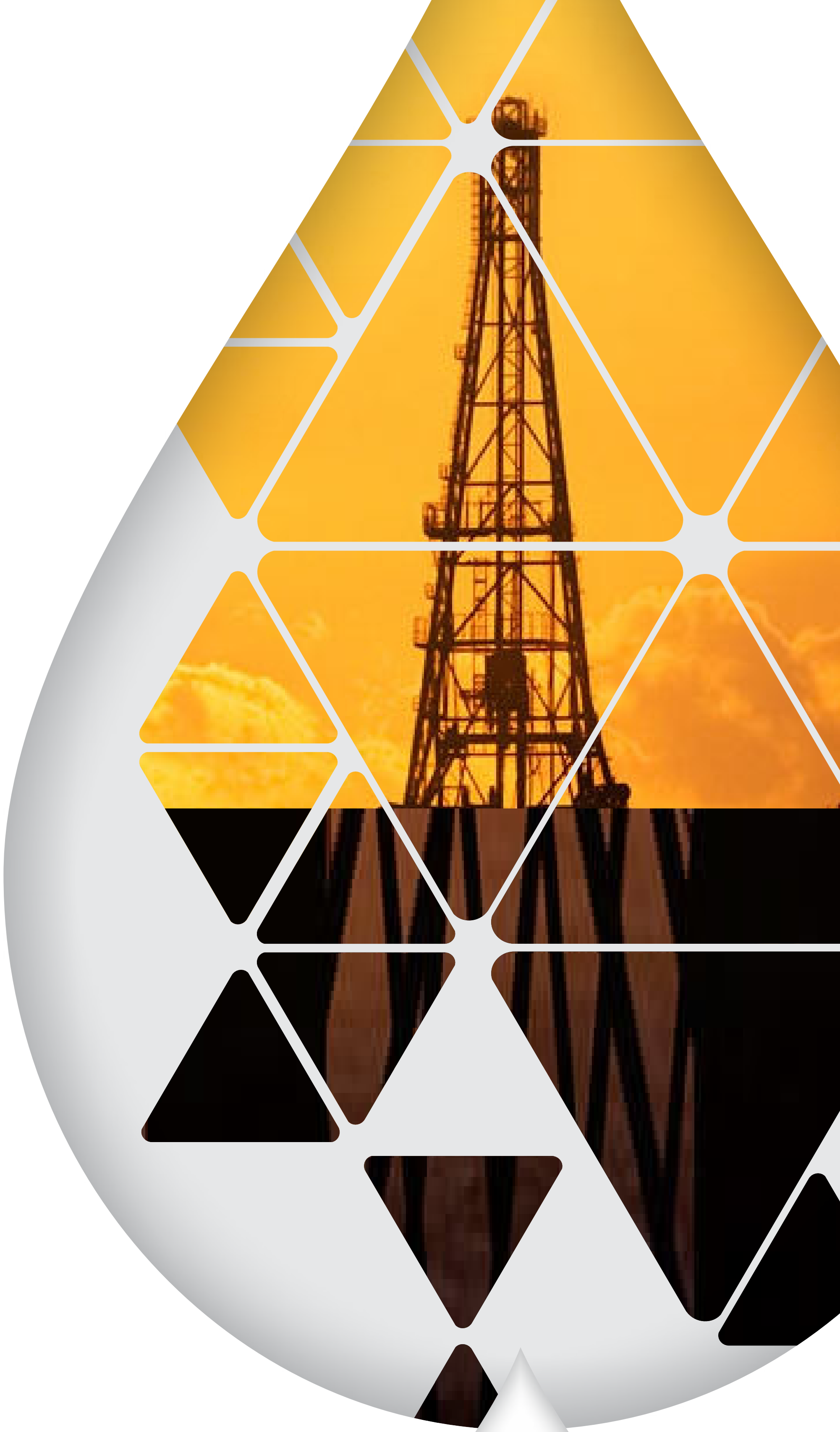
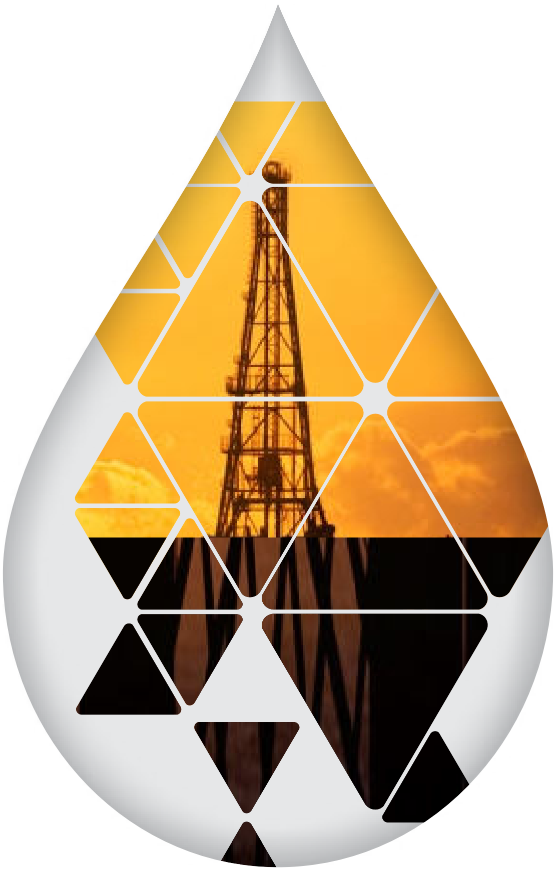
GHANA CHAMBER OF BULK OIL DISTRIBUTORS



2020/21

Ghana Petroleum Industry Report

In Partnership With



2020/21

Ghana Petroleum Industry Report

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Acknowledgment

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List of Abbreviations & Definitions

AfCFTA
African Continental Free Trade Area

ABB
All Buoy Berth

ABFA
Annual Budget Funding Amount

AGPP
Atuabo Gas Processing Plant

AMV
Africa Mining Vision

APD
Accra Plains Depot

BDC
Bulk Distribution Company

BoG
Bank of Ghana

BOST
Bulk Oil Storage and Transportation

BRV
Bulk Road Vehicle

COMPANIES ACT
The Companies Act, 2019 (Act 992)

CBOD
Ghana Chamber of Bulk Oil Distributors

CWM
Cash Waterfall Mechanism

COT
Cirrus Oil Terminal

CREPT
Credit Rating in Practice

CSPOG
Civil Society Platform on Oil and Gas

DIDT
Discounted Industrial Development Tariff

DWCTP
Deepwater Cape Three Points

DWT
Deepwater Tano

EIA
Environmental Impact Assessment

EPA
Environmental Protection Agency

EPA Act
Environmental Protection Agency Act, 1994 (Act 490)

ESIA
Environmental and Social Impact Assessment

ESLA
Energy Sector Levies Act

ESRP
Energy Sector Recovery Programme

FC
Forestry Commission

FIA
Fisheries Impact Assessment

FPSO
Floating Production Storage and Offloading

FOB
Free on Board

FX
Foreign Exchange

FLUR
Forex Loss Under Recovery

GCC
Ghanaian Content Committee

GHS
Ghana Cedi

GHF
Ghana Heritage Fund

GIPC
Ghana Investment Promotion Centre

GIPC Act
Ghana Investment Promotion Centre Act, 2013 (Act 865)

Ghana Petroleum Funds
Collectively the Ghana Heritage Fund and the Ghana Stabilisation Fund

GNPC Act
Ghana National Petroleum Corporation Act, 1983 (PNDCL 64);

GNPC
Ghana National Petroleum Corporation

GPS
Global Positioning System

GPRS
General Packet Radio Services

GSA
Gas Sales Agreement

GSF
Ghana Stabilisation Fund

GOGIP
Ghana Oil and Gas Insurance Pool

GOVERNMENT
The Government of the Republic of Ghana

GoG
Government of Ghana

GRA
Ghana Revenue Authority

HSE
Health, Safety and Environment

IFC
International Finance Corporation

IGC
Indigenous Ghanaian company, being a company incorporated under the Companies Act that has at least 51% of its equity held by a citizen of Ghana; and at least 80% of its executive and senior management positions and 100% of non-managerial and other positions also held by citizens of Ghana.

IMP
International Market Price

INCOME TAX ACT
Income Tax Act, 2015 (Act 896)

INSURANCE ACT
Insurance Act, 2006 (Act 724)

INTERNAL REVENUE ACT
Internal Revenue Act, 2000 (Act 592) (as amended)

IOC
International Oil Company

IVM
In-Vehicle-Management

LBT
Land Boundary Terminus

LBL
Legacy Bonds Limited

LCO
Light Crude Oil

LPG
Liquified Petroleum Gas

Local Content Regulations
Petroleum (Local Content and Local Participation) Regulations, 2013 (LI 2204)

Measurement Regulations
The Petroleum (Exploration and Production) (Measurement Regulations), 2016 (LI 2246)

MGO
Marine Gasoil

Minister
Minister of Energy

NDPC
National Development Planning Commission

NIC
National Insurance Commission

NPA
National Petroleum Authority

NGTIN
Natural Gas Transmission Infrastructure Network

OCTP
Offshore Cape Three Points

OMC
Oil Marketing Company

OMA
Operation Management Agreement

OTC
Oil Trading Company

PA
Petroleum Agreement

PC
Petroleum Commission

Petroleum Commission Act
Petroleum Commission Act, 2011 (Act 821)

Petroleum Data Management Regulations
Petroleum (Exploration and Production) (Data Management) Regulations, 2017 (LI 2257)

Petroleum Fees and Charges Regulations
Petroleum Commission (Fees and Charges) Regulations, 2015 (LI 2221)

PEPA
The Petroleum (Exploration and Production) Act, 2016 (Act 919)

Petroleum General Regulations
Petroleum (Exploration and Production) (General) Regulations, 2018 (LI 2359)

Petroleum HSE Regulations
Petroleum (Exploration and Production) (Health, Safety and Environment) Regulations, 2017 (LI 2258)

PHF
Petroleum Holding Fund

PIAC
Public Interest and Accountability Committee

Petroleum Measurement Regulations
The Petroleum (Exploration and Production) (Measurement) Regulations, 2016 (LI 2246)

PITL
Petroleum Income Tax Law 1987 (PNDCL 188)

PNDCL 84
The Petroleum (Exploration and Production) Act, 1984 (PNDCL 84)

PPM
Price Parity Margin

PMS
Premium Motor Spirit

PRMA
Petroleum Revenue Management Act, 2011 (Act 815)

PSP
Petroleum Service Provider

RAA
Revenue Administration Act, 2016 (Act 919)

RFO
Residual Fuel Oil

RFID
Radio Frequency Identification Device

RSL
Road Safety Limited

RVF
Real Value Factor

SORF
Sanzule Onshore Receiving Facility

SEIA
Strategic Environmental Impact Assessment

SPT
Special Petroleum Tax

TDS
Takoradi Distribution Station

TFC
Tema Fuel Company

TOR
Tema Oil Refinery

TTF
Tema Tank Farm

TTIP
Takoradi-Tema Interconnection Project

UNFCCC
United Nations Framework Convention on Climate Change

UPPF
Unified Petroleum Price Fund

WAGP
West African Gas Pipeline

WCTP
West Cape Three Points

WTI
West Texas Intermediate

Units

BBLS
Barrels

BCF
Billion cubic feet

bn
Billion

GHS
Ghana Cedis

ltrs
Litres

mmscf
milliion standard cubic feet

mn
Million

mt
Metric tonnes

ppm
Parts per million

USD
US Dollar

$
US Dollar

Executive Summary

The 2020/21 Ghana Petroleum Industry Report is an amalgamation of the 2020 and 2021 Industry reports. The Report extensively reviews Ghana's upstream and downstream petroleum sectors spanning policy, finance, infrastructure, and market activities in 2020 and 2021. The Report also highlights key developments and risks faced by the industry and provides recommendations for consideration by stakeholders.

The in-depth analysis of this report intends to provide insight and relevant information to industry players, policymakers, academics, and business leaders to be able to make informed business, investment, and policy decisions. The Report has been segmented into eight chapters; the first four chapters review developments in the upstream whiles the remaining four chapters review developments in the downstream sector.

The outbreak of Covid-19 during the period under review had a severe impact particularly on the upstream petroleum sector globally. Due to the restrictions implemented to contain the spread of the Virus, industrial activities slumped, resulting in the oil market's collapse. Hence, the period saw Brent Crude falling from an average of $63.5 per barrel in January 2020 to $32 per barrel in March and further to a record low of $18.38 per barrel in April 2020. Due to the unprecedented fall in crude prices in 2020, the government-projected receipt of $761.5 million in 2020 was revised down to $285.8 million, leading to a revenue shortfall of $475.7 million. However, the recovery from the pandemic outbreak resulted in relatively favourable international prices in 2021. Therefore, total receipts from petroleum production increased from $666.39 million in 2020 to $783.33 million in 2021, although production in 2020 was higher than that of 2021.

Some key developments in the downstream sector in 2020 and 2021 were the establishment of the Petroleum Hub Development Corporation and the commencement of the development of the National Energy Transition Policy. The government of Ghana proceeded with its commitment to turn Ghana into Africa's first petroleum hub with the enactment of the Petroleum Hub Development Corporation ACT1053, to promote and develop a Petroleum and Petrochemicals Hub. The Hub is to be located on a 20,000-acre parcel of land, along the coastline of the Jomoro District of the Western region. The Petroleum Hub has been structured to be developed in 3 phases, with specific projects earmarked for construction under each phase.

For the period under review, the National Energy Transition Committee was commissioned to develop a national energy transition policy to evaluate the current energy sector, set national objectives and targets for the energy transition, and prescribe policies and measures for achieving these targets as well as assess the benefits, risks, and costs of the global energy transition.

Also, the Cylinder Recirculation Model (CRM), which is part of the National LPG Promotion Policy to ensure that 50% of Ghanaians have access to safe, clean, and environmentally friendly LPG for domestic, commercial, and industrial usage by 2030, was piloted in five regions across the country. An impact assessment carried out in two of the pilot regions to ascertain the impact of the pilot CRM revealed that the inadequate and untimely supply of branded cylinders affected the smooth running of the pilot program. However, some stakeholders believe that introducing new players in the supply chain will lead to a rise in the pre-tax cost of bottled gas and may require the Government to favorably consider proposals for the downward revision of taxes to compensate for any rise in pre-tax prices.

As of the end of 2021, the total number of BIDECs stood at forty-one (41), compared with thirty-six (36) in 2020, with the top ten (10) importing 75% of the total petroleum products imported in 2021. An analysis of BIDECs' sales volume performance for 2021 also revealed that the top ten (10) BIDECs supplied 72% of petroleum products to the market. Notwithstanding, the BIDEC market has witnessed an increase in competition since 2013. The Herfindahl-Hirschman Index (HHI) showed a declining trend between 2013 and 2021, suggesting that the market is less concentrated, even though not highly competitive.

The number of OMCs also increased from 192 in 2020 to 230 in 2021, representing an increase of 20%. The increase in the number of OMCs significantly influenced the market dynamics of the industry, with the market share of the top 10 OMCs declining from 59% in 2020 to 56% in 2021. Moreover, the period also witnessed the number of retail outlets growing considerably from 2,745 in 2017 to 4,557 in 2021, representing an increase of 66%.

While the number of BRVs increased from 2,179 in 2013 to 4,413 in 2021, the average volume carried per BRV declined from 1,543 MT in 2013 to 1,050 MT in 2021. This calls into question the viability and sustainability of the transporter sub-sector.

For the period under review, the estimated suppliers' premium for petrol in 2021 ranged between -\$31.25/mt and \$93.19/mt while that of diesel ranged between \$3.66/mt and \$94.06/mt averaging \$53.07/mt. However, compared to 2020, suppliers' premiums plummeted in 2021.

The resulting shortfall in the government's receipts from the sales of petroleum products in 2020 due to the pandemic, led to the institution of two additional levies (the Energy Sector Recovery Levy (ESRL) and the Sanitation and Pollution Levy (SPL)) which imposed a 20 pesewa and a 10 pesewa levy respectively on the price per litre of petrol/diesel in 2021.

The GRA reported a total actual petroleum tax collection of Ghs8,180.63 mn in 2021 and Ghs6,299.31 mn in 2020, representing a 30% growth in actual collections. Notwithstanding this growth, the reported collections for the two years (2020 and 2021) are less than the expected collections estimated by the CBOD (Ghs1.22 bn). The expected collections estimated by CBOD are calculated based on official volumes procured from the NPA and adjusted by the reported exemptions and revenue losses where applicable. This continued the trend of under-reported taxes observed from 2015 to 2019. Comparing contributions to Government's total revenue by the upstream and downstream sectors, the downstream sector contributed \$1,336.49 while the upstream contributed \$783.33 in 2021. This shows the dominance of the downstream sector's contribution to total revenues compared to the upstream sector's contribution.

The period under review saw gross national consumption increase by 8.92% from 4.26 mn mt in 2020 to 4.64 mn mt in 2021. A total of 4.55mn mt was consumed by the non-power sector, representing 98% of the gross consumption, while 2% was consumed by the power sector (fuel oil for power). The growth in consumption by the non-power sector was due to the increase in consumption of Gasoline, Gasoil, Residual Fuel, Marine Gasoil (Foreign), Premix, ATK, Gasoil (mines), and LPG Domestic. However, MGO Local dropped by 55% from 2020 to 2021, whilst Gasoil Rig also decreased by 8% from 2020 to 2021. ATK witnessed a significant increase in volume consumed after recording a drastic decrease in 2020 due to the outbreak of the COVID-19 pandemic.

Proper supervision should be carried out to ensure the menace of tax evasion is eliminated in the downstream sector. Moreover, the government should consider clearing some of the taxes on the price build-up of LPG as this will enhance the attainment of the LPG promotion policy target.

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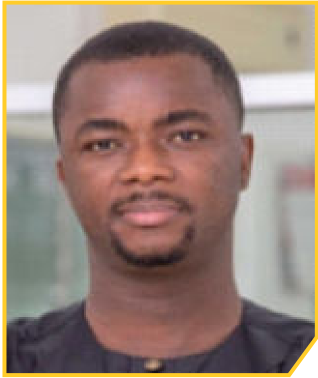

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Key Personalities In The Industry

Dr. Matthew Opoku Prempeh
Minister for Energy, Ghana

Dr. Matthew Opoku Prempeh, is the Minister for Energy and the Member of Parliament (MP) for the Manhyia South constituency in the Ashanti Region. He was born on May 23, 1968 in Kumasi, where he went on to have his primary, secondary and tertiary education.

At the Kwame Nkrumah University of Science and Technology (KNUST), he obtained a Bachelor of Science (BSc) degree in Human Biology in 1992 and a Bachelor of Medicine and Surgery (MB,ChB) degree in 1995. After serving as a House Officer at the Okomfo Anokye Teaching Hospital from 1995 until 1997, Dr. Prempeh continued his education at the Erasmus University in The Netherlands, obtaining an M.Sc in Clinical Epidemiology in 1998. He proceeded to the United Kingdom to work, becoming a member of the Royal College of Physicians and Surgeons in Glasgow in 2002. He returned to Ghana in 2003 to pursue a career in business and politics.

He is also a Harvard Scholar and an alumnus of the Harvard Ministerial Leadership Program.

Political Career

Dr Matthew Opoku Prempeh ran for Parliament on the ticket of the New Patriotic Party (NPP) during the 2008 general elections and won the mandate to represent the people of Manhyia. Subsequently, the constituency was divided into two and he went on to become Member of Parliament for the Manhyia South Constituency in 2012. He retained the seat at the 2016 elections and again at the 2020 elections.

Following the victory of the NPP in the 2016 general elections, Dr. Prempeh was appointed by President Akufo-Addo as Minister for Education from 2017 to 2021. During his tenure, he successfully led the team at the Ministry to deliver on the flagship education programme of the government, the Free Senior High School programme, to wide admiration even from his political opponents. His team also delivered on curriculum reforms, teacher reforms and several initiatives to promote and mainstream Technical, Vocational Training and Education (TVET), among others.

In the aftermath of the NPP's victory at the 2020 general elections, President Akufo-Addo nominated Dr. Prempeh to serve as Minister for Energy. He has since championed various major projects including ensuring 100% electricity access rate by 2024 (Current access rate is 87.03%); renegotiation of Power Agreements; the revamping of Ghana's cylinder manufacturing company and improvement of the cylinder recirculation model to meet Ghana's clean energy goals; the establishment of a petroleum hub; revision of local content legislation, improving the efficiency of electricity producers and distributors; and relieving the energy debt stock of Ghana through the Energy Sector Recovery Programme (ESRP).

Awards

Dr. Matthew Opoku Prempeh was adjudged the best Minister in 2017 and 2019 and is the recipient of the 2020 Harvard Ministerial Medal of Achievement in recognition of his exemplary leadership style. He has also received 2 Honorary Doctorates from the University of Education, Winneba and the University of Professional Studies, Accra, for his leadership and achievements as Education Minister. He was also recently named in the top 25 Movers and Shakers in the Energy Sector by the African Energy Chamber.

Dr. Mohammed Amin Adam

Dr. Mohammed Amin Adam is a politician with considerable experience in the energy and petroleum sector.

He has held many positions in Government. He was the Metropolitan Chief Executive of Tamale and Deputy Northern Regional Minister during the Kufour Administration. Under President Akufo-Addo's government, he has been Deputy Minister for Energy since 2017. He is currently a Member of Parliament for the Karaga Constituency and serves on the Finance Committee and Defence and Interior Committee in Parliament.

He has worked extensively on extractive industries and resource management as a university lecturer, advisor and resource governance advocate. He has advised governments and provided technical support to civil societies and parliamentary committees on energy, mines and finance in several countries, including Ghana, Liberia, Sierra Leone, Uganda, Tanzania, Senegal, South Sudan and Kenya.

Before joining the Ministry of Energy as Deputy Minister, Dr. Adam was the Founder and Executive Director of the Africa Centre for Energy Policy (ACEP). He also worked as an Energy Policy Analyst at the Ministry of Energy in Ghana, Commissioner of Ghana's Public Utilities Regulatory Commission, and was also the Africa Coordinator of extractives industries in Ibis.

He has held Board positions in global organizations such as the Open Contracting Partnership; the Natural Resources Community Review; the Advisory Committee of the International Finance Corporation-World Bank Disclosure to Development Program, and has been appointed by the Finance Minister as Ghana's Champion of the Extractive Industries Transparency Initiative (EITI). He is also now chairing the National Energy Transition Committee.

Locally, he held board positions in Weston Oil and Gas Fund; and Zoil Oil Waste Services, among others.

Dr. Adam is an accomplished professional with extensive consulting background. He has consulted for the World Bank, the International Labour Organization, UNDP, STAR-Ghana, African Center for Economic Transformation, Oxfam, the Natural Resources Governance Institute, and the United Nations Economic Commission for Africa, among others. He has been an Expert Witness at the Committee on Foreign Affairs of the US Congress - testifying on how Africa could end the Resource Curse in the management of her natural resources.

Dr. Adam has strong academic credentials with more than 10 scholarly and public policy publications. He has taught graduate courses in Petroleum Economics at the University of Professional Studies, Accra, and also taught at the Columbia Center for Sustainable Development Online Moot Course on Petroleum Revenue Management. He has been a visiting speaker at University of Houston Law Center, University of California - Santa Cruz, University of Seattle, University of Stanford, the Brookings Institution in Washington DC, and Chattam House in London.

Dr. Adam holds a PhD. in Petroleum and Energy Economics from the University of Dundee in the United Kingdom; Master of Philosophy in Economics and Bachelor of Arts Honours in Economics from the University of Cape Coast. He also has Executive Certificate Education from the Columbia University in New York, the EcoMod Modeling School in Washington D.C; and the University of Texas at Austin. He had his secondary education at NOBISCO and TAMASCO, which opened the gate for what can be described as an excellent career.

He is a Fellow of The Institute of Chartered Economists Ghana, Member of the Executive Session on the Politics of Extractive Industries of the Columbia University, Member of the International Research Collaborative on Natural Resource Governance, Inequality and Human Rights, Law and Society; Member of the Sustainable Energy for All Network; and Member of the Governance of Extractive Industries Network.

Andrew Kofi Egyapa Mercer is Deputy Minister for Energy and Member of Parliament for Sekondi Constituency in the Western Region of Ghana.

Andrew Mercer is also a lawyer with extensive corporate, commercial and finance sector practice experience. Prior to his appointment as Deputy Minister, he served as Lead Attorney and Chief Executive of Messrs. Mercer & Company, a corporate and investment law firm based in Accra. He previously served as the head of the Legal Division of First Atlantic Bank; overseeing the Legal, Company Secretarial and Corporate Affairs Departments of the Bank.

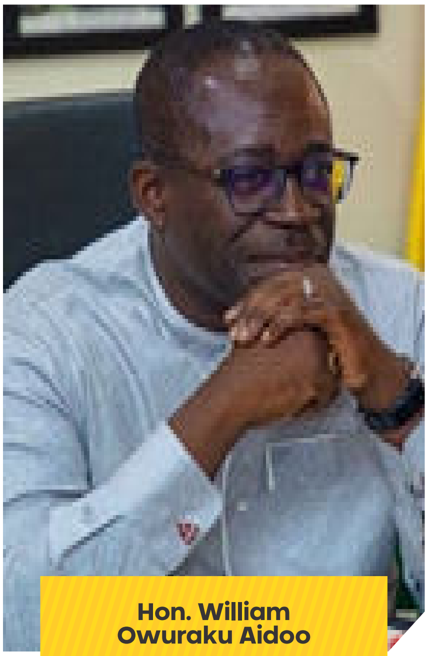
Andrew also had a previous practice stint with Messrs. Acquah-Sampson & Associates where he commenced his legal practice initially as a pupil and subsequently as Senior Associate before joining the Bank.

Presently, he serves on the Constitutional, Legal & Parliamentary Affairs, the Privileges and the Special Budget Committees of Parliament. He previously served on the Communications Committee of Parliament.

He is a Member of the Ministerial Advisory Board of the Ministry of Energy and has previously served on several Boards of corporate entities in both the public and private sectors.

Andrew is married and has 3 children.

Andrew Kofi Egyapa Mercer



Hon. William Owuraku Aidoo

Honourable William Owuraku Aidoo is a Ghanaian Politician and a member of the 6th, 7th and 8th Parliament of the Fourth Republic of Ghana, representing the Afigya Kwabre South Constituency in the Ashanti Region on the ticket of the New Patriotic Party.

He was born on January 30th, 1964 and hails from Hemang-Kwabre in the Ashanti Region of Ghana. He obtained his GCE O LEVEL from Opoku Ware Secondary School and received his Bachelor of Laws (LL.B) Degree from the Ghana Institute of Management and Public Administration (GIMPA) in 2013.

Hon. Aidoo is an Energy Consultant and a Farmer. Prior to entering politics, he was the Managing Director of Kucons Company Limited, a construction company involved in the construction and rehabilitation of dams. He also served as a Police Officer in the United Kingdom, being the first Black Police Officer in Sussex. As a farmer, he won the National best farmer award for cashew production in Ghana in the year 2011.

He is currently the Deputy Minister for Energy, having served in the same capacity from 2017- 2020 during which time he was in charge of the Power sector. He is currently a member of the Board of Directors of Nuclear Power Ghana, an institution with focus on adding nuclear power to the energy mix of Ghana.

Hon. William Owuraku Aidoo is married with five (5) children.

Dr. Mustapha Abdul-Hamid was born on the 14th of June 1971 in Tamale, in the Northern Region of Ghana. He attended the then Station Experimental Primary School at the Kamina Barracks from 1976- 1982. In 1982, he gained admission into Bawku Secondary School, where he sat for the Ordinary Level Examination in 1987. He then proceeded to Tamale Secondary School for his Sixth Form education.

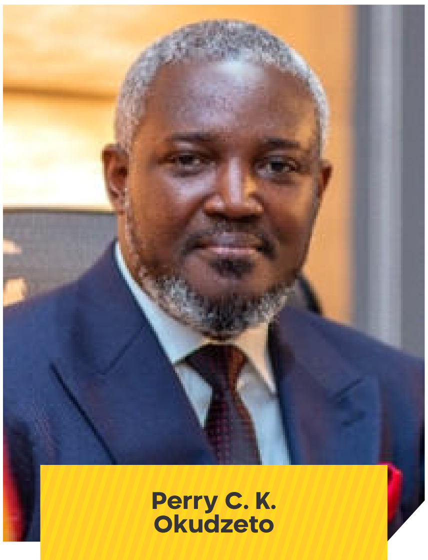
Dr. Abdul-Hamid wrote the Advanced Level Examination in 1989 and then entered the University of Cape Coast in 1991, where he was offered admission to study Classics, English and Religion. He majored in Religious Studies. He was admitted to the Bachelor of Arts Degree in 1996, with Second Class Honours, Upper Division. He also obtained a Diploma in Education, which he undertook concurrently with the Degree. Dr. Abdul-Hamid later obtained an M.Phil in Religious Studies, also from the University of Cape Coast. In 2018 he completed his Ph.D programme in the same university.

In 2003, he entered full time politics, and became the National Youth Organizer of the New Patriotic Party (NPP). In 2007, he became Spokesperson for the then Presidential candidate of the New Patriotic Party (now President of Ghana), Nana Addo Dankwa Akufo-Addo, until February 2017. Dr. Abdul-Hamid was also a Lecturer in the Department of the Religion and Human Values at the University of Cape Coast between August 2009 and April 2014. He was later promoted to Senior Lecturer in April 2014, a position he held until February 2017.

He has published widely in scholarly journals around the world. In February 2017, He was appointed Minister of State in charge of Information and Government Communications. In August, 2018, he was reassigned to be Minister for Inner City and Zongo Development. In 2020, he was appointed the Deputy National Campaign Manager for the New Patriotic Party for the Presidential Elections. He has a reputation for upholding honesty and integrity in his public life. He is currently the Chief Executive Officer of the National Petroleum Authority.

Mrs. Linda Asante was appointed a Deputy Chief Executive of the National Petroleum Authority in March 2022. She has nearly two decades experience in the Petroleum Downstream Industry having started her career with a short stint at the Tema Oil Refinery as a Chemist in 2005. She subsequently joined the National Petroleum Authority following its establishment in 2005 as a Planning Officer where she rose through the ranks to serve as Planning Manager from 2010 till 2013 and subsequently promoted to the position of Takoradi Zonal Manager from 2013-2017. Mrs. Asante was later re-assigned in 2017 to the Head Office to oversee the Planning Department - a position she held until she was appointed a Deputy Chief Executive, becoming the first ever staff to be appointed to that role. She is an active member of the African Refiners and Distribution Association Workgroup in charge of Fuel Storage and Distribution. She has also served as the Chairperson for the Welfare Association of the National Petroleum Authority for three consecutive terms.

She holds an MSc (Oil and Gas Management) from the Ghana Telecom University and a BSc (Chemistry) from the University of Cape Coast.



Perry C. K. Okudzeto is an all-rounder, Communications strategist, a highly motivated and organized personality. Has interest and experience in Sales, Marketing, Advertising and political campaign communications.

He has a career background in International Public Relations.

He has several years of experience in managerial positions coupled with appointments at the Ministerial level as former Deputy Minister of Information and Deputy Minister of Youth and Sports.

He possesses great interpersonal skills and has the ability to work in multiple sectors. He is an advocate for entrepreneurship, domestic production and consumption of local goods.

Currently a Deputy Chief Executive at the National Petroleum Authority, helping to steer, oversee, monitor and regulate activities of players in the Petroleum downstream sector in Ghana.

Senyo is a finance and economic policy analyst with management experience in various industries including downstream petroleum, finance, logistics and commodity trading. He has an MBA in Finance and an MA in Economic Policy Management from the University of Ghana.

He has played a key role in the development and implementation of major policies in Ghana's energy sector. In particular, the deregulation of the downstream petroleum sector, the use of low-sulphur fuel, and the conceptualization and rationalisation of the Energy Sector Levies Act and its subsequent debt management interventions.

He is the Managing Trustee of Ghana's COVID-19 Private Sector Fund which led major interventions in the fight against COVID-19. He is the first and current Chief Executive Officer of Legacy Bonds Limited and Kleeve & Tove Limited. He also previously served as the Chief Executive Officer of the Ghana Chamber of Bulk Oil Distributors for a decade till August 2022.

He is an advisor to the Ministry of Energy and sits on the boards of several public and private organisations including, the Ghana Highways Authority, the Private Enterprise Federation, Legacy Bonds Limited and AppsNmobile Solutions Limited.

Kwaku Agyemang-Duah has been involved in the industry since 1987. He has worked in various senior management capacities in health and safety, production/operations, marketing, logistics and projects.

He is also an astute Quality Management systems expert and served on the Ghana Quality Standards Committee in the 1990's. Currently, he is the CEO/Industry Coordinator of the Oil Marketing Association of Ghana with more than one hundred Oil Marketing Companies and LPG Marketers. He is also the Chairman of the Governing Council of the Private Enterprises Federation, an organisation of fourteen major private associations in the country.

Kwaku holds a degree in Engineering and a Post-Graduate Diploma in Industrial Management as well as an MBA in Finance.

Dr. Ben K. D. Asante, a renowned Oil and Gas Engineer, is the Caretaker Chief Executive Officer (CEO) of the Ghana National Gas Company (Ghana Gas). He has over 25-years global experience in the Oil and Gas industry. He is one of few black Oil and Gas engineers to have testified as an expert pipeline engineer before the US Supreme High Court.

He has also provided expert witness testimonies on gas custody transfer disputes in South America.

Dr. Asante is a Lecturer at the School of Engineering, Kwame Nkrumah University of Science and Technology (KNUST) and a former Engineering and Technical Director of Ghana's premier Gas Infrastructure project, which birthed the Atuabo Gas Processing Plant and allied gas infrastructure in the Western Region. He is the mastermind of Ghana's first Gas Master Plan in 2008.

He has also provided consulting, engineering services, project management, and technical support for various projects throughout the world, including the World Bank and Asian Development Bank (ADB). He has also worked in various technical and management roles for major Operating Companies and Engineering Consulting companies in Canada, including Nova/TransCanada; US and Ghana. He was adjudged the Best Worker for the Year for Excellence at the global energy firm, Enron Corporation, in 2001.

Dr. Ben K. D. Asante

Dr. Asante holds a BSc in Chemical Engineering from KNUST, Ghana and MSc in Chemical Engineering from the University of Calgary, Canada. He also obtained a PhD in Chemical Engineering from Imperial College, London/University of Calgary, where he later taught Gas Processing and Pipeline Engineering.

He has published 15 technical papers and made over 80 technical presentations within and outside North America on Oil/Gas Infrastructure Design and Operations.

Dr. Kofi Koduah Sarpong is a Ghanaian by birth born on 10th September, 1954 and hails from Beposo near Nsuta in the Ashanti Region of Ghana. Dr. Sarpong is married with adult children.

He began his primary education in his hometown. He then proceeded to the SDA Secondary School, Bekwai Ashanti from 1968 to 1973 and later to Sekondi College from 1973 to 1975 for his GCE 'O' Level and GCE 'A' Level certificates, respectively. Thereafter, Dr. Sarpong attended the University of Ghana where he obtained a Bachelor of Science (B.Sc.) degree in Business Administration and a Master of Business Administration (MBA).

Dr. Kofi Koduah Sarpong

He was also awarded a Master of Arts (MA) in Ministry from the Trinity Theological Seminary (Legon), a Master of Accountancy (M.Acc.) in International Accounting and Multinational Financial Management from the University of Glasgow (Scotland), and a Doctor of Philosophy (PhD) degree in Industrial & Business Studies from University of Warwick (England).

Dr. Sarpong qualified as a Chartered Accountant (CA Ghana) with the Institute of Chartered Accountants (Ghana) nearly four decades ago.

Dr. Sarpong has been in executive management for nearly thirty-five (35) years. Dr. Sarpong served as Chief Executive of Ghana National Petroleum Corporation (GNPC) from January 2017 to April 2022.

Dr. Sarpong has had an extensive Board exposure in twenty-six (26) organisations spanning financial services, transportation, manufacturing, commerce, mining, energy, education, NGOs and sports. Dr. Sarpong devotes his own resources to educate persons who show academic promise and assist persons with disabilities.

Edwin Alfred Provencal before his appointment as the Managing Director of the Bulk Oil Storage and Transportation (BOST) Company Limited was the Technical Advisor to the Minister of Energy, Hon. John Peter Amewu, now Minister for Railway Development and MP for Hohoe Constituency.

He has over 15 years' experience in Executive Management roles in various organizations including serving as Chief Executive Officer (CEO) of Vodafone Wholesale/National Communications Backbone Company and Director of Strategy in Vodafone Ghana. Under his leadership, Vodafone leapfrogged from #3 to #2 in Revenue Market Share in the telecoms industry.

His other places of work include Ghana Telecoms, K-Net; a leading Internet Service Provider in Ghana where he successfully managed over fifteen (15) projects including Wide Area Networks for Ghana Commercial Bank, Standard Chartered Bank, VALCO, Ghana Bauxite amongst others as well as Globacom Ghana Limited.

Mr. Provencal holds amongst other qualifications an MPhil in Economics as well as MBA in Management Information Systems (MIS) from the University of Ghana, Legon. He is also a product of the Kwame Nkrumah University of Science and Technology (KNUST), Kumasi where he graduated with a BSc in Electrical Engineering.

He obtained a Post Graduate Diploma in Financial Management from ACCA and he is a Project Management Professional (PMP) which he attained from the Project Management Institute in USA.

Mr. Provencal was a visiting lecturer at the Central University Business School and Regent University in Ghana.

He is the founder and managing Partner of Provencal & Associates with a keen focus on improving shareholder value by building high performing teams and developing leaders using various tools such as the Balanced Scorecard, Project Management and Coaching.

He was appointed the Managing Director of BOST in August 2019 and was recently adjudged the Petroleum CEO of the year 2022 in the Ghana Energy Awards.

Benjamin Boakye is an Energy Governance Professional and the Executive Director of the Africa Centre for Energy Policy (ACEP). In this role, he provides strategic oversight for delivering ACEP's vision of an Africa where energy and extractive resources are utilized for economic transformation and sustainable, inclusive development. Prior to becoming the Executive Director, he served as the Deputy Executive Director, Programmes Director, and Operations Director, managing the Research Unit and the Programmes Unit.

Over the last decade, Benjamin has contributed to the extractive sector governance in Ghana and Africa, with much focus on corporate governance, institutional development, fiscal governance, contract governance, local content development and the evolution of legal frameworks for the effective management of extractive resources. He has written extensively on these areas in the petroleum, mining, and power sectors. He has recently contributed a book chapter on "Utilizing Ghana's Gas Resources: Implications for Industrial Development and Inclusive Growth" to a Palgrave MacMillan book titled "Petroleum Resource Management in Africa: Lessons from Ghana." He has also consulted for the World Bank Group, UNDP, and many research institutions in the resource sector.

He has spoken at various international conferences on the extractive sector, particularly on extractive revenue management and fiscal governance. In addition, he works with host communities, analyzing the communities' issues relative to the development of extractives projects and revenue redistribution.

Benjamin holds an MSc. from the University of Dundee, UK, in Energy Studies and a BA (Hons.) in Sociology with Information Studies from the University of Ghana.

Mr. Egbert Faibille Jnr
CEO of Petroleum Commission

EGBERT FAIBILLE JNR was appointed Chief Executive Officer of the Petroleum Commission in August 2017. As the CEO of the Petroleum Commission, and Chairman of the Local Content Committee, he has a keen desire to promote local content and Ghanaian Participation in the oil and gas industry. These have been the underlining factors driving all projects that have been undertaken under his leadership.

Under his leadership, the Commission has seen steady increase in job role localisation for qualified Ghanaians in the upstream petroleum sector. He also initiated a Local Content Procurement Conference, an annual conference that seeks to create a platform for local companies to understand the procurement needs of major International Oil Companies (IOCs). This ensures they are well equipped to bid for and win contracts in the upstream petroleum industry.

As part of the Government's Accelerated Oil and Gas Capacity Programme (AOGC) and under the leadership of the Ministry of Energy, Mr. Faibille Jnr. led the Commission to establish the Ghana Welding Bureau (GWB). GWB aims to standardise welding training in Ghana under CTVET to international standards and thereby give Ghanaian welders a competitive edge in the upstream industry.

He has also successfully, led three Trade Missions to Aberdeen, Scotland; Stavanger, Norway; and Calgary, Canada: three cities regarded as leading cities in upstream petroleum activities. These Trade Missions provide opportunities for Ghanaian oil and gas companies to network and interact with their international counterparts in a bid to establish the necessary partnerships needed to build their capacities to play effective roles in the industry.

Prior to his appointment, Mr. Faibille was the Managing Partner at Faibille and Faibille, a law firm in Accra. At one point, he was also the Ghana Country Communications Representative of the West African Gas Pipeline Project (WAGP) when the project was at its definitional phase and later became the Corporate and Regulatory Affairs Manager of British American Tobacco, Ghana.

Professional Background

Mr. Charles Owusu has more than a decade's wealth of experience and expertise in oil and gas, power, shipping and ports, mining, FMCG industries and a stint at consulting with Deloitte.

Charles Owusu
Chief Executive Officer

He has both national and international exposure through work and engagements with the Ministry of Finance, Deloitte, Blue Ocean Investments (Bulk Oil Distribution Company) now Puma Energy and the Energy Commission of Ghana. His keen interest and knack for the oil and gas industry earned him an adjunct-lectureship service at Central University College-Ghana, where he trained executive scholars.

He is well-skilled and has mastery in public and private bond issuance, corporate business tax, transfer pricing, tax due diligence/compliance, taxation, oil trading, power regulations and financial services.

His critical thinking and unmatched work ethic as well as excellent client relationship skills have resulted in the provision of clear cut and tailored solutions, design of actionable policy, development of strategies and creation of manuals.

Technical Advisor to Minister of Finance

- Coordinated the special purpose vehicle to initiate a 10-year ESLA Bond programme of GHS10 billion.
- Facilitated in delivering four consecutive Ghana Eurobond roadshows from 2018-2021 of US$9 billion (US$3 billion each year) as budget support and liability management.
- Led in the BDCs and GoG Negotiation on US$1.43 billion legacy debts from 2011 to 2015.
- Led a team to establish SMEs Credit Fund to fill the gap created due to the financial sector clean up.

- Led the timely disbursement of GHS1.2 billion Coronavirus Alleviation Programme [CAP] funds.
- Played a key role in domestic revenue mobilization institutions reforms to build efficient and responsive revenue authority.
- Tax Audit Transformation Advisor – Ghana Revenue Authority.
- Led a team to establish a manufacturing plant towards National Digital Literacy Project (NDLP).

Ivy Apea Owusu is the Chief Executive Officer of Cirrus Oil Services Limited. In this role, she has been instrumental in the successful implementation of the downstream sector deregulation policies and has also spearheaded a wide range of health and education related community activities. She has over 20 years' experience in the Energy Sector. Ivy previously worked with GE Capital in the US and UK in Energy Structured Finance specializing in both Debt and Equity financing in the Oil & Gas, Power Generation, Renewable and Ancillary Energy Services Sectors.

Ivy is the board chairman for the Chamber of Bulk Oil Distributors (CBOD) and also sits on the boards of Woodfields Energy Resources Ltd and Legacy Bonds Ltd. She is a member of the Executive Women's Network and a Corporate Executive in Residence for University of Ghana Business School (UGBS) Department of Accounting. She served as a founding board member of the Women in Energy Ghana Board as well as an advisory board member of the 2019 Africa Oil Week in South Africa. Ivy has held numerous speaking engagements including Guest Speaker at the 2022 University of Ghana School of Humanities Graduation Ceremony, 2020 ABSA Bank Ghana International Women's Day, African Refiners Association South Africa and CWC Energy Ghana.

Ivy holds leadership certificates from both Harvard and Stanford Business Schools in the USA, an MBA from Vanderbilt University in TN, USA and a BA Admin (Accounting) from the University of Ghana, Legon.

Ivy has won numerous awards including the Exceptional Woman in Oil award at the 2021 Instinct Woman Awards and the 2018 Oil and Gas personality of the year at the GOGA Awards. In January 2022, she was named by African Shapers as one of the 100-outstanding female executives in the African Oil and Gas Industry.

Ivy is married with two children.

Dr. Ofori assumed office as the Chief Executive Officer of CBOD on August 1, 2022. Prior to his appointment at CBOD, he was the Crude Product Marketing Manager at the Ghana National Petroleum Corporation, performing commercial negotiations on crude oil and gas, including negotiations with off-takers and trading houses, overseeing market research, trading, and branding to promote GNPC and Ghana Crude Oil. He also monitored the effective implementation of commercial agreements and ensured product-backed funding was adhered to. He previously worked as the GNPC's Institutional Reporting Manager, where he facilitated dialogue with the Corporation's business leaders and coordinated engagements with external agencies such as the Public Interest and Accountability Committee (PIAC), EITI, NRGI, International Finance Corporation (IFC) World Bank, and rating agencies. Also included developing and elevating strategic partnerships and engaging relevant stakeholders.

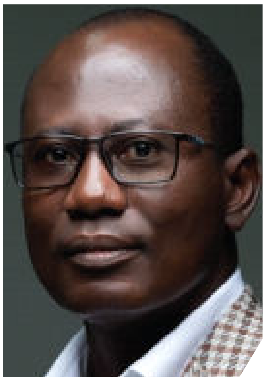
He has more than sixteen years of varied executive professional experience spanning Higher Education, Sports and the Oil and Gas industry.

He holds a Ph.D. in Sports Psychology from the University of Stirling, Scotland and an MSc in Accounting and Finance from the University of Ghana. He is a Commonwealth Scholar and an International Convention on Science, Education and Medicine in Sports (ICSEMIS) Scholar.

Dr. Ofori is also the Founding Head of the Department of Sports Science at the University of Cape Coast.

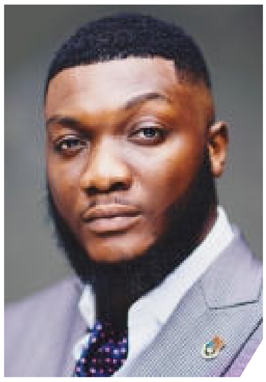
Board of CBOD

Ivy Apea Owusu
CEO, Cirrus Oil Services Ltd.



Alex Amoaku
Terminal Manager, Quantum Terminals Ltd.

Amentor Aziakar
Operations and Marketing Manager, Goenergy Co. Ltd.

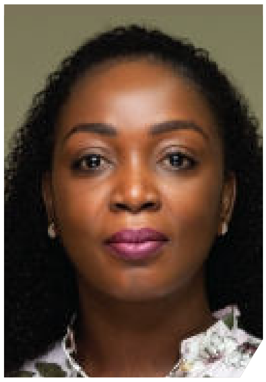


David Jones-Mensah
MD, Dominion International Petroleum Ltd.

Elton Dusi
CEO, Maranatha Oil Services Ltd.

Gifty Ashiley
Chief Risk and Compliance Officer, Juwel Energy Ltd.

Kingsley Sarpong
MD, Chase Petroleum Ghana Ltd.



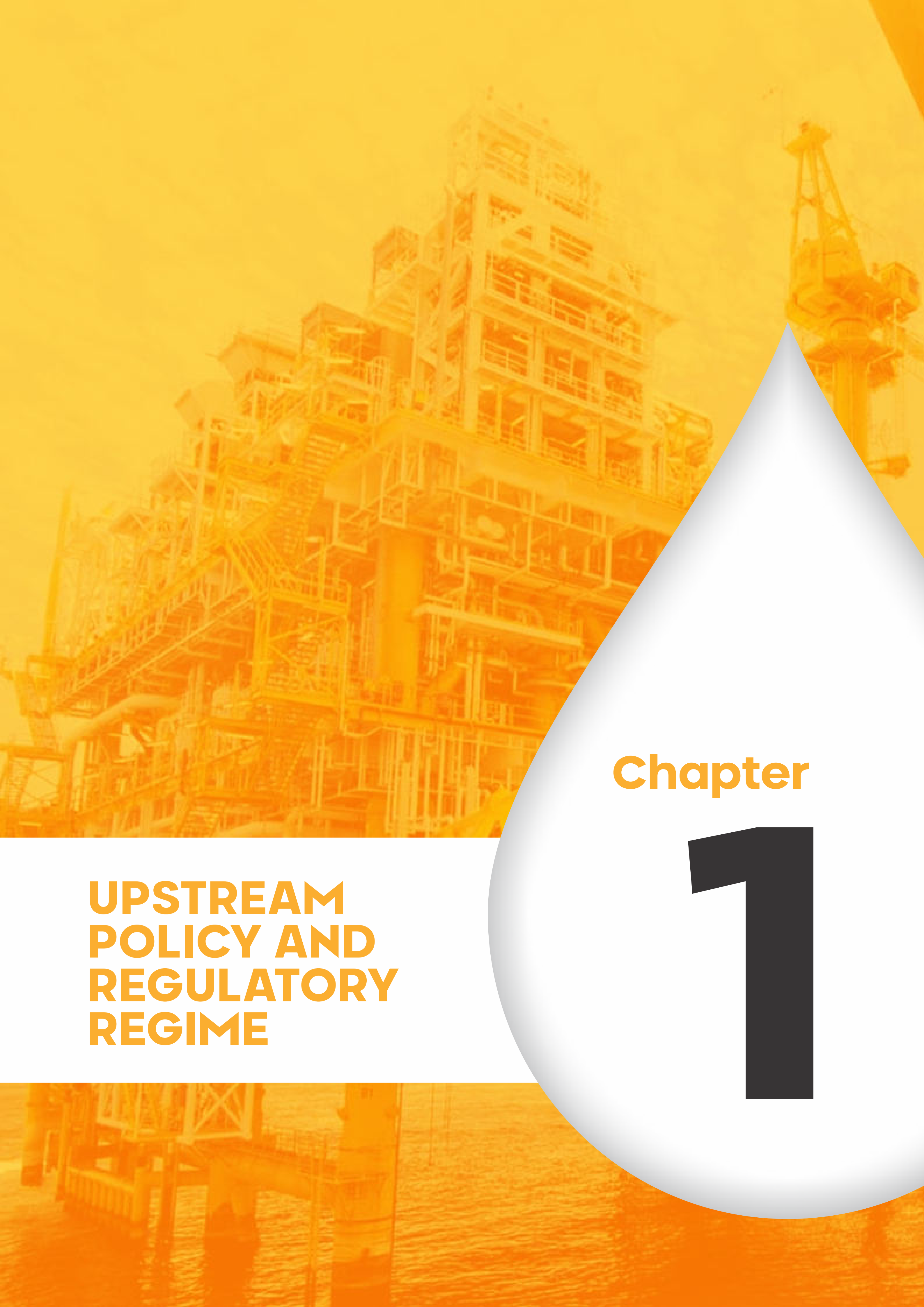
Nana Adwoa Serwaa Kuma-Duah
Chief Finance Officer and Head of Stocks, Tema Fuel Co. Ltd.

Senyo Kwasi Hosi
CEO, (CBOD)
2012 – July 2022

Yvette Ayele Selormey
MD for Downstream, Sahara Energy Group

Yaw Koduah-Sarpong
CEO,
SA Energy Ltd.

Patrick Kwaku Ofori, Ph,D
CEO, CBOD
August 2022 -



Chapter

1

UPSTREAM POLICY AND REGULATORY REGIME

Upstream Policy And Regulatory Regime

1.0 Policy And Regulatory / Infrastructure Review

1.1 Overview of the policy and regulatory framework

The adoption of a new Energy Sector Policy to replace the National Energy Policy of 2010 was expected to mark Government's major policy framework intervention in 2020. This was, however, delayed and, subsequently, overtaken by the Energy Ministry's decision to re-focus its attention on the development of a national energy transition policy and strategy in 2021. The National Energy Transition Committee (NETC), established to spearhead the development of the national policy / strategy, was inaugurated on 21st December 2021, and is expected, among others, to assess the risks and opportunities of the global energy transition for the country's hydrocarbon industry.

As at the close of 2021, the pre-existing policies, laws and regulations, as captured below, remained in force and governed the upstream oil and gas industry:

» Energy Sector Strategy and Development Plan;

» Gas Master Plan;

» Gas Pricing Policy Guidelines to the Petroleum (Exploration and Production) (Measurement) Regulations;

» Ghana National Petroleum Corporation Law, 1983 (PNDC Law 64);

» Petroleum Revenue Management Act, 2011 (Act 815) as amended by the Petroleum Revenue Management (Amendment) Act, 2015 (Act 893);

» Petroleum Commission Act, 2011 (Act 821);

» Petroleum (Exploration and Production) Act, 2016 (Act 919), which replaced PNDCL 84;

» The Model Petroleum Agreement;

» Income Tax Act 2015 (Act 896);

» Petroleum (Exploration and Production) (General) Regulations, 2018 (LI 2359);

» Local Content and Local Participation Regulations, 2013 (LI 2204);

» Petroleum Commission (Fees and Charges) Regulations, 2015 (LI 2221);

» Petroleum (Exploration and Production) (Measurement) Regulations, 2016 (LI 2246);

» Petroleum Exploration and Production-Data Management Regulation, 2017 (LI 2257);

» Petroleum (Exploration and Production) (Health, Safety and Environment) Regulations, 2017 (LI 2258);

» Guidelines for the formation of joint venture companies in the upstream petroleum industry of Ghana (March 2016).

The Petroleum Commission (PC), during the period, initiated amendments to some provisions of the Local Content Regulations, 2013 (LI 2204) to enhance local content development. The draft amendment bill was submitted to Parliament in the third quarter of 2021, and was still awaiting approval as at the end of the year.

Again, in line with the object of the Local Content and Local Participation Regulations, the Commission developed minimum local content standard requirements for long-leased items, such as FPSO, rig and subsea systems. These are planned to be operationalized in 2022.

The PC also finalized the development of Guidelines to reserve the importation, storage, and management of standard commodity chemicals for Indigenous Ghanaian Companies (IGCs). The Guidelines were expected to be published by end of the second quarter of 2022. However, as at the time of this publication, the guidelines had not been published.

As at the end of 2021, the Commission had commenced engagements with the Bank of Ghana to develop the Financial Services Guidelines.

Another major legislative development during the period, was the amendment of the Ghana Infrastructure Investment Fund Act, 2014 (Act 877), by the Ghana Infrastructure Investment Fund (Amendment) Act, 2021 (Act 1063). As part of the amendments, Section 9 of the Earmarked Funds Capping and Realignment Act, 2017 (Act 947) was repealed to allow for a resumption of allocation of a portion of the Annual Budget Funding Amount (ABFA) to the GIIF.

Other Regulatory Interventions

The Petroleum Commission embarked on a review of several other operational guidelines between 2020 and 2021. As at the close of 2021, four out of ten guidelines had been approved, four were awaiting approval, while two reviews had been completed and ready for submission to the board.

Table 1 below provides details of the guidelines under review, their status and web links.

Table 1: Guidelines under review, their status and web links

Guidelines	Purpose	Status	Web Link
Guidelines for the formation of Joint Venture Companies in the upstream petroleum sector	To guide industry players on the formation and structuring of joint venture companies.	**Approved**	https://www.petrocom.gov.gh/wp-content/uploads/2018/12/JV-Guidelines.pdf
Oil and Gas Insurance Placement Protocol for the Upstream Sector	To create opportunities for Ghanaian insurance companies and brokers to access opportunities in the oil and gas business in Ghana.	**Approved**	https://www.petrocom.gov.gh/wp-content/uploads/2018/12/OIL-GAS-INSURANCE-PLACEMENT-FOR-THE-UPSTREAM-SECTOR.pdf
Guidelines on Company Registration and Participation in Tender Processes	To provide a step-by-step registration guidance to all companies intending to operate in Ghana's upstream petroleum sector.	**Approved**	https://www.petrocom.gov.gh/licensing-and-permit/
Guidelines for the Submission of Contracts for approval by the Petroleum Commission	To ensure compliance with Local Content requirements.	**Approved**	Not available online

Guidelines	Purpose	Status	Web Link
Guidelines for Electronic Filing of Documents	To digitalize oil and gas-related transactions and reporting for efficient administration.	**Awaiting board's approval**	Not available online
Guidelines for Submission of Local Content Plans &Performance Report (Goods and Service)	To ensure compliance with local content requirements.	**Awaiting board's approval**	Not available online
Research and Development Guidelines	To promote investment into Research and Development in order to enhance technological innovation in Ghana's upstream oil and gas industry.	**Awaiting board's approval**	Not available online
Guidelines for the Petroleum (Exploration and Production) (Health, Safety and Environment)	To ensure compliance with environment, health and safety regulations.	**Awaiting board's approval**	Not available online
Draft Guidelines for Reporting Geophysical Data to Petroleum Commission		**Ready for submission to the board for approval**	Not available online
Guidelines for the Reservation of Goods and Services		**Ready for submission to the board for approval**	Not available online

Source: Author's construct, based on Petroleum Commission data.

Existing Petroleum Agreements

The number of PAs in existence, as at the close of 2021, were 18, according to the Ghana Petroleum Register, managed by the Petroleum Commission. (www.ghanapetroleumregister.com)

Table 2 Particulars of existing Petroleum Agreements in Ghana's Upstream Petroleum Sector as at 2021

Contract Area	Operator	Partners	Stage of Operation
1. Deepwater Tano	Tullow Ghana Limited – 35.48% interest in block	Anadarko Petroleum Corporation – 24% Interest in Block Kosmos Energy Ghana HC – 24% Interest in Block PetroSAGhana Limited – 2.52% Interest in Block GNPC –14% Interest in Block	Production

Contract Area	Operator	Partners	Stage of Operation
2. West Cape Three Points	Tullow Ghana Limited – 25.66% interest in block	Kosmos Energy Ghana HC – 30.02% interest in block Anadarko Petroleum Corp.– 30.02% interest in block PetroSA Ghana Limited – 1.80% interest in block GNPC – 12.5% interest in block	Production
3. Offshore Cape Three Points	ENI Ghana Exploration & Production Limited – 44.44% interest in block	1. Vitol Upstream Ghana Limited – 35.56% interest in block 2. Ghana National Petroleum Corporation (GNPC) – 20% interest in block	Development and Production
4. Deepwater Tano/ Cape Three Points	Aker Energy Ghana Limited – 50% interest in block	Lukoil Overseas Ghana Limited – 38% interest in block FT Exploration and Production Limited – 2% interest in block Ghana National Petroleum Corporation (GNPC) – 10% interest in block	Pre-Development
5. Cape Three Points Block 4	ENI Ghana Exploration & Production Limited – 42.47% interest in block	Vitol Upstream Tano Limited – 33.98% interest in block Woodfields Upstream Limited – 9.56% interest in block Ghana National Petroleum Corporation (GNPC) – 10% interest in block Explorco – 4% interest in block	Exploration
6. Central Tano Block	Amni International Petroleum Development Company (Ghana) Limited – 90% interest in block	GNPC – 10% interest in block	Exploration
7. Deepwater Cape Three Points West Offshore	ECO ATLANTIC OIL AND GAS – 50.42% interest in block	A-Z Petroleum Products Ghana Limited – 27.88% interest in block Petrogulf Limited – 4.35% interest in block GNPC Exploration and Production Company Limited (GNPC EXPLORCO) – 4.35% interest in block GNPC – 13% carried interest in block	Exploration
8. East Cape Three Points	Medea Development Limited – 36% interest in block	Cola Natural Resources –54% interest in block Ghana National Petroleum Corporation (GNPC) – 10% interest in block	Exploration
9. East Keta Block	GNPC Operating Services Company Limited (GOSCO) – 11% interest in block	Heritage Exploration and Production Ghana Limited – 38.7% interest in block Blue Star Exploration Ghana Limited – 38.7% interest in block GNPC Exploration and Production Company Limited (GNPC EXPLORCO) – 11.6% interest in block	Exploration

Contract Area	Operator	Partners	Stage of Operation
10. Expanded Shallow Water Tano Block	Base Energy Limited – 67.5% interest in the block	GNPC Exploration and Production Company Limited (GNPC EXPLORCO) – 22.5% interest in block Ghana National Petroleum Corporation (GNPC) – 10% interest in block	
11. West Cape Three Points Block 2	Springfield E&P Limited – New Discoveries (84%); Existing Discoveries (82%) interest in block	Ghana National Petroleum Corporation (GNPC) – New Discoveries (11%); Existing Discoveries(8%) interest in block GNPC Exploration and Production Company Limited (GNPC EXPLORCO) – New Discoveries (5%); Existing Discoveries (10%)	Exploration
12. Offshore South-West Tano Block	GNPC Operating Services Company Ltd (GOSCO) – 12% interest in block	Heritage Exploration and Production Ghana Limited – 39.60% interest in block Blue Star Exploration Ghana Limited – 39.60% interest in block GNPC Exploration and Production Company Limited (GNPC EXPLORCO) – 8.8% interest in block	Exploration
13. Onshore/Offshore Keta Delta Block	Swiss African Oil Company Limited – 83% interest in block	Pet Volta Investments Limited – 5% interest in block Ghana National Petroleum Corporation (GNPC) – 12% interest in block	
14. South Deepwater Tano	AGM PETROLEUM GHANA LIMITED – (66%) interest in block	GNPC – 10% interest in block GNPC Exploration and Production Company Limited (GNPC EXPLORCO) – 24% interest in block	Exploration
15. South West Saltpond	Brittania-U Ghana Limited – 76% Interest in block	OTHER CONTRACTING PARTIES: Hills Oil Marketing Company Limited – 4% Interest in block Ghana National Petroleum Corporation (GNPC) – 20% interest in block	Exploration
16. Shallow Water Cape Three Points	Sahara Energy Fields Ghana Ltd – 85% interest in block	Ghana National Petroleum Corporation (GNPC) – 10% Interest in Block Sapholda E&P Limited – 5% Interest in Block	Exploration
17. Offshore Cape Three Points South	UB Resources Limited – 70.47% Working interest in block	Royalgate Gh Limited – 4.35% interest in block Houston Drilling Management Gh Limited –12.18% interest in block GNPC – 13% interest in block	Exploration
18. Deepwater Cape Three Points	Exxonmobil Exploration and Production Ghana (Deepwater) Limited – 80% interest in block	GOIL Offshore Ghana Limited – 5% interest in block GNPC – 15% interest in block	Exploration

Source: Author's construct, based on Petroleum Commission Data.

Out of the 18, three, i.e., Jubilee, TEN, and SGN, were producing, while 15 were at various levels of exploration and development.

1.2 The Upstream Petroleum Fiscal Regime

The standard fiscal terms on which Petroleum Agreements (PAs) are negotiated remained unchanged. These are derived from the Petroleum (Exploration and Production) Act 2016 (Act 919), the Petroleum (Exploration and Production) (General Regulations), LI2359, the Model Petroleum Agreement, and the Income Tax Act 2015 (Act 896). The main elements of the fiscal regime as detailed in these statutory instruments are:

» **Royalty:** 5.0-12.5%.

» **GNPC Initial Interest** (Carried) – 15%.

» **GNPC Additional Interest** (Paying) – Negotiable.

» **Petroleum Income Tax** – 35%.

» **Additional Oil Entitlement** – based on targeted Rate of Return. The set benchmarks for RORs in LI 2359 are 15%, 20%, 25% and 30%.

» **Surface rental (offshore)** – US$150-600/sq.km/year, depending on stage of operation.

» **Surface rental (onshore)** – US$225-900/sq.km/year, depending on stage of operation.

» **Capital Allowance** (Cost Recovery) – 5 years straight-line depreciation of exploration and development costs and other capital expenditures, including buildings, transportation and communication facilities.

» **Thin capitalization** – Debt-Equity ratio of 3:1.

Additionally, section 18 of the E&P Act, 919 grants Ghana preemptive rights in the event that a contractor decides to dispose of all or part of its assets in a Petroleum Agreement (PA).

1.3 Developments in the upstream sector during the Period

The year 2020 witnessed a general decline in the industry globally, which experts attributed to two main factors, i.e., the collapse of the oil market, arising from a downturn in global industrial activity and, therefore, occasioning a suppressed demand for crude oil. The downturn in industrial activity was as a result of COVID-19 and the measures instituted to contain the pandemic. The other factor had to do with challenges associated with sourcing project finance, as a result of an obvious shift in investments from fossil fuels to clean energy.

In 2021, global economies began to recover from the adverse impact of the outbreak of the COVID-19. There was a gradual resumption of production and expansion plans by the various petroleum exploration companies, as most restrictions put in place during the COVID-19 pandemic were eased over time, and measures were put in place to allow for work to continue during the period under review. The upstream sector of Ghana also recovered steadily in 2021, as most of the International Oil Companies (IOCs) operating in Ghana resumed the planning and execution of preparatory activities relating to drilling campaigns. For instance, Amni International Petroleum Development and GNPC Operating Services Company Ltd., each resumed operations in the first quarter of 2021 with revised plans to start drilling from their obligatory wells in the second quarter of the year. Eco Atlantic Oil and Gas also resumed by revising plans to drill its obligatory exploration well; Dawadawa-1X in the third quarter of the year. Eni, in 2021, contracted Saipem 10,000 drillship to drill its second exploration well, the Eban-1X, in the CTP Block 4.

1.4 New Licenses

Following the successful completion of Ghana's First Open Licensing and Bid Round, new PAs were expected to be negotiated with the bid winners, Eni Ghana, and First E&P Ltd. The negotiations, which commenced soon after the bid rounds in 2019, were not concluded as at the close of 2021, even though the processes are said to be far advanced. The delay in concluding the negotiations was blamed on the Covid-19 pandemic.

1.5 Termination of Existing Licenses

The Petroleum Commission terminated four (4) contracts in 2021 for non-performance. The affected companies were Swiss African Oil Company Limited –SWAOCO, UB Resources, Brittania U and Sahara Energy Fields Ghana Limited.

Apart from failing to meet their minimum work obligations, the four companies owed about 73 percent of outstanding Surface Rentals of US$2,579,170.22.

Table 3: Details of the terminated contracts

Name of Contractor	Block	Area (sq.km)	Effective date of PA	Termination Date
Brittania-U Ghana, Hills Oil Marketing Company Limited and GNPC	Southwest Saltpond	2,050	17th July, 2014	27th April, 2021
Sahara Energy Fields Ghana Limited, Sapholda E&P Limited and GNPC	Shallow Water Cape Three Points	1500	17th July, 2014	27th April, 2021
UB Resources Limited, Royalgate Gh Limited, Houston Drilling Management Gh Limited and GNPC	Offshore Cape Three Points South	755	17th September, 2014	27th April, 2021
Swiss African Oil Company Limited, Pet Volta Investments Limited and GNPC	Onshore/Offshore Keta	3000	11th March, 2016	27th April, 2021

Source: Petroleum Commission.

1.6 Exploration and Production activities in GNPC's GH-WB-01 Block

In line with Section 11(1) of the Petroleum (Exploration & Production) Act 2016 (Act 919), and Regulation 36(1) of the Petroleum (Exploration & Production) General Regulations, 2018 (LI 2359), GNPC sought and obtained authorization from the Minister for Energy in 2020, to undertake exploration and production activities in its GH-WB-01 block in the Tano basin, allocated to it during the Ghana First Open Licensing and Bid Round. A decision to seek parliamentary ratification of the authorization was rescinded, as the activities envisaged did not involve any international partners. Not much progress can, however, be reported on the planned exploration.

1.7 Efforts at attracting investments into Exploration

While the period under review witnessed no major investments in exploration, the Petroleum Commission reports considerable interest shown in Ghana through visits to the Commission's data room by potential investors, including Hunt Oil, BP and Shell.

Following the provisions of section 10 (9) of the Petroleum (Exploration and Production) Act, 2016 (Act 919) and Regulation 19(6) of the Petroleum (Exploration and Production) (General) Regulations, LI 2359, the Ministry issued a call for the expression of interest for direct negotiations for Petroleum Exploration and Production Rights in respect of Block GH-WB-04 offshore of the Republic of Ghana. A similar call for direct negotiations for Petroleum Exploration and Production Licences for Fifteen (15) Blocks in the Eastern Basin-Offshore Ghana was issued to interested companies in 2020.

As at December 2021, negotiations were far advanced with Eni Ltd., in partnership with Vitol Upstream Tano Ltd.; CNOOC International Ltd.; Resource Base International Ltd.; KOKA Energy Company Ltd.; and First E&P towards executing new Petroleum Agreements.

1.8 Voltaian Basin Project

The Ghana National Petroleum Corporation continued with its exploratory activities in the Voltaian basin amidst COVID-19 and its containment measures, including restrictions on staff numbers and movements at the workplace.

The corporation and its consulting partners, BGP-Bay, continued with the second phase of the project which had begun in 2019, involving the planned acquisition of additional 500-line km of 2D seismic data. The exercise was completed in March 2020, bringing the total coverage of data acquisition to 667 km.

Processing of the entire Phase-II seismic data, was done at the BGP-Bay's data processing centre in China, and was completed in late July. After separate data interpretation by both the GNPC team (in-house) and the BGP-Bay's office, both teams made recommendations for the consideration of GNPC's Management. Both teams agreed that there was the need for further work on the data, which would require the deployment of a more efficient technology to identify the location of potential deposits of hydrocarbons. A team was, therefore, tasked to explore available cost-effective technologies to complement the seismic data, and to give better sense of the potential hydrocarbon accumulation.

Several technologies, according to GNPC, were considered, including the Magnetolluric (MT), Ground Penetrating Radar (GPR), Satellite Imagery and Remote Sensing. In the end, the Satellite Imagery Technology, also known as the Sub Terrain Prospection (STeP) technology, appeared to have met GNPC's requirement in terms of capabilities, success rate, time, cost and deliverables. The vendor, TerraPlanoAfrique, submitted a proposal, but the work has suffered some delays as a result of delayed approval of the recommended technology by GNPC's board.

Other activities undertaken on the Voltaian Basin Project, according to GNPC, were the acquisition of reconnaissance license and authorization for the project in March 2020; completion of the necessary permitting and compensation payments to affected farmers and landowners, through ARB Apex Bank. Over a 1,000 impacted farmers and landowners were compensated.

The Piengwa Divisional Council of Manya Krobo drew GNPC's attention to some supposed oil seepages in pre-existing "oil pits", and requested the Corporation to investigate the potentials of these pits. The areas are: Anyaboni, Aframase, Apimso, Bisa, Sedorm and their surrondings. GNPC responded with a visit to these areas, and plans to collaborate with the Volta River Authority in understanding the historical background to the pits, and is pursuing further investigations about their prospectivity.

Having completed Phase 2 of its 2D seismic data acquisition in March 2020, GNPC, in 2021, embarked on a Phase 3 Infill Campaign to acquire an additional 1,655 kilometres of 2D seismic lines. The campaign began in December, 2021 and will continue till the fouth quarter of 2022.

1.9 Developments in the producing fields

GNPC and its Greater Jubilee Field partners continued with their development activities in the field. The Maersk Venturer Drillship continued work on the J15-WI Suspension/Abandonment operations which was concluded on the 8th of January 2020. The Maersk Venturer Drillship was then used for drilling activities on the J55-WI. The J55-WI was spudded on 14th March 2020 to undertake top-hole drilling. This activity ended on the 21st March 2020.

The Jubilee partners completed the Turret Remediation Project (TRP) and Permanent Spread Mooring (PSM) work scope in May 2020. Consequently, the FPSO Kwame Nkrumah is now a full spread moored FPSO, giving the facility greater stability.

Tullow Ghana Ltd. (TGL) resumed its drilling campaign in the Jubilee Field in April, 2021. Spudding and drilling of its first well, J56-P, as well as J55-WI, were completed between April and July, 2021, for both the top-hole and lower sections. Those of J57-P commenced in August and completed in November, 2021. J12-WI well-intervention operations commenced on 24th November 2021. As at the close of 2021, J58-WI drilling operation was still in progress.

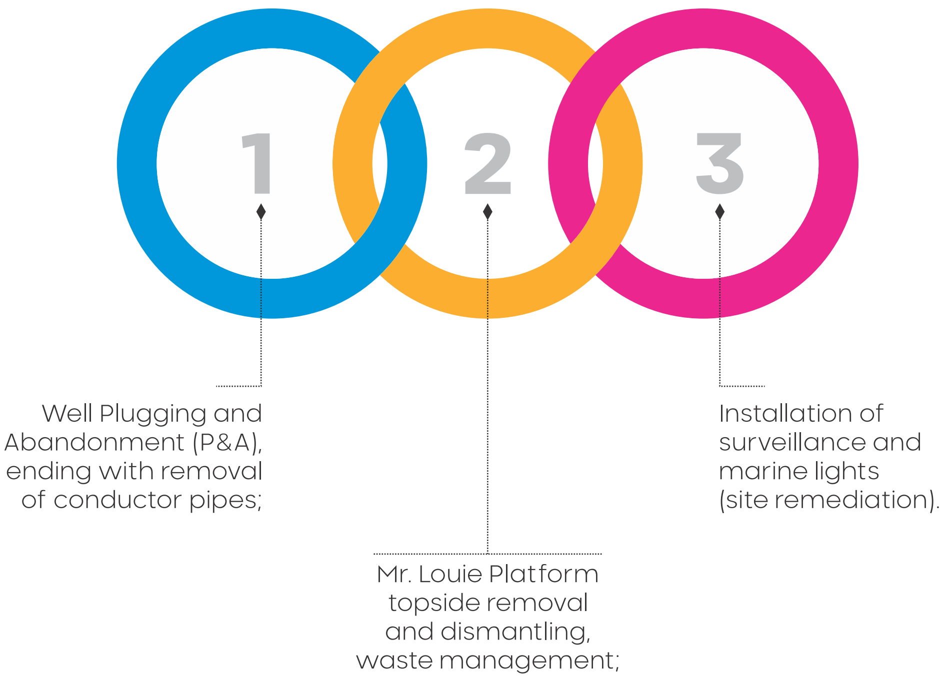
1.10 Update on the Saltpond Decommissioning Programme

On 23 December 2015, following the cessation of production activities at the Saltpond Field, and acting on the advice of an inter-agency committee, constituted to review the state of the Field, the Minister for Petroleum terminated the Saltpond Field Petroleum License, and directed the installation to be decommissioned.

GNPC soon commenced processes for the decommissioning of the installations and submitted a Decommissioning Plan to the Minister for approval.

The Petroleum Commission engaged GNPC on the overall implementation strategy, as well as the preliminary budget estimates for the project execution and provided advice in accordance with Section 3 (d) (i) of the Petroleum Commission Act (Act 821).

The execution phase of the project was categorized into 3 stages as follows:



In November 2019, the Minister authorized GNPC to decommission the field. Efforts began almost immediately to procure decommissioning contractor(s) to decommission the Field. In 2020, GNPC received approval from the Public Procurement Authority (PPA) to proceed with its procurement strategy and shortlisted companies.

As at December 2021, GNPC had selected Hans & Co. Oil and Gas Company Limited, an indigenous Ghanaian company, to undertake the decommissioning assignment. A decommissioning contract has, subsequently, been negotiated and duly signed.

1.11 Impact of COVID 19 on the Industry

The outbreak of COVID-19 was recorded in the Chinese city of Wuhan, in the Hubei Province, in December 2019. By March, 2020, the disease had spread quickly beyond China to almost every continent, with high fatality rates in many countries, causing the World Health Organisation (WHO) to declare the viral infection a global pandemic. This came with dire consequences for global industrial activity and output. Some companies had to shut down completely to contain the spread, while others had to reduce employee numbers at the workplace and cutting down production or, in some cases, running shifts. The aviation sector was also hit badly, as severe travel restrictions led to temporary grounding of several airlines. At the same time, there was a marked increase in industrial production in favour of protective gear and hand sanitizers to help contain the spread globally, but since the shift was in favour of light industry, its effect on global energy demand was marginal. In short, the global slum in industrial production, with its accompanying decline in the demand for energy led to a collapse of oil prices on the global market. This did not only stifle government's revenues but also disrupted work programmes of major international oil companies, including those operating in Ghana, as investment finance proved challenging to upstream oil and gas operators globally. Potential investors began to move their money from the upstream oil and gas sector into gold and other precious minerals to escape the risks and uncertainties of the upstream oil and gas industry.

The first half year saw Brent oil price falling from an average of $63.5 per barrel in January to $32 per barrel by March and a further fall to a record low of $18.38 per barrel in April before picking up slightly in May to $29.38 per barrel.

The major impact this situation had on the industry in Ghana, was a severe disruption to planned and ongoing exploration and appraisal activities. Approved work schedules, estimated to cost of US$324 million, had to be shelved.

1.12 COVID 19 Impact on contractual performance of some license holders

AMNI (Central Tano Block)

AMNI, the operator of the Central Tano Block, had to reschedule its planned drilling campaign from the second quarter to the fourth quarter of 2020, due to the effects of COVID 19. The company resumed operation in the first half of 2021 with revised plans to drill its obligatory exploration well, Kusia-1X, from the second to third quarter of 2022. This followed the decision of the Minister for Energy to grant the company eight (8) additional months as compensation for the time lost due to the COVID-19 pandemic.

ECO Atlantic (Deepwater Cape Three Points West Block)

ECO Atlantic, working on the Deepwater Cape Three Points West Block, also had to suspend preparations towards its exploratory drilling campaign, including rig-tendering and related service contracting, as a result of the pandemic and its consequential fragile market. Like Amni, the Minister for Energy granted the company eight (8) additional months as recompense for the Covid-induced time loss. It resumed operations in 2021, with plans to drill its obligatory well, Dawadawa-1X, in the third quarter of 2022.

GNPC Operating Services Company (Offshore South-West Tano Block)

GNPC Operating Services Company Ltd. (GOSCO) (Offshore South-West Tano) also resumed operations in the first half of 2021 with revised plans to drill its obligatory exploration well, Mansonia-1X, in the third quarter of 2022, having been granted a restitution time of nine (9) months to compensate for the time lost due to the COVID-19 pandemic.

Aker Energy (Deepwater Tano Cape Three Points Block) / AGM

Aker Energy, which was at the development phase of its US$4.4 billion Pecan project in 2020, and was expected to submit its Plan of Development (PoD) for approval, suddenly announced its decision to suspend further investment in the project, citing sluggish market conditions and supply chain disruptions due to the COVID 19 pandemic. This led to the stalling of the Pecan Field development activities. The

Government had, at the time, approved Yinson Holding to operate and maintain the Pecan Field FPSO for the DWT/CTP project, but this approval came to no effect, following Aker's decision to hold back its field development activities.

The DWT/CTP operator, however, caused a stir when it offered to offload 37 percent of its stake in the project and 70 percent of the AGM stake in the South Deepwater Tano (SDWT) block to the Ghana National Petroleum Corporation (GNPC), through GNPC Exploration and Production Company Limited (Explorco).

AGM Petroleum, at the time, had also put off indefinitely, its planned appraisal activities on its Nyankom 1X and Kyekyen 1X wells, citing COVID 19 and its attendant supply chain disruptions.

GNPC justified its decision to acquire the Aker stake on its need to acquire operatorship capability, as oil and gas majors were beginning to divert attention from fossil fuels to renewables, a move the corporation said puts Ghana's hydrocarbons at a risk of being stranded. Under the deal, GNPC would partner Aker Energy and AGM to jointly develop the DWT/CTP and SDWT blocks through a Joint Operator Company to facilitate the transfer of operatorship capability to the National Oil Company (NOC).

Some Ghanaian CSOs, working in the oil and gas space, raised concerns over the valuation of the Aker Energy assets, and petitioned the Ghanaian Parliament to look into the asset valuation.

On 5th August 2021, Parliament's Joint Committee on Energy and Finance, by consensus, recommended approval of the government's request for a loan to enable GNPC acquire the proposed 37 percent stake in Aker Energy and 70 percent in AGM Petroleum's oil blocks.

The Committee, however, reduced the requested amount from $1.65 billion to $1.45 billion, and gave the green light for the Ministers for Finance, and Energy and GNPC to proceed with negotiations and to report back after the negotiations for final approval.[1] The negotiations have not concluded as at the time of this publication.

Eni (Cape Three Points Block 4)

Eni, the Operator of the Cape Three Points Block 4, in 2020, also announced its decision to suspend its planned drilling of the Eban-1X exploratory well to the first quarter of 2021. Planned appraisal of its Akoma-1X well was also put on hold. In 2021, the company contracted Saipem 10,000 drillship to drill its second exploration well, the Eban-1X, in the CTP Block 4. This was in fulfilment of its work obligation for the First Extension Exploration Period. Eban-1X was spudded on 6th May 2021 and drilled to a total depth of 4,179m in June 2021. This proved successful in uncovering a column of hydrocarbons. ENI in a public statement, indicated that, its preliminary estimate of oil in place for the Eban 1X discovery was between 500 and 700 million barrels of oil equivalent (MMboe)[2]. In December 2021, the company submitted an Appraisal Programme to the Petroleum Commission for approval.

Springfield E&P (West Cape Three Points Block 2)

Springfield also postponed planned appraisal activities on its Afina-1X discovery indefinitely, in the second quarter of 2020, for reasons of worsening market conditions and other COVID-19-related effects on the industry. In 2021, following the grant of a restitution time of nine (9) months, the company embarked on additional geological and geophysical studies in support of its claim that its Afina discovery communicates with Eni's Sankofa East field and, therefore, warranting the execution of a Unitisation and Unit Operating Agreement with Eni.

Springfield's resumption of activities in 2021, stoked the subdued embers of a raging dispute with Eni over the former's claims that its Afina block straddles Eni's Sankofa East block.

On 25th June, 2021, following an application for the preservation of funds from Eni's operations, pending the outcome of Springfields claims, Ghana's Supreme Court ordered Eni to pay into an escrow account, 30 percent of its receipts from the Sankofa GyeNyame field.[3]

[1] Report of the Joint Committee on Mines and Energy, and Finance on the Ghana National Corporation's (GNPC) Acquisition of Significant Share in Deepwater Tano Cape Three Points, and South Deepwater Tano blocks, 5th August, 2021.

[2] Press statement by Eni, issued on 6th July 2021. https://www.eni.com

[3] https://www.energyvoice.com/oilandgas/africa/ep-africa/332926/springfield-court-enis-escrow/?plan_id=

Unhappy with the Supreme Court's directive, Eni and its partner, Vitol Upstream Limited, challenged the Energy Minister's directive for a joint operation[4], which formed the basis of the supreme Court order, at an Accra High Court. The plaintiffs pleaded the court to declare the directive as illegal. They also sought a "declaration that the Minister did not follow due process of law in issuing the purported directives". The plaintiffs again, sought an "order of interlocutory injunction restraining the Respondents from taking any step to seek to enforce the purported directive, pending the final determination of this application".

But the court, presided over by Justice Emmanuel Kwesi Mensah, dismissed the application on grounds that the motion paper to the application was "incompetent" as the affidavit was deposed to by a certain Abena Owusu, who describes herself as the Legal Manager of Eni Ghana Exploration & Production Limited, but did not state what her connection with Vitol Upstream Limited was.

The court ruled that a reading of the affidavit in support of the application confirmed that the application did not state the reliefs claimed by the application in the proceedings before the court. It again held that the subject matter of the application was a directive made by a minister of state and that, the application was not targeted at any judgment order, conviction or other proceeding. It explained that, the application before the court did not pray the court for an order of certiorari, and for this reason, the provision of rule 3 (2) of Order 55 of C.I. 47, did not apply to the matter before it [5].

A subsequent application by Eni, for leave to appeal against the Supreme Court ruling on the matter, was also dismissed on 17th November, 2021. In dismissing the application, the Supreme Court held that Eni and Vitol failed to make a case for the special leave. The court said it did not find any reason to grant the leave, as no serious error or new information has been adduced by the applicant. The court proceeded to urge the feuding parties to settle their differences out of court.

Unsatisfied with the outcome thus far, Eni filed a suit at the International Tribunal in London, United Kingdom, to challenge the directive by Ghana's Minister for Energy, directing the parties to unitise Sankofa offshore oil field and Afina oil block. The matter is yet to be determined. Meanwhile, the President of the Republic, Nana Addo Dankwa Akufo Addo, has assured Ghanaians of an amicable solution to the impasse[6].

ExxonMobil

Although ExxonMobil was granted a restitution time of nine (9) months, the company voluntarily relinquished its 80 percent stake in the Deepwater Cape Three Points Contract Area in May 2021. The development means the government will have to find a new investor to take up the relinquished stake. The remaining stake in the block is owned by GNPC – 15 percent, and GOIL – 5 percent.

Base Energy (Expanded Shallow Water Tano)

The Expanded Shallow Water Tano (ESWT) block, formerly operated by Erin Energy, was assigned to a new operator, Base Energy, following the exit of Erin Energy from the partnership. Base Energy currently holds 67.5 percent stake in the block. The contract area has three (3) existing oil and gas discoveries, namely, North Tano, West Tano and South Tano fields. The fields are estimated to hold some 600 million barrels of oil, and 160 billion cubic feet of non-associated gas[7]. GNPC Explorco holds 22.5 percent, while GNPC holds 10 percent of the remaining stake. As a result of the three-year extension to its initial exploration period granted the company in 2020, Base Energy has planned for the acquisition of new 3D seismic data over the Block.

Medea Development (East Cape Three Points)

Following the grant of an 18-month extension to Medea and Cola to enable the partners complete their minimum work obligations under the ECTP contract, the operator, Medea, initiated plans and related procurement of goods and services in the last quarter of 2021, to drill its obligatory exploration well in the first quarter of 2022.

[4] The directive in question was issued by the Minister for Energy, in a letter, dated, 14th October, 2020. It asked Eni and Springfield to unitise the Sankofa field (OCTP) and the Afina (WCTP Block 2). The directive became necessary because the parties had not complied with earlier advice, issued in April 2020. Eni had contested the directive on grounds that Springfield had not adduced incontrovertible and adequate data to demonstrate that:

(i) The Afina discovery, drilled in 2019, and the Sankofa Cenomanian Oil field, which has been in production since 2017, are straddling the licence border; (ii) The Afina discovery has been sufficiently tested or appraised to demonstrate that it is in dynamic communication with the Sankofa field and/or ascertain definitively that the discovered resources in the Afina discovery are producible; (iii) Unitisation would ensure efficient reservoir exploitation, avoid unnecessary competitive drilling, and maximise economic recovery of the hydrocarbons reserves, and/or (iv) Unitisation or any other form of coordinated development would be appropriate in accordance with Ghanaian law.

[5] https://www.modernghana.com/amp/news/1114112/court-dismisses-eni-case-against-ag-springfield.html

[6] https://ghanaoilandgasdirectory.com/court-affirms-eni-springfield-unitisation-directive/

[7] This is according to data published by Base Energy on https://baseenergygh.com.

No special fiscal incentives were provided by Government to the industry, to mitigate the adverse impact of COVID, perhaps, due to the fact that, the market collapse also meant significant budget shortfall for the country. *Government was however, very accommodating in permitting through the Petroleum Commission, a general freeze on approved work programmes and agreeing to restore the lost time for all licenses which would have, otherwise, expired in 2020.*

1.13 The Challenge of Energy Transition

Added to the adverse impact of COVID on upstream petroleum investments was the gradual shift in investments from fossil fuel to clean energy. The Economist Intelligence Unit (EIU) predicted in 2020 that, in 2021, energy investment will shift from oil and gas to renewables. Solar and wind were projected to record the strongest growth among all sources of energy in 2021. Indeed, the period saw a global slowdown in exploration-related investments. The situation is further compounded by the EU Taxonomy programme, a classification system, establishing a list of environmentally-sustainable economic activities EU-registered companies are encouraged to invest in. The EU taxonomy is an important enabler to scale up sustainable investment, discouraging investments in hydrocarbons.

Already, the daily production of oil and gas majors in Africa has been on the decline, and projected to settle at 34 percent by 2025, as they sell off assets in upstream oil and gas sector to invest in renewables.

An analysis of Ghana's oil production data since 2010 indicates that, unless new discoveries are made, Ghana's oil industry will soon become moribund. Already, 50 percent of the total Greater Jubilee reserves, 33 percent of TEN Field, and 25 percent of Sankofa have been produced. This means, unless the country is able to attract new investments into exploration, Ghana's oil and gas industry will soon be non-existent. And yet, cost of capital for upstream investments have increased from 2-3 percent in 2010-2011 to 5 percent in 2017 to 9-10 percent in 2020.

Reputable international investment banks, such as Goldman Sachs, Morgan Stanley and JP Morgan, are all in agreement that, with the shift in investment finance in favour of renewables, hydrocarbons will soon lose their place in the global energy mix, with most reserves becoming stranded.

The spectre of energy transition and its accompanying threat of stranded assets still hangs heavily on Ghana's Oil industry. It is, therefore, imperative that the country thinks through an energy transition strategy, hinged on leveraging current opportunities afforded by hydrocarbons to finance the country's transition to clean energy.

1.14 Policy and Regulatory Developments in the Gas Sub-sector

In Ghana, the mandate for the gas sub-sector regulation is split into upstream and downstream. The upstream gas sub-sector is generally understood to cover activities from the well head to the gas processing facility at Atuabo. This is regulated by the Petroleum Commission. The mid to downstream commences from the processing facility to the delivery of gas to offtakers and users. This is regulated by the Energy Commission. The two institutions, however, collaborate with each other in the performance of their respective mandates.

There was no off take of gas by the Government of Ghana and GNPC in respect of the shore in the OCTP project between 2020 and 2021. For this reason, no payment was made into the Petroleum Holding Fund, as prescribed by law.

Rather, government paid for the gas it was bound to purchase from the partners, under the take-or-pay agreement with them through the Cash Waterfall Mechanism. Government's share in respect of royalty, and GNPC's share in respect of Carried and Participating Interest will be recovered within five years as Make Up gas.

1.15 Gas Sub-Sector Institutional Alignment

In 2019, the President granted approval for the re-assignment of institutional roles within Ghana's Gas sector, with a view to making GNGC an integrated gas company, with a mandate of a gas aggregator. Subsequently, a Ministerial Gas Task Force (MGTF) was established to develop a roadmap for the implementation of the directive. As at the close of 2021, the process had still not been concluded.

1.16 Energy Sector Debt Recovery

As part of efforts at liquidating the crippling energy sector debt[8], the government, in collaboration with the World Bank, introduced, in April 2020, the Energy Sector Recovery Programme (ESRP) which has as one of its components, the Cash Waterfall Mechanism (CWM), to address the energy sector debt situation which had began threatening energy sustainability in the country.

The Cash Waterfall Mechanism sets out the principles, methodology and processes for the determination and disbursement of tariff revenue collected by the Electricity Company of Ghana (ECG) to various beneficiaries along the electricity value chain. Accordingly, all stakeholders along the electricity value chain are paid directly by CWM, a percentage of the total invoice amount submitted for each month. CWM payment structures usually require that higher-tiered creditors receive interests and principal payments, while the lower-tiered creditors receive principal payments after the higher-tiered creditors are paid back in full. According to the Ministry of Finance, the CWM allows ECG's revenues to be distributed in a more transparent manner, and managing payments of arrears, despite the challenging fiscal situation which has been exacerbated by the COVID-19 pandemic.[9] The implementation of the payment system has, however, been very sluggish, since April 2020 when it was introduced.

Another important intervention, introduced by the ESRP, is the Natural Gas Clearinghouse (NGC). A challenge associated with the implementation of the CWM was that, revenues collected in the electricity sector did not meet the associated cost of gas supplied. The Natural Gas Clearinghouse (NGC) was, therefore, proposed as a means of ensuring that gas sector entities are paid in full. As at the publication of this report, the NGC has moved into full implementation.

The NGC Committee has agreed that all power and non-power sector gas invoices and payments are to be included in the NGC.

Revenue for the period, January to December 2021, from the Cash Waterfall Mechanism (CWM) to GNPC amounted to GH¢892,445,847.00. This was paid directly to gas suppliers and service providers, such as West African Gas Pipeline Company (WAPCo) for transportation and OCTP gas accounts for SGN Partners.

The Ghana National Gas Company (GNGC) received a total CWM revenue of GH¢758,694,299.69 (US$130,671,856.72) for 2021.

[8] The energy sector debt is a legacy debt that arose partly as a result of government's failure to honour subsidies announced in the national budget over the years, and partly, as a result of ECG's inability to efficiently collect tarrifs for power sold in order to pay GRIDCO for transmission services, VRA for bulk power supply, to enable VRA pay for gas purchases from Ghana Gas for power generation.

[9] Contained in a press statement on CENIT Energy, issued by the Ministry of Finance on 25 September, 2020.

Chapter

2

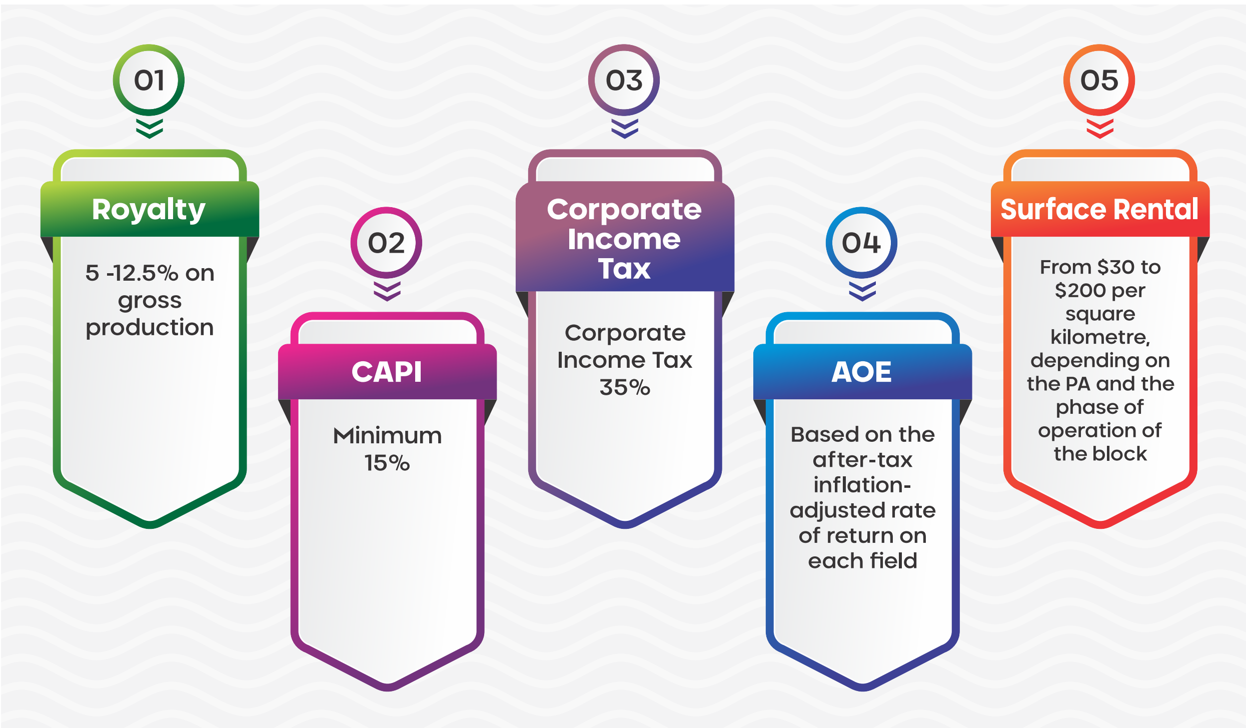
FINANCIAL OVERVIEW OF GHANA'S UPSTREAM OIL AND GAS SECTOR

Financial Overview Of Ghana's Upstream Oil And Gas Sector

2.1 Fiscal Regime of Ghana

The Petroleum (Exploration and Production) Act, 2016 (ACT 919), and the Income Tax Act, 2015 (Act 896) detail the fiscal regime and revenues to be paid to the country. However, revenues from current oil-producing fields are governed by the Petroleum (Exploration and Production) Act (PNDCL 84) and the Petroleum Income Tax Act (Act 896, 2015). Beyond these laws, Petroleum Agreements (PAs) provide more specific definitions of fiscal elements negotiated between the State and the companies. The main fiscal instruments across all producing fields are Royalties, Corporate Income Tax, Additional Oil Entitlement, Surface Rentals, and Carried and Participating Interests.

Figure 1: **Main fiscal terms of the Petroleum Agreements as per the Petroleum (Exploration and Production) Act 2016 (Act 919)**



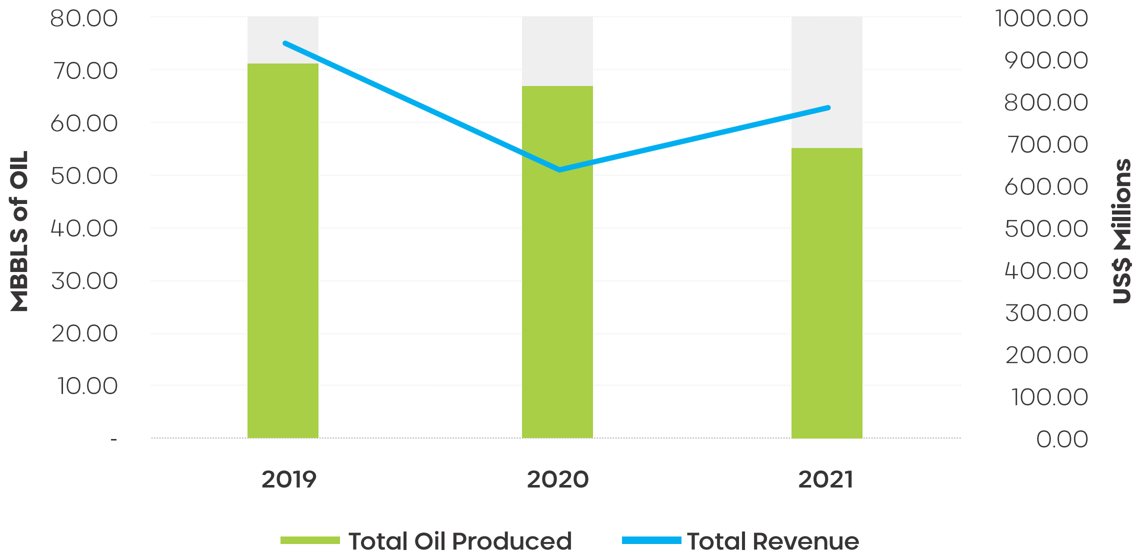
Source: Author's construct, based on Act 919 and Model Petroleum Agreement.

Royalties	This is an entitlement of the country to a percentage of gross production. Ghana's royalty interests in the three producing fields are 5 percent from the Jubilee and TEN Fields and 7.5 percent from the Sankofa Gye Nyame (SGN) Field.
Carried and Participating Interest (CAPI)	The fiscal regime provides for free carried interest. CAPI is an interest held by the State without contributing to exploration costs. In the three producing fields, the free carried interest for Ghana is 10 percent for Jubilee and TEN fields and 15 percent for the SGN field. The contract also provides additional interest, which the State can opt for after a commercial discovery is made. The additional interest in the Jubilee Field is 3.64 percent and 5 percent for the TEN and SGN fields.
Corporate Income Tax	Companies are required to pay income tax annually. Corporate Income Tax on upstream and midstream petroleum companies is 35 percent of net profit as required by the petroleum agreements.
Surface Rentals/ Acreage fees	This revenue accrues to the country from charging companies for the occupation and use of petroleum blocks belonging to the State. Surface Rental charges range from $30 to $200 per square kilometre, depending on the petroleum agreement and the phase of operation of the block.
Additional Oil Entitlements (AOE)	This is determined based on the after-tax inflation-adjusted rate of return on each field. The AOE is a windfall tax to the government and is determined by the terms of the petroleum agreement.

2.2 Petroleum Revenue for 2020 and 2021

The Petroleum Revenue Management Act (PRMA), 2011 (Act 815) sets up the framework for collecting, allocating and utilizing petroleum receipts. Based on the fiscal regime outlined above, total petroleum receipts from Ghana's three producing fields, i.e., Jubilee, TEN and Sankofa Gye Nyame, amounted to US$783.33 million in 2021 and US$666.39 million in 2020. Therefore, the cumulative total petroleum receipts, since 2011, is about US$7.36 billion at the end of 2021. Petroleum receipts in 2021 increased by 17.5 percent over receipts in 2020, even though production in 2020 was higher than in 2021 as shown in Fig. 2. The increased revenue can be more attributed to the favourable international crude prices than due to the global recovery from the Covid-19 pandemic. The average achieved price by GNPC, on behalf of the Ghana group for the three producing fields, increased by 63.7 percent, rising from US$42.11/bbl in 2020 to 69.18 per barrel in 2021, higher than the government benchmark price of US$54.75/bbl for the year 2021.

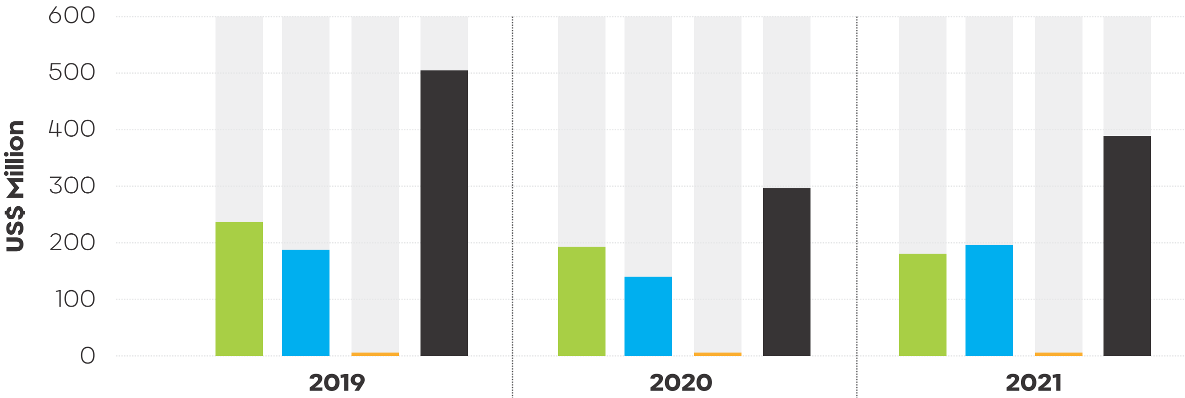
Figure 2: Total Oil Produced vs. Total Revenue, 2019-2021



Source: 2020 & 2021 PIAC Reports.

Out of the US$783.33 million received in 2021, CAPI contributed about US$392.93 million to total receipts, a 30.6 percent increase from about US$300.93 million contributed in 2020. Total royalties in 2021 amounted to US$185.68 million with the Jubilee field accounting for 50 percent of the total royalties, falling from US$195.36 million in 2020 as shown in Fig. 3. Consistently, CAPI has maintained the largest contribution to total receipts, accounting for 54 percent of total receipts in 2019, 47 percent in 2020 and 50 percent in 2021 (Fig. 4).

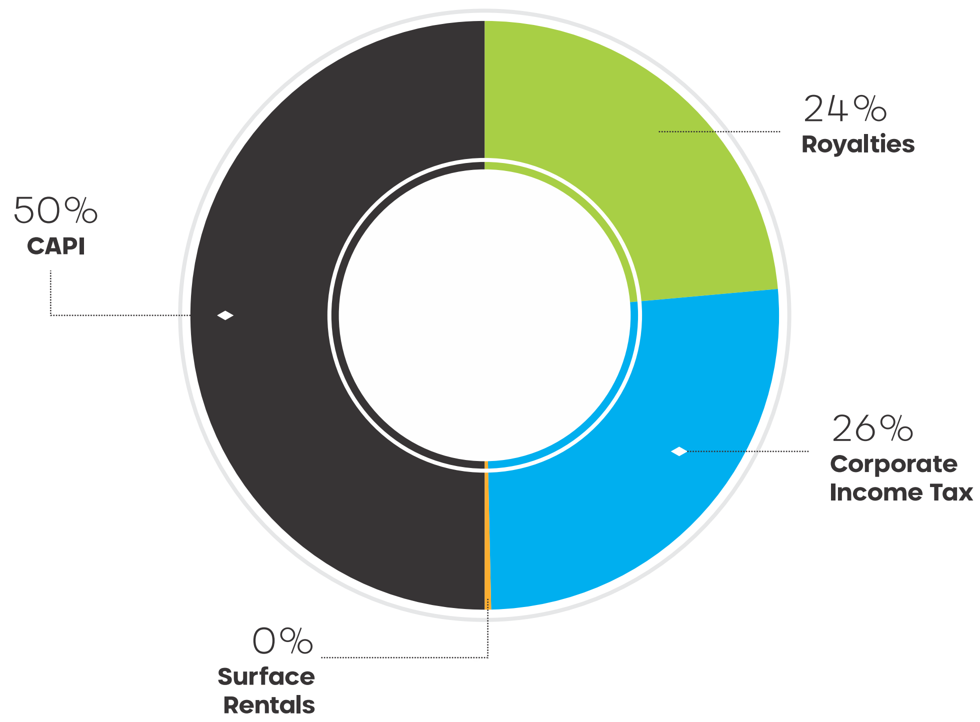
Figure 3: Contribution of Revenue Sources, 2019-2021



	2019	2020	2021
Royalties	236.79	195.36	185.68
Corporate Income Taxes	191.14	141.14	203.86
Surface Rentals	1.11	0.70	0.83
Carried and Participating Interest	505.99	300.93	392.93

Source: 2019, 2020 & 2021 PIAC Reports.

Figure 4: Share of Petroleum Revenue Sources in 2021



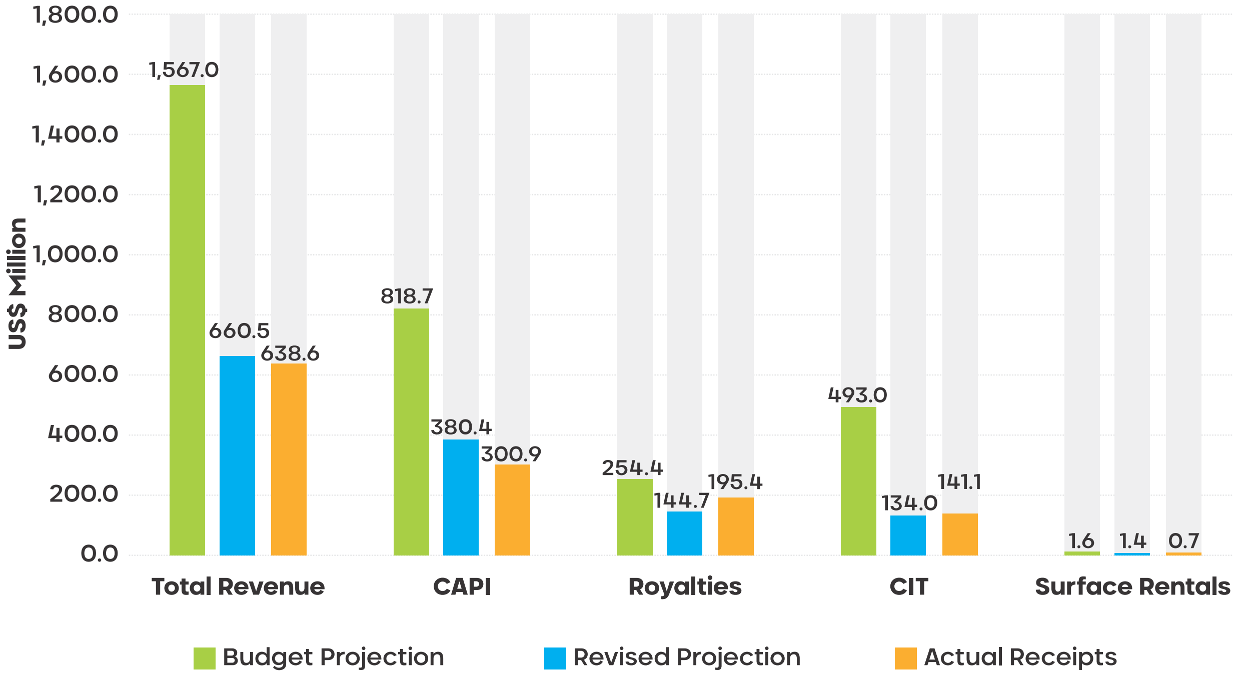
Source: 2021 PIAC Report.

2.3 The Impact of the Covid-19 Pandemic on Petroleum Revenues

In the 2020 budget, the government of Ghana projected to receive US$1,567 million, based on a projected crude oil benchmark price of US$62.6 per barrel. However, the outbreak of the Covid-19 pandemic in 2020 significantly impacted these projections, and the actual revenues realized. The Covid-19 pandemic occasioned a significant decline in global economic activity and demand for oil, thus creating excess oil supply. This, ultimately, led to a sustained fall in global crude oil prices, with an average of US$43.3 per barrel. The global fall in oil prices has had a significant impact on the cash flow of oil companies and the revenue of governments in oil-producing countries. As a result, most African governments were forced to revise their revenue targets in the year and are yet to recover from the attendant revenue losses.

In March 2020, the Minister of Finance, in a statement to Parliament, revised the projected crude oil benchmark price from US$62.6 per barrel to US$30 per barrel, which implied revenue losses to the tune of about US$906.55 million, relative to the budget projections. At the end of 2020, the realized oil revenue was US$638.64 million, a 58 percent deviation from the budget projection of US$1,567 million (Fig. 5).

Figure 5: Projected vs. Revised vs Actual Petroleum Receipts in 2020



Source: 2020 & 2021 Budget Statements.

The revenue losses to the government had severe implications for the budget, particularly physical infrastructure, and debt servicing. In the 2020 budget, Ghana's infrastructure development programme was heavily dependent on oil revenues; about 80 percent of the government's domestic revenue for its capital budget was to be sourced from the Annual Budget Funding Amount (ABFA). The government projected to receive US$761.5 million for budgetary support public expenditure in 2020. This was revised downwards to US$285.8 million on account of the impact of Covid-19 on crude prices and the attendant effect on petroleum receipts. This created a shortfall of US$475.7 million.

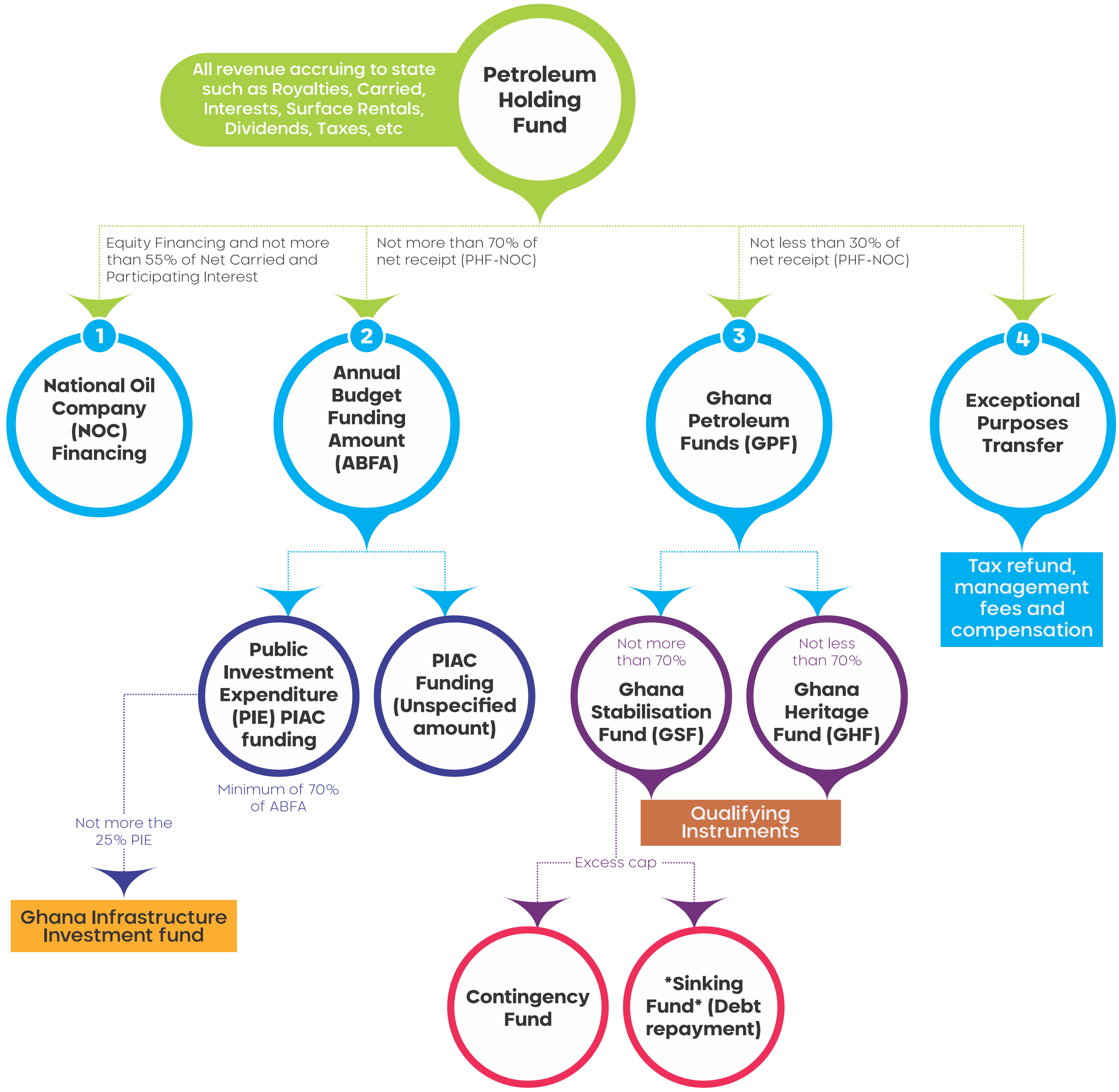
As a result, the cap on the Ghana Stabilization Fund (GSF) was reduced from US$300 million to US$100 million to allow the Minister of Finance to transfer the US$307.54 million excess over the cap to partially make up for the budget deficit and contingency spending. The realized end-of-year ABFA was US$273.4 million in 2020.

Another implication of the sustained low oil prices is the receipts due the national oil company, GNPC. Low oil prices automatically reduce GNPC's share of Net Carried Participating Interest (Net CAPI). In the 2020 budget, GNPC was projected to receive about US$156.3 million as its 30 percent share of Net CAPI. This was, however, reduced to 15 percent in the revised budget projections to mitigate the impact of the low oil price on the budget. The new allocation decreased the Net-CAPI of GNPC to about US$43.83 million in 2020.

2.4 Petroleum Revenue Allocations

The PRMA created the Petroleum Holding Fund (PHF), a transitory fund into which all petroleum-related revenues are paid before disbursement into various accounts created by law. The law prioritizes allocation to GNPC for their equity financing cost and the operations and investments of the Corporation. The balance of the PHF after deducting the allocation to GNPC (Benchmark Revenue) is disbursed into two accounts: the Annual Budgeting Funding Amount (ABFA) and the Ghana Petroleum Funds (GPFs). The ABFA receives up to 70 percent of Benchmark Revenue, while GPF receives a minimum of 30 percent of the Benchmark Revenue. ABFA is earmarked to support government expenditure in the fiscal year. Allocation to the Ghana Petroleum Funds is further divided into two accounts: the Ghana Heritage Fund (GHF) and the Ghana Stabilisation Fund (GSF), for the respective purposes of saving for the future and smoothening the ABFA in a particular year. There are also special allocations, including tax refunds and the payment of management fees.

Figure 6: The PRMA's framework for petroleum revenue collection and distribution [10]

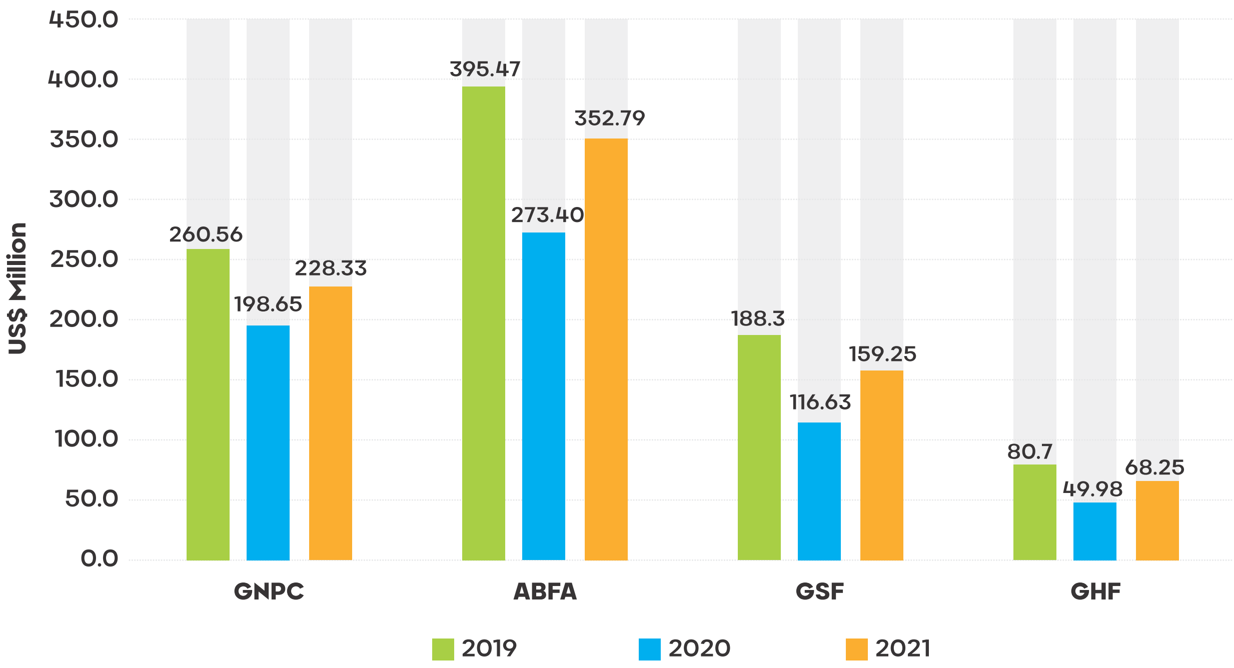


Based on the distribution architecture in the PRMA as outlined above, in 2020, out of the US$666.4 million received into the PHF, US$638.64 million was distributed into the various accounts. The GNPC received US$198.65 million, while the ABFA received US$273.40 million. The Ghana Petroleum Fund received a total of US$166.61 million, out of which US$116.63 million was disbursed to the Ghana Stabilization Fund (GSF) and the Ghana Heritage Fund (GHF) received US$49.98 million.

An outstanding balance of US$40.41 million in the PHF was carried forward into 2021, increasing the total funds available for disbursement in 2021 from the US$783.33 million received in 2021 to US$823.74 million. Out of the US$823.74 million available for disbursement on 2021, the GNPC received US$228.63 million, a 15 percent increase over the US$198.65 million received in 2020. Similarly, the ABFA received US$352.79 million, 29 percent increase over the US$273.40 million received in 2020. Disbursements to the Ghana Petroleum Funds also increased by about 36.6 percent, from US$166.61 million received in 2020 to US$227.50 million 2021.

[10] Sackey, J.A. (2018). Petroleum Revenue Management Manual. Africa Centre for Energy Policy, p. 30. Available at https://s3.amazonaws.com/new-acep-static1/reports/PRMA_MANUAL_cmyk.pdf. The illustration is based on sections 11, 12, and 16 of the PRMA.

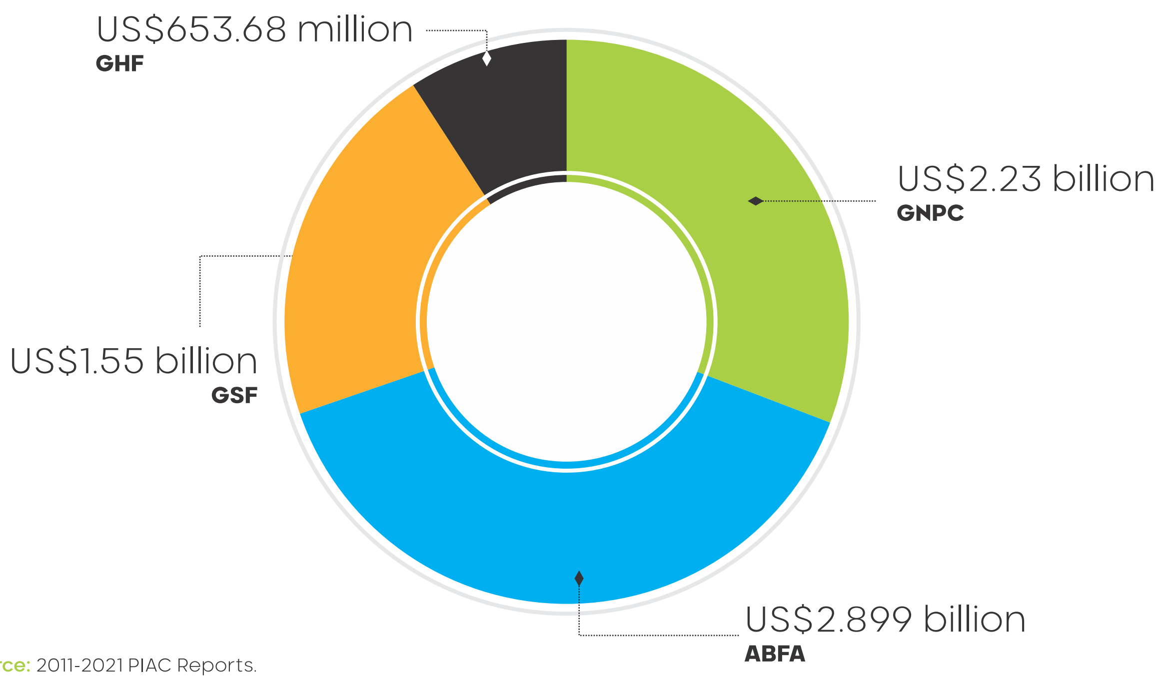
Figure 7: Petroleum Revenue Disbursement 2019-2021



Source: 2019, 2020 & 2021 PIAC Reports

Cumulatively, the GNPC has received US$2.23 billion, about 30 percent of cumulative total petroleum receipts, from 2011 to 2021, to finance its equity costs and operations. The ABFA, on the other hand, has cumulatively received about US$2.9 billion, about 40 percent of cumulative total receipts, for budgetary support and development financing, while the Ghana Petroleum Funds received US$2.2 billion out of which the GSF and the GHF received US$1.55 billion and US$653.68 million, respectively, as shown in Fig. 8.

Figure 8: Cumulative Disbursements of Petroleum Receipts 2011-2021



Source: 2011-2021 PIAC Reports.

2.5 Allocations to Ghana National Petroleum Corporation (GNPC)

The PRMA entitles GNPC to a share of petroleum revenues to finance its equity costs. The Corporation is further allowed up to 55 percent of the balance of the Net Carried and Participation Interest (CAPI) for their operations. The actual percentage to be received as Net CAPI is set by the Finance Minister to be approved by Parliament every three years. The prevailing rate is 30 percent of Net CAPI. In 2020, GNPC received a total of US$198.65 million, made of equity financing cost of US$154.82 million and US$43.83 million as its 30 percent share of Net CAPI. GNPC's receipts for 2020 represent a 24 percent decline, from the US$260.56 million it received in 2019.

In 2021, the Corporation received US$228.33 million, a 14.94 percent increase from 2020 receipts, to finance its activities. This amount is made up of US$157.79 million equity financing costs and US$70.54 million. This brings the cumulative receipts of the Corporation, since 2011, to about US$2.23 billion, as shown in Fig. 8 above.

Figure 9: Disbursements to GNPC 2019-2021

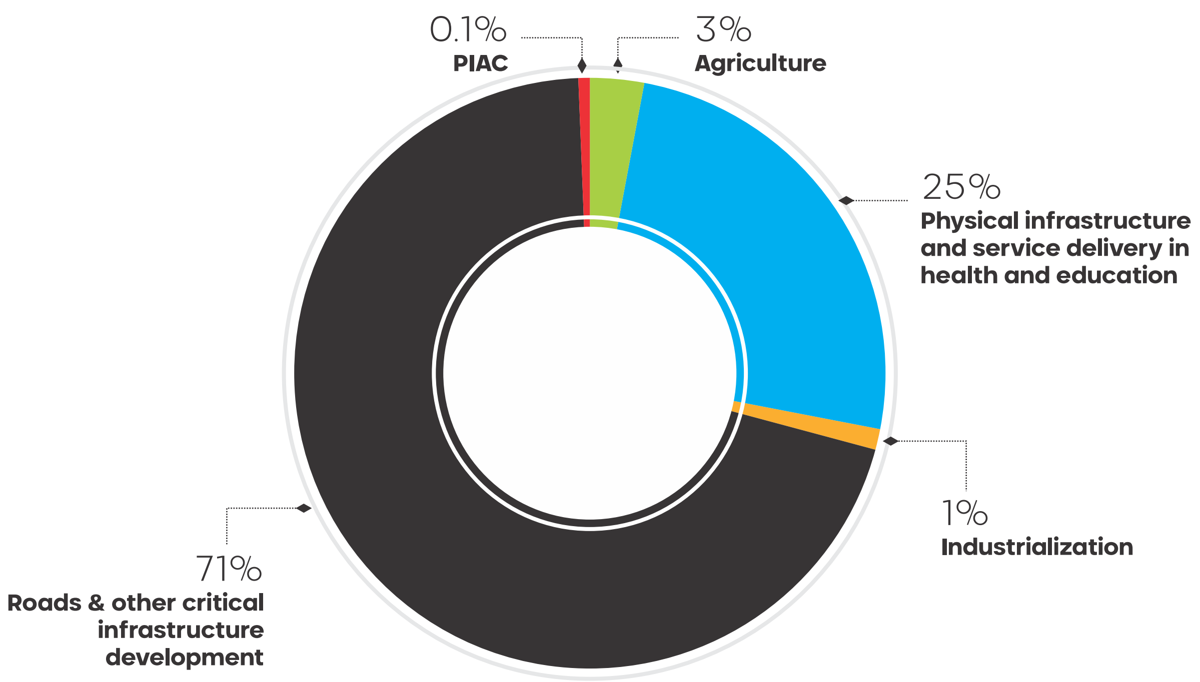
Source: 2019, 2020 & 2021 PIAC Reports.

2.6 Allocations to the Annual Budget Funding Amount (ABFA)

The Annual Budget Funding Amount is the proportion of petroleum revenues allocated to the government's annual budget to support development financing. Section 21(4) of the PRMA requires that not less than 70 percent of the ABFA is utilized on public investment expenditures. The ABFA also allocates funds to the Public Interest and Accountability Committee and the Ghana Infrastructure Investment Fund. The PRMA prescribes that the expenditure of the ABFA should be guided by a medium-term expenditure framework aligned with a long-term national development plan. In the absence of a national development plan, the Finance Minister is required to prioritize up to four of the sectors outlined in the Act every three years for ABFA expenditures. The 2020 and 2021 budgets prioritized ABFA expenditure to Agriculture, Physical infrastructure and service delivery in health and education, Roads, Rail and other critical infrastructure and Industrial Development.

In 2020, the ABFA was projected to receive US$761.5 million, but was later revised to US$285.8 million due to the impact of Covid-19 on oil prices and its attendant effects on petroleum revenues. Ultimately, the ABFA realized US$273.4 million from the 2020 total petroleum receipts. However, the actual ABFA utilization in 2020 was about US$494.84 million due to an additional US$364.28 million realized from unutilized ABFA balances between 2017 and 2020. Out of the US$494.84 million available for spending, a significant 71 percent (US$349.82 million) was disbursed for expenditure on Roads, Rail and other critical infrastructure, while about 25 percent (US$124.69 million) was disbursed for expenditure on Physical infrastructure and service delivery in health and education. Agriculture received just 3 percent (US$14.11 million) with industrialization receiving US$ 5.69 million, one percent of the ABFA disbursed. Beyond the priority areas, PIAC also received US$0.52 million for its operations in 2020.

Figure 10: Percentage ABFA Disbursement in 2020

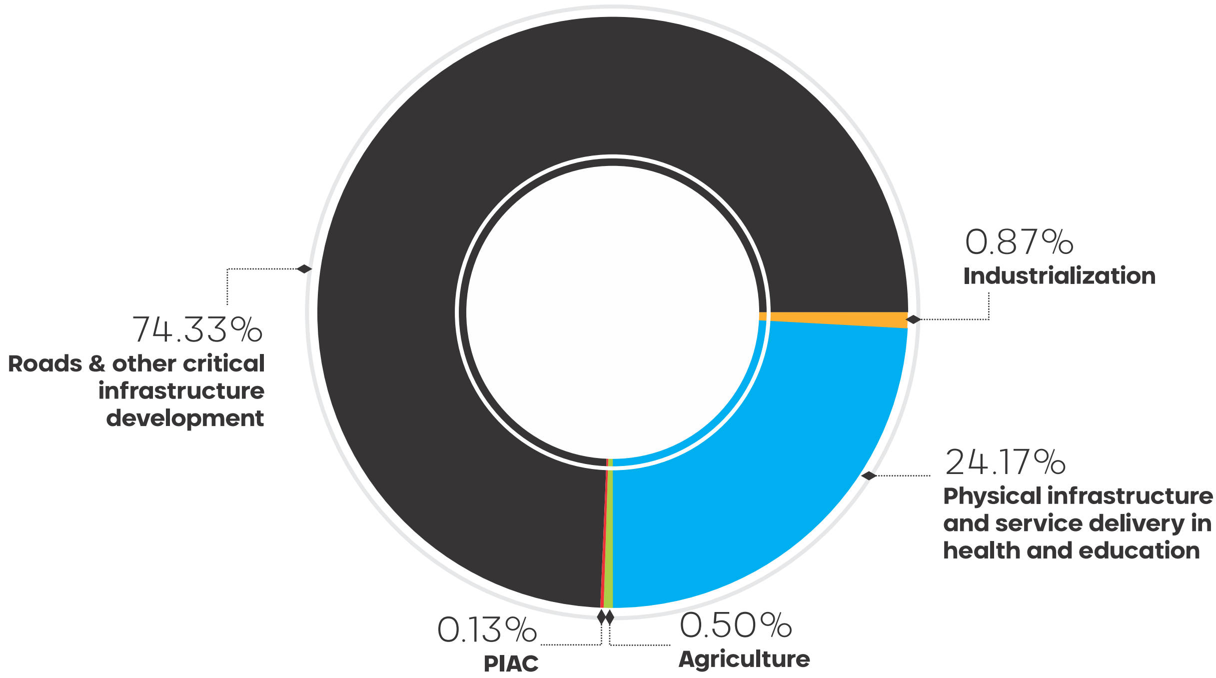


Source: 2020 PIAC Report

In 2021, the ABFA received US$352.79 million which was 29 percent higher than the 2020 receipts, even though it fell short of the 2021 budget projection by 16 percent. The ABFA receipts in 2021 brings the total cumulative ABFA received from 2011 to 2021 to about US$2.9 billion. Out of the US$352.79 million received in 2021, about 50 percent (US$177.86 million) was disbursed for expenditure on Roads, Rail and other critical infrastructure, which is 49 percent lower than the US$349.82 million disbursed to the sector in 2020. Moreover, physical infrastructure and service delivery in health and education received US$124.69 million, about 21 percent of the realized ABFA in 2021. Agriculture, on the other hand, received US$1.59 million (0.5 percent), while industrialization received US$ 5.69 million (Fig. 10). Beyond the priority areas, PIAC also received US$0.398 million for its operations in 2020.

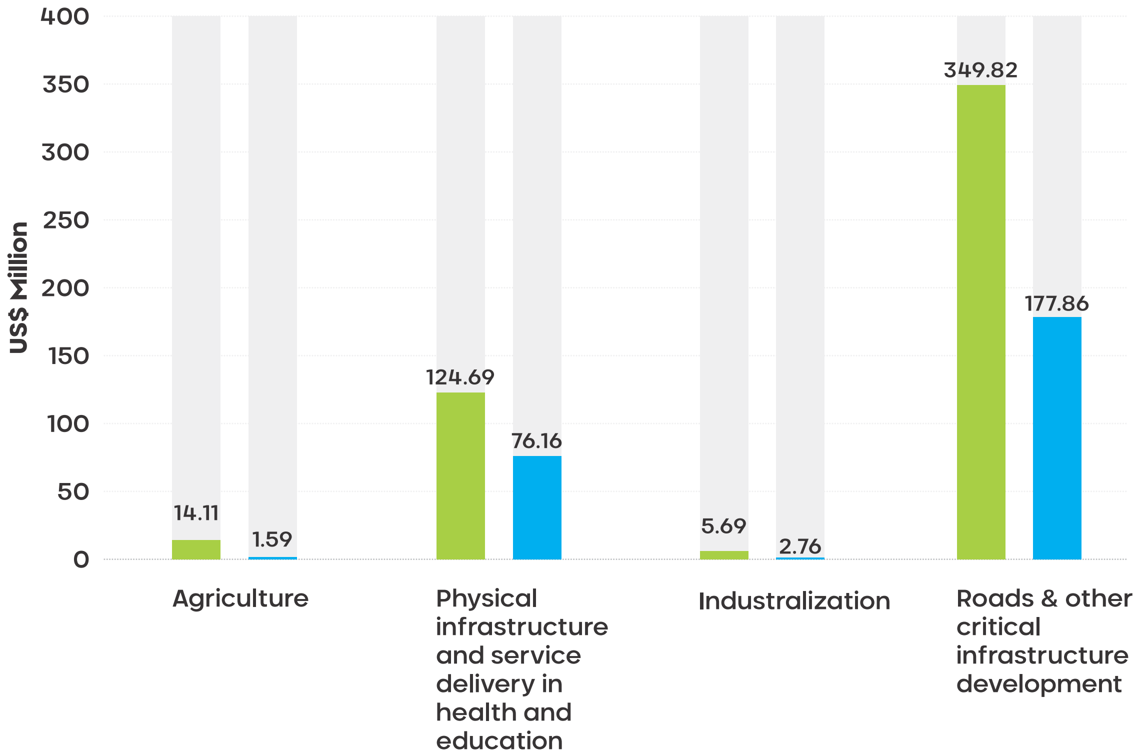
In 2021, the Ministry of Finance resumed disbursements to the Ghana Infrastructure Investment Fund (GIIF), as allowed by the amendment to the PRMA in 2015. GIIF is entitled to not more than 25 percent of the realized ABFA in the year. Consequently, the GIIF received US$49.22 million, making up about 14 percent of the 2021 realized ABFA. Additionally, the District Assemblies Common Fund (DACF) received US$5.59 million from the ABFA for the first time since the 2019 Supreme Court ruling in Kpodo v AG. The ruling directed the addition of the ABFA in the computation of total government revenue which is the basis for determining the funds received by the DACF.

Figure 11: Percentage ABFA Disbursement in 2021



Source: 2021 PIAC Report

Figure 12: ABFA Disbursements in 2020 & 2021



Source: 2020 & 2021 PIAC Reports

The total disbursements of ABFA in 2021 amounted to US$313.57 million, leaving US$39.22 million, which is 11 percent of the ABFA unutilized in the year. Unutilized balances of the ABFA is a worrying trend, especially when the balances are compared to the disbursements made to the priority sectors, such as agriculture. In 2021, agriculture received US$1.59 million (0.5 percent), yet the unutilized balance of the ABFA was US$39.22 million.

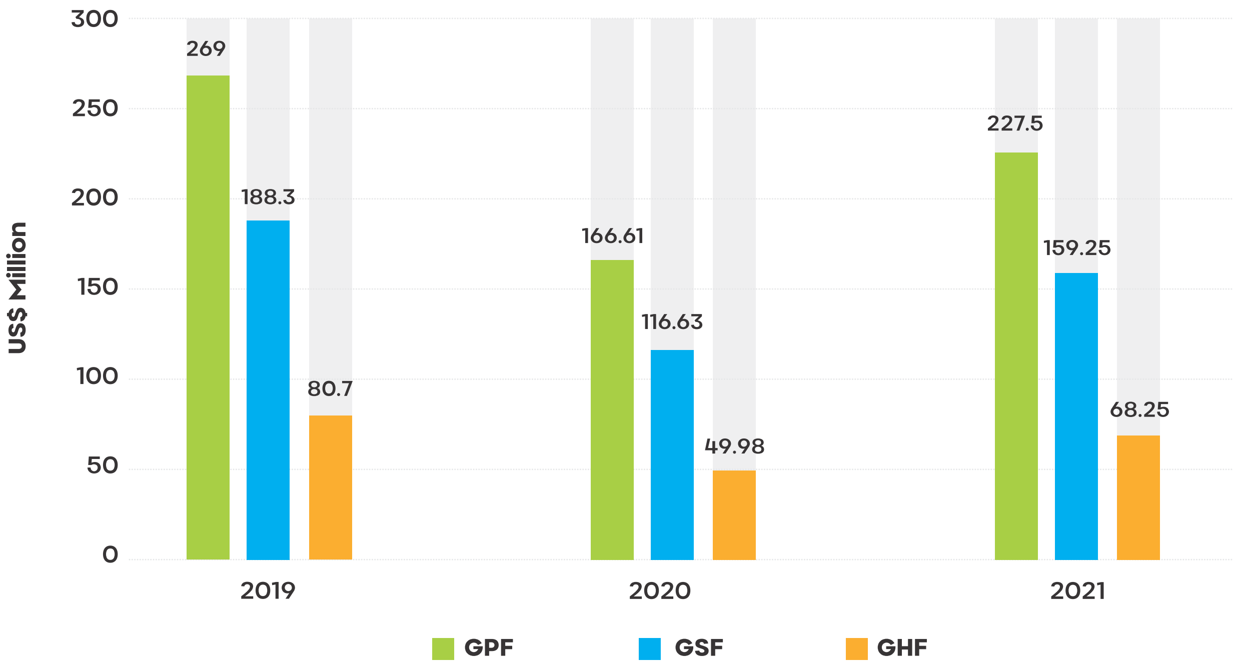
2.7 The Ghana Petroleum Funds

The Ghana Petroleum Funds (GPFs) are owned by the government of Ghana and comprises the Ghana Stabilization Fund (GSF) and the Ghana Heritage Fund (GHF). The funds are required to be transparently managed and within its constitutional and legal framework. The GSF was established to smoothen consumption during periods of ABFA revenue shortfalls. The GSF allows flexibility for government expenditure on the account of the volatilities associated with oil revenues. The GHF, on the other hand, is an endowment fund to be used only when the oil and gas resources are depleted. Essentially, the GHF is an instrument used to achieve intergenerational equity for utilizing the country's petroleum wealth.

The PRMA prescribes the realized GPF to be disbursed to the GSF and the GHF in the ratio of 70:30, i.e., the GSF receives 70 percent of the GPF with the GHF receiving the remaining 30 percent. The law also allows the Finance Minister to cap the GSF at a parliamentary approved level and withdraw the excess over the cap for contingency spending and into the Sinking Fund for debt servicing. In the determination of the retained balance in the GSF after the cap, the Finance Minister is instructed by the Petroleum Revenue Management Regulations, 2019 (L.I. 2381), to ensure the amount is not less than the average ABFA over a three-year period.

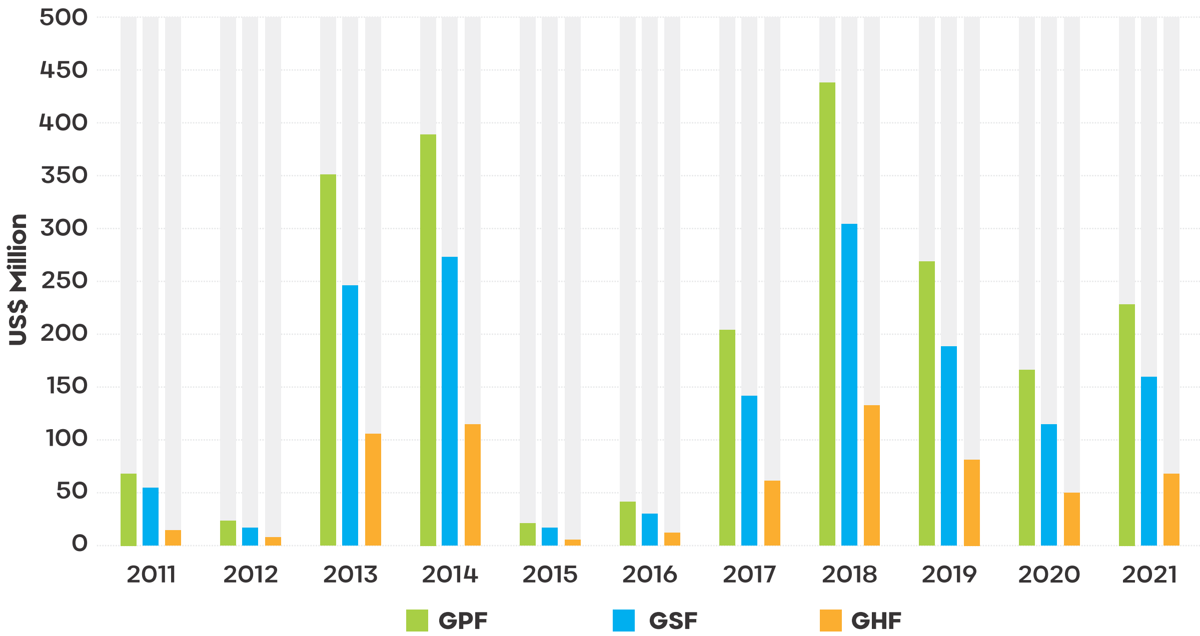
In 2020, the GPFs received US$166.61 million, out of which US$116.63 million went into the Ghana Stabilization Fund, while the Ghana Heritage Fund received US$49.98 million. Similarly, in 2021, the GPF received US$227.5 million which was 25 percent higher than the budget projection for 2021. Out of the US$227.5 million received, the GSF received US$159.25 million, a 36.6 percent increase from receipts in 2020. The GHF received the remaining US$68.25 million, which was also a 36.6 percent increase from 2020 receipts. The receipts into the GPF in 2020 and 2021 brings the cumulative total receipts to the GPF since 2011 to 2021 to US$2.2 billion. Relatedly, the cumulative total disbursement to the GSF and the GHF is US$1.55 billion and US$653.77 million, respectively.

Figure 13: Disbursements to the GPFs 2019-2021



Source: 2019, 2020 & 2021 PIAC Reports.

Figure 14: Total Annual Allocations to the Ghana Petroleum Funds from 2011-2021



Source: 2011-2021 PIAC Reports.

2.8 Investments of the Ghana Petroleum Funds

The Bank of Ghana is responsible for the operational management of the Ghana Petroleum Funds under the terms of the Operation Management Agreement (OMA) with the Minister for Finance. Section 25 (a) and (c) of the PRMA mandates the Minister for Finance to develop a policy for the investment of the GPF and make decisions in relation to the investment strategy and management of the GPF. Both the GSF and GHF are invested in dollar-denominated debt instruments that generate returns as required by the PRMA. Currently, the GPFs are invested in the following instruments: overnight and call deposits, discount notes, treasury bills, short-term deposits, investment grade bonds, certificates of deposits, commercial papers and medium-term notes.

For 2021, the Bank of Ghana[11] reported a negative 1.76 percent end-of-year return on investment for the Ghana Heritage Fund compared to the 4.66 percent return on investment realized in 2020. The two-year annualised return for the GHF in 2021 was 1.40 percent, less than the 5.27 percent realised in 2020. The net realised income for the GHF for 2021 was US$13.51 million, an 18.7 percent decline from the US$16.62 million realized in 2020, which brings the net realised income from the GHF since 2011 to 2021 to about US$72.86 million.

The GSF in 2021 hand-posted an end-of-year return on investment of 0.03 percent compared to 0.35 percent in 2020 and a 2-year annualised return of 0.19 percent compared to 1.32 percent in 2020. The net realised income for the GSF in 2021 was US$0.63 million, down by 72 percent from the US$2.31 million realised in 2020, which brings the GSF's total realised income from 2011 to 2021 to about US$24.7 million (Table 5).

[11] Bank of Ghana 2020 Petroleum Holding Fund (PHF) & GPFs Semi-Annual Report.

Table 4: Net Realised Income from GPF in 2020 & 2021

Name of Fund	2020	2021
Net GPF Income	17.5	14.14
Net GHF Income	15.2	13.51
Net GSF Income	2.31	0.63

Source: 2020 & 2021 Ghana Petroleum Funds Reports.

Table 5: Net Accumulated Reserve of the Ghana Petroleum Funds (GPFs)

Fund Name	Allocations Since Inception (Injection)	Realised Income – Nov 2011 (Inception) to Dec 2021	Total Allocation and Net Income Since Inception	Withdrawals	Closing Value of GPFs
	31-Dec-20 US$	31-Dec-2020 US$	31-Dec-2021 US$	31-Dec-2021 US$	31-Dec-2021 US$
Ghana Heritage Fund	653,677,565.50	72,860,388.08	726,537,953.58	-	726,537,953.61
Ghana Stabilization Fund	1,546,453,001.76	24,697,325.39	1,571,150,327.15	(1,326,261,966.37)	244,888,360.88
Total	**2,200,130,567.26**	**97,557,713.47**	**2,297,688,280.73**	**(1,326,261,966.37)**	**971,426,314.49**

Source: Bank of Ghana 2021 Petroleum Holding Fund (PHF) & GPFs Semi-Annual Report.

2.9 Expenditure from the Ghana Stabilization Fund (GSF)

The PRMA allows the Minister for Finance to set a cap on the GSF and transfer the excess over the cap into the Contingency Fund for contingency expenditure and the Sinking Fund for debt servicing. The law also allows withdrawals when petroleum revenues collected in any quarter falls below one quarter of the Annual Budget Funding Amount for that financial year. In the 2020 budget, the GSF was capped at US$300 million. This was, however, revised downwards to US$100 million on account of the impact of Covid-19 on crude prices and the attendant effect on petroleum receipts and allocations to ABFA. This allowed the Minister of Finance to transfer the US$307.54 million excess over the cap to partially make up for the budget deficit and contingency spending. This withdrawal brings the total withdrawal from the GSF since 2011 to about US$1.33 billion (Table 5).

At the end of December 2020, the accumulated excess over the cap stood at about US$99.99 million, while the closing amount stood at US$199.99 million. In 2021, US$114.98 million was withdrawn from the GSF as the excess over the US$100 million cap set by the Finance Minister, leaving a closing balance of US$222.89 million as of December 2021.

GAS SECTOR REPORT

Chapter 3

Gas Sector Report

3.1 The Natural Gas Sector Overview

Natural gas has become the fuel of choice for power generation in Ghana and will continue to be a critical factor in achieving competitive production of electricity in the country. By the end of 2020, almost all, except ASKA thermal plant, were running on natural gas, while maintaining their dual fuel capacity to provide security of power supply and these continued to the end of 2021.

The switch to gas provides a cheaper and environmentally cleaner option relative to liquid fuels for power generation. Thus, maximizing the utilization of domestic gas will be very key to ensuring cost-effective power supply in the country. Besides power generation, natural gas is used currently by two ceramics manufacturing companies for their operations. The government, through the Ministry of Energy, is also advancing plans to extend usage of natural gas to other industries, such as cement, fertilizer/urea production, transportation (Compressed Natural Gas) and for export. As part of the grand agenda to establish Ghana as a hub for the natural gas industry in the West African sub-region, the Ministry is exploring ways to establish Tema as a hub for LNG bunkering for vessels that utilize LNG as source of fuel. Government's efforts to create a vibrant natural gas sector is in line with the policy to transition progressively from high carbon energy sources to low carbon sources. As of 2021, about 13 percent of the gas produced in the country was consumed by domestic users.

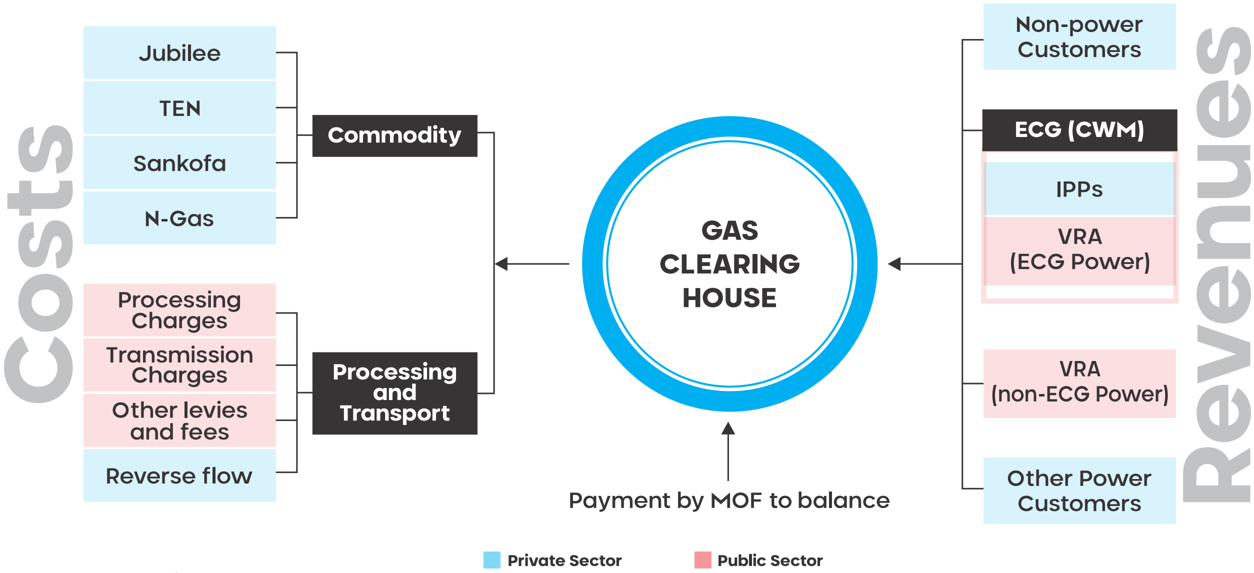
3.2 Gas Sector Policy Developments in 2020/2021

3.2.1 Natural Gas Clearinghouse (NGC)

For the period under review, ECG's revenue collections have been allocated and paid out through the Cash Waterfall Mechanism (CWM). While this is a good step in distributing funds from the regulated power sector equitably, it only covers revenue from ECG's power sales. Natural Gas is also consumed in power generation for NEDCo, Enclave Power Ltd., VRA's private customers, Genser's customers and for export. In addition, some power is consumed by some industrial customers (ceramics companies) in the Western Region. Much of the revenue associated with these gas sales is not recovered by the gas suppliers and service providers, and the Ministry of Finance (MoF) is, in some cases, called on to cater for this revenue gap.

Since the MoF's role in covering the sector gap is not sustainable, the NGC is proposed to fulfil this requirement. This is particularly important for ensuring that the private players in the gas sector are paid in a timely manner. These companies include Eni and Vitol (the Sankofa partners), N-Gas and WAPCo, and they have contractual credit mechanisms that can further damage State-Owned Enterprises (SOE) and Government of Ghana (GOG) credit ratings. The conceptual framework for the NGC is shown in the graphic below:

Figure 15: Conceptual Framework



Source: Ministry of Energy

The NGC will provide a mechanism for the implementation of the Weighted Average Cost of Gas (WACOG) and Discounted Industrial Development Tariff (DIDT) and calculate the allocation and disbursement of associated revenues under a clearinghouse system. Ultimately, the goal is a complete balancing of costs and revenues across the gas sector through appropriate tariff structures and debt collection, but until that is achieved, the NGC is designed to minimize the amount that MoF is called upon to pay to close the revenue gap.

3.2.2 Status of Institutional Alignment

Since the approval of the Gas Master Plan (GMP) by Cabinet in 2016, measures to implement institutional alignment in the gas sector remain hanging. The overlapping mandates of the operational companies and the multiplicity of regulatory roles are viewed by many experts as unhealthy for a nascent gas industry, such as Ghana's. The intended merger between the GNGC and GNPC did not materialise, despite the advantages of a more integrated managing and financing in the oil and gas sector.

In 2015, in line with the recommendation of the GMP, government approved, the GNPC took over the Ghana National Gas Company (GNGC) as a subsidiary. A key consideration for this consolidation was to make it possible to have a more integrated management and financing of projects in the oil and gas sector. This was particularly necessary to provide the needed financial securities for the development of the Offshore Cape Three Points (OCTP) project. The take-over of GNGC by GNPC as a subsidiary of the latter provided an institutional arrangement where GNPC occupies the strategic responsibility of gas aggregator with a function to pool gas resources from all upstream sources and sell to bulk consumers. GNGC is, primarily, responsible for the processing of gas and the sale of natural gas liquids. There has also been the policy flexibility for the GNGC to sell gas to non-power and industrial consumers.

The announcement of the merger has been met with stiff opposition from GNGC and, so far, it has been the only entity within the sector that has shown opposition to the policy that has received approval from all industry players. Unfortunately, the merger only lasted for five months and was abandoned after a change of government.

To improve operational and process efficiency within the gas sector value chain, the government of Ghana in May 2020, approved a process to consolidate the midstream gas sector in Ghana; thus, making GNGC an integrated gas company and to perform the following:

- **Gas aggregation:** the gathering of both domestic and international gas. Currently, GNPC remains the gas aggregator.
- **Gas processing:** the processing of raw gas into lean gas and other derivatives for downstream use. Some of these derivatives are condensates, LPG and isopentanes. GNGC, currently, processes raw gas from the Jubilee and TEN Fields.

- **Gas shipping:** the sale of processed gas to downstream customers. Currently, GNPC performs this role (power customers), while GNGC ships to non-power customers; and

- **Gas transportation:** the transportation of lean gas and other derivatives through gas pipelines to downstream customers. Currently, GNGC and WAPCo are the most recognized transporters.

3.3 Gas Infrastructure Developments

3.3.1 Completion of the Takoradi to Tema Interconnection Project (TTIP)

The last phase of the TTIP was completed in July 2020, after the capacity of the West African Gas Pipeline Company (WAPCo)'s Tema Regulating and Metering Station was increased from 140 MMscfd to 235 MMscfd. The previous phase (Takoradi Phase) saw the expansion of the Ghana National Gas Company (GNGC)'s Takoradi Distribution Station (TDS) from 150 MMscfd to 405 MMscfd, expansion of WAPCo's Takoradi Regulating and Metering Station (TRMS) from 120 to 225 MMscfd, as well as an interconnection between the TDS and TRMS by a 1.5 Km pipeline.

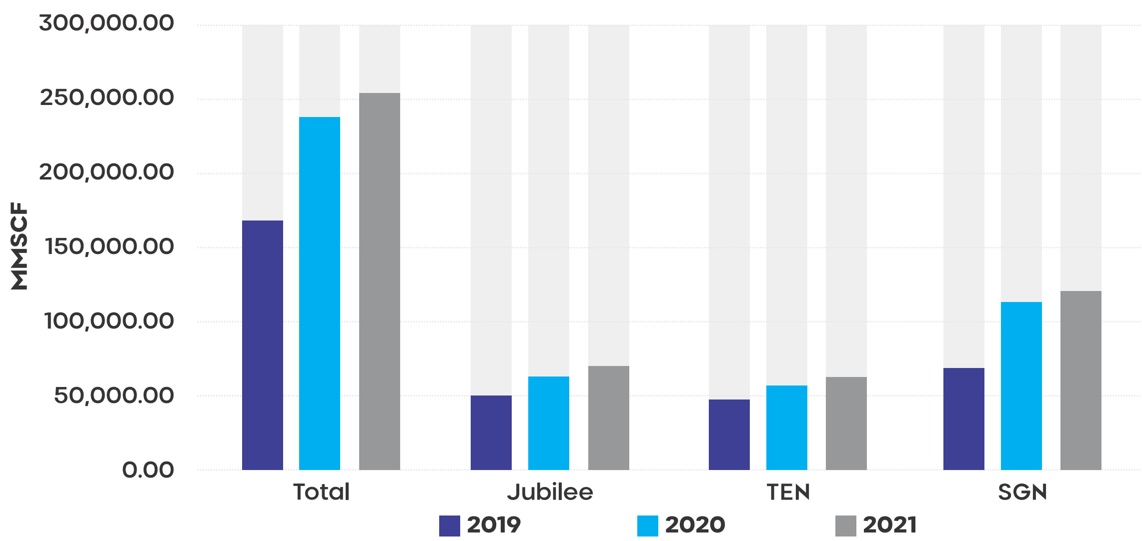
3.3.2 Supply of Gas to the Ashanti Region

Genser Energy has been granted the approval to construct a 20-inch natural Gas pipeline from Prestea in the Western region to Kumasi in the Ashanti region, which has been constructed up to Dawusaso in the Ashanti region and is expected to be extended to Kumasi. With efforts to supply gas for mining activities, the Genser Energy project will be constructing a lateral pipeline from the Dawusaso Branch Point Station to Nyinahin for the bauxite companies within that enclave. This project will facilitate industrialization within the middle belt as it will promote the generation of power for industries.

3.4 Domestic Gas Production and Exports for 2020 and 2021

Total domestic gas consisting of Associated Gas (AG) and Non-Associated Gas (NAG) produced from the three production fields (Jubilee, TEN and SGN) increased from a total volume of 169,508.61 mmscf in 2019 to a total of 237,962.82 mmscf in 2020, representing an increase of 40 percent. In 2021, total gas production was 256,262.04 mmscf, a 7.7 percent increase over 2020 production. The increase in production was largely accounted for by significant increase in production from the Sankofa Gye Nyame (SGN) field coupled with relative stability in gas production from both the Jubilee and TEN fields. Production from SGN increased by 60 percent, from 69,941.60 mmscf in 2019 to 114,825.74 mmscf in 2020 and by about 6 percent to 121,604.96 mmscf in 2021. At the end of 2021, total gas production from the Jubilee field rose from 64,462.41 mmscf in 2020 to 70,527.21 mmscf in 2021, while gas production on the TEN field in 2021 was 64,129.87 mmscf, rising from 58,674.67 mmscf in 2020.

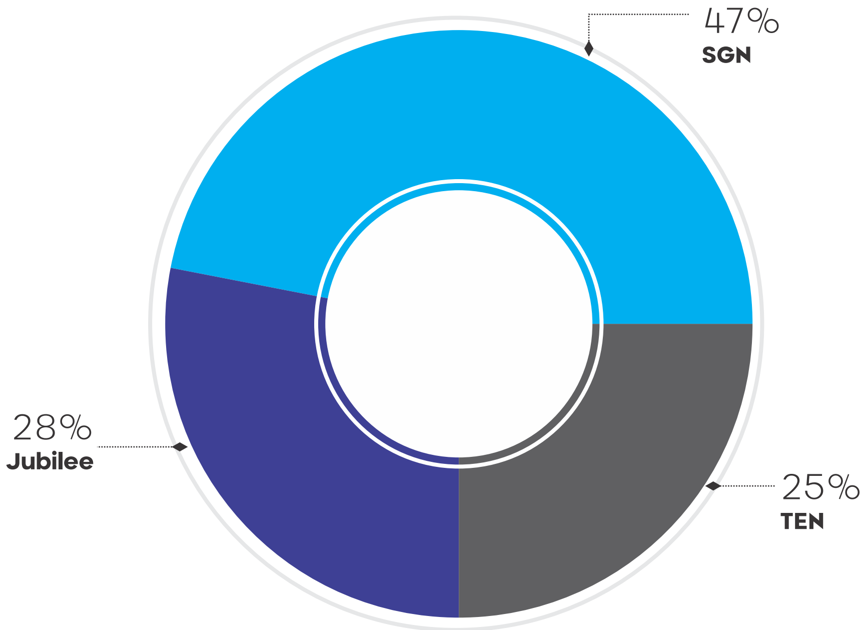
Figure 16: Domestic gas production 2019-2021



Source: 2019, 2020 & 2021 PIAC Reports

In terms of the percentage contribution to total gas production in 2021, SGN's production contributed 47 percent, while Jubilee and TEN contributed 28 percent and 25 percent, respectively, as shown in Fig. 17.

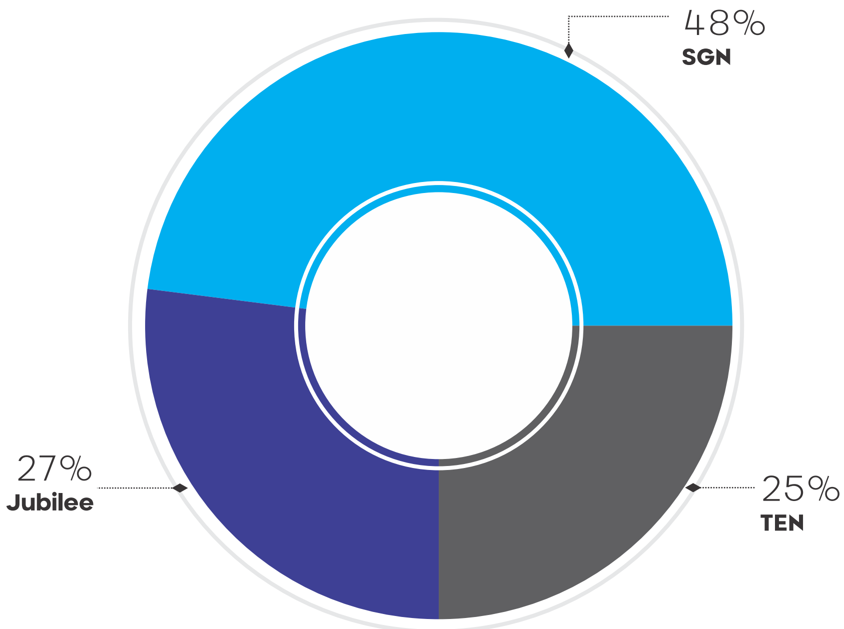
Figure 17: Contribution of producing fields to total gas production in 2021



Source: 2021 PIAC Report

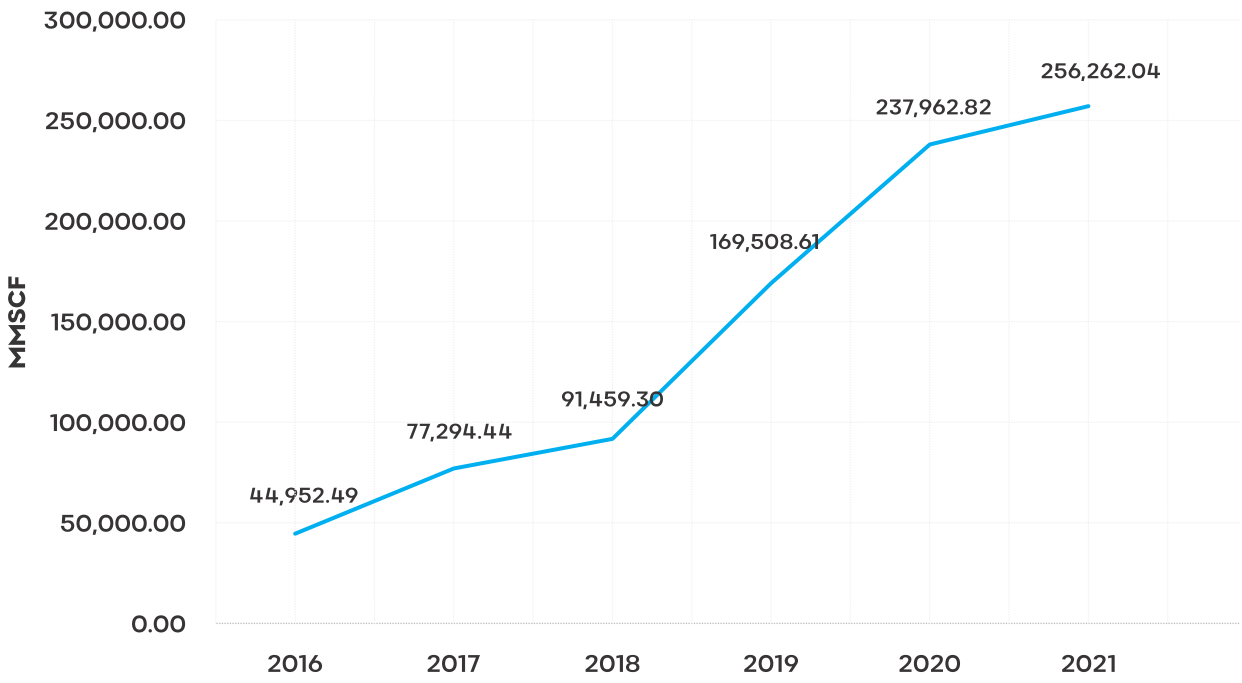
Similarly, in 2020, SGN's production contributed 48 percent to total gas production in the year, while Jubilee and TEN contributed 27 percent and 25 percent, respectively, as shown in Fig 16.

Figure 18: Contribution of producing fields to total gas production in 2020



Source: 2020 PIAC Report

Figure 19: Trend of total domestic gas production between 2016 and 2021

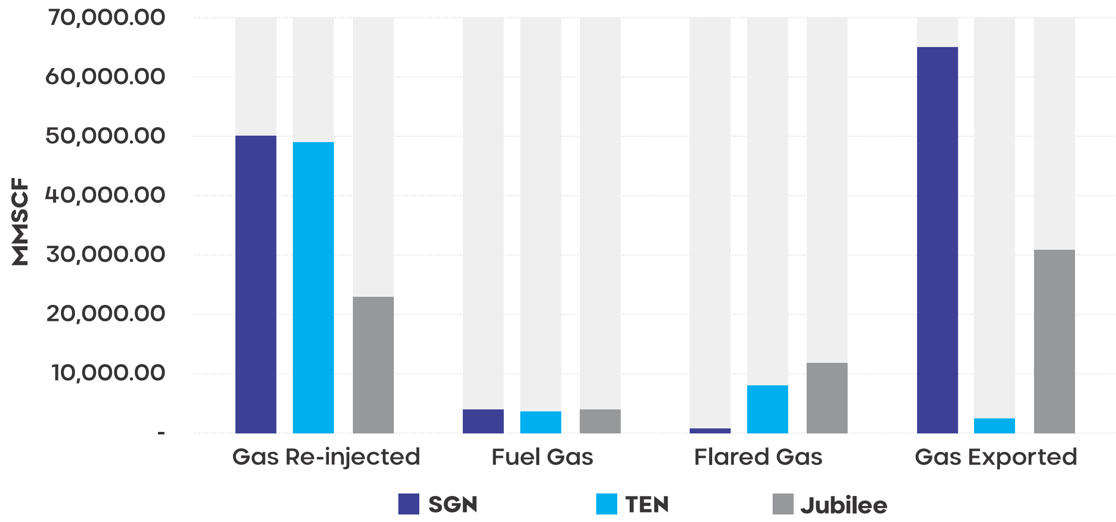


Source: 2016-2021 PIAC Reports

Out of the 237,962.82 mmscf domestic gas produced in 2020, gas exports to Ghana National Gas Company (GNGC) and the Onshore Receiving Facility (ORF) for power generation and non-power use amounted to 88,530.59 mmscf. In addition, 116,252.81 mmscf was reinjected to maintain reservoir pressure, 12,371.26mmscf was used as fuel on the FPSOs and 19,753.51 mmscf was flared. Comparatively, in 2021 a total 122,990.09 mmscf was reinjected whiles about 98,900.58 mmscf was exported to GNGC and the ORF. Fuel gas and flared gas amounted to 12,126.27 mmscf and 21,214.80 mmscf in 2020 and 2021, respectively. While TEN exported only 4.31% and reinjected 76.78% of total production, Jubilee exported 43.95 percent and reinjected 33 percent, SGN also exported 53.57 percent of its total output to the ORF.

The amount of gas flared in 2020 (19,753.51 mmscf) represented a 231 percent increase in gas flaring from the 5,972.32 mmscf flared in 2019, increasing again by 7 percent to 21,214.80 mmsfc in 2021, with Jubilee and TEN fields contributing 53 percent and 42 percent, respectively to the total gas flared. This sets the country back on its zero-flaring policy. Tullow has explained that after 10 years of excess gas injection on Jubilee, it sought permission to flare in order to protect the reservoirs and to sustain oil production at business planned levels. The company also explained that on the TEN FPSO, several Enyenra wells, due to progressive declining/reducing reservoir pressure, can recently only be produced into the FPSO by routing fluid to a separation vessel that has to operate at a pressure much lower than its original design intent. As a result, low pressure separated gas from this vessel (up to 30 mmscfd) is currently being flared, until such time that gas tie-in(s) are installed to reroute this gas to the low-pressure section of FPSO gas processing train. Tullow indicated that it needs to secure long-term firm gas supply and offtake agreement with the Government of Ghana to successfully eliminate routine flaring and support oil production.

Figure 20: Domestic gas statistics in 2021

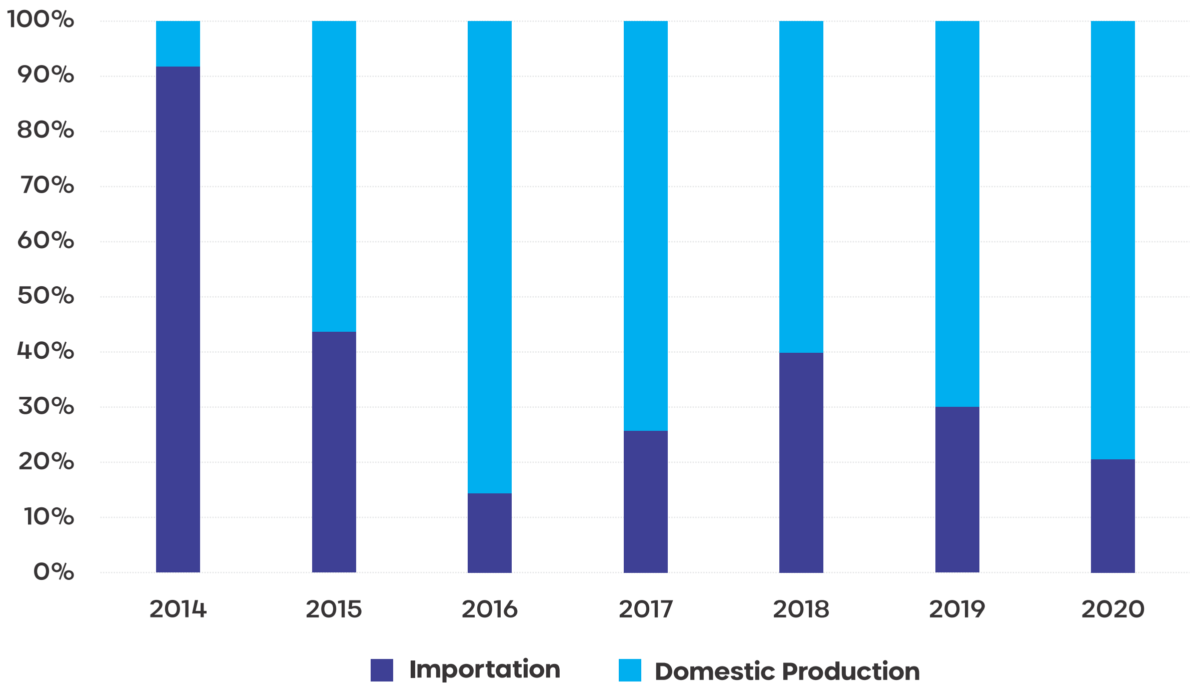


Source: 2021 PIAC Report

3.5 Gas Imports

As the production of gas continues to increase, the importation of gas from Nigeria through the West African Gas Pipeline (WAGP) continued to decline. The share of imported gas in the domestic gas supply fell to about 20.4 percent with domestic production contributing the remaining 79.6 percent. For the year 2020, HFO import volumes dropped by 82.8% which can be attributed to the increased utilization of natural gas by thermal power plants, as thermal plants contributes about 64 percent of the annual electricity generation.

Figure 21: Trend of domestic production vs gas imports



Source: Annual Petroleum Reports, Energy Statistics & PIAC Reports.

3.6 LNG Imports and Fiscal Implications for Ghana

Ghana was expected to take delivery of LNG cargoes at the end of the first half of 2021 when the construction of the Tema regasification facility was expected to be completed. Supply of regasified LNG was expected to start at approximately 75 mmscfd eventually ramping up to circa 200 mmscfd by 2025. However, due to several reasons including but not limited to delays in the construction of the Terminal facilities the Terminal was not commissioned as anticipated– it must be noted that the Terminal is now mechanically complete and is ready for commissioning. GNPC, the Buyer, insists the import of LNG offers a cheaper opportunity to secure the country's future energy needs by diversifying the energy mix for power generation and industrial use, as well as fuel for vehicles.

Any justification for the need to import LNG to augment the gas supply must account for the contextual realities of the current gas supply dynamics in the country. Ghana's three producing fields can produce about 345mmscfd for power generation i.e., 210mmscfd gas production from SGN without any additional investments and 135mmscfd from the Jubilee and TEN fields. The reliability of gas supply from Nigeria has improved drastically over the last 12-18 months averaging 60mmscfd. This brings the total gas available from both domestic sources and imports to 405mmscfd. It is also important to note that gas supply from Nigeria could increase to 120mmscfd if N-Gas decides to implement the full terms of the gas supply agreement, since the force majeure it declared on the pipeline in 2013 is now lifted. The 2021 Electricity Supply Plan projects a power demand peak of 3,303.72 MW which only translates to about 400mmscfd gas demand for power. Since current non-power demand is less than 10%, this imposes a risk of excess gas supply on the sector. (NOTE: This analysis is valid in the short term, the Jubilee field has been producing for over 12 years and will start its decline soon, investment is required to maintain these rates going forward, recent challenges with gas production in Nigeria, reference NLNG declaring Force Majeure, suggest that in the medium to long term gas supply could be adversely affected. This analysis also doesn't take into consideration the off grid demand that exists at the moment mainly because of reliability concerns and the non-power demand which is expected to continue to increase as government pushes its industrialization agenda. Siting of an LNG terminal in Ghana provides a significant advantage to the Country as it is able to service regional demand which is quite significant)

Based on the above analysis, any further commitments to gas supplies from external sources will only contribute to excess gas supply and ultimately exacerbate the current financial woes of the sector if efforts to accelerate growth in demand is not commensurate. The 75mmscfd LNG expected to be delivered in 2021 translates into about $300 million[12] and could go higher if the Brent price against which the LNG is benchmarked appreciates over the year. This fiscal burden is further complicated by the fact that there is currently no single binding contract between GNPC and any potential consumer of the LNG to warrant the Corporation taking the risks to contract the commodity, even though GNPC continues to insist it has a market beyond Ghana.

[12] ACEP (2021) Advisory Paper on Power Sector Priorities for Government Action (Access here: https://bit.ly/2WcYlxX

Chapter 4

LEGAL

Legal

4.0 The Modified Model Petroleum Agreement: Developments In The Contractual Framework Of Ghana's Upstream Petroleum Industry

Thomas Kojo Stephens*

4.1 Introduction

Ghana made a large-scale commercial discovery of crude in its offshore territory in 2007. At the time, the country was using the open-door policy/discretionary allocation/direct negotiation in licensing its acreage. The regulatory legislation in place were the Ghana National Petroleum Corporation Act, 1983 (PNDCL 64), the Petroleum (Exploration and Production) Act, 1984 (PNDCL 84) and the Petroleum Income Tax Act, 1987 (PNDCL 188), complemented by a Model Petroleum Agreement (MPA) which was used as a template in negotiating with the oil companies. The Ministry of Energy, the mandated regulator of the industry, relied heavily on the technical expertise of GNPC to carry out its regulatory function. As such, at the time of the large-scale commercial discovery, the two main entities responsible for the regulation of the upstream petroleum industry were the Ministry of Energy and GNPC.

The discovery heightened interest in Ghana's acreage and led to an increase in companies coming into the jurisdiction seeking to prospect. The efficacy of the MPA, as well as the laws governing the industry, became a matter of crucial importance. Laws, such as the Petroleum (Exploration and Production) Act, 1984 (PNDCL 84), were found to be uncomprehensive enough to deal with emerging issues. Consequently, a Petroleum (Exploration and Production) Bill was drafted and revised over time. The inadequacies of the Petroleum Income Tax Act, 1987 (PNDCL 188) were also exposed during this period when, for instance, the absence of a provision for Capital Gains Tax, resulted in Ghana losing millions of dollars when the EO Group sold its interest to Tullow Oil. What eventuated was that the gaps and loopholes in the existing legislation were addressed by incorporating clauses in the MPA to deal with the exigencies of the situation, while the Petroleum (Exploration and Production) Bill, intended to replace the existing Petroleum Act, remained a work in progress.

In 2011, the Petroleum Commission Bill was enacted into law as the Petroleum Commission Act, 2011 (Act 821). Act 821 established the Petroleum Commission as the regulatory body for the industry, with extensive regulatory, technocratic, managerial and advisory functions.[13] As a result, the Commission assumed certain quasi-regulatory functions, that had previously been performed by GNPC, both in practice and under the MPA, leaving GNPC to focus exclusively on its commercial role.

The Petroleum (Local Content and Local Participation) Regulations, 2013 (LI 2204) was also passed to give impetus to the desire to enable more Ghanaians and indigenous businesses to participate in the industry. Additionally, there were local content provisions under PNDCL 84, LI 2204 which provided much more detail and were specifically designed to drive the local content agenda. During this period, the Model Petroleum Agreement was consistently revised and updated in accordance with the country's practical experiences in the industry and to deal with exigencies of emerging situations, as well as to fill gaps in legislation. The MPA was, therefore, in a constant state of revision and enhancement and the new

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[13] The Petroleum Revenue Management Act, 2011 (Act 815) was also passed in this year.

provisions inserted were tested when agreements came into effect. These new provisions were also incorporated in the Petroleum (Exploration and Production) Bill.

In 2016, the Petroleum Act, 1984 was repealed when the Petroleum (Exploration and Production) Act, 2016 (Act 919) was enacted. Among others, it made competitive bidding the default system of licensing in Ghana. In 2018, the Petroleum (Exploration and Production) (General) Regulations, 2018 (L.I. 2359) was also passed. In 2019, the Petroleum (Exploration and Production) (General)(Amendment) Regulations, 2019 (L.I 2390) came into force, and made amendments to the General Regulations. Further, all the changes that had been progressively made to the MPA over time and incorporated in the Petroleum Act, 2016, as well as some of the provisions in the Petroleum (General) Regulations and also the Petroleum (General)(Amendment) Regulations, were harmonized as updated MPA in 2019. This brought this standardized document in consonance with developments in the law and policy. As such, in various parts of the MPA, 2019, direct reference is made to these pieces of legislation as the frame of reference. The MPA, 2019, modified and updated the MPA, 2000. Unlike the MPA, 2000, that has 27 Articles, that of 2019 has 25 Articles.

This article seeks to review the modifications that have been made in Ghana's Model Petroleum Agreement, examining and assessing developments in Ghana's contractual framework. The MPA has undergone modifications over time as Ghana has gained more practical experience in the industry. These have resulted in additions and changes in the MPA, many of which have crystallized into law. This Article discusses the salient changes made to the MPA, explains what the current position of the law is, and highlights the rationale for making these changes. It discusses the implications of these changes for Ghana's contractual framework. The article takes cognizance of the fact that these provisions were developed over time and have been transposed into Ghana's laws, such that at various points in the modified MPA, reference is consistently made to the relevant legislation applicable to the matter at hand.

4.2 Definitions

The MPA, 2019 makes important additions to the definitions in the MPA based on experiences over time, as well as developments in the industry. Some salient ones are enumerated below.

4.2.1 Institutional Framework

In respect of the institutional framework, the MPA, 2019 includes a definition of the word "Commission"[14] to take into account the institution added to the institutional framework in 2011 as well as to take into cognizance the role performed by the Petroleum Commission in the current dispensation, which can be broadly categorized as regulatory and managerial. It bears noting that the MPA, 2000 made no reference to the Commission as it was not in existence at the time it was drafted. Under the MPA, 2019, in the definition section, cognizance is made of the existence of this entity and a foundation is laid for an expatiation on the various roles to be performed by the entity under the current institutional arrangement.

4.2.2 Contractual Arrangements

In respect of the contractual arrangements between GNPC and the parties, the MPA 2019 defines the term "Default Rate"[15] as well as "LIBOR."[16] It defines default rate "…to have the meaning ascribed in Article 24.6" Article 24.6 states:

> Except for payment obligations arising under the Income Tax Act, any Party failing to pay any amounts payable by it under this Agreement (including the provisions of the Accounting Guide) on the respective dates on which such amounts are payable by such Party hereunder shall be obligated to pay interest on such unpaid amounts to the Party to which such amounts are payable. The rate of such interest (Default Rate) with respect to each day of delay during the period of such non-payment shall be [LIBOR plus [ ] percent (%]. Such interest shall accrue from the respective dates such amounts are payable until the amounts are duly paid. The Party to whom any such amount is payable may give notice on non-payment to the Party in default, and if such amount is not paid within fifteen (15) days after such notice, the Party to which the amount is owed may, in addition to the interest referred to above, seek remedies available…

[14] Article 1.17.
[15] Article 1.27.
[16] Article 1.55.

LIBOR is defined as:

> The interest rate per annum equal to the London Interbank Offered Rate administered by ICE Benchmark Limited (or any other person which takes over the administration of that rate) for one (1) month U.S. dollar deposits, as published in London by the Financial Times. In the event that the Financial Times is not published, then as published by The Wall Street Journal.

Under this arrangement, any party failing to pay any amounts payable by it under the Agreement (including the provisions of the Accounting Guide) – except for payment obligations arising under the Income Tax Act[17] – on the respective dates on which such amounts are payable, is obligated to pay interest on such unpaid amounts to the Party to whom such amounts are payable.[18] The rate of such interest with respect to each day of delay during the period of such non-payment is LIBOR plus a percentage. Such interest accrues from the respective dates such amounts are payable until they are duly paid.[19] The Party to whom any such amount is payable may give notice of non-payment to the Party in default and if such an amount is not paid within fifteen (15) days after such notice, the Party to which the amount is owed may in addition to the interest enumerated, seek remedies pursuant to the dispute resolution mechanism under the Agreement.[20] These provisions, including the definitions of the terms, clarifies the consequences of a party's default in meeting its payment obligations under the Agreement and ensures that the Party to whom amounts are payable receives full compensation in the event of default.

It is the case, however, that internationally, LIBOR is being abandoned in favour of alternative reference rates, such as the Sterling Overnight Index Average (SONIA) and the Secured Overnight Funding Rate (SOFR). In the U.S., for instance, regulators have decided to disband LIBOR as a benchmark for determining the reset rate for loans, swaps and other derivative products and rather use the SOFR, a benchmark interest rate for dollar denominated derivatives and loans.[21] This change arose from the banks' practice of manipulating the LIBOR rate. Ghana is expected to comply with international practice.

4.2.3 New Statutes

In terms of statute, as noted, in 2013, the Petroleum (Local Content and Local Participation) Regulations, 2013 (L.I. 2204) was passed to provide more regulatory detail and to give impetus to the effort to ensure more localization of goods, services and employment in the industry. As such, the MPA, 2019 clarifies that "Local Content Regulations", refers to L.I. 2204. Likewise, the MPA, 2019 makes copious references to the Petroleum Act, and specifies that "Petroleum Act" refers to "the Petroleum (Exploration and Production) Act, 2016 (Act 919) as amended from time to time."

The MPA, 2019 also includes in its list of definition of legislation, the "Income Tax Act". The Income Tax Act, 2015 (Act 896), as amended, covers petroleum operations in Part VI of the Act. The Income Tax Act co-existed with the Petroleum Income Tax Act, 1987 (PNDCL 188), but to the extent of any inconsistency between these two pieces of legislation, the Income Tax Act, 2015 (Act 896) superseded. The Revenue Administration Act, 2016 (Act 915), which provides for the administration and collection of tax revenue, repealed the Petroleum Income Tax Act, 1987 (PNDCL 188). Thus, the governing legislation in respect of the industry is no longer the Petroleum Income Tax Act, 1987 (PNDCL 188), as was the case under the MPA, 2000, but Part VI of the Income Tax Act, 2015 (Act 896) as amended. Further, as noted, the Petroleum (Exploration and Production) (General) Regulations, 2018 (L.I. 2359) was passed in 2018 and provides further detail to provisions of the Petroleum Act, 2016. The MPA, 2019, thus, makes copious references to this piece of legislation and notes it in the definition section.

4.2.4 Sole Risk

'Sole risk operations' under the MPA, 2000, involved a situation where a project was not voted for to be executed – did not obtain the pass mark – at the Joint Management Committee but the defeated parties, nevertheless, wished to go ahead. It bears noting that this option of electing to engage in Sole Risk Operations was restricted only to GNPC. As such, "Sole Risk' was defined as "an operation conducted at the sole cost, risk and expense of GNPC…"[22]

[17] Income Tax Act, 2015 (Act 896) as amended.

[18] Article 24.6.

[19] Ibid.

[20] Article 22 – Consultation, Arbitration and Independent Expert.

[21] Colin Lloyd, "LIBOR is Out, SOFR is in: What it means" (American Institute for Economic Research, 30 October 2019) https://www.aier.org/article/libor-is-out-sofr-is-in-what-it-means/; accessed, 11 July 2021.

[22] Article 1.63

Under the MPA, 2019, there has been a change in the definition. It is stated that 'Sole Risk' "shall have the meaning given to such term in the Petroleum (Exploration and Production) (General) Regulations". Under the Petroleum (Exploration and Production) (General) Regulations, Regulation 80, titled, Interpretation, 'Sole Risk' is defined as "an operation in petroleum activities, conducted at the sole cost, risk and expense of the contractor or the Corporation in accordance with the terms of a petroleum agreement". This definition implies that 'Sole Risk' is no longer limited exclusively to GNPC.

In practice, under the MPA, 2000, in the event of a commercial discovery, when an IOC conducted operations beyond the minimum work commitment as contained in Article 4, it could deduct whatever further works from the revenue from the commercial discovery even if it made no further discovery. As such, the risk lay on the State. This did not inure to the benefit of the State as it simply increased petroleum costs and reduced revenue. Thus, this has been modified and in the MPA, 2019, in the event of a commercial discovery, any additional well drilled will need the approval of the Commission and where approval is not granted, the Contractor can still undertake the task but at its sole risk in the sense that, costs incurred in the event that there is no commercial discovery is not borne by the State and so risk is appropriately shifted to the IOC as opposed to the State. The MPA makes reference[23] to Regulation 40(9) of the Petroleum (General) Regulations which states, "The costs for additional exploration operations shall, in the absence of approval by the Commission, only be allowable petroleum costs where the additional operations result in a new or extended commercial discovery."

4.2.5 Fiscal Regime

The MPA, 2019, unlike the MPA, 2000, defines key elements in the fiscal regime. The main elements in the fiscal regime, such as the Initial Participating Carried Interest; Additional Participating Interest; Royalty, and Additional Oil Entitlement are defined under the MPA, 2019.[24] This is an acknowledgment of their importance, as ultimately, they are the key determinants of the amount of revenue the State makes from any Field. It has been the trend that the Carried Interest and the Participating Interest, referred to in petroleum revenue management jargon as "CAPI", brings in the most revenue to the State, along with royalties. It is, therefore, imperative that these fiscal elements are specifically defined in the petroleum agreements, even if encapsulated in the Petroleum Act, 2016.

Ghana has never received any revenue in respect of Additional Oil Entitlement. There has been some disagreement between the IOCs and Ghana as to the mode of calculation of Additional Oil Entitlement. The Petroleum General Regulations thus, tries to ensure certainty by explaining that it is calculated "on the basis of the after tax-inflation-adjusted rate of return that the Contractor achieves with respect to each field as stipulated in the applicable petroleum agreement," and "calculated in accordance with the formula set out in the Third Schedule [of the Regulations]." As such, the MPA, 2019, simply refers to Regulation 75 of the Petroleum (General) Regulations for the definition of Additional Oil Entitlement.

4.2.6 Regulation and Control

In terms of regulation by the State of the IOC, the MPA, 2019 defines "Control". This is necessary in respect of a change of ownership of the company. Section 15 of the Petroleum Act, 2016 (Act 919)[25] states that, a contractor or sub-contractor shall not transfer a share of its incorporated company in Ghana to a third party or affiliate without the Minister's written approval (in the case of a Contractor) or the Commission (in the case of a sub-contractor) if the effect would be to give the third party or affiliate control of the company or enable it to take over the interest of a shareholder that owns five percent or more of shares of the company. The State must have a say in who becomes the controlling mind of an entity operating in its jurisdiction and reserves the right to reject any arrangement it finds undesirable. To clarify what is meant by "control of the company" the MPA, 2019 defines it as "the direct or indirect ownership in an aggregate of fifty percent (50%) or more of voting capital or voting rights of the entitlement (directly or indirectly) to appoint a majority of the directors or equivalent management body of, or to direct the policies or operations of that entity."

[23] Article 4.10.

[24] See, Articles 1.52; 1.2; 1.80; 1.5 of the MPA 2019.

[25] This is titled, Change of Ownership.

4.2.7 Protected Assets and Pre-Award Attachment

The MPA, 2019 also introduces the terms "Protected Assets"[26] and "Pre-Award Attachment"[27]. "Protected assets" means property used for diplomatic or consular missions, property of a military character, assets of petroleum funds, and property located in Ghana and dedicated to a public or governmental use (as distinct from that dedicated to a commercial use).[28]

"Protected assets" are not subject to any proceedings brought against them in connection with the Agreement or any transaction contemplated by the Agreement.[29] The failure or refusal to submit to arbitration and/or the seeking of any Pre-Award attachment against State assets (excluding any assets of GNPC) by any Party is deemed a breach of the Agreement by such party.[30] In the event of a breach, each non-breaching party will – without prejudice to any other remedies – be entitled to recover from each breaching party all costs and expenses, including reasonable attorneys' fees, that such non-breaching party was thereby required to incur.[31] The Protected Assets are not subject to any proceedings in connection with the Agreement. It is also not subject to any transaction contemplated in the Agreement in respect of any effort to confirm, enforce, or execute any Pre-Award attachment.[32]

4.2.8 Security

The MPA, 2019, introduces the term "Security". The Petroleum Act, 2016, stipulates in Section 58, titled, Security for fulfilment of Obligations, that a licensee, Contractor or sub-contractor shall provide, as the Minister may require, performance bonds or guarantees for the fulfilment of obligations undertaken and for possible liabilities arising out of the activities undertaken. The MPA, 2019, defines security as:

(i.) an irrevocable standby letter of credit or irrevocable bank guarantee issued by a bank; (ii) an on-demand bond issued by a surety corporation; or (iii) an irrevocable guarantee issued by a company or government; (provided that the bank, surety, company, or government issuing the guarantee, standby letter of credit, bond or other security (as applicable) has a long term debt rating of at least [A+] by Standard and Poor's, or [A1] by Moody's Investors Service, or an equivalent rating by a successor entity to either agency, and has a net worth of [at least five times] the secured amount. For company, or government guarantees, ratings will be determined by looking at the ultimate parent company or sovereign rating.

As such, in respect of the exploration programme to be performed by an IOC, to ensure that the work is carried out, unlike the MPA, 2000, provision is made for the payment of security in the form of contractually agreed amounts, to cover the minimum expenditure obligation for each of the periods. This is to ensure some certainty that Contractors will be in a financial position to meet their obligations. In practice, where it is clear that the entity is a financial heavyweight, say a supermajor, for instance, it is highly unlikely that the Minister will require that such a security be posted. A parent company guarantee will suffice. Further, it bears noting that the debt rating for a company in respect of the issuance of a performance bond or guarantee may be determined by having regard to the ultimate parent company or sovereign rating.[34]

4.2.9 Wilful Misconduct

"Wilful Misconduct" has been defined alongside the existing "Gross Negligence"[35]. These are terms generally used in the upstream petroleum industry to define and allocate liability between parties. In the industry, in general, liability is strict. There are, however, certain circumstances /situations where parties to a consortium can absolve themselves from liability and insist that the Operator bears sole responsibility. These are situations where the liability is deemed to have arisen either out of the gross negligence or wilful misconduct of the Operator. Thus, in Porter v. Magill[36], the Court referred to "wilful misconduct" as "deliberately doing something wrong, knowing it to be wrong or having reckless indifference as to whether or not it is wrong". In the case of National Semiconductors (UK) Ltd. v UPS Ltd.[37], Longmore J. held that "wilful misconduct" "requires either an intention to do something that the actor knows to be wrong; a reckless act that the actor is aware may cause loss but does not care whether loss will result or

[26] Article 1.77.
[27] Article 1.73.
[28] Article 1.77.
[29] Article 22.2.
[30] Article 22.3.
[31] Ibid.
[32] Article 22.9.
[33] Article 4.5.
[34] Regulation 78 of the Petroleum (Exploration and Production) (General) Regulations, 2018 (L.I. 2359) as inserted by L.I. 2390.
[35] Article 1.46.
[36] [2001] UKHL 67.
[37] [1996] 2 Lloyd's Rep 212.

not; or the taking of a risk that the actor knew he or she ought not to take." In Graham v. Belfast and Northern Counties,[38] it was defined as:

> misconduct to which the will is party as contradistinguished from accident, and is far beyond any negligence, even gross or culpable negligence, and involves that a person wilfully misconducts himself, who knows and appreciates that it is wrong conduct in his part in the existing circumstances to do, or to fail or to omit to do (as the case may be), a particular thing, and yet intentionally does or fails or omits to do it, or persists in the act, failure or omission, regardless of the consequences.

The courts have distinguished 'gross negligence' from negligence simpliciter, by looking at the seriousness of the act or omission committed, or whether the conduct complained of equates to recklessness.[39] Under the MPA, 2019, the two are lumped together and defined as, "any act, failure to act, or failure to exercise such minimum degree of care and prudence (whether sole, joint or concurrent) by a Party which was in reckless disregard of or wanton indifference to the harmful consequences that the person knew, or should reasonably have known, could have on the safety or property of another person or entity." So, unlike the MPA, 2000, in which this definition applied only to "gross negligence" and failed to define the term "wilful misconduct", the MPA 2019 ensures that this definition applies to both industry terms.

This inclusion in the MPA was inspired by the Deepwater Horizon Oil Spill, which occurred on 20th April 2010, in the Gulf of Guinea, and considered to be the largest oil spill in the history of the petroleum industry. On 31st August 2012, the U.S. Department of Justice filed papers in the federal court in New Orleans, blaming BP for the spill and holding it out as an example of "gross negligence and wilful misconduct". On 4th September 2014, U.S. District Judge Carl Barbier ruled that BP was guilty of gross negligence and wilful misconduct and ruled that BP's decisions were "primarily driven by a desire to save time and money, rather than ensuring the well was secure".

Some may construe 'gross negligence' as having 'wilful misconduct' as an element. The Black's Law Dictionary, for instance, states in reference to gross negligence:

> As it originally appeared, this was very great negligence, or the want of even slight or scant care. It has been described as a failure to exercise even that care which a careless person would use. Several courts, however, dissatisfied with a term so nebulous..., have construed gross negligence as requiring wilful, wanton, or reckless misconduct... [40]

Despite the fact that both industry terms have been coupled under the MPA, 2019, strictly speaking, the two are not the same and it would have been more desirable if they were disaggregated and defined separately. The same Black's Law Dictionary defines "willful misconduct" as "misconduct committed voluntarily and intentionally"[41], while defining "gross negligence" as "a lack of slight diligence or care"[42]. There is an element of deliberate or intentional behavior in wilful misconduct unlike gross negligence which is more along the lines of a significant degree of carelessness.

4.2.10 Arm's Length Transactions

After gaining more exposure to the petroleum industry and practical experience, and to address existing concerns about transfer pricing, Section 91 of the Petroleum Act, titled Transactions Between Contractor and Affiliates, states that, such transactions shall be based on prevailing international competitive prices and other terms and conditions that would be reasonable and fair if they had taken place between the Contractor or sub-contractor and a non-affiliate. As such, the MPA, 2019, introduces the concept of "arm's length transaction' and defines it with reference to the meaning given to such a term in Regulation 77(12)(b) of the Petroleum (General) Regulations. Section 77(2)(b) defines it as "sales to a purchaser independent of the seller, which does not involve...", among others, "(iii) sales directly or indirectly to affiliates". This provision is intended to prevent the mischief of situations where the IOCs would simply pad their costs and increase the amount deducted as costs, while correspondingly, reducing their income tax liability.

[38] [1902] 2 IR 12.

[39] Red Sea Tankers Limited v Papachristidis [1997] 2 Lloyd's Rep 547.

[40] B Garner, Black's Law Dictionary, 8 Edition, (Thomson West, 2004) 1062.

[41] Ibid, 1020.

[42] Ibid, 1062.

4.3 Changes in the Contractual Framework

4.3.1 Interests of the Parties

The interests of the Parties are captured under Article 2 of the modified MPA, titled Scope of the Agreement, Interests of the Parties, and Contract Area. There is a marked difference, in that whilst actual agreements entered into before 2016 largely have a carried interest of 10%, those entered into after this period have a minimum carried interest of 15%, as required by the Petroleum Act, 2016.[43] Carried interest is the portion of Ghana's interest in a field for which it does not contribute anything towards exploration and development costs. Further, it bears noting that the interest that Ghana has in any field contributes the largest share of revenue in respect of Ghana's fiscal regime. Increasing the minimum carried interest that Ghana can have in any field has the direct corresponding benefit of ensuring that the minimum interest Ghana has in any field is larger than in previous contracts with the corresponding benefit of additional revenue to the State.

4.3.2 Exploration Period

Under the MPA, 2000, the Exploration Period was for a term of seven (7) years, unless extended per the terms of the Agreement.[44] The Exploration Period was divided into an Initial Exploration, and two (2) separate extension periods, totaling seven (7) years. In Article 3 of the MPA, 2019, titled, Exploration Period, reference is made to Section 21 of the Petroleum Act, 2016, titled, Exploration Period and Extension. The Exploration period remains for not more than seven years[45], but this time is divided into an initial exploration period and up to three extension periods within the total exploration period.[46] This provides for more rigour within the work programme as it ensures that a Contractor satisfies the obligation in a period before being permitted to move into the next period.

4.3.3 Minimum Exploration Programme

The MPA, 2000, provided for minimum work obligations to be performed during the exploration stage. This covers the number of wells to be drilled, acquisition, processing and interpretation of seismic data, as well as a corresponding minimum expenditure amount to be fulfilled by the Contractor during each working period of the exploration phase.[47]

The MPA, 2019, maintains these provisions and references Section 23 of the Petroleum Act, 2016, titled, Minimum Work Obligation, as well as Regulation 40 of the Petroleum (Exploration and Production) (General) Regulations, 2018 (L.I. 2359), titled, Work Programme. However, there is a proviso that takes into account, based on practical experience, difficulties that could be encountered in the drilling of a well. As such, the MPA, 2019, provides that where in the course of drilling an exploration well, the Contractor concludes that drilling to the minimum depth is impracticable, impossible or imprudent, it must notify the Commission immediately in writing. The Commission has the option of waiving the minimum depth requirement, in which case the Contractor will be deemed to have satisfied the obligation to drill the exploration well,[48] or require the Contractor to drill a substitute exploration well to the minimum depth at a location determined by the Contractor in consultation with the Commission.[49] This provision ensures flexibility and accommodates practical difficulties that may be encountered in the course of drilling exploration wells.

4.3.4 Relinquishment

Under the MPA, 2000, the manner of relinquishment could vary from agreement to agreement. The MPA, 2019, references Section 22 of the Petroleum Act, 2016 titled Relinquishment of Contract Area. The provision stipulates that the Contractor must first relinquish, at least, 50% where it elects to enter into the First Extension Period.[50] When it elects to enter into the Second or Third Extension Period, the retained contract area shall not exceed twenty-five percent of the contract area as of the effective date of the petroleum agreement.[51] Unlike the MPA, 2000, there are fixed percentage minimums that must be relinquished at specified periods in time. This brings more guidance and certainty in the way and manner in which relinquishment is done, reduces the ad hoc nature that emanates from the absence of clear parameters, and provides

[43] Section 10(14) – Petroleum Agreement.
[44] Article 3.1.
[45] Section 21(1).
[46] Section 21(2).
[47] Petroleum Agreement; Article 4 – Minimum Exploration Programme; Petroleum Act 2016 – Minimum Work Obligation.
[48] Regulation 40(6)(a).
[49] Regulation 40(6).
[50] Section 22(3).
[51] Section 22(4).

some level of uniformity amongst the petroleum agreements entered into. It bears noting, however, that Section 22(6) states that the Minister may, in exceptional cases, and in consultation with the Commission, determine that the area to be relinquished should be smaller than as set out in the Act.

4.3.5 Joint Operating Agreement

Article 6, titled, Joint Operating Agreement, is a new introduction in the MPA, 2019. Article 6 of the MPA, 2000, was titled Joint Management Committee and dealt with matters concerning the JMC. With respect to managing the relationship between the State and the Contractor parties, the petroleum agreement entered into with the State provides for a Joint Management Committee ("JMC"). The JMC supervises the activities of the Operator and ensures that petroleum operations are conducted per the terms of the petroleum agreement. The JMC is made up of representatives of the State and the Contractors.[52] "Joint Management Committee" is defined under the Petroleum (General) (Amendment) Regulations as, "the Committee established pursuant to a petroleum agreement between the Corporation and a Contractor for the conduct of petroleum activities".[53]

The contractor parties are mandated to enter into a Joint Operating Agreement (JOA) even before exploration begins.[54] An arrangement that may appear baffling is the fact that GNPC was not a party to the JOA. The rationale was that since GNPC did not from the start contribute any money towards the acquisition of its interest, it ought not to be a party to the agreement. However, Article 6 of the MPA, 2019 states, "In order that the Corporation and Contractor may cooperate in the implementation of Petroleum Operations, the Corporation and Contractor shall, subject to Regulation 25 of the Petroleum (Exploration and Production) (General) Regulations, enter into a Joint Operating Agreement (JOA)." The Petroleum (General) Regulations made an aggressive stride towards trying to vest more power in GNPC.

Regulation 25 of the Petroleum (General) Regulations, titled Joint Operating Agreements, which has since been amended, stated that, "The Corporation and each party constituting the Contractor shall enter into a joint operating agreement."[55] This was a new development as GNPC previously was not a party to the Joint Operating Agreement. Further, it stated that these joint operating agreements were to be entered into per a Model Joint Operating Agreement provided by the Minister.[56] A further change was that decisions under the joint operating agreement had to be unanimous.[57] This arrogated a lot of power to the State/GNPC, since GNPC's interest in the petroleum agreements are usually dwarfed by that of the IOCs; thus, if decisions were to be based on unanimity, this would put GNPC at a great advantage. Further, where the parties to the Joint Operating Agreement could not agree on a matter, the Operator was required to refer the matter to the Minister for resolution, not later than thirty (30) days from the date the matter was put to vote in the Joint Operating Agreement.[58] The Minister could require changes to the proposed Joint Operating Agreement, if required,[59] and the Contractor was required to submit the work programme and budget under the Joint Operating Agreement to the Commission for approval.[60]

These stipulations, which otherwise vested power in GNPC, the Minister and the Commission, in respect of what is essentially private arrangements between contractor parties, have since been reversed through amendments in the Petroleum (Exploration and Production) (General) (Amendment) Regulations, 2019 (L.I. 2390). GNPC is, however, a party to the JOA where it acquires a commercial interest in the petroleum agreement. The (General) (Amendment)(Regulations), 2019 (L.I. 2390), amends Regulation 25 of the Petroleum (General) Regulations, titled Joint Operating Agreements, to read: "Where the Corporation or a subsidiary of the Corporation acquires a commercial interest in a petroleum agreement, the Corporation and each party, constituting the Contractor, shall enter into a joint operating agreement."[61] A key word in the provision is "acquires", and thus, will refer to a situation where the State purchases part, or all of the interest of the parties, in a Field.

[52] Article 6.2(i) – Joint Management Committee.

[53] Regulation 13.

[54] Petroleum (General Regulations) – Regulation 25(1) – Joint Operating Agreements.

[55] Regulation 25(1).

[56] Regulation 25(2).

[57] Regulation 25(4).

[58] Regulation 25(5).

[59] Regulation 25(6).

[60] Regulation 25(7).

[61] Regulation 4 – Petroleum (Exploration and Production) (General)(Amendment) Regulations, 2019 (L.I. 2390).

4.3.6 Work Programme and Budget

The MPA, 2019, includes a new insertion that takes into cognizance the technical and regulatory roles of the Petroleum Commission. A Contractor is required to submit an annual work programme and budget to the Joint Management Committee for initial approval.[62] Where the Joint Management Committee grants an initial approval, the Contractor is required to submit the annual work programme and budget to the Petroleum Commission for approval.[63] Upon notice to the Commission, the Contractor can amend any work programme and budget submitted to it, which will state why, in the Contractor's opinion, the amendment is necessary or desirable. [64]

Within sixty (60) days after the date of commercial discovery, the Contractor must prepare and submit to the Commission for approval, any revisions to its annual work programme and budget that may be necessary in order to implement the Plan of Development and Operation for the remainder of that year.[65] This provision in the MPA, ensures that the Petroleum Commission has a say in an important part of the process and allows the country some measure of control over the work to be done, as well as the money to be expended. It must be reiterated that costs will be deducted by the IOCs from revenue as petroleum costs, which will, in turn, reduce the profit to be declared by the IOCs, with a corresponding reduction in the amount paid to the State as income tax.

4.3.7 Rights and Obligations of the Contractor and the Corporation

The ambit of this Article has been expanded to include GNPC. The MPA, 2000, limited it to the "Rights and Obligations of Contractor". GNPC has been introduced under this Article, though its obligations were largely captured elsewhere under the MPA, 2000. GNPC is mandated to assist the Contractor to carry out its obligations expeditiously and efficiently under the Agreement.[66] The obligations of GNPC have been mainly circumscribed to assisting the IOCs to perform their commercial role. Further, the storing and ownership of data is no longer the preserve of GNPC, but of the Petroleum Commission.[67] It is no longer worded as "the property of the Corporation"[68], but "…the property of the Republic"[69]. This takes into cognizance the fact that GNPC now performs a purely commercial role and operates like the other oil companies, having shed virtually all the quasi-regulatory functions previously performed by it.

4.3.8 Commerciality

Under the MPA, 2000, a Contractor was required to notify the Minister and GNPC in writing as soon as possible after any discovery was made, but in any event, not later than 30 days after the making of the discovery. Under the MPA, 2019, this period has been shortened to forty-eight hours. The Article refers to Section 25 of the Petroleum Act, 2016, titled, Notification of Petroleum Discovery and Appraisal, and Section 25(2)(a) requires that, where there is a discovery, within forty-eight hours, there must be written notification of the discovery to the Minister before notification to a third party. This puts the onus on the Contractor to inform the State with much more promptitude than was required under the previous arrangement.

The MPA, 2000, included the requirement that the Contractor had to, by further notice in writing to the Minister, indicate whether in the Contractor's opinion, it merited appraisal or not. Under the MPA, 2019, it modifies the requirement that the Contractor simply provide notice as to whether it merits appraisal or not, to require that it provides in writing, full particulars of the discovery to the Minister and the Commission as soon as practicable. This is in accordance with the requirement in Section 25(2)(b) of the Petroleum Act, 2016, and the effect is that it allows the State to determine, independently of the opinion of the Contractor, as to whether it deems it a commercial discovery or not.

In respect of appraisal, Article 9 of the MPA, 2019, refers to Section 25 of the Petroleum Act, 2016, as well as Regulation 41 of the Petroleum (General) Regulations, titled, Declaration of Commerciality and Appraisal. The Commission's role in the dispensation is brought to the fore as a Contractor must not commence an appraisal or enter into binding obligations relating to the programme until the Programme has been approved by the Commission.[70] Where a Contractor declares a discovery not to be

[62] Ibid., Regulation 8, amending to insert Regulation 40A(1) under the Petroleum (General) Regulations.
[63] Article 7.1 and Regulation 8 of the Petroleum (Exploration and Production) (General) (Amendment) Regulations, 2019 (L.I. 2390) amending to insert Regulation 40A(2) under the Petroleum (General) Regulations.
[64] Article 7.2(c).
[65] Article 7.3(a).
[66] Article 8.3.
[67] Section 3 of the Petroleum Commission Act, 2011 (Act 821).
[68] Section 23(2); Petroleum Act, 1984.
[69] Section 52 – Ownership of Petroleum Data; Petroleum Act, 2016.
[70] Section 25(12).

commercial, the area shall be relinquished by written notification to the Commission within five (5) days from the date of declaration.[71]

The MPA, 2000, contained provisions relating to the Development Plan. The MPA, 2019, simply refers to the relevant pieces of legislation and their provisions governing this matter. Thus, it simply references Section 27 of the Petroleum Act, 2016[72] and Regulation 43 of the Petroleum (General) Regulations.[73]

4.3.9 Measurement and Pricing of Crude Oil

The MPA, 2000, provided that whereupon the testing or examination of appliances used for the measurement of crude, if any was found to be defective, the Contractor was to take immediate steps to repair or replace such appliance,[74] and such error was deemed to have existed for three (3) months or since the date of the last examination and testing, whichever occurred more recently.

The MPA, 2019, refers to Section 37 of the Petroleum Act, 2016, titled, Measurement of Petroleum Obtained. The Petroleum Act, 2016, makes a change to the date for ascertaining whether the appliance is deemed to have been defective. It stipulates that where a measuring method or calibrated equipment is discovered to be incorrect, "that method or calibrated equipment is considered to have existed in that condition during a period that is represented by half of the period from the last occasion where the method or equipment was tested or examined to the date when the method or equipment was found to be incorrect".[75] Royalty and other payments due for that period are adjusted accordingly.[76] In effect, the method for determining when equipment is deemed to have been defective, has been modified under the MPA, 2019, in line with the stipulation of the Petroleum Act, 2016.

4.3.10 Taxation and Other Imposts

The MPA, 2000, stated thus: "No tax, duty, fee or other imposts shall be imposed by the State or any political subdivision on Contractor, its Subcontractors or its Affiliates in respect of activities related to Petroleum Operations and to the sale and export of Petroleum other than as provided in this Article 12…"[77] As such, this provision was made a one-stop fiscal enclave. In effect, where an item was not included under this Article, it could not be imposed.

Under the MPA, 2019, Article 13.1 states that the tax, duty, fees and other imposts imposed by the State or any entity or any political sub-division on the Contractor, its sub-contractor or affiliates in respect of petroleum operations and sale and export of petroleum "shall include but not be limited to the following…" Thus, the wording of the provision in the MPA, 2019, is a firm departure from the earlier wording.

Further, while there were no extensive provisions on decommissioning in the MPA, 2000, the MPA, 2019, introduces elaborate provisions. Decommissioning costs are to be estimated on a development and production basis. Pursuant to the Petroleum Act,[78] a licensee or Contractor that operates a petroleum facility is responsible for decommissioning that facility.[79] Recognizing that Regulations specifically for Decommissioning are yet to be enacted, the MPA stipulates that, "until Regulations are prescribed",[80] based on the Petroleum Act,[81] or as long as there is no conflict with such Regulation,[82] upon the earlier of fifteen (15) years prior to the projected cessation of commercial production from a development and production area,[83] or reasonable belief that fifty percent (50%) of the recoverable reserves have been produced from a development and production area,[84] each Contracting party shall, subject to the approval of the Commission, contribute to the Decommissioning Fund.

If GNPC elects to keep the facilities and equipment in order to continue petroleum operations after the expiration of the petroleum agreement or after the termination of the petroleum agreement by any of the parties, the contributions deposited into the escrow account by the Contractor must be put at GNPC's disposal to cover the later decommissioning.[85] If the Contractor had been issuing decommissioning security, it must deposit equivalent funds in the escrow account in lieu of the decommissioning security.[86] It will be released from any further decommissioning liability in respect of such facilities and equipment.[87]

[71] Section 25(14).
[72] Section 27 – Plan of Development and Operation.
[73] Regulation 43 – Plan of Development and Operation.
[74] Article 11.4(a).
[75] Section 37(7) – Measurement of Petroleum Obtained.
[76] Section 37(8).
[77] Article 12.1 – Taxation and Other Imposts.
[78] Section 43 – Decommissioning Plan.
[79] Regulation 10 of the Petroleum (Exploration and Production) (General)(Amendment) Regulations, 2019 (L.I. 2390) amending to insert Regulation 61A.
[80] Article 13.8.
[81] Section 45 - Decommissioning Fund.
[82] Article 13.8.
[83] Article 13.8(i).
[84] Article 13.8(ii).
[85] ibid.
[86] ibid.
[87] ibid.

4.3.11 Inspection, Safety and Environmental Protection

Under the MPA, 2000, the Minister and/or GNPC had the right of access, as well as the right to inspect all buildings and installations used by the Contractor relating to petroleum operations.[88]

The MPA, 2019, in accordance with the Petroleum Commission Act, 2011 (Act 821)[89] and the Petroleum Act, 2016,[90] stipulates that it is the Commission that is explicitly mandated to have access to all sites and offices of the Operator and given the right to inspect all buildings and installations used by the Operator.[91] The Petroleum Act authorizes the Commission or any person authorized by the Commission to enter any structure, platform, installation, vehicle, vessel, aircraft, office, facility or building used for petroleum operations.[92] The Commission or such person can inspect, test or audit the works, operations, equipment, records, registers and financial accounts of any of the companies related to petroleum activities or GNPC,[93] and take or remove samples of petroleum, water or other substance for the purpose of testing or analysis.[94]

4.3.12 Accounting and Auditing

Under the MPA, 2000, GNPC was the primary entity to whom accounting and auditing functions were vested. Under the MPA, 2019, the Commission, as regulator, plays a role in auditing and accounting, even though GNPC still retains auditing and accounting functions from its practical role as a party to every Joint Management Committee, and being party, first hand, to all operations and costs incurred. Thus, though the Contractor must provide GNPC, the Commission and the Minister with quarterly and annual financial statements and summaries of petroleum costs incurred,[95] it is GNPC that reviews all financial statements submitted by the Contractor and signifies its provisional approval or disapproval in writing. GNPC has the right, upon giving reasonable notice in writing to the Contractor, to audit, at GNPC's sole expense, the books and accounts of the Contractor within two (2) calendar years, after the end of the calendar year in which any report of the financial statement is submitted by the Contractor to GNPC.[96] Any such audit must be undertaken by GNPC or an independent auditing firm and must be completed within nine (9) months after commencement.[97] If GNPC desires verification of charges from an affiliate, the Contractor must, at GNPC's sole expense, obtain for GNPC or its representatives, an audit certificate from the statutory auditors of the affiliate concerned.[98]

4.3.13 Title to and Control of Goods and Equipment

The MPA, 2000, provided for the acquisition of physical assets of the Contractor once the full cost thereof had been recovered by the Contractor, or the Agreement had been terminated, and the Contractor had not disposed of such assets prior to termination. Upon termination of petroleum operations in an area, the Contractor is to give GNPC the option to acquire any movable and immovable assets owned by the Contractor for the operations – other than those leased – at a reasonable and mutually agreed price.

Under the MPA, 2019, title to, and control of physical assets used in petroleum operations by the Contractor is subject to the Petroleum Act and the Petroleum (General) Regulations.[99] Unlike the MPA, 2000, where the opportunity to acquire title to assets crystallized after either full costs had been recovered by the Contractor or the Agreement terminated, the Petroleum Act, 2016, provides that where, at least, fifty percent (50%) of the cost of a physical asset has been recovered, in accordance with the terms of an existing petroleum agreement, GNPC can have the title of that asset transferred to it by the Contractor on payment by GNPC of the unrecovered portion of the asset.

The Petroleum (General) Regulations stipulate that a physical asset not transferred to GNPC, but which is necessary for operations, may to the extent not required by the Contractor for its petroleum activities, be used by GNPC if required for further activities.[100] GNPC is liable in those circumstances, to pay a reasonable and mutually agreed fee for the use, and bears the cost of repair or replacement upon failure to keep the physical asset in good working condition, fair wear and tear excepted.[101] In the instance, where that physical asset is leased

[88] Article 17.1.

[89] Section 3 – Functions of the Commission; Petroleum Commission Act, 2011 (Act 821).

"The Commission shall;

(e) Monitor petroleum activities and carry out the necessary inspection and audit related to the activities."

[90] Section 51 – Supervision and Inspection.

[91] Article 16.1.

[92] Section 51(2)(a) – Supervision and Inspection.

[93] Section 51(2)(b).

[94] Section 51(2)(c).

[95] Article 17.4.

[96] Article 17.5.

[97] Ibid.

[98] Article 17.6.

[99] Section 19 – Transfer of Assets to the Corporation; Regulation 33 – Title to and Control of Physical Assets

[100] Regulation 33 of Petroleum (General) Regulations – Title to and Control of Physical Assets.

[101] Regulation 33(2).

from an affiliate body corporate or other related party, and GNPC and the Contractor do not agree on the renumeration for its use, the fee payable by GNPC must not be higher than that which would be payable between unrelated parties in the same or similar manner.[102] Upon the termination of petroleum activities in an area, the Contractor must give GNPC the option to acquire, at a reasonable and mutually agreed price, any movable and immovable asset used for the petroleum activities and not transferred to GNPC, unless it is required by the Contractor for petroleum activities in the contract area.[103]

4.3.14 Employment and Training

Under the MPA, 2019, the ambit of the local content provisions has been widened in the sense that, it refers to all applicable laws on local content which would include not only the Petroleum Act[104] but the Petroleum (Local Content and Local Participation) Regulations, 2013 (L.I. 2204) as well.[105] A Contractor is also required to make payment into the Local Content Fund established under the Petroleum Act, 2016.[106] It must also pay an amount withheld from each of the Contractor's payments to Sub-contractors equivalent to the obligatory contributions of the Sub-Contractors under the Petroleum Act. The Petroleum Act stipulates that the sources of money for the Local Content Fund includes "contributions from a Sub-Contractor of the sum of one percent of the total consideration payable by the Contractor or licensee for every contract".[107] All monies must be paid by the Contractor by electronic transfer to an account designated at GNPC and verified by the Contractor.[108]

4.3.15 Term and Termination

Under the MPA, 2000,[109] flowing from the Petroleum Act, 1984,[110] the duration of a petroleum agreement was for a term of thirty (30) years, though it could be terminated at an earlier time provided for in the Agreement or if no commercial discovery was made. Under the Petroleum Act, 2016 (Act 919), a petroleum agreement must be for a term not exceeding twenty-five (25) years.[111] This reduction of the period in the agreements is to the advantage of the State as a Field will have more reserves and be further away from being exhausted after twenty-five as opposed to thirty years. The State will have a lot of bargaining power as it is at liberty to choose whether to approve an extension of the petroleum agreement or call for a new petroleum agreement to be executed by direct negotiations, and most likely with better terms. In this scenario, the State has much more clout than when the agreement was first signed, as the Field is a producing one, and the IOC stands to lose a lot if the Agreement is not extended, or a new agreement is entered into.

4.3.16 Dispute Resolution

Under the MPA, 2000, the forum, when a dispute arose between parties and had to go for arbitration, was not spelt out, and varied from agreement to agreement with different venues, such as the International Centre for Settlement of Investment Disputes (ICSID), Arbitration Institute of the Stockholm Chamber of Commerce (Stockholm, Sweden) and International Chamber of Commerce (ICC), for instance. Under the MPA, 2019, it is settled that, in the event of a dispute between the parties, the matter will be settled exclusively "under the auspices of the International Chamber of Commerce (the 'ICC'), using the Rules of Arbitration of the International Chamber of Commerce (the 'ICC Rules') in force on the date on which the proceedings were instituted."[112] This brings more uniformity and certainty to the dispute resolution mechanism in the industry.

4.3.17 Assignment

Under the MPA, 2000, it was stipulated under Article 25, titled, Assignment, that the Agreement could not be assigned without the "...prior written consent of GNPC, and the Minister..."[113] The wording under the MPA, 2019, is slightly different. It stipulates that no interest in the Agreement can be assigned without the "...prior written [consent of the Corporation and] the approval of the Minister". GNPC's consent is

[102] Regulation 33(3).

[103] Regulation 33(6).

[104] Section 60 – Employment and Training of Ghanaian Citizens.
Section 61 – Use of Ghanaian Goods and Services.
Section 63 – Local Content Plan.
Section 64 – Establishment of the Local Content Fund.
Section 65 – Object of the Fund.
Section 66 – Sources of Money from the Fund.

[105] Article 19.1 – Employment and Training.

[106] Article 19.2(c); The Local Content Fund was established under Section 64 of the Petroleum Act, 2016, titled Establishment of the Local Content Fund.

[107] Section 66(1)(b) – Sources of Money for the Fund.

[108] Article 19.2.

[109] Article 23 – Term and Termination.

[110] Section 12 – Period of Validity of Petroleum Agreement.

[111] Article 21.1 – Term ad Termination; Section 14 – Duration.

[112] Ibid.

[113] Article 25.1.

still maintained as GNPC is a party to all petroleum agreements and so, it is so to speak, 'on the ground' and is well placed to make that determination as to whether the assignment is in the best interest of the State or not. It also empowers the national oil company and makes it an important voice in the consortium. Thus, under the MPA, 2019, the assignment is subject to the consent of GNPC, and the subsequent approval – 'ratification' – by the Minister. Thus, the Minister will appear to be likely guided by GNPC's consent or withholding thereof, to decide whether to approve or not. In practice, the Minister is not bound by GNPC's refusal of consent and can go ahead to unilaterally approve if he so wishes. Section 16 of the Petroleum Act, 2016,[114] does not make GNPC's consent a sine qua non. It stipulates that, "A contractor or a licensee shall not without the written approval of the Minister, directly or indirectly assign the interest of the contractor under a petroleum agreement, whether in whole or in part, to a third party or affiliate."

Under the MPA, 2000, GNPC did not have a pre-emption right to purchase the interest of a party in the consortium seeking to sell its interest. However, arising from Ghana's practical experiences in the industry, such a clause was deemed necessary. In 2009, Kosmos indicated that it intended to sell its stake in the Jubilee Field. Ghana expressed an interest in buying Kosmos' stake, arguing that it had the pre-emptive right to do so. In October 2009, however, Kosmos confirmed its intention to sell its stake to ExxonMobil for roughly $4 billion. GNPC and China National Offshore Oil Corporation Limited (CNOOC Ltd.) made a combined joint bid of $5 billion for Kosmos' stake, which was declined. In February 2010, the Ghana government announced that it would block the ExxonMobil deal. Kosmos -- in a news release, dated 18th August 2010, announced the termination of the Sale and Purchase Agreement it had entered into with ExxonMobil, dated 28th June 2010, relating to the sale of its stake in the Jubilee Field.[115] A pre-emption clause would have pre-empted the occurrence of such a tussle between an IOC and the State over the right to purchase a stake that the IOC intended to devolve.

That right of pre-emption was incorporated in later petroleum agreements, as well as under the Petroleum (Exploration and Production) Bill, which manifests as Section 18 of the Petroleum Act, 2016, aptly titled, Pre-emption. Thus, under the MPA, 2019, once a selling party and a proposed transferee have fully negotiated the final terms and conditions of a transfer, they shall be promptly disclosed in detail to GNPC and the State in a notice from the Selling party.[116] GNPC shall have the right to acquire such interest from the Selling party on the same terms and conditions if, within ninety (90) days of the Selling party's notice, GNPC delivers to the Selling party a counter-notice that it accepts the agreed terms and conditions of the transfer without reservations or conditions.[117] If GNPC does not deliver such counter-notice within the ninety (90) days, the transfer to the proposed transferee shall be made.

Under the MPA, 2019, unlike the MPA, 2000, there is a provision for GNPC to assign its interest to an entity or government agency that is wholly owned by the State.[118] This takes into account the development where GNPC, for instance, created an exploration arm, Explorco, and which like GNPC, was vested with the right to have an interest in a Field.

4.3.18 Stabilization Clauses

In respect of the governing law, the earlier petroleum agreements used the phraseology, "governed by and construed with the laws of the Republic of Ghana consistent with such rules of international law as may be applicable, including rules and principles as having been applied by international tribunals."[119] Subsequent agreements based on modifications in the MPA, 2000, put it thus: "...governed by and construed in accordance with the laws of the Republic of Ghana in effect from time to time".[120] The latter wording seeks to clarify the state's power to amend its laws as and when appropriate, which is also reflected in the fact that the agreements have seen a shift in emphasis from freezing stabilization clauses to equilibrium/economic balancing.

The updated/modified MPA, 2019, maintains this later phraseology. Ghana also affirms in the Agreement that it will accord to the Contractor parties, treatment consistent with the minimum

[114] Section 16 – Assignment.

[115] Kosmos Energy, "Kosmos Energy Agreement to Sell Ghana Business Terminated" (Kosmos Energy, 2010) <www.kosmosenergy.com/press/kosmos_PR_081810.pdf> accessed 25 April 2020.

[116] Article 23.3(i).

[117] Ibid.

[118] Article 23.3 and 23.4.

[119] Article 26.1 – Miscellaneous

[120] Article 24.1 – Miscellaneous.

standard required to be accorded foreign investors under applicable laws and customary international law.[121] Where a party claims there has been a material change in circumstances after the effective date relevant for a review under the Petroleum Act,[122] that makes further observance of the original terms and conditions of the Agreement impossible or has a material adverse effect on the rights, obligations and benefits of a party under the Agreement, or otherwise, materially affects the economic, fiscal and financial balance of the Agreement, the Parties, if so requested, are to meet as soon as possible to negotiate in good faith, possible modifications to the Agreement as may be appropriate, to restore the fiscal, economic and financial balance of the Agreement.[123]

4.3.19 Decommissioning

It bears noting that, under the MPA, 2000, in respect of production operations, GNPC was not explicitly exempted under Article 2.7(b) from the payment of costs for abandonment and decommissioning.[124] However, under the MPA, 2019, GNPC is exempt.

Article 2.7(b) of the MPA, 2019 states:

"For the avoidance of doubt, the Corporation shall only be liable to contribute to Petroleum Costs:

(b) Incurred in respect of production operations (excluding costs for abandonment and decommissioning) in any Development and Production Area to the extent of:

i) its Initial Participating Carried Interest, and

ii) any Additional Participating Interest.

4.3.20 Conclusion

Ghana, has since 2016, moved from the open-door system of licensing to competitive bidding as the default system of licensing. The MPA, 2019, which is used as a template for entering into agreements with the oil companies, is a vast improvement over that of 2000. After twelve (12) years since the large-scale commercial discovery in Ghana and the enactment of several pieces of regulatory legislation, the modified MPA draws from policy, experience of the host state and the regulatory laws, in an attempt to meet the demands of the current dispensation. The MPA, 2019, was the product of continual revisions of the MPA, 2000, and not the outcome of a one-time revision. It is more detailed, and many of its provisions are steeped in statutes.

The MPA, 2019, reduces the time frame within which the Contractor must provide notifications to the State, and perform certain obligations. It attempts to circumscribe provisions which are open-ended and place limitations thereon. It also incorporates provisions stemming from practical experience and designed to fill recognized gaps in the law, and further, modifies certain provisions to take into cognizance the presence of the Petroleum Commission in the current dispensation, and its regulatory and technocratic role, as well as the more focussed role of GNPC as a commercial entity.

It must be noted that, currently, it is intended to have a new version of the MPA, which will be much smaller than the current version. This is because virtually everything in that MPA will be captured in the law and so reference will be made to the relevant applicable provisions thereof. This will also leave very little open to negotiation with the IOC.

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[121] Article 24.2.
[122] Section 20 – Review of Terms and Conditions.
[123] Article 24.3.
[124] Article 2.7(b).

4.4 The Afina And Sankofa Field Unitization Saga: A Commentary On Events

4.4.0 Overview

Ghana's Ministry of Energy has directed that the Afina Field of indigenous Ghanaian company, Springfield Exploration and Production Ltd., be unitized with the Sankofa Field of Italian major, ENI, on the basis that the same Cenomanian channel straddles both the OCTP Block (ENI) and WCTP 2 Block (Springfield). ENI has opposed the unitization of the two fields on the basis that Springfield has not sufficiently tested its discovery to show that it is in dynamic communication with ENI's Sankofa.[125] Despairing that the parties will reach an agreement, the Ministry of Energy has issued a directive that imposes unitization on the parties. Springfield is in favour of this directive, whilst ENI challenges it.

4.4.1 Background To The Matter

Springfield Exploration and Production Ltd., Ghana National Petroleum Corporation (GNPC) and its exploration company, Explorco, per petroleum agreement with an effective date of 26th July 2016, were granted a license to a contract area known as the West Cape Three Points Block 2 ("WCTP 2"). Springfield is the Operator of the Afina Field, which is within WCTP 2, with an interest of 84%, with GNPC and Explorco, holding the remaining interest.

ENI Ghana Exploration and Production Ltd.[126] and Vitol Upstream Ghana Ltd.,[127] per a petroleum agreement with an effective date of 5th May 2008, were granted a license over the contract area known as the Offshore Cape Three Points ("OCTP") Area with ENI being the Operator and having 44.44% interest, Vitol, 35.36% interest, whilst GNPC has a combined carried and participating interest of 20%. Its Field is known as the Sankofa Field, which began production on July 2017, through the FPSO John Agyekum Kufuor.

In March 2018, after acquiring 3D seismic data and conducting analysis on that data, Springfield wrote to the Minister for Energy that per its analysis, the Sankofa Cenomanian Reservoir of ENI and Vitol, extended into its WCTP 2 Contract area. It requested the Minister to direct the parties in both fields to commence unitization discussions.

In May 2018, the Minister invited Springfield to make a presentation to the Ministry and GNPC (a partner in both the OCTP and WCTP 2 Blocks and, thus, with information on both blocks). GNPC was tasked to independently evaluate Springfield's claim, and present a report. GNPC presented its Report in support of Springfield's claim in July 2018, consequent upon which the Minister wrote to ENI informing of Springfield's claim and requesting a response.

In August 2018, ENI responded disputing Springfield's claim and asserting that per the data available to them, there was no evidence of straddling. Consequent upon that, the Ministry advised Springfield to drill its prospect to further prove its claim. Springfield spudded its first well, the Afina 1x well in WCTP 2, in October 2019.[128] The well is 60 km offshore and in close proximity to the Jubilee Field and Greater Pecan Development areas. Drilling was completed in November 2019, using the Stena Forth drillship. The acreage was relinquished by Kosmos Ghana, following the carve-out of Jubilee in 2011.[129] Commenting on the Afina discovery, Wood Mackenzie states, "If confirmed, Afina could be a defining moment for both Springfield and Ghana. It marks the first time an independent African energy company has stepped out into a sole deep-water exploration venture."[130] It further notes,

> The ingredients are certainly there – existing infrastructure and relatively favourable fiscal terms. Flanked closely by its more illustrious IOC explorers and developers, Springfield will certainly require a strong partner, and so a farm-down would be a logical next step, if Afina is big enough to attract interest. [131]

By letter, dated the 27th of January 2020, Springfield wrote to the Ministry of Energy and informed it of its post-drilling analysis. It asserted that the Afina-1x Cenomanian Reservoir and the Sankofa Cenomanian Reservoir were the same and requested that the Ministry direct the parties to WCTP-2 and OCTP, to unitize the two fields and produce them as one unit.[132] The Ministry, however, requested the Petroleum Commission to undertake an independent assessment of the post-drilling data of

[125] As noted by Ed Reed, "ENI calls for Afina Proof on Unitization Push", Energy Voice, 13 November 2020 <https://www.energyvoice.com/oilandgas/africa/ep-africa/278992/eni-afina-sankofa-unitisation/> accessed, 7 June 2021, ENI's stance is that it would want more subsurface analysis in order to demonstrate the fields were straddling the license.

[126] ENI is a company registered under the laws of Ghana in accordance with Section 70 of the Petroleum (Exploration and Production) Act, 2016, and a subsidiary of the Italian multinational company, ENI International.

[127] Vitol Upstream Ghana Ltd. is similarly incorporated in Ghana and a subsidiary of the multinational company, Vitol, an energy and commodities company.

[128] Springfield Energy, "Ghanaian Energy Company Springfield Group Spuds First Well", Springfield, 9 Oct 2019, https://www.springfieldgroup.com/ghanaian-energy-company-springfield-group-spuds-first-well/> last accessed, 9 June 2021.

[129] "Springfield Strikes Oil in Ghana – but how much?" Wood Mackenzie, November 2019, 2.

[130] Ibid.

[131] Ibid.

[132] Paragraph 23.

[133] i

Springfield's Afina 1x Well to fully satisfy all stakeholders that the accumulation actually straddled each other.

By a letter dated 9th April 2020,[133] the Ministry of Energy informed the parties that the Petroleum Commission had confirmed to the Ministry that the petroleum accumulations of the two oil fields were the same, with the effect that, the Fields straddled each other. It noted,

> Further reference is made to the Petroleum Commission's letter dated 2nd April 2020, also in respect of the above subject matter, where the Commission recommended that, after engaging both ENI and Springfield and conducting independent assessment of the parties' position, the Afina 1x Cenomanian discovery and the Sankofa Cenomanian accumulation were one and same. [134]

The Minister also noted in the said letter that, "It is worthy of note that prior to requesting the Commission to review Springfield's claim, the Ministry had, consequent to Springfield's earlier letter dated 20th March 2018, on this same subject matter, requested GNPC to furnish it with an independent opinion on the veracity or otherwise of Springfield's claim." It went on to state, "GNPC, by a letter dated 5th June 2018, with an accompanying technical report, opined that based on interpretation of seismic data, the Sankofa Field extended into the WCTP-2 Contract area." The Minister went on to note that,

> Based on this opinion, and to ensure that there was ample evidence to justify unitization, the Ministry advised Springfield to drill their side of the reservoir to confirm the seismic data interpretations…Per the post-drill data and analysis, the Afina-1x Cenomanian Reservoir has an identical reservoir and fluid properties as the Sankofa Cenomanian Reservoir, thus proving further evidence that the two reservoirs are one and the same.

The Minister went on to rebut ENI's claim that the declaration of unitization was premature. The Minister noted:

> The Commission noted that ENI, in responding to Springfield's claim, indicated that it was premature for Springfield to be talking about unitization since, per publicly available information, Springfield had not appraised and tested their discovery. The Commission, in disagreeing with this position, indicated that the unitization of the Jubilee Field was triggered by geological interpretations, seismic amplitude signature and pressure data from wells in Kosmos and Tullow Ghana's respective acreages. They further stated that testing of the respective wells was a post-unitization event.

The Minister, therefore, among others, directed that Springfield, ENI and Vitol, begin the process of unitizing the two fields, Afina and Sankofa, and accordingly, furnish the Ministry with a draft Unitization and Unit Operating Agreement (UUOA) within 120 days from the date of the letter.[135] The Minister noted that this directive was in accordance with Section 34 of the Petroleum (Exploration and Production) Act, 2016 (Act 919)[136] and was to "ensure efficient production of the reservoir, to maximize economic recovery of petroleum from the two Contract Areas, to avoid unnecessary competitive drilling which might destroy the reservoir, [and] above all, in the national interest." Further to this, the Minister noted, "You are reminded that, pursuant to Regulation 50(6) of L.I. 2359, I am to stipulate the terms and conditions of the unitization, if you fail to comply with this directive."[137]

Following this letter, Springfield wrote several letters to ENI, requesting the commencement of the unitization process and proposed in an email on 29th April 2020, for a meeting in order to meet the deadline of the Ministry. This email was followed by a letter, dated 7th May 2020, requesting for data from ENI and Vitol.

On 18th May 2020,[138] the Ministry wrote to ENI, declining a request from the company[139] on the basis of confidentiality, for copies of the Petroleum Commission's independent assessment and GNPC's Report, which formed the basis of the Directives.

On 20th May 2020, by an email with a letter attached, dated 18th May 2020, ENI and Vitol informed Springfield, among other things, that, based on data available to them, there was no existence of hydrocarbon communication between the two contract areas. They noted, "Based on data currently available to ENI Ghana, the existence of hydrocarbon between the Afina discovery and Sankofa Field has not been established." They further noted that before any discussions on the unitization process could commence, there had to be an exchange of raw

[133] Reference Number SLR/KA 118/255/05.

[134] Letter from the Minister for Energy, John Peter Amewu, to Springfield and ENI, dated, 9th April 2020.

[135] The Minister also requested the parties to exchange relevant data to establish the structural extent and distribution of the petroleum between the contract areas.

[136] Section 34, is titled, Co-ordination with Petroleum Activities and Unitization.

[137] Regulation 50 is titled, Co-ordination of Petroleum Activities and Unitization.

[138] Reference Number SLR/KA.118/255/01A.

[139] Letter dated, 11th May 2020, with Reference Number RD/MD/2020/05/587.

technical data on a like-for-like basis to determine whether the oil fields straddled each other. They noted,

> Pursuant to the Minister of Energy's request, we are ready to exchange technical raw data with Springfield for the exclusive purpose of evaluating whether such data proves hydrocarbon communication between the Afina discovery and Sankofa Field. ENI Ghana is, therefore, preparing a suitable data exchange agreement that will permit sharing of raw data, strictly for this purpose, on a like-for-like basis consistent with industry best practice.

Springfield, in a swift response to this email, contended in a letter dated, 20th May 2020, that the exchange of data was not a necessary pre-condition for commencing the unitization process and that the data exchange was to enable the parties to determine what the structural extent and distribution was, between the respective contract areas.

On 2nd June 2020, ENI, in a letter to the Minister for Energy, first acknowledged "the interest of the Republic of Ghana to maximize hydrocarbon recovery and to achieve it in an efficient manner."[140] It, however, went on to state, "We wish to emphasize, however, the critical importance of all the parties making a thorough evaluation and assessment to agree upon the existence of hydrocarbon communication as a first step, prior to establishing any appropriate technical and commercial solutions." It went on to note that, "In fact, it is impossible to confirm whether an accumulation of petroleum extends beyond the boundaries of the OCTP Contract Area without the definitive establishment of hydrocarbon communication across the boundary of two contract areas."[141] Going on to elaborate on this assertion further, it noted, "This key initial process is consistent with oil and gas best industry practice and forms the basis for the efficient management of the process. Without effective hydrocarbon communication, an imposed unitization would not render any benefit to the national interest in terms of maximizing hydrocarbon recovery."[142] It asserted, "...From the data currently available to ENI Ghana, the existence of hydrocarbon communication between the Afina discovery and Sankofa Field has not been duly established."[143]

On 8th June 2020, in an email to Springfield with a letter attached, dated 5th June 2020, ENI reiterated that, "it has not been established that an accumulation of petroleum extends beyond the boundaries of the OCTP contract area." [144]

Springfield wrote again to ENI by letter dated 10th June 2020, contending that in terms of the statutory requirements, all the parties were obliged to carry out the Minister's directives as statutorily provided for, and further contended, that ENI had treated all efforts to have it so comply, with contempt.

In a letter to the Minister for Energy, Springfield noted that, "From our engagements so far, ENI appears to be unwilling to cooperate in the process for implementation of the Directives. Please find attached, in Appendix A, a timeline of events after the Directives which demonstrates ENI's unwillingness to cooperate and intent to surreptitiously circumvent the Minister's directives." Outlining what it referred to as ENI's recalcitrance, it outlined them as:

- ENI has refused to review or sign a Confidentiality Agreement (CA) to enable us exchange data as directed by the Minister.
- ENI has refused to agree to an indicative schedule for the transaction to enable us plan the transaction milestones to meet the deadlines in the Directives.
- ENI insists on sharing only raw technical data on a "like for like" basis, even though we have pointed out to them that raw technical data sharing on a 'like for like' basis will neither be appropriate nor reasonable.
- ...ENI is not willing to exchange relevant data for this purpose but rather is seeking to exchange data to only assess the potential extension of hydrocarbon accumulation across the Afina/Sankofa boundary. The exchange of data for the purpose declared by ENI is contrary to the Directives...

On 22nd June, 2020, ENI wrote to the Minister for Energy,[145] noting that it wanted to express additional concerns and reservations regarding the Directives. It noted that, "While we acknowledge and support the Government's objectives to maximize the recovery of hydrocarbons in an efficient manner, in respect of the Afina discovery and Sankofa Field, it is

[140] Letter dated, 2nd June 2020, with Reference Number RD/MD/2020/06/687 from ENI to Hon. Peter Amewu, Minister for Energy, and copied to Dr. Kofi Koduah Sarpong, CEO of GNPC, Egbert Faibille, Chief Executive Officer of the Petroleum Commission and Jonathan Norton, Country Manager of Vitol Upstream Ghana Ltd.

[141] Ibid.

[142] Ibid.

[143] Ibid.

[144] ENI and Vitol further noted in the said letter that hydrocarbon communication across the boundaries of the two contract areas was necessary to determine the existence of a single accumulation beyond the two boundaries. They further stated that Springfield's Confidentiality Agreement was not appropriate for the purpose and that Springfield signed the data exchange agreement, in line with industry practice. They further noted that they would disclose only raw technical data on a like-for-like basis. Further, they contended that Springfield's time-table was not appropriate because it did not take into consideration the initial step of data exchange for confirming the accumulation across the boundaries.

[145] Letter, dated 22nd June 2020, with Reference Number RD/MD/2020/06/751 and copied to Jonathan Norton, Vitol Country Manager, and Dr. K.K. Sarpong, CEO of GNPC.

premature to conclude that the case for unitization has been made definitively or to impose a timetable for the preparation of any binding documentation."[146] It went on to note:

> The law and industry best practices require as a fundamental pre-requisite that a thorough technical assessment be carried out in order to determine the appropriate solution for development of the resources and recovery of petroleum. Without demonstrable evidence of the extension of the petroleum accumulations across the two contract areas and that unitization would ensure optimum recovery of petroleum from any such accumulation, we are unable to commit to the implementation of the Directives.[147]

ENI, in this letter, requested the Ministry to review its position not to furnish it with copies of the Petroleum Commission's independent assessment and GNPC's Report. ENI acknowledged the position of the Ministry regarding the confidential nature of these documents and confirmed its willingness to give a non-disclosure undertaking to cover this.

As the Public Interest and Accountability Committee aptly notes in its 2020 Annual Report, ENI's basis for objecting to the unitization are basically that, there is insufficient data to ascertain whether:

- The Afina discovery drilled in 2019, and the Sankofa Cenomanian Oil Field discovered in 2012 and in production for about 4 years, are straddling each other.
- The Afina discovery has been sufficiently tested or appraised to demonstrate that it is in dynamic communication with the Sankofa Field.
- Unitization would ensure efficient reservoir exploitation, avoid unnecessary, costly and competitive drilling (Rule of Capture), and maximize economic recovery of the reserves.
- Unitization or any other form of coordinated development would be appropriate in accordance with the laws of Ghana.[148]

On 10th July 2020, Springfield filed a suit at the Commercial Court, Accra, intituled Springfield Exploration and Production Ltd. v. ENI Ghana Exploration and Production Ltd. and Vitol Upstream Ghana Ltd. It contends that:

1. ENI and Vitol's conduct is deliberate and intended to delay and circumvent the unitization process [149]
2. ENI and Vitol had itself in a document to the Government of Ghana confirmed the straddling of the fields.[150]
3. ENI and Vitol's position is a scheme to ensure Springfield's exclusion from the proceeds of the exploration and production of its Afina Field.[151]
4. Whilst ENI and Vitol are resorting to delay tactics to frustrate the unitization, ENI and Vitol are busily exploring and producing from its Sankofa Field, the yield of which is tremendously boosted by Springfield's Afina Field, resulting in the gradual depletion of the resources in Springfield's area.[152]
5. ENI and Vitol commenced exploratory activities in the Sankofa Field sometime in 2006 and have, thus, been enjoying the proceeds of petroleum produced from the two Fields by the depletion of the accumulated petroleum resources in both fields to the exclusion of Springfield.[153]

Springfield, thus, seeks from the Court the following reliefs:

1. An order directed at ENI and Vitol to comply with the Minister for Energy's directive issued in his letter dated 9th April 2020 and enter into a Unitization Agreement.
2. An order directed at ENI and Vitol to cooperate with Springfield to develop and produce the accumulation of petroleum.
3. An order directed at ENI and Vitol to render accounts to Springfield in respect of all costs and proceeds received by ENI and Vitol for its exploration and production activities in the Sankofa Field from the year 2006, when ENI and Vitol commenced exploration of the said field till date.
4. An order that any income, profits or other finds due Springfield from ENI and Vitol's exploration and production activities in the

[146] Ibid, Page 1.

[147] Ibid.

[148] -- 2020 Public Interest and Accountability Annual Report, 15 <https://www.piacghana.org/portal/file s/downloads/piac_reports/piac_2020_annual_report.pdf> last accessed on 8 June 2021.

[149] Paragraph 41.

[150] Ibid.

[151] Paragraph 42.

[152] Ibid.

[153] Paragraph 46.

Sankofa Fields be paid to Springfield upon taking such account.

5. Costs on a full indemnity basis.

On 21st July 2020, ENI sent Springfield a letter stating that, as far as ENI and Vitol were concerned, hydrocarbon communication had not been established and so would want to exchange relevant data to establish this before proceeding with the unitization agenda.

On 27th July 2020, the Ministry of Energy wrote to both parties suspending the Directive pending the conclusion of discussions between the parties and the Ministry.

On 11th August 2020, the Ministry invited both parties to a virtual meeting on 19th August 2020.

On 19th August 2020, the parties and the Ministry held a meeting to discuss the challenges and the way forward, and the Minister informed the parties that he would be issuing a second Directive. The Minister further informed the parties that he had appointed an independent third party to ascertain the parties' respective interests in the unitized field, and would impose the findings of the independent party on them if they failed to comply with the second Directive. The Minister issued a second directive to ENI and Springfield directing them to, among others, execute a confidentiality agreement and exchange data by 26th August 2020, complete each party's respective analysis by 2nd September 2020, and submit a Report on their respective interests to the Minister by 18th September 2020.

On 26th August 2020, ENI, by email, informed Springfield that it viewed the case filed in court as a serious impediment to a constructive commercial process and would only be able to sign the confidentiality agreement after the case had been withdrawn. Springfield responded the next day, 27th August 2020, reiterating its willingness to suspend the court case once the confidentiality agreement had been signed and an engagement to give effect to the Minister's directive had begun.

On 28th August 2020, ENI informed the Minister for Energy via a letter that, it had been unable, despite its best efforts to sign the confidentiality agreement with Springfield within the indicated deadline since there was "no alignment on the purpose of the agreement."[154] It stated that the purpose of the agreement should rather be "to assess and analyze the geological structures that have been identified in OCTP and WCTP 2 (as the case may be) to determine whether one or more geological structures straddle the contract area boundary."[155] It further stated that the assessment of shares in the two fields as proposed by Springfield, required a necessary pre-requisite of hydrocarbon communication, as well as an agreement among the parties concerning the methodology for the determination of shares.[156] It also asserted that it expected legal proceedings commenced by Springfield against it and Vitol to be withdrawn "in order to allow a constructive collaboration on this matter,"[157] and requested an extension to the indicated timelines.[158]

On 8th September 2020, Springfield wrote to the Minister, requesting that he proceeded to impose on the parties, the findings of GNPC in its Report dated 1st June 2018, as the terms and conditions for the unitization of the Afina and Sankofa Fields. Springfield's CEO, Kevin Okyere, speaking at the Africa E & P Virtual Summit in mid-September stated, "The discovery we made is part of a field already in production. This shortens our life-cycle. This …should put us into production at the end of this year or early next year." [159]

On 14th October 2020,[160] the Minister for Energy imposed terms and conditions on Springfield and ENI. Among others, the Minister stated:

- All rights and interests of the parties under the OCTP petroleum agreement and the WCTP 2 petroleum agreement insofar as they relate to the Unit Interval, the Unit Petroleum and the conduct of Operations in the unit area, were unitized.

- The Unit area would be the Sankofa Field in the Offshore Cape Three Points Area and the Afina Field in West Cape Three Points Block 2 Area. The Unit Interval would be all depths within the Unit area.

- The basis for unitization and for calculating the Tract Participation of the parties was Hydrocarbons Originally in Place (STOOIP).[161]

[154] Letter with Reference Number RD/MD/2020/08/1130, dated 28th August 2020, signed by Roberto Daniele, Managing Director, and addressed to the Minister for Energy, John Peter Amewu, and copied to Dr. K.K. Sarpong, Chief Executive Officer of GNPC and James Thorburn, Country Manager, Vitol Upstream Ghana Ltd.

[155] Page 1.

[156] Ibid.

[157] Ibid, 2.

[158] Ibid.

[159] --, "Ghana Orders ENI, Springfield to Unitize" Energy Voice, 10 Nov 2020, accessed <https://www.sp ringfieldgroup.com/ghanaian-energy-company-springfield-group-spuds-first-well/> last accessed, 9 June 2021.

[160] Reference No. SCR/KA 118/255/01.

[161] Stock tank original oil-in-place.

Based on the GNPC Independent Report, the in-place oil volumes for the WCTP tract is 642 MMbbls and the OCTP tract is 535 MMbbls. Consequently, the Initial Tract Participation of the WCTP 2 Tract and the OCTP Tract in the Unit Area would be 54.545% for the WCTP parties and 45.455% for the OCTP parties.

- All Unit petroleum produced and saved (including all volumes starting from the first hydrocarbon production of the Unit Area) would be allocated to the WCTP 2 Tract or the OCTP Tract in proportion to its Tract Participation.

- All expenditures properly chargeable to the Unit Account (including all costs starting from the development of either the Sankofa or the Afina side of the Unit Area) would be allocated to each Contract Group in proportion to its Tract Participation and among the parties in the applicable Contract Group in proportion to their Group Paying Interests.

- As the Sankofa Field was already in production, ENI would issue to the Parties a Schedule indicating past expenditures for Unit Operations prior to the Effective Date and a schedule indicating past production of Unit Petroleum and reserves derived from sale of such Unit Petroleum from the Unit Area prior to the Effective Date.

- The Parties would reconcile the amount of each Party's aggregate surplus or deficiency of such actual net expenditures and also reconcile the amount of each Party's aggregate surplus or deficiency of such revenue of such Unit Petroleum as if this directive had been in effect prior to the Effective Date.

- The Parties would reconcile the amount of each's aggregate surplus or deficiency of such actual net expenditures, as well as each party's aggregate surplus or deficiency of revenue of such Unit Petroleum as if this directive had been in effect prior to the Effective Date. The Parties would set off any aggregate deficiency in past net expenditures against any aggregate surplus in revenue from past production and would only make payment of the outstanding balance, if any, after set-off immediately after such reconciliation.

- As the Sankofa Field was already in production, the past expenditure of the Sankofa Field was to be netted off against the past revenue from the sale of hydrocarbon produced from the Sankofa Field, and any party with a positive balance was to be paid immediately.

- The Parties were to undertake a redetermination exercise within eighteen (18) months of the date of the letter; and

- ENI would be the Unit Operator of the Unit area.

On 28th October 2020, ENI and Vitol wrote to the Ministry of Energy, questioning the imposition of the terms and conditions and, to a large extent, rejecting them. ENI and Vitol indicated that, despite repeated requests for data to ascertain whether the fields straddled, data relating to the Afina discovery of Springfield had not been availed to it at all, nor an appraisal of the discovery. They asserted that the approach taken by the Ministry constituted a violation of their rights under Ghanaian law, international law and the OCTP petroleum agreement. [162]

On 6th November 2020, the Ministry wrote to ENI and Vitol,[163] indicating that the steps taken in respect of the matter had been in compliance with the laws of Ghana and so expected the parties to comply with the directive.[164] The Ministry of Energy imposed further terms and conditions, in the form of a Unitization and Unit Operating Agreement (UUOA) on the parties. [165]

ENI and Vitol responded by letter dated 24th November 2020, stating that they did not see any legal basis for the UUOA "given that the Ministry's unilateral attempt to impose conditions for the unitization of OCTP and WCTP2 is invalid."[166] They asserted that should the Ministry continue on that path, as well as failing to provide them with the requested data, they would have no option "but to take steps to commence enforcement of their rights under Ghanaian law, international law and pursuant to Article 24 of the OCTP Petroleum Agreement."[167] They indicated that this step would not be

[162] Letter dated 28th October 2020 with Reference Number GV/MD/2020/10/1337, Paragraph 4 and 6.

[163] Both letters bore the same reference number, SCR/KA118/255/01B.

[164] ENI indicated that they received this letter on the 17th of November 2020.

[165] The letter dated 6th November 2020 had attached to it, a draft Unitization and Unit Operating Agreement.

[166] Letter dated 24th November 2020, with Reference Number GV/MD/2020/11/1425, from Guiseppe Valenti, Managing Director of ENI and James Thorburn, Country Manager, Vitol, and addressed to John Peter Amewu, Minister for Energy and copied to the Secretary, Office of the President, the Minister for Finance, the Deputy Minister, Petroleum, Chief Director, Ministry of Energy, Director, Petroleum Upstream, CEO, Petroleum Commission, CEO of GNPC, COO of GNPC Exploration and Production Company Limited, and CEO of Springfield.

[167] Ibid., Page 2, Paragraph 4.

necessary if, by the 2nd of December 2020, they received confirmation of the withdrawal of the Ministry's terms and conditions, and assurances that it would "continue to seek discontinuation by Springfield of the court proceedings" brought against them.[168]

On 4th December 2020, ENI and Vitol sent a Notice of Dispute[169] to the Republic of Ghana, via the Minister for Energy.

By a letter, dated 29th January 2021, ENI and Vitol, provided GNPC with a Dispute Notice[170] pursuant to Article 24.1 of their petroleum agreement[171] in respect of the Offshore Cape Three Points Area. They laid out their claim as follows:

> ...2. In reliance on GNPC's 'technical report' and 'independent opinion' dated 5th June 2018, which ENI and Vitol have not received but which are referred to in the MoE's letter of 9th April 2020, and the GNPC Report, the Republic of Ghana, acting through the MoE, has sought to impose terms and conditions for the unitization of the Afina Discovery in the West Cape Three Points Block 2 Area and the Sankofa Field in the Offshore Cape Three Points Area **('the purported unitization.')**
>
> 3.The Republic of Ghana, acting through the MoE, has by virtue of the purported unitization breached the Petroleum Agreement...
>
> 4. By virtue of producing the 'technical report' and 'independent opinion' dated 5th June 2018 and the GNPC Report, GNPC has enabled the MoE's unlawful conduct in relation to the purported unitization. In doing so, GNPC has also breached the Petroleum Agreement. Accordingly, we hereby serve you with this written notice of dispute regarding the purported unitization, pursuant to Article 24.1 of the Petroleum Agreement ('the notice.')[172]

They noted in conclusion that:

> This notice triggers a 30-day consultation and negotiation period under Article 24.1 during which we should be pleased to meet with you. We invite your proposals in this regard. If the Dispute is not resolved within that period, we reserve our right to proceed to refer the Dispute to arbitration in accordance with Article 24 of the Petroleum Agreement without further notice to you..." [173]

ENI, in the said letter, stressed a desire to avoid the matter going to arbitration. It noted that, "We have been seeking and continue to seek to avoid the need for formal arbitration proceedings through amicable discussions with the MoE." [174]

On 9th April 2021, ENI and Vitol met with the President of Ghana, President Akufo-Addo, and noted that they had no objection in principle to any potential unitization, as long as it followed a consensual process, was in accordance with Ghanaian law and recognized international oil and gas best practice. [175]

ENI and Vitol, referencing this meeting with the President, subsequently, noted in a letter to the Minister for Energy, dated the 12th of April 2021 that, notwithstanding their willingness to engage in this process, they were obliged to take steps to preserve their legal rights in respect to Springfield's continued pursuit of its legal action in relation to the "purported unitization"[176], as well as the expiry of the limitation period of 6 months (on 14th April 2020) of the right to apply for judicial review of the Minister's directive of 14th October,[177] while reserving the right to progress with international arbitration under the petroleum agreement.[178] They noted that Springfield was now seeking to rely upon the Minister's letter imposing terms and conditions for unitization to support an application for a court order to freeze their accounts.[179] They noted that they would process the available data related to the Afina discovery received from the Petroleum Commission and deliver the outcome of the analysis by the end of April 2021. They concluded by noting that they were confident that an intervention by the Minister could "steer the process and contribute to solving amicably the matter in dispute..."[180]

[168] Ibid, Page 2, Paragraph 6.

[169] GV/MD/2020/12/1593.

[170] Letter addressed to Dr. Kofi Koduah Sarpong, CEO, GNPC, Reference Number GV/MD/2021/01/100, and signed by Giuseppe Valenti, Managing Director, ENI Ghana E & P Ltd., and James Thorburn, Country Manager, Vitol Upstream Ghana Ltd.

[171] Article 24 - Consultation, Arbitration, Independent Expert and Settlement of Third Party Disputes

24.1. Subject to the prior fulfilment of any procedures specified in this Agreement to resolve disputes arising hereunder, any dispute arising between the State and GNPC or either of them on one hand and Contracto,r on the other hand, in relation to or in connection with or arising out of this Agreement, shall be resolved by consultation and negotiation among senior personnel authorized by each. In the event that no agreement is reached within thirty (30) days after the date when the State and/or GNPC on the one hand and the Contractor, on the other hand, notifies the other that a dispute exists within the meaning of this Article or such longer period specifically agreed to by the parties or provided elsewhere in this Agreement, any party shall have the right subject to Article 24.9 [determination by a sole expert] to have such dispute settled exclusively through international arbitration under the auspices of the International Chamber of Commerce (the "ICC) and adopting the Rules of Arbitration of the International Chamber of Commerce (the "ICC Rules") in force on the date on which the proceedings are instituted, which ICC Rules are deemed incorporated by reference into this Article 24, save as otherwise provided herein."

[172] Letter (n 46), Page 1.

[173] Ibid., Page 2.

[174] Ibid., Page 1.

[175] See letter dated 12th April 2021 with Reference Number GV/MD/2021/04/398, from ENI and Vitol, to the Minister for Energy, Matthew Opoku Prempeh, and copied to Nana Asante Bediatuo, Executive Secretary to the President, and Dr. K.K. Sarpong, Ghana National Petroleum Corporation.

[176] Ibid.

[177] Ibid.

[178] Ibid., 2, Paragraph 4.

[179] Ibid., 1, Paragraph 3a.

[180] Ibid., 2, Paragraph 5.

Thus, in June 2021, ENI and Vitol noted that they were working with the Ministry of Energy, Petroleum Commission and GNPC, to find a mutually acceptable solution to enable the country to capitalize on the Afina discovery. Giuseppe Valenti, Managing Director of ENI Ghana, noted that, "In principle, we are not opposed to unitization, but this needs to follow an appropriate, shared work programme and evaluation process to assess the elements listed above before taking decisions in the interest of all parties." [181]

4.4.2 Springfield's Position

Springfield's position is that its WCTP and ENI and Vitol's OCTP share a common boundary. Springfield noted in a letter, dated 20th March 2018, to the then Minister for Energy, Hon. Boakye Kyerementeng Agyarko, thus: "As our technical report clearly indicates, the Sankofa Production Area is part of a common reservoir complex straddling the two licensed areas (OCTP and WCTP 2)."

Springfield's case is that it came to its attention that the accumulation of petroleum in ENI and Vitol's Sankofa Cenomanian Reservoir extended beyond and into Springfield's WCTP-2 Contract area where its petroleum within its area is accumulated. Springfield notes that these facts became known to it after it conducted some geophysical and geological analysis of its data, including seismic attribute analysis and structural analysis. [182]

It is Springfield's position that the effect, therefore, of its finding that ENI and Vitol's accumulation extended into its reservoir is that any exploration and production activities carried out in ENI and Vitol's production area would automatically affect petroleum accumulations in its contract area, and vice versa.[183] It noted in the aforementioned letter: "We understand from our technical studies that failure to treat the broader Sankofa Reservoir complexes in the licensed areas as a unit area for the purposes of joint development and unitized operations between the Sankofa production area and the Sankofa extension in WCTP 2 will result in sub-optimal development of the resource base." Making the argument along the lines of the preservation of the reservoir, as well as the interest of the Government of Ghana, it noted:

> If both operators of OCTP and WCTP 2 continue to independently develop the Field, based on the rule of capture, it would lead to accelerated loss of reservoir pressure and drive mechanism, a major reduction in the maximum ultimate recovery of the common reservoir and a competitive drilling and production practice by both operators. This would further lead to a consequent waste of capital investment and erosion of economic value and returns. Furthermore, such excessive wells and unnecessary infrastructure would represent a duplication of costs, such increased costs to ultimately be recovered as Cost Oil from the production revenue of the common reservoir. This 'economic waste' of higher costs and uncoordinated drilling and infrastructure will, ultimately, lead to the physical waste of oil or gas as the field will be abandoned earlier than is the norm as it will cease to be commercially profitable in its later stages. This potential economic and physical waste will also have a direct and adverse economic impact on the Government of Ghana's revenues and minimize the gas production. The increased cost of oil to be recovered because of duplication in drilling and infrastructure costs will significantly reduce the Government's share of revenues from production of the common reservoir. Furthermore, the reduction in ultimate recoveries from the common reservoir because of early abandonment due to uncoordinated drilling that reduces commercial profitability will have a negative impact on the Government's projected revenues.

Making arguments in specific reference to the impact on its operations, it noted:

> Specifically, we understand from public domain information that the OCTP development is based on the assumption that the oil reservoirs are in an Oil-Down—To (ODT) situation meaning that no oil-water-contact (OWC) could be found. According to ENI's plan disclosed at the time of first oil, the water injection well for the development are located close to the WCTP 2 boundary. The location of water injection wells so close to the WCTP 2 boundary could sweep oil in WCTP 2 reservoirs without any control and can seriously compromise Springfield's efforts to recover oil from its part of the joint pool and may even damage the reservoirs, affecting the oil recovery. The planned water injectors may adversely affect the sweep efficiency and, hence, the ultimate recovery of the WCTP 2 part of the Sankofa East oil field.

[181] --, "ENI says working to find an acceptable solution to unitization stalemate", Ghana Business News, 5 June 2021 <https://www.ghanabusinessnews.com/2021/06/05/eni-says-working-to-find-acceptable-solution-to-unitisation-stalemate/> last accessed, 11 June 2021

[182] Paragraph 9.

[183] Paragraph 12.

It is Springfield's case that, although its data confirmed that ENI and Vitol's Sankofa Cenomanian Reservoir extended into its contract area, it decided, for the avoidance of doubt, to engage the services of an independent expert to determine whether or not its findings that ENI and Vitol's reservoir extended into its contract area, was correct.[184] It noted that it, thus, engaged the services of an expert in the industry, ERC Equipoise, to verify its findings. Springfield noted in the said letter, dated 20th March 2018, that:

> WCTP shares an Eastern boundary with Offshore Cape Three Points (OCTP), a block licensed to and operated by ENI Ghana Exploration & Production Ltd. ("ENI"). From our extensive geological and geophysical studies, including seismic attribute analysis of the WCTP2 contract area, we have discovered that the Sankofa production area contained in the OCTP license area extends into WCTP2. This has been proven by extensive work carried out by Springfield's in-house geoscientists and verified by ERC Equipoise (a leading United Kingdom Oil and Gas Reservoir Evaluation Firm and an independent third party expert on the subject matter).[185]

It is Springfield's case that the independent expert confirmed its findings that Vitol and ENI's Sankofa Cenomanian Reservoir, indeed, extended into its contract area and that, any activity undertaken in ENI and Vitol's reservoir would affect Springfield's right and petroleum deposits in the WCTP-2.[186]

Springfield, thus, in the said letter of 20th March 2018, requested the Ministry to exercise its statutory mandate to direct the parties to "commence unitization discussions immediately with regards to the Sankofa production area in OCTP and the Sankofa extension in WCTP 2 and to enter into a unitization agreement within a defined and reasonable time." [187]

The Ministry requested Ghana National Petroleum Corporation (GNPC) to independently assess Springfield's claim and it is Springfield's position that, GNPC, upon concluding its investigations, confirmed its position that the deposits of ENI and Vitol extended into its contract area.[188] Springfield contends that it was to establish beyond every shadow of doubt that the deposits in ENI and Vitol's Sakofa Field actually extended into and included petroleum deposits in Springfield's area, that the Ministry advised in August 2018 that a well be drilled within its contract area,[189] which it did[190] by successfully drilling the Afina-1x well in the WTCP-2 Block. It is Springfield's position that it, indeed, drilled this well to, among others, confirm whether or not the petroleum accumulation in the Sankofa Cenomanian Reservoir straddled the contract areas of the parties.[191] Springfield contends that the post-drilling data, confirmed that ENI and Sankofa's accumulation, indeed, extended into Springfield's contract area and that the two fields are one and the same.[192]

Springfield contends – including in a letter, dated 10th June 2020, to ENI – that ENI has rebuffed all efforts to commence unitization efforts.

4.4.3 ENI's Position

It is ENI's position that there has not been enough data to establish the veracity of the claim that there is some communication between Sankfoa and Afina, nor ascertain definitively that the discovered resources are producible.[193] It notes that, without that, it is difficult to accept the unitization deal as presented by the Ministry of Energy on behalf of the Government.[194] It contends that Springfield's Afina discovery has not been sufficiently tested to show that it shares a reservoir with the Sankofa Field.

ENI noted in its letter, dated 22nd June 2020, to the Minister for Energy that, "The law and industry best practice require as a fundamental pre-requisite that a thorough technical assessment be carried out in order to determine the appropriate solution for the development of the resources and optimum recovery of petroleum."[195] It then stated its position unequivocally, thus, "Without demonstrable evidence of the extension of the petroleum accumulations across the two contract areas and that unitization would ensure optimum recovery of petroleum from any such accumulation, we are unable to commit to the implementation of the Directives."[196]

[184] Paragraph 13.

[185] Letter to the Minister for Energy, Hon. Boakye Kyeremateng Agyarko, dated, 20th March 2018, Page 1.

[186] Paragraph 14.

[187] Page 2 of letter, Paragraph 17 of Statement of Claim.

[188] Paragraph 17.

[189] Paragraph 19.

[190] Paragraph 20.

[191] Ibid.

[192] Paragraph 21.

[193] Iain Esau and Barry Morgan, "ENI hits back at Ghana for Imposing Unitization Deal on Sankofa and Afina Fields" <https://www.upstreamonline.com/production/eni-hits-back-at-ghana-for-imposing-unitisation-deal-on-sankofa-and-afina-fields/2-1-913911> Upstream Energy Explored, 18 November 2020.

[194] Ibid.

[195] Page 1.

[196] Ibid.

ENI went on to make reference to Section 34(1) of the Petroleum Act, 2016,[197] which notes that the Minister may direct contractors to enter into a Unitization and Unit Operating Agreement where an accumulation of petroleum extends beyond the boundaries of one contract area and for the purpose of ensuring optimum recovery of petroleum from the accumulation. It argued that, "the law therefore requires that there must necessarily be a comprehensive assessment of the petroleum accumulation to establish and confirm the extension of an accumulation across any shared contract area boundary in a manner that would ensure the optimum recovery of petroleum prior to determining the appropriate course of action and setting out the relevant timetable."[198]

ENI further contended that the law, under Section 34(3) of the Petroleum Act, 2016, considers alternatives to unitization that may be more appropriate where accumulations are in proximity. It contended that, however, in this case, there is not sufficient evidence to demonstrate that a unitization approach will deliver optimum recovery of petroleum. It emphasized its position that, "based on the data available to us, the existence of hydrocarbon communication between the Afina discovery and the Sankofa Field has not yet been duly established and a proper evaluation, by all parties, is required."

Further making arguments as to why the decision to unitize had not crystallized, it noted that, with regard to the timetable indicated in the Directives, Regulation 50(4) of the Petroleum (Exploration and Production) (General) Regulations, 2018 (L.I. 2359)[200] provides that relevant contractors are to submit a draft Unitization and Unit Operating Agreement to the Minister within six (6) months, following the finalization of the appraisal of the petroleum accumulation. Regulation 50(4) states,

> The relevant contractors shall submit to the Minister a draft unitization and unit operating agreement or an agreement to coordinate and develop separate petroleum accumulations based on the model agreement described in sub-regulation (1) within six months after the finalization of appraisal of the petroleum accumulation.[201]

ENI, thus, contended that, it was necessary to first appraise the hydrocarbon accumulations and only when this appraisal was finalized, would it be possible to determine the appropriate course of action and set out the relevant timetable. ENI argued that, consequently, the statutory timeline of six (6) months, according to Regulation 50(4), began only after the finalization of the appraisal of the petroleum accumulation. It was, thus, their submission that the proposed timeline requiring the parties to submit a draft Unitization Agreement within 120 days from the date of the Directives was practically impossible to commit to, and was also inconsistent with Regulation 50(4).

ENI further noted that, appraisal was defined under Section 95 of the Petroleum Act, 2016, as "operations or activities carried out following a discovery of petroleum for the purpose of delineating the accumulations of petroleum to which that discovery relates in terms of thickness and lateral extent and estimating the quantity of recoverable petroleum and all operations or activities to resolve all uncertainties required for determination of commerciality of a discovery."[202] ENI asserted that the appraisal process "must be conducted in accordance with the law and best industry practice."[203]

ENI has, in essence, noted over the months that unitization is appropriate where "a hydrocarbon accumulation straddles a contract boundary area; hydrocarbons from one contract area can migrate into another contract area; hydrocarbons are commercially producible on both sides of the contract boundary area; and the hydrocarbon accumulation can be developed as one unit for an optimum petroleum recovery and operational efficiency."[204]

ENI noted its commitment to supporting the Government of Ghana to maximizing hydrocarbon recovery, and to its commitment to progress the matter starting with the exchange of raw data with Springfield on a like-for-like basis but with the purpose of evaluating the existence of hydrocarbon communication between the Afina discovery and the Sankofa Field. It indicated that it had informed Springfield very clearly of its position and its

[197] Section 34 – Coordination of Petroleum Activities and Unitization.

[198] Page 1 of letter from ENI to the Ministry of Energy dated 22 June 2020.

[199] Page 2.

[200] Regulation 50 is titled, Coordination of Petroleum Activities and Unitization.

[201] Page 2 of letter from ENI, signed by Roberto Daniele, Managing Director to Hon. John Peter Amewu, dated 22nd June 2020, with Reference number RD/MD/2020/06/751.

[202] Section 95 is titled, Interpretation.

[203] Page 2 of letter from ENI, signed by Roberto Daniele, Managing Director, to Hon. John Peter Amewu, dated 22nd June 2020, with Reference number RD/MD/2020/06/751.

[204] Ghana Business News (n 57).

willingness to progress with technical evaluations for the purpose which it stated.

In its concluding remarks, ENI noted that the contents of Springfield's letter of 10th June 2020 were inaccurate and inflammatory. It unreservedly refuted any allegations of obstructive or irregular conduct made against it. It further stated that it had shared with Springfield a Data Exchange Agreement that was consistent with law and which Agreement did not require any party to exchange data without first obtaining any necessary approvals; followed international best practice and was entirely appropriate for the process, and offered equivalent contractual protections to the WCTP 2 form of confidentiality agreement which Springfield contended it was obliged to use.

ENI has rejected claims that it is deliberately trying to prevent unitization, or even worse, sabotage the process. Mr. Giuseppe Valenti, Managing Director of ENI Ghana, noted that, ENI has submitted to the Ministry of Energy its analysis of the two fields, and believes that cooperation and data sharing will help find a commercially viable solution. He noted thus, "We are confident that the analysis and resulting report will allow the parties to progress discussions toward an agreeable, commercial solution of the matter."[205] He further noted that ENI Ghana was only requesting an appropriate shared work programme and evaluation process to assess the elements or factors that necessitate a unitization.[206] He noted also, "ENI will need an appraisal program of the Afina area, including (but not limited to) production and interference tests in order to understand the potential benefit of a unitization of the Sankofa and Afina discovery."[207]

It bears noting that Springfield has disputed this in a statement issued.

4.4.4 Springfield's Response to ENI and Vitol's Assertions

On 5th June 2021, Springfield issued a press release in which it stated that it sought to correct inaccurate statements in respect of the unitization, which statements had been attributed to ENI, ACEP[208], PIAC[209] and IES[210]. In respect of the unitization process, it notes a number of things.

It notes that it has been stated in some publications that, "…unitization needs to follow an appropriate, shared work programme and evaluation process to assess the elements before taking decisions."[211] Springfield contends that this is erroneous and not the position of the law. It states that, "Per the laws of Ghana, the sole requirement for the unitization of fields is when an accumulation of petroleum extends from the boundaries of one contract area into another." Springfield contended that this had been established and that, "Any further activity or work programme beyond proving that the fields straddle is a post-unitization activity that would be carried out as part of the unit operations."

It further noted that it has been erroneously stated that, "…the unitization process for Afina and Sankofa Field would entail an appraisal programme of the Afina area, including (but not limited to) production and inference tests." It stated that this was inaccurate. It asserted,

> A key objective of appraisal activities is to delineate fields and know how far they extend. Thus, appraising a Field would apply to the entire petroleum accumulation and not just a portion of it. With the Afina and Sankofa Fields already established as a single unit, the drilling of Afina-1 fulfilled the appraisal objective as it proved that the Sankofa Fields extend further into the Springfield operated area. [212]

It notes that, though Afina-1 is an exploratory well for Springfield, due to contractual obligations and the fact that it is the first well drilled in the WCTP 2 area, it can be deemed an appraisal well, as well in the grand scheme of appraising the Sankofa hydrocarbon accumulation. Springfield asserts that it draws a parallel with the Hyedua well, drilled by Tullow as an exploration well for the Deepwater Tano Contract area, which was later reclassified as an appraisal well for the purposes of unitizing the Jubilee Field. It, thus, concludes that, "In this regard, the Afina 1X well can either be an exploration well or an appraisal well, depending on the context – it is an exploration well in the context of the WCTP 2 contract area, and an appraisal well in the context of the unitized field with Sankofa."[213]

[205] -- "ENI Ghana ready for Unitization with Springfield if…" Norvan Reports, 3 June 2021 <https://www. norvanreports.com/eni-ghana-ready-for-unitization-with-springfield-only-if/> last accessed, 8 June 2021.

[206] Ibid.

[207] Ibid.

[208] Africa Centre for Energy Policy.

[209] Public Interest and Accountability Committee.

[210] Institute for Energy Studies.

[211] Press Statement issued by Springfield Energy.

[212] Ibid.

[213] Ibid.

Springfield goes on to note, in respect of Costs and Liabilities, that it has been stated in some publications that, "…each party must first pay its share of the costs of producing hydrocarbons from the unitized field in order to have a right to the oil produced and proceeds from the production."[214] It rebuts this as a misrepresentation of the process. It notes that the Field has been in production for almost four (4) years already. It states that past production from the unitized field has to be re-allocated to the parties in accordance with their respective interests in the unitized field. It goes on to note that, as per industry practice, a reconciliation of past costs and past revenue from production must be conducted to determine the entitlement of the parties to past revenue and costs. It asserts that after this reconciliation, if the cost is higher than the revenues, then there will be an amount for it to pay and vice versa. It notes that, thereafter, that is, after such reconciliation, Springfield will bear its pro-rata share of future costs and be entitled to its share of oil produced in line with industry-standard practice. It contends:

> This is in line with the international convention on unitization that where there is pre-unitization expenditure and/or pre-unitization production in the Unit Area (whether by one or both Contract Groups), the Unitization and Unit Operating Agreement (UUOA) would seek to re-allocate and balance such costs and production from the unit area to the contractor groups in accordance with their respective shares of the unit. This set-off mechanism is clearly contemplated in the 2020 Model UUOA issued by the Association of International Petroleum Negotiators (AIPN).[215]

4.4.5 Different Perspectives

Some foreign publications have portrayed these events in a negative light in respect of Ghana, basically putting forth that the Government of Ghana is forcing the unitization on ENI. Thus, there have been such headings as, "Ghana Forces ENI to merge its Sankfoa Field with a Domestic Discovery," "ENI Faces Forced Unitization of West Africa Fields," "Ulterior Motive Behind Energy Minister Amewu's Push for ENI and Springfield's Shotgun Wedding," "ExxonMobil, Aker Energy and ENI Fed up with Accra," "Ghana's Political Meddling Could Derail its Oil Boom,"[216] and the like.[217] Viktor Katona, for instance, commenting on these developments in Ghana's upstream petroleum industry, has stated:

> As is often the case with projects that exceed general expectations, the Ghanaian government might be overexerting itself in making the nascent oil industry serve its interests…Accra's assertive view of how it would prefer its offshore crude production to develop has another deficiency. The Energy Ministry wants ENI to operate the prospective Sankofa-Afina field, however, it should be Springfield that gets the largest stake as Afina's nominal reserves are higher, despite its commercial nature remaining questionable. Mirroring a 54.5-45.5% split between Afina and Sankofa, ENI would receive only 20.2% of the future joint project, Vitol would be left with 16.2% whilst Springfield would get 44.7%. Interestingly, the Ghanaian authorities have set up a May 2022 deadline to finalize the unitization deal, so despite the indisposition of ENI and Vitol, the outcome is already foreordained for them. Ghana ought to be very careful in how it treats the Sankofa/Afina issue because it carries enormous reputational risks for future offshore projects.[218]

James Gavin notes that, Ghana's imposition of a unitization deal on the parties "highlights the government's impatience at delays in developing hydrocarbon resources but may also reveal an element of resource nationalism as the state throws its weight behind a homegrown company."[219]

In Ghana, the Institute for Energy Studies (IES) has led a spirited charge for the quick unitization of the two fields on the basis that the benefits to the country will be immense. According to the IES, from a study it has conducted, the unitization will lead to maximum economic benefits of some $8.4 billion to the State as opposed to the $2.065 billion to be derived if the unitization is not done.[220] IES has asserted that benefits to the State in the incidence of unitization will be in the form of a significant reduction in operational and capital costs of the unitized fields, as well as increases in royalties,

[214] Ibid.

[215] Ibid.

[216] Viktor Katona, "Ghana's Political Meddling Could Derail Its Oil Boom", OilPrice.com, 17 Jan 2021 < <https://business24.com.gh/2021/06/07/springfield-ep-is-committed-to-unitisation-process/?> last Accessed, 8 June 2021.

[217] Ekow Dontoh and Yinka Ibukun, "Ghana Forces ENI to merge its Sankofa Field with a Domestic Discovery," World Oil, 11 December 2020 < https://www.worldoil.com/news/2020/11/12/ghana-forces-eni-to-merge-its-sankofa-field-with-a-domestic-discovery> last accessed, 8 June 2021.
Ekow Dontoh and Yinka Ibukun, "ENI Faces Forced Unitization of West Africa Fields", Bloomberg, 12 December 2020 < https://www.rigzone.com/news/wire/eni_faces_forced_unitization_of_west_africa_fields-12-nov-2020-163837-article/> last accessed, 8 June 2021.
--, "Ulterior Motive Behind Energy Minister Amewu's Push for ENI and Springfield's Shotgun Wedding", Africa Intelligence, 7 December 2020 <https://www.africaintelligence.com/oil--gas_corporate-strategy/2020/12/07/ulterior-motive-behind-energy-minister-amewu-s-push-for-eni-and-springfield-s-shotgun-wedding,109625622-art> last accessed, 8 June 2021.
--, "ExxonMobil, Aker Energy and ENI fed up with Accra," Africa Intelligence, 7 June 2021, 1.
Viktor Katona, "Ghana's Political Meddling Could Derail Its Oil Boom", OilPrice.com, 17 Jan 2021 < <https://business24.com.gh/2021/06/07/springfield-ep-is-committed-to-unitisation-process/?> last accessed, 25 June 2021.

[218] Katona (n 92).

[219] James Gavin, "Ghana Unitization Order puts ENI in a bind", African Energy Newsletter, 3 December 2020.

[220] Norvan (n 81).

taxes, additional oil entitlement (AOE), levies and fees.[221]

Mark Agyemang, the Technical Director of the Public Interest and Accountability Committee, has opined that the parties come to the negotiation table and appoint an independent assessor to reassess the two fields and present the data to the parties. Agyeman noted, "In my opinion, I think that there should have been an independent assessor. It should not have been government carrying out the assessment. They should have appointed an independent assessor, who will make the data available to all parties, especially ENI."[222]

The Public Interest and Accountability Committee, commenting on this ongoing matter in its 2020 Annual Report, noted that the impasse is yet to be resolved, but noting the effect of the Minister's directive if complied with, it states:

> A successful outcome of government's directive on this would register the very first unitization agreement between an international oil company (IOC) and a Ghanaian operator, and could usher in a new era of meaningful local participation in Ghana's upstream petroleum sector.[223]

The African Centre for Energy Policy (ACEP), has noted, "The negative press associated with these issues has the potential to undermine the progress made over the years to encourage investments into Ghana's upstream petroleum sector."[224] It further noted that the situation is worsened by the current global context of the energy transition, which is engineering a shift away from fossil fuels to alternative energy sources.[225] It opined that the shift is shrinking available capital for investments in new exploration activities in the oil industry and generating extreme competition for the limited money available for upstream activities.[226] It, thus, noted that attracting investment, therefore, requires an assuring, positive, and less risky political environment. It also stated that, "ACEP's statement on these developments is a cautionary call on government and stakeholders to act right and preserve the investment climate of the industry."[227]

ACEP contextualized the issues thus:

> The reports from GNPC and ENI point to contentions about the conditions precedent for unitizing the two fields. GNPC, on the one hand, summarily, is of the view that the existing seismic data and oil properties of the Afina discovery within the same Cenomanian Channel as SGN is enough proof of straddling. On the other hand, ENI holds the opinion that further studies are required to establish commerciality and dynamic communication.[228]

ACEP concludes thus:

> ...ACEP cautions without judgment that:
>
> - Unitization is an age-old industry practice with established technical parameters and conditions necessary for joint development and production of adjacent fields, often necessitated by straddling or proximity. In most cases, the commercial benefits accruing to both parties ensure a smooth unitization process without state intervention. However, where the state's intervention becomes necessary, it is required that the state is transparent in the application of the principles, laws, and science of unitization. Unfortunately, the government's silence amid the raging media war is unhealthy for creating a competitive and assuring environment to the investor community. Government must inform the public on the basis of its unitization directive in an effort to diffuse the local and international controversies on the matter.
> - The position of GNPC and ENI also contest Ghana's Petroleum (Exploration and Production) Law's provisions on unitization and the regulations developed to operationalize it. Therefore, ACEP suggests the immediate interpretation of the provisions on unitization by the Attorney General to guide the government's position.
> - GNPC is an interested party, and, by law, a partner to every investor in the sector. That position requires that GNPC maintains credibility and trust with its partners. Government must recognize the commercial position of GNPC and not use them to settle contentious issues. In this particular unitization tussle, GNPC should not have been assumed as the independent arbiter. The Petroleum Commission or an independent party appointed by ENI and Springfield would have been better suited in this case.

[221] Ibid.

[222] --, "ENI, Springfield Impasse...PIAC calls for Independent Reassessment of Fields," Public Interest and Accountability Committee, 31 May 2021 < https://www.piacghana.org/portal/12/13/495/eni-springfield-impasse-%E2%80%A6piac-calls-for-independent-reassessment-of-fields> last accessed, 8 June 2021.

[223] PIAC (n 24) 15.

[224] --, "ACEP's Comments on the ENI-Springfield Unitization Tussle and ExxonMobil's Exit from Ghana" 1 Africa Centre for Energy Policy, 3 June 2021, https://cdn.modernghana.com/images/conten t/report_content/642021113833-0eu2xkjwwr-aceps-comments-on-the-eni-springfield-unitisation-tussle-and-exxonmobils-exit-from-ghana.pdf> last accessed, 9 June 2021

[225] Ibid.

[226] Ibid.

[227] Ibid.

[228] Ibid.

4.4.6 Current Status

The matter is currently before the High Court for determination.

On 16th July 2020, Springfield filed an application before the Court for the preservation of funds, revenue and monies earned, paid to and/or accruing from the exploration and production of petroleum by ENI and Vitol from the Sankofa Field, from the commencement of the suit pending the final determination of the matter.

ENI, the 1st Defendant, filed an application challenging the capacity of the Plaintiff, Springfield, to institute the suit. Vitol, the 2nd Defendant, also filed an application on the 29th of July 2020, seeking an order to strike out Springfield's action for want of disclosure of reasonable cause of action. The applications were dismissed by the Court on 3rd September 2020.

On 17th September 2020, Springfield intimated to the Court that it had come to its notice that ENI had filed a stay of proceedings pending appeal and, as such, their application would have to be taken after the determination of that application by ENI. The application for a stay of proceedings was dismissed, as well as a further application to the Court of Appeal.

On 2nd March 2021, the Court was informed that applications had been filed in the Supreme Court for special leave to appeal the ruling of the Court and for a stay of proceedings.

On 25th June 2021, the Court ordered ENI to pay 30% of its revenue generated from the sale of its crude from the Sankofa Field into an escrow account, pending the final determination of the matter.[229] The order took effect immediately. The Court noted that this order would protect the interests of Springfield, whiles allowing ENI and Vitol to continue operating and cover costs.[230] Whiles Springfield welcomed it as "a vindication" of its position, ENI noted in a statement issued thus, "We fully expect to take the appropriate steps necessary in order to protect our operations in the country, including appealing against this ruling."[231]

On 2nd July 2021, ENI and Vitol filed separate motions, praying the Court of Appeal to stay the execution of the ruling of the High Court pending the determination of their appeal against the ruling. They argued, inter alia, that their appeal raised serious issues to be tried and stood a very good chance of success, thus, irretrievable damage would be done to them, third parties, and the people of Ghana if the stay was not granted, and further, that special circumstances were justifying a stay of execution pending the determination of the appeal.

On 22nd July 2021, the Court of Appeal (Civil Division) dismissed the application by ENI and Vitol for a stay of execution and held that the order by the trial Court ought not to be disturbed. The Court noted: "We have read and re-read the ruling of the learned trial judge and, in particular, examined the reasoning behind the ruling she gave. We have come to appreciate the matters the trial judge took into consideration in arriving at the decision."[232]

This ruling was appealed to the Supreme Court and, on 16th November 2021, the Supreme Court dismissed the appeal and suggested to the parties to seek an out-of-court settlement. The Court noted: "The Court finds no circumstances to grant leave to the Applicants to appeal to the Supreme Court as no serious error or novelty has been raised by the Applicants. We proceed to dismiss the application. We, however, encourage parties to settle this matter out of court, if possible. Leave refused by this Court."[233]

The case remains ongoing as well as the matter before arbitration.

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[229] Alessandro Bianchi, "Court Rules30% of ENI Ghana oilfield revenue to go into escrow" (Reuters, 28 June 2021) <https://www.reuters.com/business/energy/court-rules-30-eni-ghana-oilfield-revenue-go-into-escrow-2021-06-25/> 1 July 2021.

[230] Ibid.

[231] Ibid.

[232] Ruling of the Court of Appeal (Civil Division), delivered on the 22nd of July 2021, Coram Justices B. Ackah Yensu (Presiding), Obeng Manu and Adjei Frimpong.

[233] In the Superior Court of Judicature, the Supreme Court (Civil Division); Consolidated Civil Motion Nos. J8/175/2021 and J8/177/2021.

Chapter

5

DOWNSTREAM: POLICY & REGULATORY REVIEW

Downstream: Policy & Regulatory Review

5.1 Policy and Regulatory Review

The establishment of the Petroleum Hub Development Corporation and the commencement of the development of a national energy transition policy marked the highlight of the Government's policy interventions for the period under review. The period also saw a change in sector leadership, with the appointment of Dr. Matthew Opoku Prempeh as Minister for Energy and Dr. Hamid Mustapha as CEO of the National Petroleum Authority.

5.1.1 Petroleum Hub Development Corporation

Government commenced the operationalization of its commitment to turn Ghana into Africa's first petroleum hub with the enactment of the Petroleum Hub Development Corporation Act, ACT 1053. The bill passed by Parliament was assented to by His Excellency, the President, on 29th December 2020. The ACT, as passed, established the Petroleum Hub Development Corporation (PHDC) to promote and develop a Petroleum and Petrochemicals Hub and to provide for related matters. The functions assigned PHDC in the ACT comprise:

1. Plan and implement strategies for the development of a Petroleum and Petrochemicals Hub in the country;
2. Undertake preparatory works for the promotion and development of the Petroleum and Petrochemicals Hub;
3. Provide basic utilities for companies and service providers for the development of the Petroleum and Petrochemicals Hub;
4. Assist companies operating in the Petroleum and Petrochemicals Hub to acquire all relevant licenses and permits from the relevant regulatory bodies to develop and operate their facilities within the Petroleum and Petrochemicals Hub;
5. Coordinate and facilitate investment activities in the Petroleum and Petrochemicals Hub;
6. Collaborate with investors for the development of the Petroleum and Petrochemicals Hub;
7. Monitor and evaluate the development of the Petroleum and Petrochemicals Hub to ensure value retention for the country;
8. Ensure the participation of Ghanaians in technical and managerial functions of the companies operating within the Petroleum and Petrochemicals Hub;
9. Establish, keep and maintain a register of companies and service providers operating within the Petroleum and Petrochemicals Hub;
10. Maintain and preserve records of the Corporation and publish the records in the medium that the Board considers appropriate;
11. Perform any other function ancillary to the object of the Corporation.

Government, in August 2021, appointed Mr. Charles Owusu as the CEO of the PHDC and in September 2021, constituted the Board to steer the affairs of the Hub vision. The PHDC, has since becoming operational, developed its internal structures and systems as well as pitching the project to possible investors across the globe.

The Project Location

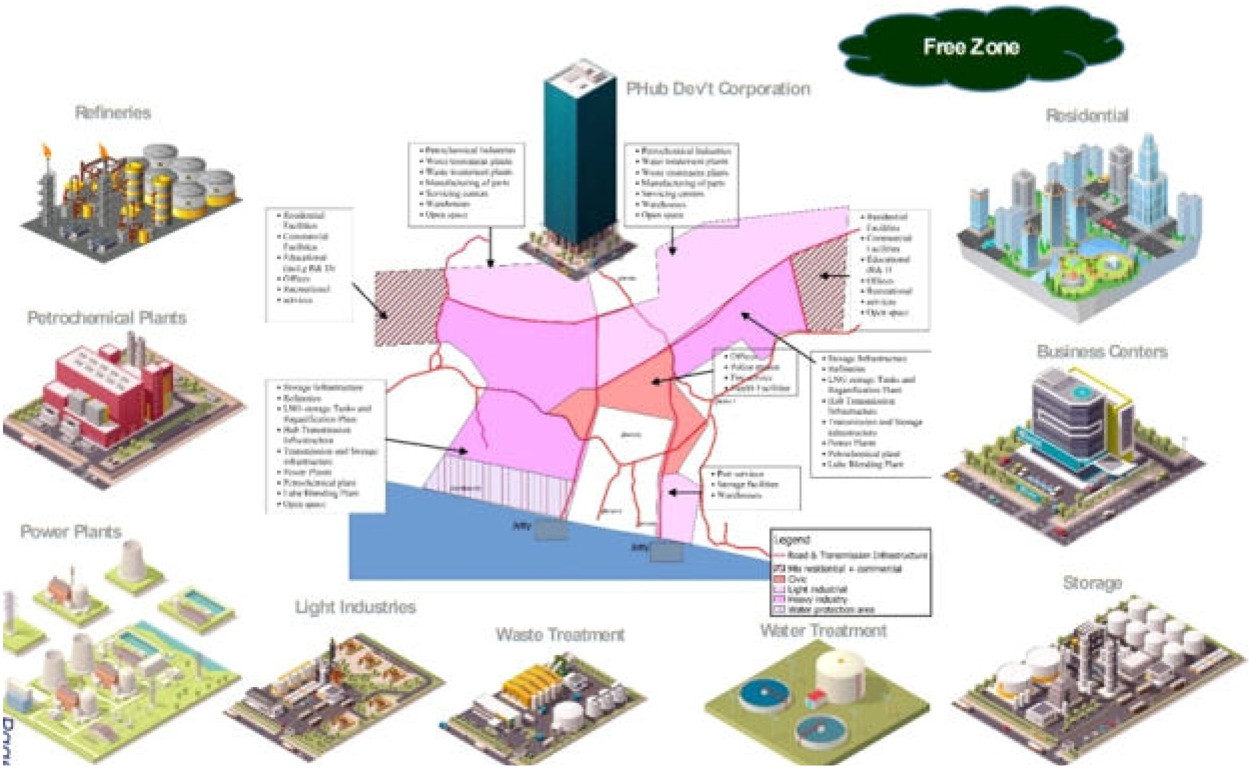
The Hub is to be located on a 20,000-acre parcel of land with the coastline in the Jomoro District of the Western region. The land was offered by the chiefs and people of the area who remain hopeful of the success and impact of the project for their people.

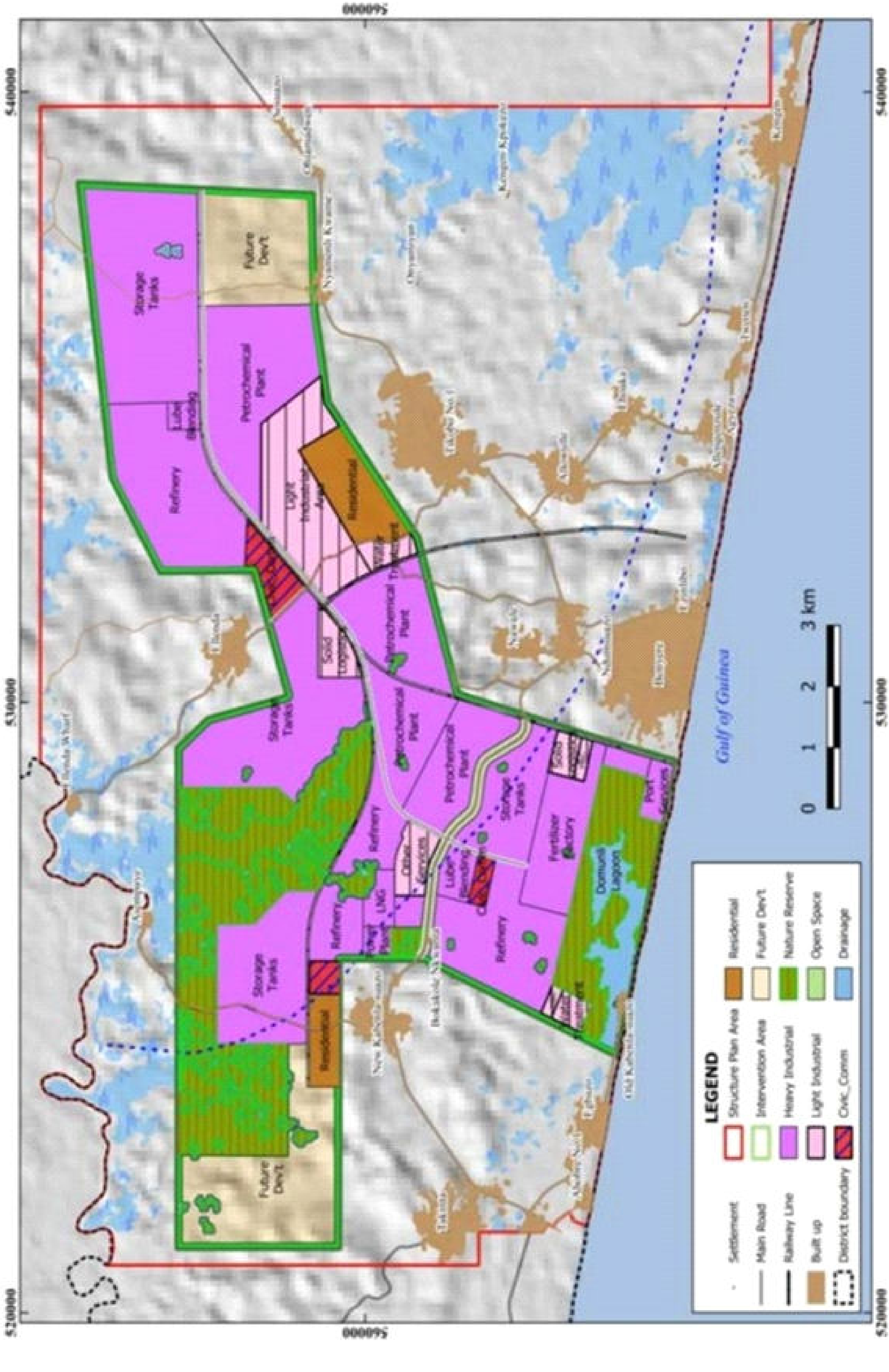
Following consultations, initiated by the Ministry towards the acquisition of the land to site the Petroleum Hub, a consultant was engaged to conduct some studies that would provide a comprehensive insight into the social and economic concerns that would emerge to affect the acquisition of the proposed 20,000 acres of land and the implementation of the Petroleum Hub project and offer detailed proposals on how those concerns could be mitigated.

In the period under review, the consultant submitted the Situational Analysis and Dispute Resolution and Boundary Demarcation Reports. Two other reports: the Sensitization and Alternative Livelihood Training Report and Resettlement Action Plan have been delayed due to delays in the release of funds to the Consultant.

Completion of the Land Acquisition Studies is necessary to ensure that the PHDC understands the issues in the area and the best approach to acquiring the proposed 20,000-acre land for the Petroleum Hub.

Spatial planning for the land has been completed and submitted to the Ministry of Energy and PHDC by the Land Use and Spatial Planning Authority (LUSPA). Processes for the completion of the land acquisition remain on-going and are expected to be completed by the end of 2022.




Gulf of Guinea
LEGEND
Settlement
Main Road
Railway Line
Built up
District boundary
Structure Plan Area
Intervention Area
Heavy Industrial
Light Industrial
Civic_Comm
Residential
Future Dev't
Nature Reserve
Open Space
Drainage
Storage Tanks
Refinery
Petrochemical Plant
Lube Blending
Light Industrial Area
Residential
Future Dev't
Fertilizer Factory
Domuni Lagoon
Port Services
LNG
Solid Disposal
0 1 2 3 km
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Phases of Development.

The development of the Petroleum Hub has been structured into 3 phases with specific projects earmarked for construction under each phase.

Phase 1

1. Construction of 3,000,000m^3 storage tanks.
2. Construction of jetty and port infrastructure.
3. Construction of 1 refinery of 300,000 bpsd.
4. Construction of 1 petrochemical plant.
5. Development of ancillary and social amenities

Phase 2

1. Construction of 1 refinery of 300,000 bpsd.
2. Construction of 2 petrochemical plant.
3. Construction of additional 4,000,000m^3 storage tanks.
4. LNG onshore infrastructure

Phase 3

1. Construction of an additional 1 refinery.
2. Construction of 2 additional petrochemical plants.
3. Additional 3,000,000 m^3 of storage tanks.
4. Development of social amenities.

Investor Engagements

The PHDC management has been engaging potential local and international investors in the development of the Hub. The PHDC made presentations and engaged investors at the recent Offshore Technology Conferences and the Dubai Expo. The PHDC has been pitching for an investor to fund and manage the servicing of the land. The government's initial commitment to fund the development of the service infrastructure seems unlikely. The commitment to investors is currently being limited to the provision of un-serviced land, regulatory support and facilitation and tax incentives.

In 2020, the Touchstone Consortium, one of the potential investors engaged the government over the possibility of developing the Hub. Following its consistency and a willingness to fund and manage the servicing of the land, the PDHC, in July of 2022, signed an exclusivity agreement for a period of eighteen months over the development of Phase 1 of the project. Phase One is estimated to cost about USD12 bn.

5.1.2 Launch of National Energy Transition Policy

Ghana has updated its national development strategy towards building a resilient society that can adequately address the challenges of climate change, as well as contribute to mitigating the issues of global emissions. As part of the policy actions outlined in the policy, the country is to accelerate its effort at sustainable energy transition. Against this backdrop, the Ministry of Energy inaugurated the National Energy Transition Committee on 12th December 2021 to develop a national energy transition policy. The Committee consists of Senior Officers from relevant Energy Sector Agencies, representatives of the Ministry of Transport, Ministry of Environment, Science and Technology and Ministry of Finance. It is chaired by Dr. Amin Adam, Deputy Minister of Energy.

The NETC is expected to undertake the following:

- Evaluate the current situation in the energy sector and the effectiveness of existing policies and measures.
- Set-up national objectives and targets for the energy transition and prescribe policies and measures for achieving these targets.
- Assess the benefits, risks and costs of the global energy transition and determine risk mitigation measures, along with cross-cutting issues that must be addressed.

The output of the committee will form the basis for the drafting of the Energy Transition Plan towards Ghana's commitment to the Paris Agreement and the 26th and 27th United Nations Climate Change Conference of Parties (COP26 & COP27).

5.1.3 Development of National Petroleum Products Quality Policy (NPPQP)

The purpose of the National Petroleum Products Quality Policy (NPPQP) (formerly National Fuel Quality Policy) is to provide the framework for the systematic reduction and/or elimination of toxic compounds in petroleum products that have negative impacts on the environment and public health. This policy proposes measures and provides the framework for deploying strategies to achieve cleaner air to help state actors and industry service providers roll out the strategies, programmes and actions required to reduce the risks of poor-quality petroleum products to the environment, health and safety of the public, the durability of motor vehicles, as well as contribute to the efforts against climate change.

The policy was drafted in 2019 with the expectation of completing the development process in the year 2020, following a review of the draft policy by industry stakeholders. Other stakeholders, such as academia, professional, and trade associations, Ministries, Departments and Agencies, and the informal sector were further engaged in the revised draft policy to address issues arising from the initial draft policy.

The delays in completing the policy were occasioned by the limitations posed by COVID-19 and the decision by the Ministry to realign the draft policy to the recent ECOWAS harmonized fuel specification directive to countries in the ECOWAS region, as well as the African Refiners and Distributors Association (ARDA) Roadmap. For instance, the ECOWAS harmonized fuel specification is to ensure that only gasoline and diesel that meet the maximum 50 ppm sulphur specification are marketed in the region beyond January 1, 2025. The harmonization of fuel specifications is an important element of the cost-effective package of Community-wide measures to reduce air pollution; provide a healthier environment for the population of the region, increase energy security in the region and strengthen regional petroleum product trade.

One critical issue standing in the way of the attainment of improved petroleum product quality standards is the ability of local refineries to align with various requirements to meet the targets of the policy. The Ministry, in collaboration with the National Petroleum Authority (NPA), seeks to ensure that such industry issues are addressed.

5.1.3.1 Highlights of the issues yet to be finalized under the draft policy

- **Further consultation on the Price Parity Margin (PPM) for financing a new project**

  The Price Parity Margin (PPM) was introduced in 2018 as an initiative to generate funds to support local refineries to procure Desulphurization Units for their plant to meet the required Sulphur content specification proposed in the Draft Policy.

  However, accruals from this PPM initiative have not been able to meet the expected target because payments into the PPM funds have not been forthcoming. As of now, amounts owed by Bulk Import Distribution and Export Companies (BIDECs) have been collected and paid into the Fund.

  Considering the PPM surcharge by the NPA on the gasoil sold by Tema Oil Refinery (TOR) between August and September 2019, TOR and its tolling partner Woodfields as of that contractual period of refining, have agreed in principle to work with the NPA to resolve all outstanding price parity margin issues.

- **Inclusion of regulatory and monitoring provisions for Residual Fuel Oil (RFO) and other petroleum products apart from Gasoline and Diesel**

  The name of the draft policy was changed from 'National Fuel Quality Policy' to "National Petroleum Products Quality Policy" to reflect the sum of changes to be exacted from the series of the Ministry's new engagements with stakeholders.

  Likewise, with Residual Fuel Oil (RFO), a fuel that is prevalently used within the industrial sector and contributes significantly to environmental pollution, the policy gives less emphasis. No monitoring and regulation provision on RFO and wood fuels was factored in the Draft Policy. The Draft Policy in its current state focusses mostly on the petroleum products consumed in the country: gasoline and diesel. It was realized that specifications on RFO and other petroleum products will compel market players to report on them and be held accountable accordingly.

- **Clarification of the overlapping roles of institutions or agencies that may arise in implementing the proposed Policy**

  The policy did not necessarily provide detailed information on the roles of the relevant institutions or agencies to help in implementing the policy. For example, the institution to assume the main responsibility for specifically undertaking petroleum product monitoring at retail outlets under the policy framework is yet to be finalized. The direction of the Ministry in this regard is to address all overlaps of roles in detail by drafting a legislative instrument from the policy after its approval.

- **The Sulphur limit (in parts per million, ppm) set for local refineries and the improbability of TOR and other local refineries to transition per the deadline set in the draft policy**

  As a result of TOR's configuration and its crude slate which is a hindrance to the production of the required fuel specifications of 50 ppm, the Ghana Standard Authority (GSA) and the NPA granted a waiver to the local refineries at the time of formulating the policy.

  Rather than increasing this grace period by five (5) years (2020-2025), as stipulated by the ECOWAS directive on harmonizing standards, the Ministry seeks to structure a feasible plan defined by implementable timelines with these local refineries, committing them towards meeting the 50 ppm Sulphur content specification.

  Due to the current situation, segregation of the grades of products at the retail outlets is being considered. Market research and engagements with industry players are still ongoing to ascertain its plausibility.

5.1.3.2 Review of the Implementation Plan of the Policy

There have been suggestions to make provisions for specifications for locally produced petroleum products different from that of imports. The reasoning is that local refineries currently have not been configured and cannot meet the standards promulgated by the GSA, particularly with respect to petroleum product quality. This will ensure the sustainability of the refineries in the short term and avoid violation of the regulation. Currently, the local refineries are producing fuels within a limit of 1500 ppm of Sulphur content.

A second schedule, that includes a Legislative Instrument (LI) for prescribed standards for local refineries, will be incorporated. This LI will specify all the parameters and details of the policy.

When the local refineries attain the ideal national standards requirements for petroleum products, these standards will be amended. Consultations would also be made with the technical committee for petroleum products whenever there is a need for change in the specifications.

Completion of the Policy is relevant in ensuring its citizens are protected and guaranteed a healthy environment. More recently, the calls for Energy Transition, where Government seeks to improve the efficient use of fuels, have made it more necessary that such policies are completed and promulgated.

Thus, this Policy will complement the efforts of the Government with regard to emission reduction and clean air promotion, while providing the required basis for strategies, programmes and actions to reduce the risks of poor-quality fuels to the environment, health and durability of equipment using the fuels. Consequently, Ghana will be fully compliant with Afri-5, and Euro-5 specifications.

It is expected that the policy will be completed by end of Q2 in the year 2022, following which implementation would be rolled out. A Cabinet Memorandum for approval of the policy is concurrently being prepared and will be ready for submission to Cabinet.

5.2 Preparation of Petroleum Products Strategic Stock Policy (PPSSP)

The Ministry continued its effort to prepare a comprehensive policy to guide the management of petroleum products' strategic stocks. A standing committee, made up of representatives of key industry stakeholders, was reconvened to continue work on this task. The committee held two (2) meetings to consider a draft concept paper and initial position papers from key stakeholders. The proposals considered and discussions of these meetings were centred on the feasibility of the country holding twelve (12) weeks of petroleum products. Issues, such as a way of funding such stocks and infrastructure arrangements, were discussed. The committee in its discussions considered the best approach in utilizing existing facilities and operational arrangements to implement a viable strategic stocks programme that will not bring to bear huge funding requirements for Government.

A Draft PPSSP Appropriation Plan, indicating clear protocols as to how and when strategic stocks can be accessed by Government, and Implementation Plan and Petroleum Products Infrastructure Risk Assessment report, are before the committee for consideration.

For the Finalization of the Policy, the Committee formed a Sub-Committee at its first meeting for 2021 to compile relevant data for its work on the following issues:

- The pros and cons of the financing options tabled before the Committee and the cost involved with implementing the respective recommendations.
- The various scenarios on the stockholding period discussed in the meeting to help the committee finalize a decision on the appropriate stockholding period for the country under the PPSSP.

Preparation of the Petroleum Products Strategic Stock Policy continued in the year 2021. The policy will provide the necessary framework to guide investments and management of strategic stocks of petroleum products to ensure the security of supply, as well as improvement in the efficiency of resource utilization.

The strategic stock of petroleum is an important component of the government's policy package, aimed at coping with severe fuel supply disruptions that exceed the level of commercial stock cover. Strategic stocks need to be seen in a wider context than just supply disruptions. This is imperative since the petroleum stockpile can tie up enormous funds that otherwise would have opportunity cost, given the exigencies of the economic imperatives and scarcity of resources available to the government. This implies the cost of holding strategic stocks needs to be balanced against the benefits of the risks; taking into account the opportunity cost of investment.

Apart from the geopolitical risk associated with imports, other local risks could be catastrophic. Currently, the refineries do not have the capacity for sustainable and adequate production for the market. This is a recipe for severe supply disruptions. Up to 92% of total imports of petroleum products, which form 80% of national consumption, are discharged; through the only SPM/CBM, thus, posing significant supply disruption in case of shutdown or any unforeseen disaster.

Ghana needs to have a comprehensive strategic stock policy that will cover the following:

- The stock holding requirements for the country and any mandatory stock holding by the industry;
- Funding mechanism;
- Infrastructural and operating maintenance costs.

There is a compelling need for the country to have in place a strategic stock policy to enhance readiness in the event of a major oil supply disruption.

5.3 Implementation of the National LPG Promotion Policy

The National LPG Promotion was approved by the government in 2017, to ensure that, at least, 50% of Ghanaians have access to safe, clean and environmentally-friendly LPG for increased domestic, commercial and industrial usage by 2030. The policy places emphasis on the use of the Cylinder Recirculation Model as a policy tool to move the LPG adoption rate from 25% to 50%. Since the inception of the policy, the implementation of the key component of the policy, the Cylinder Recirculation Model (CRM), has faced several challenges, including a lack of cooperation from the LPG Marketing Companies (LPGMCs).

As part of the preparation towards the full roll-out of the CRM, the consumer end of the CRM was piloted in five (5) regions across the country in 2020 to identify challenges and institute measures to address those challenges. The regions selected included Ashanti, Eastern, Western, Northern and Volta Regions. The pilot programme expected to be carried out in the Volta Region was suspended to address issues identified during implementation in the other regions.

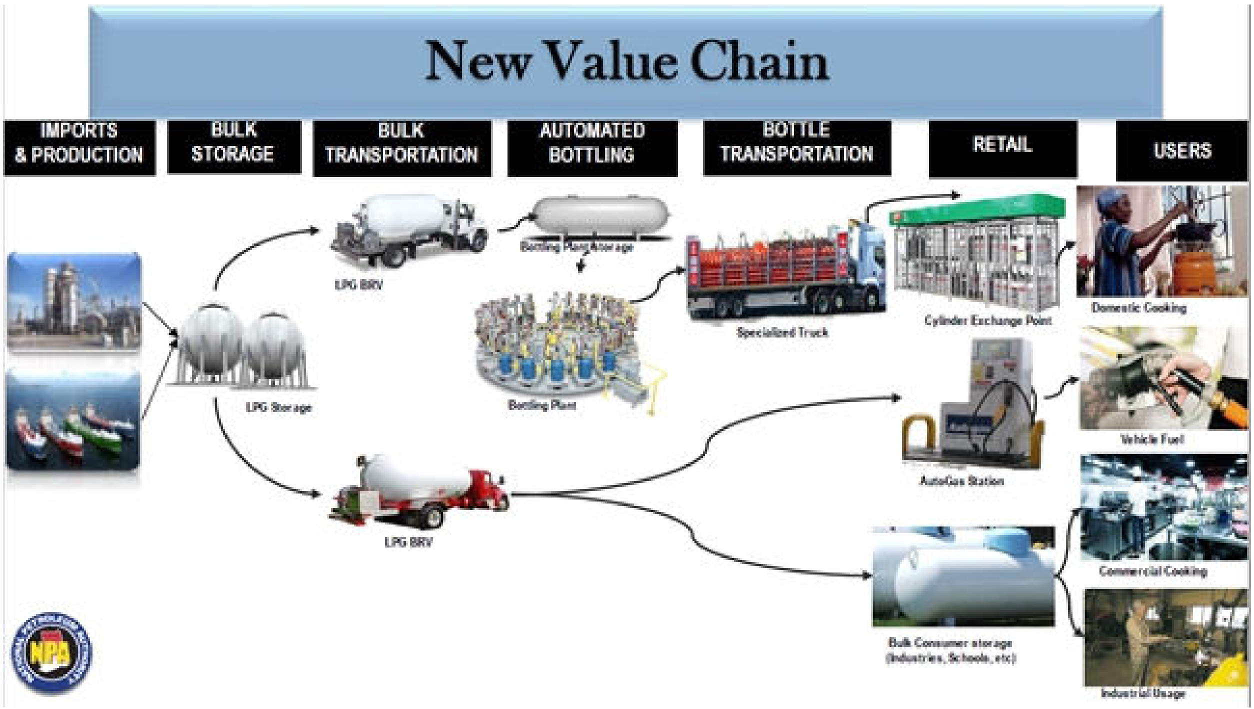
The NPA carried out a process evaluation after sixteen (16) months to identify implementation gaps and propose recommendations. The challenges identified included:

- Inadequate engagement with the LPGMCs;
- Delays in the cylinder refurbishment process;
- Lack of funding, resulting in the shortage of branded cylinders in the pilot districts; and
- Delay in the construction of bottling plants.

Given the above challenges, the NPA engaged the LPGMCs Association and requested the Association to submit a proposal for the Authority's consideration. Also, a total of 6,885 of the recalled cylinders received from the pilot areas have been refurbished and branded by GCMC.

An impact assessment was carried out in two of the pilot regions, i.e., Ashanti and Northern Regions, in March 2022, to comprehensively ascertain the impact of the pilot CRM from the perspective of both consumers and distributors. The impact assessment revealed that the inadequate and timely supply of branded cylinders affected the smooth running of the pilot programme. Additionally, there was not enough sensitization of the consumers regarding the do's and don'ts of the CRM.

These suggest that the success of the implementation of the CRM depends on how effectively the regulator (NPA) engages the players to speak the same language and ensure continuous availability of branded cylinders to avoid shortages. Therefore, cylinder ownership and financing of the cylinders should be clearly defined since CRM thrives on the availability of cylinders.



5.3.1 Policy Outlook

5.3.1.1 Pricing

The higher relative cost of transporting bottled gas compared to bulk LPG means a higher logistical cost per kilogram (KG). This, coupled with investments in cylinders required of LPGMCs, and the introduction of new players in the supply chain will lead to a rise in the pre-tax cost of bottled gas. This poses a major challenge to the success of the entire project and may require Government to favourably consider proposals for the downward revision of taxes to partly or wholly compensate for any rise in pre-tax prices. At the current total tax rate (1st August 2022) of Ghp153/kg on LPG, Government may relinquish up to Ghp62/kg of the total tax, leaving the balance still committed to the E.S.L.A.[234] Plc bond programme.

5.3.1.2 Market Shifts

The roll-out of the CRM policy is expected to improve safety in the delivery of LPG and will reshape the existing market structures beyond the new roles noted in the CRM figure above. The biggest disruption is expected at the retail level and is projected to be driven by the OMCs who are also licensed to retail LPG. The LPGMC dominance of the market (66% share) will be threatened by the more consumer-friendly OMC chains (34% share). The OMC liquid fuel outlets are generally more accessible by virtue of their location and significantly out-number the LPG outlets by a ratio of about 5:1. They also possess more easily recognized and trusted brands. An addition of LPG retailing to their traditional liquid fuel retailing will significantly hurt the market prospects of LPGMCs which are only licensed to retail LPG. It may be necessary that LPGMCs swiftly invest in multiple consumer-friendly outlets, like self-service propane outlets in the US and develop a delivery-to-consumer option to stand a fighting chance of maintaining their market share.

[234] Energy Sector Levies Act was established to correct imbalances in the collection, distribution and utilization of levies collected within the energy sector, support road maintenance and the activities of the Energy Commission, provide subsidies on premix and Residual Fuel Oil and to also provide funding for investments in public lighting and National Electrification Program.

A self-service bottled propane retail dispenser positioned in front of a supermarket in Oklahoma, US.

Source: –

5.3.1.3 Policy Pushback

As part of the implementation of the CRM policy, Government intends to have all filling plants decommissioned in favour of the bottling plants and have the filling plants converted into cylinder exchange points. The LPGMCs anticipate the major shifts enumerated in section 5.3 and are weary of the implications to their investments amidst Government's policy intent. Leveraging their current dominating market influence with 734 outlets, they continue to inspire the delay in the implementation of the CRM policy. Their primary concern is the issue of compensation for the current investments in filling plants. The LPGMC estimate their current investments at $133.4 million and expect compensation of same plus a provision to cover their loss of future business. Government, on the other hand, believes providing a sunset transition period of 5 years should eliminate the need for monetary compensation.

5.3.1.4 A Way Forward

The increased logistical cost anticipated for the CRM programme will mostly affect the poor and rural areas. The low demand in the northern sector will not inspire investments in bottling plants closer to most towns which are generally dispersed. Sub-optimal management of this policy may rather shift demand farther from LPG.

The policy is driven by two main shifts in the supply chain: The first is the circulation of prefilled cylinders and the second is the bulk bottling of cylinders. The first can be rolled out without a need for compensation or major disruption to the investment in filling plants. The bottling plants, on the other hand, may be made to operate alongside the filling plants with market efficiency driving investments and productivity. 7000 jobs, dependent on the LPGMC plants, will be mostly saved, markets improved, and no compensations paid. Government may, however, be required to cap the licensing of new LPGMC filling plants to incentivise future bottling plant investments.

5.4.1 Review of the RLPGPP to NLPGPP

The Ministry has introduced the NLPGPP as an improvement of the RLPGPP with a broader scope and new strategies. The NLPGPP in terms of coverage will concentrate on peri-urban and areas where beneficiaries can afford LPG refills. The programme also introduces new modules targeted at commercial and industrial users of LPG. The objective of the new National LPG Promotion Programme is to increase the percentage of the population that has access to LPG from 36% in 2020 to 50% by 2030. To achieve this, Government intends to pursue the following:

a) Ensure that about 2 million Ghanaian households have access to LPG for cooking by the year 2030.

b) Facilitate the setup of, at least, 520 Cylinder Exchange Points (2 in each district) by the year 2030.

c) Facilitate the installation of about 1,000 LPG Cooking Systems in public institutions, including schools, colleges, prisons, and hospitals by the year 2030.

d) Ensure that about 20,000 commercial caterers, including some caterers under Ghana School Feeding Programme (GSFP), have access to LPG for cooking by the year 2030.

e) Support, at least, 20 Artisanal Centres to build capacity for fitting LPG tanks in vehicles by 2030.

f) Support fitting of LPG tanks for, at least, 500 commercial vehicles by 2030.

g) Provide technical assistance for industries that prefer to switch from the use of diesel and RFO to LPG.

h) Provide technical assistance and incentives for local manufacturers of LPG cylinders, cookstoves and accessories.

i) Ensure the availability of skilled workers to take up job opportunities.

Under the new programme, Government intends to introduce new strategies for achieving the above-mentioned objectives. It is expected that these efforts of Government as a specific intervention, together with the expected improvement in the distribution of LPG to be provided through the CRM, will contribute immensely to achieving Government's goal of 50% by 2030.

5.4.2 LPG for Development (LPG4D)

LPG for Development (LPG4D) is an overarching programme that consolidates all the Government's efforts in the promotion of LPG under the National LPG Promotion Policy. Presently, the two main components of the LPG4D are the Implementation of the CRM and the National LPG Promotion Programme. Whereas the former serves as a vehicle for the distribution of LPG that drives access, particularly in peri-urban and low-access areas, the latter will serve as an intervention, targeted at various prospective users to ensure there is a concerted effort in encouraging people to switch to LPG.

5.5 Petroleum Downstream Infrastructure Tariff Policy

The Ministry of Energy is in the process of finalizing the Concept paper of an Infrastructure Tariff Policy for the petroleum downstream sector. It is still seeking further consideration in that regard, from academia, industry and other relevant stakeholders.

The policy will seek to remedy trade distortions with regard to infrastructure in the petroleum downstream, increase transparency in the enforcement of existing and approved tariffs in line with the Energy Policy and sanitize the current tariff regime to be in the position to facilitate the growth of the downstream industry.

5.6 Petroleum Products Marking Scheme

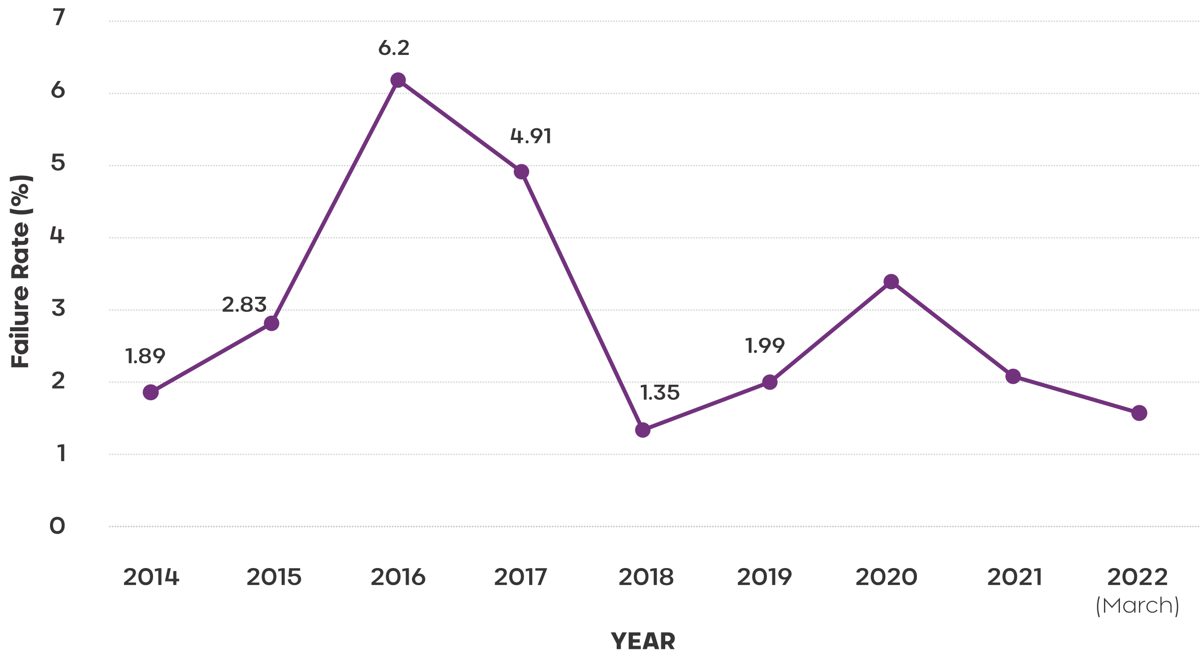
5.6.1 Field Monitoring

Field Monitoring exercises are conducted monthly with some variations and when requested by an OMC or a consumer. There is a total of ten monitoring teams across the five zones in the country. The exercise aims at covering, at least, 75% of the total retail outlets across the country every month. The pass range for all samples is 80% to 100% marker concentration and an absence of the adulterant marker. A suspect result is obtained when a sample has a marker concentration between 70% to 80% and the absence of the adulterant marker. A sample is said to not meet the standard when the marker concentration is below 70% and/or with the presence of the adulterant marker.

The implementation of the PPMS has brought about a tremendous improvement in the quality of fuel sold at the retail outlets. The trend of failure rate indicates a significant decrease in failure rate since the inception of the programme (see Figure 22). The implementation of the PPMS has resulted in the following:

- Decreased malpractices in the distribution and sale of petroleum products;
- Improved stakeholder awareness in furtherance of the NPA's medium-term strategy;
- Improved quality of petroleum products at the retail outlets, thereby increasing consumer confidence, and
- Remarkable improvement in the fuel tax loss and subsidy abuse.

Figure 22: Trend of Failure Rate of Marked Products



Source: —

A total of eleven (11) rounds of monitoring exercises nationwide were conducted by the end of 2021. A total of 25,583, operational retail outlets were monitored. About 7.48% of retail outlets visited were not operational (see Table 6). The average pass rate of retail outlets for 2021 was 1.29% higher than what was recorded in 2020, while the average failure rate decreased by 1.29% to 2.09% in 2021. The average product failure rate was 1.03%. The diesel and gasoline average failure rates were 0.75% and 1.30%, respectively. There was no case of a possible grade swapping between differentiated gasoline and domestic gasoline in 2021.

A complete set of forty-two (42) LSX 3000 equipment was made available to all regions during the eleven (11) monitoring exercises conducted. However, due to the extensive verification exercise of all retail, LPG and Bulk Consumer outlets to reconcile the data between the Licensing Master database and database on the ERDMS, the monitoring exercise in December could not be rolled out in all ten regions. Therefore, only thirty-five (35) LSX 3000 pieces of equipment were used.

Table 6: Field monitoring summary data

	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Total	%
No of outlets planned	2,453	2,374	2,376	2,402	2,407	2,456	2,515	2,541	2,570	2,521	968	25,583	
No of outlets visited	2,448	2,369	2,364	2,402	2,411	2,458	2,494	2,530	2,579	2,511	964	25,530	99.79%
No of outlets operational	2,229	2,177	2,194	2,229	2,205	2,232	2,329	2,376	2,415	2,340	894	23,620	92.52%
Pass	2,142	2,106	2,160	2,162	2,161	2,182	2,291	2,336	2,379	2,320	887	23,126	97.91%
Fail	87	71	34	67	44	50	38	40	36	20	7	494	2.09%
	2,229	2,177	2,194	2,229	2,205	2,232	2,329	2,376	2,415	2,340	894	23,620	100.00%
Diesel	2,330	2,363	2,315	2,410	2,368	2,411	2,519	2,518	2,551	2,460	861	25,106	100.00
Pass	2,304	2,334	2,301	2,387	2,351	2,388	2,506	2,500	2,533	2,454	860	24,918	99.25%
Fail	26	29	14	23	17	23	13	18	18	6	1	188	0.75%
Gasoline	2,398	2,406	2,375	2,480	2,378	2,421	2,517	2,580	2,582	2,522	886	25,545	100.00
Pass	2,338	,357	2,353	2,430	2,348	2,393	2,491	2,553	2,566	2,508	877	25,214	98.70%
Fail	60	49	22	50	30	28	26	27	16	14	9	331	1.30%
Differentiated	24	7	13	29	12	54	35	50	31	22	-	277	100.00
Pass	24	7	13	29	12	54	35	50	30	22	-	276	99.64%
Fail	-	-	-	-	-	-	-	-	1	-	-	1	0.36%
GRAND TOTAL	4,752	4,776	4,703	4,919	4,758	4,886	5,071	5,148	5,164	5,004	1,747	50,928	100.00
Pass	4,666	4,698	4,667	4,846	4,711	4,835	5,032	5,103	5,129	4,984	1,737	50,408	98.98%
Fail	86	78	36	73	47	51	39	45	35	20	10	520	1.02%

Source: —

5.6.2 Volumes Marked

A total volume of 4,658,064,800 litres of petroleum products was marked at all operational depots nationwide, from January to December 2021 (see Table 7). Regular tax fuel accounted for 94%, while low tax fuel accounted for 6% (no low tax super product was loaded) of the total volume of petroleum products marked. Super accounts for 52.11% of regular tax fuel were marked, while diesel accounted for the remaining 47.89%. Monthly comparison of the volume of regular tax products marked is presented in Table 8.

Table 7: Volumes of Petroleum Products Marked in 2021

Product (Litres)	Super	Diesel	Kerosene	Premix	MGO local	Diesel Subsidized	Total
January	186,146,950	164,986,650	823,500	8,032,500	931,500	-	**360,921,100**
February	177,493,050	163,268,900	360,000	7,101,000	1,080,000	15,731,500	**365,034,450**
March	206,630,900	199,249,300	472,500	10,489,500	1,687,500	20,164,900	**438,694,600**
April	199,681,850	194,542,850	45,000	8,019,000	2,200,500	11,625,500	**416,114,700**
May	172,889,700	150,117,350	1,003,500	9,747,000	2,146,500	13,464,000	**349,368,050**
June	188,024,650	167,236,700	405,000	9,531,000	1,822,500	19,532,200	**386,552,050**

Table 7: Volumes of Petroleum Products Marked in 2021 (continued)

Product (Litres)	Super	Diesel	Kerosene	Premix	MGO local	Diesel Subsidized	Total
July	190,124,950	154,904,700	6,588,000	468,000	202,500	17,105,500	**369,393,650**
August	183,727,400	174,117,700	9,949,500	513,000	1,197,000	13,587,500	**383,092,100**
September	182,728,650	174,006,500	7,884,000	441,000	1,012,500	11,724,500	**377,797,150**
October	182,693,250	165,103,850	8,019,000	355,500	1,143,000	14,305,500	**371,620,100**
November	189,243,900	183,708,350	9,625,500	261,000	1,201,500	15,895,500	**399,935,750**
December	213,413,150	197,488,950	9,112,500	540,000	1,147,500	17,839,000	**439,541,100**
Total	**2,272,798,400**	**2,088,731,800**	**54,288,000**	**55,498,500**	**15,772,500**	**170,975,600**	**4,658,064,800**

Source: –

Table 8: Monthly Comparison of Volume of Regular Tax Products Marked in 2021

Product (Litres)	Super	Diesel	Total
January	186,146,950	164,986,650	**351,133,600**
February	177,493,050	163,268,900	**340,761,950**
March	206,630,900	199,249,300	**405,880,200**
April	199,681,850	194,542,850	**394,224,700**
May	172,889,700	150,117,350	**323,007,050**
June	188,024,650	167,236,700	**355,261,350**
July	190,124,950	154,904,700	**345,029,650**
August	183,727,400	174,117,700	**357,845,100**
September	182,728,650	174,006,500	**356,735,150**
October	182,693,250	165,103,850	**347,797,100**
November	189,243,900	183,708,350	**372,952,250**
December	213,413,150	197,488,950	**410,902,100**
Total	**2,272,798,400**	**2,088,731,800**	**4,361,530,200**

Source: –

5.6.3 Marker Usage

A total of 46,580,648 ml of the marker was used in marking petroleum products across the country in 2021 (see Table 9). Out of this quantity, 93.63% was used for regular tax products, while the remaining 6.37% was used to mark subsidized or low-tax products.

Table 9: Monthly Marker Usage

Usage (ml)	Total Usage		
	Blend 1	Blend 2	Total Marker Usage
January-20	3,246,977	103,050	**3,350,027**
February-20	3,127,006	101,250	**3,228,256**
March-20	3,178,174	112,050	**3,290,224**
April-20	2,601,989	127,350	**2,729,339**
May-20	3,442,896	108,720	**3,551,616**
June-20	3,528,195	130,725	**3,658,920**
July-20	3,589,239	134,505	**3,723,744**
August-20	3,486,065	114,030	**3,600,095**
September-20	3,697,304	146,470	**3,843,774**
October-20	3,715,432	162,180	**3,877,612**
November-20	3,833,396	172,800	**4,006,196**
December-20	4,067,167	127,080	**4,194,247**
Total	**41,513,837**	**1,540,210**	**43,054,047**

Source: —

The Petroleum Products Marking Scheme (PPMS) Legislative Instrument (L.I. 2187) was promulgated in 2013 to ensure that all main petroleum products and their adulterants are marked at all operational depots in the country. This was to address the increasing concerns of adulteration and smuggling, which impact negatively on government tax revenue and other financial losses in the form of misapplied subsidies in the case of premix fuel.

The scheme provides a foundation for an effective quality monitoring system by introducing a marker in trace quantities into BRVs loaded with petroleum products at the depots before distribution to the market.

5.7 Unified Petroleum Price Fund Bulk Road Vehicle (BRV) Tracking Scheme

Pursuant to the mandate of the National Petroleum Authority (NPA) with the responsibility to regulate, oversee and monitor the activities in the petroleum downstream industry, the Unified Petroleum Price Fund (UPPF) was established under the NPA Act 691, Act 2005 Section 62.

The primary objectives of the Unified Petroleum Price Fund (UPPF) are to ensure a regular supply of petroleum products to all parts of the country by Bulk Road Vehicles (BRVs) and to achieve an efficient distribution system. The predominant mode of transportation is, however, associated with many challenges predominantly among which are transit product shortages and false haulage claims. To withstand some of the challenges, a tracking system was implemented in 2013 and an automatic tank gauging system, also referred to as the national retail station fuel monitoring system, was initiated in 2019.

5.7.1 Tracking Systems

In 2013, the UPPF, under the auspices of the NPA, introduced the BRV Tracking System to enable the UPPF Secretariat to independently confirm the delivery of petroleum products under the UPPF Scheme from the loading depots to all the discharge points (retail outlets and bulk consumer sites). The System enabled the Secretariat to have visibility on the loaded BRVs from Bulk Oil supply points to their intended delivery points.

Currently, two types of BRV tracking systems are in place, namely:

i. BRV Tracking and Volume monitoring System, and

ii. BRV Tracking and Electronic Sealing (Electronic Cargo tracking system).

By the end of 2021, about 4,200 BRVS, out of about 5,000 BRVs operating in the Industry, have been equipped with tracking devices.

5.7.2 Benefits

Prior to the introduction of the BRV Tracking Scheme, it was estimated that about 12% of freight paid in respect of secondary transportation of petroleum products was fraudulent due to abuse in freight claims (False Representations). As at end of 2021, the average abuse rate was around 1%. This translated to an annual savings of over USD 10 million per annum.

These savings resulted from:

- The freight differences in delivery points reported by OMCs in their submitted Returns and the actual delivery points of the product as reported by the tracking System.
- The freight difference due to non-reporting of part deliveries made on the way to the final delivery points (bulk breaking) by OMCs. The tendency is for the OMCs to make claims for all the volume on the basis of the long distance to the final delivery point.

The BRV tracking System has also helped in the monitoring and curbing of the abuse associated with the distribution of subsidized and non-taxed petroleum products, such as premix fuel and gasoil for power generation and saved the nation some revenue leakages.

5.8 National Retail Station Fuel Monitoring System

The dynamics and evolvement of illicit activities in the downstream petroleum industry require a multi-pronged solution approach to ensure sanity in the industry. The national retail station fuel monitoring system emerged to complement already implemented projects to improve upon the efficiency of the distribution system in the downstream petroleum industry that is characterized by revenue loss caused by the theft of oil and fuel estimated to cost the Government US$200 million annually.

The National Retail Station Fuel Monitoring System is comprised of the design, supply, installation and implementation of a national fuel management system (automatic tank gauging systems and forecourt control systems) for all petroleum product retail outlets across the country. The primary objective of this project is to implement an automated FUEL STATION MANAGEMENT SYSTEM that will complement measures already taken to address the challenges identified.

The project will cover 4,000 retail outlets. These outlets will have their over 12,000 underground tanks calibrated using a 3D laser calibration system known today as the most effective tool for calibrating USTs. Other features of the project include:

Deployment of Electronic Probes: Over 12,000 units. This is the measuring component of the system, equipped with Magneto strictive Level Measurement. The instruments have a long-life guarantee in extreme weather conditions and are ATEX certified. The system has tank controllers and pump controllers capable of sending all data to a central console. The data include logging and monitoring transactions in real time as well as incorporating dispenser metre data and totals for all products. The console will display all necessary information from the control of tanks, and pumps in real time, as well as all the peripheral units that are connected to the system.

Figure 23: The Vice President at the Launch of the ECTS Project

The use of technology to track road tankers and inventories at bulk storage points and retail outlets are mature and effective.

The system is integrated with the Authority's Enterprise Relational Database Management System (ERDMS) to enable the Authority to have visibility over the management of stocks at a Fuel station. The system will promote complete control for:

- **Handling:**

  Monitor and record in real time the fuel delivery, identifying the truck and the information needed (fuel density, temperature and even authorized personnel).

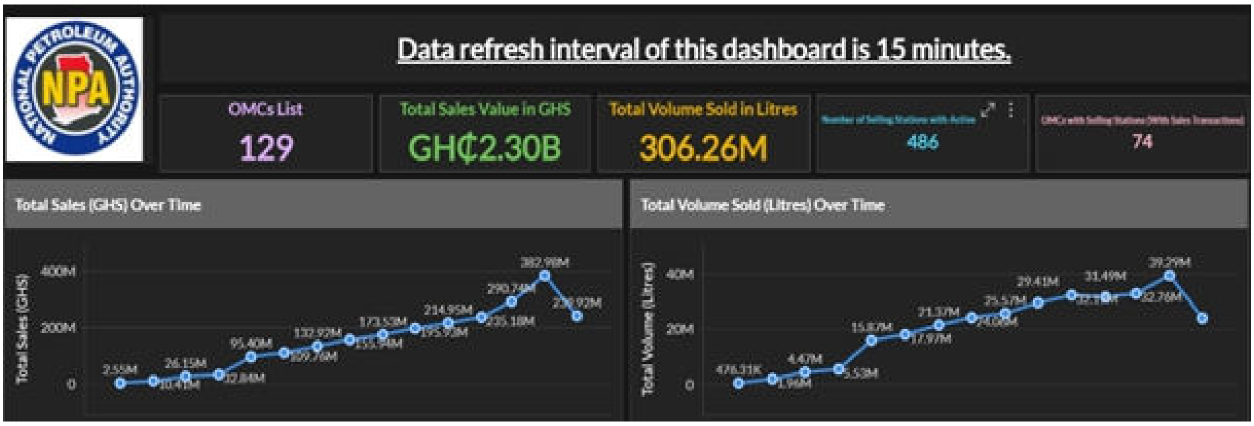
- **Fuel stocks:**

  Monitor the volume of the tank using electronic probes according to the Tank Calibration in real time. The level measurement (and, therefore, the corresponding volume) is depicted in real-time in the pc/console of the monitoring system.

- A monitoring system to control the upper and lower limits of the tank, like overfill of fuel (upper limit) and damage due to insufficient fuel (lower limit).

- Monitoring the outgoing fuel from all electronic pumps and controlling their accurate operation (Pump Controller).

Figure 24: **Real-time Dashboard showing Total Sales in GHS from inception to date.**

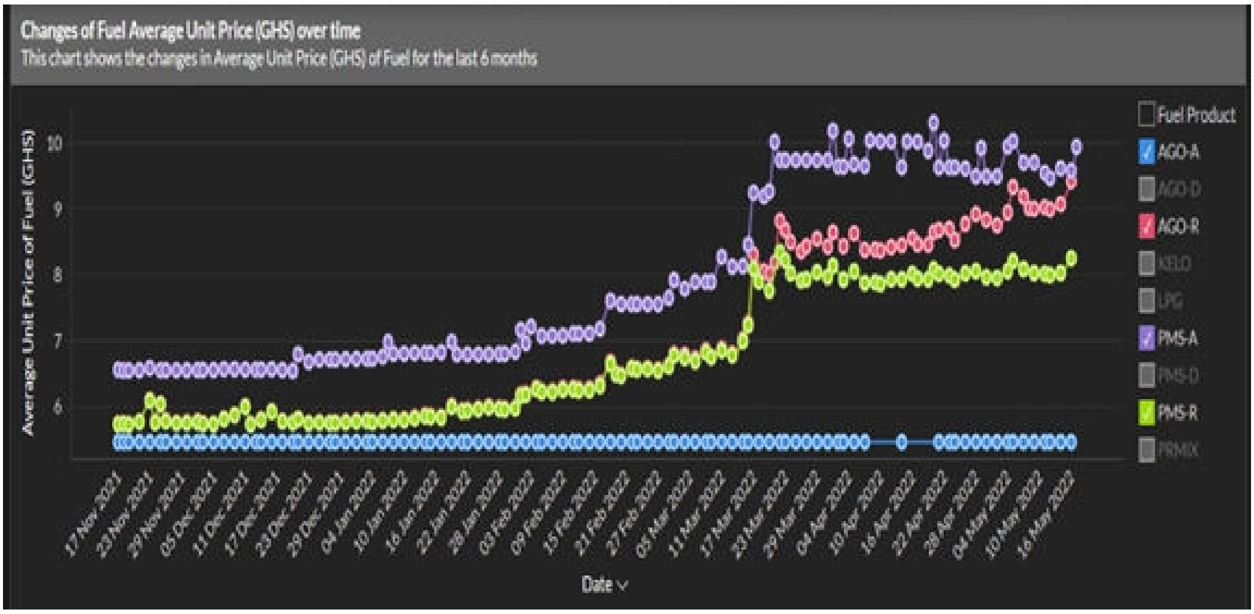


- Monitoring other information needed, according to the required framework, such as Vapor Recovery Systems, Pneumatic Fire Control Systems or Gas Monitor Systems to enhance the effectiveness of control and manageability of the supply network and to ensure effective quality and quantity through this system-driven solution to create an assurance of Value for the consumer. (Future)

- The Fuel Management System will also compare the differences in reception between the tank monitoring system and the fuel invoice, always at the natural temperature and after reduction at 20°C. It will also compare the output differences in the natural temperature and opened to 20°C between the tanks and the pumps, by system measurements or receiving documents. The data of the invoice upon receipt will be stored in the system, so that they can then be compared with the system measurements inside the tanks and with those of the pump outflow.

- All these information for control of tanks, and pumps in real-time, as well as all the peripherals, will be connected to a central system and analyzed by software (console) of the monitoring system and depicted in the pc of the fuel station and sent to the Central Data Management Server.

Figure 25: **Changes in Average Unit Price of Major Petroleum Products since inception.**



5.8.1 Benefits

The benefits of the system include the following:

- Enable the Authority to have visibility of product stock at all retail outlets and hence have good control of product availability in the country.
- To detect and quantify illicit product receipts at retail outlets and be able to determine associated tax liabilities.
- To help check third-party supplies.
- Enable the Authority to remotely monitor pump prices at retail outlets.
- Enhance the capacity of OMCs to manage the retail outlets effectively and efficiently.
- Remote setting of pump prices
    - → Placing of orders based on real-time stock positions at retail outlets
    - → Realtime monitoring of pump prices at retail outlets
    - → Central pump Unit Price changing
    - → Self Service application
    - → Shift Management
    - → Automatic Tank Calibration
    - → Fill detection
    - → Controlled filling
    - → Remote tank inventories monitoring
    - → Monitor sales and shifts online
    - → Monitor tank filling and status online.

5.8.2 Milestone Schedule

The project is to be carried out in 3 installation phases, over a 3-year period from 2020 to 2023, as below:

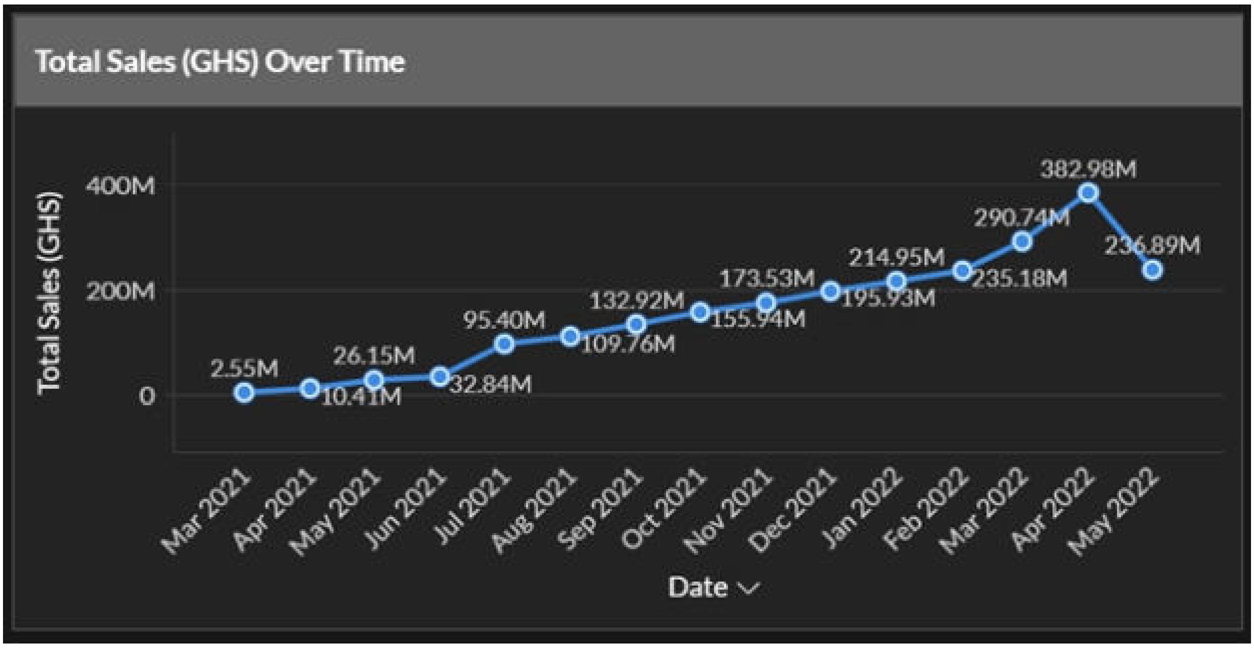
- Year 2020 – Phase 1A -- 1,000 Retail outlets & Monitoring Centre
- Year 2021 – Phase 1B -- 1,500 Retail Outlets
- Year 2023 - Phase 1C -- 1,500 Retail Outlets

The second phase of the project shall be the operations and maintenance for each installation phase.

5.8.3 Project Milestone

With the completion of Phase 1A of the project and Phase 1 & 1C currently underway, one can be certain that, in the next 2 years, the downstream petroleum sector will, surely, be an exciting field to watch. The introduction of this project will help the OMC's to address issues, such as illegal petroleum products that are estimated at costing the state above $200 M per annum.

Figure 26: Total Sales from Inception to Date.



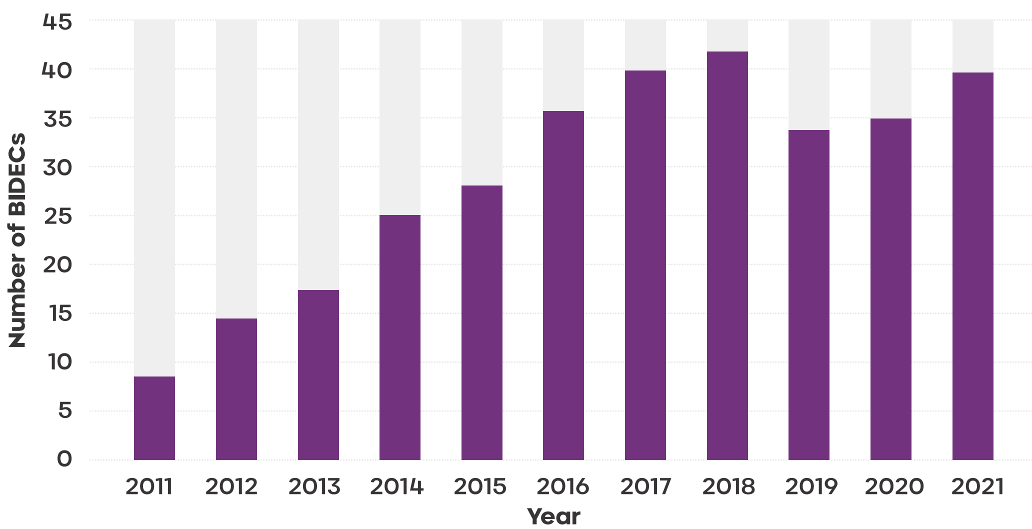
Our checks show that, today, with the current installation completed under the project, the platform has recorded over GHC2 billion by way of sales coming from some five hundred stations with its corresponding volume of products placed around over 200 M litres of petroleum. This statistic only comes to confirm the true potential of the System as developed by the regulator.

5.9 Licensing

5.9.1 Bulk Import Distribution and Export Companies (BIDEC)

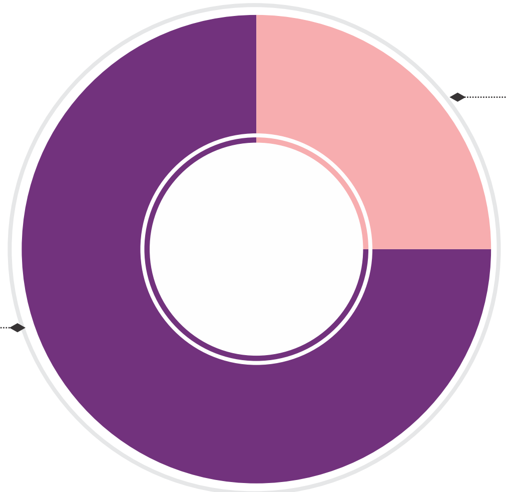
As of the end of 2021, the total number of BIDECs stood at forty-one- (41), compared with thirty-six (36) in 2020 (see Figure 27). As at the time of publishing this document, the number of BIDECs has increased from 41 to 44.

Figure 27: Number of BIDECs (2011-2020)



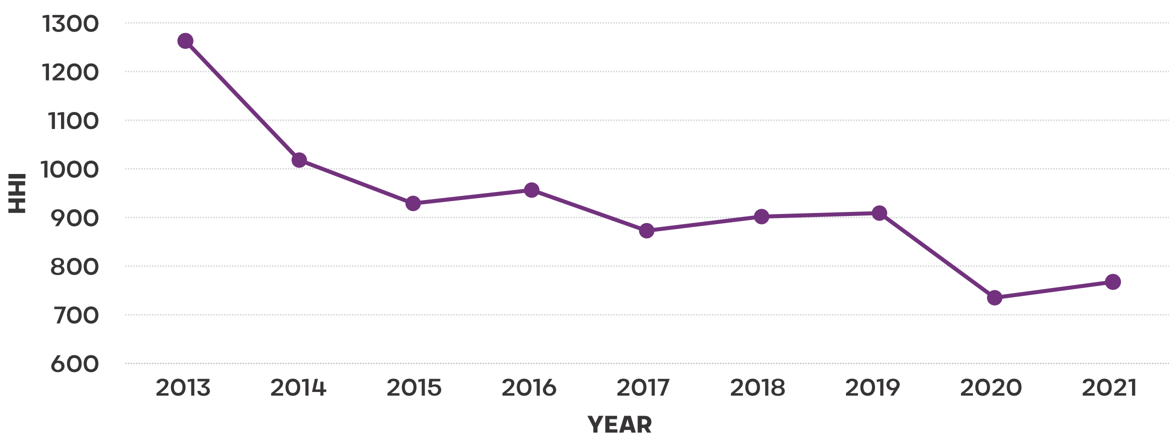
Analysis of petroleum products import outturn by the BIDECs in 2021 revealed that a total of 4.2 million mt of petroleum products was imported into the country, representing 9% decrease compared to 2020. The top ten (10) imported 75% of the total petroleum products imported, while the remaining 25% was imported by the rest of the BIDECs. Analysis of the trend of import of petroleum products over a five-year period indicates an upsurge in the importation of petroleum products. This is because of an increase in demand for petroleum products due to a surge in economic activities.

Figure 28: **Top 10 BIDEC imports of petroleum products, 2021.**



Analysis of BIDECs sales volume performance for 2021 revealed that ten (10) BIDECs supplied 72% of petroleum production unto the market, while the remaining thirty (31) supplied 28%. The BIDEC market has witnessed an increase in the competition since 2013. The Herfindahl-Hirschman Index (HHI)[235] showed a declining trend between 2013 and 2021, suggesting that the market is less concentrated, even though not highly competitive. For instance, the HHI index declined from 1266 in 2013 to 939 in 2015 due to the implementation of price deregulation. Even though the index increased marginally in 2016 to 959, it is lower compared to 2013 and 2014. Comparatively, there is heightened competition in the BIDECs market which is explained by the decline in the HHI. Between 2015 and 2021, the HHI declined by 18%, indicating that the market is becoming less concentrated due to increased competition. (See Figure 29.)

Figure 29: **Trend of BIDECs Competition (2013 to 2021).**



[235] If HHI is below 100, it indicates highly competitive industry. If it is below 1500, it means the industry is not concentrated. If it is between 1500 and 2500, it means that the industry is moderately concentrated. If it is above 2500, it means the industry is highly concentrated.

5.9.2 Oil Marketing Companies (OMCs)

The number of OMCs[236] increased from 192 in 2020 to 230 in 2021, representing an increase of 20% (see Figure 30). The increase in the number of OMCs impacted the market dynamics of the industry with the market controlled by the top 10 OMCs declining from 59% in 2020 to 56% in 2021. This could be attributed to a slight increase in competition, which is explained by the decline in the HHI index from 637 in 2019 to 534 in 2020 (see Figure 31). Additionally, there was a surge in the number of retail outlets by 5%, from 4334 in 2020 to 4,557 in 2021. As of the time of publishing this document, the number of OMCs has increased to 232.

Figure 30: Number of OMCs (2011-2021).

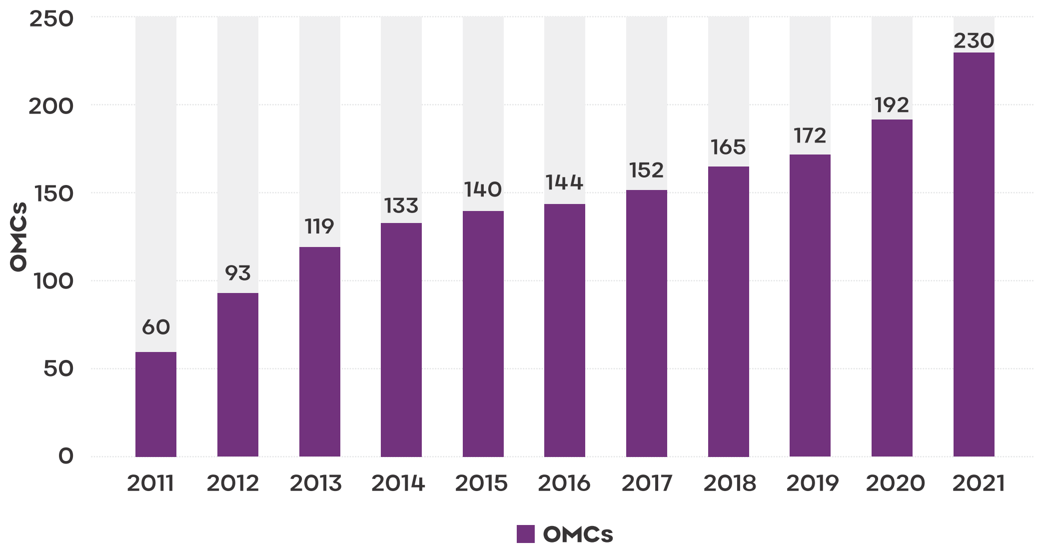
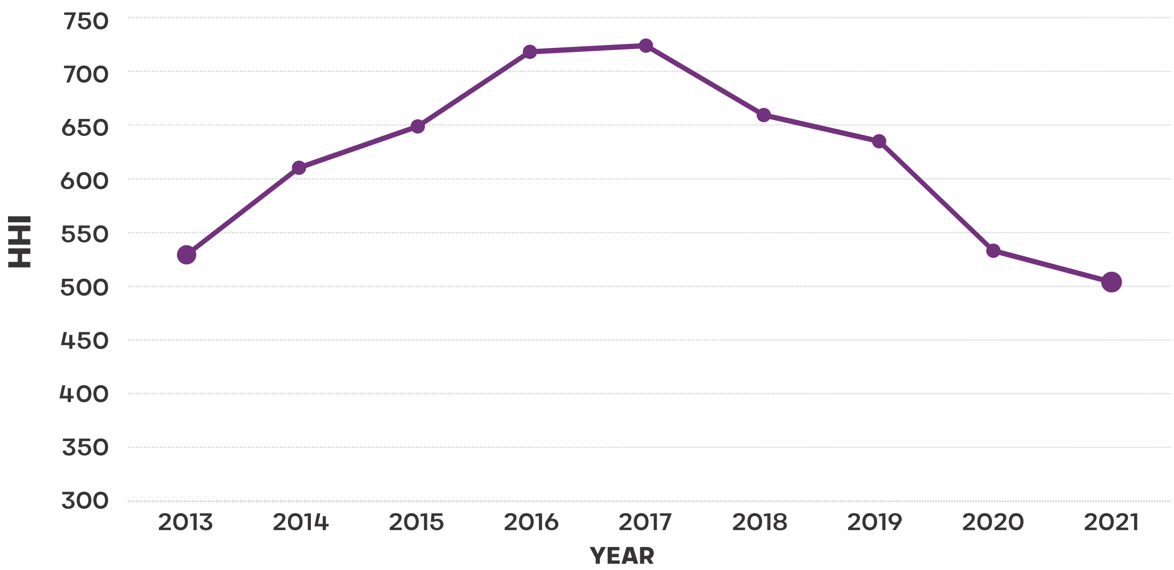
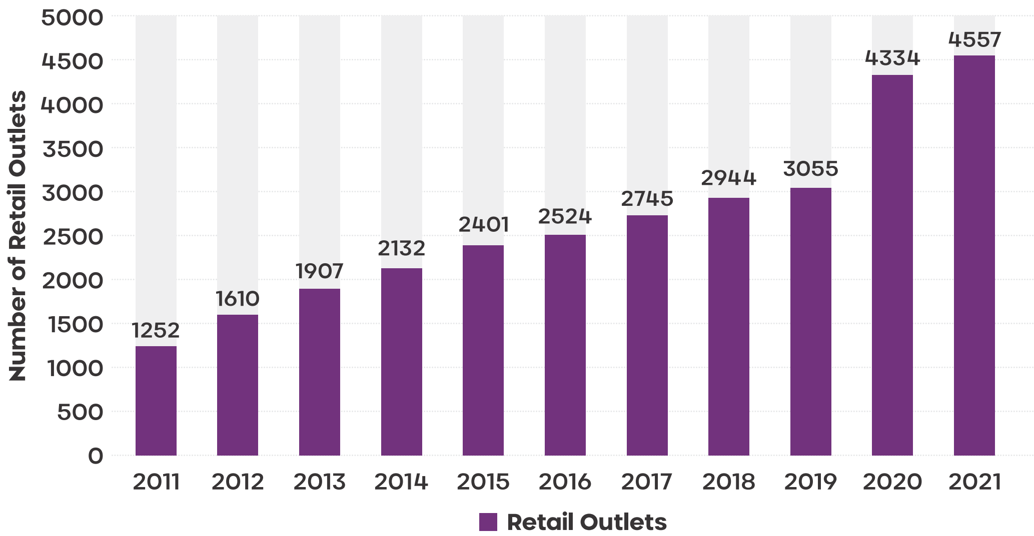


Figure 31: Trend of OMCs Competition.



[236] Including LPG Marketing companies.

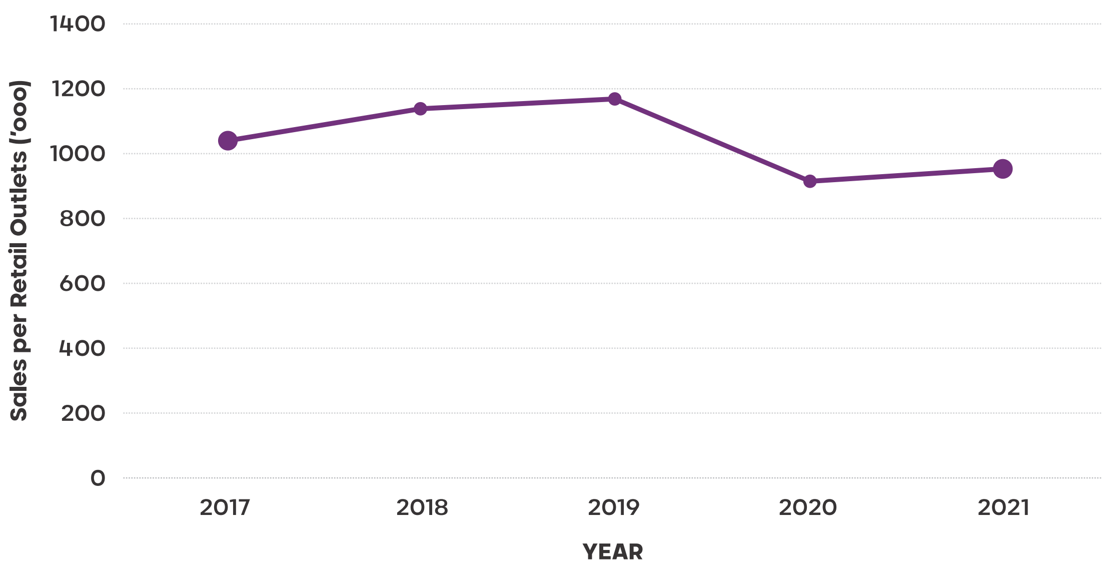
Figure 32: Number of retail outlets (2011-2021).



5.9.3 Retail Outlet Productivity

The number of retail outlets has grown considerably since 2017 with the number increasing from 2,745 in 2017 to 4,557 in 2021, representing an increase of 66%. Given the number of retail outlets and the total national consumption of gasoline and diesel, the productivity of retail outlet could be affected. Further analysis of retail outlet productivity over the last five years (2017 to 2021) indicates that the retail outlet productivity has declined by 8% between 2017 and 2021 (Figure 33.) For instance, retail outlet productivity increased by 10% from 2017 to 2018 and further increased marginally in 2019 by 3%. However, there was a significant drop in retail outlet productivity by 22% in 2020 before increasing marginally by 4% in 2021. The decline in the productivity of retail outlets is attributable to the increase in retail outlets without commensurate growth in demand. Whereas the number of retail outlets grew by 66% from 2017 to 2021, demand grew by 34%. The fall in productivity may have major implications on the commercial viability of OMCs, and possibly, an upward review of margin to sustain viability. Both situations do not bode well for consumers and the broader economy. The Regulator may have to explore implications further and consider restrictions to minimise the negative effects of excess outlets.

Figure 33: Retail Outlets Productivity

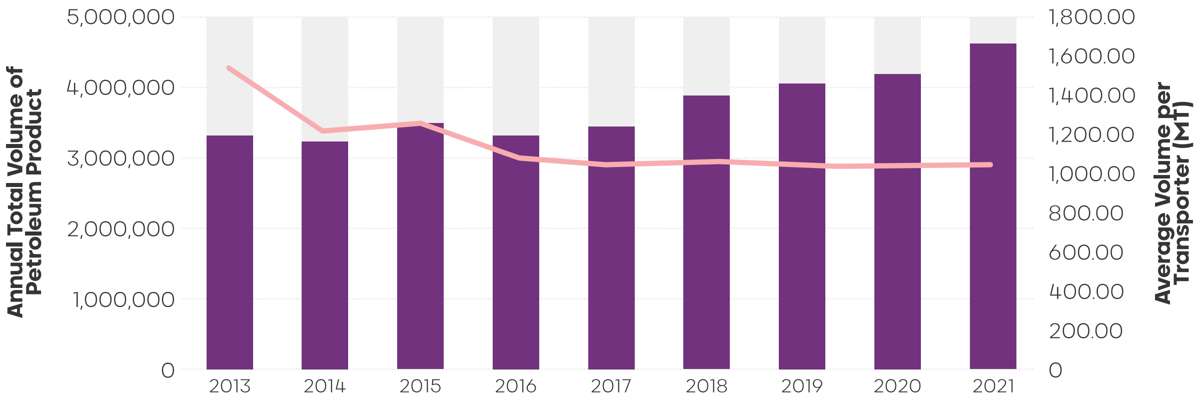


5.9.4 Transporters

While consumption of petroleum products increased over the period, volumes transported per BRV decreased. As the consumption of products witness about 31% growth from 2015 to 2021, the average volume per transporter declined by an average of 17% within the same period. The average volume per BRV declined from 1, 543MT in 2013 to 1,050MT in 2021, although the total annual volumes of petroleum products consumed increased from 3.36 million MT in 2013 to 4.37 million MT in 2021. The data clearly shows that as the number of BRVs increases the average volume of product transported per BRV declines.

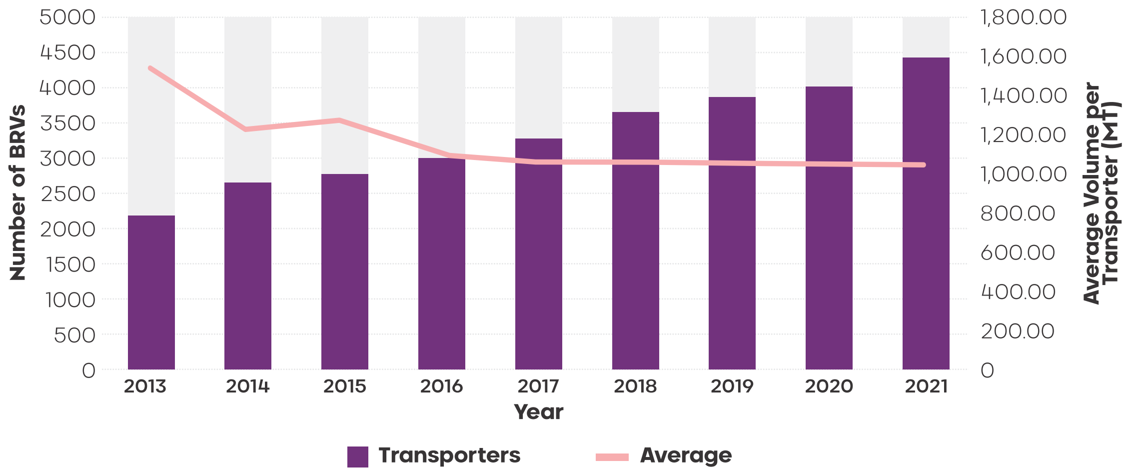
The number of BRVs increased from 2,179 in 2013 to 4,413 in 2021, whereas the average volume per BRV declined from 1,543MT in 2013 to 1,050MT in 2021. This puts in question the viability and sustainability of the transporter sub-sector. The number of BRVs needs to be controlled to ensure adequate profitability; otherwise, given the current situation, transporters would clamour for increased transport rates with its attendant increase in ex-pump price against the backdrop of an already aggravated fuel price situation. An alternative to this policy recommendation will be for the transportation sub-sector to be deregulated so consumers can benefit from lower transportation rates, resulting from the excess supply of BRVs.

Figure 34: Demand to BRV



	2013	2014	2015	2016	2017	2018	2019	2020	2021
Volumes	3,364	3,274	3,528	3,329	3,464	3,887	4,060	4,206	4,637
Average	1,543	1,233	1,270	1,110	1,062	1,065	1,053	1,046	1,050

Figure 35: Number of BRVs vs Average Volume Carried



5.9.5 Automation of Licences

Between 2020 and 2021, the NPA commenced the processes of its data capture to incorporate further automation of its processes to include the automation of the licensing regime. A consultant was engaged by the Authority to undertake a review and has, subsequently, presented its report to the Authority. Upon subsequent engagements with the consultants, NPA has accepted the recommendations presented. It is currently working with an implementation partner implementors of the Enterprise Relational Data Management System (ERDMS) towards the full implementation of the recommendations by E-Solutions..

5.10 Enforcement of National Oil Loss Control Manual

Identifying appropriate compensation for oil losses at all stages of the operations of the petroleum downstream industry remains a challenge. Oil losses occur during loading at the gantry, transportation/distribution and sales at the retail outlets. Ascertaining the accurate measurements of the quantity of petroleum delivered or received at the depots, retail outlets or bulk customer sites has been a subject of contention between the Petroleum Service Providers and has often threatened the industrial harmony of the petroleum downstream industry.

To address the challenges associated with the accuracy of measurement of oil losses, the National Oil Loss Control Committee (NOLCC) was reactivated in 2004 under the guidance of the Energy Commission to identify the major sources of oil loss at all stages of operations in the petroleum downstream industry. The Committee came up with the Oil Loss Control Manual. Furtherance of this, the National Petroleum Authority, in 2019, reconstituted the NOLCC to review the Oil Loss Control Manual to reflect current trends and development in the petroleum downstream industry.

5.10.1 Objective

The main objective of the review was to provide minimum requirements of standard procedures and methods to be used to determine the quantity of petroleum product in a storage tank, river barge, Bulk Road Vehicles (BRVs), etc., used in the distribution of petroleum products relating to the purchase, sale and custody transfer or inventory control in the Petroleum Downstream Industry. Additionally, it was to ensure that accurate measurements form the basis of transactions for the calculation of taxes, margins, fees and transit losses, amongst others.

5.10.2 Distribution Losses (White products)

The distribution losses are classified into two, namely, Physical and Apparent losses. The physical losses arise from Leakages, Spillage, Evaporation, left on board, Meter Under/Over-Delivery and Pilferage. Apparent loss, on the other hand, is due to inaccurate measurements of product volumes as well as changes in densities due to temperature variations. This is considered not a real loss and could be curtailed by ensuring accurate and systematic measurement procedures.

5.10.3 Accuracy Measurements

Accuracy of measurements ensures that within economic confines, measurements are within a specified range of tolerance (Ghana Standard Authority tolerance +/- 0.2% for flow metres). All measuring instruments must be certified by the Ghana Standards Authority.

5.10.4 Temperature Variation

Temperature variation is a major cause of change in levels of road tankers/underground tanks. The magnitude of the loss due to temperature variation depends on the magnitude of the temperature change, the capacity configuration of the compartment and product type.

5.10.5 Temperature Compensation

Temperature compensation has been pegged at 20°C for all products to minimize the effect of temperature on the losses experienced in transit and at the customer's end. All depots are expected to comply with this by installing - temperature-compensated meters to meet the 20°C product compensation at the loading gantries. Depots without temperature-compensation meters are expected to convert loaded nominal volumes to volumes at 20°C and this should form the basis of invoicing and issuing of waybills and delivery notes.

5.10.6 Allowable Transit Loss for Transportation and Barges

The following are the allowable losses applicable to Transportation and Barges:

- Diesel 0.1%
- Petrol 0.20%
- Kerosene 0.15%

Other areas emphasized in the Oil Loss Control Manual include:

- Procedure for loading petroleum products at depots and refineries;
- Post-loading inspections, tests and verifications at level bay;
- Unloading BRVs at retail outlets and bulk customer sites;
- Procedure for receiving white products at depots from BRV (Top-Up method);
- Procedure for discharging petroleum products from BRV using flow meters;
- Calibration Procedures;
- Receipt of petroleum products from vessels via pipelines from the harbour;
- Standard Operating Procedure (SOP) for inter-depot transfer of petroleum products by Barges, and
- Loading and offloading of LPG depots to refilling plants and bulk customer sites.

Since the implementation of the National Oil Loss Control Manual, issues related to temperature variations and incessant complaints by PSPs have reduced significantly. Now the effect of temperature on losses is a thing of the past and most PSPs are satisfied with the implementation of the National Oil Loss Control Manual.

Chapter 6

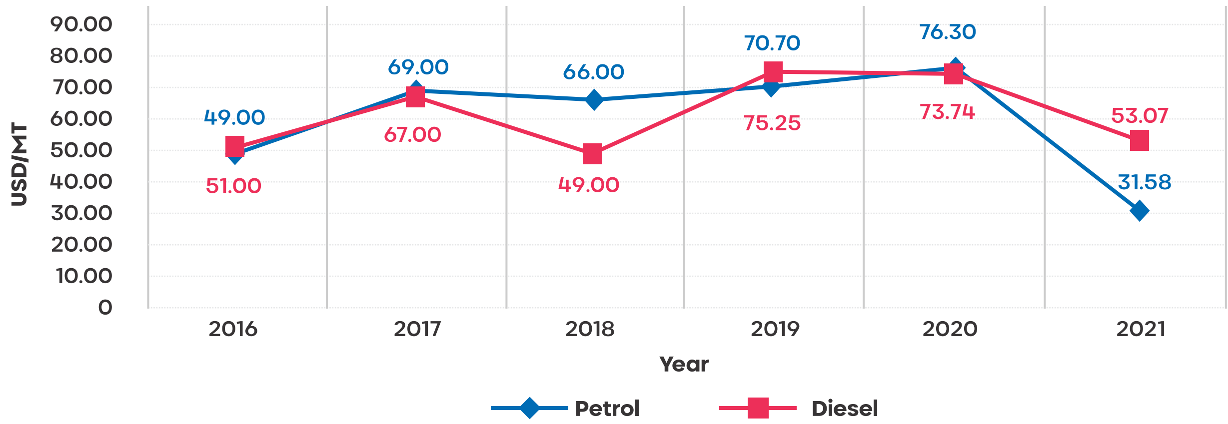
FINANCIAL REVIEW

Financial Review

6.1 Suppliers' Premiums

To ensure full cost recovery of investment at the importer's stage of the downstream petroleum supply chain, the BDCs are provided with a SUPPLIERS' PREMIUM to cater for all costs associated with importing petroleum products into the country. The BDCs include this premium in the calculation of the Ex-refinery prices of the petroleum products that are being sold to the OMCs. The estimated suppliers' premiums used by BDCs in computing their ex-refinery prices were extrapolated through a backward calculation from the average ex-refinery prices and the estimated exchange rates for each selling window within the year.

Figure 36: Average BDC Premiums (2016-2021)



The estimated suppliers' premium used by BDCs for petrol in 2021 ranged between -$31.25/mt and $93.19/mt. This, notwithstanding, the annual window average stood at $31.58/mt. The year 2021 had suppliers experiencing negative premiums for petrol in most of the selling windows; suppliers witnessed negative premiums for petrol from the second selling window of July to the second selling window of October. After recovering from the negative premiums in the first quarter of November, suppliers' premiums for petrol in 2021 peaked at $93.19/mt in the last selling window of the year.

Compared to 2020, the suppliers' premiums on petrol were much higher, averaging $76.3/mt with the highest being $112.17/mt and the lowest being $27.74/mt. This indicates that the average supplier's premium for 2021 plummeted from the 2020 figure by $44.72/mt, indicating an average fall of about 59 percent.

The average suppliers' premium used by BDCs for the year 2021 for diesel ranged between $3.66/mt and $94.06/mt and averaged at $53.07/mt. In 2021, the supplier's premium on diesel recorded its lowest in the second window of October, while the highest premiums were recorded in the last selling window of the year just like the premiums of petrol. Compared to the premiums on petrol, average suppliers' premiums on diesel on an annual average was about $21.49/mt higher. The suppliers' premium on diesel recorded the lowest of $47.84/mt in 2020 as compared to recording the lowest of $3.66/mt in 2021. From the year 2020 to 2021, the average supplier's premium fell by an average of 39 percent compared to the premiums on petrol which fell by 59 percent. On a year-on-year basis, the supplier's premiums on petrol and diesel fell by 55 percent and 29 percent respectively, indicating that suppliers' premiums on petrol, although higher than that of diesel in 2020, plummeted sharply below that of diesel in 2021.

The suppliers' premium on LPG averaged $172.29/mt after recording the lowest and highest of $142.13/mt and $196.52/mt in 2021, respectively. On a year-on-year basis, suppliers' premiums on LPG fell by an average of $32/mt, representing about a 16 percent decline. The high suppliers' premiums in 2020 could be attributed to the restriction and the various hurdles that confronted the supply chain in 2020 because of the Covid-19 pandemic lockdowns, thus increasing the various costs associated with the importation of petroleum products.

Figure 37: Trend of Suppliers' Premiums for the year 2021.

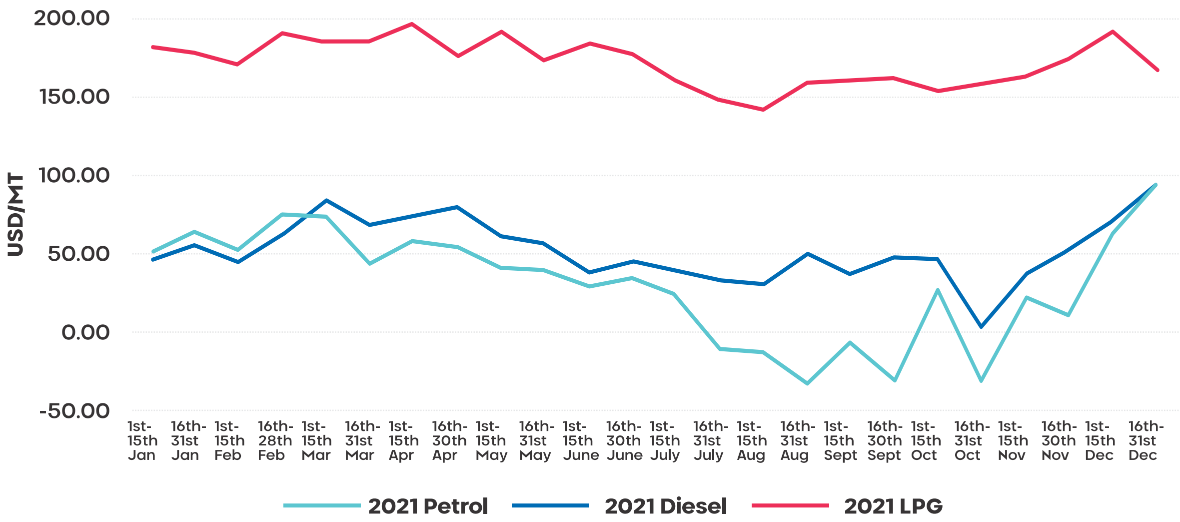


Figure 38: Trend of Suppliers' Premiums for the year 2021.

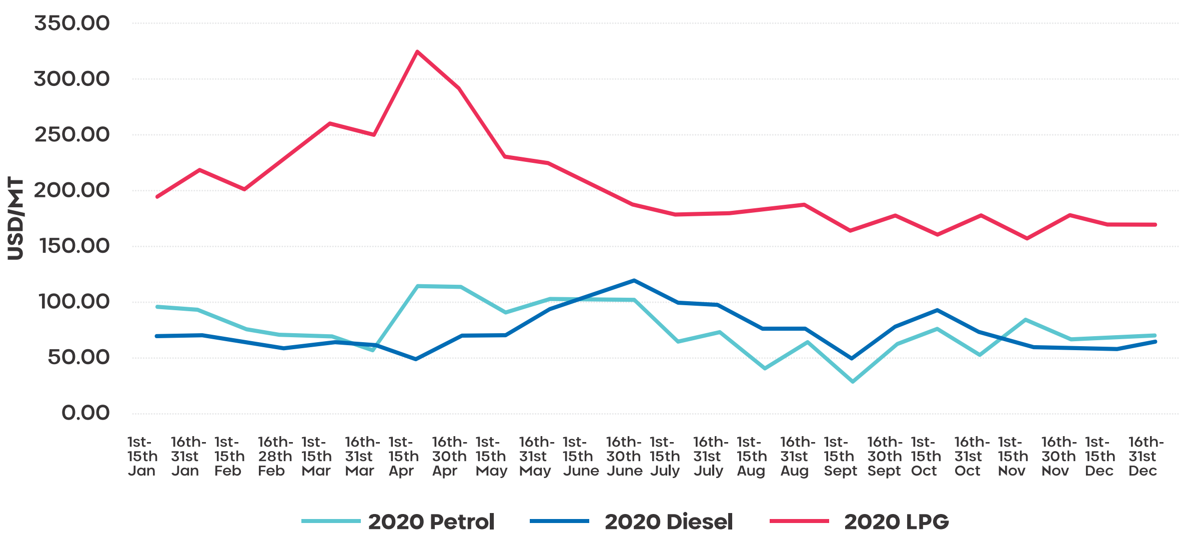


Table 10 below shows the average suppliers' premiums for the years under consideration.

Table 10: Suppliers' Premiums for 2020 and 2021

	2020			2021		
	Petrol	Diesel	LPG	Petrol	Diesel	LPG
1st – 15th Jan	95.00	70.00	195.00	52.82	46.61	180.99
16th – 31st Jan	93.02	69.37	219.41	65.87	56.72	179.24
1st – 15th Feb	75.00	65.00	200.00	53.07	45.28	171.19
16th – 28th Feb	68.78	58.09	233.07	75.08	63.20	190.08
1st – 15th Mar	70.00	63.00	260.00	74.71	84.89	185.26
16th – 31st Mar	59.46	60.32	250.53	44.76	68.98	185.62
1st – 15th Apr	112.17	50.00	325.00	58.47	74.47	196.52
16th – 30th Apr	112.17	70.00	290.00	54.35	80.43	175.61
1st – 15th May	90.00	70.00	230.00	42.02	60.84	192.25
16th – 31st May	101.12	94.52	223.98	39.93	57.30	173.12
1st – 15th June	103.44	103.50	207.47	30.39	39.01	183.65
16th – 30th June	101.54	119.25	186.68	35.77	45.42	176.87
1st – 15th July	63.28	99.75	178.11	24.74	39.79	160.94
16th – 31st July	72.05	94.60	178.11	-8.65	34.01	148.34
1st – 15th Aug	39.33	74.67	183.41	-11.25	31.52	142.13
16th – 31st Aug	64.30	74.25	186.98	-31.25	50.86	159.56
1st – 15th Sept	27.74	47.84	162.01	-5.32	38.27	160.41
16th – 30th Sept	62.34	78.34	177.10	-30.0	47.62	161.85
1st – 15th Oct	75.48	92.46	161.44	28.51	47.26	153.58
16th – 31st Oct	51.39	72.73	176.71	-29.86	3.66	159.19
1st – 15th Nov	83.25	61.55	158.36	23.73	38.01	163.61
16th – 30th Nov	67.99	57.23	176.31	12.32	53.73	174.46
1st – 15th Dec	71.13	58.30	169.25	64.57	71.61	192.10
16th – 31st Dec	71.13	65.00	170.00	93.19	94.06	168.27
Min	27.74	47.84	158.36	(31.25)	3.66	142.13
Max	112.17	119.25	325.00	93.19	94.06	196.52
Average	76.30	73.74	204.12	31.58	53.07	172.29

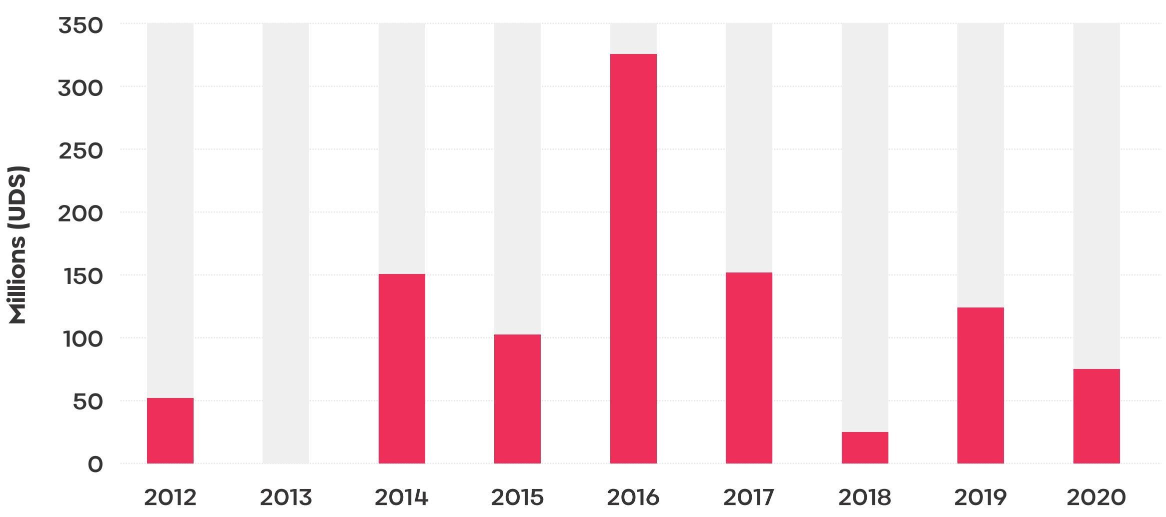
6.2 GoG Legacy Debt to BIDECs

The government's debt owed to BIDECs has been fully settled. This follows the payment of the last tranche of Ghs418.97mn (US$75.60) paid to BIDECs on 13th January 2020.

Table 11: Summary of Legacy Debt payments to BIDECs (2012-January 2020)

Date of Payment	Payment by	Payment Type	GH¢	USD
1-Oct-2012	NPA	Cash	40,000,001	21,148,356
1-Nov-2012	MoF	Cash	38,032,833	20,070,097
1-Dec-2012	NPA	Cash	21,737,987	10,533,502
1-Jun-2014	BoG	Cash	434,784,919	150,000,000
20-Apr-2015	MoF	Cash	50,000,000	13,073,171
29-Jul-2015	MoF	Cash	195,964,032	56,587,939
16-Oct-2015	MoF	Cash	117,408,563	32,859,939
1-Jan-2016	MoF	Cash	292,929,293	74,862,206
15-Nov-2016	MoF	Cash	124,000,000	31,000,000
23-Dec-2016	BoG	BoG Bonds	900,000,000	219,077,753
10-Jan-2017	MoF	Cash	47,000,000	11,000,070
1-Nov-2017	MoF	ESLA Bonds	542,124,026	122,824,783
9-Nov-2017	MoF	ESLA Bonds	77,356,872	17,526,139
3-Sep-2018	NPA/MoF	Cash	121,466,012	25,684,262
28-Jun-2019	MoF	ESLA Bonds	648,928,861	123,332,990
13-Jan-2020	MoF	ESLA Bonds	418,969,716	75,597,646
			4,070,703,115	1,005,178,854

Figure 39: Legacy Debt Payment Distribution (2012-2020).



6.3 Stock Accounting in the Sector

6.3.1 National Stock Reconciliation

Gasoline and Gasoil remained the largely consumed petroleum products in Ghana for the 2021 and 2020 financial years. Other products consumed in the country included Fuel oil, Gas oil, Unified, Kerosene, LPG, Premium, Premix and ATK. These products are either imported as finished products or produced by the local refineries. Taxes on the sale of these products accounted for about 12% of total domestic tax revenue in 2021 and about 13% of domestic tax revenue in 2020.. This emphasizes the importance of petroleum tax revenue to the Government's fiscal policy and the need to monitor stock movement and accounting to ensure the optimization of this revenue by the State.

In accounting for stock movements, this report considers the following elements as depicted in the formula below: Opening Stock positions, Stock Inflows (Imports and Production), Closing Stock, Domestic Reported Sales and Exports and provisions for operational losses.

Official unaccounted stocks = **Expected Sales (ES)** - **Reported Sales (RS)**

Where
Expected Sales
=Opening Stock+ Purchases (Imports)for the year
+ Production- Less Allowable Losses within the year
- Less Closing Stock

And
Reported Sales
=Domestic Reported Sale
+Export Reported Sales

The analysis develops an expectation of sales in line with stock accounting principles after adjusting for operating losses, where applicable, and compares it with officially reported sales (domestic and exports).

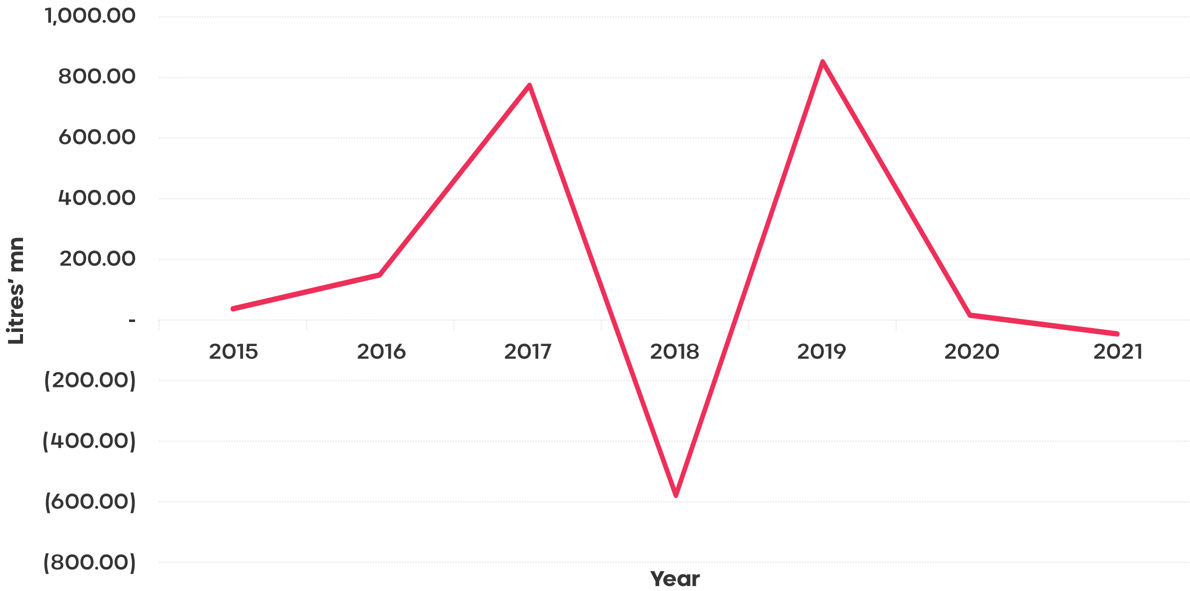
An analysis of the position using official records of the NPA revealed that, in 2020, 24.47 mn litres of stocks of gasoil and gasoline delivered into the country were not accounted for and may have evaded Ghana's tax regime. (See appendix 1) The estimated tax revenue associated with this was Ghs34.22 mn. In 2021, however, the trend changed with reported sales exceeding the actual sales by 41.15 mn litres, resulting in a net estimated savings of Ghs19.94 mn to the State.

There appears to be an improvement in the phenomena for 2020 and 2021 compared to the trend in previous years -See Figures 40 and 41. It further evidences the successes recorded by the State in combating the illicit trade menace.

Figure 40: Expected vs Actual sales and Variances (2015-2021).

	2021	2020	2019	2018	2017	2016	2015
Expected Sales	4,850	4,490	4,611	3,465	4,740	4,330	4,038
Actual Sales	4,892	4,466	3,756	4,039	3,959	4,173	3,995
Variance	(41.1	24.47	855.1	(574.	781.6	156.2	43.29

Figure 41: Growth in Official Unaccounted Stocks (2015-2021).



6.4 Petroleum Taxes

Petroleum taxes are charges levied on the sale of specified petroleum products, such as petrol, kerosene, diesel, liquefied petroleum gas and fuel oil. Until 2015, petroleum taxes in Ghana was referred to as 'petroleum taxes and related levies[237] which comprised six levies (namely, cross-subsidy levy, energy levy, hydrocarbon exploration levy, road levy, specific levy and the Tema oil refinery debt recovery levy), in addition to petroleum excise. However, following the passage of the Energy Sector Levies Act (ESLA), Act 899 in 2015[238], these six levies were consolidated into four levies under the new Act as part of the governments efforts to reduce the tax burden on consumers of petroleum products, to manage the hard-core liabilities of the Energy Sector State-Owned Enterprises, promote investments in the sector and also support road maintenance activities. This was followed by the abolishment of the Petroleum Excise in 2017.

The Act and its subsequent amendments specifically established the Energy Debt Recovery Levy (EDRL), Price Stabilisation and Recovery Levy (PSRL), Road Fund Levy (RFL), Energy Fund Levy (EFL), Energy Sector Recovery Levy (ESRL), Sanitation and Pollution Levy (SPL) and Public Lighting, and National Electrification Scheme Levies. These levies are charged on the sale of petrol, diesel, Marine Gas Oil (MGO), Residual Fuel Oil (RFO), Liquefied Petroleum Gas (LPG), kerosene, and electricity.

However, for this report, the six consolidated levies, namely, Energy Debt Recovery Levy, Energy Fund Levy, Price Stabilization and Recovery Levy, Road Fund Levy, Energy Sector Recovery Levy and Sanitation and Pollution Levy, shall collectively be referred to as Petroleum Product Taxes and shall form the basis of our analysis of petroleum taxes.[239] Also included in the analysis of petroleum taxes is the Special Petroleum Tax (SPT). SPT was introduced by the government in 2014 (Special Petroleum Tax Act, 2014, Act 879), originally at an ad valorem rate of 17 percent on the ex-depot price of petroleum products but was reduced to 15 percent in 2017 before being converted to a specific tax in February 2018[240] (the specific tax amounts to an effective rate of 13 percent). The change from ad valorem to specific tax was intended to reduce the tax burden imposed on taxpayers and to provide some relief to users of petroleum products. The tax is charged at specific rates per litre or kilogram on specified petroleum products (petrol, diesel, liquefied petroleum gas, natural gas, and kerosene) sold by licensed oil-marketing companies under the National Petroleum Authority Act, 2005 (Act 691).

[237] [Customs and Excise (Petroleum Taxes and Petroleum Related Levies) Act 2005, Act 685).

[238] The imposition of the levies resulted in the amendment and repeal of the Customs Excise (Petroleum Taxes and Petroleum Related Levies) Act, 2005 (Act 685), as amended Act 867, Debt Recovery (Tema Oil Refinery Company) Fund Act, 2003 (Act 642), Electricity (Special Levies) Act 1995, and the National Petroleum Authority (Prescribed Petroleum Pricing) Regulations, 2012 (L.I 2186).

[239] The other two levies under the ESLA, namely, the Public lighting levy and National Electrification Scheme Levy, will not form part of our analysis in this report as they do not fall under petroleum taxes (the base of this levy is electricity).

[240] Special Petroleum Tax (Amendment) Act, 2017 (Act 942) and Special Petroleum Tax (Amendment) Act, 2018 (Act 965), respectively.

The energy sector levies have been amended three times since their passage in 2015. The first amendment was done in 2017 which saw a reduction of the Public Lighting Levy and National Electrification Scheme Levy from 5 percent to 3 percent and 5 percent to 2 percent, respectively. The second amendment, which relates to the analysis done in this report, was done in 2019 which saw an upward revision of the Energy Debt Recovery Levy, Road Fund, and Price Stabilization and Recovery Levy. Specifically, the levies on petrol, diesel, and LPG were increased marginally by GHp0.24 and GHp0.08, respectively, following the amendment of the ESLA Act in August 2019. The upward revision in the rates was done to correct the loss in value due to currency depreciation and inflation over the years without a commensurate increase in the fixed specific-type levies in the price build-up.

The third and most recent amendment was done in 2021. This amendment introduced two additional levies, namely, the Energy Sector Recovery Levy (ESRL) or Delta Fund Levy and the Sanitation and Pollution Levy (SPL) which imposed a 20 pesewas and 10 pesewas levy on the price per litre of petrol/diesel under the Energy Sector Levies Act, respectively. The SPL was introduced to address the rising sanitation issues in the country, as well as improve the quality of air in the urban areas, provide dedicated support for maintenance and management of major landfill sites and other waste treatment plants and facilities, eliminate open defecation, and serve as a buffer for the fumigation of public spaces. The ESRL also seeks to support the payments of energy sector bills, feedstock and other capacity charges.

In terms of Government revenue classification, the Energy Fund Levy, Road Fund Levy, and SPT are classified as tax revenue and this is because the levies are deposited into the 'Ghana Consolidated Fund'. Revenue collections from the Energy Debt Recovery Levy, Price Stabilization and Recovery Levy, Energy Sector Recovery Levy and the Sanitation and Pollution Levy are classified as 'other revenue' and this is because they are earmarked into specific accounts other than the Consolidated Fund. However, for this report, all taxes and levies charged on pump prices (i.e., Energy Fund Levy, Road Fund Levy, Energy Debt Recovery Levy, and Price Stabilization & Recovery Levy and Special Petroleum Taxes, Energy Sector Recovery Levy and the Sanitation and Pollution Levy) are considered as Petroleum Taxes. Fig. 42 and Table 12 provide the composition and description of the seven petroleum taxes in effect in Ghana as of 2021, respectfully.

Figure 42: Composition of Petroleum Taxes (2021).

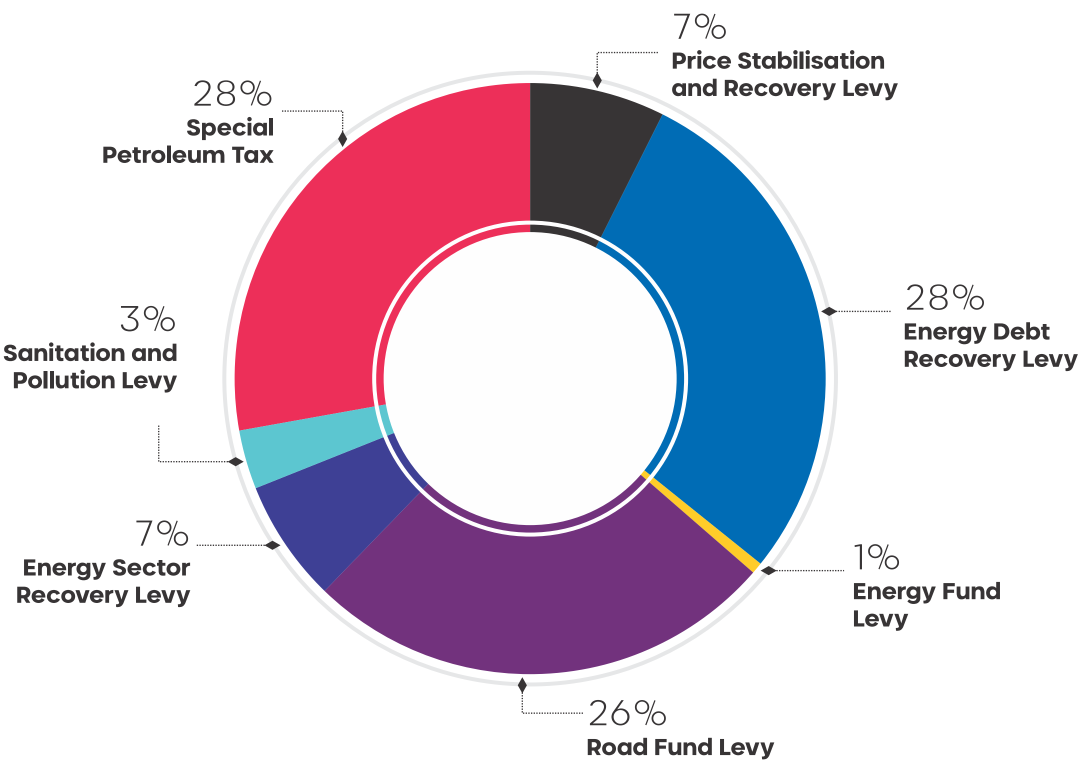


Table 12: Petroleum taxes and levies rate, 2021.

Levy	Item	Rate	Purpose
Energy Debt Recovery Levy	Petrol, Diesel Marine gas Oil Fuel Oil Liquefied Petroleum gas Unified/naphtha	GH₵ 0.49 per litre GH₵ 0.03 per litre GH₵ 0.04 per litre GH₵ 0.41 per kg GH₵ 0.49 per litre	Debt recovery of Tema Oil Refinery; downstream petroleum sector foreign exchange under-recoveries; boost investments in power infrastructure
Energy Sector Recovery Levy (Delta Fund	Petrol, diesel Liquefied Petroleum gas	GH₵ 0.20 per litre GH₵ 0.18 per litre	Support the payment of capacity charges and gas supply bills in the energy sector
Sanitation and Pollution Levy	Petrol, diesel	GH₵ 0.10 per litre	Support the re-engineering and maintenance of landfill sites; support fumigation of public spaces, schools, health centres and markets; construct waste disposal and treatment plants; and improve urban air quality and combat pollution
Energy Fund Levy	Petrol, kerosene, diesel, fuel oil, Unified/Naphtha	GH₵ 0.01 per litre	Support activities of the Energy Commission
Price Stabilisation and Recovery Levy	Petrol Diesel Liquefied petroleum gas	GH₵ 0.16 per litre GH₵ 0.14 per litre GH₵ 0.14 per kg	Used as a buffer for under-recoveries, or subsidies to stabilise petroleum prices for the consumer
Road Fund Levy	Petrol, diesel	GH₵ 0.48 per litre	Support road maintenance
Special Petroleum Tax	Petrol Diesel Kerosene Liquefied petroleum gas Natural gas	GH₵ 0.46 GH₵ 0.46 GH₵ 0.39 GH₵ 0.48 per kg GH₵ 0.35 per kg	

Source: ESLA Act (2015) Act 899 as amended 2017 (Act 946), 2019 (Act 997), 2021 (Act 1064) and Special Petroleum Tax (Amendment) Act, 2018 (Act 965).

6.5 Revenue Under-Reporting

The GRA reported a total actual petroleum tax collection of Ghs8,180.63 mn in 2021 and Ghs6,299.31 mn in 2020. This represents a 30% growth in actual collections. In spite of the growth, the reported collections for the two years (2020 and 2021) are less than the expected collections estimated by the CBOD by Ghs1.22 bn. The expected tax receipts estimated by the CBOD are computed based on official volumes procured from the NPA and adjusted by reported exemptions and revenue losses where applicable **(see appendix for details of the computations)**. This continued the trend of under-reported taxes observed in 2015, 2016, 2017, and 2019.

The recurrence of the under-reporting of tax receipts evidences the fact that some aspects of the illegal trade continue unabated and are supported by a well-networked group of public and private officials. These observations are based on traceable official data and hence, culprits of these highly corrupt and criminal acts can be significantly tracked.

The variances are reported in Tables 13, 14, 15, 16 and 17.

Table 13: Government's 2021 Petroleum Tax Collections v Expected Receipts.

Taxes (2021)	Actual Collections Ghsmn	Expected Collections Ghsmn	Variance Ghsmn
ESLA	5,010.88	5,256.57	(245.69)
o/w Price Stabilisation and Recovery Levy	412.17	612.92	(200.76)
o/w Energy Debt Recovery Levy	2,373.89	2,395.54	(21.65)
o/w Energy Fund Levy	47.37	47.60	(0.23)
o/w Road Fund Levy	2,177.45	2,200.50	(23.05)
Special Petroleum Tax	2,338.84	2,353.56	(14.72)
Sanitation and Pollution Levy	264.82	282.09	(17.28)
Energy Sector Recovery Levy	566.09	833.68	(267.60)
Total	**8,180.63**	**8,725.90**	**(545.27)**

Table 14: Government's 2020 Petroleum Tax Collections v Expected Receipts.

Taxes (2020)	Actual Collections Ghsmn	Expected Receipts Ghsmn	Under-Reporting Ghsmn
ESLA	4,342.89	4,786.57	(443.68)
o/w Price Stabilisation and Recovery Levy	484.31	580.09	(95.78)
o/w Energy Debt Recovery Levy	2,040.27	2,173.95	(133.68)
o/w Energy Fund Levy	38.38	42.71	(4.33)
o/w Road Fund Levy	1,779.93	1,989.82	(209.89)
Special Petroleum Tax	1,956.42	2,186.65	(230.23)
Total	**6,299.31**	**6,973.23**	**(673.92)**

Table 15: Government's 2019 Petroleum Tax Collections v Expected Receipts.

Taxes (2019)	Actual Collections Ghsmn	Expected Receipts Ghsmn	Under-Reporting Ghsmn
ESLA	3,573.84	3,982.87	(409.03)
o/w Price Stabilisation and Recovery Levy	269.59	505.32	(235.73)
o/w Energy Debt Recovery Levy	1,712.60	1,799.37	(86.77)
o/w Energy Fund Levy	38.79	40.16	(1.37)
o/w Road Fund Levy	1,552.86	1,638.03	(85.17)
Special Petroleum Tax	1,928.00	2,001.51	(73.51)
Export Duty[241]	26.91	26.91	-
Total	**5,528.75**	**6,011.29**	**(482.54)**

[241] Excise duty and Export Duty were computed using NPA's 2017 OMC Performance Statistics. Government actuals not available at the time of publication.

Table 16: Government's 2018 Petroleum Tax Collections v Expected Receipts.

Taxes (2018)	Actual Collections Ghsmn	Expected Receipts Ghsmn	Under-Reporting Ghsmn
ESLA	2,973.98	3,267.05	(293.07)
o/w Price Stabilisation and Recovery Levy	142.46	225.33	(82.87)
o/w Energy Debt Recovery Levy	1,471.96	1,480.13	(8.17)
o/w Energy Fund Levy	35.27	39.52	(4.25)
o/w Road Fund Levy	1,324.29	1,522.08	(197.78)
Special Petroleum Tax	1,812.01	1,952.69	(140.68)
Export Duty[242]	23.26	23.26	-
Total	**4,809.25**	**5,243.00**	**(433.75)**

Table 17: Government's 2017 Petroleum Tax Collections v Expected Receipts.

Taxes (2017)	Actual Collections Ghsmn	Expected Receipts Ghsmn	Under-Reporting Ghsmn
ESLA	2,820.95	3,066.49	(245.54)
o/w Price Stabilisation and Recovery Levy	345.31	392.32	(47.01)
o/w Energy Debt Recovery Levy	1,293.03	1,295.09	(2.06)
o/w Energy Fund Levy	30.65	34.97	(4.32)
o/w Road Fund Levy	1,151.96	1,344.11	(192.15)
Special Petroleum Tax	1,582.12	1,731.02	(148.90)
Export Duty[243]	18.19	18.19	-
Export Duty[244]	15.26	15.26	-
Total	**4,436.52**	**4,830.97**	**(394.44)**

Table 18: Government's 2016 Petroleum Tax Collections v Expected Receipts.

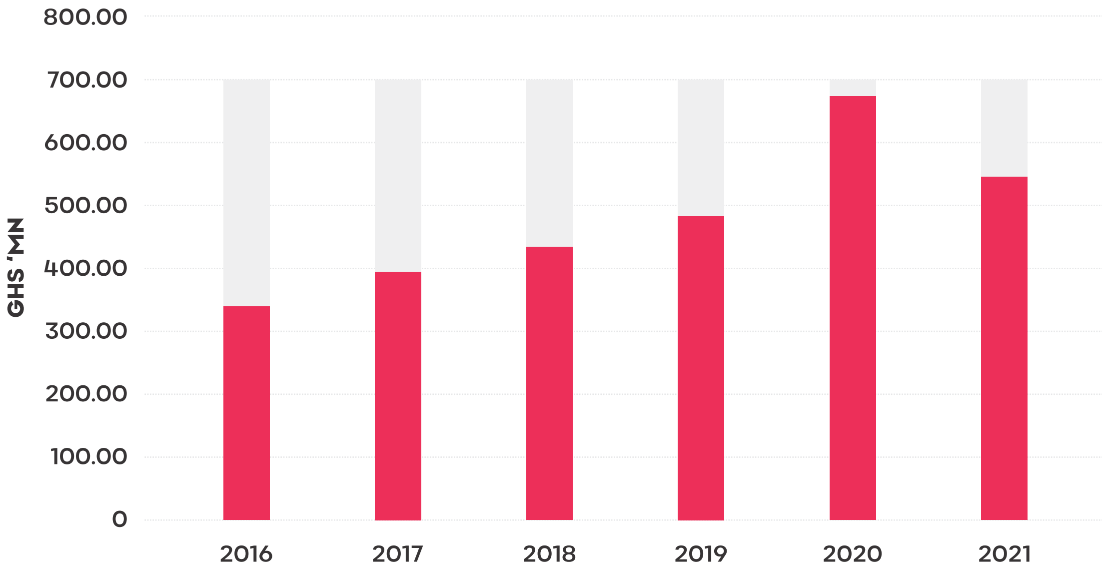
Taxes (2016)	Actual Collections Ghsmn	Expected Receipts Ghsmn	Under-Reporting Ghsmn
ESLA	2,853.67	3,193.80	(340.13)
o/w Price Stabilisation and Recovery Levy	338.47	403.29	(64.82)
o/w Energy Debt Recovery Levy	1,281.18	1,370.29	(89.11)
o/w Energy Fund Levy	29.84	34.86	(5.02)
o/w Road Fund Levy	1,204.18	1,385.36	(181.18)
Special Petroleum Tax	1,607.42	1,607.42	-
Export Duty[245]	14.44	14.44	-
Total	**4,475.53**	**4,815.66**	**(340.13)**

[242] Refer to footnote 4.
[243] Refer to footnote 4.
[244] Refer to footnote 4.
[245] Refer to footnote 4.

The variance between the estimated tax receipts and the actual tax receipts dropped by 19% in 2021 having peaked in 2020. This, notwithstanding, the estimated shortfall in 2021 is the second-highest variance recorded between 2016 and 2021.

As can be seen in Fig. 43, under-reported taxes have been growing since 2016. This is a major cause of concern for government revenue and national security.

Figure 43: Petroleum Tax Revenue Shortfall Movement

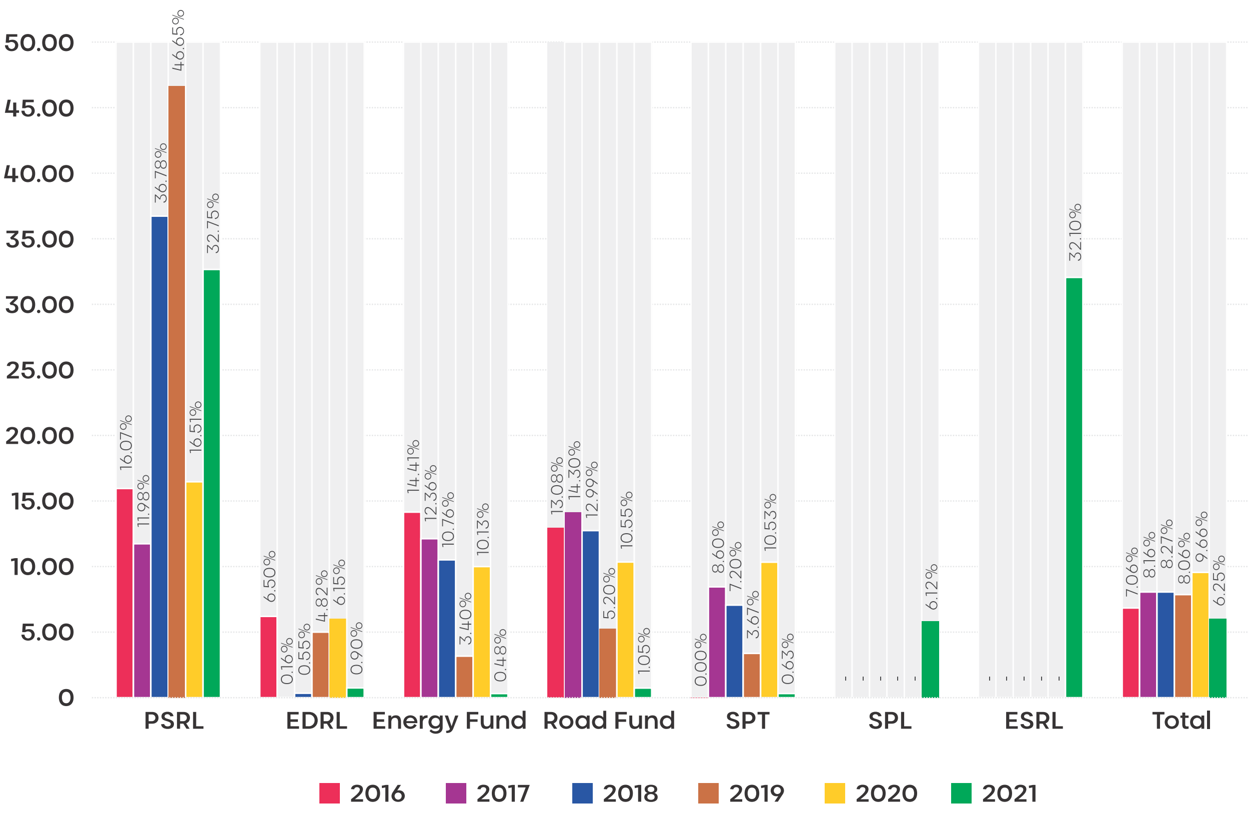


6.6 Energy Sector Levies

Actual revenue collections from the various components of ESLA amounted to GHS5,010.88 mn and GHs4,342.89mn in 2021 and 2020, respectively, according to a report to parliament by the Ministry of Finance. This excludes Public Lighting Levy and National Electrification Scheme Levy which are tax components of ESLA chargeable on power consumption and not petroleum products. The 2021 position was Ghs245.69 mn less than the expected receipts estimated by the CBOD. This, however, represents an improvement in collections relative to 2020 which recorded a variance of GHS443.68mn less than expected receipts estimated by the CBOD. The estimation is based on NPA-confirmed OMC performance data, less exemptions and downward variations.

See Table 13 for the variances recorded between 2016 and 2021.

Figure 44: Percentage of Taxes Under-Reported.



Further analysis of the variance shows that the under-reported taxes for the PSRL, when compared to the expected receipts, was 32.75% in 2021, whilst EDRL and Road Fund reported a shortfall of 0.09% and 1.05%, respectively. The low variance observed on the EDRL is attributable to the effective and independent management of the fund by KPMG operating as the administrators of the ESLA Plc, assignors of the EDRL.

The observations in the various elements of ESLA are of major concern and require committed and honest policy interventions to reverse the tide.

The variance analysis is reported in Table 13 to 18. Kindly refer to Appendices for the detailed computation of the CBOD position.

6.6.1 Special Petroleum Tax

Estimated SPT collections in 2021 amounted to Ghs2,353.56 mn compared to Ghs2,338.84 mn collected in 2020. The collection is 0.63% less than the estimated amount and constitutes a nominal negative growth of about 94% compared to the shortfall reported in 2021. SPT share of the total downstream petroleum taxes was reduced to 29% from 31% in 2020.

The reported SPT collections above are also at variance with the expected SPT value recomputed by the CBOD by Ghs14.72 mn.

Kindly refer appendix 1A to 1F for the detailed computation of the CBOD's position.

6.6.2 Revenue Loss from Illegal Trading

Petroleum tax revenue losses to the State from illegal trading activities are classified as either official or unofficial. The officially lost revenue has the tax base (volume of petroleum products) traceable. This is reflected in the disparity between the tax due from the official sales recorded by the NPA and the reported collections/receipts reported by the GRA. It is also reflected in the tax associated with volumes of stock that cannot be accounted for in the reconciliations of the officially recorded stock movements in the country.

The unofficial losses refer to the lost tax revenue from export dumping, premix dumping and smuggling sales or stock movements which are not officially captured as taxable. These cannot be traced from official stock data reports.

The revenue lost is also not just in taxes but also in regulatory margins.

Table 19: Tax Revenue Loss on Official Volumes

Year	Official Tax Loss Unaccounted Stocks Ghsmn	Official Tax Loss Accounted Sales Ghsmn	Total Ghsmn
2015*	65.16	-	65.16
2016	221.84	340.13	561.98
2017	1,103.73	394.44	1,498.17
2018	-	433.75	433.75
2019	1,187.07	482.54	1,669.61
2020	34.22	673.92	708.14
2021*	-	545.27	545.27
*Total	2,612.02	2,870.06	5,482.08

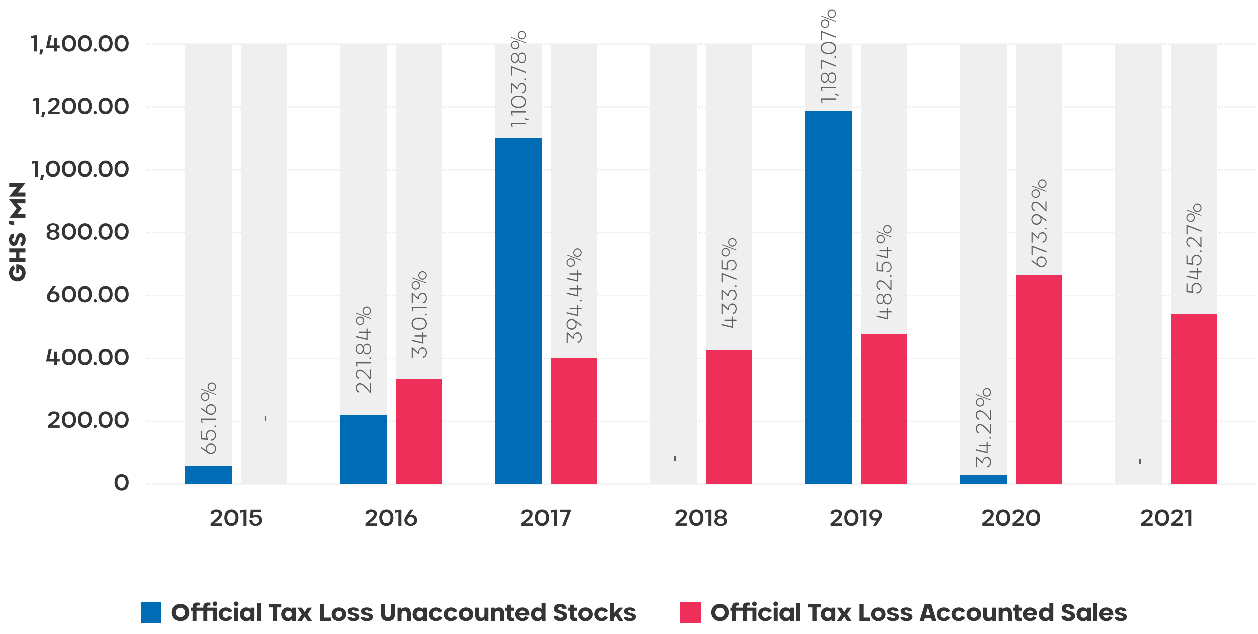
*Official tax loss on accounted sales for 2015 was not computed since there was no ESLA in 2015.

Table 20: Regulatory Margin Lost on Official Volumes

Year	Loss Official Unaccounted Stocks Ghsmn
2015	8.36
2016	25.00
2017	198.18
2018**	-
2019	273.66
2020	8.57
2021**	
*Total	513.76

**Official tax loss on unaccounted sales for 2018 and 2021 since there were no losses relating to that year.

Figure 45: Official Tax Losses (Accounted Vs Unaccounted).



6.7 Petroleum Taxation and National Taxation

6.7.1 Downstream Petroleum Taxation and National Taxation

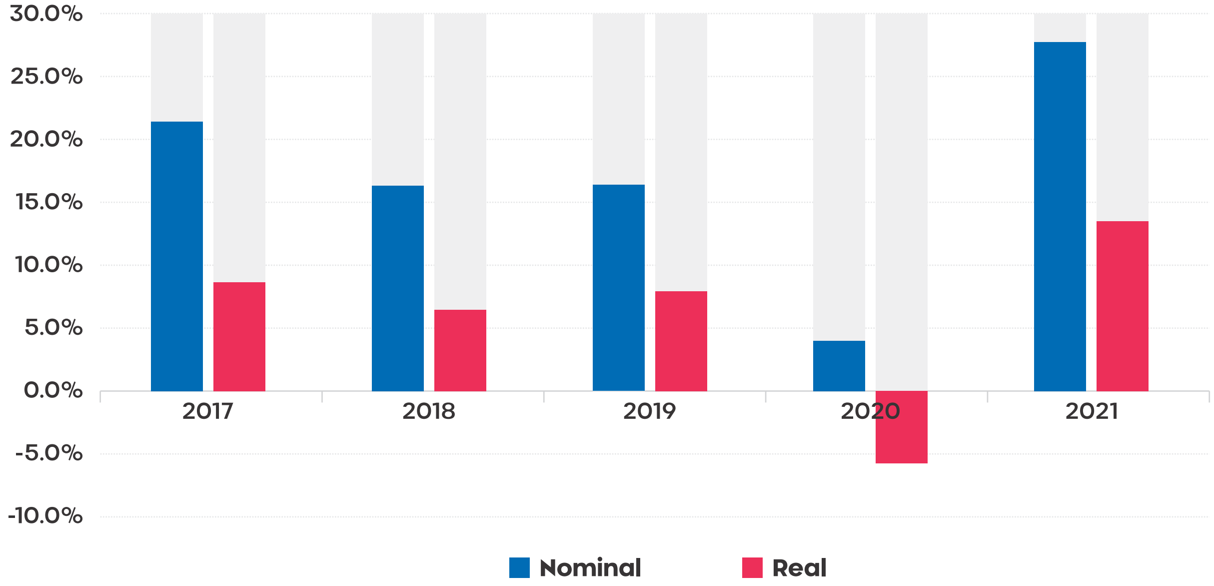
Total domestic tax revenue collections between January and December 2021 amounted to GH¢57.43 bn. This amount includes collections of the Energy Debt Recovery Levy of GH¢2.37 bn, Energy Sector Recovery Levy of GH¢0.57 bn and Sanitation and Pollution Levy[246] of GH¢0.26 bn but excludes tax revenue (CIT and royalties) and other revenue collections (surface rentals, carried and participating interest and petroleum holding fund income) from the upstream petroleum sector. This is because revenue collections from the upstream petroleum sector are collected and accounted for separately under the Petroleum Revenue Management Act 2011 (Act 815). The 2021 total domestic tax revenue collections amounted to 13.85 percent of non-oil gross domestic product, up from the 12.55 percent recorded in 2020.[247] The slight increase in tax to GDP ratio in 2021 was to be expected following the introduction of several new tax policies and administrative measures introduced in the 2021 budget statement. Despite this increase, the 2021 tax-to-GDP ratio is still low compared to the sub-Saharan average of 16.5 percent and is still much below the Ghana CARES target of 18-20 percent.

Total domestic tax revenue in 2021 increased by 27.8 percent in nominal terms when compared to collections in 2020. However, nominal figures do not account for inflation, and this is problematic because inflation erodes the value of money over time. To capture the changing value of domestic tax revenue, real growth rates should be used to compare collections over time. Adjusting for inflation, total domestic tax revenue increased by 13.5 percent in real terms between 2021 and 2020 and this represents a significant improvement from the negative real growth in collections recorded in 2020 and by far the largest real growth recorded for the past five years (2017-2021), as shown in Fig. 46.

[246] The Energy Sector Recovery Levy (ESRL) and Sanitation and Pollution Levy (SPL) were new tax measures that was introduced by Government in 2021

[247] The non-oil tax-to-GDP ratio is the ratio of non-oil tax revenue to non-oil GDP. Non-oil tax revenue excludes all receipts from upstream domestic oil production (royalties and corporate tax), and some Energy Sector levies.

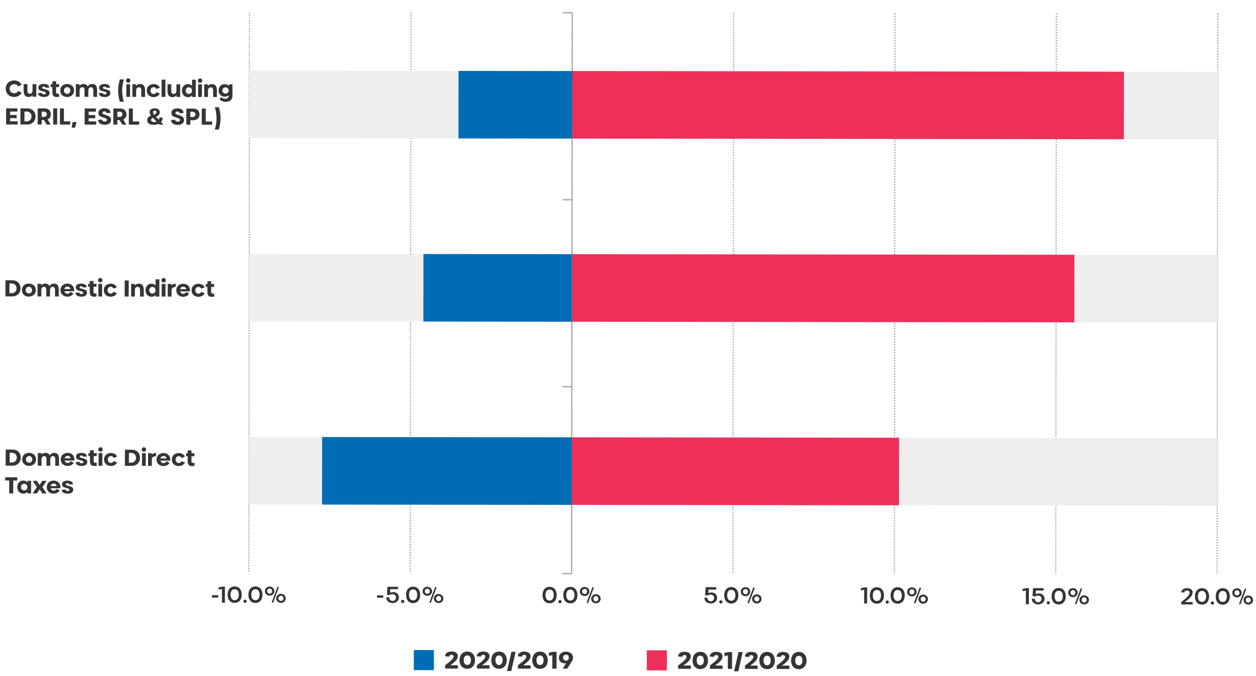
Figure 46: Nominal and real growth in total domestic collections, 2017-2021.



Source: Ghana Statistical Service (CPI), Ghana Revenue Authority (Tax revenue)

Figure 39 breaks down the real growth rate of total domestic tax revenue into the three main tax types, namely, domestic direct taxes, domestic indirect taxes and customs taxes (that include EDRL, ESRL & SPL). Domestic direct and indirect tax collections increased by 10 percent and 15.6 percent in real terms, respectively, in stark contrast to negative growth in collections recorded in 2020 (7.7 percent and 4.6 percent respectively). Customs collections in 2021, also increased in real terms by 17.1 percent. This was a significant improvement in the negative real growth of 3.5 percent recorded in 2020.

Figure 47: Real year-on-year growth in tax types (2020/2019) and (2019/2018).



A more useful indicator of tax performance is the extent to which collections exceed or fall short of revenue targets (normally set by the Ministry of Finance for Ghana Revenue Authority, taking into account inflation, policy reforms and administrative changes that could affect the country's revenue potential). Comparing the 2021 actual tax revenue collections of GH¢60.63 billion to the 2021 budget target of GH¢60.19 billion, GRA recorded an above-target collection of GH¢ 0.45 billion in absolute figures or 0.7% in percentage terms. Table 21 provides a detailed breakdown of actual and target collections in 2021 by tax type.

Domestic direct taxes recorded a negative deviation of 0.5 percent, indicating a below-target collection of GH¢ 0.13 billion. This under-collection was mainly driven by poor performance in collections from self-employed personal income tax, Company taxes, other direct taxes[248], mineral royalties and National Fiscal Stabilization Levy (NFSL). The suspension of VIT and Tax Stamp payments for the second, third and fourth quarters in 2021 and the delay in payment of District Assemblies Common Fund (adversely affected withholding tax payments usually made by MMDAs that contributes to self-employed taxes) accounted for the below target collections in self-employed personal income taxes.

Despite the poor performance of domestic direct taxes in general collections from Pay as You Earn (PAYE), airport tax and the financial sector recovery levy exceeded their target by 6.7 percent, 81 percent and 19.9 percent, respectively. The strong performance of PAYE was attributed to the increase in filed compliance activities at the various taxpayer service centres which enhanced compliance and the increase in the average monthly PAYE payments in December as a result of taxable benefits paid to staff, especially from the mining sector and reassessment of the remuneration of Directors and expatriates. Also, the easing of the COVID-19 restrictions (reopening of Ghana's air borders to international travel on 1st September 2020) allowed businesses and travel to continue as usual and this contributed, in part, to the strong performance of airport tax collections in 2021.

Domestic Indirect taxes also recorded a negative deviation of 1.5 percent or, to put it in context, collections from this tax type recorded a collection shortfall of GH¢0.20 billion. This collection shortfall was mainly driven by the poor performance of collections from excise taxes, Communication Service Tax (CST), Covid-19 Health Recovery Levy (Standard levy) and special petroleum taxes. Collections from domestic VAT, domestic NHIL, domestic GET Fund Levy and Covid-19 Health Recovery Levy (Flat rate), on the other hand, recorded positive deviations of GH¢0.25 billion, GH¢0.05 billion, GH¢0.05 billion and GH¢ 0.15 billion, respectively.

Collections from Customs taxes were above their target by 4.2 percent or GH¢0.78 billion in absolute terms. The relatively good performance in customs collection was mainly driven by the good performance of import duties and levies, import VAT, petroleum taxes and Energy Debt Recovery Levy. Import NHIL, Import GET Fund Levy, Import Covid-19 Health Recovery Levy, Energy Sector Recovery Levy and Sanitation and Pollution Levy, on the other hand, recorded below target collections. In general, the positive growth of 0.4 percent in the economy in 2020[249] coupled with the introduction of new tax policies and administrative measures in 2021, explain the above target collections of domestic tax revenue in 2021.

[248] This includes rent tax, management, and technical service fees, and tax stamps.

[249] Ghana was among the few countries in the world to record a positive growth rate in the economy.

Table 21: Actual and target domestic tax revenue (2021).

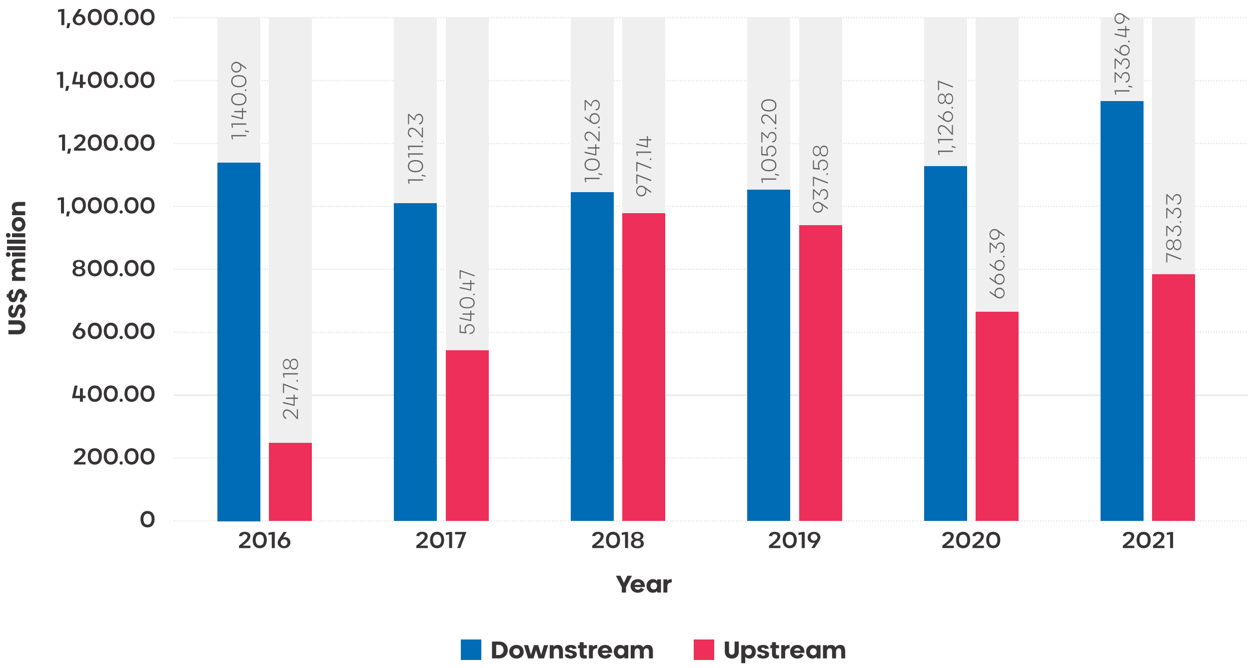
Type	Actual (GH¢ m)	Target (GH¢ m)	Deviation (GH¢ m)	Deviation %
Domestic Direct	**27,597.00**	**27,730.11**	**(133.11)**	**(0.5)**
PIT – PAYE	9,723.55	9,114.86	608.69	6.7
PIT – Self-Employed	491.45	626.52	(135.07)	(21.6)
Companies	14,479.64	14,734.56	(254.92)	(1.7)
Other direct	227.16	375.00	(147.84)	(39.4)
Mineral royalties	1,369.04	1,732.91	(363.87)	(21.0)
Airport tax	359.88	198.78	161.10	81.0
NFSL	683.49	728.39	(44.90)	(6.2)
Financial Sector Recovery Levy	262.78	219.09	43.69	19.9
Domestic indirect	**13,749.86**	**13,952.18**	**(202.32)**	**(1.5)**
Domestic VAT	6,905.22	6,653.76	251.46	3.8
Excise	526.48	696.72	(170.24)	(24.4)
Domestic NHIL	1,446.24	1,393.57	52.67	3.8
Domestic GET Fund Levy	1,446.24	1,393.57	52.67	3.8
CST	428.73	607.67	(178.94)	(29.4)
Covid-19 Health Recovery Levy (Flat Rate)	285.30	138.90	146.40	105.4
Covid-19 Health Recovery Levy (Standard Rate)	372.81	448.70	(75.89)	(16.9)
Special Petroleum Tax	2,338.84	2,619.29	(280.45)	(10.7)
Customs	**16,086.52**	**15,373.28**	**713.24**	**4.6**
Import duties and levies	6,871.67	6,613.52	258.15	3.9
Import VAT	4,857.03	4,460.62	396.41	8.9
Import NHIL	919.17	980.31	(61.14)	(6.2)
Import GET Fund Levy	919.90	994.98	(75.08)	(7.5)
Import Covid-19 Health Recovery Levy	251.06	301.47	(50.41)	(16.7)
Petroleum taxes	2,267.68	2,022.38	245.30	12.1
Total tax revenue	**57,433.38**	**57,055.57**	**377.81**	**0.7**
Energy Debt Recovery Levy	2,373.89	2,158.29	215.60	10.0
Energy Sector Recovery Levy	566.09	666.26	(100.17)	(15.0)
Sanitation and Pollution Levy	264.82	311.66	(46.84)	(15.0)
Grand total	**60,638.17**	**60,191.78**	**446.40**	**0.7**

6.8 Downstream and Upstream Sectors Contribution to Domestic Revenue

The 2021 fiscal year witnessed 18.21% growth in revenue contribution by both the Downstream and Upstream sectors of the Country from USD1,793.26 million in 2020 to USD2,119.82 million in 2021. The downstream sector's revenue contribution to the national kitty saw a nominal growth of 18.6% in 2021 (2021: USD1,336.49 million, 2020: USD1,126.87 million), whilst the upstream sectors recorded a nominal growth of 17.55% (2021: USD783.33 million, 2020: USD666.39 million) in revenue contribution to the State.

The dominance of the downstream sector over the upstream in revenue contribution to the State was largely enforced in 2021. Kindly see Figure 48.

Figure 48: Official Tax Losses (Accounted Vs Unaccounted).



Chapter

7

MARKET REVIEW

Market Review

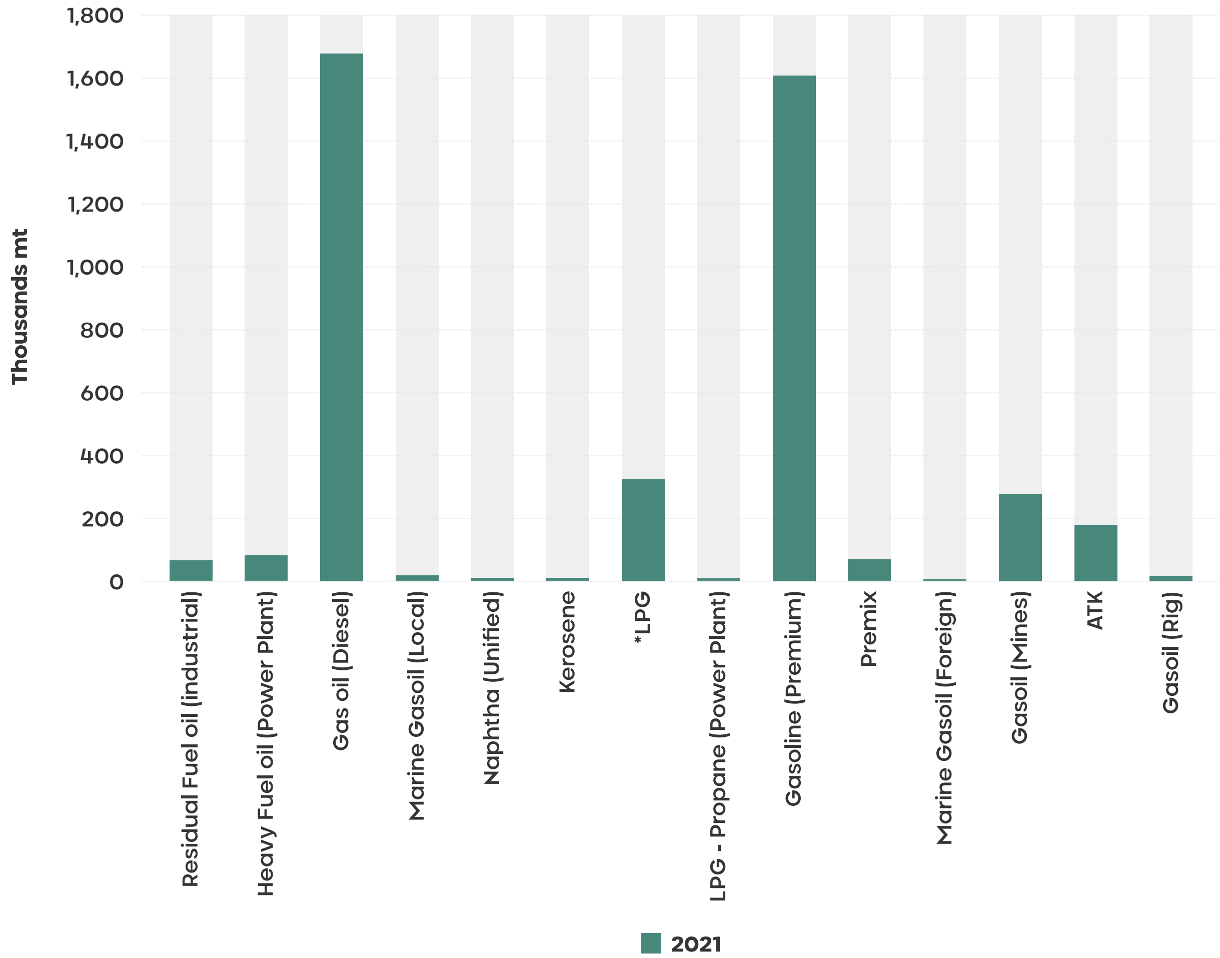
7.1 National Consumption

Ghana's gross national consumption[250] recorded 4.64 mn mt in 2021. This is 8.92% increase from the 4.26 mn mt consumed in 2020 compared to 4.06 mn mt consumed in 2019. A total of 4.55mn mt was consumed by the non-power sector, representing 98% of the gross consumption, while 2% was consumed by the power sector (fuel oil for power). The 4.55 mn mt consumed by the non-power sector was a 10% increase from the 4.14 mn mt consumed in 2020. Therefore, the 10% increase in gross national consumption was a result of the increase in consumption by the non-power sector. AKSA remained the only power plant that consumed HFO in 2021. The Covid-19 pandemic which had its peak in 2020 was observed not to have negatively impacted consumption as national consumption of petroleum products went up by close to 4% in 2020.

The 10% growth in the consumption by the non-power sector was due to the increase in consumption for Gasoline, Gasoil, Residual Fuel, Marine Gasoil (Foreign), Premix, ATK, Gasoil (mines), and LPG Domestic. This consumption volume is the highest observed to date. However, Kerosene, Gasoil Rig, MGO Local, and MGO (Rig) saw drops in their consumption relative to the previous year. MGO Local dropped by 55% from 2020 to 2021, whilst Gasoil Rig also decreased by 8% from 2020 to 2021. ATK witnessed a significant increase in volume consumed after recording a drastic decrease in 2020 due to the outbreak of the COVID-19 pandemic (see Figure 49).

[250] Gross national consumption is the sum of petroleum products (including the fuel by the power generation companies consumed in 2021.

Figure 49: Petroleum product consumption (2021)

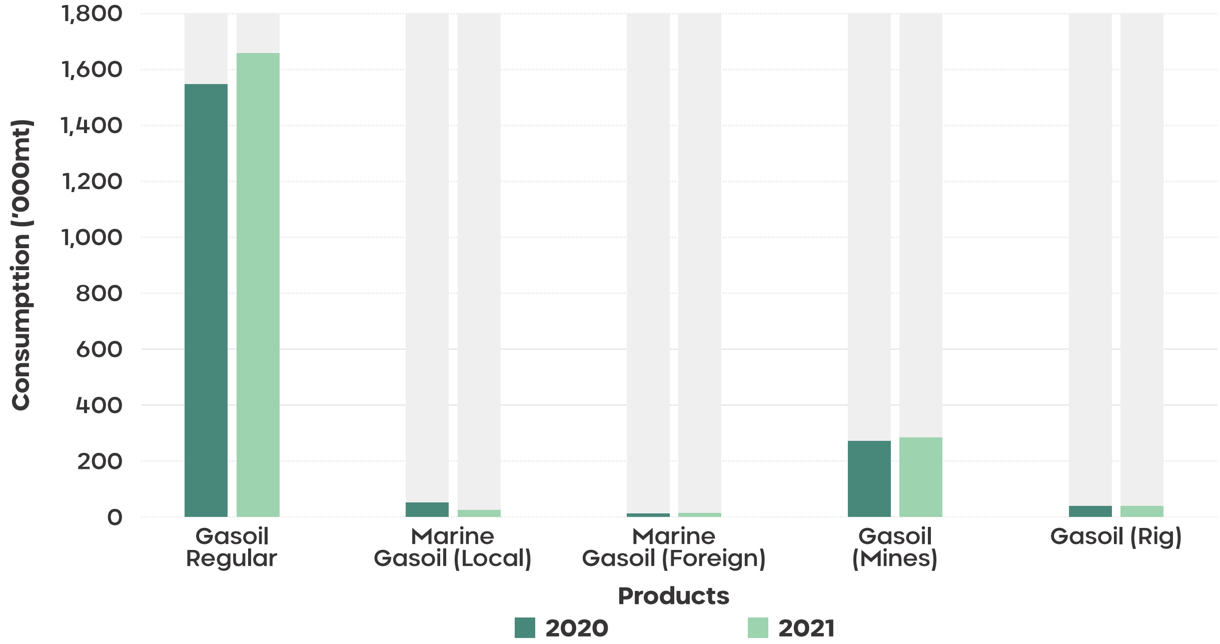


7.1.1 Gasoil

Gasoil remained Ghana's largest consumed product for 2021 and 2020. Its consumption increased to 2.13 mn mt in 2021 from 2.02 mn mt recorded in 2020 and 1.91 mn mt in 2019. This represents a 5.41% and 5.82% increase in 2021 and 2020, respectively. The increase in 2021 was driven by the surge in the consumption of gasoil regular and marine gasoil (Foreign) by 7.21% and 31.57%, respectively. Consumption of MGO Local and MGO Rig in 2021, however, fell by 54.58% and 7.96%, respectively, from 46,079 mt and 33,665 mt in 2020 to 20,928 mt and 30,985 mt in 2021 (see Figure 50). The 5.82% increase in 2020 volumes was occasioned by gasoil regular and MGO local, which increased by 9.09% and 79.05%, respectively. However, MGO foreign and MGO rigs fell by about 27.46% and 55.67%, respectively, compared to 2019 volumes.

Gasoil consumption for 2020 and 2021 is presented in Figure 50.

Figure 50: Gasoil Consumption (2020 and 2021)



The increment in the consumption of gasoil regular corresponds with the 33.08% and 25.90% increase in the number of gasoil-driven vehicles (mining equipment excluded) registered in 2021 over 2020 and 2020 over 2019 respectively. Gasoil-driven vehicles account for about 28% of the total registered vehicles in the country as of the end of 2020 and 2021. The number of gasoil-driven vehicles (mining equipment excluded) increased by 11,581 in 2020 and 18,623 in 2021, bringing the total number of gasoil-driven vehicles (mining equipment excluded) in the country to 472,317 in 2020 and 549,749 in 2021. This implies that the average gasoil-regular consumption fell from 4,303.89 litres in 2019 to 4,135.38 litres in 2020 and 3,826.58 litres in 2021. This is because as the total number of gasoil driven vehicles (mining equipment excluded) grew by 32% from 2019 to 2021, the corresponding consumption of gasoil regular grew by only 17%.

The relatively higher consumption per vehicle of gasoil regular compared to gasoline shows how heavily dependent Ghana's mass and goods transportation system is dependent on gasoil.

Figure 51: Trend of Gasoil Consumption (2016-2021)

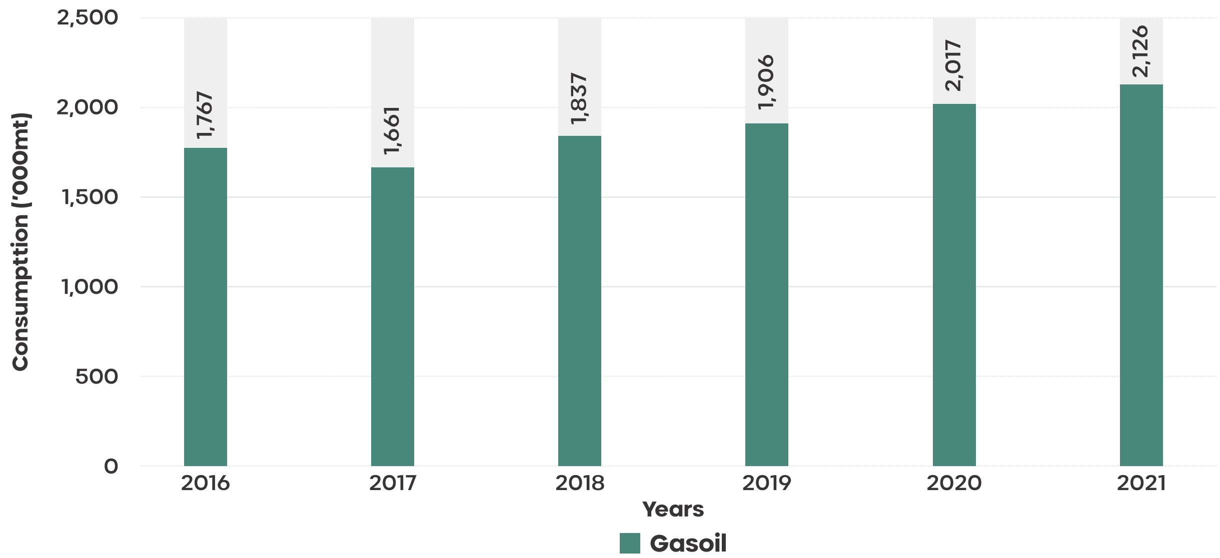
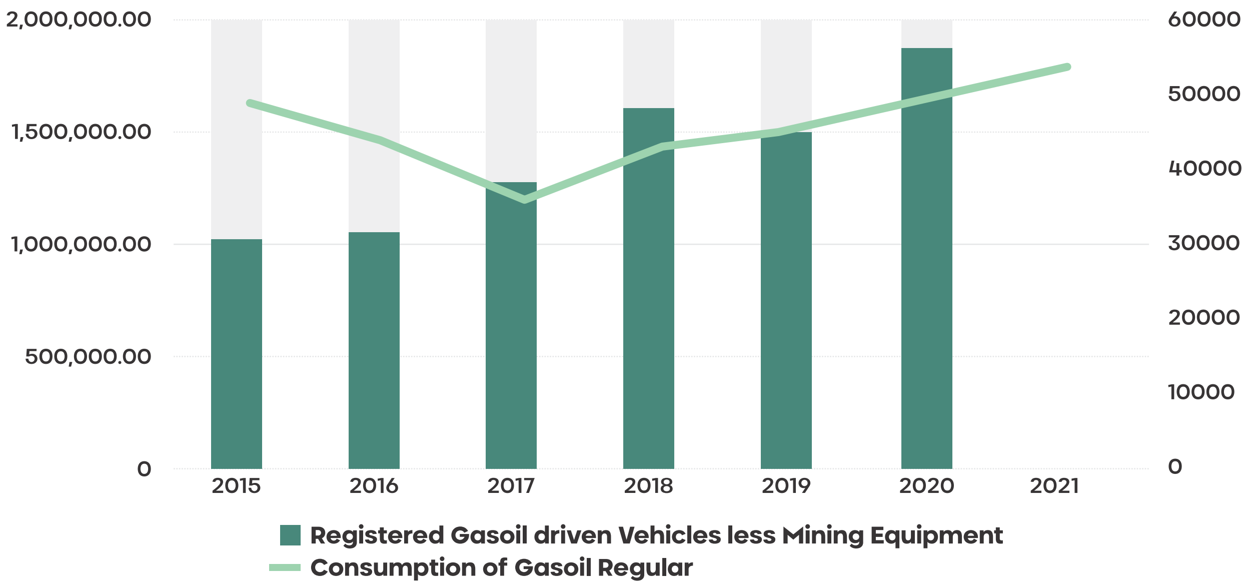


Figure 52: Gasoil Regular consumption vs Registered Gasoil-Driven vehicles



7.1.2 Gasoline

Total gasoline consumption increased to 1.71 mn mt in 2021 from 1.53 mn mt in 2020. This represents a 12.10% year-on-year growth, as compared to the 13.47% increase seen in 2020 when consumption rose to 1.53 mn mt from 1.26 mn mt in 2019.

The increase in consumption of gasoil and gasoline, among others, could also be attributed to the increase in the total number of vehicles registered in 2021. The number of vehicles registered by the DVLA increased by 204,420 in 2020 and 272,181 in 2021. This marked an increase of 22% and 33% for 2020 and 2021, respectively.

Gasoline vehicles remained the most dominant in Ghana accounting for 72% of all registered vehicles and remain the primary fuel for private transportation and small-size public transportation (Taxis, Tricycles and Motorcycles). The annual average consumption of gasoline by each gasoline driven vehicle stood at 1,625.73 litres and 1,573.63 litres in 2020 and 2021, respectively.

Figure 53: Consumption of gasoil and gasoline vis-à-vis Registered Vehicle

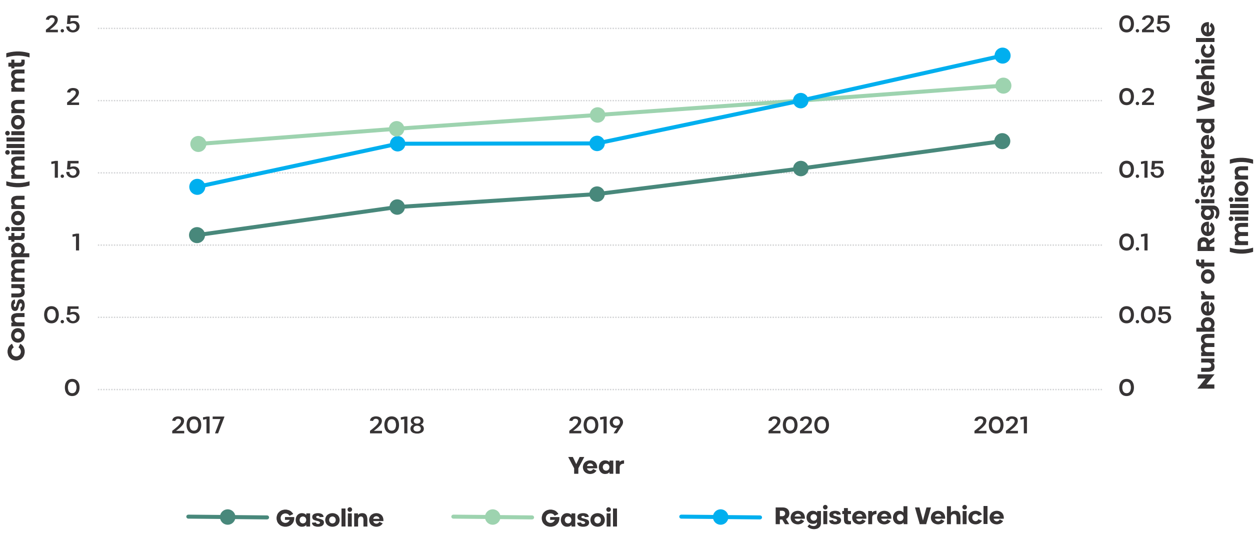


Figure 54: Gasoline Consumption

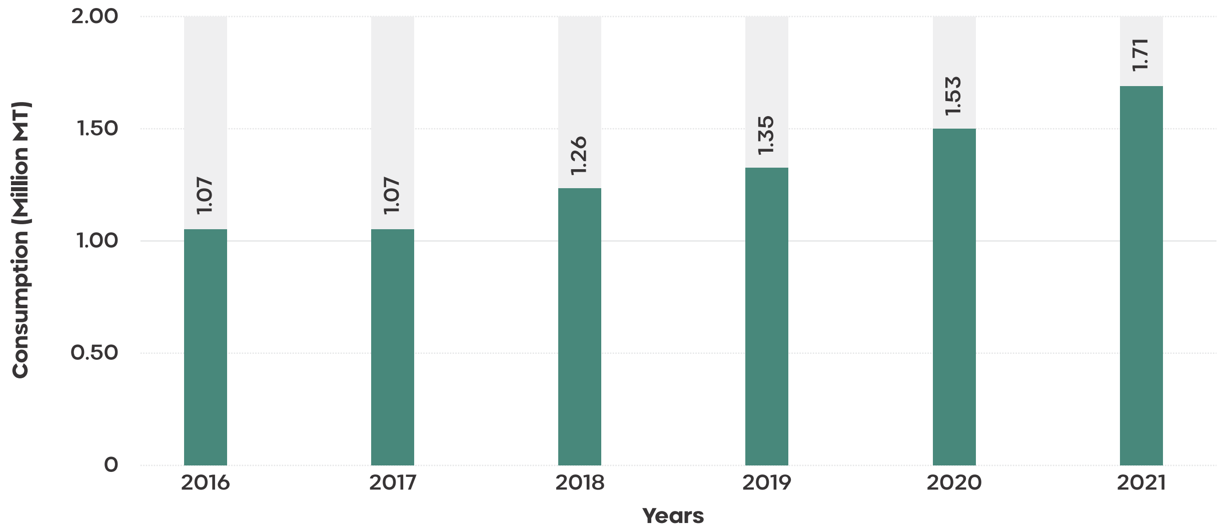
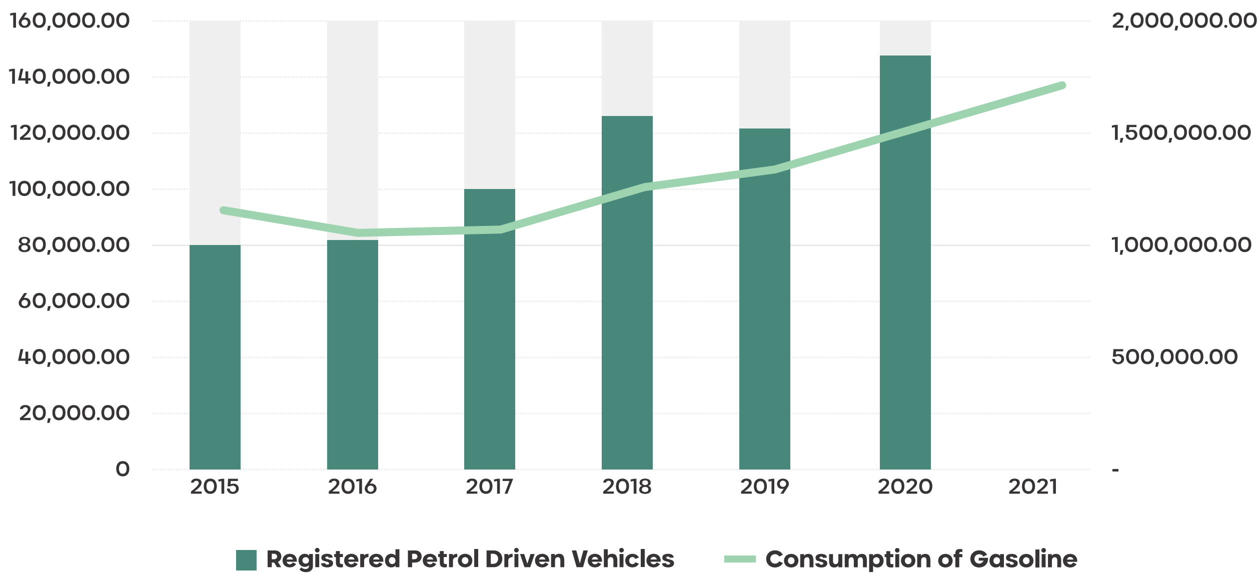


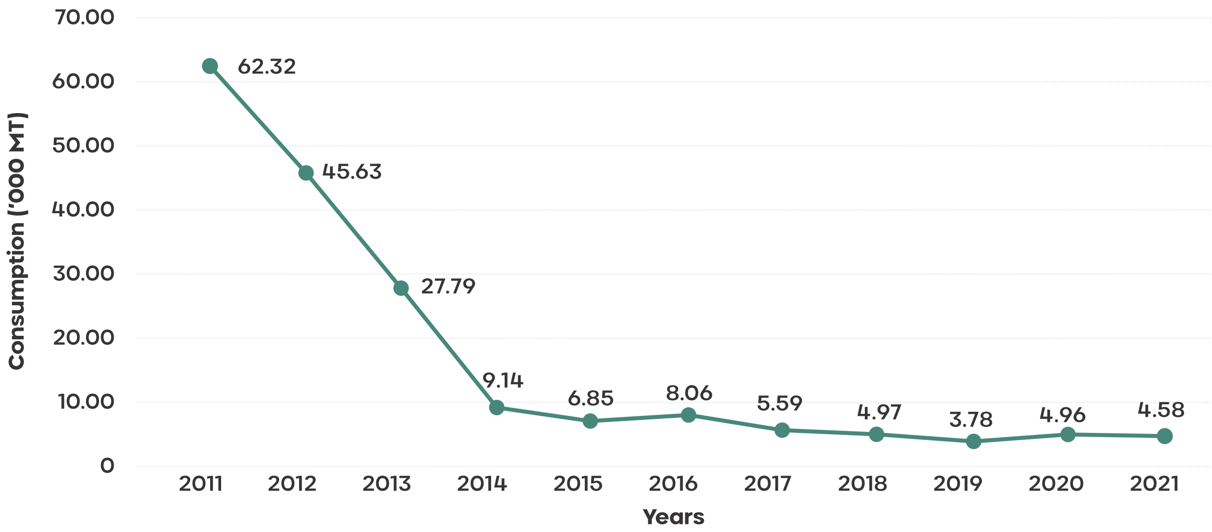
Figure 55: Trend of Gasoline regular consumption vs Registered Gasoline-driven vehicles



7.1.3 Kerosene

The consumption of kerosene declined by 7.53% to 4,585 mt in 2021, reflecting the downward trend witnessed over the years. A trend of the consumption of kerosene over the last 10 years (2011-2021) shows a peak in demand in 2011 at 62,315.01 mt, followed by a consistent fall in demand to 4,584 mt in 2021, even though there were some years where consumption witnessed an upward movement. The significant drop in the consumption of kerosene after 2011 is largely attributable to the reduction in the use of the product as an adulterant for gasoil after the NPA introduced the Fuel Marking Programme in 2012 and the removal of kerosene subsidy in 2013. Government's LPG Promotion policy, that seeks to replace the consumption of wood fuels with the use of LPG, also contributed to the significant fall in the consumption of kerosene over the years. The increasing urbanisation of the Ghanaian population also contributed to driving the switch from the use of kerosene to cleaner sources, such as LPG.

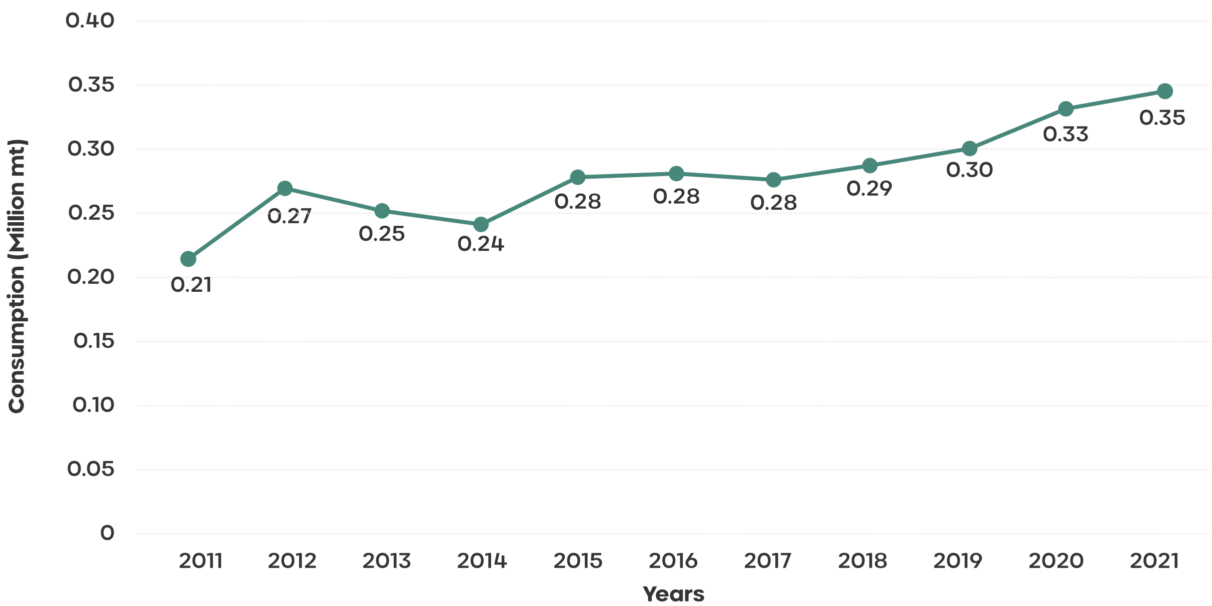
Figure 56: Kerosene Consumption (2011 -2021)



7.1.4 LPG

The consumption of LPG increased from 299,575 mt in 2019 to 332,370.37 mt in 2020 and further increased to 345,478.08 mt in 2021. Consumption of LPG increased by 3.94% between 2020 and 2021. The increase in consumption witnessed in 2021 was mainly due to an increase in domestic consumption of LPG which is a positive signal toward the achievement of the national LPG penetration goal of 50% in 2030.

Figure 57: Domestic LPG Consumption 2011-2021

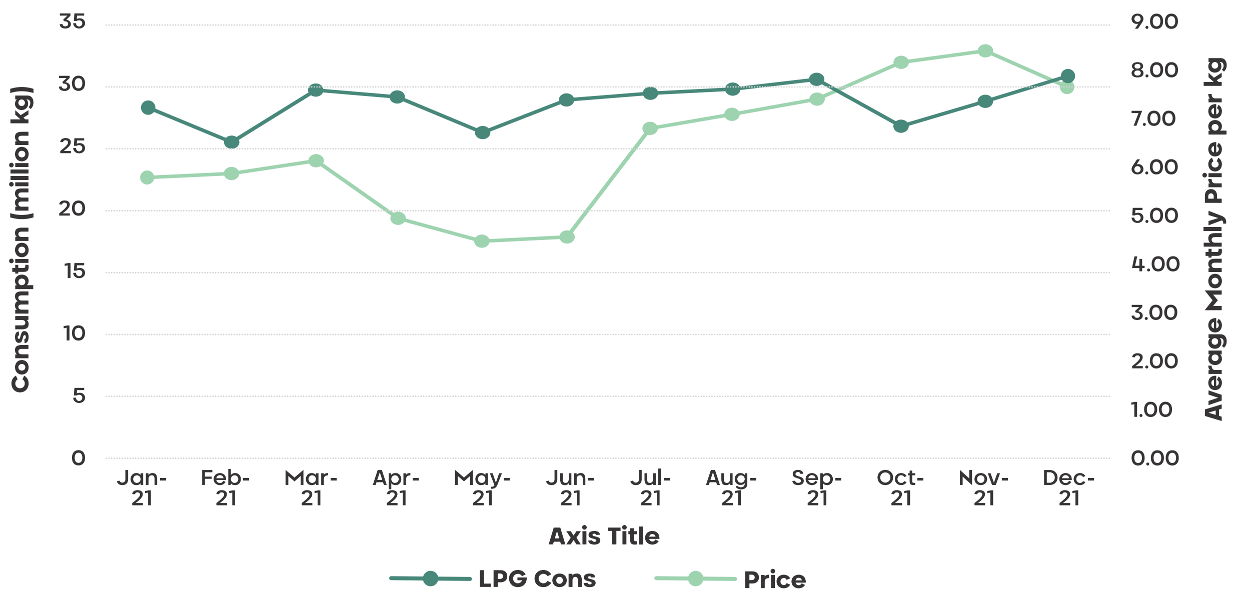


Further analysis of the consumption pattern relative to changes in price indicates that the consumption of LPG over the period increased against rising prices of LPG. For instance, in February 2021, whereas prices increased by 4.2 percent (from GHS5.95 to GHS6.20), consumption increased more than proportionate; by 16.8 percent (from 25.5 million kg to 29.8 million kg). A similar trend was observed from July 2021 to September 2021. A monthly calculation of price elasticity of demand for LPG using 2021 LPG price and consumption data indicates that on the average, LPG is price elastic (1.958). Table 22 shows that the price elasticity of demand for LPG in the month of February, March, May, June, October, and November were more than 1, thus, indicating LPG consumption is price elastic. The Table also shows that for the rest of the months, LPG consumption has been price inelastic. However, on an annual basis, as the average LPG consumption increased by 4 percent from 2020 to 2021, the corresponding price increment was 37%, indicating price inelasticity of LPG demand. Moreover, an analysis of the quarterly LPG consumption and price data for 2021 indicates that LPG demand is price inelastic. These suggest that, though the price may be one of the key determinants of LPG consumption, other behavioral factors come into play. A simple correlation carried out by plotting the monthly consumption of LPG vis-à-vis average monthly price indicates increasing consumption with increasing price. The correlation coefficient for LPG price and its consumption in 2021 (0.259) is a further indication that an increase in LPG prices may not necessarily reduce the demand for LPG, given that several other variables affect LPG consumption other than price.

Table 22: Elasticity of demand for LPG

	Consumption	Price	Percentage change in price	Percentage change in consumption	Elasticity of Demand
Jan-21	28,394,900	5.83	-	-	-
Feb-21	25,581,970	5.95	1.97%	-9.91%	5.336
Mar-21	29,848,970	6.20	4.29%	16.68%	3.666
Apr-21	29,289,620	5.00	-19.44%	-1.87%	0.088
May-21	26,311,790	4.52	-9.61%	-10.17%	1.061
Jun-21	29,123,230	4.59	1.66%	10.69%	6.157
Jul-21	29,619,710	6.86	49.35%	1.70%	0.043
Aug-21	29,911,090	7.17	4.52%	0.98%	0.221
Sep-21	30,741,480	7.49	4.47%	2.78%	0.627
Oct-21	26,882,613	8.24	10.09%	-12.55%	1.395
Nov-21	28,825,640	8.51	3.22%	7.23%	2.204
Dec-21	30,947,062	7.73	-9.11%	7.36%	0.743

Figure 58: Relationship between LPG Consumption and Average Monthly Price of LPG



7.1.5 Premix Fuel

Premix Fuel consumption increased marginally from 76,821 mt in 2020 to 78,594 mt in 2021. This indicates a 2.31% increase, relative to the 41.20% increase witnessed in 2020 when consumption of the product rose to 76,821 mt from 54,408 mt in 2019. Although Premix fuel consumption increased by 41.20% from 2019 to 2020, the total fish supply from the marine sector only increased by 5.7% from 309,319.66mt in 2019 to 326,867.55mt in 2020,[252] resulting in a less than proportionate increase in the output of marine fish production compared to Premix usage. A cursory review calls into question the advisability of continued subsidy on premix fuel as there is little effect on the resultant productivity.

Figure 59: Premix Consumption chart (2011-2021)

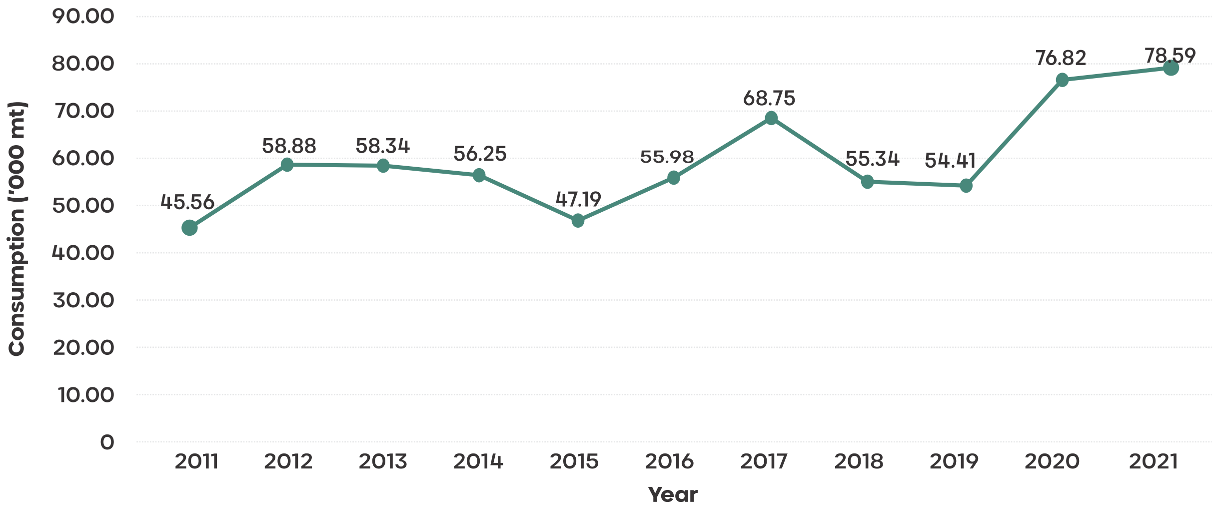
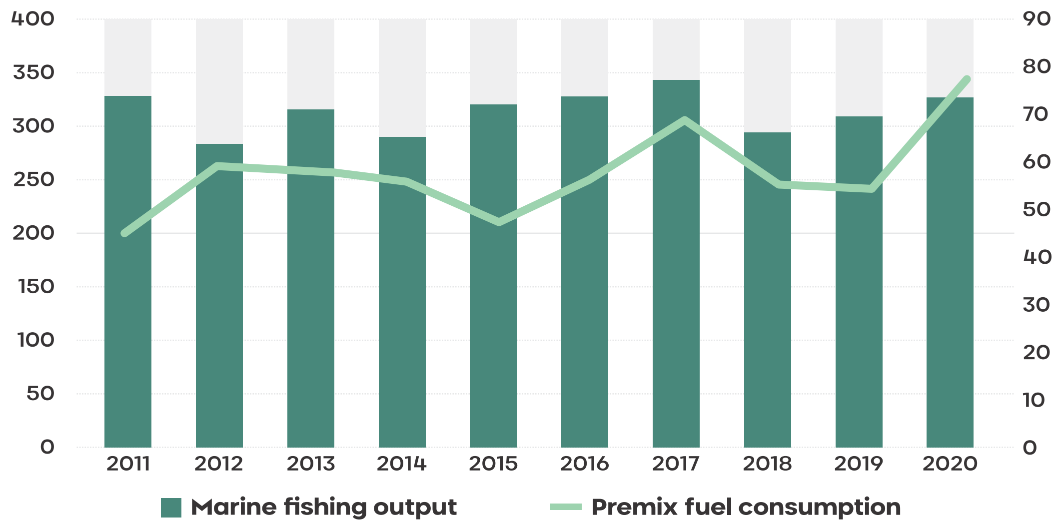


Figure 60: Marine fishing output vs Premix Fuel Consumption



7.1.6 Fuel Oil

Consumption of fuel oil declined from 174,416 mt in 2019 to 118,137 mt in 2020. At the end of 2021, fuel oil increased by 42.75% to 168,642 mt. This increase was driven solely by the significant increase in the consumption of heavy fuel oil by both industries and power plants, which witnessed upward increases of 64.07% and 27.99%, respectively, in 2021. Fuel oil consumption in 2021 comprised 89,325 mt (52.97%) of heavy fuel oil for power generation and 79,317 mt (47.03%) of residual oil for industries.

[252] Ministry of fisheries and acqua-culture development – 2020 annual progress report.

Figure 61: Fuel Oil Consumption-2021

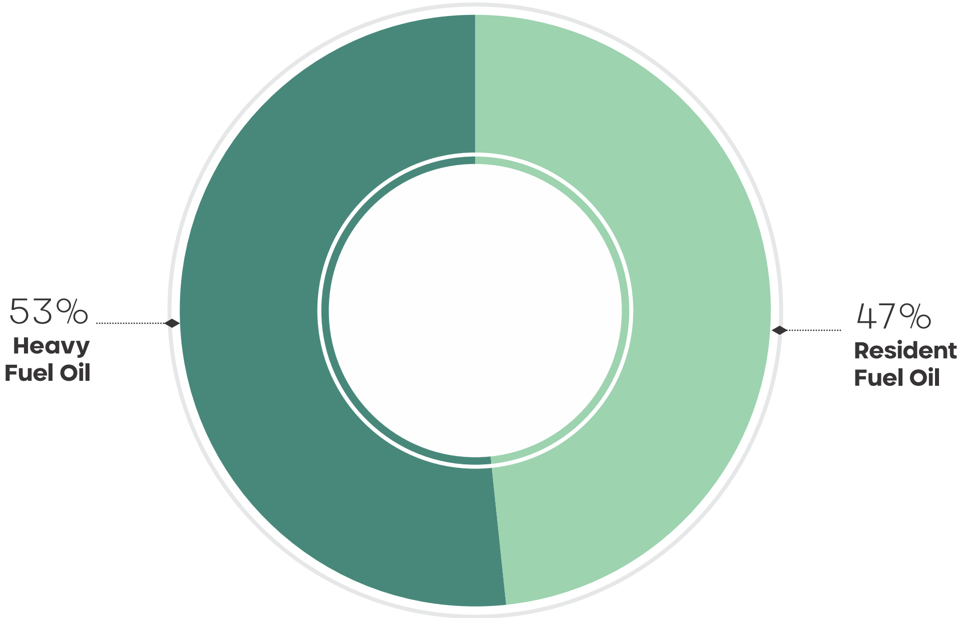
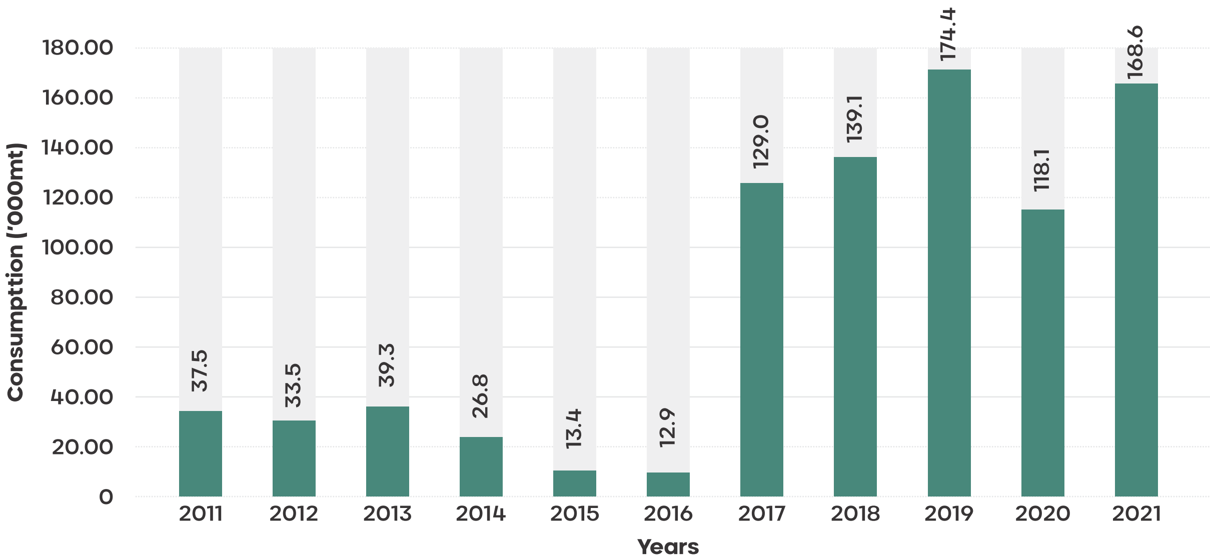


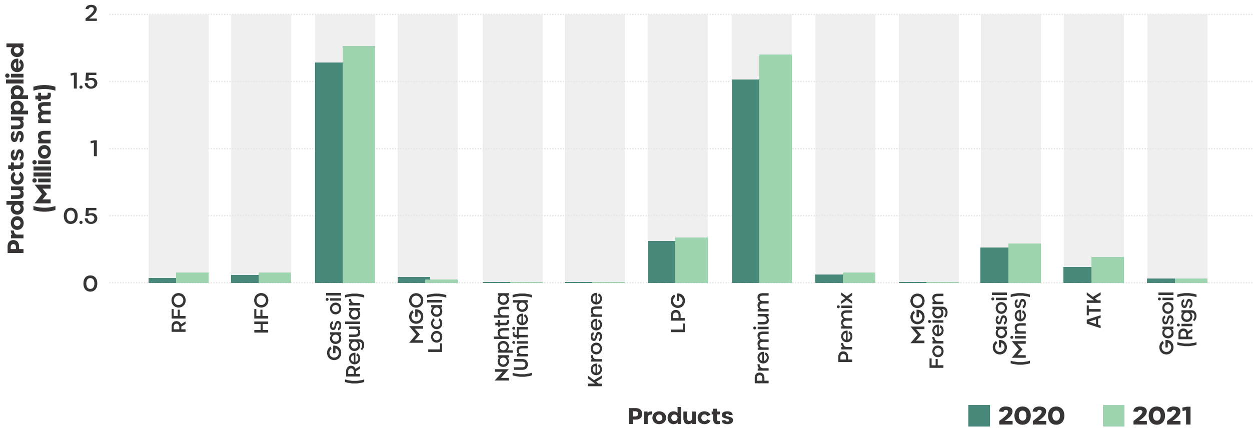
Figure 62: Fuel Oil Consumption (2011-2021)



7.2 OMC/LPGMCs Performance

A total of about 4.21 mn mt of petroleum products were sold to the local market in 2020 compared to 4.02 mn mt in 2019. This increased by 10.26% in 2021 to 4.64 mn mt. The surge in sales was driven largely by increases in the sole of gasoline, gasoil regular, Domestic LPG, Premix Fuel Industrial Residual Fuel Oil (RFO), ATK, HFO, MGO Foreign and Gasoil Mines. The supply of MGO Local, Kerosene, Gasoil (Rig), Naphtha in 2020, however, contracted (see Figure 63). The significant increase in the volume of ATK supplied is attributed to the easing of international travel restrictions.

Figure 63: Product Performance



Out of a total of 230 registered OMCs/LPGMCs in 2021, 69 sold products above 10,000 mt, while 115 sold volumes below 10,000 mt, with about 45 companies being inactive as compared to 37 companies in 2020. A lot of these seeming dormant companies are said to be indebted to GRA.

The top 25% (first quartile) LPGMCs/OMCs accounted for about 89.27% of the total market share, the second quartile accounted for 8.70%, while the 3rd and 4th quartiles accounted for 2.10% and 0.02%, respectively. Even though GOIL's dominance in the retail market continued for the 7th year running, its market share continued to decline since 2019. In 2019, GOIL commanded about 17.28% of the total market. However, its total market share declined to 15.50% in 2020 and further declined to 15.26% in 2021. The decline in the total market share could be attributed to the surge in the total number of OMCs/LPGMCs in 2020 and 2021, as well as the increased market shares of other OMCs/LPGMCs (Puma, Star and Tel energy) which increased the total quantity of petroleum products supplied to the local market, thus, reducing the market share of GOIL. GOIL's total petroleum products supplied to the local market increased by 9% but its market share declined by 0.24%. GOIL did not trade in Fuel oil in 2021, thus losing its market share in that regard. The figure below also shows that GOIL has been dropping market shares in the sales of gasoline, gasoil and LPG since 2019.

Figure 64: Goil's Market share by product

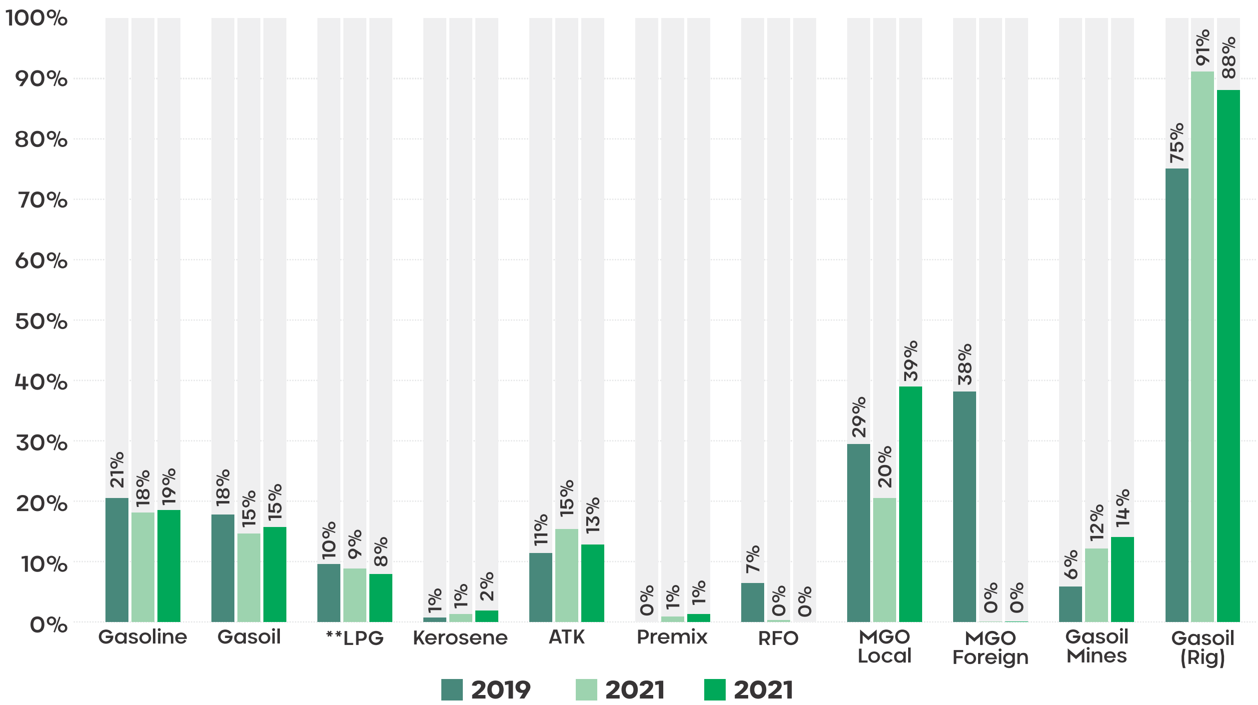
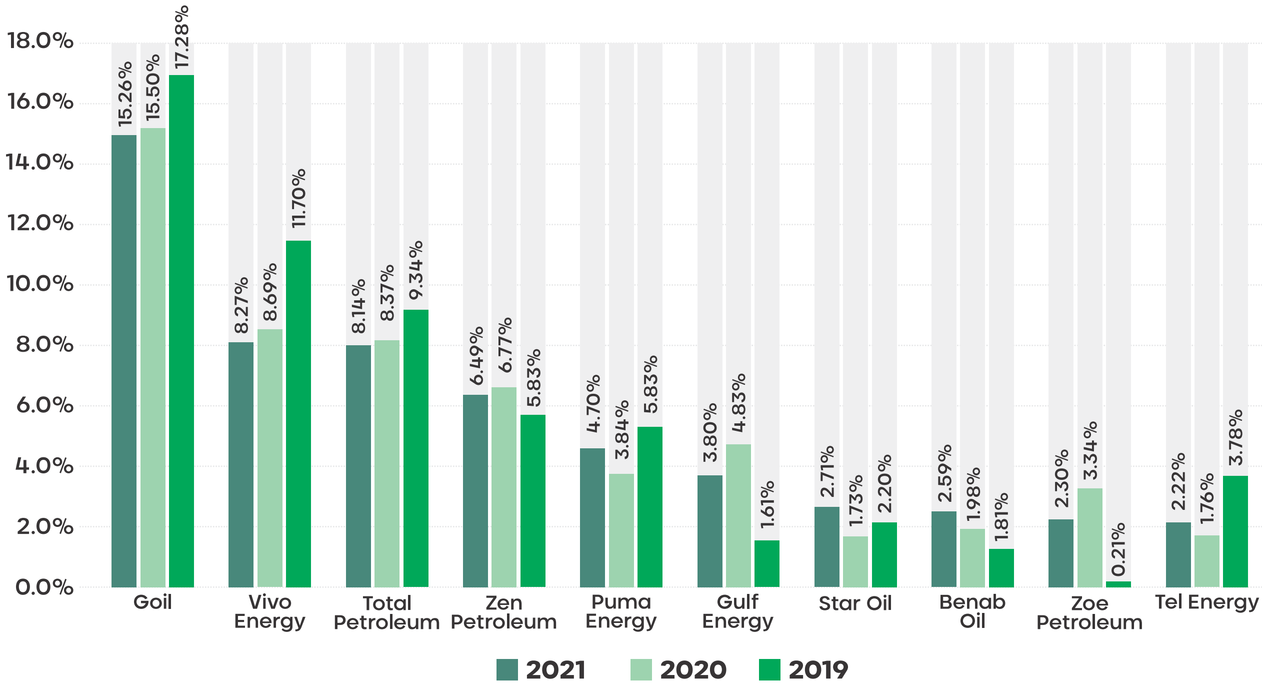


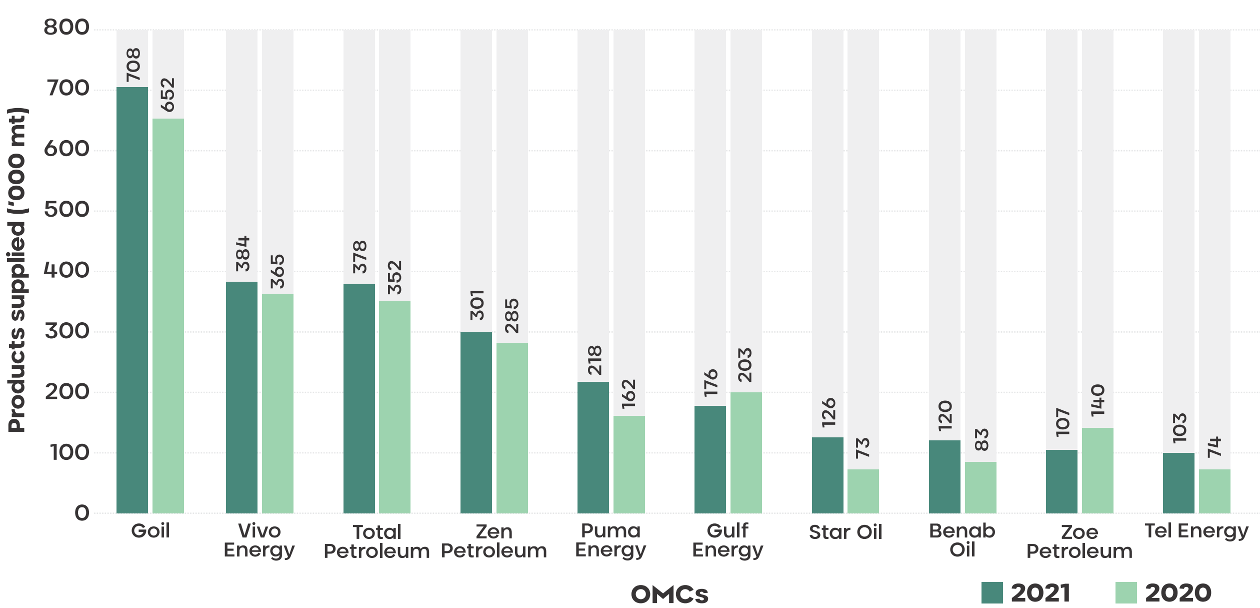
Figure 65: Market shares of Top 10 OMCs



The top 10 OMCs for 2021 saw Tel Energy and Star Oil replacing Q8 Oil (GH) and Santol. Puma Energy, which ranked 6th in 2020, displaced Gulf Energy, which ranked 5th in 2020, to rank 5th in 2021.

Although both the total volumes of products sold and the volumes sold by the top 10 OMCs in 2021 witnessed a 10.33% and 5.40% increase over their 2020 volumes, four out of the top 10 OMCs (GOIL, Vivo, Total and Puma) witnessed a 6.62%, 5.07%, 7.38% and 5.75% increase in volumes sold in 2021. New entrants (Star Oil and Tel Energy), however, witnessed a very significant surge in their 2021 volumes: Star Oil's sales of gasoline and gasoil went up by 93% and 64%, respectively. Tel Energy, on the other hand, witnessed a significant increase in the sale of HFO by 88,101 mt in 2021. This suggests that the new entrants contributed greatly to the increased sales by the top 10 OMCs in 2021 vis-à-vis 2020.

Figure 66: Top 10 OMCs by Volumes Sold (2021 vs 2020)



The 2021 gasoil mines market remained highly oligopolistic, with 3 main players (Zen Petroleum, Gaso Petroleum and GOIL) selling parcels above 20,000 mt each. The other 6 players sold volumes below 8,000 mt. This also means that the number of players in this market increased from 6 in 2020 to 10 in 2021. Of the 297,136 mt volumes of gasoil mines sold in the year under review, Zen Petroleum's sales constituted 69.79%; Gaso Petroleum had a 13.60% share, while GOIL had a 13.99% share of the market. These three players jointly command a 97.38% market share. Thus, the market is dominated solely by local players. This dominance of local players is attributed to the Ghanaian Content and Participation Policy which grants the mining companies some tax exemptions reliefs when they lift from a wholly-owned Ghanaian company.

Zen Petroleum, the leading marketer of gasoil mines, decreased its market share from 73.94% in 2020 to 69.79% in 2021. This could be attributed to the increased number of OMCs that supplied gasoil to the mines. While in 2020, 6 OMCs supplied gasoil to the mines, the number increased to 10 in 2021, thereby reducing the share of Zen Petroleum. Zen has consistently dominated the market for the sale of gasoil to the mines since 2014, after replacing Total Petroleum as the largest marketer of gasoil to the mines.

The advent of the Ghanaian Content and Participation Policy which gave a strong backing to companies with 100% Ghanaian ownership contributed to the surge in the number of Ghanaian wholly-owned companies participating in the industry. It was expected that Zen Petroleum's dominance on the market will continue to increase, as projected by the 2019 Ghana Petroleum Industry Report. This may, however, be threatened by competent local companies like Gaso, whose strategic relationship with Fueltrade may prove to be a worthy competitor to Zen.

Figure 67: 2021 Gasoil Mines Market Share Distribution

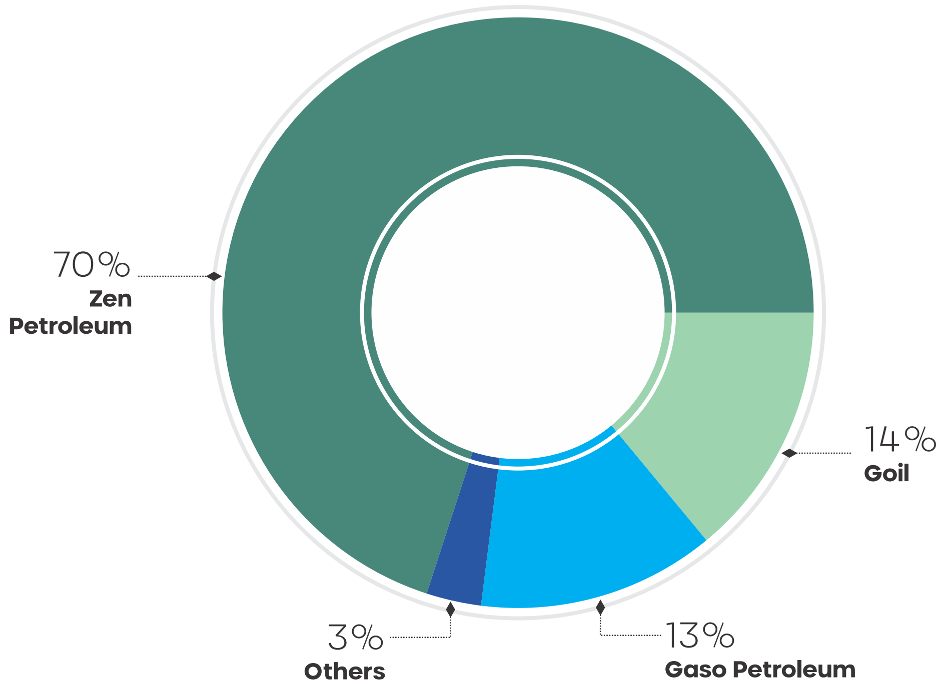
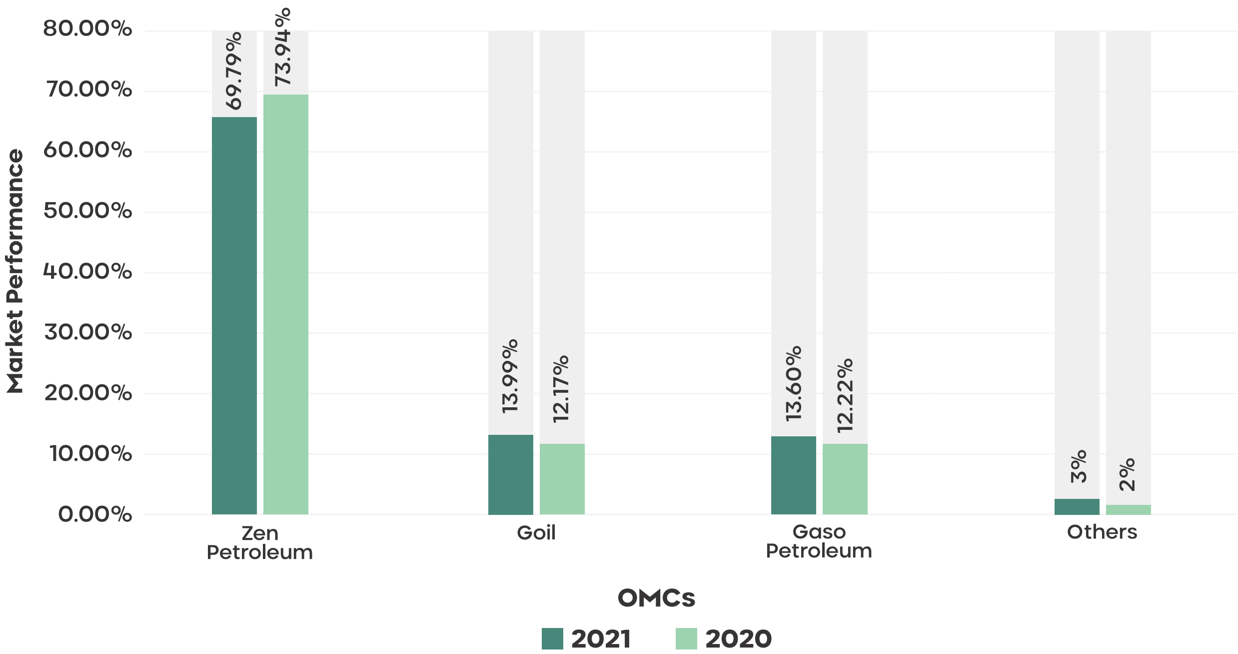


Figure 68: **Gasoil Mines Market Share (2021 vs 2020)**



7.3 BIDECs/Refinery Market

The BIDECs/Refinery market space saw the cumulative market shares of the top 10 decreasing from 78.48% in 2020 to 73.63% in 2021. The remaining BDCs controlled 26.37% of the market shares in 2021 relative to 21.52% in 2020. Also, the top 5 BDCs saw a decline in their grip on the market from 53.22% in 2020 to 48.84% in 2021. One BDC (Ebony Oil & Gas Limited) was inactive during the year, same as the 1 inactive BDC (Hask Oil Company Limited) in 2020.

Lemla Petroleum Limited lost its position in the top 10 largest distributors in 2021. The new entrant into the top 10 was Dominion International Petroleum Limited, with a market share of 6.28%, as against the 2.08% recorded the year before (2020).

Dominion International Petroleum Limited's break into the top 10 rode largely on the back of increased distribution of gasoil regular, gasoline and residual fuel oil unto the market. Overall, Dominion increased its products sale from 87,626 mt in 2020 to 291,454mt in 2021, representing a 232.61% increase.

Of the top 10 BDCs, GoEnergy, Juwel, Maranatha and Dominion saw a 15.84%, 10.40%, 7.13% and 6.28% rise in market shares in 2021 from 2020, respectively. The three local refineries together had a combined market share of 1.33% in 2021, equivalent to 61,850 mt. This was an improvement on their 2020 position of a 0.49% share of the market, equivalent to 20,751mt.

Year-on-year, Akwaaba Refinery's market shares rose to 1.20% in 2021 (equivalent to 55,849 mt) from 0.43% in 2020 (equivalent to 18,085 mt), representing a 208.81% increase in volumes supplied. Likewise, Tema Oil Refinery had its market shares increased to 0.03% in 2021 (equivalent to 1,494mt) from 0.004% (equivalent to 187mt) in 2020, representing 698.76% rise in volumes supplied. Also, Platon Gas Oil Refinery's market share increased to 0.10% (equivalent to 4,507mt) in 2021 from 0.06% (equivalent to 2,479mt) in 2020, representing an 81.79% rise in volumes distributed.

Figure 69: Top 10 BDCs (2021)

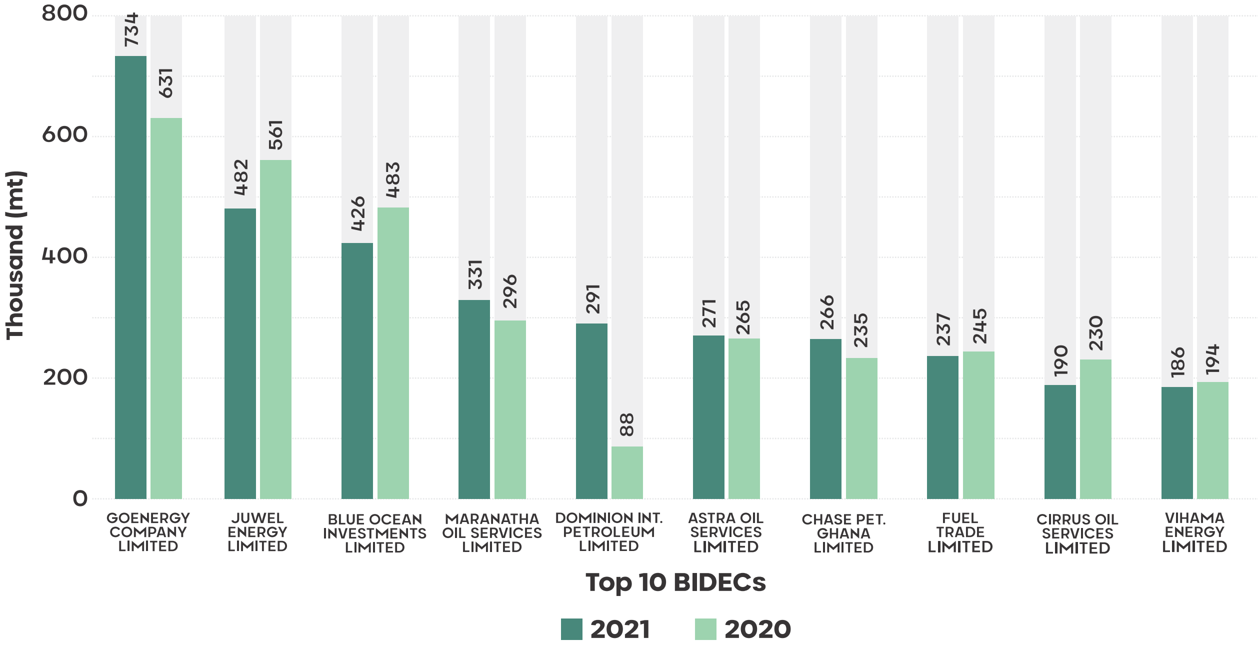
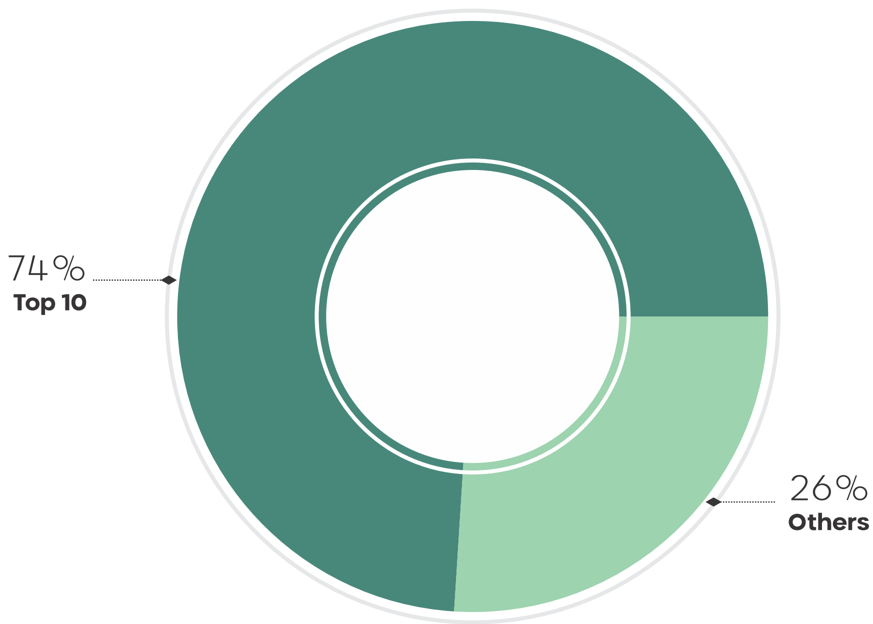
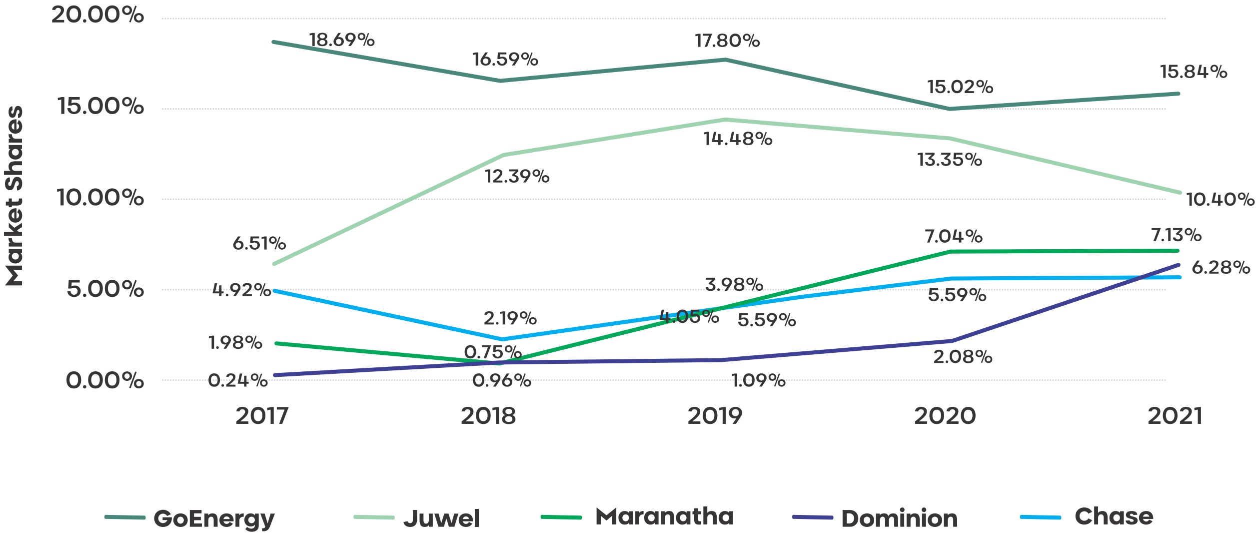


Figure 70: 2021 BDC Market Share – Top 10 vs Others



In 2021, only GoEnergy sold products above 500,000 mt; thirteen players sold products between 100,000 and 500,000 mt, while the rest sold products below 100,000 mt. GoEnergy and Juwel Energy remained the two biggest players, with GoEnergy's market share increasing marginally to 15.84% from 15.02% in 2020, while Juwel's share decreased to 10.40% from 13.35% in 2020. Blue Ocean Investments and Maranatha Oil Services maintained their 3rd and 4th spot with market shares of 9.18% and 7.13%, respectively, while Dominion displaced Astra Oil services to the 5th spot with a share of 6.28%, compared to Astra's share of 5.85% for 6th position.

Figure 71: Evolution of Top 5 BDCs in 2021.



7.3.1 Gasoil

Total gasoil supplied to the market increased from 1.91 mn mt in 2019 to 2.02 mn mt in 2020. In 2021, a total of 2.13 mn mt of gasoil was distributed,, representing 5.41% increase over the volumes sold in 2020. This included regular gasoil (1.77 mn mt), gasoil rig (30,985 mt), gasoil mines (297,136 mt), MGO foreign (6,886 mt) and MGO local (20,928 mt).

The top five distributors of regular gasoil in 2021 (GoEnergy, Juwel, Maranatha, Blue Ocean, and Dominion) sold a total of 943,308 mt, representing 53.30% of the total market share. Ten (10) players participated in the sale of gasoil to the mines in 2021 as compared to the 7 in 2020.

Astra Oil Services maintained its lead distributorship role of gasoil (mines) in 2021. Astra Oil distributed 207,502mt, representing 69.83% of the total gasoil mines distribution, as compared to the second-ranked distributor, Fueltrade, who distributed 47, 714 mt (16.06% of total gasoil mines in 2021). Only two players (GoEnergy and Astra) were active in the sale of gasoil rig in 2021, as compared to four in 2020 (GoEnergy, Cirrus Oil, Blue Ocean and Astra). GoEnergy remained the largest distributor of gasoil rig in 2021, though its volumes (as well as the total volume of gasoil rig by all BDCs) sold fell from 30,662 mt (33,665 mt) in 2020 to 27,252 mt (30,985 mt) in 2021.

A total of 18 companies distributed MGO local in both 2020 and 2021, while 4 companies distributed MGO foreign in both 2021, compared to 7 in 2020.

For the MGO local space, GoEnergy remained the largest distributor with total volumes of 9,928 mt, representing 21.55% of the total MGO local market share. Blue Ocean maintained its position as the largest distributor of MGO foreign in 2020, increasing its market share from 54.88% in 2020 to 97.13% in 2021. Nenser Petroleum, Cirrus, and GoEnergy, which distributed no volume in 2020, sold in 2021, completing the companies that distributed MGO foreign in 2021. Overall, Astra Oil Services' success is driven largely by its dominance in the gasoil mines market in 2021.

Figure 72: Gasoil Distributors Trend (2017-2021)

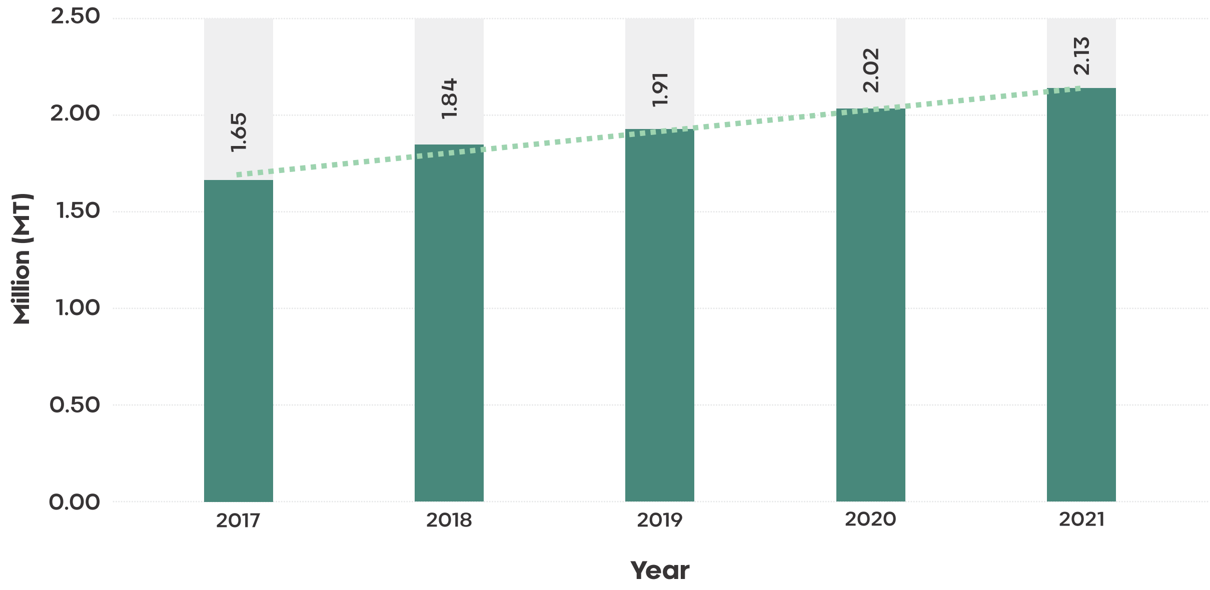


Figure 73: Top 5 Gasoil Distributors (2021 vs 2020).

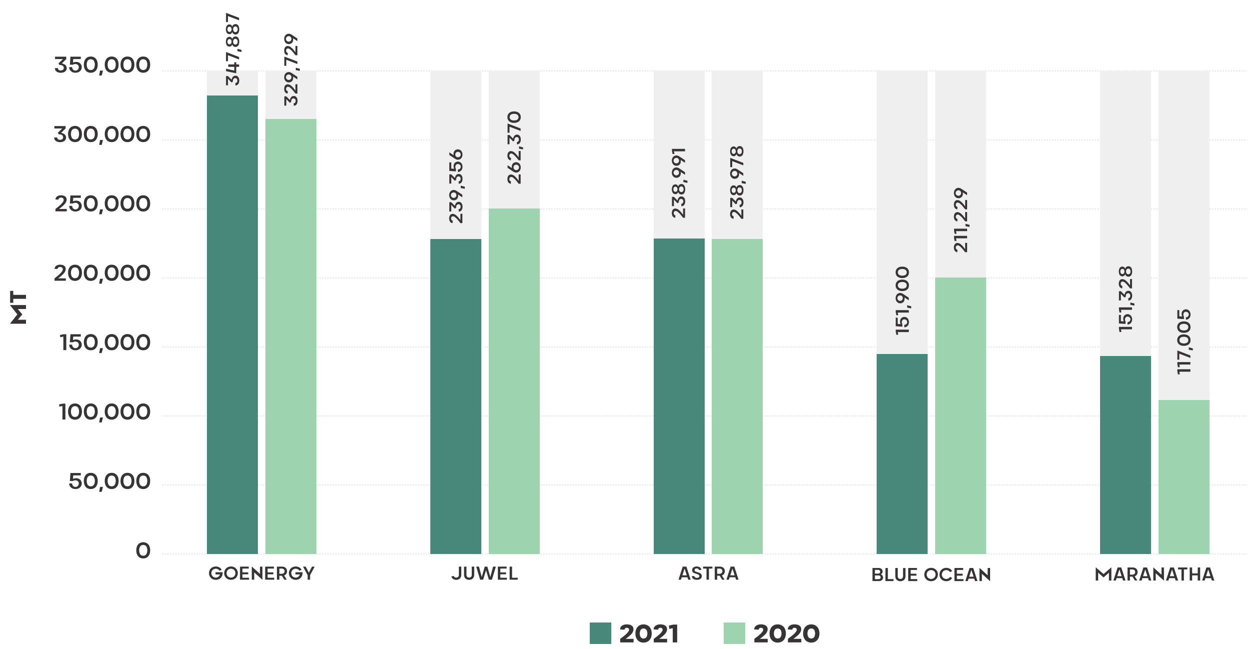
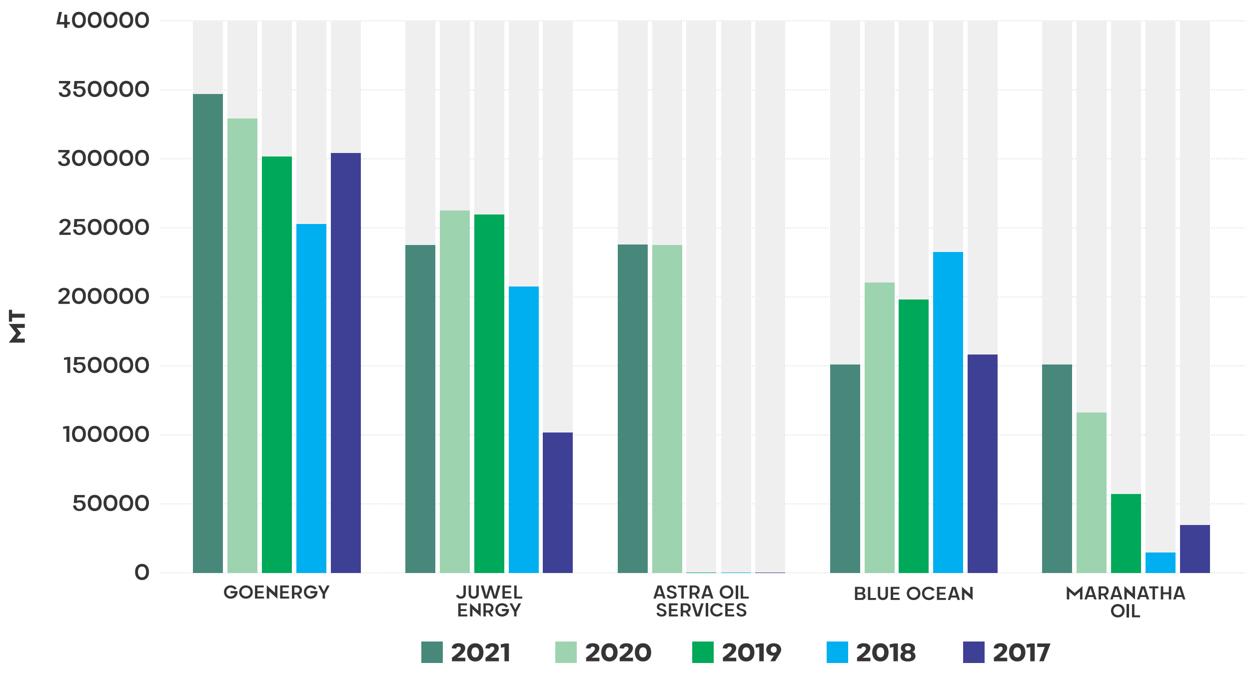


Figure 74: Top 5 Gasoil Distributors 2017 to 2021



7.3.2 Gasoline

A total of 1.71mn mt of gasoline was distributed in 2021, 12.10% higher than in 2020 (1.53 mn mt). The top five distributors of gasoline were GoEnergy (19.82%), Juwel Energy (11.98%), Maranatha (10.12%), Dominion (7.94%)), and Chase (7.57%). They accounted for a total of 983,039 mt, representing 57.43% of the total market share. Dominion moved up to become the 4th largest gasoline distributor in 2021. From a volume of 23,484 mt in 2020, Dominion increased its distribution to 135,860 mt in 2021, representing a 479% growth. Its total market shares also rose to 6.28% in 2021 from 2.08% in 2020. Chase Petroleum maintained its 5th spot in the gasoline distributors in 2021. Of the top five players, GoEnergy, and Dominion experienced increases in the volumes distributed in 2020, while the rest of the top 5 experienced decreases.

Figure 75: Gasoline Distributors Trend (2017-2021)

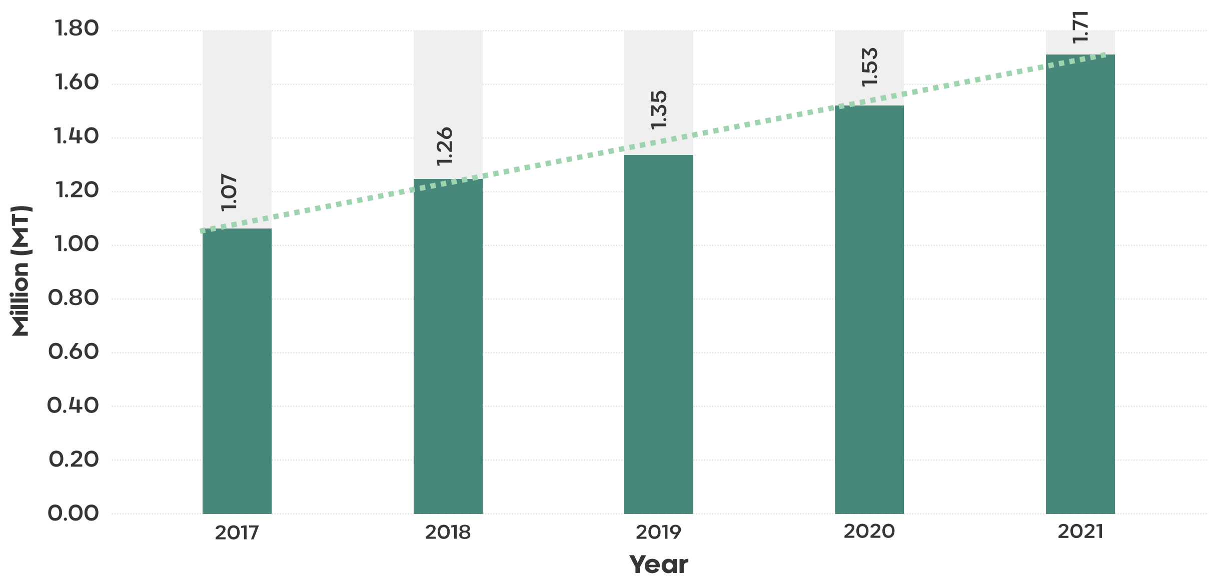
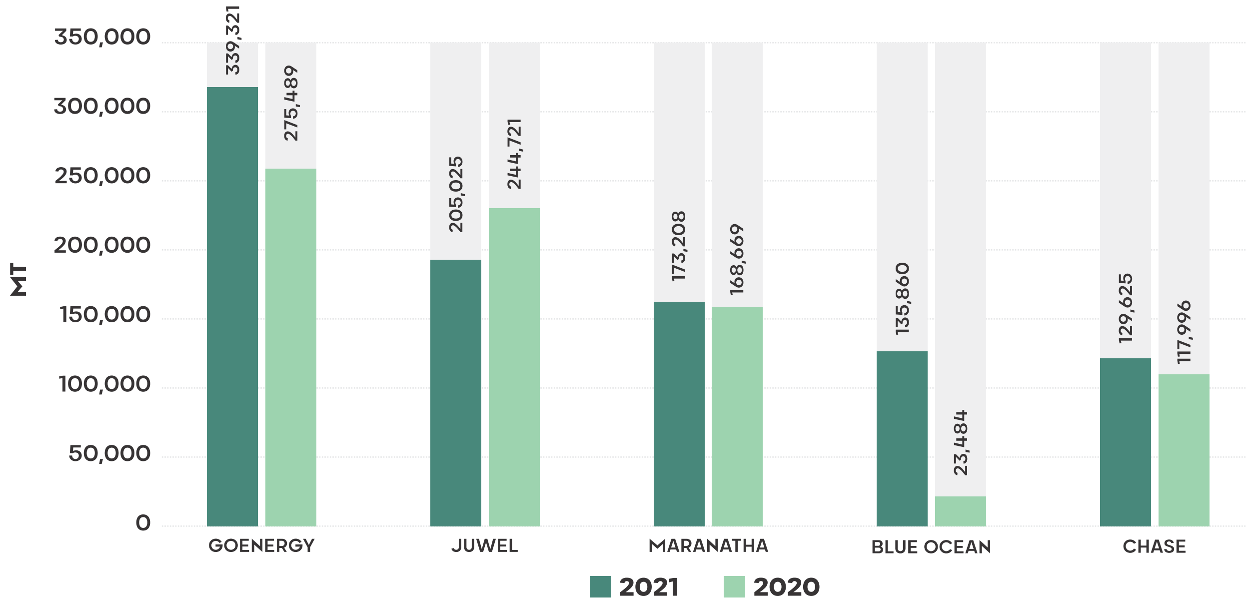


Figure 76: Top 5 Gasoline Distributors (2021 vs 2020)

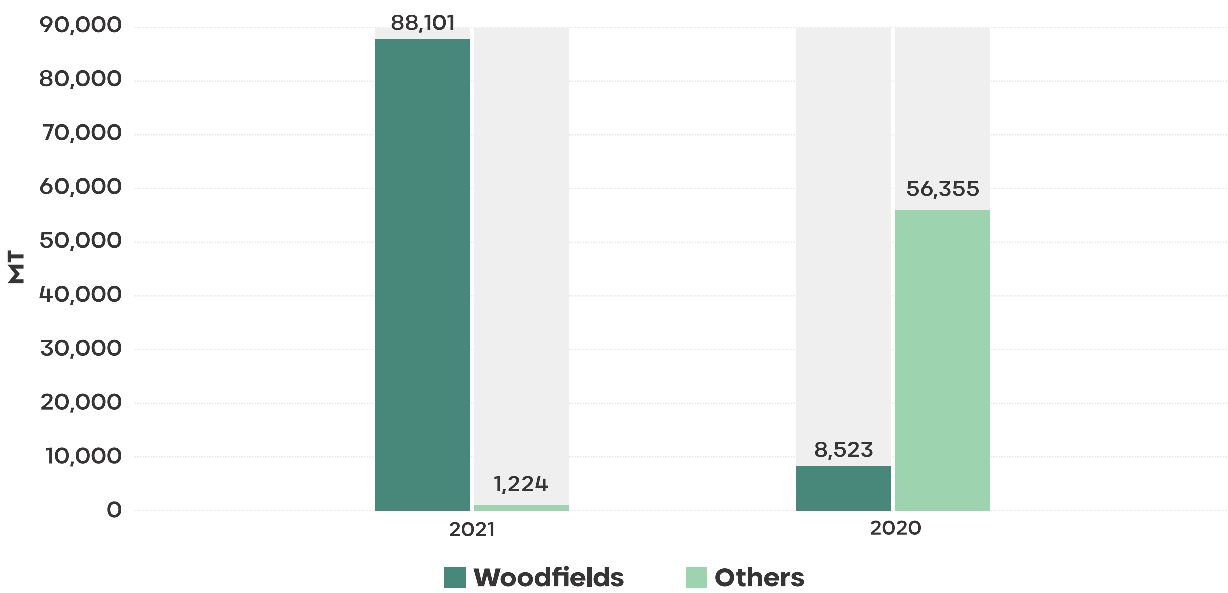


7.3.3 Fuel Oil for Power

Woodfields Energy Resources Limited displaced Cirrus Oil, maintained as the leader in the distribution of fuel oil for power generation in 2021. The volume of fuel oil for power distributed in 2021 increased by 27.99% to 89,325 mt, from the 69,793 mt supplied in 2020. This could be attributed to the surge in demand for fuel oil during periods of low production of lean gas by the Atuabo Gas Processing Plant. Of the 2021 volume distributed, 88,101 mt was supplied by Woodfields, representing 98.63% of the market. This represents a 933.74% rise over the company's 2020 distribution (8,523mt). The other distributors (Akwaaba and Dominion) sold 787 mt and 437 mt, representing 0.88% and 0.49%, respectively, in 2021.

Cirrus Oil, which supplied the highest volume in 2020, did not supply fuel oil for power in 2021. The dominance of Woodfields is attributable to their tolling arrangements with Tema Oil Refinery which made them the primary off-taker of the refinery's output. Cirrus was displaced because its primary supplier, Woodfields, had become its direct competitor who opted to route its volumes from the refinery output through its own BIDEC trading desk.

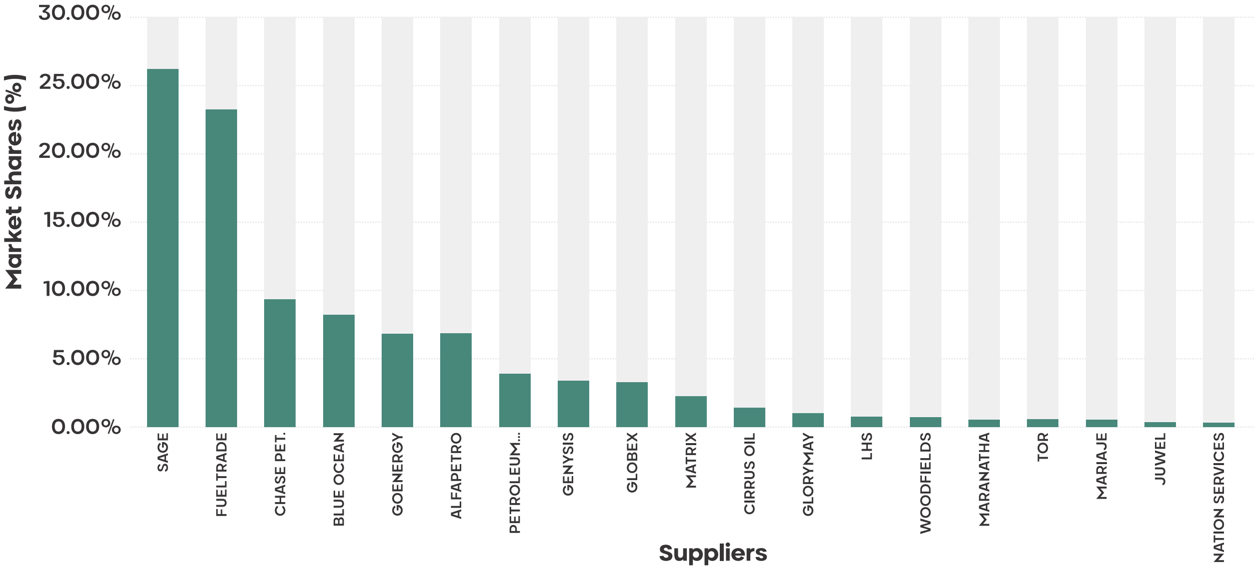
Figure 77: Woodfields vs Others 2021 vs 2020



7.3.4 LPG

A total of eighteen (18) BIDECs and TOR distributed LPG in 2021. This is the same as the number that distributed LPG in 2020. They include Fueltrade, Sage, Chase, GoEenergy, Blue Ocean, Alfapetro, etc. The 345,478 mt of LPG (butane) distributed was mainly for domestic, vehicular and industrial consumption, with no LPG (Propane) consumed by the power sector. The BIDECs supplied about 99.6% of the total quantity of LPG supplied to the market, while TOR supplied 0.4%. The largest distributor of LPG in 2021, Sage, maintained its position with a market share of 26.81%, followed by Fueltrade and Chase with 23.61% and 9.56%, respectively. This is because Sage is the sole offtaker through Quantum Terminals of the LPG produced by Ghana National Gas Company, thereby, giving them an edge and zonal (Western Zone) monopoly over the other players.

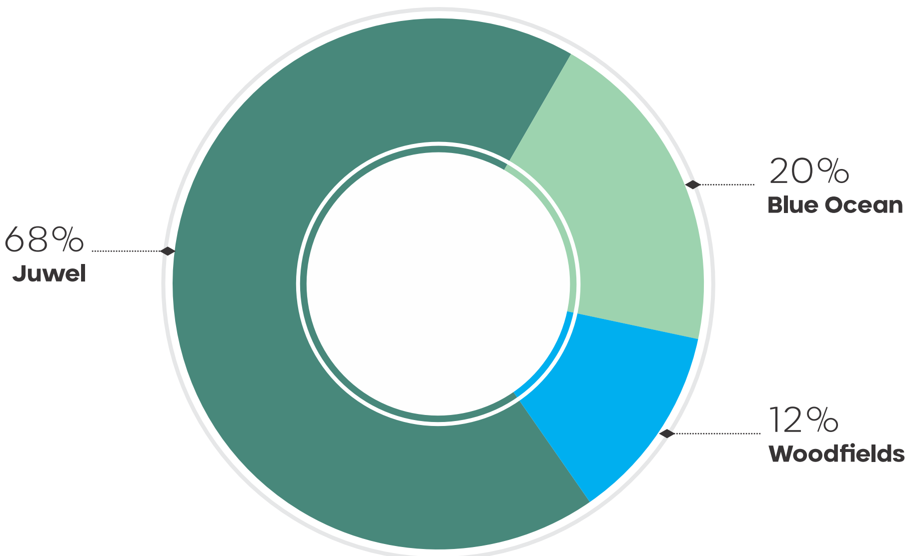
Figure 78: Market Shares of LPG BIDECs



7.3.5 Kerosene

Only three companies (Juwel, Blue Ocean, and Woodfields) distributed kerosene in 2021 totalling 4,585 mt. This was a 7.53% decline in the distribution of Kerosene from 4,958 mt in 2020 to 4,585 mt in 2021. However, over the past decade, there has been a significant decline in Kerosene distribution by 93% due to the liberalization of Kerosene prices, which has deterred the use of kerosene to adulterate diesel.

Figure 79: Kerosene Distributors (2021)

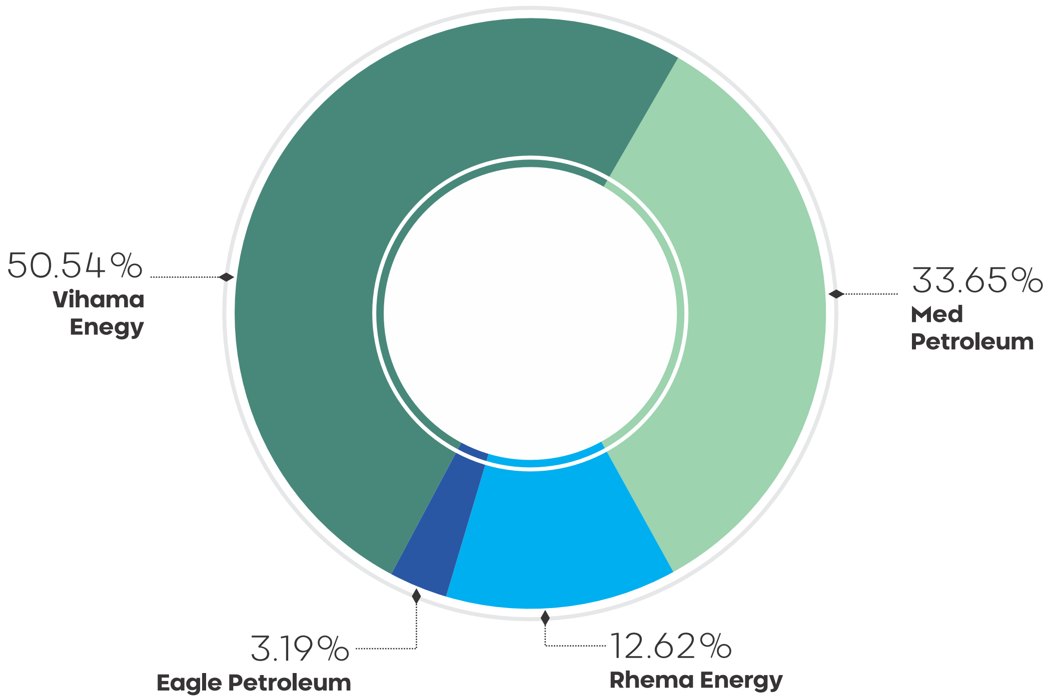


7.3.6 Premix Fuel

A total of 78,595 mt of premix was distributed in 2021, 2.31% higher than in 2020 (76,821 mt). There were four premix distributors in 2021, compared to two distributors in 2020. Vihama maintained its position as the leader in premix distribution, supplying about 50.54% (equivalent to 39,720 mt) of the total premix consumed in the country, followed by Med Petroleum with 26,450 mt, representing 33.65%. The dominance of Vihama stems from the fact that the company was the sole supplier of premix fuel for a long time before a few BIDECs joined the premix market. Additionally, most of the BIDECs find the supply of premix fuel unattractive because of the subsidy on the product.

Premix fuel is highly subsidised by the government. Currently, the price of premix fuel is about 77.97% subsidised and the amount spent on payment of premix fuel subsidy is about GHS80 million per month. To lessen the burden of subsidy payment by government, Price Stabilization and Recovery Levy (PSRL) was introduced as part of the Energy Sector Levy Act 2015 (899) on petrol, diesel and LPG to raise some funds to pay for the subsidies on premix fuel and residual fuel oil.

Figure 80: Premix Distributors (2021)

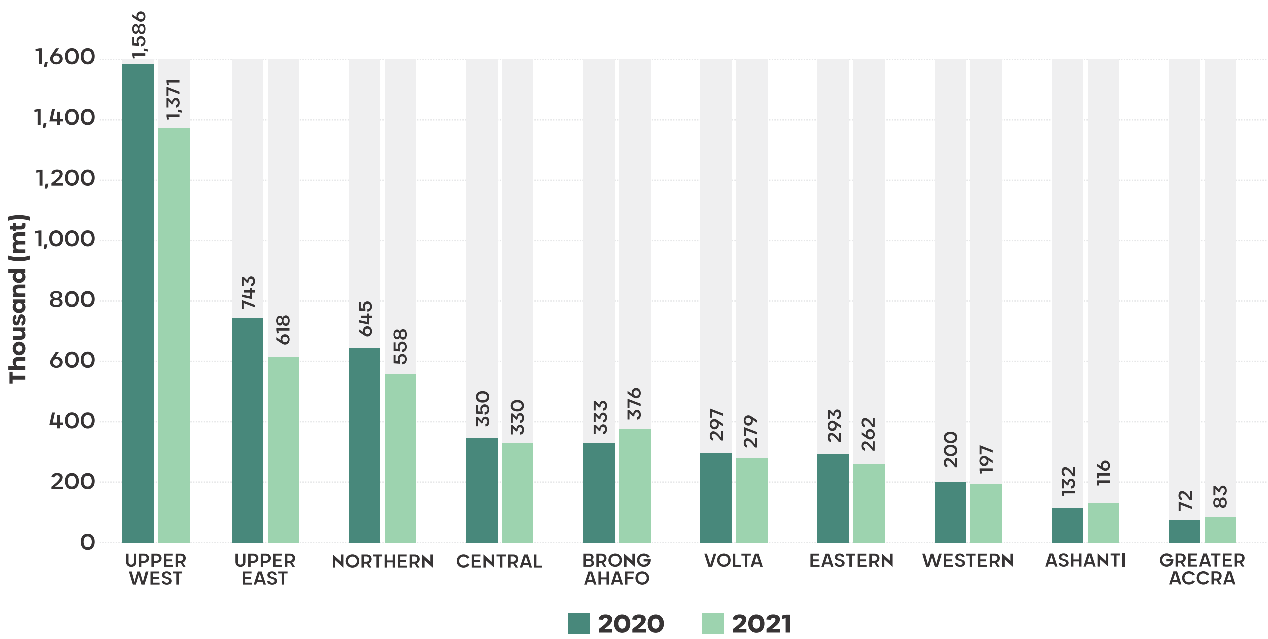


7.4 Regional Consumption

As expected, the Greater Accra Region maintained its place as the largest consuming region with 1.37 mn mt, representing a 34.2% share of total products consumed. This was, however, 15.7% higher than its 2020 consumption figure. The Greater Accra Region was followed by Ashanti and Western Regions, whose consumption stood at 743,434 mt and 618,090 mt respectively. The demand dominance of the Greater Accra Region is attributable to its position as the highest populated region (17.6%) and the highest contributor to domestic revenue (90%). Ashanti Region is Ghana's second most populated region. The consumption by the Western region is mainly attributable to the extractive (mining and petroleum) industrial activity in the region.

All the regions experienced increases in consumption except Volta, Upper East, and Upper West. The Eastern Region displaced the Volta Region to 4th in 2021, having placed 5th in 2020. The Upper West, Upper East and Northern Regions were the three least consuming regions in the country.

Figure 81: Regional Consumption (2021 vs 2020)



Over the past four (4) years, the Greater Accra Region has consistently consumed volumes above 1.0 mn mt (30%), with consumption rapidly surpassing 1.3 mn mt over the past three years (2018-2020). The 4 other regions in the top 5 consumed quantities below 700,000 mt with similar increasing trends in consumption between 2016 and 2019, except for Western Region, which has consistently experienced a decline in consumption over the past three years (2018-2020). However, Ashanti Region regained its spot as the second-largest consumer in 2020, after displacing Western Region. The decrease in Western Region's consumption was significantly spurred by the decrease in consumption of AGO Mines and no consumption of LPG for power (propane) in 2020. Also, Volta Region displaced Central Region as the 5th largest consumer of petroleum products in 2020.

Figure 82: Top 5 Regional Consumers of Petroleum Products (2017-2021)

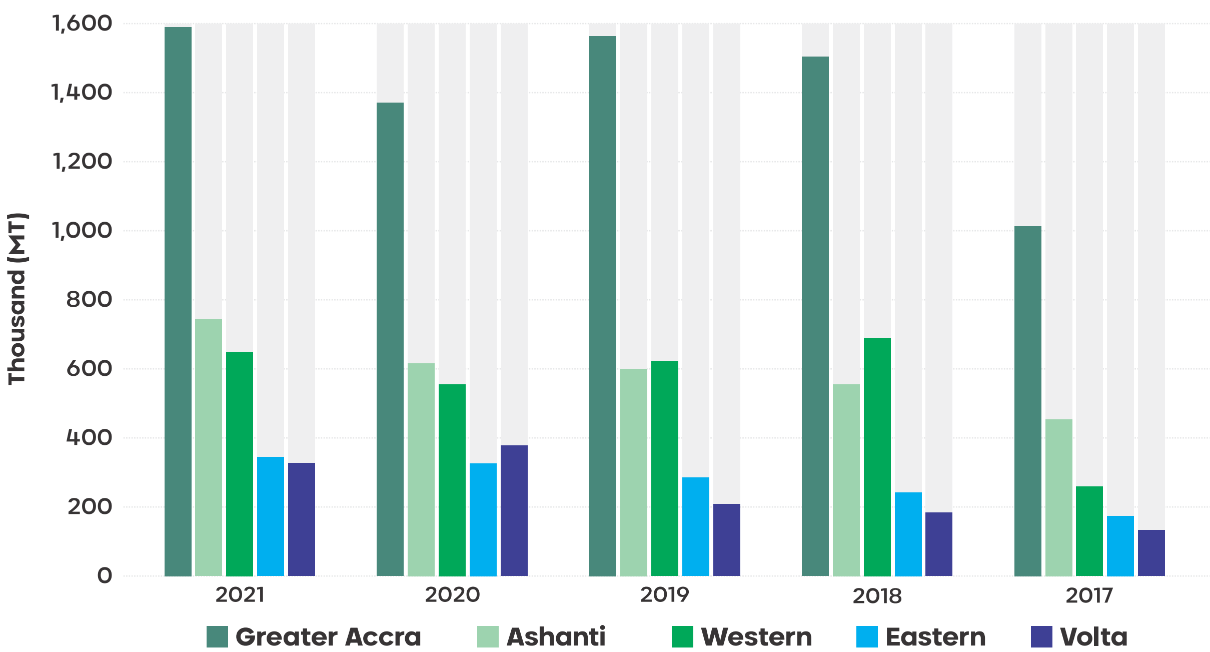
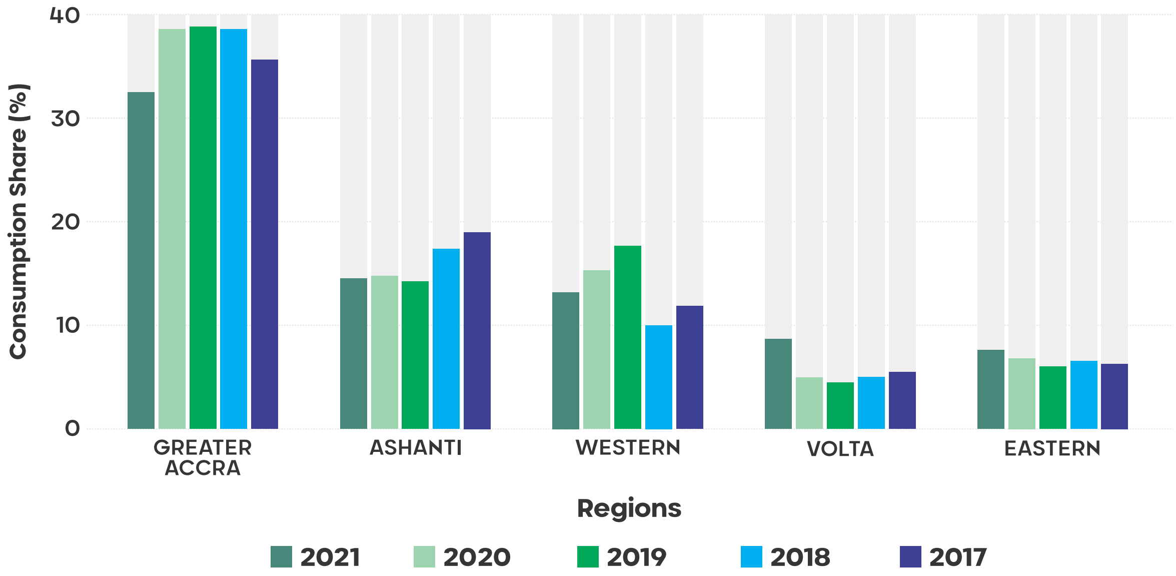
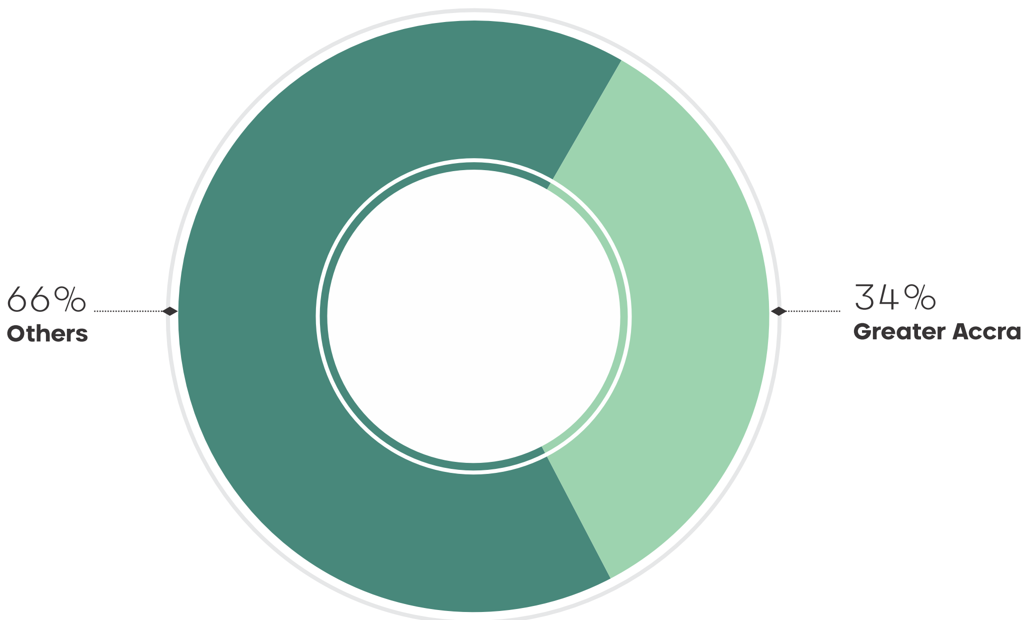


Figure 83: Top 5 Regional Consumers of Petroleum Products (2017-2021)



It is evident from the Chart above that, for the fourth year running, the Greater Accra Region alone has consistently accounted for more than 30% share of total petroleum product consumption in the country, with the other regions (9) accounting for about 67%.

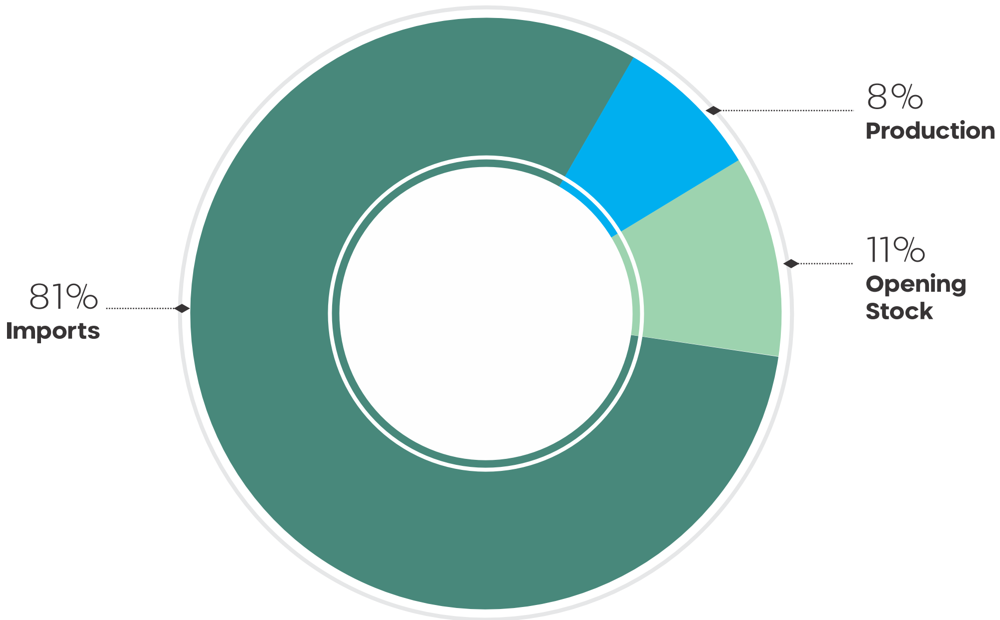
Figure 84: Regional Consumption: Greater Accra vs Others (2021)



7.5 Supply

Total petroleum product supply reached 5.09 mn mt in 2021. This comprised imports of 4.13 mn mt (81%), local production of 410,571 mt (8%) and an opening stock position of 556,967 mt (10%). The 2021 supply was 11.0% lower than 2020, which had a total supply position of 5.72 mn mt.

Figure 85: Total Supply Breakdown (2021)

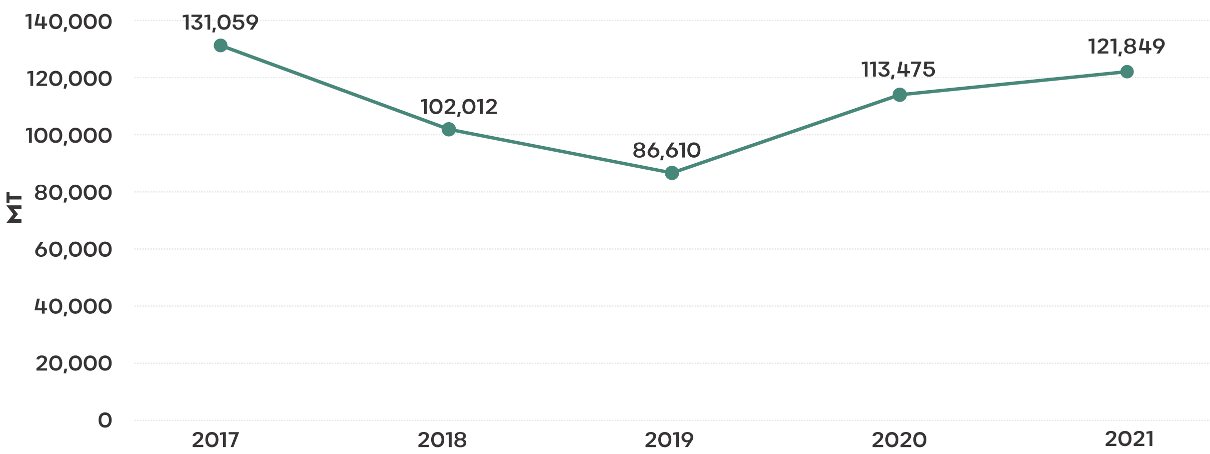


7.6 Production

Local refinery production accounted for 8% of the total supply in 2021. Local production represents the output from the Tema Oil Refinery, Akwaaba Refinery, Platon Gas Oil and the Ghana National Gas Company (GNGC). Products refined from TOR amounted to 212,905 mt in 2021, down 55.1% from 2020.

Total production from TOR accounted for 51.9% of total refinery production in 2021. Akwaaba and Platon's outputs were 53,501 mt (a 149.4% increase over the previous year's production) and 22,317 mt (a 716.9% increase over the previous year's production), respectively. Their refinery production accounted for 13.0% and 5.4%, respectively, of total production. GNGC's output (LPG & Condensate only) was 121,849 mt, representing 7.4% increase over its 2020 production and representing 29.7% of total refinery output for 2021.

Figure 86: Ghana National Gas Company (GNGC) Refinery Production (2017-2021)



Local production of petroleum products declined from 717,235 mt in 2019 to 611,350 mt in 2020. Total refinery output further declined by 32.8% to 410,571 mt in 2021.. The fall in local refinery output was because of a significant fall in production from Tema Oil Refinery, owing to the non-operationalisation of the Refinery since May 2021.

RFO was the largest product obtained from refinery operations in 2021, with its share of refinery output increasing from 35.3% in 2020 to 35.8% of total production (146,912 mt) in 2021. This is mainly due to the business model as well as the configuration of the refineries for the 2021 operational year. RFO was followed by gasoil with a share of 94,836 mt (23.1%) in 2021 which is lower as compared to the 2020 share of 24.5%. Other products realised from the refinery process included ATK, Kerosene, Naphtha, LPG, and Condensate.

With negotiations ongoing to revamp TOR under a lease arrangement and the completion of the Sentuo refinery, the local production share of Ghana's supply market is expected to materially improve.

Figure 87: Output of Local refineries

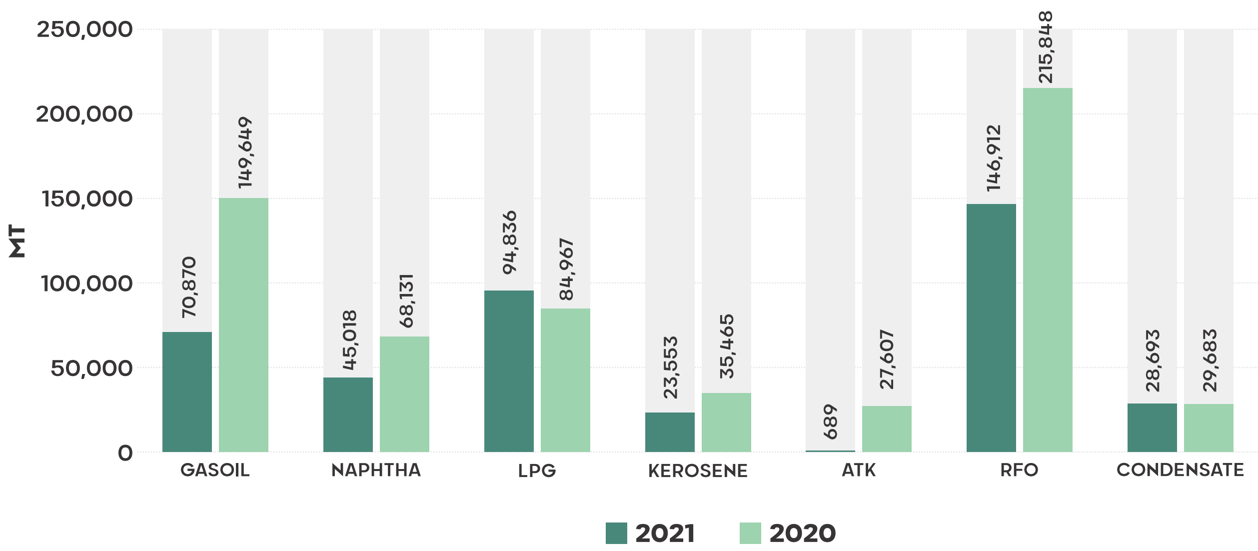


Figure 88: Refinery Output (2017-2021)

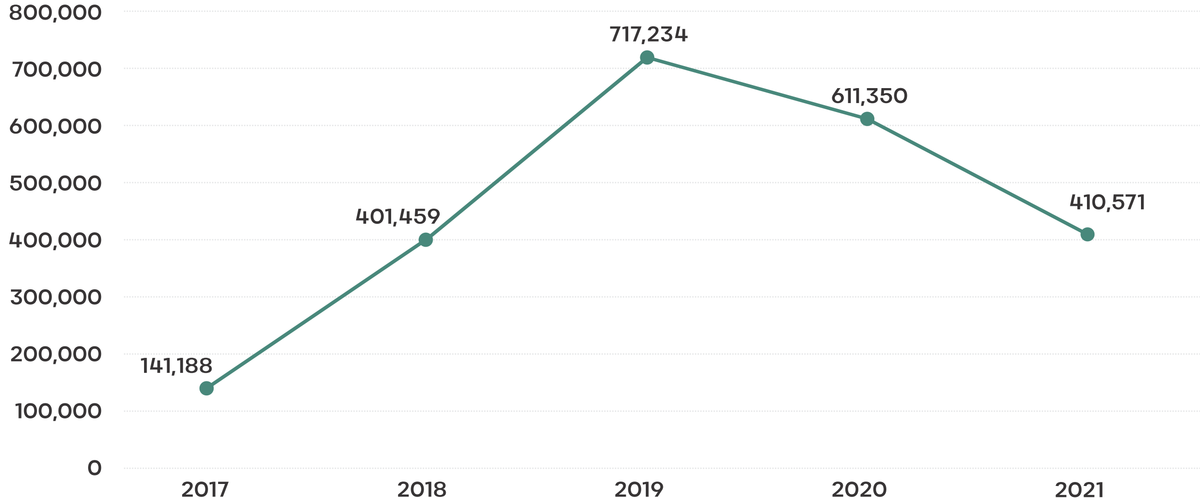


Figure 89: Total Refinery Output

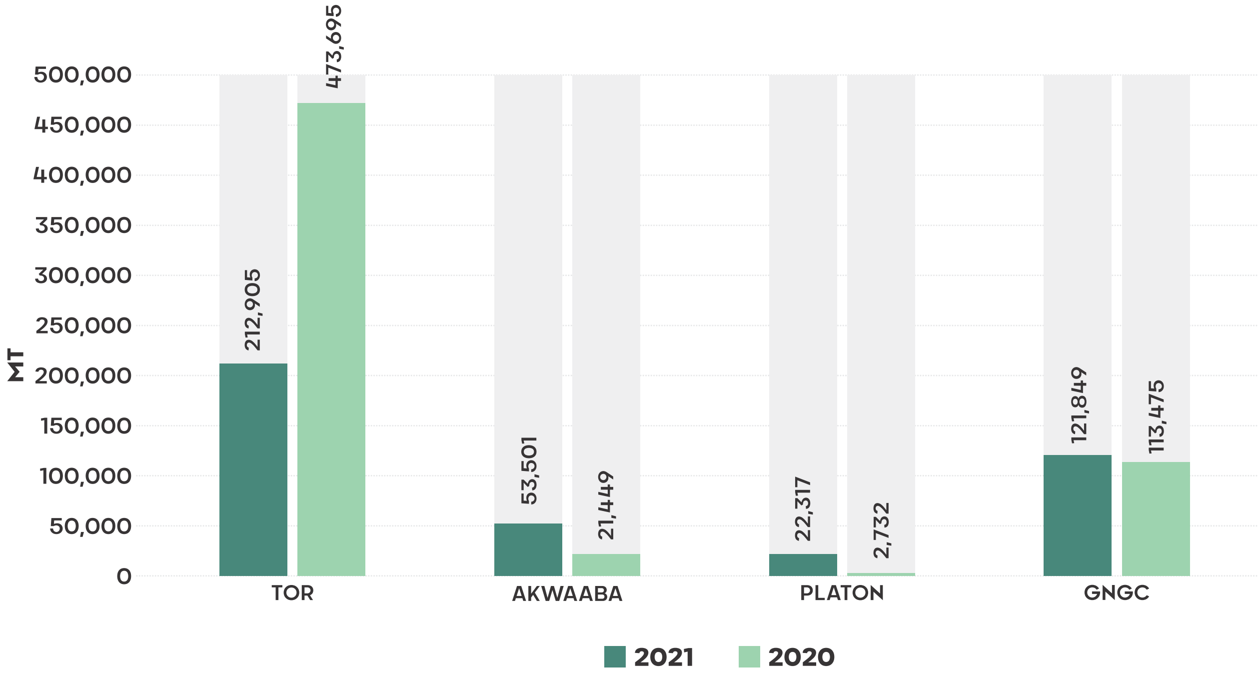
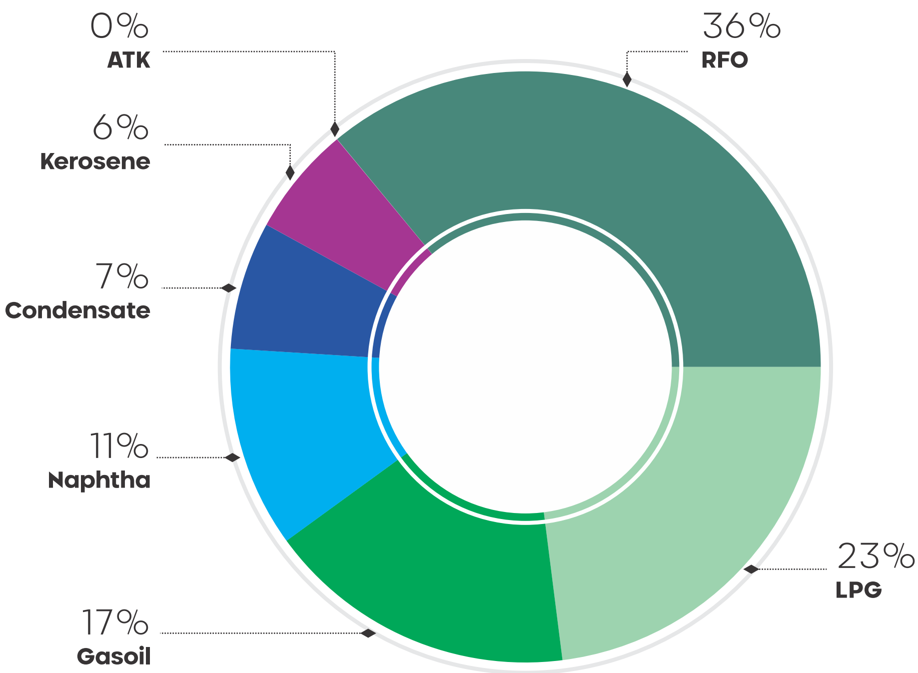


Figure 90: Refinery Output (2021)



7.7 Imports

Imports of crude oil and refined products decreased by 11.12% in 2021 from 2020. Total imports of crude oil and refined products reached 4.20 mn mt in 2021 from 4.72 mn mt in 2020. Total imports for 2021 comprised 4.15 mn mt (99%) for the Ghanaian market and 48,031 mt (1%) (only gasoline) by Sonabhy for transit to Burkina Faso. Crude oil imports accounted for 2% (73,414 mt), while petroleum products accounted for 98% of total imports. Of all the crude oil volume imported into the country, 73,414 mt was refined into petroleum products with none for power generation. However, crude oil, used as second fuel for power generation, was from stock rollover from 2020. The year under review also witnessed a 2.30% increase in the importation of refined products with the importation of crude oil falling by 89.39%, which was a result of Tema Oil Refinery's inability to import crude oil for the year under review.

Figure 91: Petroleum product import (2017-2021)

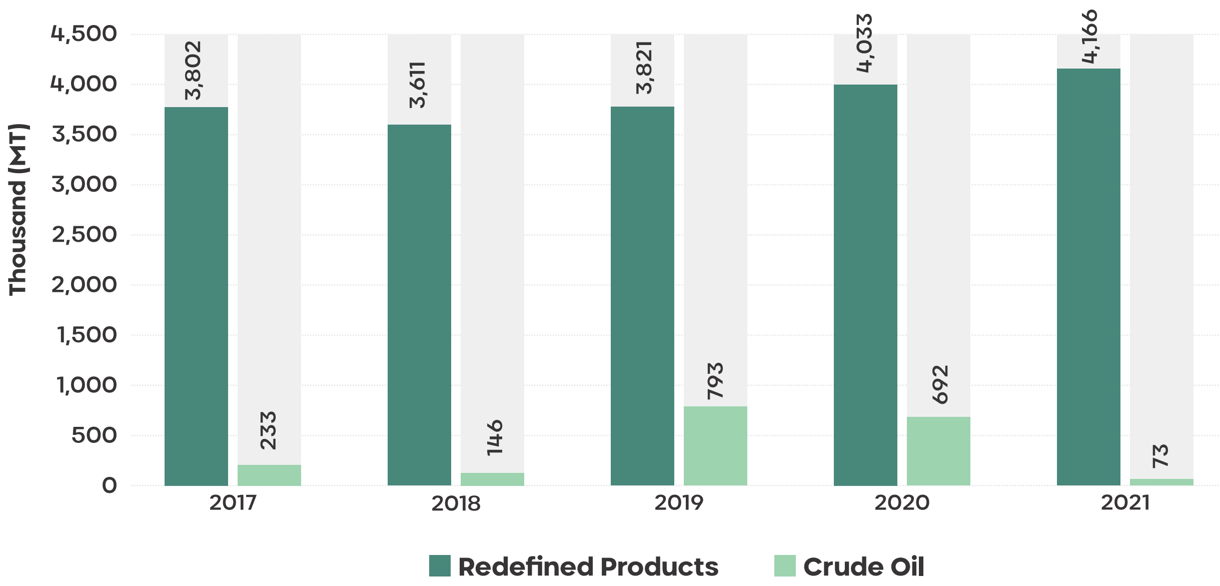


Figure 92: Total Imports for 2021: Ghanaian Market vs Transit to Burkina Faso

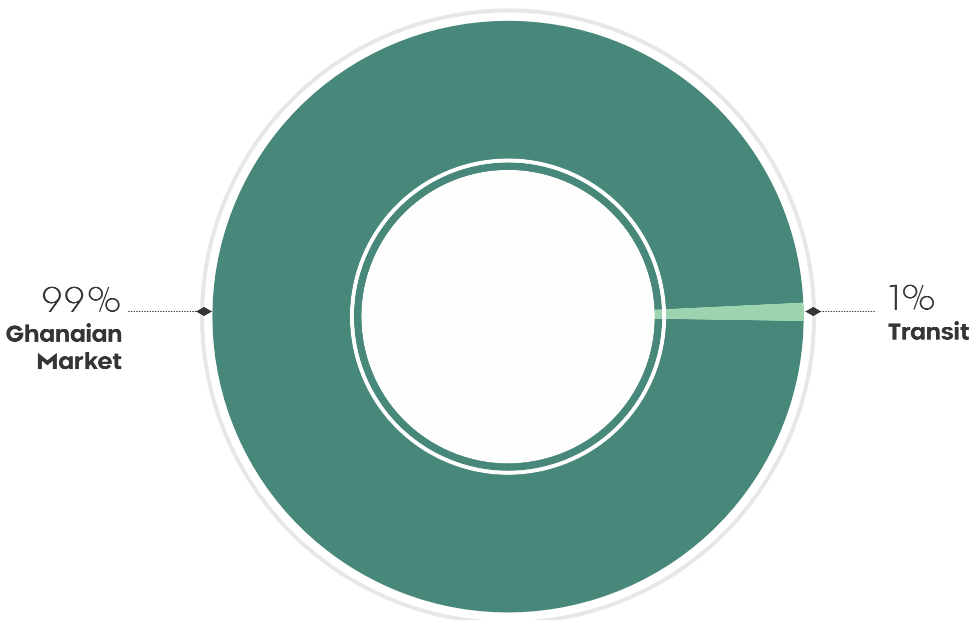
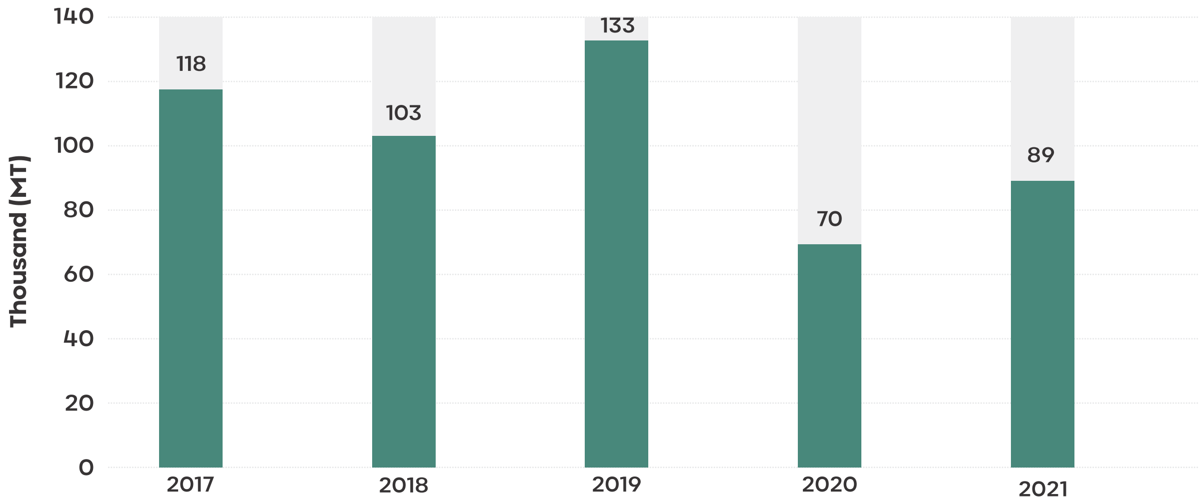


Figure 93: HFO Consumption for Power (2017-2021)



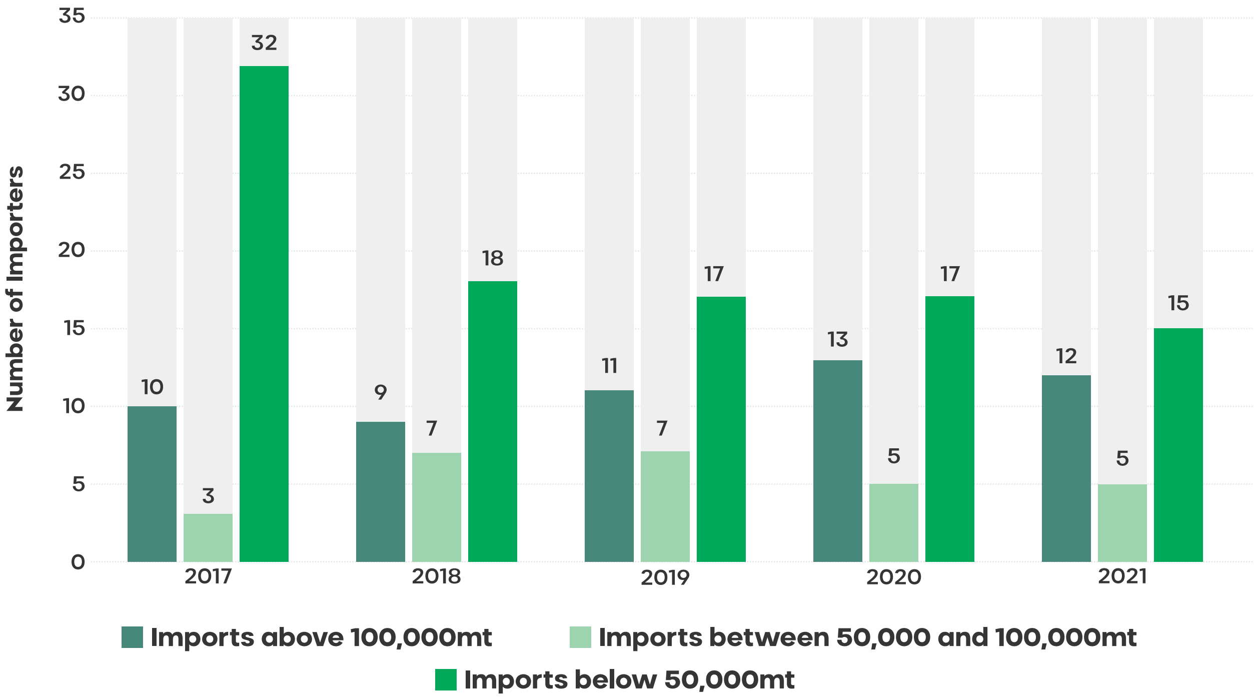
Refined product imports went up by 3.30% in 2021 from 2020 volumes, increasing from 4.03 mn mt in 2020 to 4.17 mn mt in 2021. All refined products, except gasoil, increased for the period under review. The increases were gasoline (5.19%), LPG (0.35%), ATK (136.58%), and HFO (35.92%). Gasoil, however, decreased by 6.50% for the period under review.

A total of 36 companies (including Sonabhy which transits through Ghana to Burkina Faso) imported products in 2020; 12 companies imported products above 100,000 mt, accounting for 85% of total imports relative to 13 companies in 2020. 5 companies imported products between 50,000 mt and 100,000 mt to account for 8% of imports as against 5 companies importing the same quantity band in 2020. 15 companies brought in cargoes below 50,000 mt, accounting for 8% of total imports as against 5% in 2020.

There was an increase in the number of importers who brought in products equivalent to the standard single cargo size of 30,000 mt when compared to 2020. In 2021, 20 companies imported products above 30 kt as compared to 21 in 2020.

Figure 94: BDC Import Distribution (2021)

Figure 95: Importers Activity (2017-2021)



The top 10 refined products importers brought in 3.177 mn mt of products in 2021, representing a 1.3% decline in imports compared to 2020. Their imports in 2021 accounted for 77.0% of total imports, compared to 79.8% in 2020. GoEnergy displaced Juwel Energy as the highest importer of refined products in 2021, with a share of 15.7%, compared to Juwel's share of 11.0% in second. Cirrus Oil and Lemla lost their top 10 positions in 2021 from 2020. Dominion and Woodfields Energy gained grounds in the refined products import space, featuring in the top 10 importers in 2021. Go Energy, Juwel, Blue Ocean, Fueltrade, Astra, Maranatha, Chase, and Vihama maintained their top 10 positions in 2021 from 2020.

For the crude oil space, only Akwaaba Oil Refinery and Platon Gas Oil Refinery imported crude oil in 2021, amounting to 73,414 mt. This represented an 89.4% decrease in crude oil import from 2020, mainly due to Woodfield's inability to import crude oil for the country's main and biggest refinery, TOR. Woodfield's crude oil import accounted for a whopping 88.1% share of all crude oil imports in 2020. Also, there was no crude oil import for power generation in 2021, compared to a share of 8.3% of all crude oil imports in 2020 by Adinkra Energy.

Figure 96: Top 10 Importers (2021)

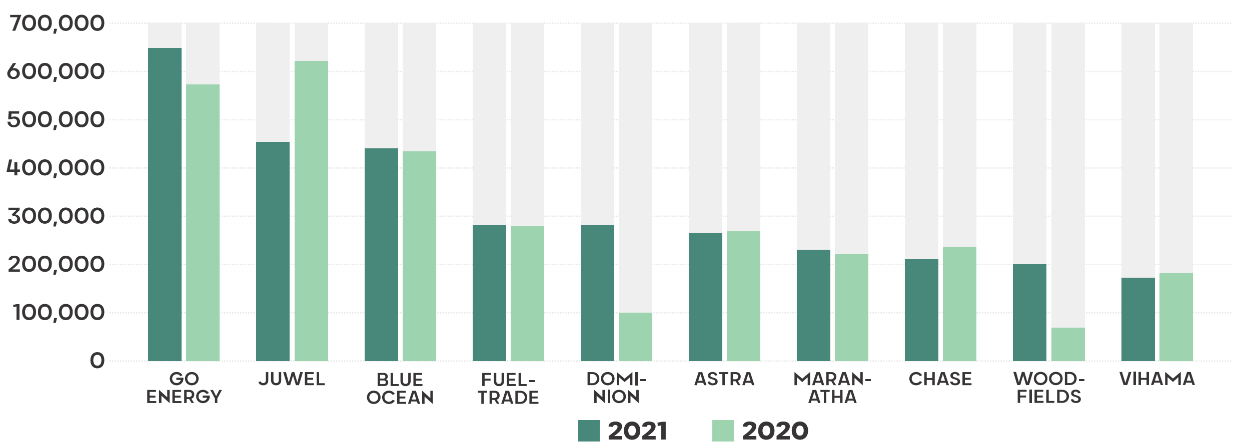
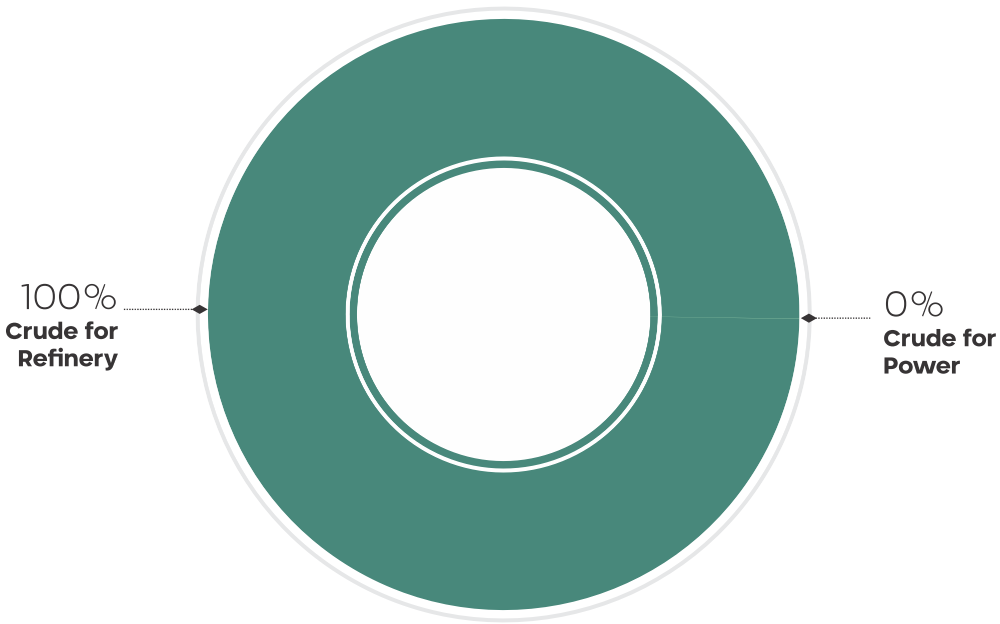


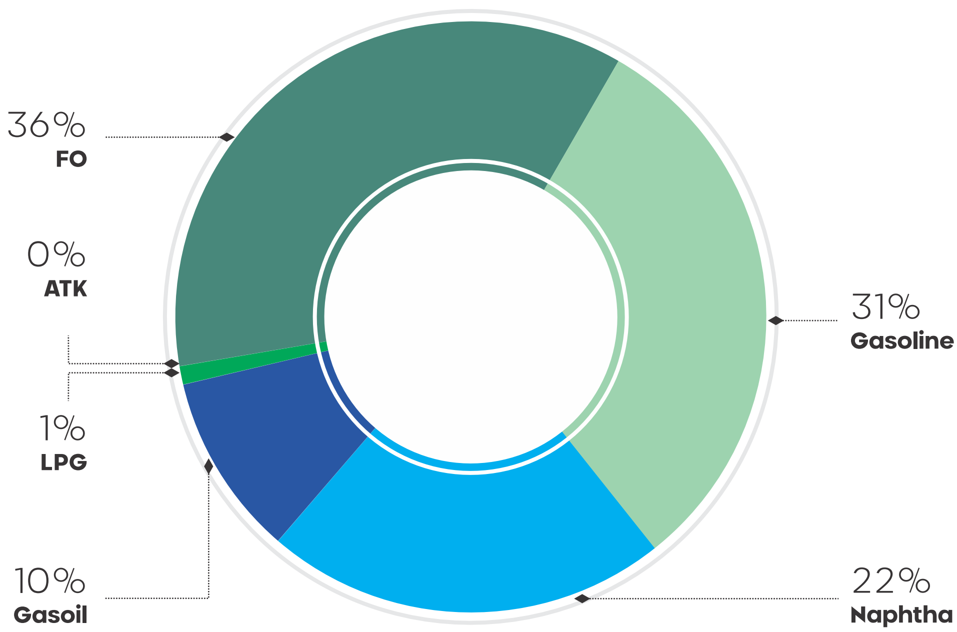
Figure 97: Crude Oil Import for 2021



7.8 Exports

Refined products exported in 2021 amounted to 403,057mt. This was made up of 20,874 mt of gasoil, 63,992 mt of gasoline, 2,235 mt of LPG, 221 mt of Kerosene, 44,461 mt of Naphtha and 75,126 mt of Fuel Oil. A total of 21,873 mt was imported for re-export, while 65,449 mt was refined locally and exported.

Figure 98: Exports



7.9 Pricing Review

Dated Brent crude prices averaged S69.45/bbl in 2021, up to 63 percent from the previous year. The biweekly FOB prices of Dated Brent for the year 2021 ranged between USD50.70/bbl and USD84.61/bbl. The lowest price was recorded in the first window of January, while the highest price was recorded in the first window of November. The FOB price of Dated Brent in 2021 saw a net increase of 44.48%.

The rise in crude oil prices was largely driven by the lifting of restrictions on the movement of people, as well as the opening of economies for trading that resulted in rapid growth in demand for oil, after the huge slump in 2020. However, there were declines in prices in November and December due to a surge in the Omicron variant of the COVID-19 virus across the world; there were fears that this could lead to lockdowns and slow down oil demand.

The biweekly FOB prices of gasoline (petrol) for the year 2021 ranged between USD436.69/MT and USD837.77/MT, and averaged USD660.94/MT, representing an increase of 69 percent from 2020. The lowest price was recorded in the first window of January, while the highest price was recorded in the second window of November. The FOB price of petrol in 2021 saw a net increase of 53.60%.

The biweekly FOB prices of gasoil (diesel) for the year 2021 ranged between USD419.28/MT and USD731.80/MT, and averaged USD570.10/MT, representing an increase of 50 percent from 2020. The lowest price was recorded in the first window of January, while the highest price was recorded in the first window of November. The FOB price of diesel in 2021 saw a net increase of 48.75%.

The biweekly FOB prices of LPG for the year 2021 ranged between USD445.69/MT and USD825.48/MT, and averaged USD593.41/MT, representing an increase of 79 percent from 2020. The lowest price was recorded in the first window of January, while the highest price was recorded in the second window of November. The FOB price of LPG in 2021 saw a net increase of 53.63%.

The biweekly FOB prices of Aviation Turbine Kerosene (ATK/Jet) for the year 2021 ranged between USD441.03/MT and USD765.07/MT, and averaged USD594.28/MT, representing an increase of 61 percent from 2020. The lowest price was recorded in the first window of January, while the highest price was recorded in the first window of November. The FOB price of ATK in 2021 saw a net increase of 50.28%.

The biweekly FOB prices of Residual Fuel Oil (RFO) for the year 2021 ranged between USD332.75/MT and USD538.93/MT, and averaged USD446.10/MT, representing an increase of 56 percent from 2020. The lowest price was recorded in the first window of January, while the highest price was recorded in the first window of November. The FOB price of RFO in 2021 saw a net increase of 41.77%.

Figure 99: **Trend of Crude Oil FOB Prices (January - December 2021)**

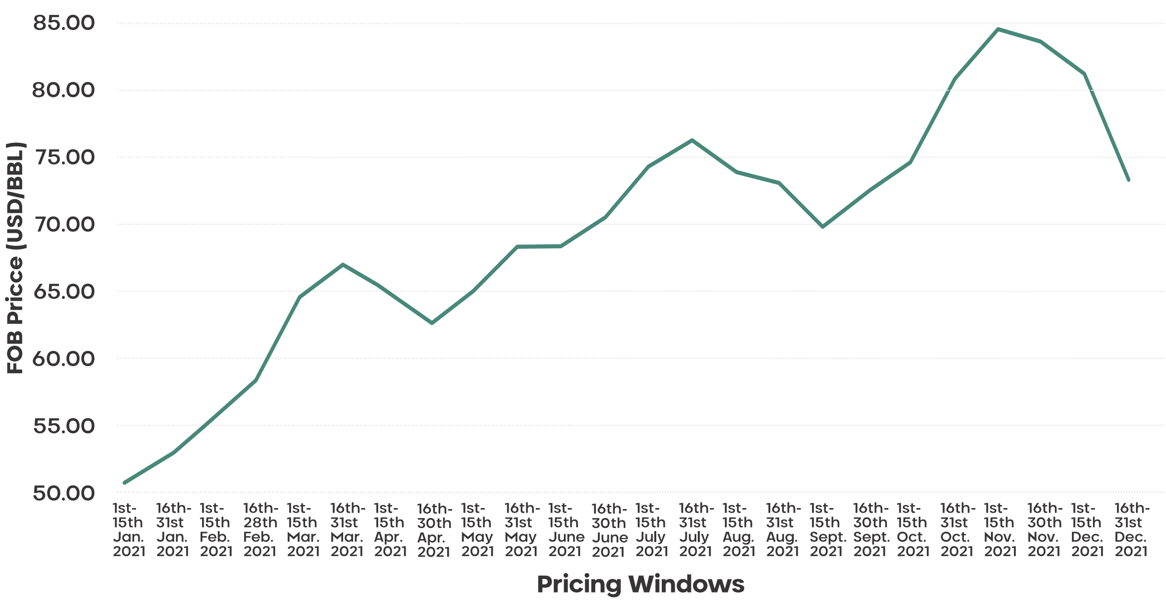


Figure 100: Trend of Finished Products FOB Prices (January - December 2021)

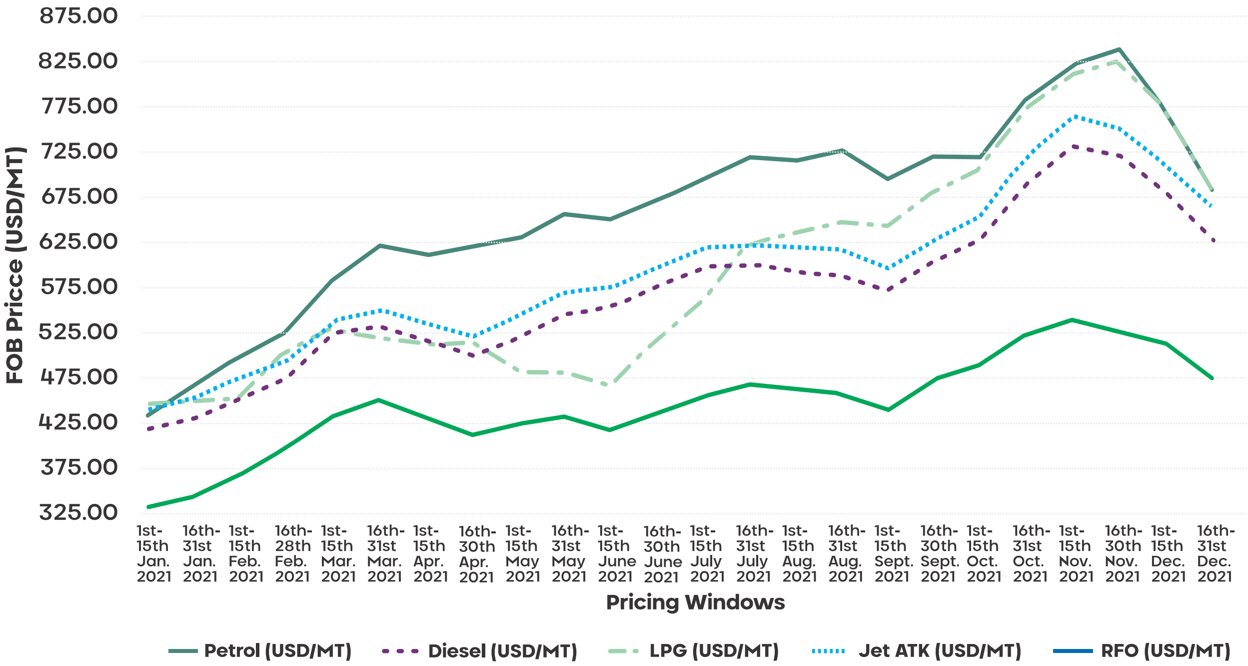


Figure 101: Average Gasoline Inter-Window Changes (2021)

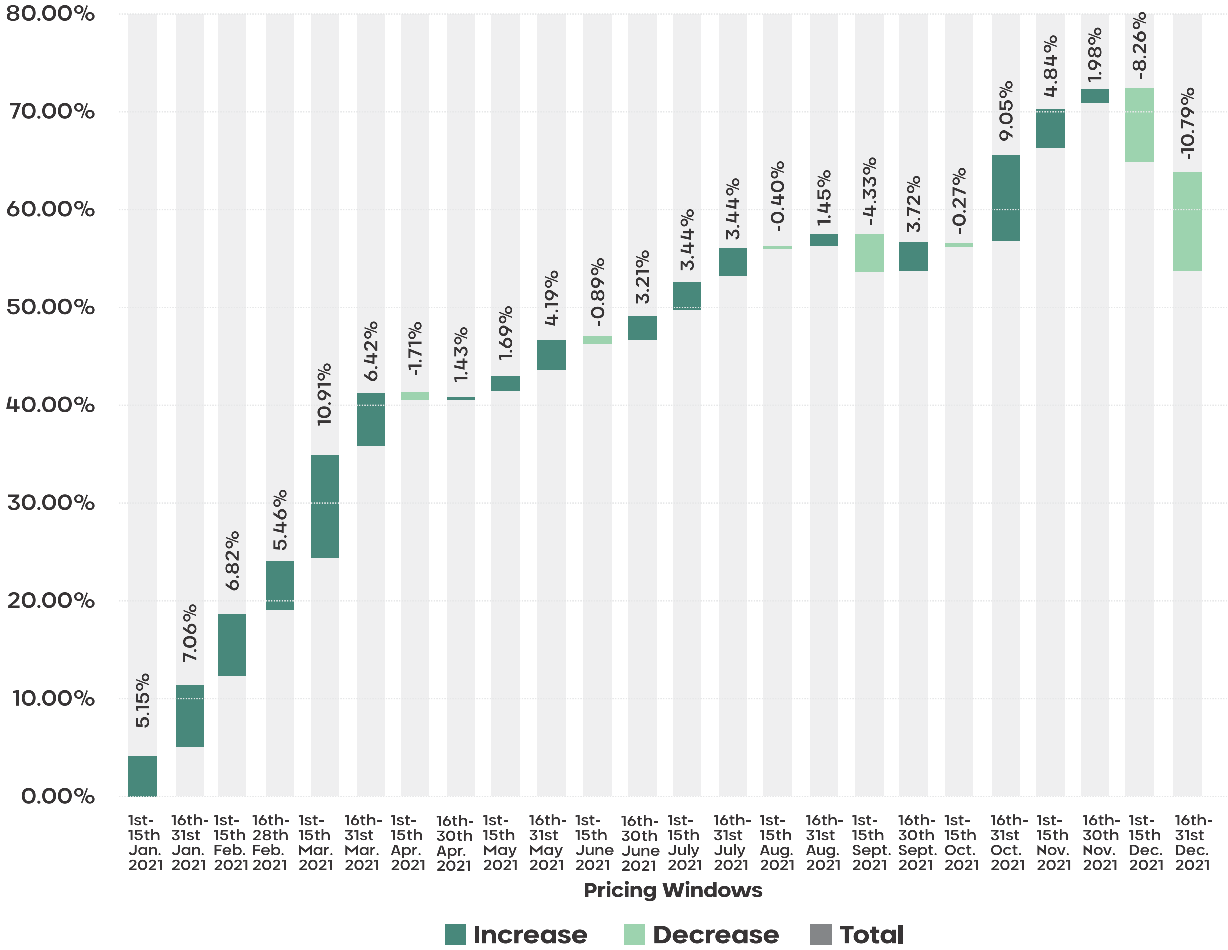


Table 23: 2021 Pricing window prices

Pricing Window	Petrol (USD/MT)	%age Change	Diesel (USD/MT)	%age Change	LPG (USD/MT)	%age Change	Jet/ATK (USD/MT)	%age Change	RFO (USD/MT)	%age Change	Brent Dated (USD/BBL)	%age Change
1st - 15th Jan, 2021	436.69	5.15%	419.28	5.70%	445.69	6.70%	441.03	6.98%	332.75	3.08%	50.70	4.75%
16th - 31st Jan, 2021	467.53	7.06%	431.31	2.87%	449.00	0.74%	454.06	2.95%	345.14	3.72%	52.59	3.74%
1st - 15th Feb, 2021	499.41	6.82%	452.89	5.00%	454.59	1.25%	475.30	4.68%	368.57	6.79%	55.41	5.36%
16th - 28th Feb, 2021	526.69	5.46%	474.77	4.83%	506.63	11.45%	493.83	3.90%	397.35	7.81%	58.32	5.24%
1st - 15th Mar, 2021	584.14	10.91%	523.41	10.24%	527.73	4.17%	539.07	9.16%	433.93	9.21%	64.61	10.79%
16th - 31st Mar, 2021	621.64	6.42%	532.33	1.71%	520.42	-1.39%	550.58	2.14%	450.17	3.74%	66.96	3.64%
1st - 15th Apr, 2021	611.00	-1.71%	515.82	-3.10%	511.77	-1.66%	535.14	-2.81%	429.50	-4.59%	65.11	-2.77%
16th - 30th Apr, 2021	619.75	1.43%	500.22	-3.02%	514.63	0.56%	521.34	-2.58%	412.78	-3.89%	62.55	-3.93%
1st - 15th May, 2021	630.25	1.69%	520.32	4.02%	480.11	-6.71%	544.20	4.38%	424.43	2.82%	65.07	4.03%
16th - 31st May, 2021	656.63	4.19%	545.50	4.84%	481.78	0.35%	570.05	4.75%	432.10	1.81%	68.34	5.03%
1st - 15th June, 2021	650.77	-0.89%	554.05	1.57%	467.00	-3.07%	575.43	0.94%	417.93	-3.28%	68.42	0.12%
16th - 30th June, 2021	671.66	3.21%	576.93	4.13%	518.30	10.99%	596.89	3.73%	436.80	4.52%	70.45	2.97%
1st - 15th July, 2021	694.78	3.44%	597.30	3.53%	561.75	8.38%	618.53	3.63%	454.90	4.14%	74.33	5.51%
16th - 31st July, 2021	718.68	3.44%	600.40	0.52%	624.38	11.15%	622.78	0.69%	467.78	2.83%	76.28	2.62%
1st - 15th Aug, 2021	715.80	-0.40%	592.32	-1.35%	635.80	1.83%	619.48	-0.53%	462.52	-1.12%	73.97	-3.03%
16th - 31st Aug, 2021	726.15	1.45%	588.67	-0.62%	647.10	1.78%	617.27	-0.36%	457.60	-1.06%	73.02	-1.28%
1st - 15th Sept, 2021	694.70	-4.33%	572.14	-2.81%	644.55	-0.39%	595.89	-3.46%	441.25	-3.57%	69.84	-4.35%
16th - 30th Sept, 2021	720.53	3.72%	604.55	5.66%	682.00	5.81%	627.53	5.31%	472.65	7.12%	72.43	3.71%
1st - 15th Oct, 2021	718.60	-0.27%	629.55	4.14%	706.63	3.61%	653.65	4.16%	490.15	3.70%	74.57	2.95%
16th - 31st Oct, 2021	783.61	9.05%	690.00	9.60%	774.30	9.58%	720.23	10.19%	523.50	6.80%	80.88	8.46%
1st - 15th Nov, 2021	821.50	4.84%	731.80	6.06%	812.11	4.88%	765.07	6.23%	538.93	2.95%	84.61	4.61%
16th - 30th Nov, 2021	837.77	1.98%	720.50	-1.54%	825.48	1.65%	751.04	-1.83%	526.00	-2.40%	83.63	-1.16%
1st - 15th Dec, 2021	768.61	-8.26%	680.09	-5.61%	766.82	-7.11%	710.41	-5.41%	511.98	-2.67%	81.25	-2.85%
16th - 31st Dec, 2021	685.68	-10.79%	628.28	-7.62%	683.28	-10.89%	663.83	-6.56%	477.78	-6.68%	73.38	-9.69%
Min	*436.69*		*419.28*		*445.69*		*441.03*		*332.75*		*50.70*	
Max	*837.77*		*731.80*		*825.48*		*765.07*		*538.93*		*84.61*	
Average	*660.94*		*570.10*		*593.41*		*594.28*		*446.10*		*69.45*	
Total Decreses		*-26.65%*		*-25.67%*		*-31.22%*		*-23.53%*		*-29.27%*		*-29.06%*
Total Increases		*80.25%*		*74.41%*		*84.85%*		*73.81%*		*71.04%*		*73.53%*
Net Change		*53.60%*		*48.75%*		*53.63%*		*50.28%*		*41.77%*		*44.48%*

7.10 Exchange Rate

The BoG Interbank exchange rate of the Ghana Cedi against the USD generally traded high throughout 2021. The average USD/GHS exchange rate monitored by the Bank of Ghana for the period ranged between USD/GHS5.7225 and USD/GHS5.9344, averaging USD/GHS5.7959. The lowest exchange rate was recorded in the first window of January, while the highest exchange rate was recorded in the second window of December. The Bank of Ghana's exchange rate monitored throughout the year saw a net depreciation of 3.74%.

The average USD/GHS exchange rate monitored from the Commercial Banks (Absa, Stanbic and Standard Chartered) for the period ranged between USD/GHS5.7819 and USD/GHS6.3637, and averaged USD/GHS5.9835. The lowest exchange rate was recorded in the second window of March, while the highest exchange rate was recorded in the second window of December. The average commercial banks' exchange rate monitored throughout the year saw a net depreciation of 7.32%. The spread between the BOG Interbank rate and the Market rate averaged GHp19 in 2021.

Figure 102: FX Rates US$/GHS (2021)

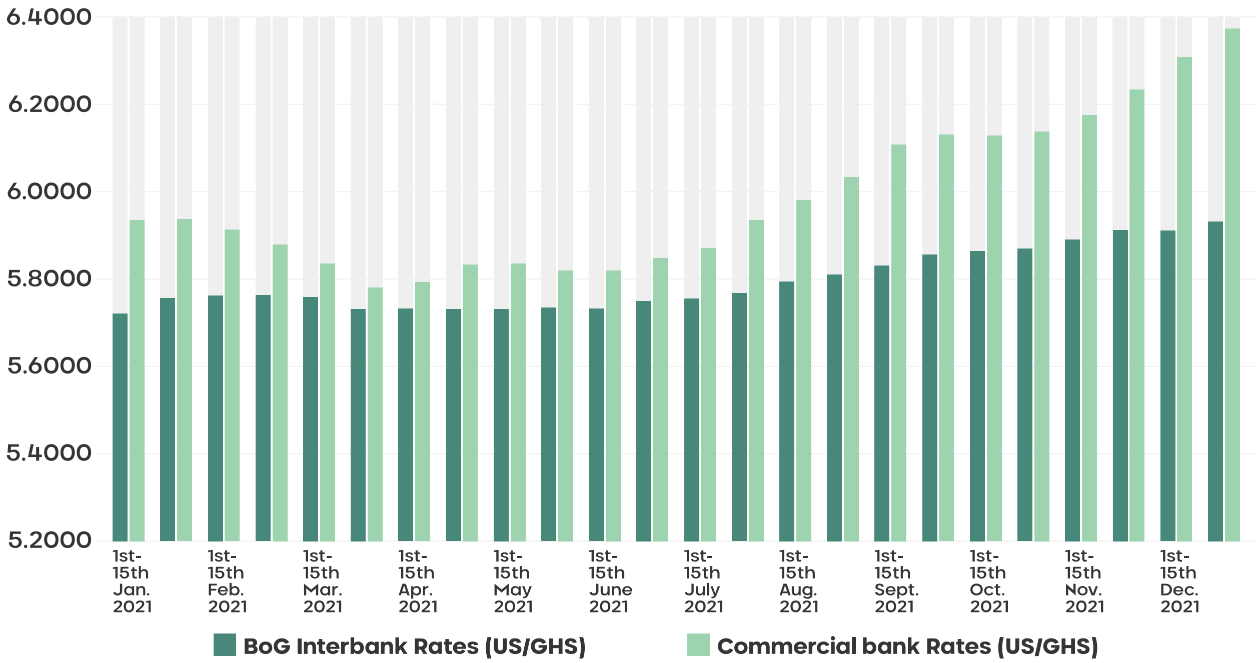


Figure 103: Trend of US$/GHS Exchange Rate (January – December 2021)

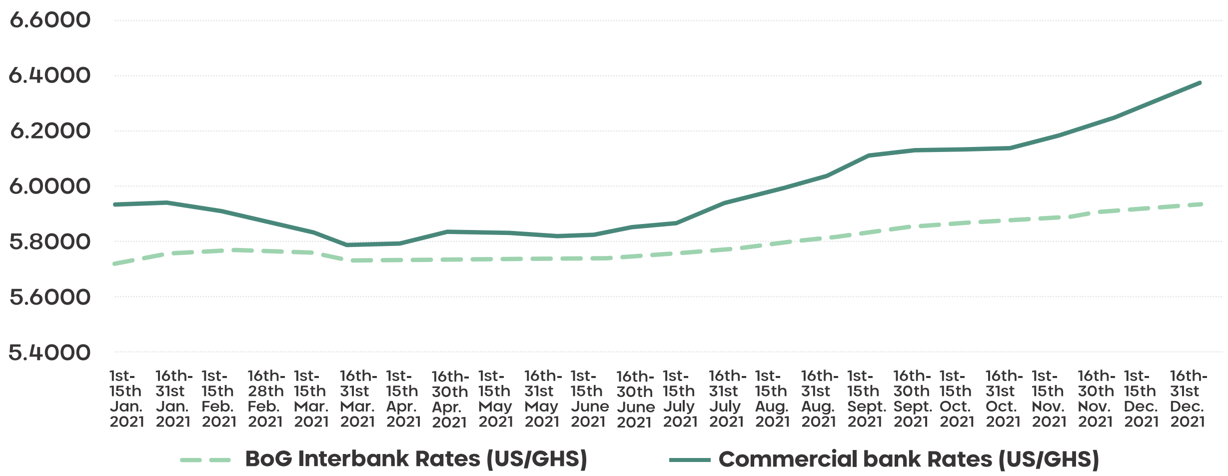


Figure 104: Trend of BOG US$/GHS Exchange Rate Appreciation (Decrease)/Depreciation (Increase) (Jan. – Dec. 2021)

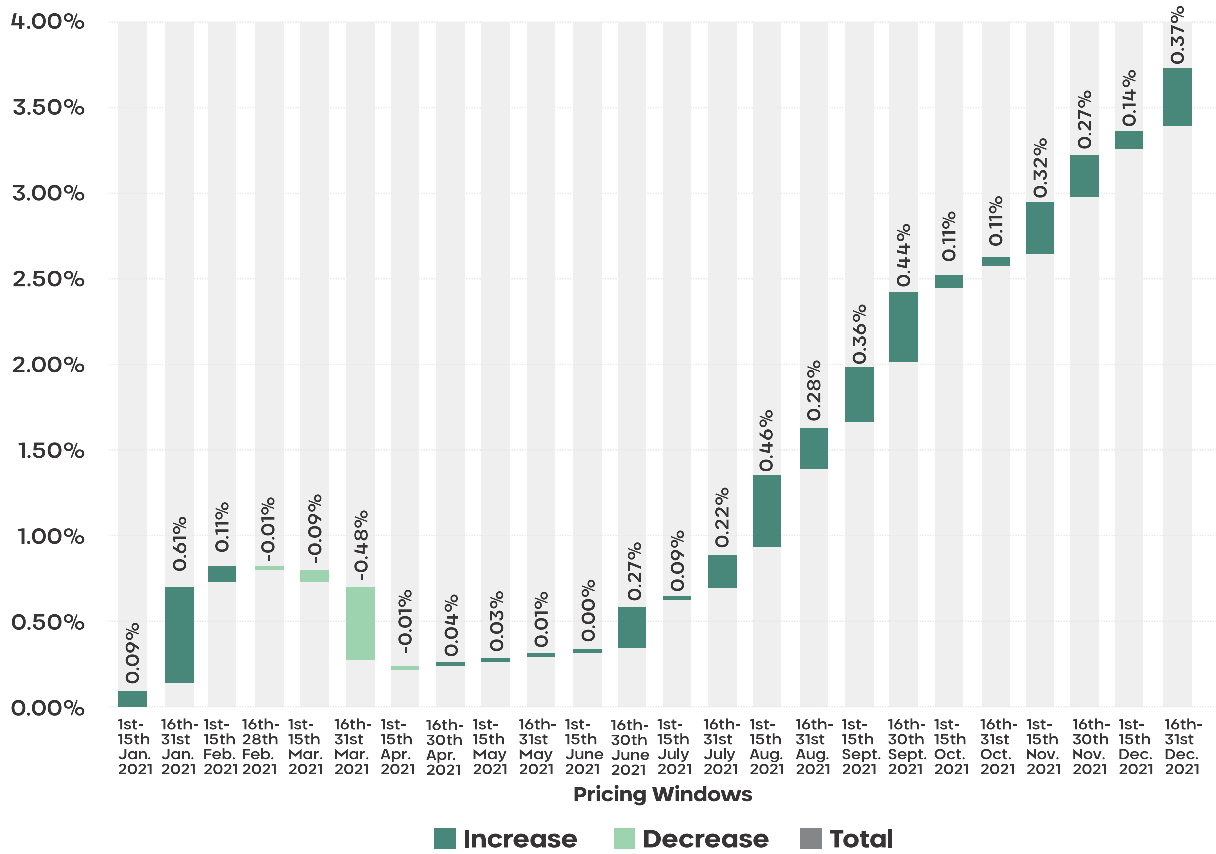


Table 24: **US$/GHS exchange rates for the period 2021**

Pricing Window	BoG Interbank Rates (USD/GHS)	%age Change	Commercial Bank Rate (USD/GHS)	%age Change
1st - 15th Jan, 2021	5.7225	0.09%	5.9330	0.26%
16th - 31st Jan, 2021	5.7573	0.61%	5.9352	0.04%
1st - 15th Feb, 2021	5.7638	0.11%	5.9130	-0.37%
16th - 28th Feb, 2021	5.7634	-0.01%	5.8769	-0.61%
1st - 15th Mar, 2021	5.7581	-0.09%	5.8360	-0.70%
16th - 31st Mar, 2021	5.7303	-0.48%	5.7819	-0.93%
1st - 15th Apr, 2021	5.7300	-0.01%	5.7918	0.17%
16th - 30th Apr, 2021	5.7322	0.04%	5.8331	0.71%
1st - 15th May, 2021	5.7339	0.03%	5.8339	0.01%
16th - 31st May, 2021	5.7345	0.01%	5.8203	-0.23%
1st - 15th June, 2021	5.7347	0.00%	5.8197	-0.01%
16th - 30th June, 2021	5.7503	0.27%	5.8494	0.51%
1st - 15th July, 2021	5.7553	0.09%	5.8687	0.33%
16th - 31st July, 2021	5.7681	0.22%	5.9363	1.15%
1st - 15th Aug, 2021	5.7944	0.46%	5.9786	0.71%
16th - 31st Aug, 2021	5.8107	0.28%	6.0273	0.81%
1st - 15th Sept, 2021	5.8315	0.36%	6.1082	1.34%
16th - 30th Sept, 2021	5.8571	0.44%	6.1277	0.32%
1st - 15th Oct, 2021	5.8635	0.11%	6.1257	-0.03%
16th - 31st Oct, 2021	5.8698	0.11%	6.1373	0.19%
1st - 15th Nov, 2021	5.8884	0.32%	6.1730	0.58%
16th - 30th Nov, 2021	5.9042	0.27%	6.2289	0.91%
1st - 15th Dec, 2021	5.9126	0.14%	6.3036	1.20%
16th - 31st Dec, 2021	5.9344	0.37%	6.3637	0.95%
Min	*5.7225*		*5.7819*	
Max	*5.9344*		*6.3637*	
Average	*5.7959*		*5.9835*	
Total Decreses		*-0.59%*		*-2.88%*
Total Increases		*4.33%*		*10.20%*
Net Change		*3.74%*		*7.32%*

7.11 Ex-Refinery Prices

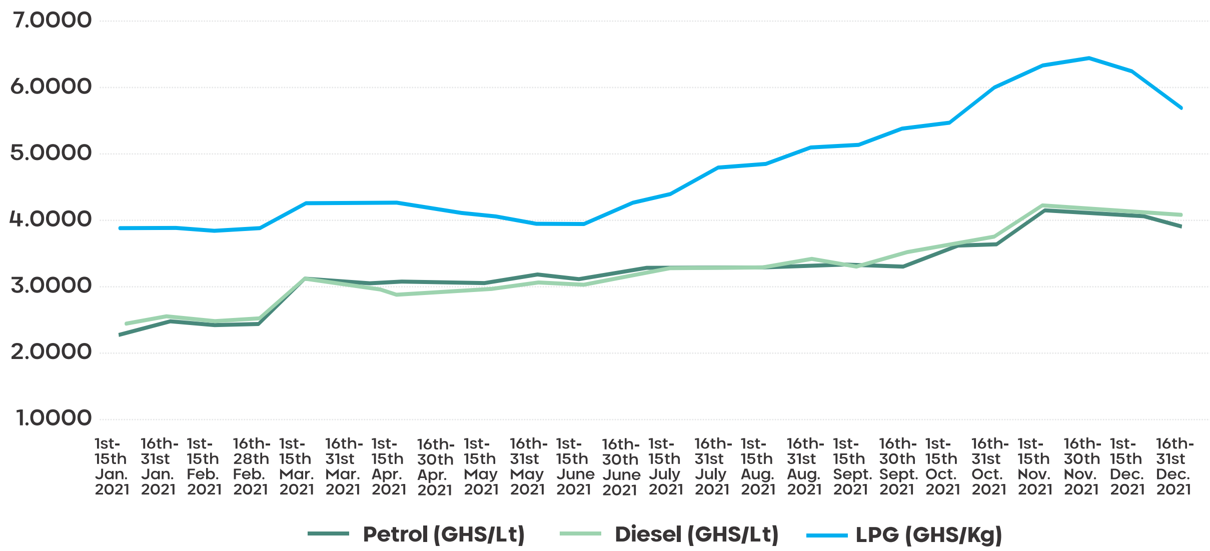
The year under review saw the average ex-refinery price for petrol ranging between GHS2.3000/Lt and GHS4.1400/Lt, and averaging GHS3.2623/Lt. The lowest ex-refinery price was recorded in the first window of January, while the highest was recorded in the first and second windows of November. The ex-refinery price of petrol saw a net increase of 59.86% in 2021. The ex-refinery price of petrol constituted 55% of the average ex-pump price for 2021.

The average ex-refinery price for diesel ranged between GHS2.4500/Lt and GHS4.2200/Lt, and averaged GHS3.2804/Lt. The lowest ex-refinery price was recorded in the first window of January, while the highest was recorded in the second window of November. The ex-refinery price of diesel saw a net increase of 58.18% in 2021. The ex-refinery price of diesel constituted 56% of the average ex-pump price for 2021.

The average ex-refinery price for LPG ranged between GHS3.8500/Lt and GHS6.4500/Lt, and averaged GHS4.7810/Lt. The lowest ex-refinery price was recorded in the first window of February, while the highest was recorded in the second window of November. The ex-refinery price of LPG saw a net increase of 47.67% in 2021. The ex-refinery price of petrol constituted 70% of the average ex-pump price for 2021.

Year-on-year, all three products on average recorded drops in their ex-refinery prices by 26.91%, 24.37% and 6.63% for gasoline, gasoil and LPG, respectively.

Figure 105: **Trend of Ex-Refinery Prices for 2021 (GHS/Lt;Kg)**



As can be seen in the graph, the ex-refinery prices fell significantly from March to May 2022. This was in response to the fall in the FOB prices of crude oil and finished products over the same period.

7.12 Ex-Pump Prices

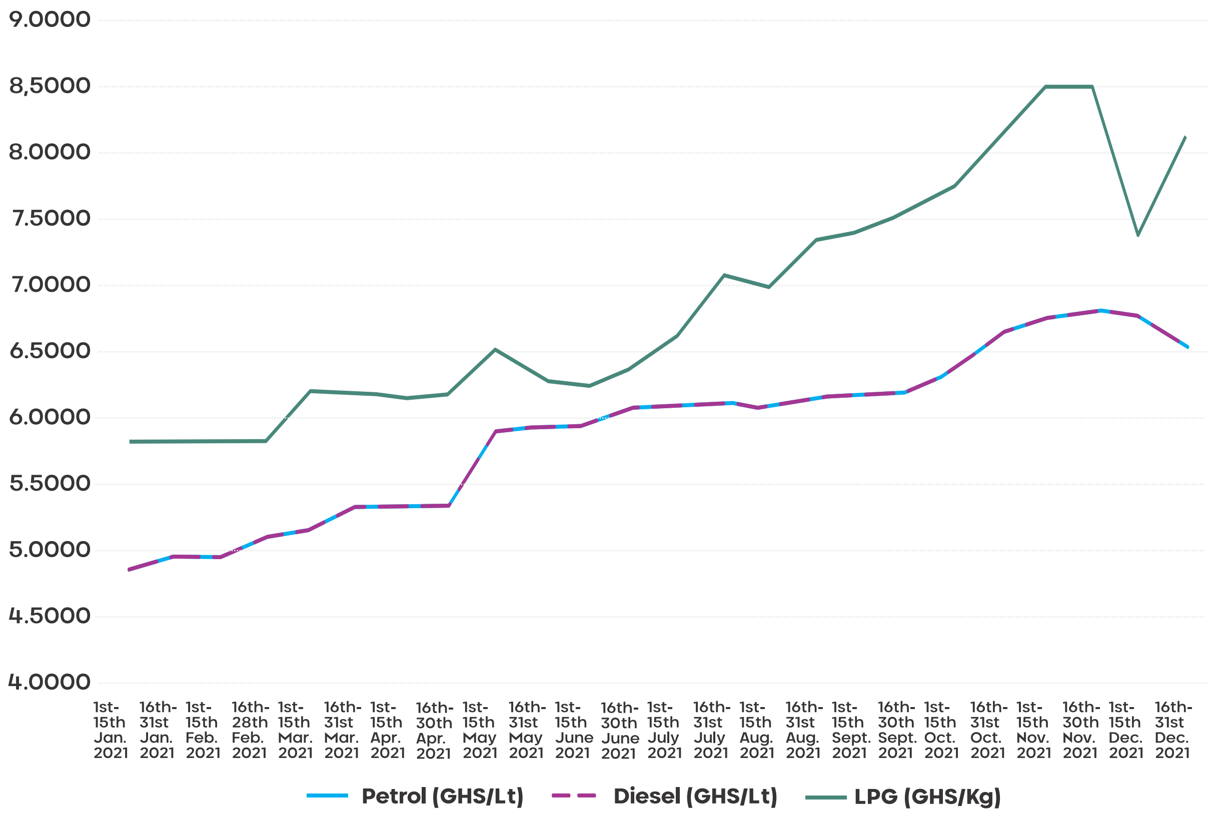
The average ex-pump price of petrol in the year 2021 ranged between GHS4.8619/Lt and GHS6.8075/Lt, and averaged GHS5.8988/Lt, up 26 percent from 2020. The lowest price was recorded in the first window of January, while the highest price was recorded in the second window of November. The ex-pump price of petrol in 2021 saw a net increase of 33.29%.

The average ex-pump price of diesel for the period ranged between GHS4.8622/Lt and GHS6.8094/Lt and averaged GHS5.8984/Lt, up 25 percent from 2020. The lowest price was recorded in the first window of January, while the highest price was recorded in the second window of November. The ex-pump price of diesel in 2021 saw a net increase of 33.28%.

The average ex-pump price of LPG for the period ranged between GHS5.8182/Kg and GHS8.5069/Kg, and averaged GHS6.8677/Kg, up 33 percent from 2020. The lowest price was recorded in the first window of January, while the highest price was recorded in the second window of November. The ex-pump price of LPG in 2021 saw a net increase of 41.47%.

Please see Figure 106, a graphical representation of the trend of the ex-pump prices of gasoline, gasoil and LPG in the year 2021.

Figure 106: Trend of Ex-Pump Prices for the year 2021 (GHS/Lt;Kg)



The graph shows a fall in ex-pump prices from March to May, in the same way, the FOB prices and ex-pump prices fell during the same period. This is a reflection of the direct relationship between the prices of petroleum products on the world market and ex-pump prices.

Table 25: Average Ex-Pump Prices

Pricing Window	Petrol (GHS/Lt)	%age Change	Diesel (GHS/Lt)	%age Change	LPG (GHS/Kg)	%age Change
1st - 15th Jan. 2021	4.8619	2.60%	4.8622	2.60%	5.8182	5.73%
16th - 31st Jan. 2021	4.9596	2.01%	4.9596	2.00%	5.8383	0.35%
1st - 15th Feb. 2021	4.9469	-0.26%	4.9469	-0.26%	5.8235	-0.25%
16th - 28th Feb. 2021	5.1108	3.31%	5.0792	2.67%	5.8235	0.00%
1st - 15th Mar. 2021	5.1694	1.15%	5.1644	1.68%	6.1990	6.45%
16th - 31st Mar. 2021	5.3269	3.05%	5.3340	3.28%	6.2008	0.03%
1st - 15th Apr. 2021	5.3173	-0.18%	5.3159	-0.34%	6.1411	-0.96%
16th - 30th Apr. 2021	5.3277	0.20%	5.3301	0.27%	6.1853	0.72%
1st - 15th May. 2021	5.8958	10.66%	5.8914	10.53%	6.5158	5.34%
16th - 31st May. 2021	5.9308	0.59%	5.9328	0.70%	6.3124	-3.12%
1st - 15th June. 2021	5.9409	0.17%	5.9397	0.12%	6.2360	-1.21%
16th - 30th June. 2021	6.0689	2.15%	6.0698	2.19%	6.3723	2.19%
1st - 15th July. 2021	6.1146	0.75%	6.1169	0.78%	6.6358	4.14%
16th - 31st July. 2021	6.1066	-0.13%	6.1064	-0.17%	7.0720	6.57%
1st - 15th Aug. 2021	6.0854	-0.35%	6.0843	-0.36%	6.9792	-1.31%
16th - 31st Aug. 2021	6.1581	1.20%	6.1636	1.30%	7.3505	5.32%
1st - 15th Sept. 2021	6.1731	0.24%	6.1772	0.22%	7.4013	0.69%
16th - 30th Sept. 2021	6.1918	0.30%	6.1918	0.24%	7.5658	2.22%
1st - 15th Oct. 2021	6.3566	2.66%	6.3586	2.69%	7.7514	2.45%
16th - 31st Oct. 2021	6.6304	4.31%	6.6327	4.31%	8.1280	4.86%
1st - 15th Nov. 2021	6.7663	2.05%	6.7645	1.99%	8.5033	4.62%
16th - 30th Nov. 2021	6.8075	0.61%	6.8094	0.66%	8.5069	0.04%
1st - 15th Dec. 2021	6.7744	-0.49%	6.7800	-0.43%	7.3614	-13.46%
16th - 31st Dec. 2021	6.5492	-3.32%	6.5500	-3.39%	8.1030	10.07%
Min	*4.8619*		*4.8622*		*5.8182*	
Max	*6.8075*		*6.8094*		*8.5069*	
Average	*5.8988*		*5.8984*		*6.8677*	
Total Decreses		-4.73%		-4.95%		-20.32%
Total Increases		38.02%		38.24%		61.79%
Net Change		33.29%		33.28%		41.47%

7.13 Marketers and Dealers Margins

The estimated "Marketers and Dealers Margins" used by OMCs for petrol ranged between GHp33.00/Lt and GHp70.00/Lt, and averaged GHp50.4167/Lt, down 26 percent from 2020. The lowest margin was recorded in the first window of December, while the highest margin was recorded in the second window of October. The "Marketers and Dealers Margin" of petrol saw a net increase of 9.01% in 2021.

The estimated "Marketers and Dealers Margins" used by OMCs for diesel ranged between GHp23.00/Lt and GHp67.00/Lt, and averaged GHp49.25/Lt, down 9 percent from 2020. The lowest margin was recorded in the second window of December, while the highest margin was recorded in the first window of September. The "Marketers and Dealers Margin" of diesel saw a net decrease of 20.11% in 2021.

The estimated "Marketers and Dealers Margins" used by OMCs for LPG ranged between GHp50.2247/Kg and GHp82.2247/Kg, and averaged GHp65.0070/Kg, up 16 percent from 2020. The lowest margin was recorded in the second window of August, while the highest margin was recorded in the second window of July. The "Marketers and Dealers Margin" of LPG saw a net increase of 68.36% in 2021.

Figure 107: Trend of Marketers and Dealers Margins for the year 2021 (GHp/Lt;Kg)

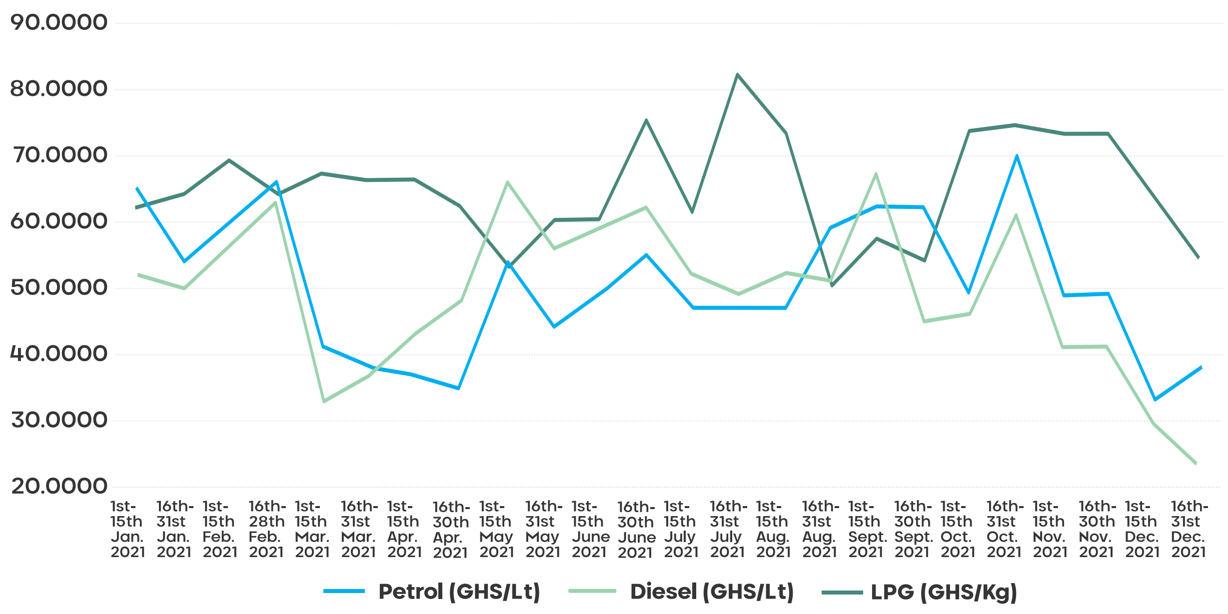
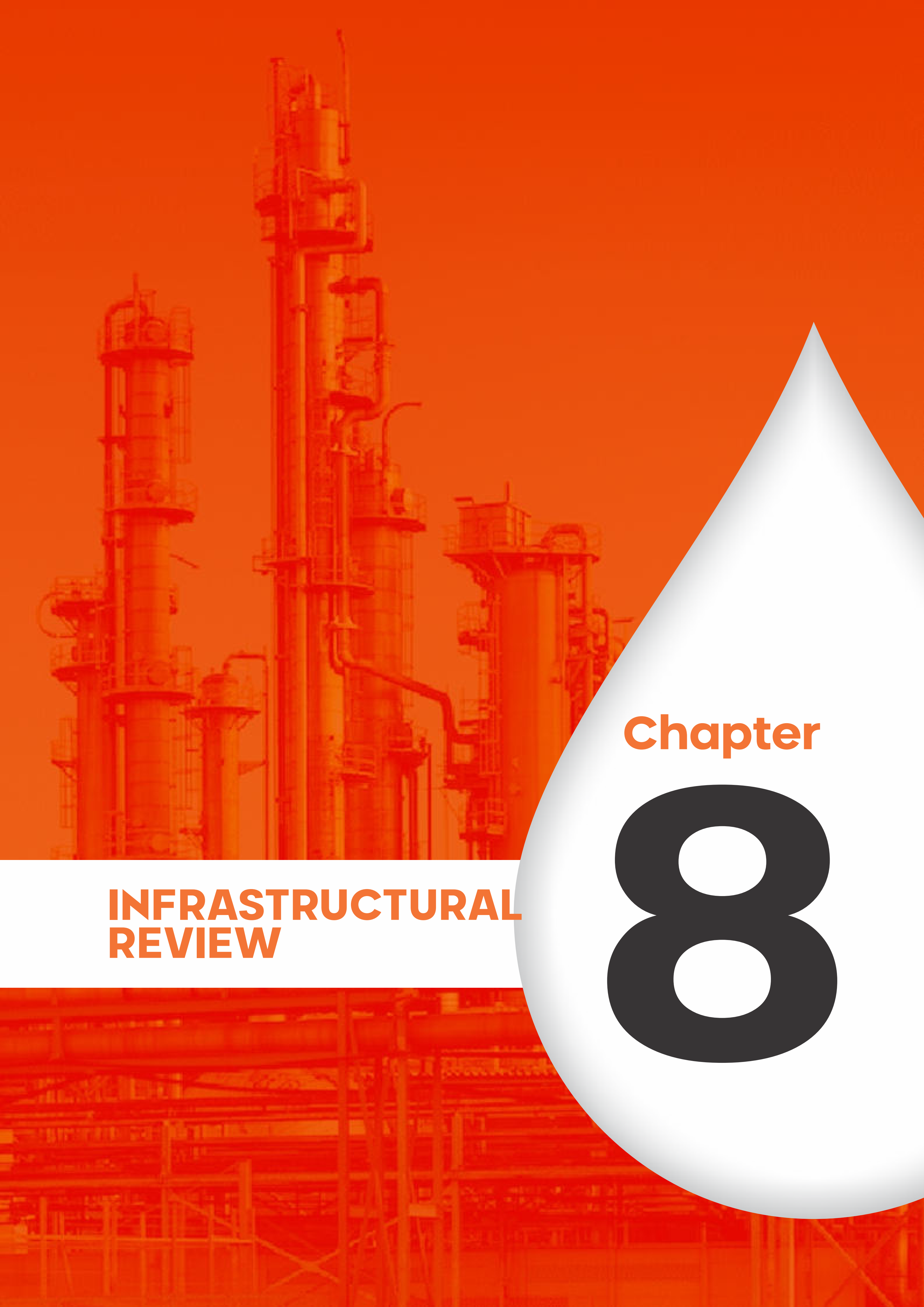


Table 26: Marketers' and Dealers' Margins

Pricing Window	Petrol (GHp/Lt)	%age Change	Diesel (GHp/Lt)	%age Change	LPG (GHp/Kg)	%age Change
1st - 15th Jan, 2021	65.0000	*8.22%*	52.0000	*1.17%*	62.2247	*54.69%*
16th - 31st Jan, 2021	54.0000	*-16.92%*	50.0000	*-3.85%*	64.2247	*3.21%*
1st - 15th Feb, 2021	60.0000	*11.11%*	56.0000	*12.00%*	69.2247	*7.79%*
16th - 28th Feb, 2021	66.0000	*10.00%*	63.0000	*12.50%*	64.2247	*-7.22%*
1st - 15th Mar, 2021	41.0000	*-37.88%*	33.0000	*-47.62%*	67.2247	*4.67%*
16th - 31st Mar, 2021	38.0000	*-7.32%*	37.0000	*12.12%*	66.2247	*-1.49%*
1st - 15th Apr, 2021	37.0000	*-2.63%*	43.0000	*16.22%*	66.2247	*0.00%*
16th - 30th Apr, 2021	35.0000	*-5.41%*	48.0000	*11.63%*	62.2247	*-6.04%*
1st - 15th May, 2021	54.0000	*54.29%*	66.0000	*37.50%*	53.2247	*-14.46%*
16th - 31st May, 2021	44.0000	*-18.52%*	56.0000	*-15.15%*	60.2247	*13.15%*
1st - 15th June, 2021	49.0000	*11.36%*	59.0000	*5.36%*	60.2247	*0.00%*
16th - 30th June, 2021	55.0000	*12.24%*	62.0000	*5.08%*	75.2247	*24.91%*
1st - 15th July, 2021	47.0000	*-14.55%*	52.0000	*-16.13%*	61.2247	*-18.61%*
16th - 31st July, 2021	47.0000	*0.00%*	49.0000	*-5.77%*	82.2247	*34.30%*
1st - 15th Aug, 2021	47.0000	*0.00%*	52.0000	*6.12%*	73.2247	*-10.95%*
16th - 31st Aug, 2021	59.0000	*25.53%*	51.0000	*-1.92%*	50.2247	*-31.41%*
1st - 15th Sept, 2021	62.0000	*5.08%*	67.0000	*31.37%*	57.2247	*13.94%*
16th - 30th Sept, 2021	62.0000	*0.00%*	45.0000	*-32.84%*	54.2247	*-5.24%*
1st - 15th Oct, 2021	49.0000	*-20.97%*	46.0000	*2.22%*	73.2247	*35.04%*
16th - 31st Oct, 2021	70.0000	*42.86%*	61.0000	*32.61%*	74.2247	*1.37%*
1st - 15th Nov, 2021	49.0000	*-30.00%*	41.0000	*-32.79%*	73.2247	*-1.35%*
16th - 30th Nov, 2021	49.0000	*0.00%*	41.0000	*0.00%*	73.0000	*-0.31%*
1st - 15th Dec, 2021	33.0000	*-32.65%*	29.0000	*-29.27%*	63.2247	*-13.39%*
16th - 31st Dec, 2021	38.0000	*15.15%*	23.0000	*-20.69%*	54.2247	*-14.23%*
Min	*33.0000*		*23.0000*		*50.2247*	
Max	*70.0000*		*67.0000*		*82.2247*	
Average	*50.4167*		*49.2500*		*65.0070*	
Total Decreses		*-186.84%*		*-206.02%*		*-124.70%*
Total Increases		*195.85%*		*185.91%*		*193.06%*
Net Change		*9.01%*		*-20.11%*		*68.36%*



Chapter

8

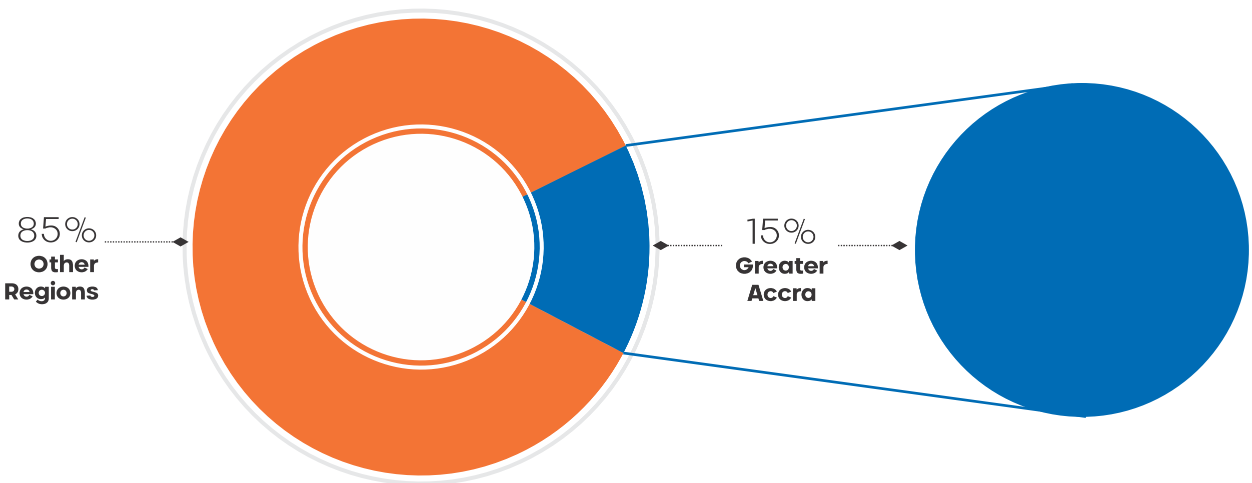
INFRASTRUCTURAL REVIEW

Infrastructural Review

8.1 Storage

Greater Accra Region remained host to most of Ghana's storage infrastructure accounting for over 80% of national storage. These petroleum terminals are largely privately owned with exceptions being Tema Oil Refinery (T.O.R.) and the Accra Plains Depot (A.P.D.) owned by Bulk Oil Storage and Transportation.

Figure 108: Distribution of Storage facilities



The Tema/Kpone Enclave continues to serve as the country's petroleum hub serving the local market and providing the channel (A.P.D) through which other parts of the country are served. It remains the only area that has storage capacity for all petroleum products served on the market.

Ghana's petroleum storage capacity in 2021 increased by 1% to 1.9 million mt. Two LPG storage infrastructures that were added had capacities of 6,000 mt and 3,000 mt. This

- B.O.S.T and T.O.R continue to have the largest storage capacities for gasoil, gasoline and crude Oil.
- Tema Tank Ltd. continues to be the privately owned terminal with the largest storage capacity (about 192,000 m^3).
- Gasoil storage capacity remains the largest in the country from the 2019 Ghana Petroleum Industry Report.

* My very sincere gratitude goes to Professor Christine Dowuona-Hammond of the University of Ghana School of Law, for reviewing and editing this article. This Article has been published in (2020-2021) Vol. 31 UGLJ.

[12] ACEP (2021) Advisory Paper on Power Sector Priorities for Government Action (Access here: https://bit.ly/2WcYlxX)

The Country's largest Refinery, T.O.R., remains very strategic as it has storage capacity for almost all petroleum products, ranging from Crude Oil to its distillates. Apart from its about 17,500 m^3 LPG storage capacity, pipelines of other terminals, such as Quantum, T.M.P.T. and T.F.C. are tied in into TOR's pipelines. The same can be said of the Ridge Terminal that transits JET A1 fuel to the KIA Terminal through Bulk Road Vehicles after receiving through the Tema Oil Jetty.

Gasoil storage terminals dominate the Takoradi market due to a lot of bunkering and mining activities in the area. The Blue Ocean terminal in Takoradi remains the ONLY terminal with gasoline storage to serve that market. The Zen Terminal is ONLY a gasoil storage facility to serve the Takoradi market.

8.2 Acquisitions

After Zen acquired the Cirrus Terminal in Takoradi and Vana Energy Ltd. also acquired the Cirrus Terminal in Tema, in 2019, the ownerships of these storage terminals have largely remained unchanged in 2020.

Vana Terminal receives 1,500 ppm gasoil from TOR through pipelines to serve its customers. However, gasoline receipt into the terminal is through the ABB facility via TOR Y-junction.

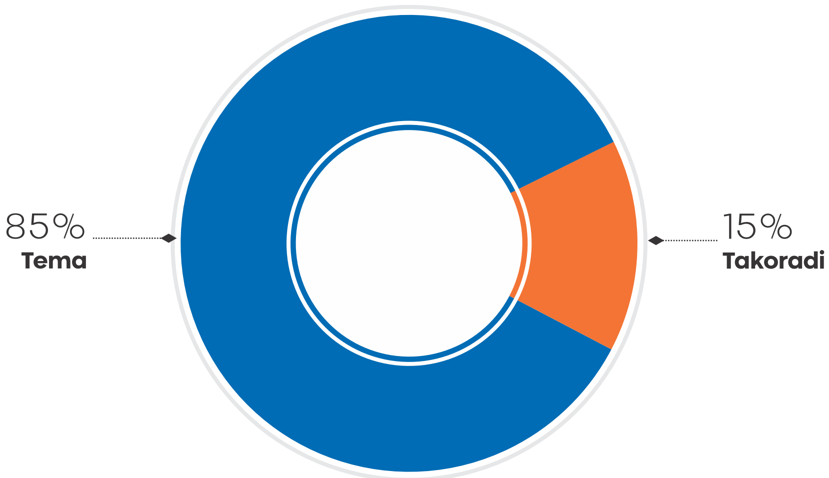
8.3 Discharge Facilities

There was about 7.78% increase (compared to the 2019 figures) in the total volume of petroleum products discharged through the 4 main discharge facilities in the country: Tema ABB, Tema Oil Jetty, Tema Main Port and Takoradi Oil Jetty.

Over 90% of Ghana's total petroleum imports (4.72 m mt) came through the 3 discharge facilities located in Tema.

This can be largely attributed to the vast majority of petroleum storage facilities located in this area, as well as the quantum of petroleum activities in this area (link to other regions).

Figure 109: Petroleum Discharge Facility Distribution



About 3.87 m mt (about 82% of total import, an improvement of 2019 -75%) of petroleum product was discharged through the ABB/SPM Facility. All the major terminals in Tema are linked to this facility, as such, commanding this high throughput. Keeping this facility up and running further strengthens the product security of the country. It serves as a major source of gasoil, gasoline and Crude Oil import.

Takoradi Jetty serves as the 2nd major source of gasoil imports in the country. Out of about 445,463 mt of total imports through that facility, gasoil/MGO contributed to about 87.2% of its import, largely due to the quantum of bunkering and mining activities in the area. The Blue Ocean terminal in Takoradi remains the only facility with gasoline storage in the area.

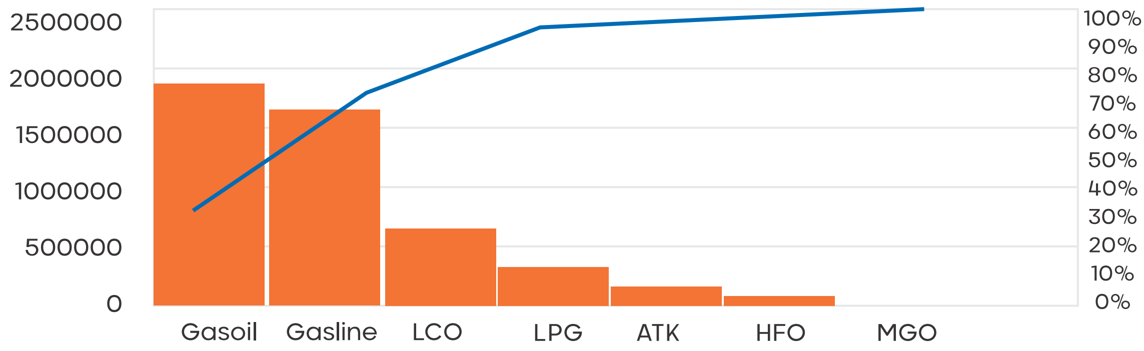
The Tema Oil Jetty remains a driving force for LPG Imports into the country. About 240,482 mt out of the total LPG import of 261,650 mt in 2020 was discharged through this facility. TOR, TMPT and TFC are the main LPG storage facilities in Tema

It also served as the ONLY discharge facility through which ATK was imported. As such, this facility remains very instrumental and critical in Ghana's Aviation Industry. ATK discharged through this facility are largely to TOR and the Ridge Terminal in Tema.

About 0.5% of Ghana's total petroleum import was discharged through the Tema Main Port.

Overall, gasoil/MGO was imported the most (about 41%) in 2020. Gasoline followed closely at about 35.6 %. It can be deduced that gasoil/gasoline (about 76.5%) are the most consumed petroleum product in the country.

Figure 110: Petroleum Import in all 4 Discharge Facilities

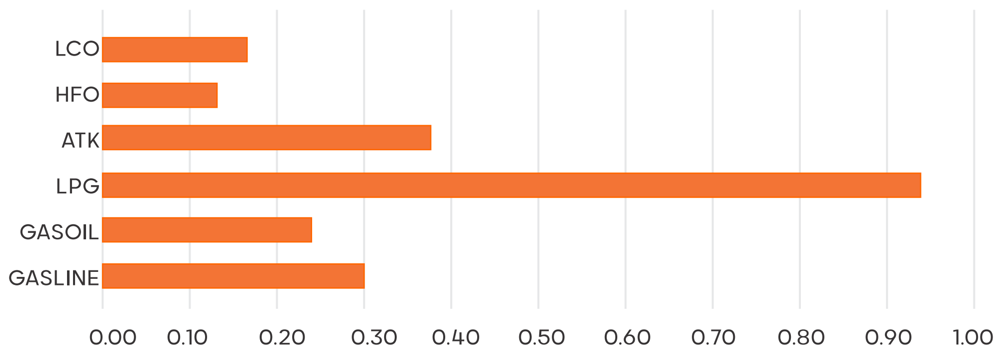


8.4 Depot Utilizations

The national average tank-turn rate was 0.20 times per month for 2020, which is not too far from 0.21 for both 2018 and 2019. Below are tank-turn rates for storage facilities of some petroleum products.

- Gasoline 0.30 times per month (as against 0.25 in 2019). This represents some improvement.
- Gasoil 0.23 times per month (as against 0.22 in 2019).
- LPG 0.92 times per month, representing the highest.
- ATK 0.28 times per month.

Figure 111: Tank Turn Rate (2020)



Ghana's storage facilities continue to be underutilized per the 1 per month global minimum tank-turn. This is expected to continue should more storage facilities be added (which is likely) and there is no significant improvement in the national consumption of petroleum products (more demand).

8.5 Projects

Quantum's LPG facility is yet to be fully commissioned. Quantum Gas Terminal Ltd. (QGTL) is expected to store and deliver propane for power generation. 4 parcels of propane have already been received into the 3 spheres (about 13,600 m3) in the facility via the Tema Oil Jetty. The power generation plant is currently being commissioned in phases.

Quantum LPG Logistics Ltd. (QLLL) is currently being completed and has started operating to serve the domestic market with butane. 3 LPG bullets of a total capacity 900 mt have been constructed.

Construction of Vihama's tank farm facility is still ongoing. Pipelines are being laid and the terminal is expected to be ready in Q4 2021. Should it be completed, 50,000 m3 (25,000 m3 each of gasoil and gasoline) is expected to be added to the petroleum storage of the country.

Matrix Gas 6,000 mt LPG Facility has been completed and has started operations. This terminal was completed in late Q4 2021.

8.6 The Sentuo Oil Refinery Project

The Sentuo Oil Refinery Limited (SORL) was incorporated in Ghana on 18th November 2018 under Ghana's Company Code. The company will construct and operate a 100,000 bpsd complex petroleum refinery to process light, medium, and heavy crude oil into various products such as Diesel, Liquefied Petroleum Gas, Aviation Turbine Kerosene, Gasoline, Fuel Oil and Sulphuric Acid. The company after the completion of Phase 2 will be capable of supplying about 90% of Ghana's refined petroleum needs. The project will be executed in two phases; Phase 1, made up of 40,000 bpsd crude oil processing capacity, and Phase 2, constituting an additional 60,000 bpsd capacity. Phase 1 is expected to be operational by the end of March 2023 and Phase 2 by the end of March 2025. The site of the proposed oil refinery is located within the Tema Heavy Industrial Area. The size of the land for the refinery is 100 acres located on Plot No. IND/HI/21/5 at the Tema Heavy Industrial Area, which is one of the core areas of Ghana's industrial activities.

The Refinery will have the ability to produce to international specifications for all refined products, operate in an environmentally acceptable way, and have all the automation and controls to ensure safe operations

A major advantage of a reliable and efficient refinery in Ghana will be the foreign exchange savings over the import of refined products.
The nation will be self-sufficient in refined products since as the developed countries implement their green energy projects, their refineries are closing and sources for imports will dwindle.

8.7 Tema Oil Refinery and Decimal Capital agreement

The government of Ghana through the Ministry Of Energy has given TOR the go-ahead to negotiate the lease agreement to refine crude oil with a private investor, Decimal Capital Limited, whose proposal emerged as the most favoured to meet the needs of the refinery among other hosts of proposals that were presented to the government. TOR is expected to restart operations when negotiations with Decimal Capital are fully completed; this arrangement will help to boost the domestic supply of refined oil products in the wake of the ongoing global market crises.

It is expected that TOR's position would be strengthened to boost the local supply of petroleum products and help stabilize the Ghana cedi in the phase of continued forex shortage. A local transactional advisor has been contracted by TOR to lead the negotiation in formulating the lease agreement. Production from TOR can contribute about a third of the current monthly consumption of diesel and the full requirement of ATK and fuel oil needs of the country. This is expected to contribute significantly to improving fuel security in the country. TOR, when fully operational, is expected to produce 45,000 bpsd. Output from phase one of this partnership project would be used to revamp the RFCC and the other associated units of the company to maximize production from the refinery.

Appendices

Appendix 1

2021 (JAN - DEC) PETROLEUM TAX REVENUE

Tax Revenues	GASOLINE	GASOIL	KEROSENE	MGO LOCAL	FUEL OIL	LPG DOMESTIC	LPG POWER	UNIFIED	MGO Foreign	ATK	GASOIL MINES	GASOIL RIGS	PREMIX	EXEMPTIONS	EST. TAX LOST (SUSPENSION/LATE INTRO.)	TOTAL
ENERGY DEBT RECOVERY LEVY	1,110,827,501	1,026,229,932	-	743,021	6,806,924	141,646,011	-	-	3,992,842	-	172,303,159	17,967,344	-	(84,974,085)		**2,395,542,648**
ROAD FUND	1,088,157,552	1,005,286,464	-	-	-	-	-	-	3,911,356	-	168,786,768	17,600,663	-	(83,239,920)		**2,200,502,883**
ENERGY FUND	22,669,949	20,943,468	56,880	-	1,701,731	-	-	-	81,487	-	3,516,391	366,680	-	(1,734,165)		**47,602,421**
PRICE STABILISATION AND RECOVERY LEVY	362,719,184	293,208,552	-	-	-	48,366,931	-	-	1,140,812	-	49,229,474	5,133,527	-	(24,278,310)	(122,599,362)	**612,920,808**
EXPORT DUTY	-	-	-	-	-	-	-	-	-	28,462,321	-	-	-	-		**28,462,321**
SPT	1,042,817,654	963,399,528	2,218,320	-	-	165,829,476	-	670,680	-	-	161,753,986	16,867,302	-	-		**2,353,556,946**
SANITATION AND POLLUTION LEVY	226,699,490	226,699,490	-	-	-	-	-	-	-	-	-	-	-	(17,341,650)	(153,963,050)	**282,094,280**
ENERGY SECTOR RECOVERY LEVY	453,398,980	453,398,980	-	-	-	-	408,059,082	-	-	-	-	-	-	(34,683,300)	(446,492,845)	**833,680,897**
Total	4,307,290,310	3,989,166,414	2,275,200	743,021	8,508,655	355,842,417	408,059,082	670,680	9,126,497	28,462,321	555,589,778	57,935,516	-	(246,251,430)	(723,055,257)	8,754,363,204
Product Share of Revenue	49.20%	45.57%	0.03%	0.01%	0.10%	4.06%	4.66%	0.01%	0.10%	0.33%	6.35%	0.66%	0.00%	-2.81%	-8.26%	111.07%
	100															

2021 (JAN - DEC) PETROLEUM TAX RATES AND VOLUMES

Tax Revenues	GASOLINE	GASOIL (REG.)	KEROSENE	MGO LOCAL	FUEL OIL	LPG DOMESTIC	LPG POWER	UNIFIED	MGO Foreign	ATK*	GASOIL MINES	GASOIL RIGS	PREMIX	TOTAL
VOLUMES (LITRES EXCEPT LPG IN KG)	2,266,994,900	2,094,346,800	5,688,000	24,767,350	170,173,097	345,478,075		1,458,000	8,148,658	250,548,600	351,639,100	36,668,048	104,098,500	**5,660,009,128**
ENERGY DEBT RECOVERY LEVY	49.00	49.00	-	3.00	4.00	41.00		-	49.00	-	49.00	49.00	-	
ROAD FUND	48.00	48.00	-	-	-	-		-	48.00	-	48.00	48.00	-	
ENERGY FUND	1.00	1.00	1.00	-	1.00	-		-	1.00	-	1.00	1.00	-	
PRICE STABILISATION AND RECOVERY LEVY	16.00	14.00	-	-	-	14.00		-	14.00	-	14.00	14.00	-	
EXPORT DUTY	-	-	-	-	-	-		-	-	11.36	-	-	-	
SPT	46.00	46.00	39.00		-	48.00	48.00	46.00	-	-	46.00	46.00	-	
SANITATION AND POLLUTION LEVY	10.00	10.00												
ENERGY SECTOR RECOVERY LEVY	20.00	20.00					18.00							

All taxes are in Ghp/litre

* *2 Cents per litre of ATK were converted at a rate of Ghs5.68 to US$*

2020 PETROLEUM TAX REVENUE

Tax Revenues	GASOLINE	GASOIL	KEROSENE	MGO LOCAL	FUEL OIL	LPG DOMESTIC	LPG POWER	UNIFIED	MGO Foreign	ATK	GASOIL MINES	GASOIL RIGS	PREMIX	EXEMPTIONS	TOTAL
ENERGY DEBT RECOVERY LEVY	990,959,169	955,533,247	-	1,635,935	4,768,380	136,271,852	-	-	3,034,815	-	162,889,377	19,521,725	-	(100,659,573)	**2,173,954,926**
ROAD FUND	970,735,512	936,032,568	-	-	-	-	-	-	2,972,880	-	159,565,104	19,123,323	-	(98,605,296)	**1,989,824,091**
ENERGY FUND	20,223,657	19,500,679	61,515	-	1,192,095	-	-	-	61,935	-	3,324,273	398,403	-	(2,054,277)	**42,708,279**
PRICE STABILISATION AND RECOVERY LEVY	323,578,504	273,009,499	-	-	-	46,531,852	-	-	867,090	-	46,539,822	5,577,636	-		**696,104,403**
EXPORT DUTY	-	-	-	-	-	-	-	-	-	17,845,310	-	-	-		**17,845,310**
SPT	930,288,199	897,031,211	2,399,085	25,084,332	-	159,537,778	-	1,070,190	-	-	152,916,558	18,326,518	-		**2,186,653,871**
Total	3,235,785,040	3,081,107,203	2,460,600	26,720,267	5,960,475	342,341,481	-	1,070,190	6,936,720	17,845,310	525,235,134	62,947,604	-	(201,319,146)	7,107,090,878
Product Share of Revenue	45.53%	43.35%	0.03%	0.38%	0.08%	4.82%	0.00%	0.02%	0.10%	0.25%	7.39%	0.89%	0.00%	-2.83%	102.83%

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2020 PETROLEUM TAX RATES AND VOLUMES

Tax Revenues	GASOLINE	GASOIL (REG.)	KEROSENE	MGO LOCAL	FUEL OIL	LPG DOMESTIC	LPG POWER	UNIFIED	MGO Foreign	ATK*	GASOIL MINES	GASOIL RIGS	PREMIX	TOTAL
VOLUMES (LITRES EXCEPT LPG IN KG)	2,022,365,650	1,950,067,850	6,151,500	54,531,157	119,209,500	332,370,370	-	2,326,500	6,193,500	159,615,300	332,427,300	39,840,256	101,749,500	**5,126,848,383**
ENERGY DEBT RECOVERY LEVY	49.00	49.00	-	3.00	4.00	41.00		-	49.00	-	49.00	49.00	-	
ROAD FUND	48.00	48.00	-	-	-	-		-	48.00	-	48.00	48.00	-	
ENERGY FUND	1.00	1.00	1.00	-	1.00	-		-	1.00	-	1.00	1.00	-	
PRICE STABILISATION AND RECOVERY LEVY	16.00	14.00	-	-	-	14.00		-	14.00	-	14.00	14.00	-	
EXPORT DUTY	-	-	-	-	-	-		-	-	11.18	-	-	-	
SPT	46.00	46.00	39.00	46.00	-	48.00	48.00	46.00	-	-	46.00	46.00	-	

All taxes are in Ghp/litre

* *2 Cents per litre of ATK were converted at a rate of Ghs5.5901 to US$*

2019 PETROLEUM TAX REVENUE

Tax Revenues	GASOLINE	GASOIL	KEROSENE	MGO LOCAL	FUEL OIL	LPG DOMESTIC	LPG POWER	UNIFIED	MGO Foreign	ATK	GASOIL MINES	GASOIL RIGS	PREMIX	EXEMPTIONS	TOTAL
ENERGY DEBT RECOVERY LEVY	780,467,448	781,528,881	-	911,384	7,039,991	115,036,104	-	-	3,595,544	-	146,295,528	38,401,735	-	(73,910,939)	**1,799,365,676**
ROAD FUND	762,644,536	763,630,856	-	-	-	-	-	-	3,510,160	-	142,939,744	37,503,052	-	(72,199,560)	**1,638,028,788**
ENERGY FUND	17,822,912	17,898,025	46,935	-	1,759,998	-	-	-	85,384	-	3,355,784	898,683	-	(1,711,379)	**40,156,341**
PRICE STABILISATION AND RECOVERY LEVY	238,738,976	202,835,178	-	-	-	34,150,856	-	-	901,240	-	37,912,032	9,764,700	-	(18,985,990)	**505,316,993**
EXPORT DUTY	-	-	-	-	-	-	-	-	-	32,658,137	-	-	-		**32,658,137**
SPT	819,853,929	823,309,150	1,830,465	13,974,559	-	143,795,996	-	3,044,970	-	-	154,366,064	41,339,399	-		**2,001,514,532**
								-	-						
Total	2,619,527,800	2,589,202,090	1,877,400	14,885,944	8,799,988	292,982,957	-	3,044,970	8,092,329	32,658,137	484,869,152	127,907,568	-	(166,807,868)	6,017,040,467
Product Share of Revenue	43.54%	43.03%	0.03%	0.25%	0.15%	4.87%	0.00%	0.05%	0.13%	0.54%	8.06%	2.13%	0.00%	-2.77%	102.77%
	100														

JAN. TO AUG. 2019 PETROLEUM TAX RATES AND VOLUMES

0	GASOLINE	GASOIL (REG.)	KEROSENE	MGO LOCAL	FUEL OIL	LPG DOMESTIC	LPG POWER	UNIFIED	MGO Foreign	ATK*	GASOIL MINES	GASOIL RIGS	PREMIX	TOTAL
VOLUMES (LITRES EXCEPT LPG IN KG)	1,160,690,200	1,193,429,300	2,965,500	16,906,500	118,907,765	194,741,060	-	3,091,500	7,353,401	188,731,900	226,723,600	70,421,398	51,664,500	**3,235,626,624**
ENERGY DEBT RECOVERY LEVY	41.00	41.00	-	3.00	4.00	37.00		-	41.00	-	41.00	41.00	-	
ROAD FUND	40.00	40.00	-	-	-	-		-	40.00	-	40.00	40.00	-	
ENERGY FUND	1.00	1.00	1.00	-	1.00	-		-	1.00	-	1.00	1.00	-	
PRICE STABILISATION AND RECOVERY LEVY	12.00	10.00	-	-	-	10.00		-	10.00	-	10.00	10.00	-	
EXPORT DUTY	-	-	-	-	-	-		-	-	11.36	-	-	-	
SPT	46.00	46.00	39.00	46.00	-	48.00	48.00	46.00	-	-	46.00	46.00	-	
	1,782,291,150	1,790,833,999	4,693,500	30,379,477	175,999,765	299,574,992		6,619,500	8,538,401	287,483,600	335,578,400	89,868,258	72,063,000	

All taxes are in Ghp/litre

* *2 Cents per litre of ATK were converted at a rate of Ghs5.68 to US$*

2018 PETROLEUM TAX REVENUE

Tax Revenues	GASOLINE	GASOIL	KEROSENE	MGO LOCAL	FUEL OIL	LPG DOMESTIC	LPG POWER	UNIFIED	MGO Foreign	ATK	GASOIL MINES	GASOIL RIGS	PREMIX	EXEMPTIONS	TOTAL
ENERGY DEBT RECOVERY LEVY	681,598,883	693,969,444	-	854,196	5,614,474	106,681,650	-	-	4,006,668	-	137,771,726	42,781,253	-	(193,152,543)	**1,480,125,752**
ROAD FUND	664,974,520	677,043,360	-	-	-	-	-	-	3,908,944	-	134,411,440	41,737,808	-		**1,522,076,072**
ENERGY FUND	16,624,363	16,926,084	61,610	-	1,403,619	-	-	-	97,724	-	3,360,286	1,043,445	-		**39,517,130**
PRICE STABILISATION AND RECOVERY LEVY	199,492,356	169,260,840	-	-	-	28,832,879	-	-	977,236	-	33,602,860	10,434,452	-	(217,270,000)	**225,330,623**
EXPORT DUTY	-	-	-	-	-	-	-	-	-	23,263,166	-	-	-		**23,263,166**
SPT	764,720,698	778,599,864	2,402,790	13,097,678	-	138,397,817	52,071,337	830,070	-	-	154,573,156	47,998,479	-		**1,952,691,888**
Total	2,327,410,820	2,335,799,592	2,464,400	13,951,874	7,018,093	273,912,346	52,071,337	830,070	8,990,571	23,263,166	463,719,468	143,995,438	-	(410,422,543)	5,653,427,174
Product Share of Revenue	41.17%	41.32%	0.04%	0.25%	0.12%	4.85%	0.92%	0.01%	0.16%	0.41%	8.20%	2.55%	0.00%	-7.26%	100.00%

2018 PETROLEUM TAX RATES AND VOLUMES

Tax Revenues	GASOLINE	GASOIL (REG.)	KEROSENE	MGO LOCAL	FUEL OIL	LPG DOMESTIC	LPG POWER	UNIFIED	MGO Foreign**	ATK	GASOIL MINES	GASOIL RIGS	PREMIX	TOTAL
VOLUMES (LITRES EXCEPT LPG IN KG)	1,662,436,300	1,692,608,400	6,161,000	28,473,212	140,361,853	288,328,785	108,481,952	1,804,500	9,772,360	248,538,100	336,028,600	104,344,520	73,291,500	**4,700,631,082**
ENERGY DEBT RECOVERY LEVY	41.00	41.00	-	3.00	4.00	37.00		-	41.00	-	41.00	41.00	-	
ROAD FUND	40.00	40.00	-	-	-	-		-	40.00	-	40.00	40.00	-	
ENERGY FUND	1.00	1.00	1.00	-	1.00	-		-	1.00	-	1.00	1.00	-	
PRICE STABILISATION AND RECOVERY LEVY	12.00	10.00	-	-	-	10.00		-	10.00	-	10.00	10.00	-	
EXPORT DUTY	-	-	-	-	-	-		-	-	9.36	-	-	-	
SPT	46.00	46.00	39.00	46.00	-	48.00	48.00	46.00	-	-	46.00	46.00	-	

All taxes are in Ghp/litre

* 2 Cents per litre of ATK were converted at a rate of Ghs4.68 to US$

** Net volume position after adjusting gross volume of 12.14mn with 2.37mn litres sold in the first window of the year when the product was non-taxable.

2017 PETROLEUM TAX REVENUE

Tax Revenues	GASOLINE	GASOIL	KEROSENE	MGO LOCAL	FUEL OIL	LPG	UNIFIED	MGO Foreign	ATK	GASOIL MINES	GASOIL RIGS	PREMIX	EXEMPTIONS	TOTAL
ENERGY DEBT RECOVERY LEVY	586,742,021	583,503,595	-	1,141,813	5,199,659	102,380,032	-	43,559,538	-	127,144,936	36,765,734	-	(191,347,740.00)	**1,295,089,588**
ROAD FUND	572,431,240	569,271,800	-	-	-	-	-	42,497,110	-	124,043,840	35,869,009	-		**1,344,112,999**
ENERGY FUND	14,310,781	14,231,795	69,300	-	1,299,915	-	-	1,062,428	-	3,101,096	896,725	-		**34,972,040**
PRICE STABILISATION AND RECOVERY LEVY	171,729,372	142,317,950	-	-	-	27,670,279	-	10,624,278	-	31,010,960	8,967,252	-		**392,320,091**
EXPORT DUTY	-	-	-	-	-	-	-	-	18,193,085	-	-	-		**18,193,085**
SPT	693,357,339	683,439,259	2,128,203	17,846,542	-	127,272,214	648,454	-	-	160,047,565	46,279,989	-		**1,731,019,566**
Total	2,038,570,753	1,992,764,399	2,197,503	18,988,356	6,499,574	257,322,525	648,454	97,743,353	18,193,085	445,348,397	128,778,709	-	(191,347,740)	5,007,055,108
Product Share of Revenue	40.71%	39.80%	0.04%	0.38%	0.13%	5.14%	0.01%	1.95%	0.36%	8.89%	2.57%	0.00%	-3.82%	100.00%

2017 PETROLEUM TAX RATES AND VOLUMES

Tax Revenues	GASOLINE	GASOIL (REG.)	KEROSENE	MGO LOCAL	FUEL OIL	LPG	UNIFIED	MGO Foreign	ATK	GASOIL MINES	GASOIL RIGS	PREMIX	TOTAL
VOLUMES (LITRES EXCEPT LPG IN KG)	1,431,078,100	1,423,179,500	6,930,000	38,060,444	129,991,486	276,702,788	1,503,000	106,242,775	206,739,600	310,109,600	89,672,522	91,719,000	**4,111,928,815**
ENERGY DEBT RECOVERY LEVY	41.00	41.00	-	3.00	4.00	37.00	-	41.00	-	41.00	41.00	-	
ROAD FUND	40.00	40.00	-	-	-	-	-	40.00	-	40.00	40.00	-	
ENERGY FUND	1.00	1.00	1.00	-	1.00	-	-	1.00	-	1.00	1.00	-	
PRICE STABILISATION AND RECOVERY LEVY	12.00	10.00	-	-	-	10.00	-	10.00	-	10.00	10.00	-	
EXPORT DUTY	-	-	-	-	-	-	-	-	8.80	-	-	-	
SPT	48.45	48.02	30.71	46.89	-	45.996	43.14	-	-	51.61	51.61	-	

All taxes are in Ghp/litre

* 2 Cents per litre of ATK were converted at a rate of Ghs4.44 to US$

2016 PETROLEUM TAX REVENUE

Tax Revenues	GASOLINE	GASOIL	KEROSENE	MGO LOCAL	FUEL OIL	LPG	UNIFIED	MGO Foreign	ATK	GASOIL MINES	GASOIL RIGS	PREMIX	EXEMPTIONS	TOTAL
ENERGY DEBT RECOVERY LEVY	589,649,721	702,877,084	-	1,199,370	520,320	104,306,944	-	1,114,380	-	95,180,393	31,168,894	-	(155,729,628.00)	**1,370,287,478**
ROAD FUND	575,268,021	685,733,740	-	-	-	-	-	1,087,200	-	92,858,920	30,408,677	-		**1,385,356,558**
ENERGY FUND	14,381,701	17,143,344	100,000	-	130,080	-	-	27,180	-	2,321,473	760,217	-		**34,863,994**
PRICE STABILISATION AND RECOVERY LEVY	172,580,406	171,433,435	-	-	-	28,191,066	-	271,800	-	23,214,730	7,602,169	-		**403,293,606**
EXCISE DUTY	39,981,127	30,858,018	103,700	117,738	-	2,103,054	97,717	-	-	-	-	-		**73,261,354**
EXPORT DUTY	-	-	-	-	-	-	-	-	14,442,243	-	-	-		**14,442,243**
Total	1,391,860,976	1,608,045,620	203,700	1,317,109	650,400	134,601,063	97,717	2,500,560	14,442,243	213,575,516	69,939,957	-	(155,729,628)	3,281,505,233
Product Share of Revenue	42.42%	49.00%	0.01%	0.04%	0.02%	4.10%	0.00%	0.08%	0.44%	6.51%	2.13%	0.00%	-4.75%	104.75%

2016 PETROLEUM TAX RATES AND VOLUMES

Tax Revenues	GASOLINE	GASOIL (REG.)	KEROSENE	MGO LOCAL	FUEL OIL	LPG	UNIFIED	MGO Foreign	ATK	GASOIL MINES	GASOIL RIGS	PREMIX	TOTAL
VOLUMES (LITRES EXCEPT LPG IN KG)	1,438,170,052	1,714,334,350	10,000,000	39,979,016	13,008,000	281,910,659	3,515,000	2,718,000	164,116,400	232,147,300	76,021,692	75,181,500	**4,051,101,969**
ENERGY DEBT RECOVERY LEVY	41.00	41.00	-	3.00	4.00	37.00	-	41.00	-	41.00	41.00	-	
ROAD FUND	40.00	40.00	-	-	-	-	-	40.00	-	40.00	40.00	-	
ENERGY FUND	1.00	1.00	1.00	-	1.00	-	-	1.00	-	1.00	1.00	-	
PRICE STABILISATION AND RECOVERY LEVY	12.00	10.00	-	-	-	10.00	-	10.00	-	10.00	10.00	-	
EXCISE DUTY	2.78	1.80	1.04	0.29		0.75	2.78						
EXPORT DUTY	-	-	-	-	-	-	-	-	8.80	-	-	-	

All taxes are in Ghp/litre

* 2 Cents per litre of ATK were converted at a rate of Ghs4.44 to US$

Appendix 2

National Petroleum Stock Reconciliation (2015 to 2021)

2021

	Opening Stock (1/1/21)	Purchases (Imports) for the year	Production	Available Stock	Less Allowable Losses within the year*	Less Closing Stock (30/09/21)	Expected Sales (ES) for 2020	Domestic Reported Sales	Export Reported Sales	Total Reported Sales (RP)	Difference (ES-RP)	Total
	(a)	(b)	(c)	(d=a+b+c)	(e)	(f)	(g=d-e-f)	(h)	(i)	(j=h+i)	(j=g-j)	(Σj)
GASOIL	369,008,654	2,154,059,478	84,360,210	2,607,428,342	(5,596,049)	(161,343,582)	2,440,488,711	2,515,569,956	24,703,500	2,540,273,456	(99,784,745)	
GASOLINE	261,805,951	2,343,255,979	57,606,562	2,662,668,492	(7,682,760)	(244,600,424)	2,410,385,308	2,266,994,900	84,757,309	2,351,752,209	58,633,099	(41,151,646)
	630,814,605	4,497,315,457	141,966,772	5,270,096,834	(13,278,809)	(405,944,006)	4,850,874,019	4,782,564,856	109,460,809	4,892,025,665	(41,151,646)	

2020

	Opening Stock (1/1/20)	Purchases (Imports) for the year	Production	Available Stock	Less Allowable Losses within the year*	Less Closing Stock (31/12/20)	Expected Sales (ES) for 2020	Domestic Reported Sales	Export Reported Sales	Total Reported Sales (RP)	Difference (ES-RP)	Total
	(a)	(b)	(c)	(d=a+b+c)	(e)	(f)	(g=d-e-f)	(h)	(i)	(j=h+i)	(j=g-j)	(Σj)
GASOIL	258,973,959	2,303,833,944	177,098,942	2,739,906,845	(6,202,332)	(369,008,654)	2,364,695,858	2,328,528,906	34,331,500	2,362,860,406	1,835,452	
GASOLINE	79,737,818	2,227,660,837	88,055,032	2,395,453,687	(7,410,291)	(261,805,951)	2,126,237,445	2,022,365,650	81,235,500	2,103,601,150	22,636,295	24,471,747
	338,711,777	4,531,494,782	265,153,973	5,135,360,532	(13,612,623)	(630,814,605)	4,490,933,303	4,350,894,556	115,567,000	4,466,461,556	24,471,747	

2019

	Opening Stock (1/1/19)	Purchases (Imports) for the year	Production	Available Stock	Less Allowable Losses within the year*	Less Closing Stock (31/12/19)	Expected Sales (ES) for 2019	Domestic Reported Sales	Export Reported Sales	Total Reported Sales (RP)	Difference (ES-RP)	Total
	(a)	(b)	(c)	(d=a+b+c)	(e)	(f)	(g=d-e-f)	(h)	(i)	(j=h+i)	(j=g-j)	(Σj)
GASOIL	418,702,815	2,051,440,023	234,468,421	2,704,611,260	(5,714,771)	(258,973,959)	2,439,922,530	1,790,833,999	138,988,500	1,929,822,499	510,100,031	
GASOLINE	416,024,954	1,675,477,263	165,496,421	2,256,998,638	(5,891,116)	(79,737,818)	2,171,369,704	1,782,291,150	43,987,500	1,826,278,650	345,091,054	855,191,085
	834,727,769	3,726,917,286	399,964,842	4,961,609,897	(11,605,887)	(338,711,777)	4,611,292,234	3,573,125,149	182,976,000	3,756,101,149	855,191,085	

2018

	Opening Stock (1/1/18)	Purchases (Imports) for the year	Production	Available Stock	Less Allowable Losses within the year*	Less Closing Stock (31/12/18)	Expected Sales (ES) for 2018	Domestic Reported Sales	Export Reported Sales	Total Reported Sales (RP)	Difference (ES-RP)	Total
	(a)	(b)	(c)	(d=a+b+c)	(e)	(f)	(g=d-e-f)	(h)	(i)	(j=h+i)	(j=g-j)	(Σj)
GASOIL	148,616,601	2,048,956,564	137,112,640	2,334,685,805	-	(418,702,815)	1,915,982,990	2,173,595,092	65,504,579	2,239,099,671	(323,116,681)	
GASOLINE	102,508,741	1,726,486,851	136,380,235	1,965,375,827	-	(416,024,954)	1,549,350,873	1,735,727,800	64,760,680	1,800,488,480	(251,137,607)	(574,254,289)
	251,125,342	3,775,443,414	273,492,875	4,300,061,631	-	(834,727,769)	3,465,333,862	3,909,322,892	130,265,259	4,039,588,151	(574,254,289)	

2017

	Opening Stock (1/1/17)	Purchases (Imports) for the year	Production	Available Stock	Less Allowable Losses within the year*	Less Closing Stock (31/12/17)	Expected Sales (ES) for 2017	Domestic Reported Sales	Export Reported Sales	Reported Sales (RP) for 2017	Difference (ES-RP)	Total
	(a)	(b)	(c)	(d=a+b+c)	(e)	(f)	(g=d-e-f)	(h)	(i)	(j=h+i)	(j=g-j)	(Σj)
GASOIL	211,995,001	2,533,920,517	12,893,367	2,758,808,885	(6,367,035)	(148,616,601)	2,603,825,250	1,967,264,841	236,704,766	2,203,969,607	399,855,642	
GASOLINE	136,569,861	2,100,852,093	8,665,884	2,246,087,838	(6,750,458)	(102,508,741)	2,136,828,639	1,522,797,100	232,255,122	1,755,052,222	381,776,417	781,632,059
	348,564,862	4,634,772,610	21,559,251	5,004,896,723	(13,117,492)	(251,125,342)	4,740,653,889	3,490,061,941	468,959,888	3,959,021,829	781,632,059	

2016

	Opening Stock (1/1/16)	Purchases (Imports) for the year	Production	Available Stock	Less Allowable Losses within the year*	Less Closing Stock (31/12/16)	Expected Sales (ES) for 2016	Domestic Reported Sales	Export Reported Sales	Reported Sales (RP) for 2016	Difference (ES-RP)	Total
	(a)	(b)	(c)	(d=a+b+c)	(e)	(f)	(g=d-e-f)	(h)	(i)	(j=h+i)	(j=g-j)	(Σj)
GASOIL	224,710,508	2,080,574,229	314,444,673	2,619,729,410	(5,987,547)	(211,995,001)	2,401,746,862	2,091,572,978	311,393,128	2,402,966,106	(1,219,245)	
GASOLINE	112,258,640	1,631,445,112	327,460,366	2,071,164,118	(6,268,498)	(136,569,861)	1,928,325,759	1,510,273,052	260,599,420	1,770,872,472	157,453,287	156,234,043
	336,969,148	3,712,019,341	641,905,039	4,690,893,528	(12,256,045)	(348,564,862)	4,330,072,621	3,601,846,030	571,992,548	4,173,838,578	156,234,043	

2015

	Opening Stock (1/1/15)	Purchases (Imports) for the year	Production	Available Stock	Less Allowable Losses within the year*	Less Closing Stock (31/12/15)	Expected Sales (ES) for 2015	Domestic Reported Sales	Export Reported Sales	Reported Sales (RP) for 2015	Difference (ES-RP)	Total
	(a)	(b)	(c)	(d=a+b+c)	(e)	(f)	(g=d-e-f)	(h)	(i)	(j=h+i)	(j=g-j)	(Σj)
GASOIL	222,176,636	2,155,824,192	53,658,759	2,431,659,586	(5,523,707)	(224,710,508)	2,201,425,371	2,256,529,716	10,202,000	2,266,731,716	(65,306,345)	
GASOLINE	221,415,725	1,691,130,682	42,699,269	1,955,245,677	(5,548,256)	(112,258,640)	1,837,438,780	1,623,189,850	105,653,127	1,728,842,977	108,595,803	43,289,458
	443,592,361	3,846,954,874	96,358,028	4,386,905,263	(11,071,963)	(336,969,149)	4,038,864,151	3,879,719,566	115,855,127	3,995,574,693	43,289,458	

* Allowable losses are computed on the following rate on total volume imports and production

Product	Rate
Gasoil	0.25%
Gasoline	0.32%

Appendix 3

2021 TAX REVENUE SAVINGS (IN VALUE)

Tax Revenues	GASOLINE	GASOIL	KEROSENE	MGO LOCAL	FUEL OIL	LPG DOMESTIC	LPG POWER	UNIFIED	MGO Foreign	ATK	GASOIL MINES	GASOIL RIGS	PREMIX	EXEMPTIONS	TOTAL
ENERGY DEBT RECOVERY LEVY	28,730,219	(48,894,525)	-	-	-	-	-	-	-	-	-	-	-		(20,164,307)
ROAD FUND	28,143,888	(47,896,678)	-	-	-	-	-	-	-	-	-	-	-		(19,752,790)
ENERGY FUND	586,331	(997,847)	-	-	-	-	-	-	-	-	-	-	-		(411,516)
PRICE STABILISATION AND RECOVERY LEVY	9,381,296	(13,969,864)	-	-	-	-	-	-	-	-	-	-	-		(4,588,568)
EXPORT DUTY	-	-	-	-	-	-	-	-	-	-	-	-	-		-
SPT	26,971,226	-	-	-	-	-	-	-	-	-	-	-	-		26,971,226
SANITATION AND POLLUTION LEVY	5,863,310	(9,978,475)	-	-	-	-	-	-	-	-	-	-	-		(4,115,165)
ENERGY SECTOR RECOVERY LEVY	11,726,620	(19,956,949)	-	-	-	-	10,553,958	-	-	-	-	-	-		2,323,629
Total	111,402,888	(141,694,339)	-	-	-	-	10,553,958	-	-	-	-	-	-	-	(19,737,492)
Product Share of Revenue	-564.42%	717.89%	0.00%	0.00%	0.00%	0.00%	-53.47%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%

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2021 TAX RATES AND EST. STOCK SAVINGS (IN VOLUME)

Tax Revenues	GASOLINE	GASOIL (REG.)	KEROSENE	MGO LOCAL	FUEL OIL	LPG DOMESTIC	LPG POWER	UNIFIED	MGO Foreign	ATK*	GASOIL MINES	GASOIL RIGS	PREMIX	TOTAL
VOLUMES (LITRES EXCEPT LPG IN KG)	58,633,099	(99,784,745)												(41,151,646)
ENERGY DEBT RECOVERY LEVY	49.00	49.00	-	3.00	4.00	41.00		-	49.00	-	49.00	49.00	-	
ROAD FUND	48.00	48.00	-	-	-	-		-	48.00	-	48.00	48.00	-	
ENERGY FUND	1.00	1.00	1.00	-	1.00	-		-	1.00	-	1.00	1.00	-	
PRICE STABILISATION AND RECOVERY LEVY	16.00	14.00	-	-	-	14.00		-	14.00	-	14.00	14.00	-	
EXPORT DUTY	-	-	-	-	-	-		-	-	11.36	-	-	-	
SPT	46.00	46.00	39.00	46.00	-	48.00	48.00	46.00	-	-	46.00	46.00	-	
SANITATION AND POLLUTION LEVY	10.00	10.00												
ENERGY SECTOR RECOVERY LEVY	20.00	20.00					18.00							

All taxes are in Ghp/litre

* *2 Cents per litre of ATK were converted at a rate of Ghs5.68 to US$*

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