the model and they are presented in Figure 100.

Figure 100 Additional information for the infrastructure component of GMPM



A tool included in the model helps the user determine the technical characteristics of the pipelines based on the outputs of the maximum required volumes of gas in region. The

analysis includes the option of (i) reverse flow on WAGP and (ii) two different locations for an LNG regasification terminal.

The GMPM will allow the user to simulate a variety of different infrastructure combinations and assess the impact on the following key outputs:

Total investment costs of the chosen infrastructure combinations – this will simply be the sum of capital costs for each infrastructure option.

Total unmet demand – this is the sum of unmet demands across regionsdiscounted at a social discount rate.

Transmission tariff resulting from the infrastructure combination – this will be the postage stamp cost-recovery tariff in line with the gas pricing policy document of GoG.

The year of first operation and for each infrastructure component – this will be based on the earliest year any gas flows from a supply region to a demand region are needed and the maximum flows that are needed.

Figure 101 Illustration of GMPM outputs for the infrastructure options

Results

Tariff

Domestic pipelines tariff	0.828	US$/MMBtu
WAGP reverse flow tariff	0.000	US$/MMBtu
Total transportation tariff	0.828	US$/MMBtu

Calculate tariff

Investment costs

	Construction year	Year required	Capital Costs
1. Tema - Accra	2014	2016	34.5
2. Accra -Cape Point	2014	2016	149.6
3. Cape Point - Takoradi	2014	2016	75.9
4. Accra - Koforidua	n/a	0	0.0
5. Koforidua -Kumasi	n/a	0	0.0
6. Axim - Prestea	2015	2017	56.2
7. Prestea - Obuasi	2019	2021	56.2
8. Obuasi - Kumasi	2019	2021	26.7
9. Kumasi - Sunyani	n/a	0	0.0
10. Sunyani - Tamale	n/a	0	0.0
11. Tamale - Bolgatanga	n/a	0	0.0
Total			399.1

This approach provides a simple way for a scenario combining supply, demand and a set of infrastructure options to be analysed and the results presented in the GMPM; it avoids the model appearing to be a 'black box' providing a set of non-transparent results. Instead, the approach is a more flexible and interactive process, where the user can iteratively obtain the

combination of transportation infrastructure options that meet the criteria set out by the user. The format of interaction sheet where the user can select his combination of options is shown in Figure 101. On the left hand side, users can select or deselect the infrastructure options they want to include in the simulated scenario.

A5.5 GMPM Training

For the utilisation of the model from the relevant parties in Ghana a three day training workshop was set focusing on the Ghana Gas Master Plan model. The aim of the training course was to provide to the participants useful insights on the gas sector in Ghana and to train them on the operation of the Ghana Gas Master Plan model. The training included participant from all the relevant bodies of the gas sector and concentrated on the utilisation of the model. The context covered during the training workshop can be summarised in:

Introduction:

- General understanding of the gas sector in Ghana
- Utilisation options in the gas sector in Ghana and quantifying methods to address them
- Key lessons learned from international case studies

Main training on the GMPM model:

- Theoretical principles and methodologies for the analysis of gas sector issues
- Modelling tips in Excel
- Ghana Gas Master Plan model user's manual
- Practical exercises and one to one interaction sessions on the GMPM

Using the model for policy issues:

- Open discussion, questions and exercises on the GMPM model
- Application of the GMPM model to policy issues

The participants found the training workshop useful or very useful and they commented positively on the outcome of this workshop.

A5.6 Ghana Gas Master Plan Model inputs

The most significant input data and assumptions used are described in this annex. The key input data includes:

General assumptions, economic parameters, time parameters, etc.

Gas supply

- Domestic gas reserves and alternative external gas supply options together with production profiles from each field and gas supply scenarios
- Natural gas exploration and production costs
- Cost of external supply options

Gas demand

- Gas demand from the power sector:
  - Existing and planned power plants data, fuel data and power demand forecast
- Gas demand from the industrial and the residential sector
  - Industrial demand: cement, industrial heat, aluminium, ammonia, urea, steel, methanol, transportation
  - Residential demand
- Gas exports

The remainder of this annex outlines the main inputs used in each of these categories.

A5.6.1 General input data

The general parameters that were used in the model are described in Table 23 below.

Table 23General assumptions					
A5.7	**Section**	**A5.8**	**Parameters**	**A5.9**	**Description**
A5.10	**Time parameters**	A5.11	Year of study, hours per year, days per year, monrths per year, hours per year	A5.12	2013-2040
A5.13	**Economic / Financial parameters**	A5.14	Currency	A5.15	US$
A5.16		A5.17	Real discount rate	A5.18	12%
A5.19		A5.20	Social discount rate	A5.21	8%
A5.22		A5.23	Annual GDP growth rate	A5.24	5%
A5.25		A5.26	Initial gas price	A5.27	US$8.6 /mmbtu
A5.28		A5.29	Infrastructure RoI	A5.30	15%
A5.31		A5.32	Royalties rate	A5.33	5%[53]
A5.34		A5.35	Levies for E&P	A5.36	14%[54]
A5.37		A5.38	E&P Corporate income tax	A5.39	35%
A5.40		A5.41	Transportation Corporate income tax	A5.42	25%
A5.43		A5.44	WTP for the power supply of VALCO	A5.45	US$8.4 /mmbtu
A5.46		A5.47	WTP for power supply	A5.48	US$17 /mmbtu
A5.49	**Gas pipeline costs and parameters**	A5.50	Pipeline loss rate	A5.51	1.5% of throughput volume
A5.52		A5.53	Pipeline CapEx	A5.54	US$64,348 per inch per km
A5.55		A5.56	Pipeline OpEx	A5.57	3% of CapEx
A5.58		A5.59	Construction time	A5.60	2 years
A5.61		A5.62	Depreciation Life	A5.63	13 years
A5.64		A5.65	Transportation tariff WTP	A5.66	US$2 /mmbtu
A5.67		A5.68	WAGP transportation tariff	A5.69	US$4.5 /mmbtu[55]
A5.70	**E&P operating costs**	A5.71	E&P operating costs	A5.72	6% of total E&P costs
A5.73	**Conversion factors**	A5.74	Several conversion factors necessary for the calculations		

[53]PNDC Law 84 and the MPA provide that a rate between 4% and 12.5% would be charged on gross production of oil and gas.

[54]The law provides for carried interest to be levied at a rate between 7.5% and 15%. The optional additional interest may be added on top of that at an average rate of 3.5%.

[55] Source: Middle Africa Briefing Note | Energy, Oil and Gas 26 February 2014, Ecobank

A5.74.1 Power sector input data

Power plants

The current installed capacity of the power generation system in Ghana is 2847 MW[56]. The operational power plants and their corresponding installed capacities are described in Table 24.

Table 24 Existing power plants

Installed power plants	Intalled capacity (MW)	Type	Fuel type
Akosombo	1,020	Hydro	Water
Kpong	160	Hydro	Water
TAPCO (T1)	330	Thermal	LCO/Gas
TICO (T2)	220	Thermal	LCO/Gas
Aboatze T3	132	Thermal	LCO/Gas
TT1PP	110	Thermal	LCO/Gas
TT2PP	50	Thermal	DFO/Gas
MRP	80	Thermal	DFO
Solar	2.5	Renewable	Solar
Sunon Asogli	200	Thermal	Gas
CENIT	126	Thermal	LCO/Gas
BUI	400	Hydro	Water
Total	2,846.5		

The expansion of generation through to 2026 is based on the Power sector development plan with modifications to account for more current information included in the World Bank 2013 Energy Sector Master Plan, the 2014 Energy Commission Supply and Demand Outlook for Ghana, the GRIDCo 2013 Electricity Supply Plan, the 2010 Ministry of Energy Energy Sector Strategy and Development Plan and the Project Information Memorandum (PIM).

Key changes from the MP include:

Changes in the expected commissioning of Phase 2 of the Sunon Asogli power plant. This is shown in the Base Expansion Plan of the MP for commissioning in 2014. According to

[56] as of October 2014; (Volta River Authority, 2014, http://www.vraghana.com/resources/facts.php)

the PIM, Sunon Asogli is conducting a feasibility study and thus a commissioning date by 2014 is unlikely. For this study, the plant is assumed to enter service in 2021.

The removal of two additional GTs at Tema of 100 MW capacity each. The first GT was selected for service in 2016 and the second in 2024. Note that neither the PIM or the World Bank 2013 Energy Sector Review identify these as coming into the generation mix.

The commissioning of the Osonor (now CENIT) 110 MW GT has been moved forward from the 2014 date identified in the MP given that the plant has already entered service.

In the MP, no candidate power plants are identified for Domunli (the MP notes that, despite initial interest in the area, investors were showing a preference to locate projects in Tema). However, there is discussion that 900 MW is to be commissioned in Domunli. This is supported by the PIM, whichidentifies a 450 MW VRA project and another 450 MW project under development by Sithe Global, an IPP. As noted in the PIM, VRA is performing site preparation and contracting for preparation of detailed technical specifications and an environmental and social impact assessment, with the objective of commissioning 450 MW in 2016. This seems optimistic and we assume commissioning of these two units in 2018. While Sithe Global is discussing potential off-take with members of the West African Power Pool (WAPP) we assume that this capacity will all be available to Ghana if needed.

The start year of the Bui hydro plant has been moved from 2013 to 2014 – one turbine has already been commissioned in 2013 whilst the others are due to enter service by the end of the year. Hence, the first full year of service is assumed to be 2014. According to the 2014 Energy Commission Supply and Demand Outlook for Ghana, the dependable capacity of the Bui hydro power plant was changed from 342 MW to 380 MW.

The dependable capacity of the Akosombo hydro power plant was changed from 900 MW to 960 MW from 2015 and onwards, according to the 2014 Energy Commission Supply and Demand Outlook for Ghana.

The 2010 Ministry of Energy's'Energy Sector Strategy and Development Plan' assumes the development of the Western Rivers Hydropower Project until 2014. None of the PIM, the World Bank 2013 Energy Sector Review and the MP identify this project as coming into the generation mix. The hydro sites that have been identified as having generation potential are Pwalugu (48 MW), Kulpawn (80 MW), Juale (87 MW), Daboya (44 MW), and Hemang (75 MW). However, none of these sites has a full feasibility available yet, and given the long lead time in constructing such plants, it is not expected any of them could produce power before 2020.

The 2010 Ministry of Energy's'Energy Sector Strategy and Development Plan' assumes the operation of Osagyefo Power Barge Project (125 MW) from 2010 and onwards. However, due to legal disputes the power plant is not operational.

The MP identifies 5 MW of solar entering service in 2012 and another 5 MW entering service in 2013. Of the planned installations, none have been commissioned. A 2 MW project is currently under construction, with commissioning expected later in 2013, whilst funding is still being sought for the remaining 8 MW. Hence, 2 MW is shown as entering service in 2013 whilst the remaining solar is shown as entering service in 2017. Genser power PV plant has an installed capacity of 5 MW and was commissioned in 2014.

The MP identifies 50 MW of wind being commissioned in 2014 and an additional 100 MW being commissioned in 2015. More recently, the VRA has established a target of 2015 for commissioning. Currently, there are just two wind projects being considered for development – NEK at 50 MW and China Wind Power at 50 MW – and both are in the

initial stages of planning and are unlikely to be commissioning by the dates identified in the MP. Hence, the assumed MP commissioning dates have been moved to 2016 and 2017, with the latter assumed to be 50 MW rather than the 100 MW assumed in the MP for the second installation.

In the high case scenario from 2020 onwards, new CCGT capacity is added as needed to maintain reserve margins[57] and meet demand. The first of these plants is assumed to be added to the Tema complex, the second to be located at Takoradi, the third one in Tema and the fourth one in Kumasi. In the base case scenario, from 2027 and onwards the installed capacity is insufficient to meet the demand and maintain the reserves margin. However, we have not assumed the addition of new generic gas power plants in this base as the available gas resources from that year and onwards are not enough to justify the addition of new generic power plants. In the low case scenario the assumed plan is adequate to cover the power demand until 2035.

The existing and the planned power plants of the power sector in Ghana as well as the assumed commissioning and decommissioning dates, the location, the operating fuel and the assumed technical characteristics of the power plants are presented in Table 25.

[57] The required reserves margin is assumed to be 18% based on the Power Sector Development Plan and the Gridco 2013 Electricity supply report.

Table 25GMPM included power plants

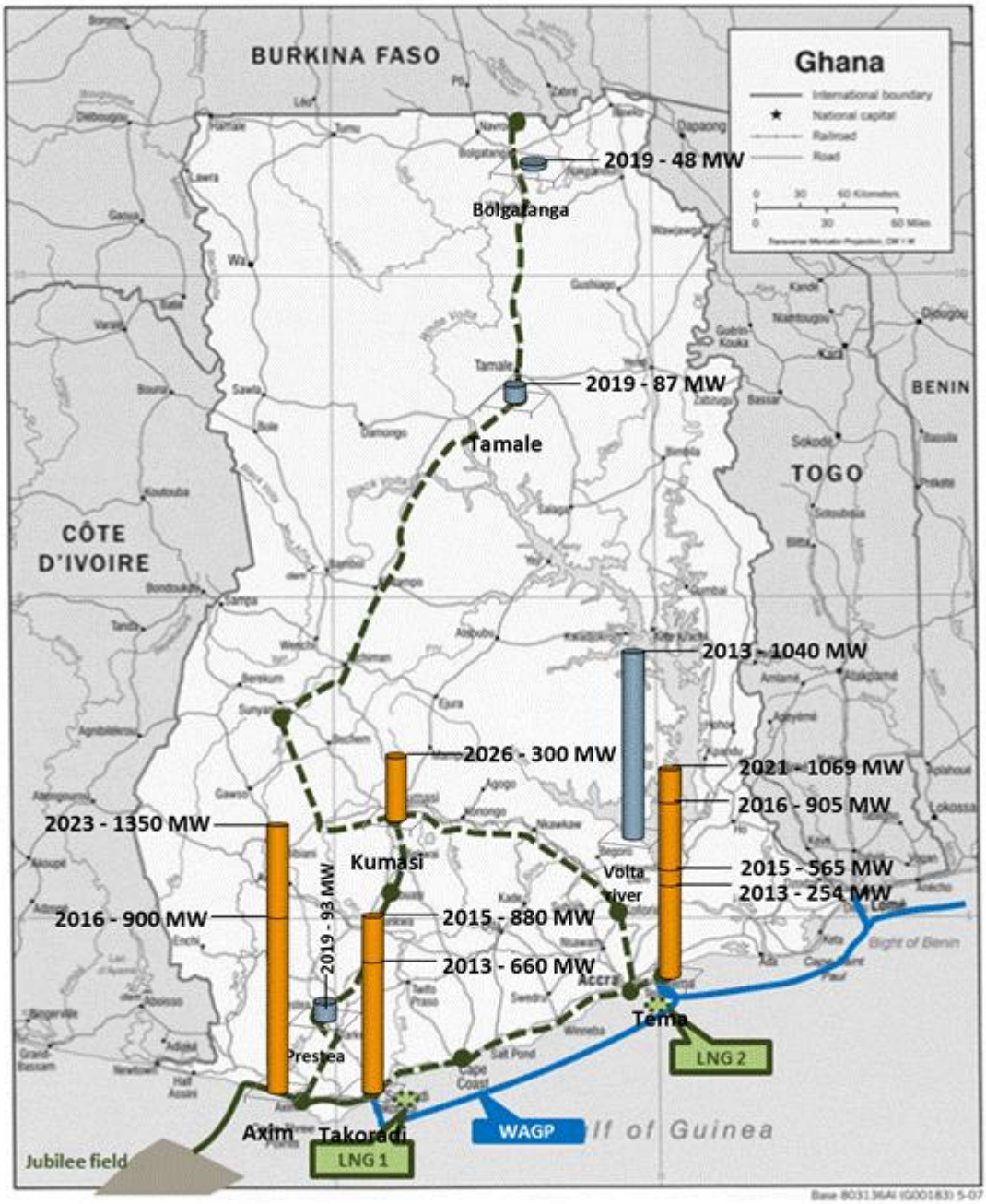
	Plant name	Plant type	Fuel type	Location	Year available	Year retired	Dependable Capacity (MW)	Hydro Known Generation (GWh)	Combined Forced Outage Rate (%)	Base load heat rate (GJ/MWh)	Vbl. O&M cost (US$/MWh)
1	Akosombo	HY	Hydro	Kaforidua	1965	2014	900	5,118	6.00	0.000	0.10
2	Akosombo	HY	Hydro	Kaforidua	2015		960	5,118	6.00	0.000	0.10
3	Kpong	HY	Hydro	Kaforidua	1982		140	939	6.00	0.000	0.10
4	TT1PP	TH	LCO	Tema	2008	2014	110		10.88	11.600	6.50
5	Osonor (on site of TT1PP)	TH	LCO	Tema	2013	2014	110		10.88	11.600	3.75
6	TT1PP - CC conversion	TH	Gas	Tema	2015		300		12.85	7.678	2.00
7	TT2PP	TH	Diesel	Tema	2008	2015	45		10.88	11.162	4.50
8	TT2PP	TH	Gas	Tema	2016		45		10.88	11.060	4.50
9	MRP	TH	Diesel	Tema	2007	2014	40		10.88	13.636	4.50
10	MRP	TH	Diesel	Tema	2015		40		10.88	13.636	4.50
11	TICO 1	TH	LCO	Takoradi	2010	2014	110		10.88	13.015	1.00
12	TICO 2	TH	LCO	Takoradi	2010	2014	110		10.88	13.015	1.00
13	TICO 1+2 - CC conversion	TH	Gas	Takoradi	2015		300		12.85	7.678	2.00
14	TAPCO	TH	LCO	Takoradi	2012	2014	300		12.85	8.676	5.00
15	TAPCO	TH	Gas	Takoradi	2015		300		12.85	7.955	5.00
16	Aboadze T3	TH	Gas	Takoradi	2015		120		12.85	8.125	2.00
17	Aboadze T3	TH	LCO	Takoradi	2012	2014	120		12.85	8.200	5.00
18	Aboadze T3 - Expansion	TH	Gas	Takoradi	2015		120		12.85	8.125	2.00
19	Asogli I (Sunon in Tema)	TH	Gas	Tema	2010	2014	180		49.00	6.750	2.00
20	Asogli I (Sunon in Tema)	TH	Gas	Tema	2015		180		12.85	6.750	2.00
21	Asogli II	TH	Gas	Tema	2021		164		12.85	7.763	3.00
22	Kpone (KTPP)	TH	LCO	Tema	2016	2017	340		12.85	8.061	3.50
23	Kpone (KTPP)	TH	Gas	Tema	2018		340		12.85	7.678	1.00
24	Domumli1	TH	Gas	Axim	2018		450		12.85	7.678	3.00
25	Domumli2	TH	Gas	Axim	2018		450		12.85	7.678	3.00
26	Domumli3	TH	Gas	Axim	2023		450		12.85	7.678	3.00
27	Kumasi	TH	Gas	Kumasi	2026		300		12.85	7.678	3.00
28	BUI	HY	Hydro	Sunyani	2013	2013	400	503	60.00	0.000	0.10
29	BUI	HY	Hydro	Sunyani	2014		400	980	60.00	0.000	0.10
30	Juale	HY	Hydro	Tamale	2019		87	308	60.00	0.000	1.51
31	Pwalugu	HY	Hydro	Bolgatanga	2019		48	140	60.00	0.000	1.51
32	Hemang	HY	Hydro	Prestea	2019		93	258	60.00	0.000	1.51
33	PV1	RES	Solar	-	2014		2		10.00	0.000	0.00
34	PV2	RES	Solar	-	2017		8		10.00	0.000	0.00
35	NEK WPP	RES	Wind	-	2016		50		68.00	0.000	9.50
36	China Wind	RES	Wind	-	2017		50		68.00	0.000	9.50
37	Wind1	RES	Wind	-	2020		38		68.00	0.000	9.50
38	Wind2	RES	Wind	-	2021		20		68.00	0.000	9.50
39	Wind3	RES	Wind	-	2022		18		68.00	0.000	9.50
40	Wind4	RES	Wind	-	2023		20		68.00	0.000	9.50
41	Wind5	RES	Wind	-	2024		21		68.00	0.000	9.50
42	Wind6	RES	Wind	-	2025		22		68.00	0.000	9.50
43	Wind7	RES	Wind	-	2026		23		68.00	0.000	9.50

Table 26High scenario additional power plant assumptions

	Plant name	Plant type	Fuel type	Location	Year available	Year retired	Dependable Capacity (MW)	Hydro Known Generation (GWh)	Combined Forced Outage Rate (%)	Base load heat rate (GJ/MWh)	Vbl. O&M cost (US$/MWh)
44	Generic CCGT 1	TH	Gas	Tema	2020		300		12.85	7.678	3.00
45	Generic CCGT 2	TH	Gas	Takoradi	2022		300		12.85	7.678	3.00
46	Generic CCGT 3	TH	Gas	Tema	2024		300		12.85	7.678	3.00
47	Generic CCGT 4	TH	Gas	Kumasi	2026		100		12.85	7.678	3.00

The location and the capacity of most significant power plants in Ghana from 2013 until 2030 are depicted in Figure 102 below. Most of the thermal capacity is located in the area around Axim, Takoradi and Tema. However, the potential supply of gas to central regions will contribute to the development of gas power plants in Kumasi.

Figure 102Location and capacity power plants (2013-2030)



The average power generation from the Akosombo power plant in the past years was 5% higher during the wet season and the duration of the wet season can be defined as 6 months per year[58]. For the modelling of the Akosombo power plant it was assumed that it will follow the same seasonal pattern for power generation in the preceding years. The Kpong, Bui, Jwale, Pwalugu and Hemang hydro power plants are assumed to follow the same seasonal pattern.

[58] Calculated from the power generation data for Akosombo power plant included in the Tractebel Engineering, 2011, Generation Master Plan Study for Ghana.

The power generation from other renewable energy sources (ie wind and PV) is assumed to follow a flat load profile. The amount of generation from these sources is estimated using typical capacity factors for wind and photovoltaic power plants for Ghana[59]. The contribution of renewable generation constitutes less than 1% of total capacity and the impact the above assumption introduces is negligible.

Table 27Assumptions for RES generation

A5.75 Parameter	A5.76 Description	A5.77 Value
A5.78 Wet season generation factor	A5.79 Portion of the amount of generation from hydro power plants during the wet season in comparison to the average generation within a year for the past 10 year.	A5.80 105%
A5.81 Dry season generation factor	A5.82 Portion of the amount of generation from hydro power plants during the dry season in comparison to the average generation within a year for the past 20 year.	A5.83 95%
A5.84 Wet season duration factor	A5.85 The duration of the wet season as a portion within a year.	A5.86 52%
A5.87 Dry season duration factor	A5.88 The duration of the dry season as a portion within a year.	A5.89 48%
A5.90 Wind average capacity factor	A5.91 The ratio of the actual output of wind turbines to the potential output if it was operating at full capacity over the same period of time.	A5.92 23%
A5.93 PV average capacity factor	A5.94 The ratio of the actual output of photovoltaic plants to the potential output if it was operating at full capacity over the same period of time.	A5.95 23%

Power demand forecast

The power demand forecast for the low, base and high scenarios is depicted in Table 28, Table 29 and Table 30respectively[60].

[59] *Feasibility Study of Wind Energy Utilization along the Coast of Ghana,Francis Nkrumah, 2002; Design and Analysis of a 1MW Grid-Connected Solar PV System in Ghana, Ebenezer Nyarko Kumi, The Energy Center Kwame Nkrumah University of Science and Technology Kumasi-Ghana, 2013;Tractebel Engineering, 2011, Generation Master Plan Study for Ghana.*

[60] Source: GRIDCo, 2013, 2013 Electricity Supply Plan; Tractebel Engineering, 2011, Generation Master Plan Study for Ghana.

Table 28Energy demand forecast: low case, *GWh*							
	Domestic	VALCO	CEB Exp	SONABEL Exp	EDM Exp	Losses	Total generation
2013	11,658	626	867	77	0	496	13,724
2014	12,163	626	705	307	0	518	14,318
2015	12,689	1,251	705	307	0	537	14,864
2016	13,238	1,251	705	307	0	558	15,433
2017	13,811	1,251	705	307	0	579	16,027
2018	14,408	1,251	705	307	0	602	16,647
2019	15,031	1,251	705	307	0	625	17,294
2020	15,682	1,251	705	307	0	649	17,969
2021	16,360	1,251	705	307	0	675	18,672
2022	17,068	1,251	705	307	0	701	19,407
2023	17,806	1,251	705	307	0	729	20,173
2024	18,577	1,251	705	307	307	770	21,291
2025	19,380	1,251	705	307	307	800	22,124
2026	20,219	1,251	705	307	307	831	22,994
2027	21,093	1,251	705	307	307	864	23,902
2028	22,006	1,251	705	307	307	898	24,849
2029	22,958	1,251	705	307	307	934	25,836
2030	23,951	1,251	705	307	307	971	26,867
2031	24,987	1,251	705	307	307	1,010	27,942
2032	26,068	1,251	705	307	307	1,050	29,063
2033	27,196	1,251	705	307	307	1,093	30,233
2034	28,373	1,251	705	307	307	1,137	31,454
2035	29,600	1,251	705	307	307	1,183	32,727
2036	30,881	1,251	705	307	307	1,231	34,056
2037	32,216	1,251	705	307	307	1,281	35,442
2038	33,610	1,251	705	307	307	1,333	36,888
2039	35,064	1,251	705	307	307	1,388	38,397
2040	36,581	1,251	705	307	307	1,445	39,970
2041	38,164	1,251	705	307	307	1,504	41,612
2042	39,815	1,251	705	307	307	1,566	43,325
2043	41,537	1,251	705	307	307	1,631	45,112
2044	43,334	1,251	705	307	307	1,698	46,977
2045	45,209	1,251	705	307	307	1,768	48,922
2046	47,165	1,251	705	307	307	1,842	50,951
2047	49,205	1,251	705	307	307	1,918	53,068
2048	51,334	1,251	705	307	307	1,998	55,276
2049	53,555	1,251	705	307	307	2,081	57,580
2050	55,872	1,251	705	307	307	2,168	59,984

Table 29Energy demand forecast: Base case, *GWh*

	Domestic	VALCO	CEB Exp	SONABEL Exp	EDM Exp	Losses	Total generation
2013	11,658	626	867	77	0	496	13,724
2014	12,385	626	920	322	0	557	15,411
2015	13,158	1,251	920	613	0	597	16,513
2016	13,978	1,852	920	613	0	628	17,365
2017	14,850	1,852	920	613	0	660	18,269
2018	15,775	1,852	920	613	0	695	19,229
2019	16,759	1,852	920	613	0	732	20,250
2020	17,804	1,852	920	613	0	771	21,334
2021	18,914	1,852	920	613	0	813	22,486
2022	20,093	1,852	920	613	0	857	23,709
2023	21,346	1,852	920	613	0	904	25,009
2024	22,677	1,852	920	613	613	977	27,026
2025	24,091	1,852	920	613	613	1,030	28,493
2026	25,593	1,852	920	613	613	1,086	30,052
2027	27,189	1,852	920	613	613	1,146	31,707
2028	28,885	1,852	920	613	613	1,210	33,466
2029	30,686	1,852	920	613	613	1,277	35,335
2030	32,599	1,852	920	613	613	1,349	37,320
2031	34,631	1,852	920	613	613	1,425	39,429
2032	36,791	1,852	920	613	613	1,506	41,669
2033	39,085	1,852	920	613	613	1,592	44,049
2034	41,522	1,852	920	613	613	1,684	46,577
2035	44,111	1,852	920	613	613	1,781	49,263
2036	46,861	1,852	920	613	613	1,884	52,117
2037	49,783	1,852	920	613	613	1,993	55,148
2038	52,887	1,852	920	613	613	2,110	58,369
2039	56,185	1,852	920	613	613	2,233	61,790
2040	59,688	1,852	920	613	613	2,365	65,425
2041	63,410	1,852	920	613	613	2,504	69,286
2042	67,363	1,852	920	613	613	2,653	73,388
2043	71,564	1,852	920	613	613	2,810	77,746
2044	76,026	1,852	920	613	613	2,977	82,375
2045	80,766	1,852	920	613	613	3,155	87,293
2046	85,802	1,852	920	613	613	3,344	92,518
2047	91,152	1,852	920	613	613	3,545	98,068
2048	96,835	1,852	920	613	613	3,758	103,965
2049	102,873	1,852	920	613	613	3,984	110,229
2050	109,288	1,852	920	613	613	4,225	116,884

Table 30Energy demand forecast: High case, *GWh*							
	Domestic	VALCO	CEB Exp	SONABEL Exp	EDM Exp	Losses	Total generation
2013	11,658	626	867	77	0	496	13,724
2014	12,601	626	1,226	920	0	599	16,572
2015	13,621	1,852	1,226	920	0	637	17,630
2016	14,723	2,469	1,226	920	920	713	19,728
2017	15,913	2,469	1,226	920	920	758	20,963
2018	17,201	2,469	1,226	920	920	806	22,299
2019	18,592	2,469	1,226	920	920	858	23,742
2020	20,096	2,469	1,226	920	920	915	25,303
2021	21,722	2,469	1,226	920	920	976	26,989
2022	23,479	2,469	1,226	920	920	1,041	28,812
2023	25,378	2,469	1,226	920	920	1,113	30,783
2024	27,431	2,469	1,226	920	920	1,190	32,912
2025	29,650	2,469	1,226	920	920	1,273	35,214
2026	31,498	2,469	1,226	920	920	1,342	37,132
2027	33,462	2,469	1,226	920	920	1,416	39,170
2028	35,549	2,469	1,226	920	920	1,494	41,335
2029	37,765	2,469	1,226	920	920	1,577	43,634
2030	40,120	2,469	1,226	920	920	1,665	46,077
2031	42,622	2,469	1,226	920	920	1,759	48,673
2032	45,279	2,469	1,226	920	920	1,859	51,430
2033	48,102	2,469	1,226	920	920	1,965	54,359
2034	51,102	2,469	1,226	920	920	2,077	57,471
2035	54,288	2,469	1,226	920	920	2,197	60,777
2036	57,673	2,469	1,226	920	920	2,324	64,289
2037	61,269	2,469	1,226	920	920	2,459	68,019
2038	65,089	2,469	1,226	920	920	2,602	71,983
2039	69,148	2,469	1,226	920	920	2,754	76,194
2040	73,459	2,469	1,226	920	920	2,916	80,667
2041	78,039	2,469	1,226	920	920	3,087	85,419
2042	82,905	2,469	1,226	920	920	3,270	90,467
2043	88,075	2,469	1,226	920	920	3,464	95,830
2044	93,566	2,469	1,226	920	920	3,670	101,528
2045	99,400	2,469	1,226	920	920	3,888	107,581
2046	105,598	2,469	1,226	920	920	4,121	114,011
2047	112,182	2,469	1,226	920	920	4,368	120,842
2048	119,177	2,469	1,226	920	920	4,630	128,099
2049	126,608	2,469	1,226	920	920	4,909	135,809
2050	134,502	2,469	1,226	920	920	5,205	143,999

Fuel prices for power generation

The assumed delivered prices for power generation are described in Table 31below.

Table 31Assumed delivered fuel price at the power stations[61]

A5.96 Fuel	A5.97 Assumed delivered price at the power station	A5.98 Source / Comments
A5.99 Light crude oil	A5.100 US$101.2/bbl; A5.101 US$17.8/GJ	A5.102 Based on the Ghana MP, which links the price of LCO to the price of oil, which is set to $US100/barrel.
A5.103 Diesel	A5.104 US$125.1/bbl; A5.105 US$21.9/GJ	A5.106 Based on the Ghana MP, which links the price of diesel to the price of oil, which is set to $US100/barrel.
A5.107 Gas price	A5.108 Calculated in the model based on supply costs after balancing the demand with the supply volumes.	

[61] Tractebel, 2011, Generation Master Plan Study for Ghana.

A5.108.1 Industrial netback calculation assumptions

Table 32Industrial demand netback analysis product assumptions

A5.109 Product	A5.110 Estimated Current Price	A5.111 Source / Comments
A5.112 Cement	A5.113 $153/t	A5.114 Based on Dangote report
A5.115 Alumina	A5.116 $400/t	A5.117 Based on current spot market plus shipping prices for Australia and China and typical percentage of price of Aluminium
A5.118 Aluminium	A5.119 $2,000/t	A5.120 Based on average of recent traded prices on London Metal Exchange, rounded to avoid unjustified implied accuracy
A5.121 Urea	A5.122 $350/t	A5.123 Based on World Bank Commodity Price Database global price, average of recent prices, rounded to avoid unjustified implied accuracy
A5.124 Steel	A5.125 $600/t	A5.126 Based on international steel prices
A5.127 Methanol	A5.128 $480/t	A5.129 Based on recent Methanex quote for Asian Posted Contract Price
A5.130 RFO	A5.131 $0.64/l	A5.132 Based on regulated prices as per National Petroleum Authority of Ghana July 2014, stripped of taxes, margins and subsidies
A5.133 Gasoline	A5.134 $0.85/l	A5.135 Based on regulated prices as per National Petroleum Authority of Ghana July 2014, stripped of taxes, margins and subsidies
A5.136 Diesel	A5.137 $0.85/l	A5.138 Based on regulated prices as per National Petroleum Authority of Ghana July 2014, stripped of taxes, margins and subsidies
A5.139 Product	**A5.140 Estimated current annual domestic demand**	**A5.141 Source / Comments**
A5.142 Cement	A5.143 3.5 Mt	A5.144 Approximated using clinker import data from UN Comtrade Database
A5.145 Alumina / Aluminium	A5.146 0.08 Mt / 0.04 Mt	A5.147 Based on current operational capacity at VALCO and net zero trade balance
A5.148 Urea	A5.149 0.02 Mt	A5.150 Approximated using import data from UN Comtrade Database and assuming no domestic production
A5.151 Steel	A5.152 1.6 Mt	A5.153 Based on company published data regarding domestic production capacity and UN Comtrade Database
A5.154 Methanol	A5.155 0.001 Mt	A5.156 Approximated using import data from UN Comtrade Database and assuming no domestic production
A5.157 RFO	A5.158 400 Ml	A5.159 Based on demand in four industrial regions identified in Gas Utilization Plan for Ghana produced by Dr Ben Asante.

A5.109 Product	A5.110 Estimated Current Price	A5.111 Source / Comments
A5.160 Gasoline	A5.161 150 Ml	A5.162 Based on World Bank estimate of 60 cars per 1,000 people, Accra population of 4 million, usage per car per annum of 80k km and gasoline to diesel car ratio of 80:20
A5.163 Diesel	A5.164 30 Ml	A5.165 As for gasoline

Table 33Industrial demand netback analysis annual growth assumptions

A5.166 Parameter	A5.167 Cement	A5.168 Alumina	A5.169 Steel	A5.170 Urea	A5.171 Methanol	A5.172 RFO, gasoline and diesel
A5.173 Product price growth (real terms)	A5.174 0.0%	A5.175 0.0%	A5.176 0.0%	A5.177 0.0%	A5.178 0.0%	A5.179 0.0%
A5.180 Demand growth			A5.181 1.0*GDP growth rate			
A5.182 Demand from exports	A5.183 0	A5.184 0.5 Mt	A5.185 0	A5.186 0.5 Mt	A5.187 1.5 Mt	A5.188 0
A5.189 Capacity build-rate	A5.190 1.5 Mt	A5.191 0.4 Mt	A5.192 0.35 Mt	A5.193 0.5 Mt	A5.194 1.5 Mt	A5.195 RFO: 40 Ml A5.196 Gasoline: 6 Ml A5.197 Diesel: 1.5 Ml
A5.198 Build time (years)	A5.199 3.0	A5.200 3.0	A5.201 3.0	A5.202 3.0	A5.203 5.0	A5.204 1.0

Table 34Industrial demand cost input data

A5.205 Parameter	A5.206 CAPEX A5.207 *US $*	A5.208 OPEX A5.209 *US $*	A5.210 Consumption	A5.211 Source / Comments
A5.212 Cement	A5.213 0.31 bil	A5.214 44.6 / t	A5.215 3.51 mmbtu/t	A5.216 Various industry sources including Dangote and World Business Council for Sustainable Development
A5.217 Alumina[1]	A5.218 0.72 bil	A5.219 220 / t	A5.220 14.0mmbtu/t	A5.221 CAPEX based on Emos Consulting figures; OPEX estimated from Alumina Ltd. reporting; consumption on The International Aluminium Institute

A5.205 Parameter	A5.206 CAPEX A5.207 *US $*	A5.208 OPEX A5.209 *US $*	A5.210 Consumption	A5.211 Source / Comments
A5.222 Aluminium (VALCO)	A5.223 -	A5.224 350 / t	A5.225 99.2 mmbtu/t	A5.226 OPEX based on Aluminium Journal, July 2012; consumption on The International Aluminium Institute with dedicated CCGT gas to power plant thermal efficiency of 55%
A5.227 Aluminium (additional)	A5.228 1.20 bil	A5.229 350 / t	A5.230 74.4 mmbtu/t	A5.231 CAPEX based on Emos Consulting figures, OPEX as above
A5.232 Urea	A5.233 0.85 bil	A5.234 66 / t	A5.235 22.1 mmbtu/t	A5.236 Based on figures from Yara International; OPEX includes an assumed shipping cost of exports
A5.237 Methanol	A5.238 1.32 bil	A5.239 35 / t	A5.240 33.0 mmbtu/t	A5.241 Based on Nexant figures; OPEX includes an assumed shipping cost of exports
A5.242 Steel	A5.243 0.35 bil	A5.244 315 / t	A5.245 32.2 mmbtu/t	A5.246 Various industry sources including steelonthenet.com
A5.247 Industrial heat (RFO)	A5.248 45 k / site	A5.249 0.2 / mmbtu	A5.250 4.1 k mmbtu/yr	A5.251 Figures based on figures reported in National Gas Utilization Plan for Ghana, inflated to 2013; CAPEX does not include distribution infrastructure construction cost; OPEX covers assumed distribution tariff
A5.252 Gasoline	A5.253 6 k / vehicle	A5.254 0.57 / mmbtu	A5.255 0.05 kg CNG / km	A5.256 Based on news reports and industry sources
A5.257 Diesel	A5.258 6 k / vehicle	A5.259 0.57 / mmbtu	A5.260 0.05 kg CNG / km	A5.261 As above

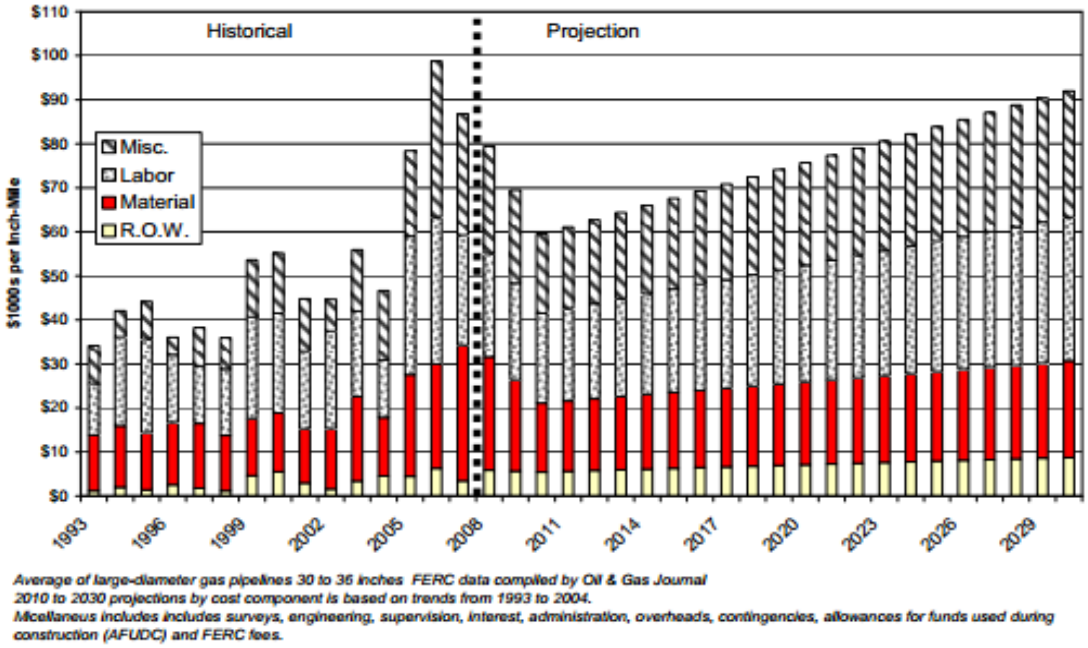
A5.261.1 Infrastructure plan input data

Pipeline CAPEX

The main costs for pipeline development can be split into capital expenditures (CAPEX) and operating expenditures (OPEX). Our general approach for the pipeline capital cost estimation is to use an inch of diameter and per km of pipeline length cost number. This is then extrapolated by the distance of the respective pipeline and the diameter. The diameter will depend on throughput volumes and expected peak flow and the distance will be influenced by the terrain. As a cost approximation for the connection concepts we use as a starting point gas pipeline cost estimates from the United States. To take into consideration the lower costs of pipelines in Africa compared to the US, we apply a cost reduction factor of 0.9 in line with IEA publications. According to the IEA, this is driven by the significantly lower labour costs.

The original CAPEX data as published by The Interstate Natural Gas Association of America (INGAA) in its *Natural Gas Infrastructure and Storage Projections until 2030*is shown in Figure 103.The costs are broken down into its main components: materials, labour, miscellaneous (includes surveys, engineering, supervision, interest, administration, overheads, contingencies, etc...) and right of way.We update the data in the diagram by a steel price index and US inflation to project reasonable CAPEX figures for 2013, which amount to US$64,300 /inch-km.

Figure 103INGAA Gas pipeline CAPEX projections



OPEX for pipelines will depend on the location of the pipeline and on technical parameters. In general however, OPEX will lie between 3% and 5% of CAPEX. Making a conservative cost estimate, our calculations assume a 5% share of CAPEX for OPEX. The resulting cost numbers per inch of pipeline diameter and kilometre of pipeline length (US$ per inch-km) is shown in Table 35.

Table 35 Gas pipeline costs in Africa, *2013 US$//inch of diameter/km length*

Materials	Labour	Miscell-aneous	Right of way	Total CAPEX	OPEX	Total Cost
25,900	16,900	18,700	2,800	64,300	2,000	66,300

Source: Natural Gas Infrastructure and Storage Projections until 2030, INGAA, 2009

The total pipeline costs vary by diameter, length and the terrain the pipeline passes through. We take into consideration each of these factors in our scoping model and discuss these briefly here. Our resulting CAPEX projection lie close to the average cost data of historic African gas pipeline comparisons, as shown in Table 36.

Table 36 Historic gas pipeline CAPEX in Africa

Pipeline	Status	Capacity	Diameter	Length	Cost	Unit cost
		bcf/y	*inches*	*km*	*mm $*	*US$/in-km*
WAGP	Operating	63	20	678	950	70,005
Sasol	Operating	106	26	865	650	28,900
Songo Songo	Under Construction	286	36	532	1,200	62,660
Dar – Mombasa	Feasibility	63	24	442	435	42,337
Trans-Saharan	Feasibility	912	48	4,300	10,000	48,450
AKK	Feasibility	658	36	560	1,490	73,908
Average						**63,616**
CAPEX used in this Report						***64,300***

Pipeline input data

The inner diameter of the pipelines that were used to assess the infrastructure plan and the time requirements of each pipeline are presented in Table 37. The inner diameter of the pipelines is calculated based on the maximum required capacity in 2030. A statistical estimate using regression equation based upon the pipelines inner diameter and typical throughput volumes was the key to determinethe inner diameter of pipelines. The accurate technical characteristics of the pipelines should be determined through feasibility studies that would take into account the inlet and outlet pressures, the temperature, the friction factor and roughness, the operational data, the exact distances and the landscape slopes, the requirements for steady state periods,**etc.**

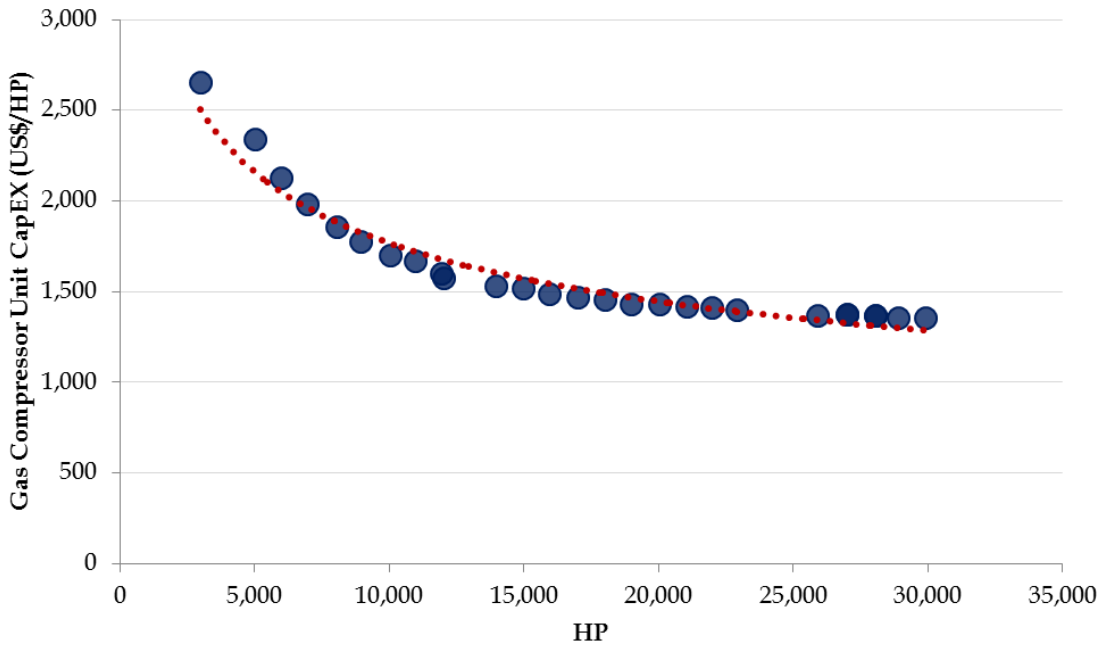
Table 37 Pipeline Inner diameter and year it will be required										
A5.262 Infra structure scenarios	A5.263 Low case		A5.264 Base case		A5.265 High case		A5.266 Low demand – High supply [62]		A5.267 High demand - Low supply	
	A5.268 nner diametr (inch)	A5.269 ear required	A5.270 nner diametr (inch)	A5.271 ear required	A5.272 nner diametr (inch)	A5.273 ear required	A5.274 nner diametr (inch)	A5.275 ear required	A5.276 nner diametr (inch)	A5.277 ear required
A5.278 Tema -Accra	A5.279 2	A5.280 015	A5.281 2	A5.282 015	A5.283 4	A5.284 015	A5.285 4	A5.286 015	A5.287 4	A5.288 015
A5.289 Accra -Cape Coast	A5.290 2	A5.291 015	A5.292 2	A5.293 015	A5.294 4	A5.295 015	A5.296 4	A5.297 015	A5.298 4	A5.299 015
A5.300 Cape Coast- Takoradi	A5.301 2	A5.302 015	A5.303 2	A5.304 015	A5.305 4	A5.306 015	A5.307 4	A5.308 015	A5.309 4	A5.310 015
A5.311 Accra -Kaforidua	A5.312 2	A5.313 021	A5.314 2	A5.315 021	A5.316 4	A5.317 021	A5.318 4	A5.319 021	A5.320 4	A5.321 021
A5.322 Kafor idua-Kumasi	A5.323 2	A5.324 021	A5.325 2	A5.326 021	A5.327 4	A5.328 021	A5.329 4	A5.330 021	A5.331 4	A5.332 021
A5.333 Axim -Prestea	A5.334 2	A5.335 021	A5.336 2	A5.337 021	A5.338 4	A5.339 021	A5.340 4	A5.341 021	A5.342 4	A5.343 021
A5.344 Prest ea-Obuasi	A5.345 2	A5.346 021	A5.347 2	A5.348 021	A5.349 4	A5.350 021	A5.351 4	A5.352 021	A5.353 4	A5.354 021
A5.355 Obua si-Kumasi	A5.356 2	A5.357 021	A5.358 2	A5.359 021	A5.360 4	A5.361 021	A5.362 4	A5.363 021	A5.364 4	A5.365 021

Compressor cost CapEx

Compressor station cost components have economies of scale with respect to compressor station capacity. It is difficult to know the precise costs without the technical parameters of WAGP, so we have opted for a standard cost of compression. Figure 104 below shows the trend of compressor station capital cost components as related to compressor station capacity. The blue dots represent the capital costsof compressor stations in the USbased on a data set of 220 compressor station costs. The red dotted line is the trend lineof the compressors capacity against the capital cost. The compressor station capital costs may vary from US$7 to 40 million for a capacity range of 3,000 to 30,000 HP.

[62] The Unbalanced scenarios assume that the infrastructure plan will be similar to the High case supply/demand balance scenario and only for infrastructure scenario 1.

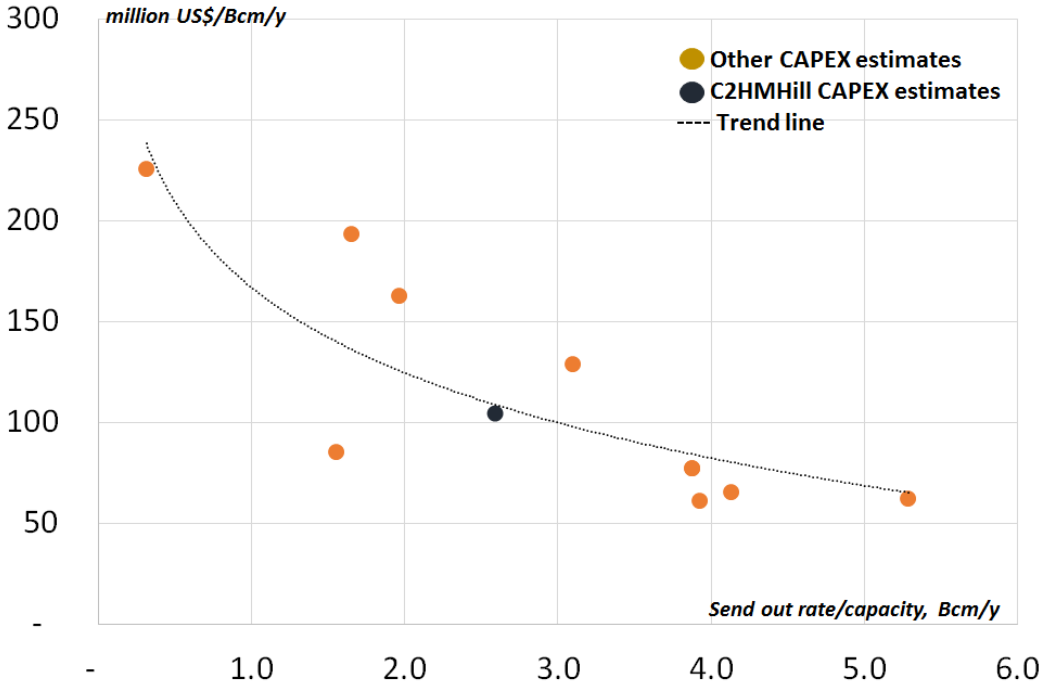
Figure 104 Compressor station capital costs



LNG CAPEX

CAPEX cost assumptions in the pre-feasibility study range between US$40 million (Multi-Point Mooring facility) and US$270 million (Fixed berth) for a terminal with a capacity of 250 mmcfd. We apply a conservative assumption and assume that a fixed berth facility would be constructed. The resulting per unit CAPEX costs of US$1.1 million/mmcfd are then applied to the required capacities. These costs are in line with recent global FSRU projects, as shown in the diagram below.

Figure 105LNG CAPEX comparison



A5.366 Ghana Gas Master Plan Model outputs

A5.366.1 Supply/demand balance

Table 38Low case: Balanced demand, *bcf*

	Tema	Accra	Cape Coast	Takoradi	Kaforidua	Kumasi	Axim	Prestea	Obuasi	Sunyani	Tamale	Bolgatanga	Power sector demand	Industrial sector demand	Exports	Total gas demand Demand	Unmet demand
2013	6.99	0.00	0.00	23.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.69	0.00	0.00	30.69	12.44
2014	8.23	0.24	0.00	24.44	0.00	0.00	0.00	0.22	0.00	0.00	0.00	0.00	31.31	1.83	0.00	33.14	14.89
2015	28.84	0.49	0.00	35.10	0.00	0.00	0.00	0.43	0.00	0.00	0.00	0.00	61.20	3.65	0.00	64.85	15.43
2016	38.37	0.73	0.00	30.29	0.00	0.00	0.00	0.65	0.00	0.00	0.00	0.00	64.56	5.48	0.00	70.03	20.61
2017	40.62	0.98	0.00	32.99	0.00	0.00	0.00	0.86	0.00	0.00	0.00	0.00	68.14	7.30	0.00	75.44	15.07
2018	50.59	1.22	0.00	15.51	0.00	0.00	12.57	1.08	0.00	0.00	0.00	0.00	71.84	9.13	0.00	80.97	0.00
2019	51.84	1.46	0.00	15.18	0.00	0.00	12.59	1.29	0.00	0.00	0.00	0.00	71.41	10.95	0.00	82.36	0.00
2020	53.08	1.71	0.00	16.68	0.00	0.00	15.56	1.51	0.00	0.00	0.00	0.00	75.76	12.78	0.00	88.54	0.00
2021	54.33	0.98	0.00	17.46	0.00	0.98	19.73	1.72	0.00	0.00	0.00	0.00	80.59	14.61	0.00	95.19	0.00
2022	55.58	1.10	0.00	17.74	0.00	1.10	24.65	1.94	0.00	0.00	0.00	0.00	85.67	16.43	0.00	102.10	0.00
2023	56.83	1.22	0.00	17.86	0.00	1.22	29.93	2.15	0.00	0.00	0.00	0.00	90.95	18.26	0.00	109.21	0.00
2024	58.07	1.34	0.00	17.97	0.00	1.34	37.76	2.37	0.00	0.00	0.00	0.00	98.77	20.08	0.00	118.86	0.00
2025	59.32	1.46	0.00	18.09	0.00	1.46	43.50	2.58	0.00	0.00	0.00	0.00	104.52	21.91	0.00	126.43	0.00
2026	60.57	1.59	0.00	18.21	0.00	1.59	49.49	2.80	0.00	0.00	0.00	0.00	110.51	23.74	0.00	134.25	0.00
2027	61.82	1.71	0.00	18.33	0.00	1.96	55.85	3.02	0.00	0.00	0.00	0.00	117.12	25.56	0.00	142.68	0.00
2028	63.06	1.83	0.00	18.45	0.00	4.07	60.75	3.23	0.00	0.00	0.00	0.00	124.01	27.39	0.00	151.39	0.00
2029	64.31	1.95	0.00	18.57	0.00	7.90	64.23	3.45	0.00	0.00	0.00	0.00	131.19	29.21	0.00	160.41	11.06
2030	67.16	2.07	0.00	18.69	0.00	11.91	66.25	3.66	0.00	0.00	0.00	0.00	138.71	31.04	0.00	169.75	24.11
2031	71.56	2.20	0.00	20.23	0.00	13.31	68.35	3.88	0.00	0.00	0.00	0.00	146.65	32.86	0.00	179.51	15.42
2032	74.18	2.32	0.00	25.23	0.00	13.43	70.53	4.09	0.00	0.00	0.00	0.00	155.09	34.69	0.00	189.78	0.00
2033	75.43	2.44	0.00	31.88	0.00	13.55	72.80	4.31	0.00	0.00	0.00	0.00	163.90	36.52	0.00	200.41	4.04
2034	77.35	2.56	0.00	38.26	0.00	14.34	74.51	4.52	0.00	0.00	0.00	0.00	173.20	38.34	0.00	211.54	23.27
2035	80.38	2.68	0.00	40.20	0.00	16.45	75.00	4.74	0.00	0.00	0.00	0.00	179.28	40.17	0.00	219.45	74.64
2036	82.06	2.81	0.00	40.32	0.00	18.72	75.00	4.95	0.00	0.00	0.00	0.00	181.87	41.99	0.00	223.87	97.82
2037	85.00	2.93	0.00	40.73	0.00	19.60	75.00	5.17	0.00	0.00	0.00	0.00	184.60	43.82	0.00	228.42	90.40
2038	87.18	3.05	0.00	42.84	0.00	19.72	75.00	5.38	0.00	0.00	0.00	0.00	187.54	45.65	0.00	233.18	95.81
2039	88.43	3.17	0.00	46.04	0.00	19.84	75.00	5.60	0.00	0.00	0.00	0.00	190.62	47.47	0.00	238.09	80.55
2040	89.68	3.29	0.00	49.34	0.00	19.96	75.00	5.81	0.00	0.00	0.00	0.00	193.80	49.30	0.00	243.10	108.78

Table 39 Low case: balanced supply by supply option, *bcf*

	Jubilee	TEN	Sankofa	MTA	Jubilee (blow down gas) - low&cent case	TEN (blow down gas)	Sankofa (blow down gas) - low&cent case	WAGP - low case	LNG imports (Tema)	Domestic	WAGP	LNG imports	Total Supply
2013	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.25	0.00	0.00	18.25	0.00	18.25
2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.25	0.00	0.00	18.25	0.00	18.25
2015	31.17	0.00	0.00	0.00	0.00	0.00	0.00	18.25	0.00	31.17	18.25	0.00	49.42
2016	31.17	0.00	0.00	0.00	0.00	0.00	0.00	18.25	0.00	31.17	18.25	0.00	49.42
2017	31.17	10.95	0.00	0.00	0.00	0.00	0.00	18.25	0.00	42.12	18.25	0.00	60.37
2018	31.17	10.95	38.85	0.00	0.00	0.00	0.00	0.00	0.00	80.97	0.00	0.00	80.97
2019	26.15	10.95	27.01	18.25	0.00	0.00	0.00	0.00	0.00	82.36	0.00	0.00	82.36
2020	21.83	10.95	37.50	18.25	0.00	0.00	0.00	0.00	0.00	88.54	0.00	0.00	88.54
2021	18.13	10.95	47.86	18.25	0.00	0.00	0.00	0.00	0.00	95.19	0.00	0.00	95.19
2022	14.95	10.95	57.67	18.25	0.00	0.00	0.00	0.28	0.00	101.82	0.28	0.00	102.10
2023	12.22	7.30	57.67	18.25	0.00	0.00	0.00	13.76	0.00	95.44	13.76	0.00	109.21
2024	9.88	7.30	57.67	18.25	0.00	0.00	0.00	18.25	7.51	93.10	18.25	7.51	118.86
2025	7.87	7.30	57.67	18.25	0.00	0.00	0.00	18.25	17.09	91.09	18.25	17.09	126.43
2026	6.14	7.30	57.67	18.25	0.00	0.00	0.00	18.25	26.64	89.36	18.25	26.64	134.25
2027	4.65	7.30	57.67	15.05	0.00	0.00	0.00	18.25	39.75	84.67	18.25	39.75	142.68
2028	3.38	7.30	57.67	12.00	0.00	0.00	0.00	18.25	52.79	80.35	18.25	52.79	151.39
2029	2.29	7.30	57.67	9.09	0.00	0.00	0.00	18.25	54.75	76.35	18.25	54.75	149.35
2030	1.35	7.30	57.67	6.32	0.00	0.00	0.00	18.25	54.75	72.64	18.25	54.75	145.64
2031	0.54	0.00	57.67	3.68	0.00	29.20	0.00	18.25	54.75	91.09	18.25	54.75	164.09
2032	0.00	0.00	57.67	0.00	36.50	29.20	0.00	18.25	48.16	123.37	18.25	48.16	189.78
2033	0.00	0.00	57.67	0.00	36.50	29.20	0.00	18.25	54.75	123.37	18.25	54.75	196.37
2034	0.00	0.00	49.58	0.00	36.50	29.20	0.00	18.25	54.75	115.28	18.25	54.75	188.28
2035	0.00	0.00	42.62	0.00	0.00	29.20	0.00	18.25	54.75	71.82	18.25	54.75	144.82
2036	0.00	0.00	36.63	0.00	0.00	16.43	0.00	18.25	54.75	53.05	18.25	54.75	126.05
2037	0.00	0.00	31.47	0.00	0.00	0.00	29.90	21.90	54.75	61.38	21.90	54.75	138.03
2038	0.00	0.00	27.04	0.00	0.00	0.00	33.68	21.90	54.75	60.72	21.90	54.75	137.37
2039	0.00	0.00	23.22	0.00	0.00	0.00	57.67	21.90	54.75	80.89	21.90	54.75	157.54
2040	0.00	0.00	0.00	0.00	0.00	0.00	57.67	21.90	54.75	57.67	21.90	54.75	134.32

Table 40Base case: Balanced demand, *bcf*

	Tema	Accra	Cape Coast	Takoradi	Kaforidua	Kumasi	Axim	Prestea	Obuasi	Sunyani	Tamale	Bolgatanga	Power sector demand	Industrial sector demand	Exports	Total gas demand Demand	Unmet demand
2013	6.99	0.00	0.00	23.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.69	0.00	0.00	30.69	12.44
2014	8.23	0.24	0.00	24.44	0.00	0.00	0.00	0.22	0.00	0.00	0.00	0.00	31.31	1.83	0.00	33.14	14.89
2015	29.80	0.49	0.00	39.55	0.00	0.00	0.00	0.43	0.00	0.00	0.00	0.00	66.61	3.65	0.00	70.27	0.00
2016	44.29	0.73	0.00	38.89	0.00	0.00	0.00	0.65	0.00	0.00	0.00	0.00	79.08	5.48	0.00	84.56	12.44
2017	48.14	0.98	0.00	41.04	0.00	0.00	0.00	0.86	0.00	0.00	0.00	0.00	83.72	7.30	0.00	91.02	7.95
2018	50.59	1.22	0.00	17.26	0.00	0.00	29.61	1.08	0.00	0.00	0.00	0.00	90.63	9.13	0.00	99.76	0.00
2019	51.84	1.46	0.00	17.64	0.00	0.00	31.66	1.29	0.00	0.00	0.00	0.00	92.93	10.95	0.00	103.89	0.00
2020	53.08	1.71	0.00	20.11	0.00	0.00	36.77	1.51	0.00	0.00	0.00	0.00	100.40	12.78	0.00	113.18	0.00
2021	58.93	0.98	0.00	19.84	0.00	0.98	40.68	1.72	0.00	0.00	0.00	0.00	108.51	14.61	0.00	123.12	0.00
2022	61.18	1.10	0.00	24.66	0.00	1.10	43.87	1.94	0.00	0.00	0.00	0.00	117.40	16.43	0.00	133.84	0.00
2023	59.89	1.22	0.00	18.17	0.00	1.22	61.80	2.15	0.00	0.00	0.00	0.00	126.20	18.26	0.00	144.46	0.00
2024	64.20	1.34	0.00	25.00	0.00	1.34	66.79	2.37	0.00	0.00	0.00	0.00	140.96	20.08	0.00	161.04	0.00
2025	65.45	1.46	0.00	33.07	0.00	1.46	69.53	2.58	0.00	0.00	0.00	0.00	151.65	21.91	0.00	173.56	0.00
2026	66.70	1.59	0.00	30.05	0.00	12.70	72.45	2.80	0.00	0.00	0.00	0.00	162.54	23.74	0.00	186.28	4.35
2027	68.83	1.71	0.00	38.36	0.00	13.73	74.76	3.02	0.00	0.00	0.00	0.00	174.84	25.56	0.00	200.40	23.35
2028	71.65	1.83	0.00	39.37	0.00	17.03	75.00	3.23	0.00	0.00	0.00	0.00	180.72	27.39	0.00	208.11	39.19
2029	74.91	1.95	0.00	39.67	0.00	18.62	75.00	3.45	0.00	0.00	0.00	0.00	184.39	29.21	0.00	213.60	51.74
2030	77.20	2.07	0.00	42.78	0.00	18.74	75.00	3.66	0.00	0.00	0.00	0.00	188.43	31.04	0.00	219.46	63.77
2031	78.45	2.20	0.00	47.18	0.00	18.86	75.00	3.88	0.00	0.00	0.00	0.00	192.71	32.86	0.00	225.57	53.39
2032	80.53	2.32	0.00	50.30	0.00	18.99	75.00	4.09	0.00	0.00	0.00	0.00	196.55	34.69	0.00	231.24	28.89
2033	82.17	2.44	0.00	50.42	0.00	19.11	75.00	4.31	0.00	0.00	0.00	0.00	196.94	36.52	0.00	233.46	40.40
2034	83.42	2.56	0.00	50.54	0.00	19.23	75.00	4.52	0.00	0.00	0.00	0.00	196.94	38.34	0.00	235.28	50.14
2035	84.67	2.68	0.00	50.66	0.00	19.35	75.00	4.74	0.00	0.00	0.00	0.00	196.94	40.17	0.00	237.11	76.97
2036	85.92	2.81	0.00	50.78	0.00	19.47	75.00	4.95	0.00	0.00	0.00	0.00	196.94	41.99	0.00	238.94	97.34
2037	87.16	2.93	0.00	50.90	0.00	19.60	75.00	5.17	0.00	0.00	0.00	0.00	196.94	43.82	0.00	240.76	92.57
2038	88.41	3.05	0.00	51.02	0.00	19.72	75.00	5.38	0.00	0.00	0.00	0.00	196.94	45.65	0.00	242.59	94.44
2039	89.66	3.17	0.00	51.14	0.00	19.84	75.00	5.60	0.00	0.00	0.00	0.00	196.94	47.47	0.00	244.41	95.49
2040	90.91	3.29	0.00	51.26	0.00	19.96	75.00	5.81	0.00	0.00	0.00	0.00	196.94	49.30	0.00	246.24	97.32

Table 41 Base case: balanced supply by supply option, *bcf*

	Jubilee	TEN	Sankofa	MTA	Hess	Jubilee (blow down gas) - low&cent case	TEN (blow down gas)	Sankofa (blow down gas) - low&cent case	WAGP - central case	LNG imports (Tema)	Domestic	WAGP	LNG imports	Total Supply
2013	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.25	0.00	0.00	18.25	0.00	18.25
2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.25	0.00	0.00	18.25	0.00	18.25
2015	35.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00	34.64	0.00	35.62	34.64	0.00	70.27
2016	35.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00	36.50	0.00	35.62	36.50	0.00	72.12
2017	35.62	10.95	0.00	0.00	0.00	0.00	0.00	0.00	36.50	0.00	46.57	36.50	0.00	83.07
2018	35.62	10.95	53.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	99.76	0.00	0.00	99.76
2019	29.97	10.95	44.72	18.25	0.00	0.00	0.00	0.00	0.00	0.00	103.89	0.00	0.00	103.89
2020	25.12	10.95	57.67	18.25	0.00	0.00	0.00	0.00	1.19	0.00	111.99	1.19	0.00	113.18
2021	20.95	10.95	57.67	18.25	7.30	0.00	0.00	0.00	8.00	0.00	115.12	8.00	0.00	123.12
2022	17.37	10.95	57.67	18.25	13.14	0.00	0.00	0.00	16.46	0.00	117.38	16.46	0.00	133.84
2023	14.30	7.30	57.67	18.25	18.25	0.00	0.00	0.00	28.69	0.00	115.77	28.69	0.00	144.46
2024	11.66	7.30	57.67	18.25	18.25	0.00	0.00	0.00	36.50	11.41	113.13	36.50	11.41	161.04
2025	9.40	7.30	57.67	18.25	18.25	0.00	0.00	0.00	36.50	26.19	110.87	36.50	26.19	173.56
2026	7.45	7.30	57.67	18.25	18.25	0.00	0.00	0.00	36.50	36.50	108.92	36.50	36.50	181.92
2027	5.78	7.30	57.67	15.05	18.25	0.00	0.00	0.00	36.50	36.50	104.05	36.50	36.50	177.05
2028	4.35	7.30	57.67	12.00	14.60	0.00	0.00	0.00	36.50	36.50	95.92	36.50	36.50	168.92
2029	3.12	7.30	57.67	9.09	11.68	0.00	0.00	0.00	36.50	36.50	88.86	36.50	36.50	161.86
2030	2.06	7.30	57.67	6.32	9.34	0.00	0.00	0.00	36.50	36.50	82.70	36.50	36.50	155.70
2031	1.16	0.00	57.67	3.68	7.48	0.00	29.20	0.00	36.50	36.50	99.18	36.50	36.50	172.18
2032	0.00	0.00	57.67	0.00	5.98	36.50	29.20	0.00	36.50	36.50	129.35	36.50	36.50	202.35
2033	0.00	0.00	49.58	0.00	4.78	36.50	29.20	0.00	36.50	36.50	120.06	36.50	36.50	193.06
2034	0.00	0.00	42.62	0.00	3.83	36.50	29.20	0.00	36.50	36.50	112.14	36.50	36.50	185.14
2035	0.00	0.00	36.63	0.00	3.06	0.00	29.20	0.00	36.50	54.75	68.89	36.50	54.75	160.14
2036	0.00	0.00	31.47	0.00	2.45	0.00	16.43	0.00	36.50	54.75	50.35	36.50	54.75	141.60
2037	0.00	0.00	27.04	0.00	0.00	0.00	0.00	29.90	36.50	54.75	56.94	36.50	54.75	148.19
2038	0.00	0.00	23.22	0.00	0.00	0.00	0.00	33.68	36.50	54.75	56.90	36.50	54.75	148.15
2039	0.00	0.00	0.00	0.00	0.00	0.00	0.00	57.67	36.50	54.75	57.67	36.50	54.75	148.92
2040	0.00	0.00	0.00	0.00	0.00	0.00	0.00	57.67	36.50	54.75	57.67	36.50	54.75	148.92

Table 42 High case: Balanced demand, *bcf*

	Tema	Accra	Cape Coast	Takoradi	Kaforidua	Kumasi	Axim	Prestea	Obuasi	Sunyani	Tamale	Bolgatanga	Power sector demand	Industrial sector demand	Exports	Total gas demand Demand	Unmet demand
2013	6.99	0.00	0.00	23.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.69	0.00	0.00	30.69	12.44
2014	8.82	0.24	0.00	24.44	0.00	0.00	0.00	0.22	0.00	0.00	0.00	0.00	31.90	1.83	0.00	33.73	15.48
2015	30.41	0.49	0.00	45.16	0.00	0.00	0.00	0.43	0.00	0.00	0.00	0.00	72.84	3.65	0.00	76.49	0.00
2016	50.55	0.73	0.00	44.02	0.00	0.00	0.00	0.65	0.00	0.00	0.00	0.00	90.47	5.48	0.00	95.95	0.00
2017	51.80	0.98	0.00	46.34	0.00	0.00	0.00	0.86	0.00	0.00	0.00	0.00	92.67	7.30	0.00	99.97	0.00
2018	50.59	1.22	0.00	30.70	0.00	0.00	43.83	1.08	0.00	0.00	0.00	0.00	118.28	9.13	0.00	127.41	0.00
2019	52.54	1.46	0.00	34.09	0.00	0.00	45.55	1.29	0.00	0.00	0.00	0.00	123.98	10.95	0.00	134.93	0.00
2020	64.19	1.71	0.00	31.43	0.00	0.00	48.40	1.51	0.00	0.00	0.00	0.00	134.46	12.78	0.00	147.24	0.00
2021	73.15	0.98	0.00	34.40	0.00	0.98	50.00	1.72	0.00	0.00	0.00	0.00	146.61	14.61	0.00	161.22	0.00
2022	77.52	1.10	0.00	44.34	0.00	1.10	50.00	1.94	0.00	0.00	0.00	0.00	159.56	16.43	0.00	175.99	0.00
2023	74.86	1.22	0.00	37.50	0.00	1.22	74.64	2.15	0.00	0.00	0.00	0.00	173.34	18.26	0.00	191.60	0.00
2024	90.83	1.34	0.00	37.73	0.00	1.34	75.00	2.37	0.00	0.00	0.00	0.00	188.54	20.08	0.00	208.62	0.00
2025	94.52	1.46	0.00	52.04	0.00	1.46	75.00	2.58	0.00	0.00	0.00	0.00	205.17	21.91	0.00	227.08	0.00
2026	94.91	1.59	0.00	46.48	0.00	21.96	75.00	2.80	0.00	0.00	0.00	0.00	219.00	23.74	0.00	242.74	0.00
2027	98.45	1.71	0.00	55.21	0.00	22.08	75.00	3.02	0.00	0.00	0.00	0.00	229.90	25.56	0.00	255.47	0.00
2028	103.39	1.83	0.00	56.04	0.00	22.20	75.00	3.23	0.00	0.00	0.00	0.00	234.31	27.39	0.00	261.70	0.00
2029	107.32	1.95	0.00	56.16	0.00	24.13	75.00	3.45	0.00	0.00	0.00	0.00	238.80	29.21	0.00	268.01	10.01
2030	110.54	2.07	0.00	59.19	0.00	24.30	75.00	3.66	0.00	0.00	0.00	0.00	243.73	31.04	0.00	274.77	24.14
2031	111.79	2.20	0.00	64.58	0.00	24.42	75.00	3.88	0.00	0.00	0.00	0.00	249.00	32.86	0.00	281.86	8.48
2032	114.26	2.32	0.00	66.97	0.00	24.54	75.00	4.09	0.00	0.00	0.00	0.00	252.50	34.69	0.00	287.19	20.66
2033	115.51	2.44	0.00	67.09	0.00	24.66	75.00	4.31	0.00	0.00	0.00	0.00	252.50	36.52	0.00	289.02	25.11
2034	116.76	2.56	0.00	67.21	0.00	24.79	75.00	4.52	0.00	0.00	0.00	0.00	252.50	38.34	0.00	290.84	31.52
2035	118.00	2.68	0.00	67.33	0.00	24.91	75.00	4.74	0.00	0.00	0.00	0.00	252.50	40.17	0.00	292.67	38.16
2036	119.25	2.81	0.00	67.45	0.00	25.03	75.00	4.95	0.00	0.00	0.00	0.00	252.50	41.99	0.00	294.50	27.85
2037	120.50	2.93	0.00	67.57	0.00	25.15	75.00	5.17	0.00	0.00	0.00	0.00	252.50	43.82	0.00	296.32	17.52
2038	121.75	3.05	0.00	67.69	0.00	25.27	75.00	5.38	0.00	0.00	0.00	0.00	252.50	45.65	0.00	298.15	26.31
2039	123.00	3.17	0.00	67.80	0.00	25.40	75.00	5.60	0.00	0.00	0.00	0.00	252.50	47.47	0.00	299.97	34.13
2040	124.24	3.29	0.00	67.92	0.00	25.52	75.00	5.81	0.00	0.00	0.00	0.00	252.50	49.30	0.00	301.80	22.86

Table 43 High case: balanced supply by supply option, *bcf*

	Jubilee	TEN	Sankofa	MTA	Hess	Shallow Tano	Other non-associated	Other associated	Jubilee (blow down gas) - high case	TEN (blow down gas)	Sankofa (blow down gas) - high case	WAGP - high case	LNG imports (Tema)	Domestic	WAGP	LNG imports	Total Supply
2013	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.25	0.00	0.00	18.25	0.00	18.25
2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.25	0.00	0.00	18.25	0.00	18.25
2015	35.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	40.87	0.00	35.62	40.87	0.00	76.49
2016	35.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	60.33	0.00	35.62	60.33	0.00	95.95
2017	35.62	10.95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	53.40	0.00	46.57	53.40	0.00	99.97
2018	35.62	10.95	57.67	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	23.17	0.00	104.24	23.17	0.00	127.41
2019	35.62	10.95	33.61	18.25	0.00	0.00	0.00	36.50	0.00	0.00	0.00	0.00	0.00	134.93	0.00	0.00	134.93
2020	35.62	10.95	45.91	18.25	0.00	0.00	0.00	36.50	0.00	0.00	0.00	0.00	0.00	147.24	0.00	0.00	147.24
2021	35.62	10.95	52.59	18.25	7.30	0.00	0.00	36.50	0.00	0.00	0.00	0.00	0.00	161.22	0.00	0.00	161.22
2022	35.62	10.95	57.67	18.25	13.14	0.00	3.86	36.50	0.00	0.00	0.00	0.00	0.00	175.99	0.00	0.00	175.99
2023	35.62	14.60	57.67	18.25	18.25	0.00	10.71	36.50	0.00	0.00	0.00	0.00	0.00	191.60	0.00	0.00	191.60
2024	29.97	14.60	57.67	18.25	18.25	0.00	33.38	36.50	0.00	0.00	0.00	0.00	0.00	208.62	0.00	0.00	208.62
2025	25.12	14.60	57.67	18.25	18.25	9.13	36.50	36.50	0.00	0.00	0.00	11.07	0.00	216.01	11.07	0.00	227.08
2026	20.95	14.60	57.67	18.25	18.25	18.25	36.50	36.50	0.00	0.00	0.00	21.77	0.00	220.97	21.77	0.00	242.74
2027	17.37	14.60	57.67	15.05	18.25	18.25	36.50	36.50	0.00	0.00	0.00	41.27	0.00	214.19	41.27	0.00	255.47
2028	14.30	14.60	57.67	12.00	14.60	18.25	36.50	36.50	0.00	0.00	0.00	57.28	0.00	204.42	57.28	0.00	261.70
2029	11.66	14.60	57.67	9.09	11.68	18.25	36.50	36.50	0.00	0.00	0.00	62.05	0.00	195.95	62.05	0.00	258.00
2030	9.40	14.60	57.67	6.32	9.34	18.25	36.50	36.50	0.00	0.00	0.00	62.05	0.00	188.58	62.05	0.00	250.63
2031	7.45	14.60	57.67	3.68	7.48	18.25	36.50	36.50	0.00	29.20	0.00	62.05	0.00	211.33	62.05	0.00	273.38
2032	5.78	14.60	57.67	0.00	5.98	18.25	36.50	36.50	0.00	29.20	0.00	62.05	0.00	204.48	62.05	0.00	266.53
2033	4.35	14.60	57.67	0.00	4.78	18.25	36.50	36.50	0.00	29.20	0.00	62.05	0.00	201.85	62.05	0.00	263.90
2034	3.12	14.60	57.67	0.00	3.83	15.86	36.50	36.50	0.00	29.20	0.00	62.05	0.00	197.27	62.05	0.00	259.32
2035	2.06	14.60	57.67	0.00	3.06	12.87	36.50	36.50	0.00	29.20	0.00	62.05	0.00	192.46	62.05	0.00	254.51
2036	0.35	9.08	57.67	0.00	2.45	9.13	36.50	36.50	36.50	16.43	0.00	62.05	0.00	204.60	62.05	0.00	266.65
2037	0.00	0.00	49.58	0.00	0.00	0.00	36.50	36.50	36.50	0.00	57.67	62.05	0.00	216.75	62.05	0.00	278.80
2038	0.00	0.00	42.62	0.00	0.00	0.00	36.50	36.50	36.50	0.00	57.67	62.05	0.00	209.79	62.05	0.00	271.84
2039	0.00	0.00	36.63	0.00	0.00	0.00	36.50	36.50	0.00	0.00	57.67	62.05	36.50	167.30	62.05	36.50	265.85
2040	0.00	0.00	31.47	0.00	0.00	0.00	36.50	36.50	0.00	0.00	57.67	62.05	54.75	162.14	62.05	54.75	278.94

Table 44 Low demand – High supply case: Balanced demand, *bcf*

	Tema	Accra	Cape Coast	Takoradi	Kaforidua	Kumasi	Axim	Prestea	Obuasi	Sunyani	Tamale	Bolgatanga	Power sector demand	Industrial sector demand	Exports	Total gas demand Demand	Unmet demand
2013	6.99	0.00	0.00	23.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.69	0.00	0.00	30.69	12.44
2014	8.23	0.24	0.00	24.44	0.00	0.00	0.00	0.22	0.00	0.00	0.00	0.00	31.31	1.83	0.00	33.14	14.89
2015	28.84	0.49	0.00	35.10	0.00	0.00	0.00	0.43	0.00	0.00	0.00	0.00	61.20	3.65	0.00	64.85	0.00
2016	38.37	0.73	0.00	30.29	0.00	0.00	0.00	0.65	0.00	0.00	0.00	0.00	64.56	5.48	0.00	70.03	0.00
2017	40.62	0.98	0.00	32.99	0.00	0.00	0.00	0.86	0.00	0.00	0.00	0.00	68.14	7.30	0.00	75.44	0.00
2018	50.59	1.22	0.00	15.51	0.00	0.00	12.57	1.08	0.00	0.00	0.00	0.00	71.84	9.13	0.00	80.97	0.00
2019	51.84	1.46	0.00	15.18	0.00	0.00	12.59	1.29	0.00	0.00	0.00	0.00	71.41	10.95	0.00	82.36	0.00
2020	53.08	1.71	0.00	16.68	0.00	0.00	15.56	1.51	0.00	0.00	0.00	0.00	75.76	12.78	0.00	88.54	0.00
2021	54.33	0.98	0.00	17.46	0.00	0.98	19.73	1.72	0.00	0.00	0.00	0.00	80.59	14.61	0.00	95.19	0.00
2022	55.58	1.10	0.00	17.74	0.00	1.10	24.65	1.94	0.00	0.00	0.00	0.00	85.67	16.43	0.00	102.10	0.00
2023	56.83	1.22	0.00	17.86	0.00	1.22	29.93	2.15	0.00	0.00	0.00	0.00	90.95	18.26	0.00	109.21	0.00
2024	58.07	1.34	0.00	17.97	0.00	1.34	37.76	2.37	0.00	0.00	0.00	0.00	98.77	20.08	0.00	118.86	0.00
2025	59.32	1.46	0.00	18.09	0.00	1.46	43.50	2.58	0.00	0.00	0.00	0.00	104.52	21.91	0.00	126.43	0.00
2026	60.57	1.59	0.00	18.21	0.00	1.59	49.49	2.80	0.00	0.00	0.00	0.00	110.51	23.74	0.00	134.25	0.00
2027	61.82	1.71	0.00	18.33	0.00	1.96	55.85	3.02	0.00	0.00	0.00	0.00	117.12	25.56	0.00	142.68	0.00
2028	63.06	1.83	0.00	18.45	0.00	4.07	60.75	3.23	0.00	0.00	0.00	0.00	124.01	27.39	0.00	151.39	0.00
2029	64.31	1.95	0.00	18.57	0.00	7.90	64.23	3.45	0.00	0.00	0.00	0.00	131.19	29.21	0.00	160.41	0.00
2030	67.16	2.07	0.00	18.69	0.00	11.91	66.25	3.66	0.00	0.00	0.00	0.00	138.71	31.04	0.00	169.75	0.00
2031	71.56	2.20	0.00	20.23	0.00	13.31	68.35	3.88	0.00	0.00	0.00	0.00	146.65	32.86	0.00	179.51	0.00
2032	74.18	2.32	0.00	25.23	0.00	13.43	70.53	4.09	0.00	0.00	0.00	0.00	155.09	34.69	0.00	189.78	0.00
2033	75.43	2.44	0.00	31.88	0.00	13.55	72.80	4.31	0.00	0.00	0.00	0.00	163.90	36.52	0.00	200.41	0.00
2034	77.35	2.56	0.00	38.26	0.00	14.34	74.51	4.52	0.00	0.00	0.00	0.00	173.20	38.34	0.00	211.54	0.00
2035	80.38	2.68	0.00	40.20	0.00	16.45	75.00	4.74	0.00	0.00	0.00	0.00	179.28	40.17	0.00	219.45	0.00
2036	82.06	2.81	0.00	40.32	0.00	18.72	75.00	4.95	0.00	0.00	0.00	0.00	181.87	41.99	0.00	223.87	0.00
2037	85.00	2.93	0.00	40.73	0.00	19.60	75.00	5.17	0.00	0.00	0.00	0.00	184.60	43.82	0.00	228.42	0.00
2038	87.18	3.05	0.00	42.84	0.00	19.72	75.00	5.38	0.00	0.00	0.00	0.00	187.54	45.65	0.00	233.18	0.00
2039	88.43	3.17	0.00	46.04	0.00	19.84	75.00	5.60	0.00	0.00	0.00	0.00	190.62	47.47	0.00	238.09	0.00
2040	89.68	3.29	0.00	49.34	0.00	19.96	75.00	5.81	0.00	0.00	0.00	0.00	193.80	49.30	0.00	243.10	0.00

Table 45 Low demand – High supply case: balanced supply by supply option, *bcf*

	Jubilee	TEN	Sankofa	MTA	Hess	Shallow Tano	Other non-associated	Other associated	Jubilee (blow down gas) - high case	TEN (blow down gas)	Sankofa (blow down gas) - high case	WAGP - high case	LNG imports (Tema)	Domestic	WAGP	LNG imports	Total Supply
2013	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.25	0.00	0.00	18.25	0.00	18.25
2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.25	0.00	0.00	18.25	0.00	18.25
2015	35.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	29.23	0.00	35.62	29.23	0.00	64.85
2016	35.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	34.41	0.00	35.62	34.41	0.00	70.03
2017	35.62	10.95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	28.87	0.00	46.57	28.87	0.00	75.44
2018	35.62	10.95	34.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	80.97	0.00	0.00	80.97
2019	35.62	10.95	0.00	18.25	0.00	0.00	0.00	17.54	0.00	0.00	0.00	0.00	0.00	82.36	0.00	0.00	82.36
2020	35.62	10.95	0.00	18.25	0.00	0.00	0.00	23.71	0.00	0.00	0.00	0.00	0.00	88.54	0.00	0.00	88.54
2021	35.62	10.95	0.00	18.25	0.00	0.00	0.00	30.37	0.00	0.00	0.00	0.00	0.00	95.19	0.00	0.00	95.19
2022	35.62	10.95	0.00	18.25	0.77	0.00	0.00	36.50	0.00	0.00	0.00	0.00	0.00	102.10	0.00	0.00	102.10
2023	35.62	14.60	0.00	18.25	4.23	0.00	0.00	36.50	0.00	0.00	0.00	0.00	0.00	109.21	0.00	0.00	109.21
2024	29.97	14.60	1.29	18.25	18.25	0.00	0.00	36.50	0.00	0.00	0.00	0.00	0.00	118.86	0.00	0.00	118.86
2025	25.12	14.60	4.59	18.25	18.25	9.13	0.00	36.50	0.00	0.00	0.00	0.00	0.00	126.43	0.00	0.00	126.43
2026	20.95	14.60	7.45	18.25	18.25	18.25	0.00	36.50	0.00	0.00	0.00	0.00	0.00	134.25	0.00	0.00	134.25
2027	17.37	14.60	22.66	15.05	18.25	18.25	0.00	36.50	0.00	0.00	0.00	0.00	0.00	142.68	0.00	0.00	142.68
2028	14.30	14.60	37.50	12.00	18.25	18.25	0.00	36.50	0.00	0.00	0.00	0.00	0.00	151.39	0.00	0.00	151.39
2029	11.66	14.60	55.70	9.09	14.60	18.25	0.00	36.50	0.00	0.00	0.00	0.00	0.00	160.41	0.00	0.00	160.41
2030	9.40	14.60	57.67	6.32	11.68	18.25	15.33	36.50	0.00	0.00	0.00	0.00	0.00	169.75	0.00	0.00	169.75
2031	7.45	14.60	57.67	3.68	9.34	18.25	2.81	36.50	0.00	29.20	0.00	0.00	0.00	179.51	0.00	0.00	179.51
2032	5.78	14.60	57.67	0.00	7.48	18.25	20.30	36.50	0.00	29.20	0.00	0.00	0.00	189.78	0.00	0.00	189.78
2033	4.35	14.60	57.67	0.00	5.98	18.25	33.86	36.50	0.00	29.20	0.00	0.00	0.00	200.41	0.00	0.00	200.41
2034	3.12	14.60	57.67	0.00	4.78	15.86	36.50	36.50	0.00	29.20	0.00	13.31	0.00	198.23	13.31	0.00	211.54
2035	2.06	14.60	57.67	0.00	3.83	12.87	36.50	36.50	0.00	29.20	0.00	26.23	0.00	193.23	26.23	0.00	219.45
2036	0.35	9.08	57.67	0.00	3.06	9.13	36.50	36.50	36.50	16.43	0.00	18.66	0.00	205.21	18.66	0.00	223.87
2037	0.00	0.00	57.67	0.00	2.45	0.00	36.50	36.50	36.50	0.00	57.67	1.13	0.00	227.29	1.13	0.00	228.42
2038	0.00	0.00	57.67	0.00	0.00	0.00	36.50	36.50	36.50	0.00	57.67	8.34	0.00	224.84	8.34	0.00	233.18
2039	0.00	0.00	57.67	0.00	0.00	0.00	36.50	36.50	0.00	0.00	57.67	49.75	0.00	188.34	49.75	0.00	238.09
2040	0.00	0.00	57.67	0.00	0.00	0.00	36.50	36.50	0.00	0.00	57.67	54.76	0.00	188.34	54.76	0.00	243.10

Table 46 High demand – Low supply case: Balanced demand, *bcf*

	Tema	Accra	Cape Coast	Takoradi	Kaforidua	Kumasi	Axim	Prestea	Obuasi	Sunyani	Tamale	Bolgatanga	Power sector demand	Industrial sector demand	Exports	Total gas demand Demand	Unmet demand
2013	6.99	0.00	0.00	23.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.69	0.00	0.00	30.69	12.44
2014	8.82	0.24	0.00	24.44	0.00	0.00	0.00	0.22	0.00	0.00	0.00	0.00	31.90	1.83	0.00	33.73	15.48
2015	30.41	0.49	0.00	45.16	0.00	0.00	0.00	0.43	0.00	0.00	0.00	0.00	72.84	3.65	0.00	76.49	27.07
2016	50.55	0.73	0.00	44.02	0.00	0.00	0.00	0.65	0.00	0.00	0.00	0.00	90.47	5.48	0.00	95.95	46.53
2017	51.80	0.98	0.00	46.34	0.00	0.00	0.00	0.86	0.00	0.00	0.00	0.00	92.67	7.30	0.00	99.97	39.60
2018	50.59	1.22	0.00	30.70	0.00	0.00	43.83	1.08	0.00	0.00	0.00	0.00	118.28	9.13	0.00	127.41	9.37
2019	52.54	1.46	0.00	34.09	0.00	0.00	45.55	1.29	0.00	0.00	0.00	0.00	123.98	10.95	0.00	134.93	3.67
2020	64.19	1.71	0.00	31.43	0.00	0.00	48.40	1.51	0.00	0.00	0.00	0.00	134.46	12.78	0.00	147.24	20.28
2021	73.15	0.98	0.00	34.40	0.00	0.98	50.00	1.72	0.00	0.00	0.00	0.00	146.61	14.61	0.00	161.22	0.00
2022	77.52	1.10	0.00	44.34	0.00	1.10	50.00	1.94	0.00	0.00	0.00	0.00	159.56	16.43	0.00	175.99	1.17
2023	74.86	1.22	0.00	37.50	0.00	1.22	74.64	2.15	0.00	0.00	0.00	0.00	173.34	18.26	0.00	191.60	23.16
2024	90.83	1.34	0.00	37.73	0.00	1.34	75.00	2.37	0.00	0.00	0.00	0.00	188.54	20.08	0.00	208.62	42.52
2025	94.52	1.46	0.00	52.04	0.00	1.46	75.00	2.58	0.00	0.00	0.00	0.00	205.17	21.91	0.00	227.08	62.99
2026	94.91	1.59	0.00	46.48	0.00	21.96	75.00	2.80	0.00	0.00	0.00	0.00	219.00	23.74	0.00	242.74	80.38
2027	98.45	1.71	0.00	55.21	0.00	22.08	75.00	3.02	0.00	0.00	0.00	0.00	229.90	25.56	0.00	255.47	97.79
2028	103.39	1.83	0.00	56.04	0.00	22.20	75.00	3.23	0.00	0.00	0.00	0.00	234.31	27.39	0.00	261.70	108.35
2029	107.32	1.95	0.00	56.16	0.00	24.13	75.00	3.45	0.00	0.00	0.00	0.00	238.80	29.21	0.00	268.01	118.66
2030	110.54	2.07	0.00	59.19	0.00	24.30	75.00	3.66	0.00	0.00	0.00	0.00	243.73	31.04	0.00	274.77	129.13
2031	111.79	2.20	0.00	64.58	0.00	24.42	75.00	3.88	0.00	0.00	0.00	0.00	249.00	32.86	0.00	281.86	117.77
2032	114.26	2.32	0.00	66.97	0.00	24.54	75.00	4.09	0.00	0.00	0.00	0.00	252.50	34.69	0.00	287.19	90.82
2033	115.51	2.44	0.00	67.09	0.00	24.66	75.00	4.31	0.00	0.00	0.00	0.00	252.50	36.52	0.00	289.02	100.74
2034	116.76	2.56	0.00	67.21	0.00	24.79	75.00	4.52	0.00	0.00	0.00	0.00	252.50	38.34	0.00	290.84	109.53
2035	118.00	2.68	0.00	67.33	0.00	24.91	75.00	4.74	0.00	0.00	0.00	0.00	252.50	40.17	0.00	292.67	153.84
2036	119.25	2.81	0.00	67.45	0.00	25.03	75.00	4.95	0.00	0.00	0.00	0.00	252.50	41.99	0.00	294.50	173.60
2037	120.50	2.93	0.00	67.57	0.00	25.15	75.00	5.17	0.00	0.00	0.00	0.00	252.50	43.82	0.00	296.32	162.73
2038	121.75	3.05	0.00	67.69	0.00	25.27	75.00	5.38	0.00	0.00	0.00	0.00	252.50	45.65	0.00	298.15	164.59
2039	123.00	3.17	0.00	67.80	0.00	25.40	75.00	5.60	0.00	0.00	0.00	0.00	252.50	47.47	0.00	299.97	165.65
2040	124.24	3.29	0.00	67.92	0.00	25.52	75.00	5.81	0.00	0.00	0.00	0.00	252.50	49.30	0.00	301.80	167.48

Table 47High demand – Low supply case: balanced supply by supply option, *bcf*

	Jubilee	TEN	Sankofa	MTA	Jubilee (blow down gas) - low&cent case	TEN (blow down gas)	Sankofa (blow down gas) - low&cent case	WAGP - low case	LNG imports (Tema)	Domestic	WAGP	LNG imports	Total Supply
2013	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.25	0.00	0.00	18.25	0.00	18.25
2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.25	0.00	0.00	18.25	0.00	18.25
2015	31.17	0.00	0.00	0.00	0.00	0.00	0.00	18.25	0.00	31.17	18.25	0.00	49.42
2016	31.17	0.00	0.00	0.00	0.00	0.00	0.00	18.25	0.00	31.17	18.25	0.00	49.42
2017	31.17	10.95	0.00	0.00	0.00	0.00	0.00	18.25	0.00	42.12	18.25	0.00	60.37
2018	31.17	10.95	57.67	0.00	0.00	0.00	0.00	18.25	0.00	99.79	18.25	0.00	118.04
2019	26.15	10.95	57.67	18.25	0.00	0.00	0.00	18.25	0.00	113.02	18.25	0.00	131.27
2020	21.83	10.95	57.67	18.25	0.00	0.00	0.00	18.25	0.00	108.70	18.25	0.00	126.95
2021	18.13	10.95	57.67	18.25	0.00	0.00	0.00	18.25	37.97	105.00	18.25	37.97	161.22
2022	14.95	10.95	57.67	18.25	0.00	0.00	0.00	18.25	54.75	101.82	18.25	54.75	174.82
2023	12.22	7.30	57.67	18.25	0.00	0.00	0.00	18.25	54.75	95.44	18.25	54.75	168.44
2024	9.88	7.30	57.67	18.25	0.00	0.00	0.00	18.25	54.75	93.10	18.25	54.75	166.10
2025	7.87	7.30	57.67	18.25	0.00	0.00	0.00	18.25	54.75	91.09	18.25	54.75	164.09
2026	6.14	7.30	57.67	18.25	0.00	0.00	0.00	18.25	54.75	89.36	18.25	54.75	162.36
2027	4.65	7.30	57.67	15.05	0.00	0.00	0.00	18.25	54.75	84.67	18.25	54.75	157.67
2028	3.38	7.30	57.67	12.00	0.00	0.00	0.00	18.25	54.75	80.35	18.25	54.75	153.35
2029	2.29	7.30	57.67	9.09	0.00	0.00	0.00	18.25	54.75	76.35	18.25	54.75	149.35
2030	1.35	7.30	57.67	6.32	0.00	0.00	0.00	18.25	54.75	72.64	18.25	54.75	145.64
2031	0.54	0.00	57.67	3.68	0.00	29.20	0.00	18.25	54.75	91.09	18.25	54.75	164.09
2032	0.00	0.00	57.67	0.00	36.50	29.20	0.00	18.25	54.75	123.37	18.25	54.75	196.37
2033	0.00	0.00	49.58	0.00	36.50	29.20	0.00	18.25	54.75	115.28	18.25	54.75	188.28
2034	0.00	0.00	42.62	0.00	36.50	29.20	0.00	18.25	54.75	108.32	18.25	54.75	181.32
2035	0.00	0.00	36.63	0.00	0.00	29.20	0.00	18.25	54.75	65.83	18.25	54.75	138.83
2036	0.00	0.00	31.47	0.00	0.00	16.43	0.00	18.25	54.75	47.90	18.25	54.75	120.90
2037	0.00	0.00	27.04	0.00	0.00	0.00	29.90	21.90	54.75	56.94	21.90	54.75	133.59
2038	0.00	0.00	23.22	0.00	0.00	0.00	33.68	21.90	54.75	56.90	21.90	54.75	133.55
2039	0.00	0.00	0.00	0.00	0.00	0.00	57.67	21.90	54.75	57.67	21.90	54.75	134.32
2040	0.00	0.00	0.00	0.00	0.00	0.00	57.67	21.90	54.75	57.67	21.90	54.75	134.32

A5.366.2 Regional distribution of supply from the infrastructure options

The detailed distribution of the demand and the supply after setting the infrastructure parameters is displayed in Figure 106, Figure 107 and Figure 108 for the low, base and high aligned case scenarios, respectively.

Figure 106 Regional distribution of supply and demand: Low case, *bcf*

Infrastracture flows (Bcf)

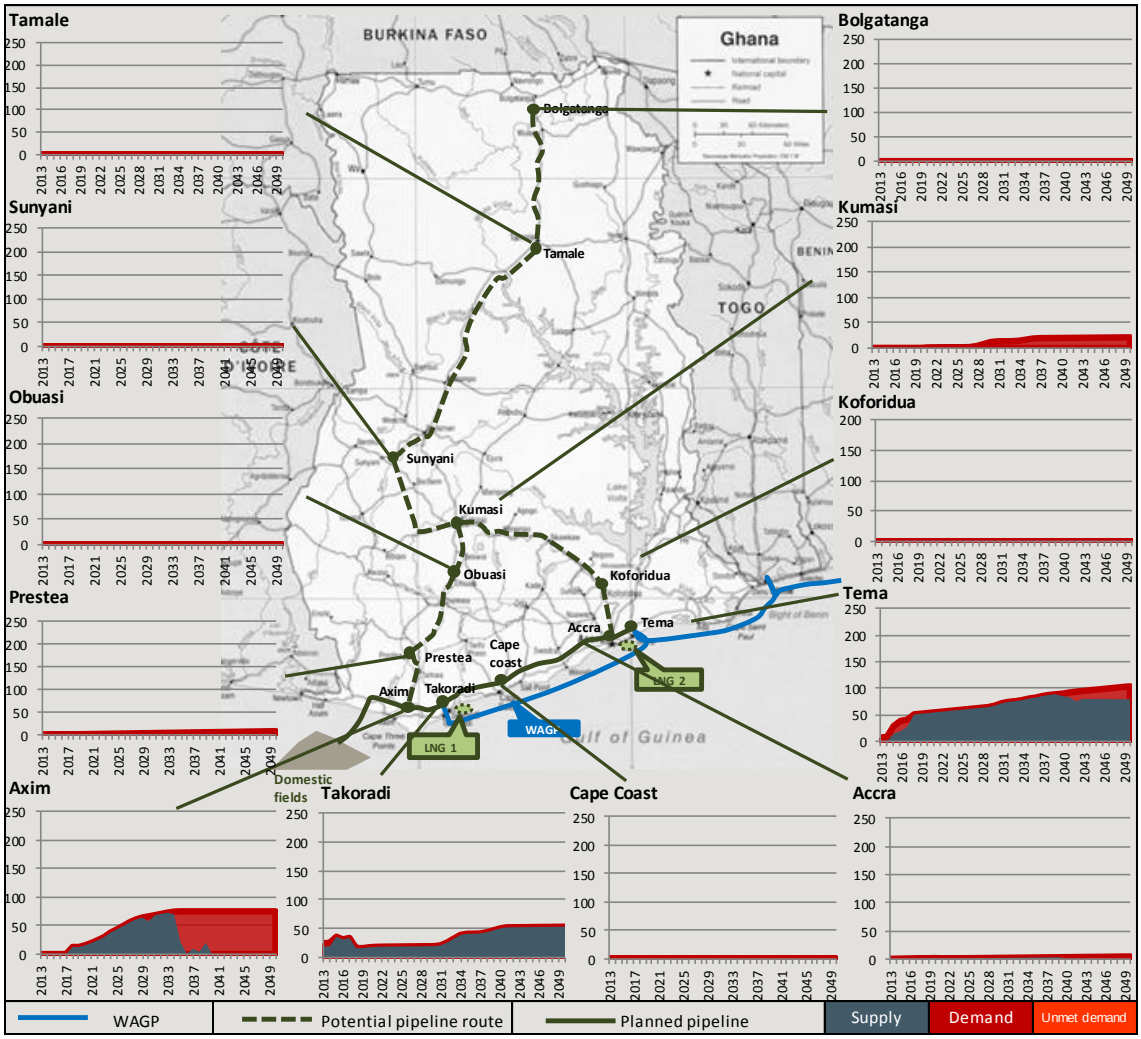


Figure 107 Regional distribution of supply and demand: Base case, *bcf*

Infrastructure flows (Bcf)

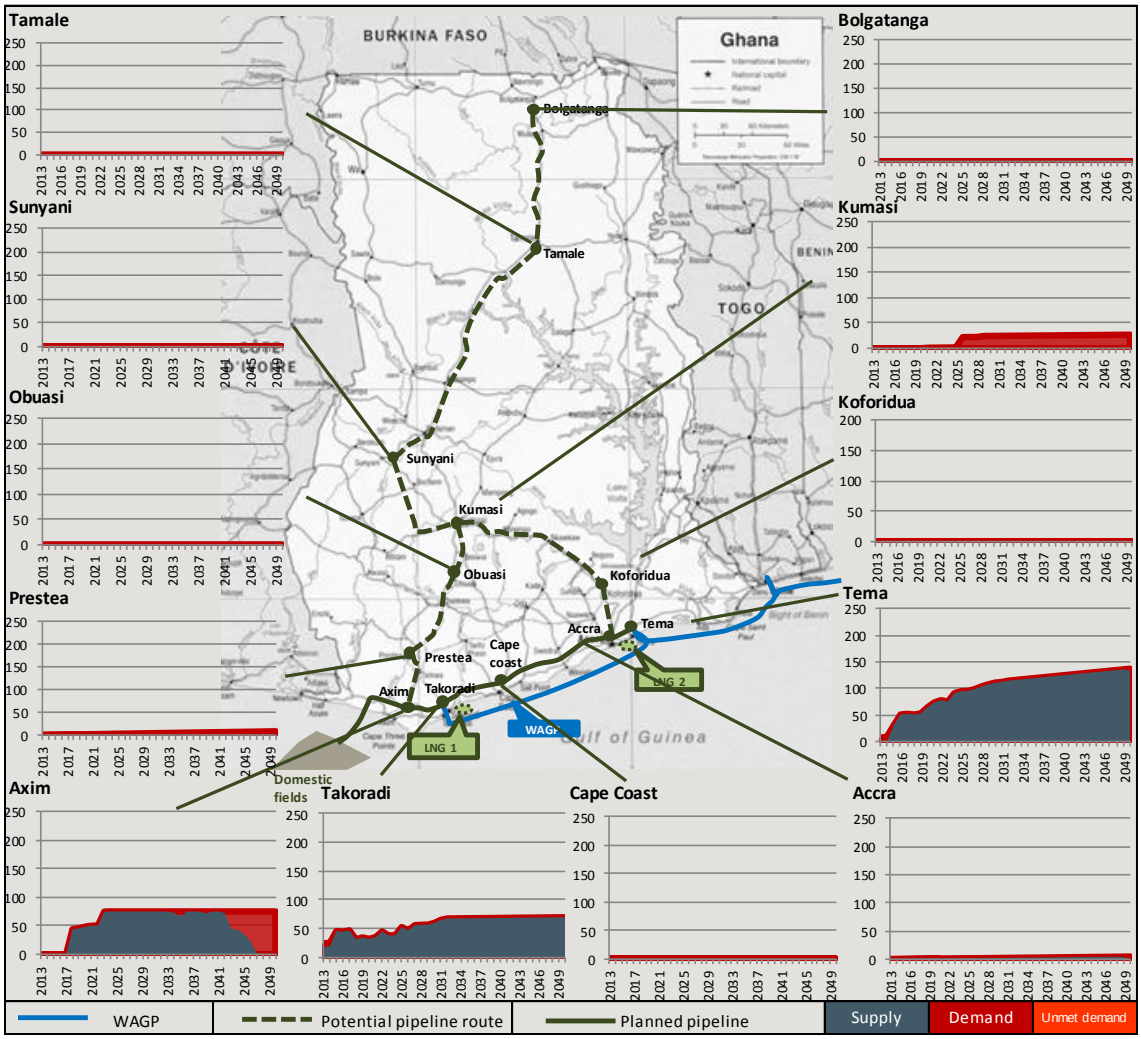
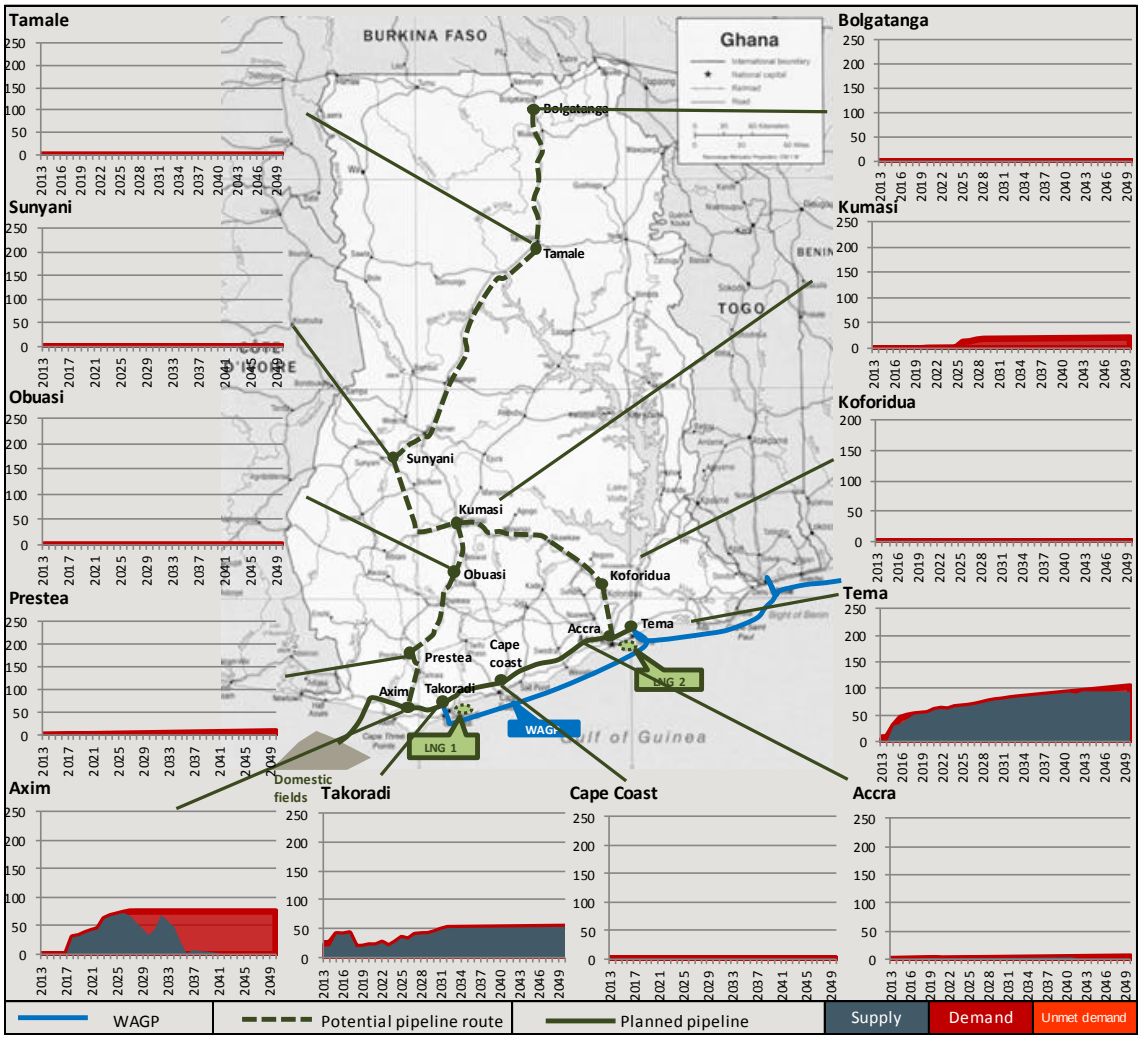


Figure 108 Regional distribution of supply and demand: High case, *bcf*

Infrastructure flows (Bcf)



A5.366.3 Indirect economic value – multiplier effect

Direct economic value is a result of an activity benefiting from the lower cost of inputs. But there is a knock on effect from one sector to another, as additional income to sector A will lead to further purchases (and hence income), for sector B. This is the multiplier effect due to the links between sectors.

Production of a good or service in a given sector will involve forward and backward linkages to other sectors.

Backwards linkages are created through intermediate demand for input goods and services. As supply of a product is increased so demand for its inputs to produce that supply will increase.

Forward linkages exist when the supplied product will be used as an input for the supply of other goods or services.

In addition, the increase in supply will have consumption linkages through additional factor incomes (wages, profits) which may then be used to purchase further goods and services, also known as **'induced' effects**.

In order to derive multiplier factor estimates for Ghana, a Social Accounting Matrix (SAM) developed in 2007 by the International Food Policy Research Institute (IFPRI) has been used[63]. The matrix includes information for 56 production activities and 59 commodities. Backward and forward multiplier factors have been calculated from this SAM for each gas utilisation option discussed in Section 2.2. Before applying these factors to the data there are a number of considerations to note:

The Ghana SAM provides a limited level of sector granularity and so multiplier factors for one or more aggregated sectors must be adopted for particular industries such as 'Metal Products' for steel and aluminium.

Where an industry currently imports all or a majority of its demand for goods and services from other industries, a low backward linkage multiplier results (eg Fertilizer).

Conversely where an industry currently exports the majority of its production, a low forward linkage results (eg Mining).

For these reasons, taking current multipliers with no adjustment, would provide unrepresentative results for the proposed integrated supply chains of Alumina-Aluminium and Ammonia-Urea as imports of intermediate demand would be replaced with domestic supply.

Of the industries where gas could be used which are modelled in this report, **Electricity,Gasoline and Diesel** were expressed as stand-alone sectors within the Ghana SAM. For other industries, the following proxy sectors have been adopted:

For **Alumina:** the Mining sector

For **Aluminium** and **Steel**: Metal Products

For **Ammonia** and **Urea:** Fertilizer

For **Cement**: Metal Products and Construction

For **Industrial Heat**: Textiles and Paper, Publishing and Printing sectors

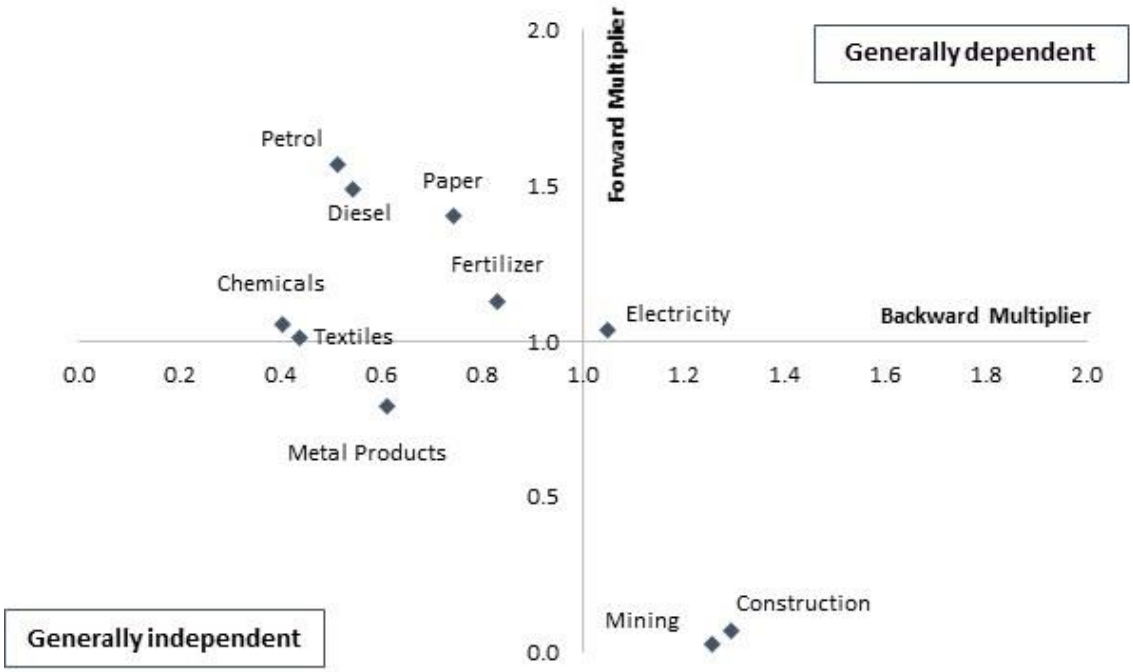
For **Methanol:** Other Chemicals.

The calculated multipliers were then normalised to the economy as a whole using a weighted average of the value of each sector's production. Sectors with backward multipliers greater than 1 are then generally dependent on inter-industry supply relative to the average within the economy, while those with forward multipliers greater than 1 are dependent on inter-industry demand. If both measures are greater than 1, the industry can be said to be generally dependent and to play a key role within the wider economy. The results for the Ghana SAM analysis are shown in Figure 109.

For Fertilizer as Ghana does not currently undertake any domestic production, the normalised backward multiplier from a SAM for Indonesia was adopted.

[63] http://www.ifpri.org/dataset/ghana

Figure 109 Multiplier effects in Ghana economy



From Figure 109, it can be seen that only electricity shows both backwards and forwards multipliers greater than 1, demonstrating its important role in the economy. Fuel for transport, including Petrol and Diesel both show strong forward linkages as does Paper.

Figure 109 shows a particularly low forward multiplier for mining which is due to the fact the vast majority of mined materials are exported from Ghana rather than used as intermediate demand for other industries[64]. In the case of an integrated alumina-aluminium supply chain, mined Bauxite would be utilised downstream in Ghana, improving the forward multiplier result. However any heavily export dependent industry, which covers the strategic industry utilization options of expanded aluminium production, fertilizer and methanol will show similarly low forward linkage results. This indicates the less important role they would play in Ghana's economy and provides further support to the conclusions drawn in the netback analysis in Section 2 that the power sector, followed by domestic-focused small industries and transport should be prioritized.

[64] The backwards multipliers represent the increased activity in the part of the domestic economy modelled endogenously per unit of additional exogenous demand (eg exports), thus *including* the added economic activity from the direct production of those product. In performing this task it assumes unconstrained excess production capacity in all industries, fixed prices and no product substitution occurs. Conversely, the forward economic multipliers represent the added economic activity arising from an increase in supply from an exogenous source (eg imports) within the endogenous elements of the model. This therefore *excludes* the economic value derived from production of the product in question.

A6 Background to financing structures

A6.1 Sources of funding for midstream infrastructure

Sources of project equity	Driver for investment	Examples
Government	To meet policy objectives where project is not financially viable without such support	Mahgreb pipeline, Morocco to Spain section (91% owned by Spanish government)
SOE/National Oil & Gas Companies	For commercial reasons, possibly supplemented by political goals and learning via technology transfer	Common form of ownership; with exception of WAGP, current Ghanaian pipeline infrastructure is wholly owned and operated by SOEs
International Oil & Gas majors	Usually as per upstream project sponsor; ie to develop export routes and markets for production	Similar to national companies, many international oil and gas majors are involved in pipeline construction. IOCs are part-owners of WAGP
Utilities and EPC construction firms	Distribution lines are often part of core business while knowledge and experience in the sector can be translated to transmission networks	Typically operate domestic gas distribution networks. Following privatization, many international utilities associated with gas distribution entered the pipeline market in Australia
Private Equity	Passive investor seeking financial return	Private equity investment is present in Alliance pipeline in North America as well as in Australia's privatized networks (eg Babcock & Brown Infrastructure Group)
Institutional investors (sovereign wealth funds, pension funds and insurance funds)	Low-risk long-term steady financial return, usually interested in operational rather than brownfield developments	China Investment Corporation hold stake in LNG facility in Trinidad. Pension Denmark hold stake in offshore wind projects while North American pension funds invested in UK-France Channel Tunnel rail link

Sources of project debt	Driver for investment	Examples
Commercial bank loans	Standard project financing arrangements albeit for large projects due to size usually involve a syndicate of banks. Domestic banks in developing markets typically demonstrate greater risk appetite particularly regarding political risk	Commercial bank loans are common for all infrastructure forms although in regions of high political risk some form of credit guarantee, high equity ratio or subordinate debt finance is often required to enable lending
National development banks loans	Provide low interest finance either in order to subsidise development or substitute for lack of market-based options. Can be done as subordinate debt via mezzanine financing	Typically issued via national development banks such as the KfW bank of Germany and BDNES of Brazil, both heavily involved in energy infrastructure financing
International development bank loans	Low interest inter-governmental financing to contribute to economic and social development of developing and undeveloped nations	Each of the World Bank and continental development banks (EBRD, ADB, AfDB and IADB) are heavily involved in infrastructure lending stretching to gas pipelines such as the WAGP
Export Credit Agencies (ECA)	To support market for export of goods from home country and support financing options of importer	The Baku-Ceylon pipeline received substantial ECA lending from Japanese, American and European agencies
Bond markets	Passive investors looking for steady low-risk return (pension and insurance funds often targeted here)	Project bonds are a major source of large-scale project finance in markets with liberalized infrastructure sector. Between 1996 and 2009, 72% of projects in UK larger than UK£500 million used bond financing[65]

[65] CBI (2012), "An offer they shouldn't refuse: Attracting investment to UK infrastructure"

A6.2 Forms of PPP for midstream infrastructure

A6.2.1 Concession

A concession is a long-term agreement (typically 25 to 30 years) where the private entity takes responsibility for capital investment, construction, operations and revenue collection of an asset or set of assets. A revenue stream, likely to derive from user tariffs, may be defined in the contract with regulated conditions on how is can be changed over the course of the contract. This is particularly important where a concession provides local monopoly conditions such as for gas and electricity pipeline networks, or rail transportation routes.

Concessions are an effective way to develop and refurbish facilities by leveraging private finance under conditions with a predicable level of returns. Further advantages of a concession are that it incentivises efficient running and innovation by the concessionaire as it gives full control over investment and operational costs as well as revenue collection. On the downside, contracts can be complicated due to the need for regulating tariffs while incentivising investment during the latter years of the concession period where pay-back time is limited can be difficult.

Concession contracts are a common structure for transmission and (particularly) distribution pipeline networks, an example of which is provided by Turkey as described in Box 2.

BOX 2

Turkey – Distribution pipeline tenders

The Turkish gas market has been undergoing gradual liberalization since the introduction of the Natural Gas Market Law in 2001. The provisions of the law included a measure to privatise local distribution companies. As of end 2011, the Turkish Energy Market Regulatory Authority (EMRA) had issued "in-city distribution licences" for 62 regions (55 under current tender regulations), all but two with private investment[1]. The tenders are perceived to have been very successful in raising private finance particularly from an array of local entities with an estimated TL 2.3 billion invested between 2003 and 2010[2].

To pre-qualify for a tender a company must meet minimum financial capacity (minimum shareholder equity of TL 1 million, approximately US$ 0.5 million) and experience criteria. The auction for qualified bidders then proceeds solely on the basis of proposed distribution charge (consisting of unit service and depreciation charges) valid for 8 years with the licence valid for 30 years. The 3 lowest bidding entities are invited to second bidding round before a final winner is announced. Time limits on investment and connection milestones discourage project delay.

[1] http://www.emra.org.tr/documents/strategy/publishments/Sgb_Rapor_Yayin_Yatirimciel_Kitabi_Eng_2012_xDJvq5GQTz98.pdf

[2] http://www.deloitte.com/assets/Dcom-Turkey/Local%20Assets/Documents/turkey_tr_energy_naturalgas_030512.pdf

A6.2.2 BOOT

A BOOT structure is a form of concession well suited to stand-alone easily defined green-field projects. It usually involves a tender process (preceded by a pre-qualification round) for a long-term (usually 20 to 40 years) concession to a private entity to build, own and operate a given infrastructure project. The project will be financed against revenues received during its concession lifetime, investment and operating costs are borne by the private company and, at the end of the concession period, the project will be transferred to the government (this last step is not always included and hence the arrangement becomes a BOO contract). A BOOT contract may either be designed as a result of government studies for a specified project or derive from an unsolicited proposal from a private player.

The BOOT structure, like a concession, encapsulates consideration of full lifetime costs and potential returns by the private sector partner and thus largely avoids the issue of misaligned incentives which can characterise narrower PPP contract forms. They are often project-financed with efficient leveraging of debt by experienced market players.

Potential drawbacks of this approach include the complexity of designing and managing a robust tender process that invites sufficient competition, while protecting the government-side from project non-delivery risk. The length of contract required is also substantial and therefore any bid must price-in significant uncertainty and risk regarding possible environmental changes that could occur through the project lifetime. As a result, political and regulatory risk is a key concern of potential bidders. Furthermore if used for a single pipeline development the project design and financing structure must be carefully defined in order to ensure the project is aligned with broader network developments. For this reason, in the context of this study a BOOT structure may be most suitable for LNG processing facilities and point-to-point transmission pipeline connections.

A6.2.3 Public–Private Joint–Venture

A JV represents a true partnership in that both the state and private entities will invest equity into a project, usually via a Special Purpose Vehicle (SPV) set up specifically for the project. Key advantages of this approach over a standard concession style contract are that it can encourage local capacity building within the government entity/SOE involved, while allowing for direct reflection of government objectives in project delivery. It is a popular approach for SOE where a new technology or technical process is being introduced and they keen to gain learning through the implementation process, as illustrated by the case study in Box 3 on shale gas development in China.

BOX 3

China – Shale gas Joint Ventures

China has long made use of JV partnerships in the energy industry between its SOEs and foreign private players to help build domestic capacity in an industry and facilitate technology transfer as well as maintain control over a sensitive sector. Shale gas is the most recent such drive where China is seeking to utilise foreign expertise, gained primarily from the US shale gas boom, via strategic partnerships with its large oil and gas SOEs. BP, Chevron, ConocoPhillips, and Shell are all currently involved in JVs in the country (albeit some of these companies played only a minor role in the US scene). China is able to attract this interest from major foreign players, despite the risk of political interference from an SOE partner and the possibility of giving away technical knowledge to a potential competitor, largely due to the sheer size of the market and potential rewards on offer.

However the need to operate on a JV basis has slowed down progress highlighting a drawback to stipulating such an approach[1].

[1] http://www.reuters.com/article/2013/09/17/column-russell-shale-asia-idUSL3N0HD0B820130917

Principal drawbacks of the public-private JV approach are the potential for political interference to discourage private sector involvement, as well as raising interface inefficiencies and risks between the respective scopes of work of each party.

A6.3 Potential financial support mechanisms

9.1.1 Direct support

Grants

Direct support for capital expenditure (Capex) can be provided most simply in the form of project grants in order to make a project financially viable. Advantages of this approach are the lack of complexity in administering the subsidy and its potential to help raise finance for early stage developmental technology. The latter justification derives from the wider social benefit which can potentially be gained from research and development of innovative technology or technical processes, for which the associated technical risk makes debt financing prohibitively expensive.

Examples include efforts in Europe and North America to develop Carbon Capture and Storage Technology (CCS)

The drawback of grant funding is that it targets only Capex rather than lifetime project costs. This can result in a bias within the economic case for a project towards the investment cost component and away from efficient operation of a facility. Grants can also be awarded in a somewhat ad-hoc fashion based on fast changing political dynamics and thus fail to provide long-term stable support to a given sector.

Viability Gap Funding (VGF) is a term for direct investment from government that can either be a grant as described above or an equity investment by a governmental entity. VGF has proved popular for infrastructure projects in India where around 200 PPP projects have received support in this way. The rationale is as stated for grants generally; a project provides net benefit based on a full cost-benefit analysis of all economic effects for society, but is not financially viable to a private sector firm as some benefits may not be fully internalized in project revenues. Even in this case a subsidy to revenues (thus rewarding efficient production) may be the most suitable option unless there is no direct tariff payment for the subsidy to be attached to. For example, this may be the case for some transportation projects where tolling is difficult or unattractive to implement, but is considered less likely to be the case for gas infrastructure projects.

An additional form of direct subsidy to Capex is to provide tax breaks on equipment purchases, often via reducing importation tariffs. For capital intensive projects where significant levels of material equipment must be imported, a reduction in taxation on these imports can be a significant incentive. This method has proved a popular approach for encouraging renewable energy development with Brazil, Poland and Turkey among the countries offering reductions on related import duties[66]. Downstream gas infrastructure projects are similarly capital intensive and so are likely to benefit from such a measure. Potential downsides are reducing government taxation intake, incentivising investment rather than efficient operation and creating market distortions between different industrial sectors due to varying tax rates.

Concessional finance

Of greater relevance here is support to loan repayments by offering a lending facility on improved terms to what is available in the private sector. Subsidised loans can be in the form of low interest rates or subordinate debt. These may be offered by national or international development banks or other quasi-governmental entities, namely export credit agencies. As with project grants, the basic rationale is to fulfil financing needs for projects which are attractive from a socio-economic perspective but where project risk (technical, commercial or political) is considered overly onerous to attract sufficient lending from the private sector at financially viable rates of interest.

Development banks may also be willing to take a longer-term perspective than shareholders will tolerate for commercial debt financing, a key advantage for infrastructure which is frequently expected to have a lifetime of many decades. The advantage of a loan over grants is the principle of encouraging discipline in project delivery and ensuring production is sufficient to cover debt repayments.

Examples of subsidised loans for infrastructure are numerous and widespread. Energy infrastructure in particular is a major recipient of international development bank loans which have provided consistent support to projects in regions with underdeveloped domestic financing sectors.

Subordinate debt finance and mezzanine financing is a variant of subsidised loan. Subordinate debt can enhance the credit rating of the remaining project debt by placing itself

[66] See KPMG 2012 report "Taxes and incentives for renewable energy" available at http://www.kpmg.com/Global/en/IssuesAndInsights/ArticlesPublications/Documents/taxes-incentives-renewable-energy-2012.pdf

lower in the ranking of creditors in case of loss, while mezzanine debt can be used to offer funding beyond the level a commercial bank is willing to bear.

Guarantees

Indirect financial support via the provision of commercial and non-commercial guarantees can also be used to provide security to investors and lenders and enhance a project's credit rating. Commercial guarantees can be used to insure a first loss debt tranche either for commercial bank loans or project bonds. An example of this approach has been adopted by the European Investment Bank (EIB) in their Europe 2020 Project Bond Initiative where up to 20% of debt may be covered under the mechanism.

Non-commercial guarantees cover all debt for non-performance on specific contractual obligations. They typically focus on political and regulatory risk issues which often present a significant barrier to funding, particularly in developing nations. This form of support is offered by commercial banks where they deem it feasible to do so, but it is a speciality of international development banks, most notably the World Bank via its Multilateral Investment Guarantee Facility (MIGA) and the European Union via its EU-Africa Infrastructure Trust Fund.

By virtue of being contingent rather than direct liabilities, such guarantees only affect a government's fiscal position in times of distress. Nevertheless the possibility of such unfortunate circumstances arising and contingent liabilities becoming real liabilities should not be discounted and distribution of guarantees must be monitored closely to avoid repeating the kind of unmanageable liability burden seen in South-East Asia during the Asian financial crisis of 1997-1998[67].

Revenue support

The neatest method of internalising a benefit through subsidies is to attach it to project revenues where this approach is feasible. This is because by aligning returns with production the government is incentivising cost efficient operation of an asset rather than its mere installation. For a gas distribution pipeline this may be calculated as a top-up to the tariff charged for actual throughput volume. This approach may be politically desirable in a situation where a large subsidy for an alternative fuel source has been in place and government wishes to encourage fuel-switching without causing the adverse social impact sudden withdrawal of the full subsidy may have. Nevertheless it does involve implementing a market distortion and has an opportunity cost attached to it by redirecting potential exports so justification should be carefully considered before this type of subsidy is implemented.

A more nuanced version of the approach is to differentiate between industrial and residential consumers (who receive gas supply at different pressures) and implement different top-up levels or a cross-subsidy between customer classes in order to protect the most vulnerable members of society.

For a back-bone transmission pipeline being developed as a stand-alone project there is a possible role for government revenue support in ensuring it is built with sufficient capacity

[67] Llanto, M. and Zen, F. (2013), "Government Fiscal Support for Financing Long-term Infrastructure Projects in ASEAN Countries" Discussion Paper No.2013-08, Philippine Institute of Development Studies.

to provide an economically-optimal throughput volume when other future planned developments are also completed. A private developer may be concerned of holding a stranded asset due to the risk of other upstream plans not being realised. Therefore in these circumstances the government could provide a 'minimum revenue guarantee' to the operator to insure against the possibility of other connections not coming on-stream.

A6.3.1 Indirect support

Project preparation

Governments can provide indirect subsidy during the pre-operational phases of a project's life by undertaking early stage project development work on a developer's behalf, or by relaxing procedures to enable more efficient project construction such as by easing immigration procedures for certain international staff.

The rationale for a government leading on early development work prior to tender award is based on the premise that there are a number of key risks during this phase which are better borne by government than private players. By performing this work the government not only reduces the Capex the developer will subsequently need to spend but, by reducing project risk, they can also reduce investor and lender hurdle rates.

Areas of risk better dealt with by government are focused on activities which require interaction with other government (central and local) agencies such as permitting and licensing issues. Environmental Impact Assessments (EIA) are another area where government assistance can provide an efficient contribution to project development. For instance, the Nabucco pipeline planned to run from the Caucasus to Central Europe had its feasibility study, incorporating an EIA, funded by the European Union.

Other early stage development work may include targeting technical areas of high exploratory risk in order to provide clearer indications to bidders on technical feasibility of the project.

A potential drawback of this approach is that it can place significant pressure on the institutional capacity of government agencies for carrying out, or managing procurement of, the tasks at hand. Delays may result affecting tender preparation and timetables by bidders. Furthermore the exact scope to be undertaken should be carefully selected to avoid over stretching by government agencies on technical issues most efficiently dealt with by experienced developers.

Indirect financial support

An indirect form of support for revenues is to increase the cost of alternative sources of supply although sound justification from a socio-economic perspective is required before following this route. Renewable energy projects benefit in this manner from carbon tax systems which increase the cost of fossil fuel energy. The justification in this case is internalizing a non-priced cost, ie the environmental damage caused by carbon emissions.

A6.3.2 Tax incentives

Revenue support can be provided via tax allowances or reductions on profits and dividends. This can be in the form of an income tax holiday or tax credits related to production (or throughput) volume as is the case in the American wind industry.

Alternatively, tax reductions can be applied to bond interest and dividend payments for specific green-field infrastructure projects. This approach has been followed in Korea and suggested for Australia[68] and the UK where it is highlighted for its appeal to institutional investors. A reduction in withholding tax for non-residents may be used as a way of encouraging foreign investment.

Another method of reducing payments during the operational phase of a project's life is to provide for accelerated depreciation on an asset's recorded value, thus reducing the tax burden. This is a method followed in Malaysia for general infrastructure projects in specified zones as well as in India for wind energy projects. While being a popular initiative in both countries and showing success in incentivising developments, the Indian case has been criticised for shifting owner's emphasis away from efficient generation and as a result the allowance was reduced sharply in 2012.

[68] Curran, M. (2013), "Tax incentives for Public-Private Partnerships", RMIT APEC Research Centre, available at http://www.apec.org.au/docs/Tax%20Incentives%20for%20PPPs.pdf

A7 Gas pricing policy implementation

Four main steps would be needed to successfully implement the pricing policy:

1: Re-write existing pricing policy -The existing pricing policy needs to be reviewed to bring it in line with the revised approach such as the recommendations of this report and the recent USAID funded publications. It is the Ministry's responsibility to determine the pricing policy, though an inter-agency task force could contribute to the proposals and ensure consultation.

2: Design gas regulatory framework–The re-designed pricing policy needs to be translated into a fully specified gas pricing regulatory framework. The framework needs to specify the following items among others: approach and detailed methodology applied for price setting, institutional responsibilities, the price review process, responsibilities of the regulated companies.

3: Strengthen PURC–PURC will be the key entity in the gas regulation process and its role and capabilitiesmay need to be strengthened, given this is a relatively new and growing sector. Firstly, PURC must be assured of political and legal backing to act independently and to freely apply the regulations outlined in Section 7. Secondly, capacity building of PURC staff may be needed to expand PURC's role in applying the regulatory procedures in an expanding sector. This may include the need for regulatory tools to be developed.

4: Define responsibilities of regulated companies– Ensure their ability to maintain records, provide the regulatory information and implement regulatory decisions.