

Africa energy outlook 2021.

African Energy Chamber.

2020



**African
Energy
Chamber**

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Africa Energy Outlook 2021



Africa Energy Outlook 2021

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Africa Energy Outlook 2021

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A Year Like No Other

Dear Reader,

2020 has been a year of unprecedented challenges, and the trials and tribulations have made the African Energy Chamber's work more important now than ever. We are committed to helping Africa's oil and gas stakeholders navigate a complex and ever-changing global energy landscape. We will continue our mission to support the dynamic private sector and unlock the continent's remarkable energy potential.

Africa's oil and gas industry is facing extraordinary circumstances. An ongoing energy transition and new efforts to decarbonize the world are weighing on oil demand. The shale revolution is exacerbating these pressures. And of course, the COVID-19 pandemic has wrought havoc on markets around the world, accelerating and intensifying existing trends.

External headwinds are forcing African petroleum producers to re-examine their strategies. Conventional petroleum resources here should be globally competitive, but growth has lagged because of conditions above the ground, not below. Restrictive fiscal regimes, inefficient and carbon-intensive production, and difficulties in doing business are preventing the industry from reaching its full potential. As companies delay projects and cut costs, planned capital expenditure in 2020-2021 has fallen from \$90 billion pre-COVID-19, to \$60 billion now. To remain competitive, African producers and governments must adapt. But how can they do it when the economic order is being remade?



We have to cut red tape to make life easier for hard-working Africans, businesses and investors to work and grow the energy sector. We know from experience this will reduce the cost of doing business, speed up approvals and make life better for Africans. We must never be ashamed of supporting an industry that has brought so much to Africa and will continue to bring people out of poverty and reduce reliance on foreign aid.

In 2021, Africa will benefit greatly if we create an investment climate that supports the development of all energy resources. At the African Energy Chamber, we believe supporting the energy industry, promoting free markets, the rule of law, individual freedoms and limited government, is a duty for all Africans.

But we must not stop there, advocating for a market driven Afro-centric energy transition, with a specific focus on natural gas to expand market opportunities is something we will continue to drive. The oil and gas industry is a force for good and we must not join those forces that want to demonize hardworking people whose only crime is to work hard and play by the rules and embrace hope rather than fear mongering and embrace economic empowerment rather than development aid. That's why we believe implementing programs like local content, economic diversification that support natural gas value chains, making fiscal terms competitive and reducing red tape and streamlining regulatory processes must be priorities in 2021.

Our African Energy Outlook 2021 addresses these challenges head-on. Building on last year's success, our second annual report offers an even more exhaustive and comprehensive look to the year ahead for African oil and gas.

The 2021 outlook details all of the major challenges facing African oil and gas stakeholders, as well as workable solutions that will keep the industry on a strong and

stable growth path. We believe the short-term outlook will improve if countries apply more competitive fiscal regimes. Emissions can be reduced by curbing flaring and monetizing gas, improving and future-proofing the carbon profile of African petroleum production.

Developing gas-to-power infrastructure will increase access to affordable energy for all sectors of the economy, offering massive knock-on benefits and making it easier to do business. Reducing lead times to limit risk premiums put on long cycle projects will further bolster the industry's viability and growth prospects. It will not be easy, but these reforms are necessary.

Again and again, our oil and gas sector has proven its resilience and adaptability. The world still needs oil and gas, and Africa still holds enormous untapped potential. The African Energy Chamber will remain a committed partner of choice for the industry as we advance into an uncertain future.

Thank you,

NJ Ayuk
Executive Chairman
African Energy Chamber

African **Energy Outlook 2021**

High level take aways

Time to act!

The global energy transition and decarbonization drive are putting pressure on oil demand while shale has unlocked abundant resources. The global context forces African petroleum producers to adapt or become uncompetitive.

The coronavirus pandemic (COVID-19) has accelerated this underlying pressure by causing unprecedented havoc on global energy markets that Africa is not insulated from.

Conventional petroleum resources such as those in Africa should be competitive in the global supply stack,

but above surface conditions related to fiscal regimes, carbon emissions and general difficulty of doing business are holding projects back.

The CAPEX spending 2020 - 2021 outlook pre-COVID-19 was almost \$90 billion for 2020 and 2021, but has been significantly reduced to about \$60 billion due to project delays and cost cutting measures.

The 2021 outlook therefore appears weak on new project sanctions, but relatively stronger for jobs and drilling markets on the back of ongoing projects initiated pre-COVID-19.

The impact of COVID-19 on 2021 liquids production is however not so severe as the current 2021 outlook stands at about 7.6 million barrels per day compared to 8.2 million barrels per day in the beginning of the year.

Outside COVID-19, regulatory matters have also unnecessarily delayed major projects in Nigeria, Kenya, Uganda and Tanzania that represent big opportunity losses for local content development, delayed job creation and further deteriorated Africa's competitive position versus resources elsewhere.

The African Energy Chamber believes that the short-term outlook can be remedied by:

Applying more competitive fiscal regimes that can help unlock 4.4 billion barrels of liquids and \$100 billion of additional investments by 2030.

Curbing flaring and monetizing gas, which will help improving the carbon emission profile of African petroleum production that currently bottom tier among the continents.

Developing gas to power infrastructure that will increase access to affordable energy to all sectors of the economy.

Reducing lead time as higher risk premiums are put on long cycle projects versus short cycle projects.

Gas to power push represents the **most promising way** to decarbonize the African upstream

Strong incentives to monetize African gas and create new demand centers, especially in promoting gas to power internally, will fasten the decarbonization of African upstream activities.

Africa to remain at least until 2025 the least carbon efficient oil producing frontier with over 30 kilogram CO2 emitted per barrel of oil equivalent produced.

Continued high carbon emission is a threat to Africa's global competitiveness.

The energy transition forces more attention to carbon emissions to attract capital.

Africa must work harder on curbing flaring to remain an attractive arena for future hydrocarbons-related investments.

As the world is moving towards the energy transition in order to curb greenhouse gas emissions and meet the targets in the Paris agreement, the oil and gas industry is doing its share. While combustion of hydrocarbons by off-takers and consumers does represent around 90% of total emissions, the remaining 10% is what oil and gas companies are targeting to cut through initiatives such as electrification, reduced flaring and more energy efficient extraction methods. An often-used metric to determine hydrocarbon production's carbon efficiency is to consider the amount of emissions outside combustion per unit of production. The lower this ratio is, the more efficient your production is.

While carbon efficiency used to be more of a corporate social responsibility (CSR) metric, the metric is now used increasingly in financial calculations and by global investors before they make investment decisions. The emission cost is increasing as a function of limited carbon emission budget in order to stay within the globally-stated temperature increase target, and as such any expensive hydrocarbon production with high emissions are generally considered to be the first in line to be curtailed. Capital is therefore facing higher and high-

er premiums to be deployed in carbon inefficient hydrocarbon production, and it is therefore increasingly important to help minimize emissions in order to have a competitive project. Unfortunately, Africa continues to operate carbon inefficient production, which further impacts its ability to raise capital for oil and gas projects.

A data base has been built on the back of all knowledge about emissions and the type of hydrocarbon production (on-shore, offshore, oil type etc.) in order to have a view of carbon efficiency globally. This is illustrated on Figure 1.1 where the sum of each continent's upstream production and upstream emissions from 2018 are compared to each other.

While Africa benefits from conventional and easy to extract hydrocarbons, the inability to prevent gas flaring nevertheless catapults the continent to the overall least carbon efficient continent at about 31kg CO2 emitted per barrel of oil equivalent produced. European production as a comparison is rather similar to African production in terms of extraction emissions, but has easier and more cost-efficient methods to handle associated gas than flaring on the back of a big demand center that can create value from gas.

Gas to power push represents the most promising way to decarbonize the African upstream

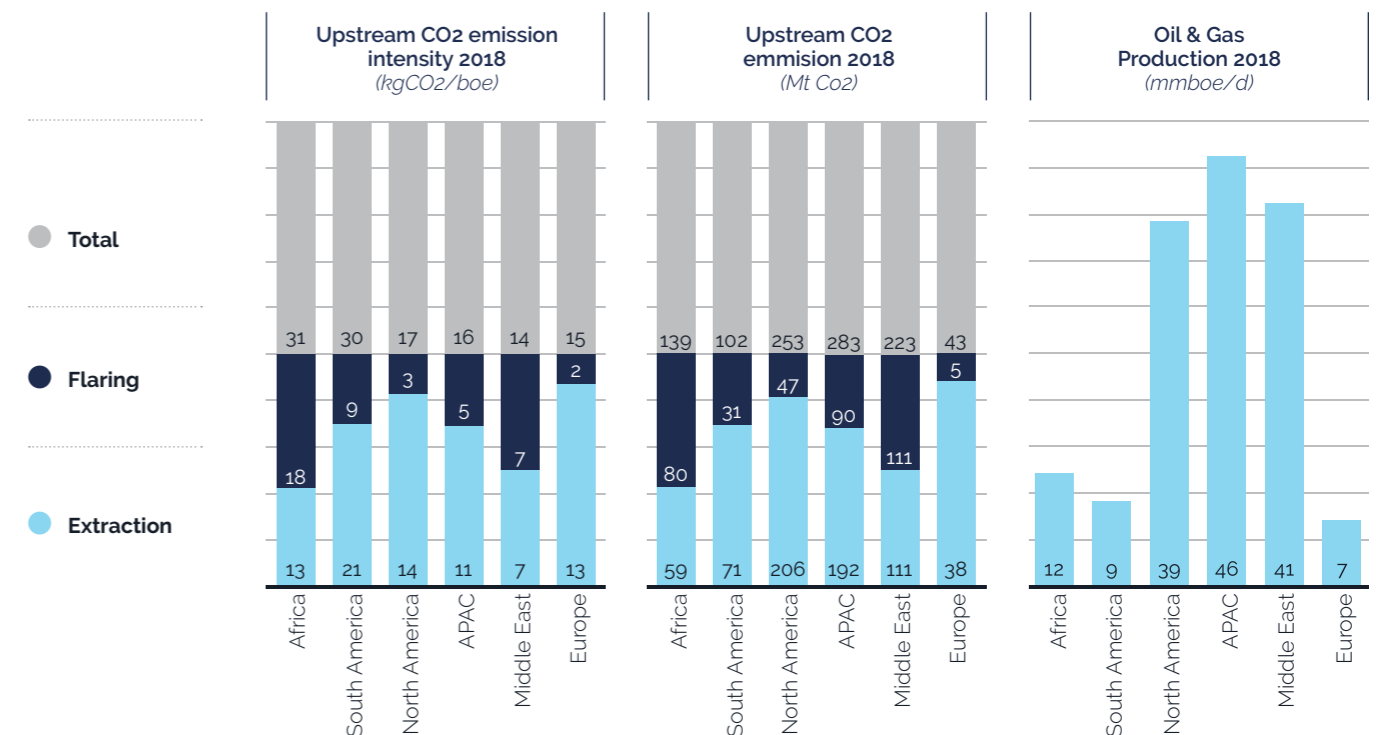
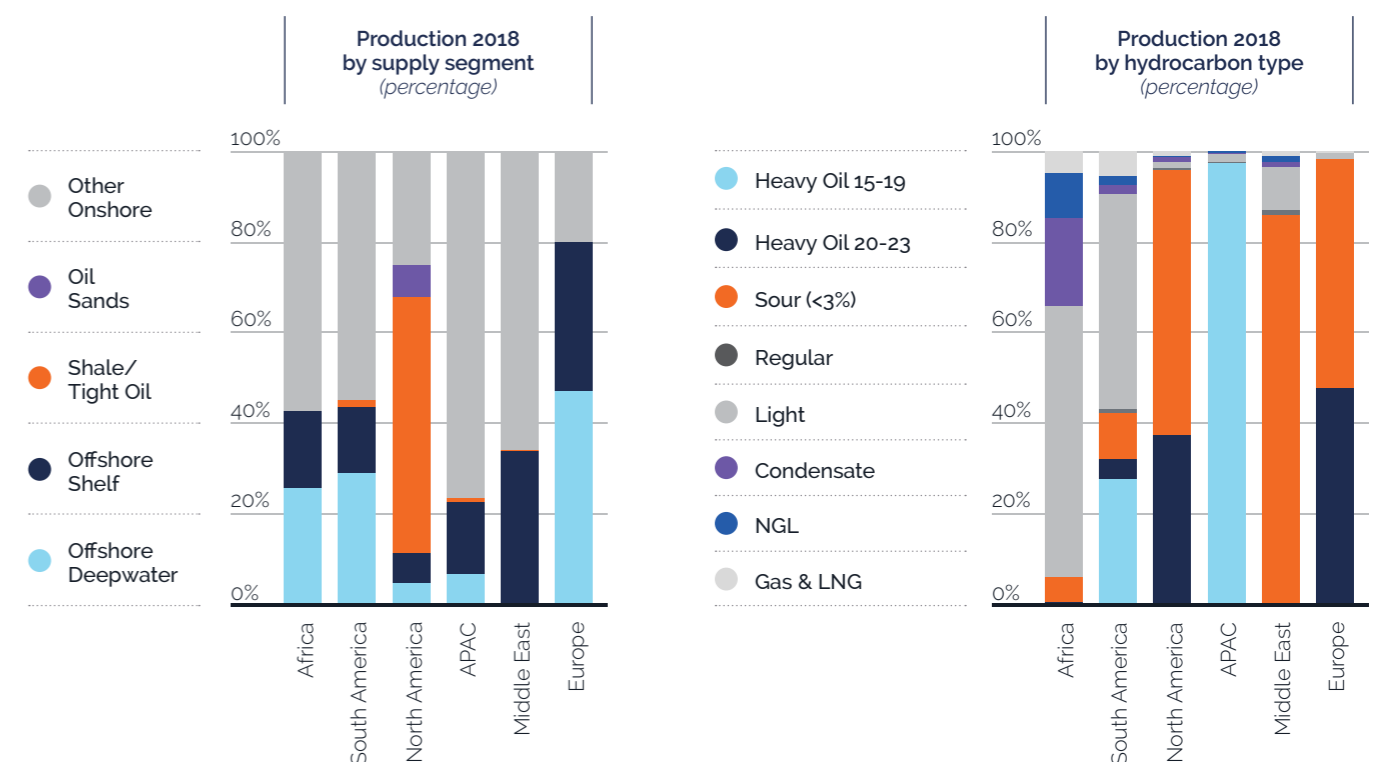


Figure 1.1: Upstream emissions | Continent comparison
Flaring varies globally and contributes significantly to upstream emissions intensity



APAC includes Russia, East Asia, South Asia, and Oceania
Data Source: Rystad Energy Research & Analysis

Fig. 1.2 Historical Oil & Gas Production
(mmboe/d)

Africa
1960 - 2018

South America
1940 - 2018

North America
1920 - 2018

APAC
1960 - 2018

Middle East
1950-2018

Europe
1950 - 2018

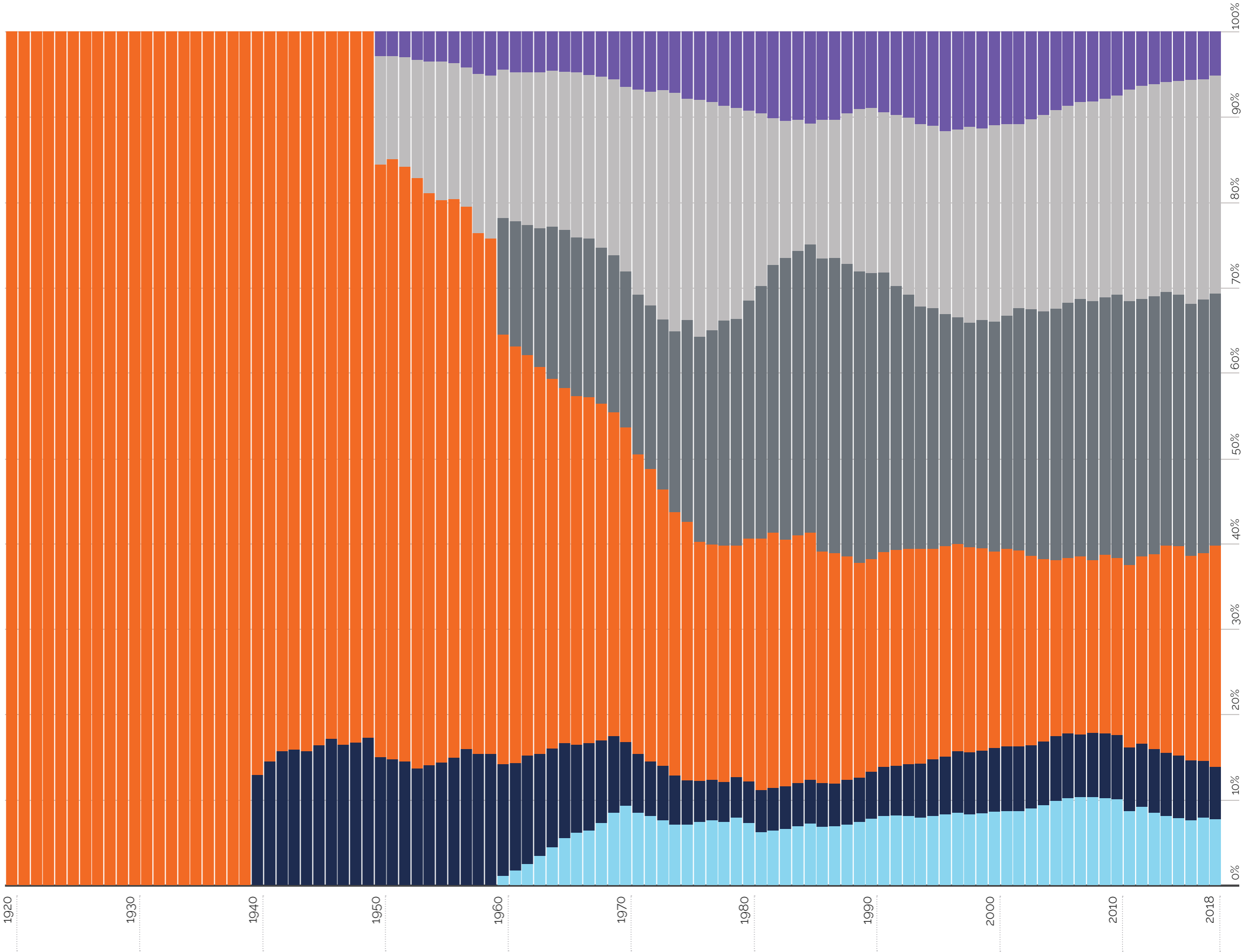


Figure 1.3: Upstream Flaring Emissions | Large differences in flaring
Between 5085% of total upstream for oil fields

Data Source: Rystad Energy Research & Analysis; NOAA/World Bank

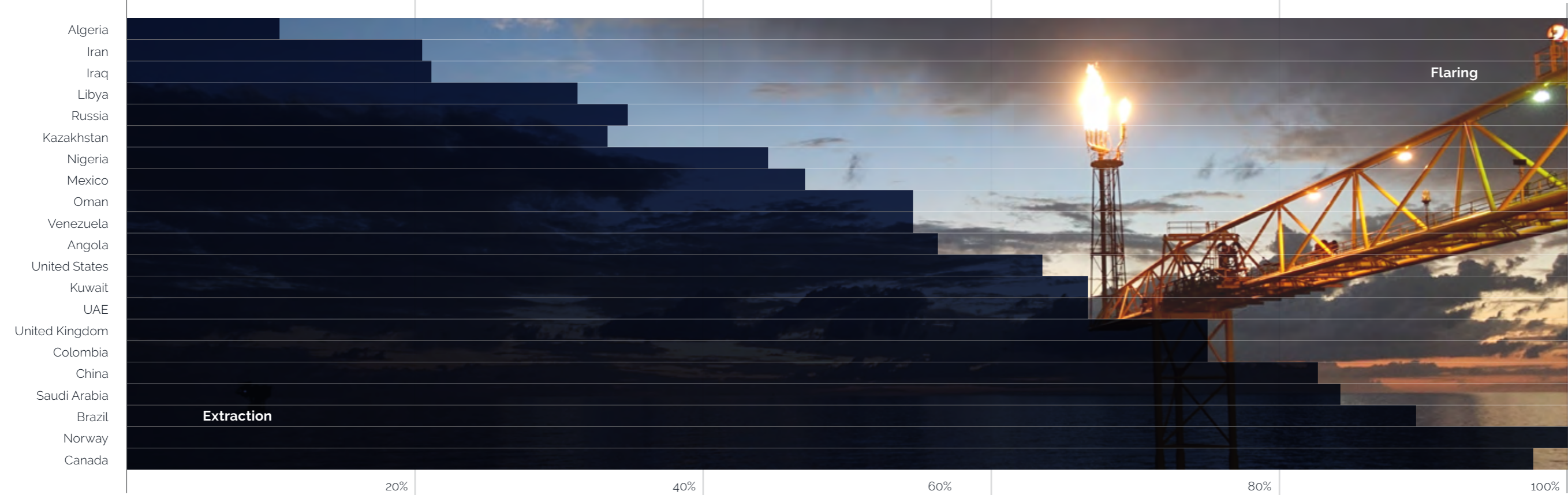


Figure 1.2 breaks down the top 20 oil producers globally on how much flaring represents in terms of emissions versus the emission from the extraction process. Ideally, the flaring component is as small as possible.

Of four African countries on the list (Algeria, Libya, Nigeria and Angola) none of the coun-

tries are in the upper half with Angola as the best performer of the group. It is primarily the North African countries Algeria and Libya that have poor performance with regards to flaring emissions.

2018 is currently the last year with high quality data, but projections towards 2025 neverthe-

less points to Africa overall not improving its position with emissions remaining above 30 kg CO2 per barrel of oil equivalent. While flaring is and upstream emissions are not always easy to reduce, it nevertheless does represent an enormous opportunity for Africa to reduce its carbon emission per production unit and thereby increase

the resources' competitiveness in a world with increasingly constrained carbon emission budget. In this context, political will and industry compliance will be key. Initiatives such as the Nigerian Gas Flare Commercialization Program are extremely positive steps in that direction and must be encouraged and supported by all stakeholders.

COVID-19 curbs free cash flow and government take but 2021 outlook improves

Generated free cash flow and government take is expected to decline by north of 50% in 2020 from approximately \$10/boe nominal in 2019 to \$4/boe nominal in 2020.

Improved outlook for 2021 at \$6/boe nominal on the back of curbed expenditure and higher commodity prices.

Continued impact of COVID-19 on demand and commodity prices will be crucial to short-term forecast and expectations

The goal of any project within the oil and gas world is to create value by generating sufficient revenue to recuperate all cost and generate sufficient free cash flow to justify the required rate of return. Multiple parameters influence the free cash flow generation, but chief among them is commodity prices that determine how much revenue is generated. As projects are evolving through their life cycles at different points in time, the sum of all cash flows across all projects create trends. Versus other continents, Australia has and is expected to generate on average the highest free cash flow per barrel of oil equivalent from 2018 to 2025 (Figure 2.1). African performance is however in line with other continents and exhibits similar volatility on the back of the industry's typical boom and bust cycles.

Analyzing free cash flow from all African projects, one notices that 2012 and 2013 remain some of the most profit-

able years in history on the back of high commodity prices and capital programs ramping up (Figure 2.2). In 2014, the commodity prices started to decline to thereby decrease free cash flow generation, but more impactful were the numerous giant projects initiated from 2012 to 2014 that represented enormous capital expenditure. It was these locked-in capital programs, together with the drop in commodity prices, that caused free cash flow generation to be highly constrained during 2015 and 2016.

From 2017 onwards, the capital programs were completed, the projects started to produce and generate revenue, and commodity prices increased. The result was an improving free cash flow that grew to \$55 billion in 2018. The industry had effectively responded to the commodity price shock in 2014 and rebalanced spending and revenue to be more sustainable than what was the case in 2015 and 2016.

Figure 2.1: Free cash flow evolution per Continent
USD/boe nominal

Data Source: UCube August 2020

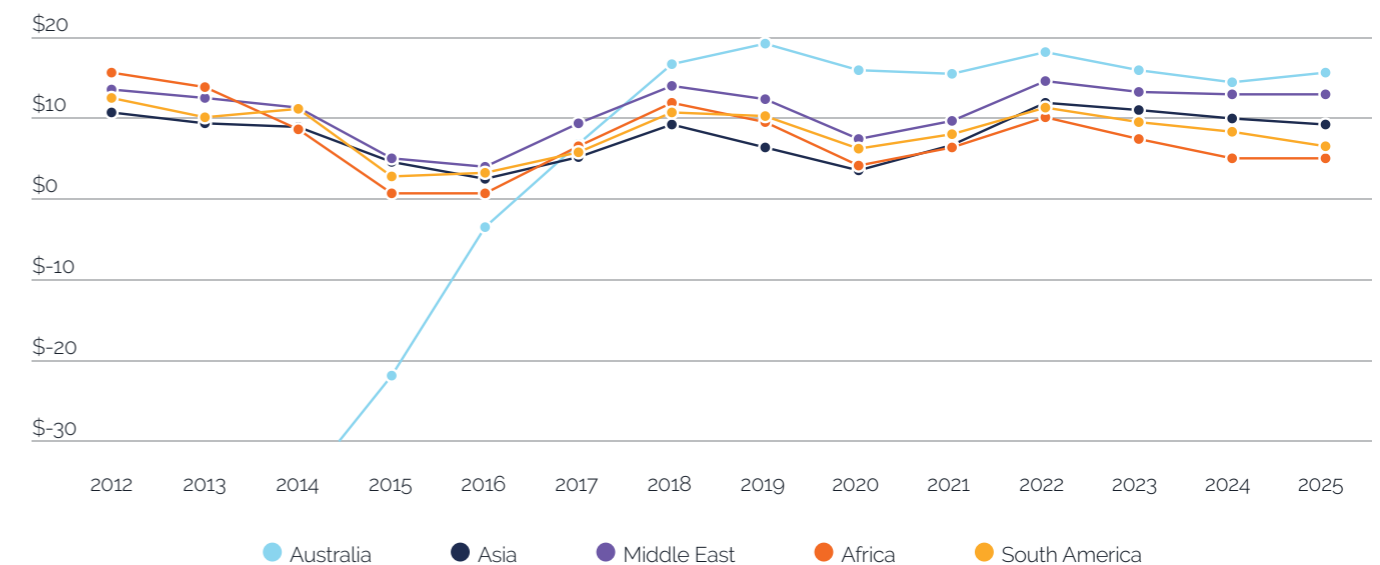
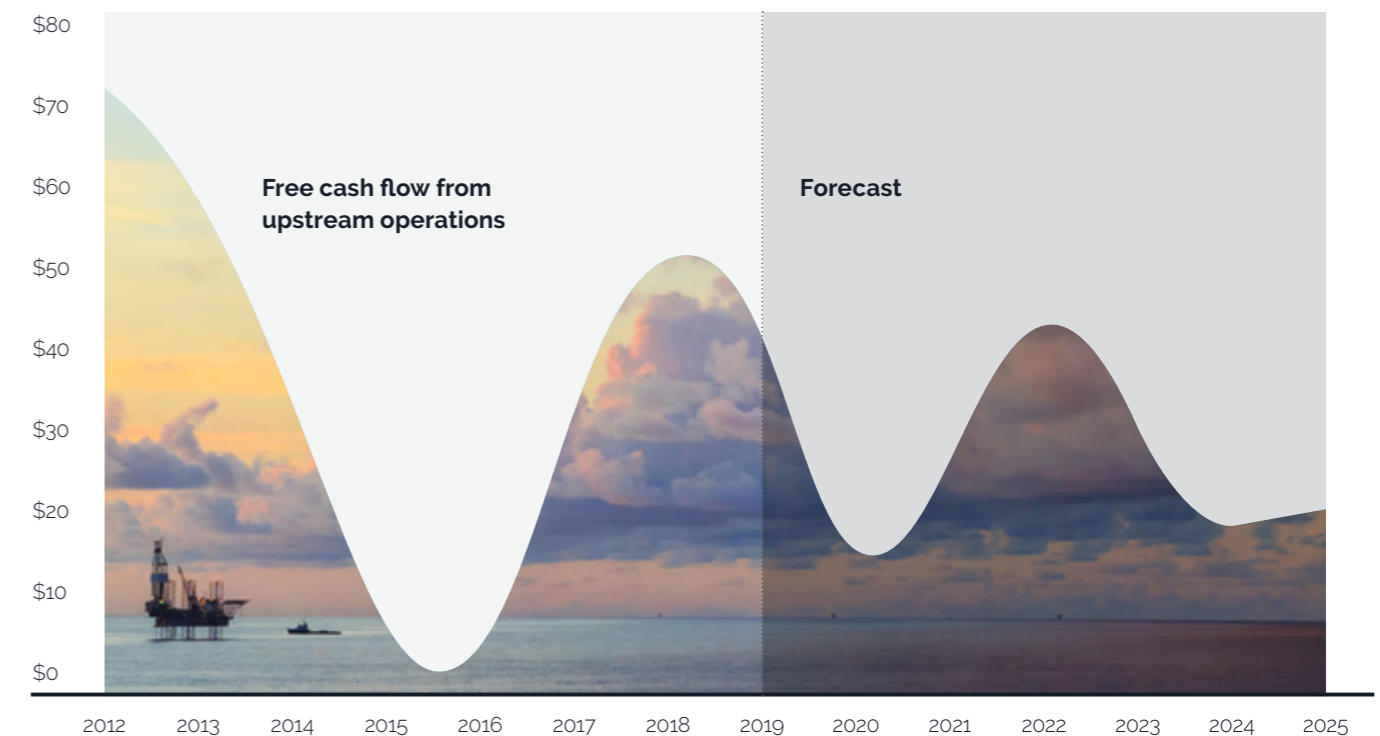


Figure 2.2: Free cash flow evolution for Africa
USD billion nominal

Data Source: UCube August 2020



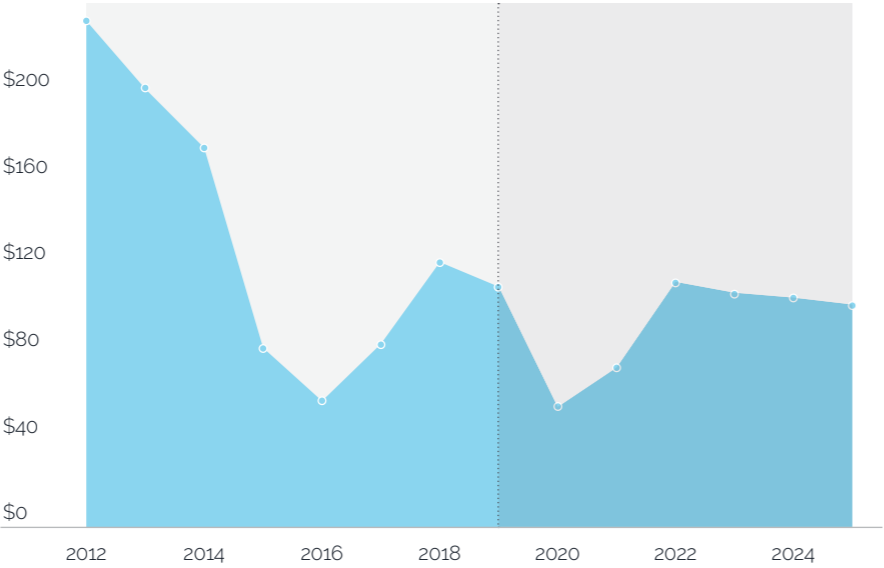
Under normal circumstances, this new balance was expected to continue, but the impact of COVID-19 has created many similarities to 2015 and 2016 whereby free cash flow will be squeezed on the back of reduced revenue and locked in capital programs. As such, the industry will once again have to rebalance its spending and revenue which typically implies curbing exploration activity and deferring new investment decisions. While 2020 free cash flow is not expected to decline towards the same depth as during 2015 and 2016, the spend curtailment and expected higher commodity prices are anticipated to create a rebound into 2021. With more free cash flow generated in 2021, the scene is set for a new cycle of investments with activity picking up for deferred projects and exploration activity. For the same reason, we can expect most key final investment decisions (FID) on African projects to be taken in 2021.

While fiscal parameters such as depreciation and royalties can cause distortions versus the observed free cash flow

The rebound by 2021 in free cash flow and government take described above is dependent on increasing commodity prices in order to generate more revenue. For instance, scenarios where oil remains at \$50/bbl or below implies that free cash flow and government take will be unable to reach 2019 levels. Figure 2.4 breaks down the expected 2021 free cash flow per top 10 companies with activity in Africa. The list is dominated by majors and national oil companies (NOCs), which is to be expected given the player landscape on the con-

Figure 2.3: Government take evolution for Africa
USD billion nominal

Data Source: UCube August 2020



generated for companies, the general relationship between commodity prices and locked in capital programs will also influence government take. From a government perspective, 2020 is potentially the worst year since at least 2012 with

only about \$55 billion in government take (Figure 2.3). However, as commodity prices are expected to increase and the balance between revenue and cost improves, so will also expected government take towards 2021 and onwards.

continent. CNOOC is the sole exception at 10th place, representing growing Chinese interest in African resources.

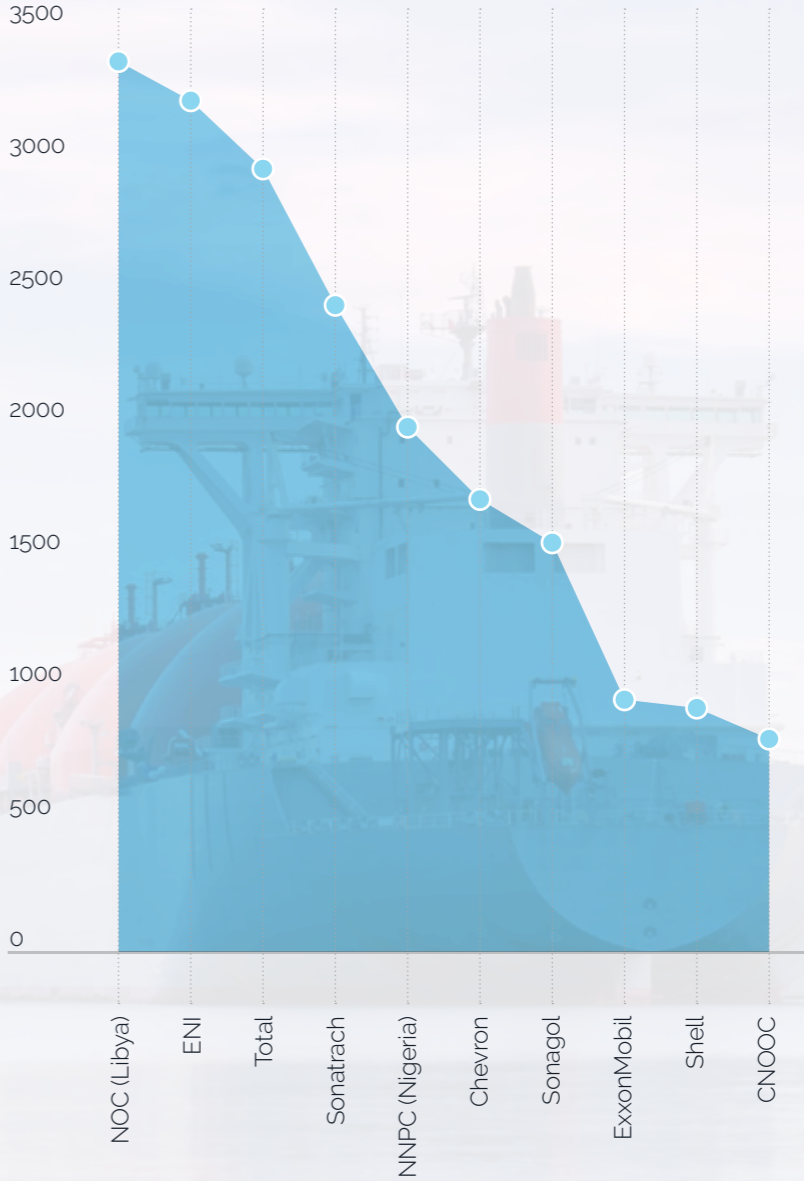
The economies of the hydrocarbon-producing African nations are heavily reliant on their respective output to meet both domestic energy needs and exports. For example, Nigeria had previously set its 2020 capital budget based on its plans to produce 2.1 million barrels per day of oil in 2020 at a crude price of \$57 per barrel. An extended period of the current price scenario will therefore prove detrimental to the health of these economies.

The African OPEC nations may soon lose the capacity to produce at their desired levels if upstream operators and international majors stop investing and delay the sanctioning of projects. While Angola or Gabon have been implementing a strong enabling environment for their oil and gas investors in recent years, policy uncertainty and in some cases the unchecked use by African policy-makers of the oil & gas sector as a cash cow could adversely affect the continent's production outlook and competitiveness.

COVID-19 curbs free cash flow and government take but 2021 outlook improves

Figure 2.4: Top 10 free cash flow for companies operating in Africa
USD billion nominal

Data Source: UCube August 2020



COVID-19 causes unprecedented oil market turmoil

High uncertainty around short-term outlook for 2021 due to the COVID-19 pandemic.

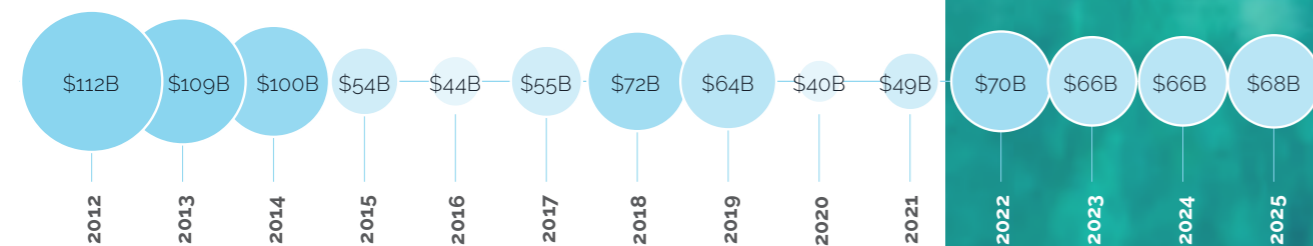
COVID-19 caused unprecedented disruption in the oil market, exemplified by reference prices trading at negative values

Reference prices recovery for 2021 (\$49/bbl) and 2022 (\$70/bbl) expected to mimic global economic recovery

2020 has been one of, if not the most, volatile years in oil price history. The COVID-19 pandemic has ravaged the global energy markets, and as such global liquids demand that has typically increased by about 1 to 1.5 million barrels per day year-over-year, is currently expected to see an annual average contraction of 10 million barrels per day from 2019 to 2020.

The impact on average oil price per year is real, and best estimate projection towards 2025 do not expect the \$70/bbl threshold to be reached before 2022 (Figure 3.1).

Figure 3.1: Oil price outlook
Brent USD/bbl nominal



Data Source: UCube August 2020

COVID-19 curbs free cash flow and government take but 2021 outlook improves

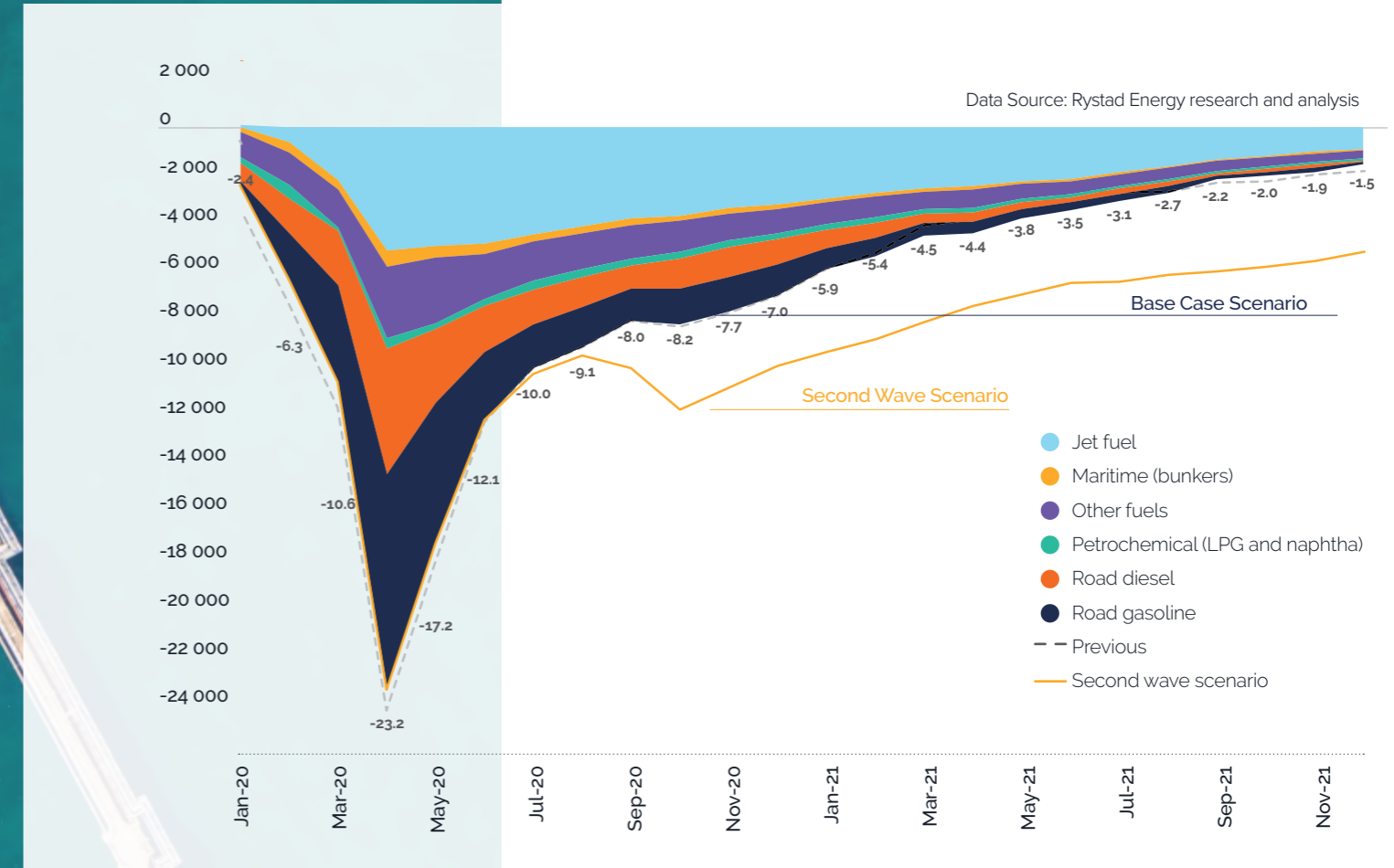


Figure 3.2: Global oil products (liquids) demand forecast by scenario
Million barrels per day

It was in particular April 2020 that saw unprecedented market turmoil as the full impact of various economies entering lockdown, and thereby reducing demand, as well as OPEC and Russia increasing production, and thereby increasing supply, resulted in an oversupply situation of about 23 million barrels per day (Figure 3.2).

At this rate of oversupply, the global storage capacity was rapidly filling up leading to negative pricing for various reference prices. In particular, the negative West Texas Intermediary price at -\$37.63/bbl on 20 April 2020 will remain a testament to the extraordinary circumstances the market was subject to.

Globally, suppliers responded to the oversupply situation and negative prices by curtailing production. The biggest reduction came from OPEC+ that decided on a 9 million barrels per day production cut to help balance the market, and to which several African OPEC and non-OPEC nations rallied.

Also, other countries instituted government mandated production cuts such as Norway while other countries saw market forces forcing production cur-

tailments such as the oil sand production in Canada. Overall, production was reduced with about 12.5 million bpd from March 2020 to June 2020.

Africa was also impacted by the production cuts with up to 460,000 barrels of oil per day (bopd) curtailed in May and June 2020. OPEC members Algeria and Nigeria have faced the majority of the production cuts with about 40 percent each, followed by non-OPEC members Sudan and South Sudan.

OPEC members Angola and Libya did not face the same production cuts as the Angolan production is declining, and Libya faces domestic unrest.

The initial turmoil caused by COVID-19 stabilized over the summer months as demand bounced back following lockdown measures being removed and the supply being curtailed.

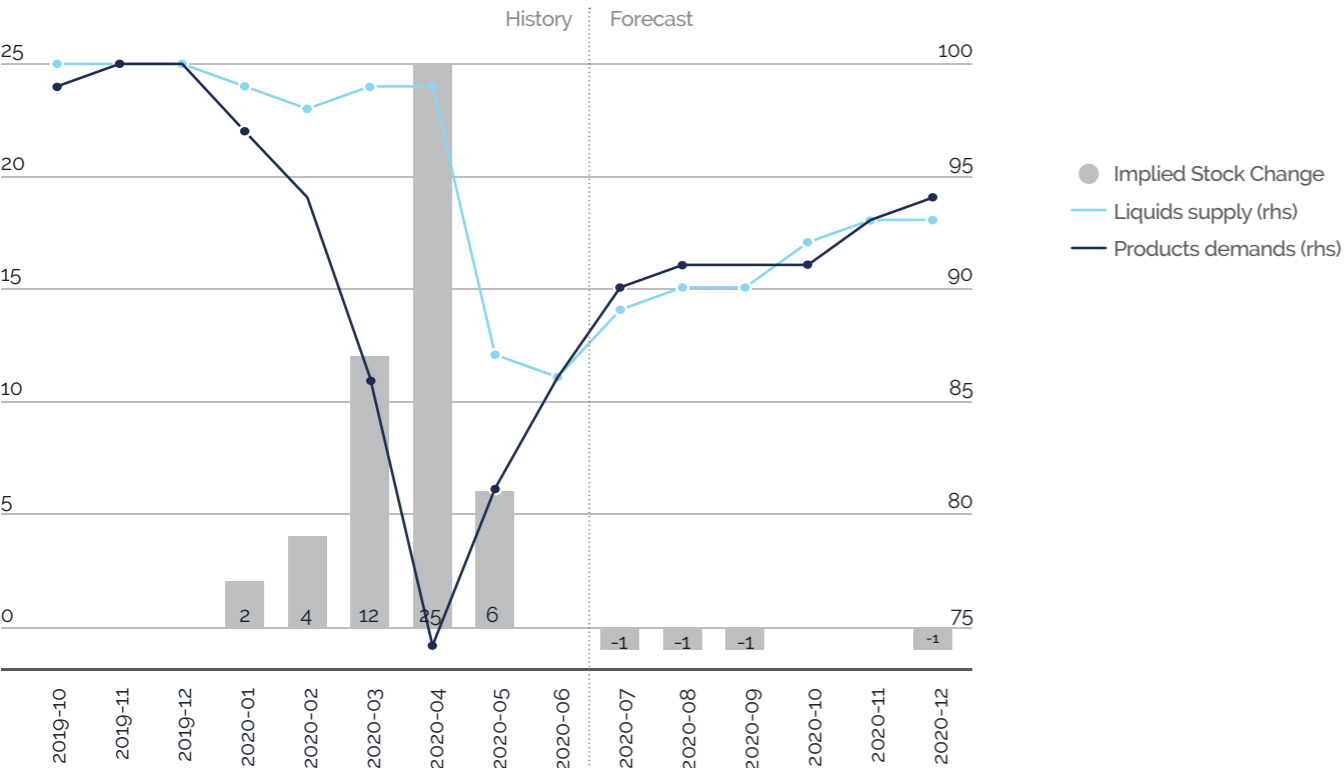
The Brent oil price subsequently increased from sub \$20/bbl to over \$40/bbl.

Going forward towards 2021, there remains high uncertainty around how the virus outbreak will unfold, how economies will react and ultimately what the impact will be on oil markets. Figure 3.3 illustrates a potential view of what can happen should a second wave of COVID-19 manifest itself and see the reinstatement of the draconian lockdowns from spring 2020. The base view is a gradual increase in demand throughout the remainder of 2020 and throughout 2021 to reach the pre-COVID-19 demand levels by late 2021.

Should the demand outlook unfold similar to the base view, the oil price is expected to see a similar gradual increase. By 2022, assuming the virus is under control and normalcy has returned, there is a risk of spiking oil prices above \$70/bbl as the dearth of investments throughout 2020 and 2021 may lead to a constrained supply outlook. Beyond 2022, the expectation is for the oil price to stabilize around \$60-65/bbl. Benchmarked versus the oil price expectations of leading E&Ps the general consensus appears to be a

downwards revision in oil price outlook, but nevertheless an expectation that the price will remain north of \$50/bbl. Figure 3.4 compares the communicated oil price outlooks from the latest Q2 2020 updates. For African nations, such price outlook will notably call for much more competitive frameworks on deep water developments and projects, which continue to represent a substantial share of the continent's production but are also the most expensive and most uneconomically feasible ventures given this outlook.

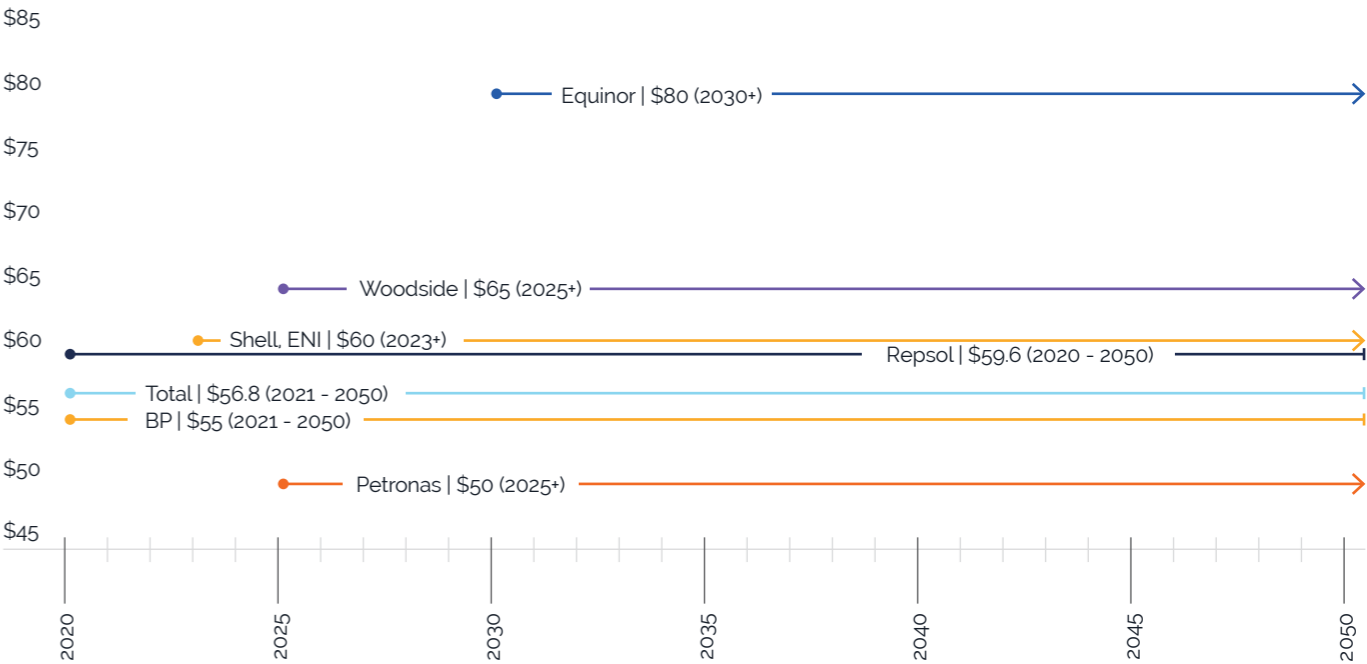
Figure 3.3: Global liquids supply and demand balances | Current base case
Million barrels per day



Data Source: Rystad research and analysis; OilMarketCube

Draws in June and July helped support sturdy oil prices in \$40s

Figure 3.4: Long-term oil price assumptions vary widely across companies
USD per barrel



Data Source: Rystad research and analysis

2021 to see a renewed push towards domestic gas monetization as Global LNG glut continues to depress prices

Depressed global gas prices and the ever-increasing demand for affordable power offer a unique environment for Africa to push for further domestic gas monetization.

COVID-19 also caused gas demand disruption. While less prominent than for oil, it was nevertheless sufficient to further depress prices.

As a result, all major reference prices have converged as a glut of LNG has to be absorbed.

Africa is expected to increase its gas exports once big LNG facilities are on-stream, ultimately increasing African exposure to global gas market.

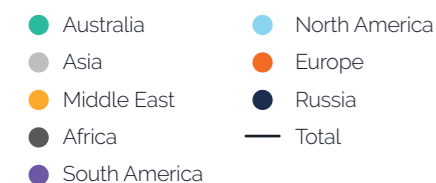
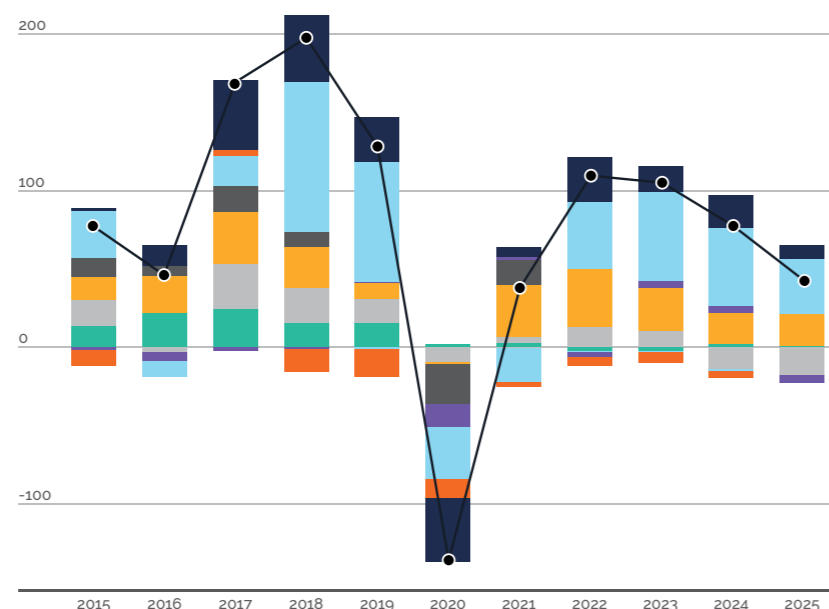


Figure 4.1: Global gas supply growth by continent
Billion cubic meters

Over the last five years, the global supply and demand for gas has grown rapidly. Demand has been spearheaded by growth in North America and Asia while supply growth has come from North America through the vast growth in hydrocarbon production from shale formations. 2017, 2018 and 2019 in particular saw strong growth with an average growth of 170 billion cubic meters per year (Figure 4.1). However, global gas production is expected to decline in 2020 on the back of production curtailments in North America and Russia. It will be the first time since 2009 that global gas production experiences a decline.

Gas markets are not insulated to COVID-19, but are less exposed than the oil market as a result of COVID-19 curtailing transportation more than anything else. Gas is less used in transportation, and as a result less impacted by COVID-19. The gas market was nevertheless already facing a glut of LNG even before COVID-19, resulting in even more depressed prices as the pandemic's impact on demand started to manifest in the spring of 2020.

As a result, key reference prices in Europe, North America and Asia all have experienced negative pressure since the start of 2020.



Data Source: UCube August 2020

2021 to see a renewed push towards domestic gas monetization as Global LNG glut continues to depress prices

Looking forward, expectations for the global market fundamentals are to remain loose through 2021 on the back of weak COVID-19 induced demand and continued high supply of LNG before prices tighten significantly as LNG demand growth will outpace liquefaction capacity due to more delays in project sanctioning (Figure 4.2). The forecast points to a tight LNG balance between 2023 and 2025, and along with it, a price spike. Following this period, there is a downside risk in prices for 2026 and 2027 driven by the potential of seeing a new wave of sanctioning activity during 2021 and 2022.



Figure 4.2: Gas reference prices moving forward
USD per million Btu

Data Source: GasMarketCube August 2020

Only gas-friendly policies can further unlock Africa's gas potential

Domestic use of gas on the African continent would have many positive benefits. Including:

Minimize flaring and improve carbon emission metrics for upstream production

Capture more value from the natural resources for the local economy

Create more jobs and activity related to use of gas across industries

Improve project economics if the gas otherwise would be flared.

Given the gas glut on global markets with corresponding depressed prices, there may now be an opportunity to stimulate to more domestic gas consumption. Expanding infrastructure to displace diesel, increased use of gas in the power mix and gas for industrial purposes are all initiatives that would benefit from the low cost of gas.

In this regard, Figure 4.3 illustrates expectations on production, demand and net export of gas from the African continent. Supply and demand have overall experienced a similar pace of growth to maintain a net export capacity of about 100 billion cubic meters per year. Post

2025, gas production is expected to accelerate on the back of big new developments in East Africa coming on-stream. Domestic gas consumption is still not expected to follow this growth acceleration unless strong gas-friendly policies are adopted and result in the expansion of African gas infrastructure, which implies increased exports towards 2030. Only sustained political will, friendly legislation and strong industry support can unlock the true potential African gas can have within Africa.

A source of African gas currently not used is flared gas from oil production. Figure 4.4 illustrates estimated flaring

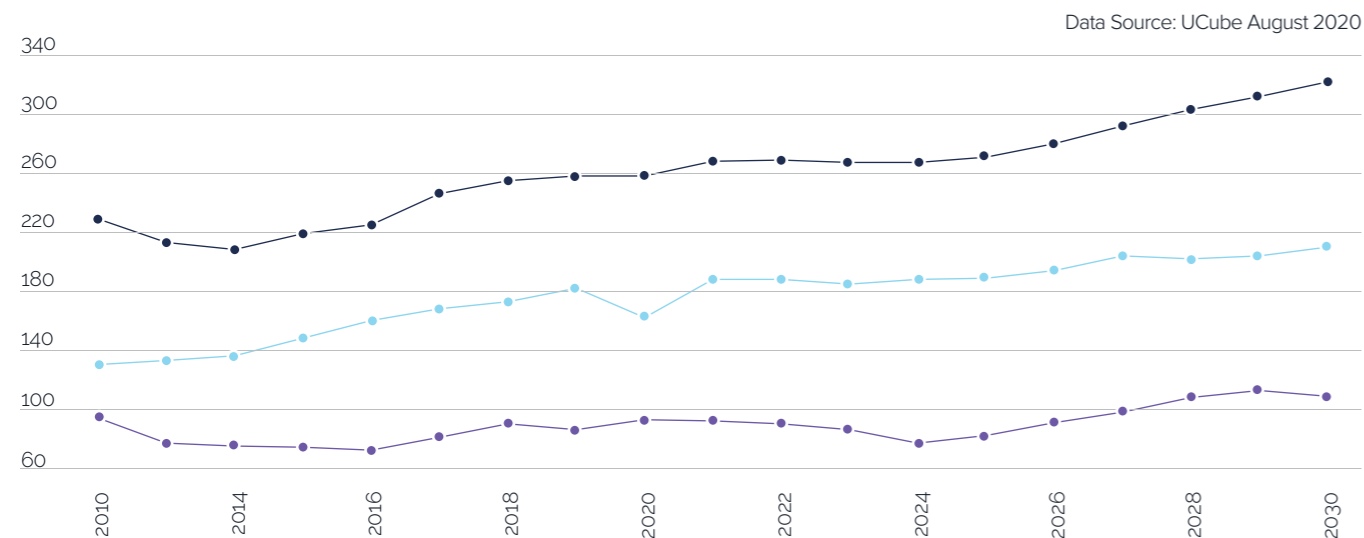


Figure 4.3: Africa gas net gas production balance
Billion cubic meters

- Gas Demand Base Case
- Gas Production
- Net Gas Import

levels for the continent split on key countries. Overall flaring is expected to decline in line with the oil production, but nevertheless represents significant resources that could be utilized for industrial purposes for example.

The African gas trade balance would shift should all the flared gas be utilized (Figure 4.5). The gas could either represent an uplift in domestic demand and maintain expected export capacity, or it could represent additional export capacity in the case of fixed domestic demand. It would result in a 13 percent uplift in demand or a 28 percent uplift in net export capacity.

Figure 4.4: Estimated African gas flaring
Billion cubic meters

Data Source: UCube August 2020

- Nigeria
- Algeria
- Libya
- Angola
- Egypt
- Other Countries

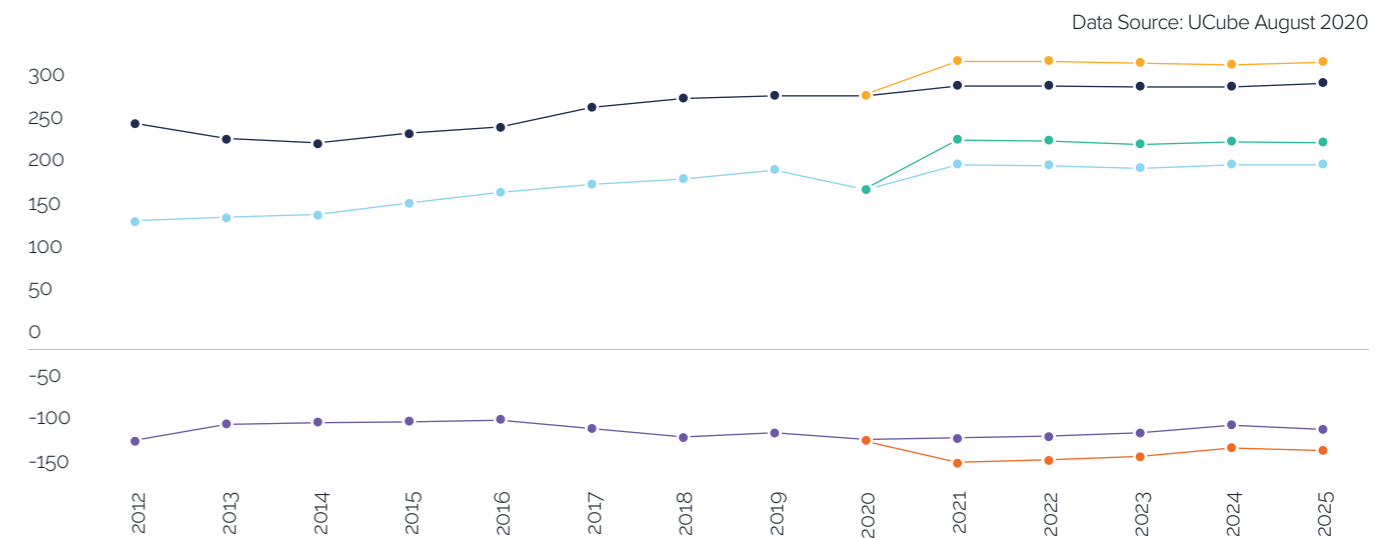
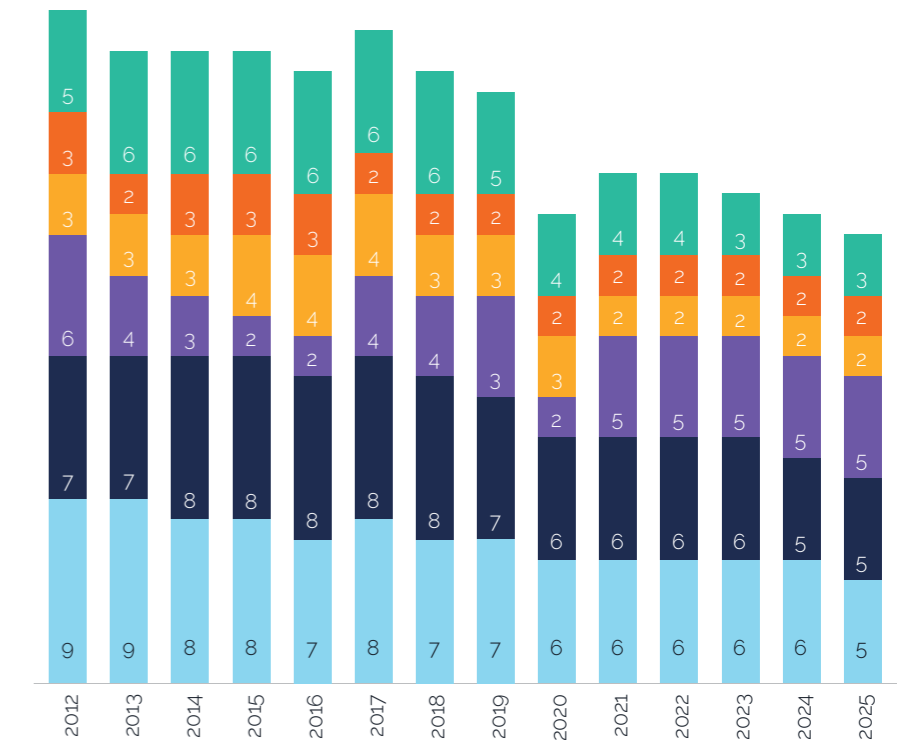


Figure 4.5: Potential Africa gas net gas production balance with flaring included
Billion cubic meters

- Gas Demand Base Case
- Gas Production
- Net Gas Import
- Flaring add to production
- Extra export capacity
- Extra domestic demand

COVID-19 capex cuts expected to **impact drilling activity** in **2021**

Drilling activity expected to fall below 800 wells per year in 2021 versus the 966 wells drilled in 2019 pre-COVID-19

Offshore rig demand expected to drop year-on-year in 2020 by 30 percent with 2021 expected to experience a slight increase from 2020, spelling out a tough environment for drilling service providers

High impact exploration drilling may create new opportunities that can drive drilling demand on a mid-term basis

Overall environment favorable for increased local procurement of goods and services to cut cost.

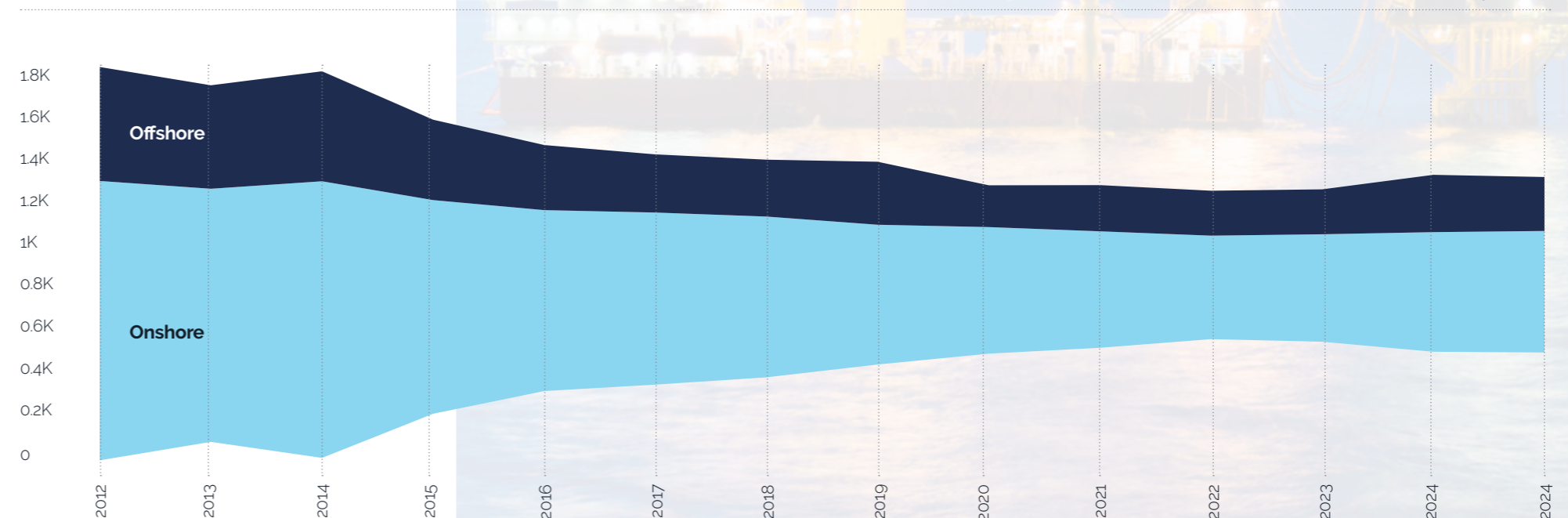
Limited Outlook

Wells drilled on the African continent and its continental shelves ultimately represent the activity that ensures hydrocarbon recovery from its underground deposits. An estimated 1,850 wells were drilled during 2012 with about 1,350 or 73 percent drilled onshore and the remaining 500 or 27 percent drilled offshore (Figure 5.1).

The trend since 2012 has been a declining number of wells drilled per year, and in particular since the oil price drop in late 2014 which exacerbated this trend. As a result, the 2019 estimate of wells drilled was almost 1,000, a drop of about 45 percent in activity versus 2012. Reduced drilling activity onshore Libya and Egypt are the main drivers behind this decline.

Going into 2020, the activity is expected to decline further as a result of COVID-

Figure 5.1: Estimated number of wells drilled in Africa



Data Source: WellCube August 2020

19's impact on global and African energy supply. The current estimate points to only about 800 wells to be drilled, representing a year over year decline of about 20 percent versus 2019. Beyond 2020, there is limited respite expected until 2024 with

the number of wells hovering around 700 per year. By 2024, as a result of new projects being sanctioned for development on the back of a higher oil price, activity is expected to increase again towards 800 wells per year.

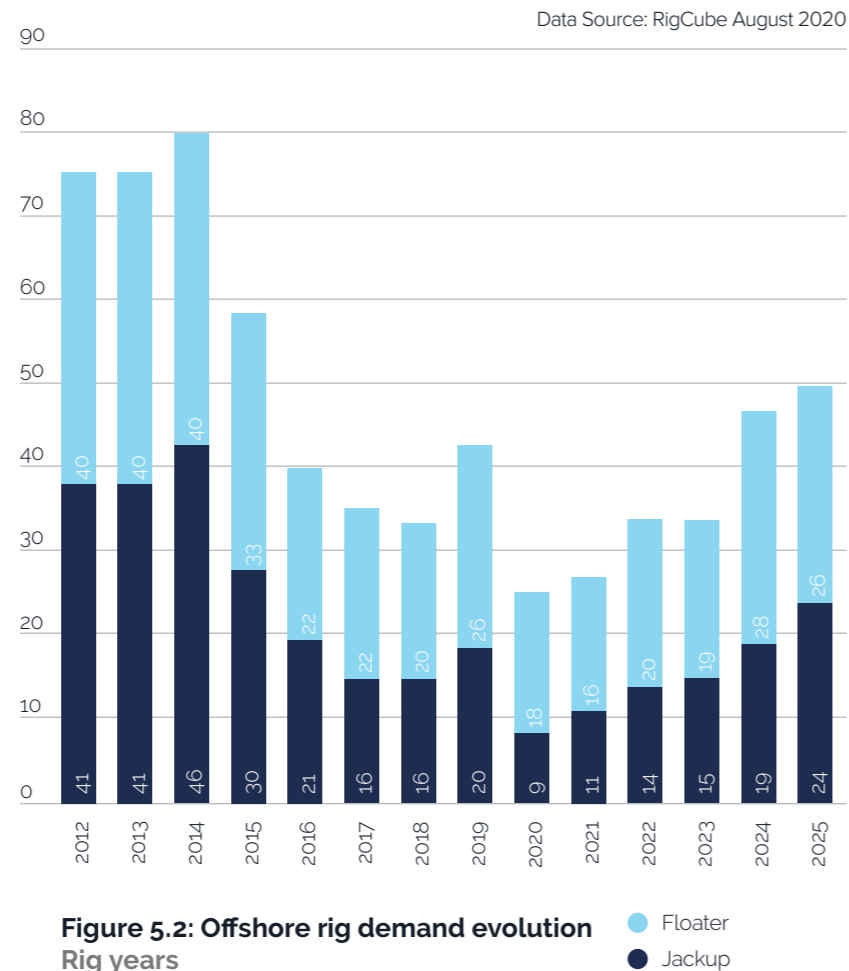


Offshore Rig Demand

The number and type of wells can be translated into rig demand expectations. In other words, how many drilling rigs have to be operational for a year in order to drill the wells. Figure 5.2 illustrates the offshore rig demand split by jack-ups and floaters. Jack-ups are typically used in shallow water with water depth up to 125 meters while floaters serve drilling demand in deeper waters.

From a high level of demand in 2012 to 2014 of about 80 rig years, the late 2014 oil price collapse reduced drilling demand significantly. By 2018, demand was down to 35 rig years implying a reduction of 56%. 2019 was in that respect a more promising year as demand increased towards 45 rig years, representing an increase of almost 30 percent.

At the start of 2020, the demand was not expected to decline towards and below 2018 levels again, but the extraordinary impact of COVID-19 means that estimates for 2020 and 2021 are pointing to record low rig demand of less than 30 rig years. It is in particular floating rigs that will be impacted by lower demand versus the 2019 actuals.



However, from 2022 onwards the expectation is for rig demand to rebound slightly as drilling programs associated with projects currently under development are initiated and a higher oil price expectation help revive exploration activity.

However, the expected growth towards 50 rig years in 2025 is obviously contingent on new projects being sanctioned (Figure 5.3). Based on the oil price outlook presented under the oil market section, the combined po-

tential of these new projects and further exploration activity will be able to increase demand towards its highest level since 2015. However, should the oil price not recover, it would jeopardize about 50 percent of the expected 2025 rig demand.

Breaking down cumulative offshore rig demand from 2020 to 2025 per country reveals Egypt as the most active country in Africa with almost 60 rig years, followed by Angola and Nigeria.

In that regard, Figure 5.4 provides the breakdown of the top 10 countries by rig demand with associated split on what resource class is supporting the rig demand. For Angola, about 35 percent of the demand is related to contingent resources which means that rig demand in this particular area is sensitive to investment decisions expected over the next years. Ghana also has a large share of contingent demand on the back of the big Pecan project that may be sanctioned for development.

Figure 5.3: Offshore rig demand evolution per life cycle
Rig years

Data Source: RigCube August 2020

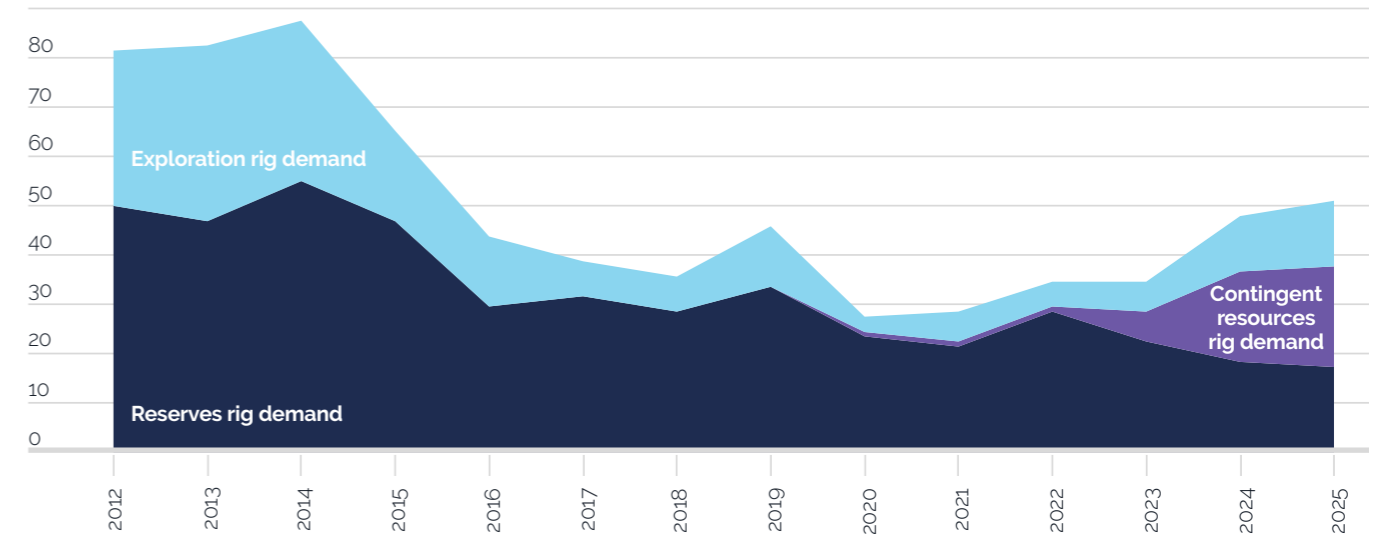
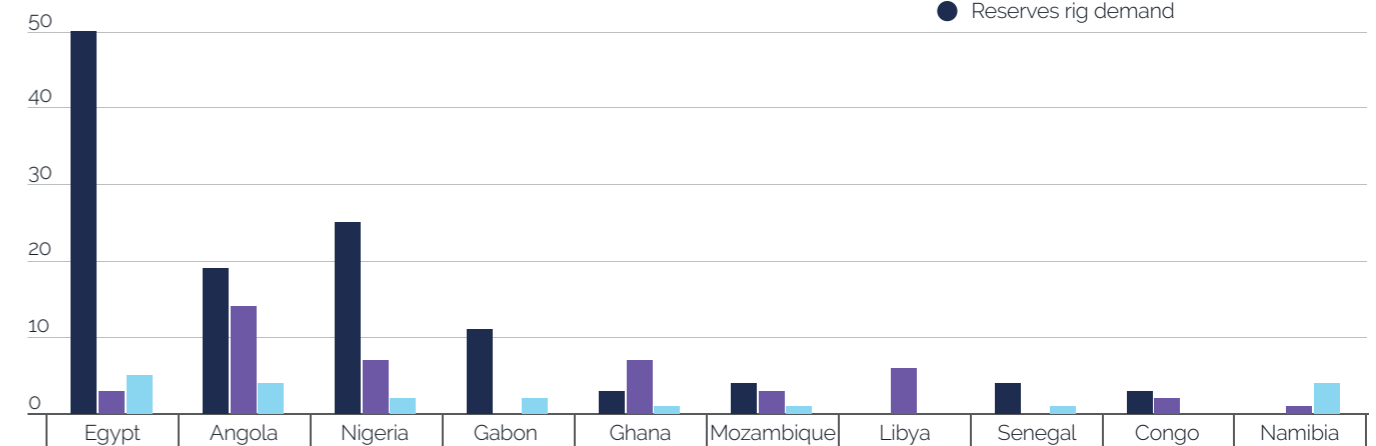


Figure 5.4: Cumulative offshore rig demand 2020-2025 per country
Rig years

Exploration Rig Demand (light blue)
Contingent Resources rig demand (purple)
Reserves rig demand (dark blue)



Data Source: RigCube August 2020

South West Africa Exploration

The southwestern coast of Africa, including Namibia and South Africa, is home to perhaps the most anticipated wildcats in 2020 and 2021 globally. The prospects, if successful, could open new basins for development and trigger big new investments towards the latter half of the 2020s.

High impact wells have been communicated by various participants from Angola all the way down to South Africa (Figure 5.5). French major Total is in the driving seat of this exploration where high impact and record setting wells will be drilled in those waters. In Angola, the well planned in block 48 will be the deepest on record in terms of water depth measuring about 3,600 meters. The Venus prospect in Namibia has perhaps the biggest impact potential as its size and remote location can be

the trigger to extend West African offshore petroleum activity further south from Angola. Finally, the follow up activity to the breakthrough 2019 Brulpadda discovery in South Africa has commenced in the second half of 2020 with the Luiperd prospect, where a significant gas discovery was made in Q4 2020.

Total is here hoping to find more liquids and confirm the South African offshore resource potential to further support a development agenda towards the latter half of the decade.

Other companies have also communicated their intention to drill in the area with the Orange Basin on the border between Namibia and South Africa as the most activity area, and by extension, presumably also the most promising area.

High impact well reason

Frontier basin:
The basin with little or no exploration

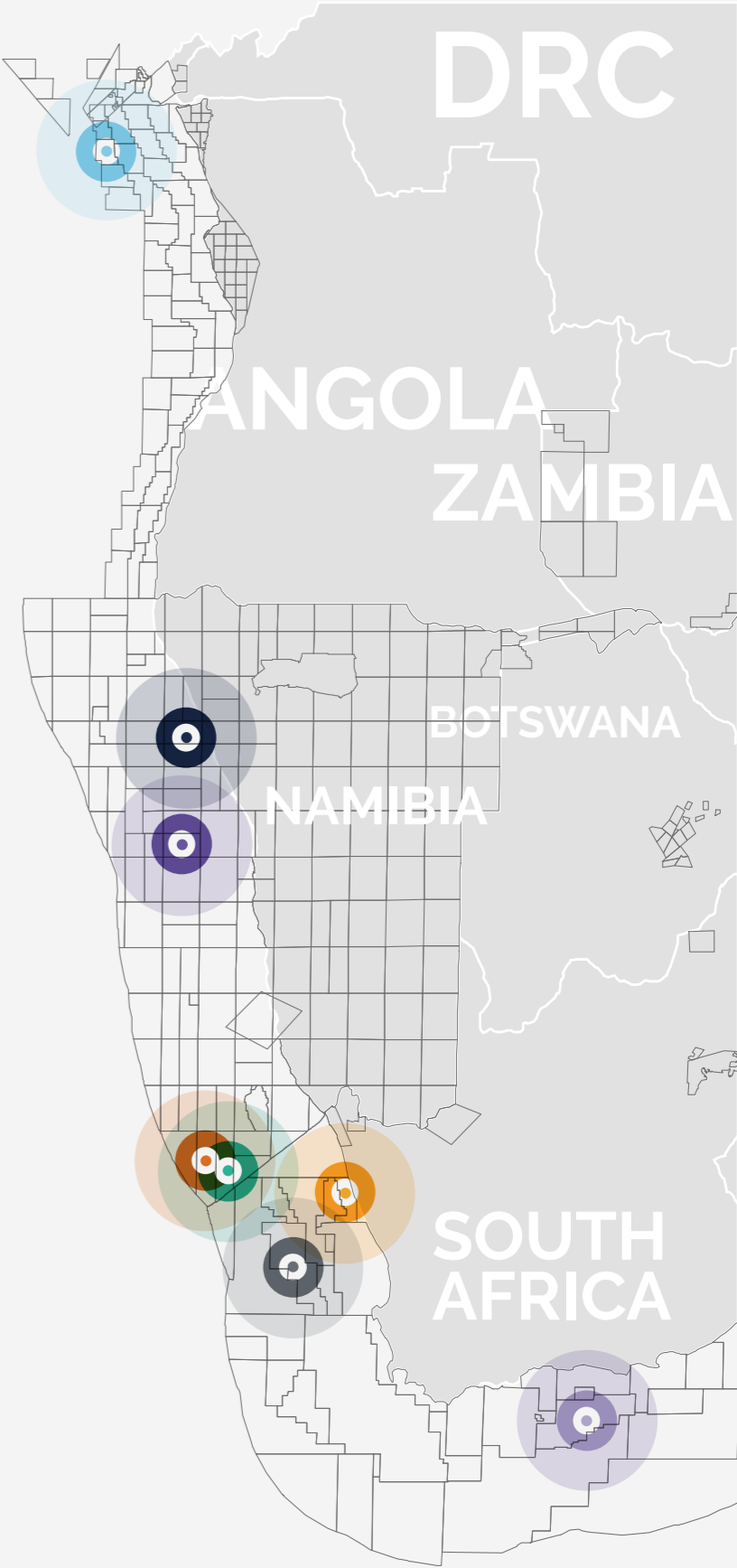
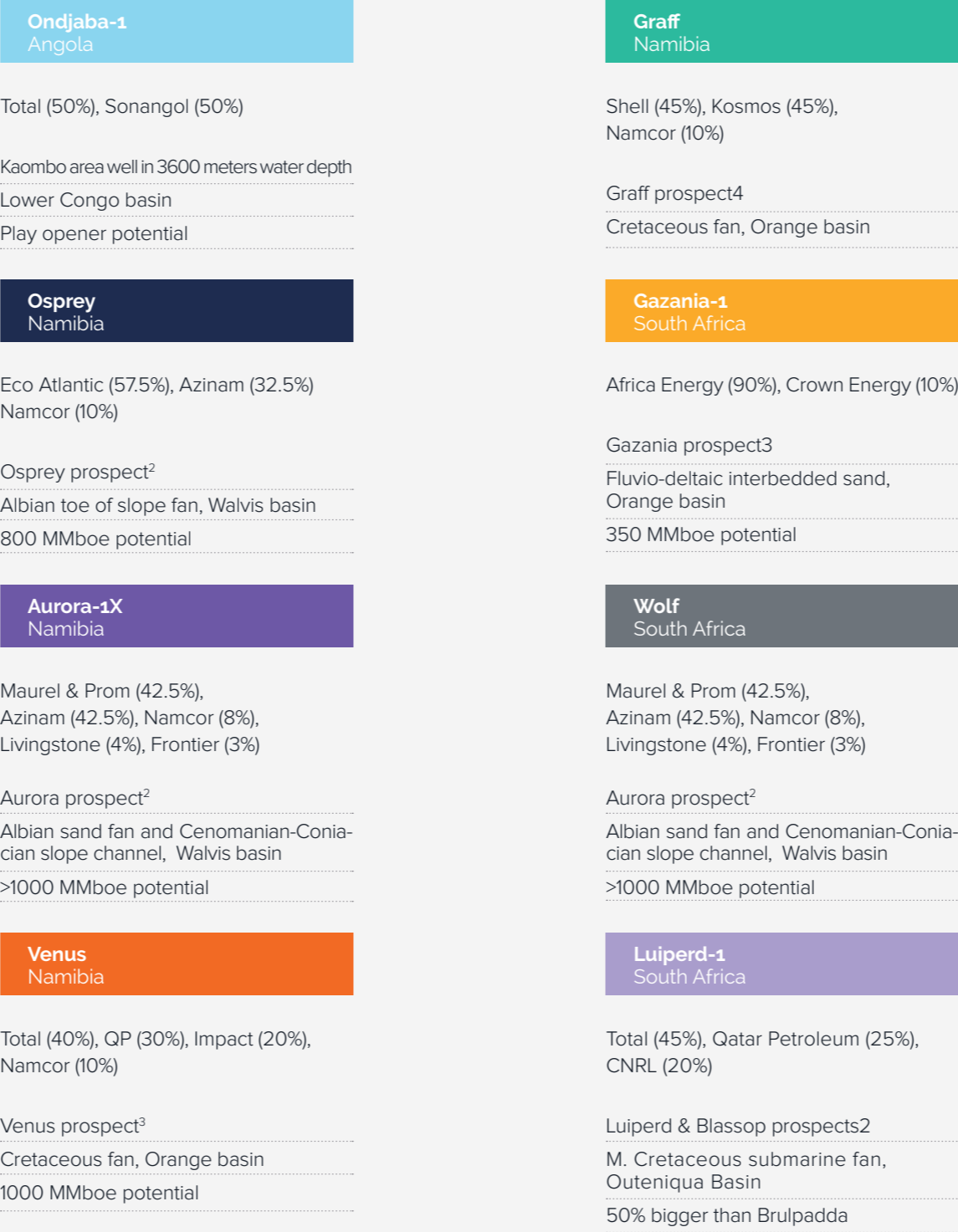
Large prospective resources:
The pre-drill estimates by the company are quite significant.

Focus for Company:
The wells which are highly talked and strategically important for companies.

Emerging Basin:
The basins where some significant recent exploration has taken place.

Play Opening:
The well targeting a new play or area within the province or basin.

Figure 5.5: High impact wells in South West Africa



Data Source: Rystad research and analysis

2020's 30% CAPEX drop expected to be recovered in 2022 on the back of mega LNG projects

Upstream investments expected to fall below \$30 billion in 2020 and 2021

Rebound in investments can be strong, but depends on projects to be sanctioned in particular related to the East African LNG facilities

Most service segments expected to see a decline in market size with the exception of EPCI benefitting from mega LNG projects.

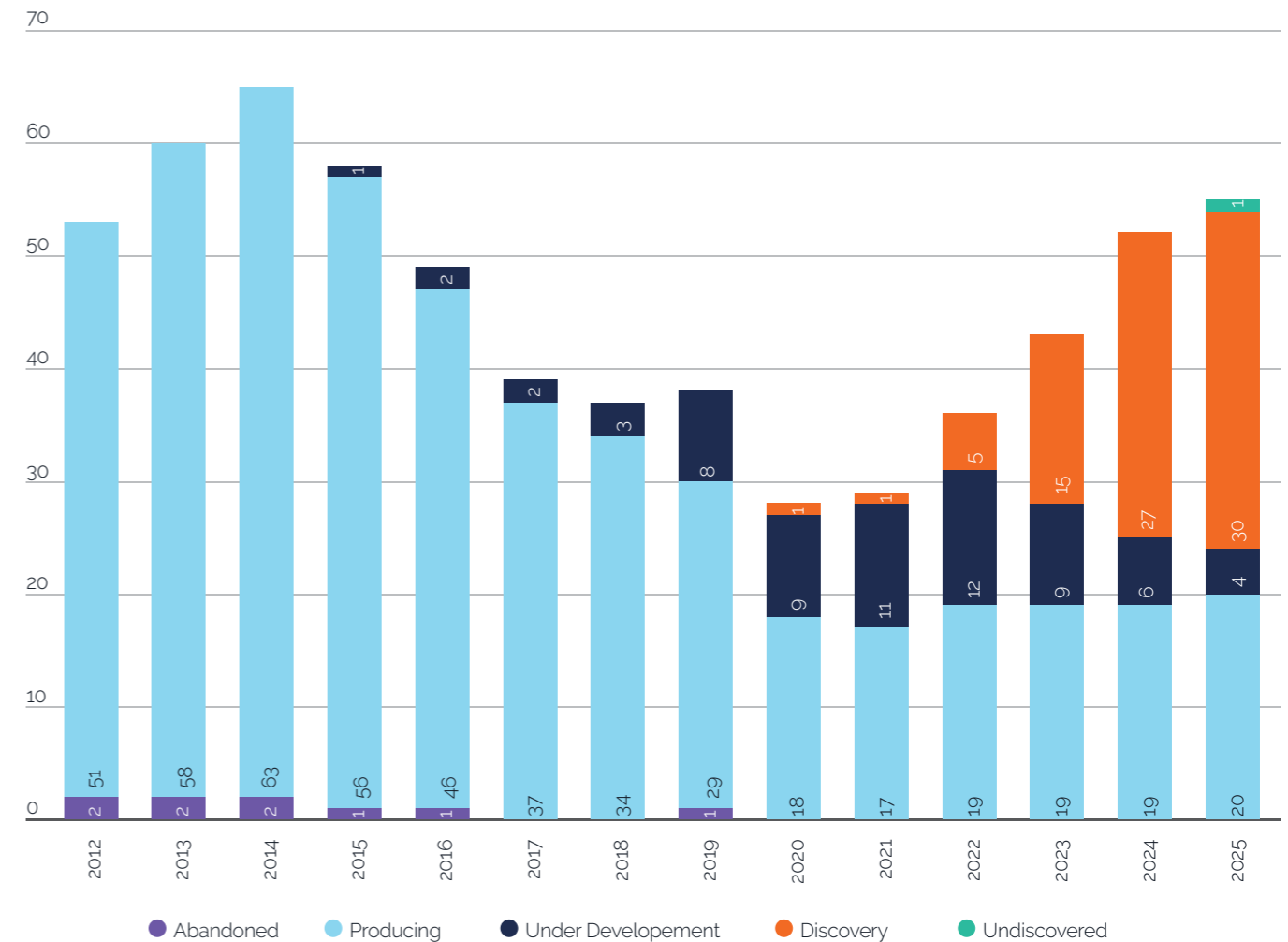
\$80bn can be unlocked by 2025 pending market conditions and policy reforms

Investments are required to convert resources in the ground to revenue and value. The investments represent jobs and business for a plethora of African service providers and is therefore an important metric to the wider activity level around the oil and gas industry. From 2020 to 2025, up to \$80bn of capital expenditure (CAPEX) remains contingent and is pending the taking of FID on new projects from discovered fields (Figure 6.1).

Such pre-FID expenditures represent about 33 percent of CAPEX expected during the next five years. This remains a heavy share of uncertain spending, and one that could translate into jobs and local content growth if approved. Put simply, African regulators, policy-makers and governments have the power to unlock an additional \$80bn of investment by 2025 if the right measures are taken and the right policies are put in place.

Figure 6.1: African upstream capital expenditure
Billion USD nominal

Data Source: UCube August 2020



Many global E&P players, including the international majors, are looking at significant cuts to their capital spending and operational expenditure. Total slashed its 2020 exploration and production budget by up to \$2.5 billion and targets \$800 million in savings in operating costs. The French major will also suspend its previously announced \$2 billion buyback program, and the other majors are doing the same. Independents with a strong presence in Africa like Kosmos Energy (Kosmos) and Tullow Oil (Tullow) have also reviewed their 2020 spending plans. Kosmos has cut its CAPEX in

2020 by 30 percent with no plans for a rebound in 2021. Kosmos seeks to become cash-flow neutral in a \$35/bbl oil price environment. Tullow has also reduced its investment budget by about a third this year and cut its exploration spending by almost half to weather the oil price storm.

From the peak in 2014 at about \$65 billion, CAPEX in Africa has steadily declined to under \$40 billion by 2019. This decline is a result of lower activity from new projects, general cost compression in the industry and friction in getting new projects sanctioned due

to external influences such as export route disagreements and fiscal parameters. Going into 2020, the expenditure is expected to drop to below \$30 billion representing an almost 30 percent drop versus 2019. The impact of COVID-19 is the main factor as it has deferred FID on many projects (Figure 6.2).

Moreover, expensive deep-water projects are most prone to the reduced outlook on investments (Figure 6.3), a key factor to take into account given that the largest discoveries and prospects on Africa's Atlantic coast are in deep water acreages.

Figure 6.2: Impact of Covid-19 and price crash
Reduced sanctioning and delayed greenfield spending
Million USD

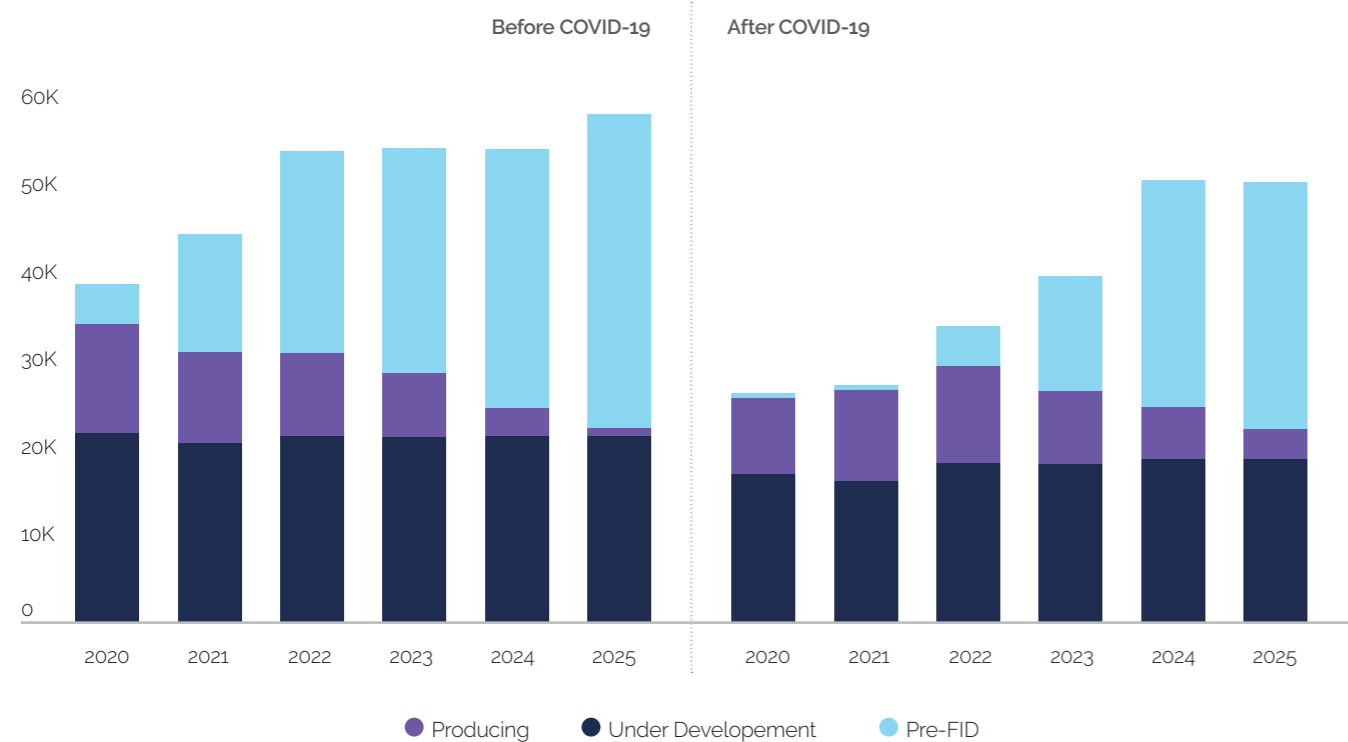
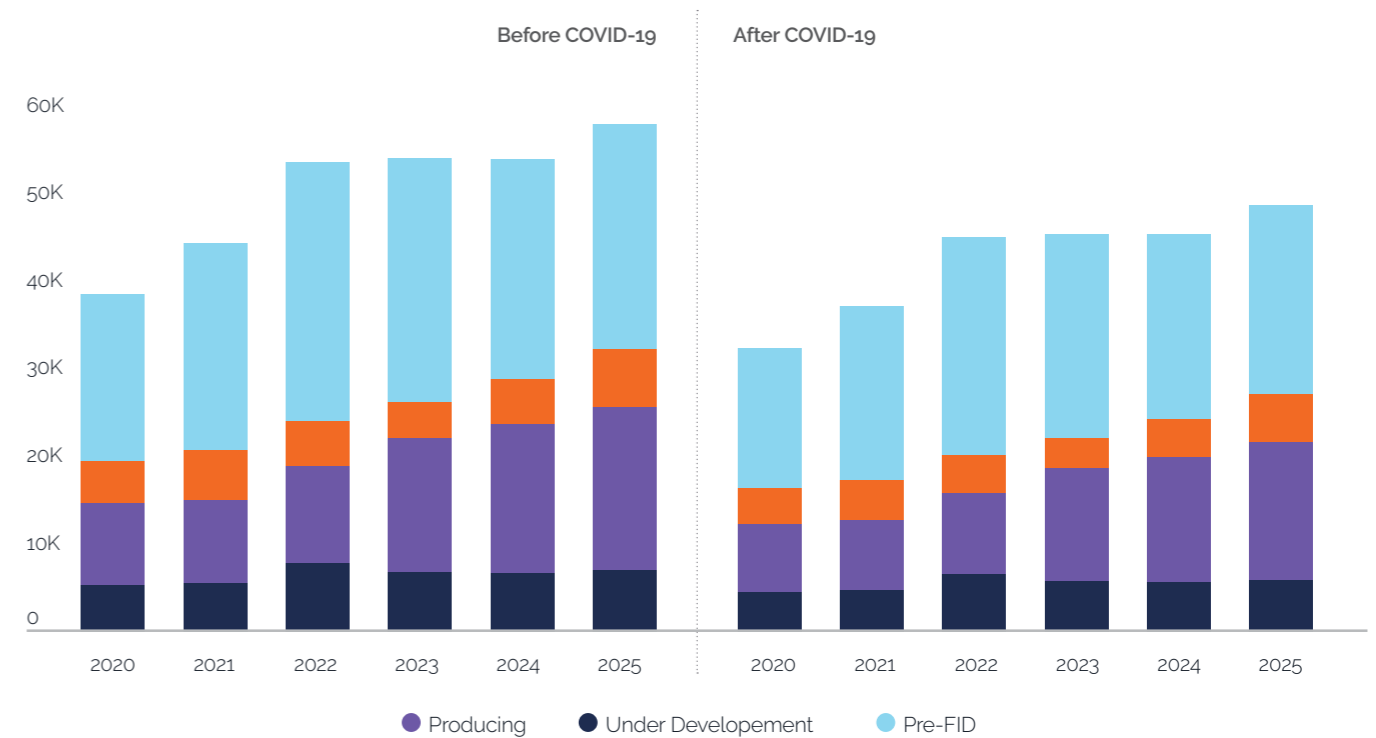


Figure 6.3: Impact of Covid-19 and price crash
Offshore, especially deepwater projects taking the brunt of CAPEX cuts
Million USD



The deferred projects and the projects originally slated for investments from 2022 onwards will together have the potential to contribute to a significant growth potential. Should the projects materialize, the potential cumulative expenditure may increase to above \$50 billion by 2024.

However, as Figure 6.4 illustrates, lower oil price expectations may shave of the growth potential as projects are not commercially viable and/or further deferred. With the oil price at \$50/bbl, investments are expected to only barely rebound in real terms to 2019 levels by 2024.

Figure 6.4: Investment outlook sensitivity based on oil price
Million USD Nominal

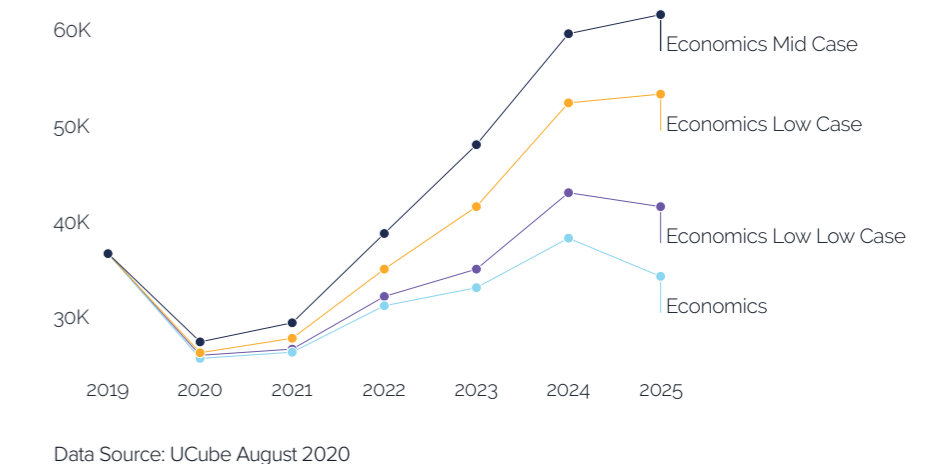




Figure 6.5: Contingent investment spending per project type
Billion USD Nominal

Data Source: UCube August 2020

Subsea Tiebacks and LNG Projects Remain Pillars of Future Industry Spending

Out of all contingent projects yet to make FID between 2020 and 2025, investments related to sub-sea tiebacks is the single greatest category, reaching almost \$20 billion across the period (Figure 6.5). Subsea tiebacks are likely to be more and more common as it makes commercial sense to piggyback smaller hydrocarbon accumulations on existing infrastructure. The breakeven therefore achieved from such a development solution is typically also very competitive. The offshore-related part of LNG

developments further boosts this category in light of the mega-projects expected in Mozambique.

The second biggest category is all investments related to onshore production. Continued drilling of new wells and other improvements are needed to arrest production decline in the mature areas of African onshore production. Big investments are also expected in Uganda and Kenya related to the greenfield onshore development of Lake Albert and the Lokichar Basin. Such greenfield developments may

be amongst the last big conventional onshore projects in the world.

The third biggest category of upcoming projects, at almost \$15 billion, relates to investments in onshore LNG facilities. It is in particular the East African gas resources that is likely to trigger these investments. In terms of resource size, these projects are the biggest and most important in Africa, and they will also help bring activity to a part of Africa that previously had not seen much hydrocarbons-related developments.

Out of upcoming major projects in Africa, the top six gas projects are all bigger in terms of oil equivalents than the oil projects (Figures 6.6 and 6.7). Taking into account all cumulative investments per country, Mozambique remains in clear lead which further emphasizes how important the LNG projects are for the African investment outlook (Figure 6.8).

The majority of the projects in Africa that were up for sanctioning were planned assuming an oil price of between \$55 and \$60/bbl. The oil price currently hovering around \$40/bbl therefore spells bad news, especially as the top upcoming FIDs in Africa have a breakeven crude price of over \$45/bbl, with some even close to \$60/bbl. ENI and ExxonMobil have both stated that they will focus on developing projects with a breakeven crude price of less than \$35/bbl. The ENI-operated Agogo full field development off Angola now faces getting delayed due to its breakeven price of \$45/bbl.

In its latest announcement, Shell distanced itself from deep-water mega-projects off the coast of Nigeria, placing the Bonga Southwest-Aparo, a 150,000 bpd FPSO development that was soon coming up for FID, on the backburner for now. Tullow is expected to delay the South Lokichar development off Kenya.

The Palas-Astraea-Juno (PAJ) marginal fields development operated by BP in Angola is another project that could see delays due to a relatively high breakeven price and BP's commitments to other parts of the world and to the energy transition.

Upcoming gas projects will also take a hit and run a risk of delays. Although Nigeria approved the development of NLNG train 7 last year, the upstream gas developments that were planned to supply feedgas to this development might now take a back seat. The FID for the Area 4 LNG project in Mozambique

(Rovuma LNG), which was to be sanctioned this year, has now spilled over to 2021 at best. The Ahmeyim and Yakaar gas hubs off the coast of Mauritania and Senegal and a few other natural gas projects in the northern and eastern regions of the African continent may have their FIDs postponed to 2022–2023 as part of Kosmos's plans to trim down its capital expenses.

The investments for the above projects will now see a timeline shift or even a spending cut altogether, which will ultimately impact production levels in this region. Current estimate is that the timeline delays for these pre-FID projects in Africa could lead to a 200,000 bpd drop in liquids production on average between 2021 and 2025.

The impact could be much higher in the longer term, with liquids production set to drop on average by close to 1.185 million bpd over the years 2026 to 2030.

Figure 6.6: Upcoming Liquids projects in Africa and their timeline and recoverable reserves estimates

Project	Country	Operator	FID*	Start-Up	Resources (MMboe)
Tilenga	Uganda	Total	2022	2025	945
Bosi	Nigeria	ExxonMobil	2025	2029	790
Bonga North	Nigeria	Shell	2026	2031	700
Bonga Southwest Aparo	Nigeria	Shell	2024	2028	630
Owovo West	Nigeria	ExxonMobil	2024	2027	550
Etan Zabazaba	Nigeria	Eni	2028	2032	520
Pecan	Ghana	Aker Energy	2022	2025	335
Chissonga	Angola	Total	2024	2029	290
Kingfisher South	Uganda	CNOOC	2022	2025	270
Agogo FFD	Angola	Eni	2022	2025	245
SNE	Senegal	Woodside	2020	2023	220
South Lokichar Phase 1	Kenya	Tullow Oil	2023	2025	220
Egina South Preowei	Nigeria	Total	2023	2026	190
Palas Astraea Juno (PAJ)	Angola	BP	2022	2025	140
Alho Cominhos, Cominhos East (ACCE)	Angola	Total	2023	2027	85

Data Source: Rystad Energy UCube

● Liquids ● Gas

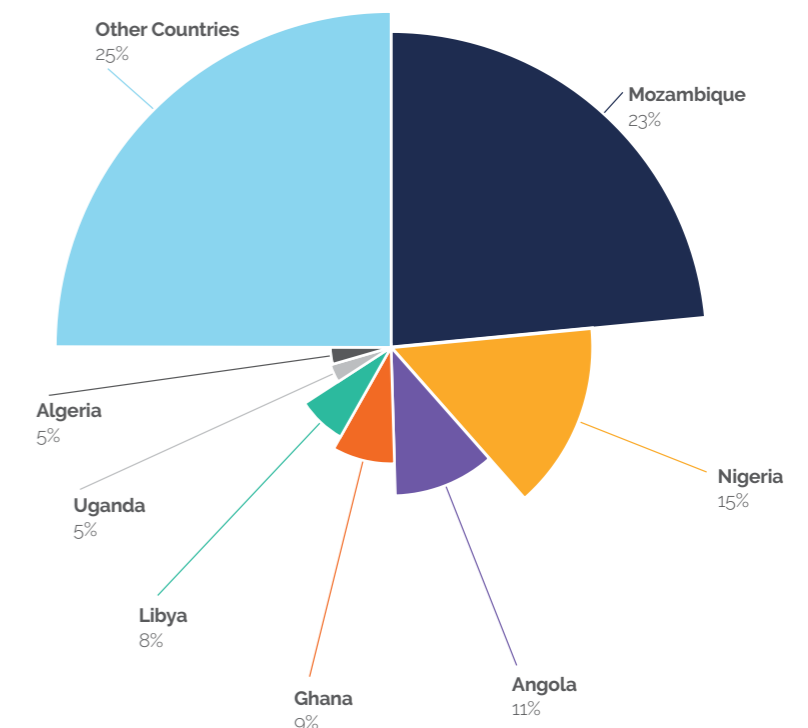
Figure 6.7: Upcoming Natural gas projects in Africa and their timeline and recoverable reserves estimates

Project	Country	Operator	FID*	Start-Up	Resources (MMboe)
MZLNG Joint Development (T1 - T2)	Mozambique	ExxonMobil	2025	2030	4625
Area 1 LNG (T1 - T2)	Mozambique	Total	2019	2025	3590
Area 4 LNG (T1 - T2)	Mozambique	ExxonMobil	2022	2026	2330
Yakaar - Teranga LNG Hub	Senegal	BP	2027	2032	2145
NLNG Seven Plus	Nigeria	Shell	2019	2025	1450
Greater Tortue Ahmeyim LNG Hub	Mauritania	BP	2024	2028	1480
Djibouti FLNG T1	Ethiopia	Poly GCL Petroleum Investment Ltd	2022	2025	520
Assa North	Nigeria	Shell	2025	2028	415
Tinrhert Gas Project	Algeria	Sonatrach	2023	2025	385
Fortuna FLNG	Equatorial Guinea	Lukoil	2025	2029	250
Quiluma/ Maboqueiro (Northern Gas Complex)	Angola	Eni	2021	2024	250
Yakaar (domestic)	Senegal	BP	2023	2025	215
HA	Nigeria	Shell	2022	2026	210
Ima gas	Nigeria	AMNI	2023	2028	185
Sanha Lean Gas	Angola	Chevron	2023	2026	115

Data Source: Rystad Energy UCube

● Liquids ● Gas

Figure 6.8: Contingent investment spending per country Billion USD Nominal



Data Source: UCube August 2020

Services sector impact

With the CAPEX and expected type of projects defined, it is possible to forecast opportunities offered to the services industry. EPCI companies are expected to benefit the most from future spending (Figure 6.9), followed by well services contractors.

As a result, EPCI is the only segment expected to buck the trend of declining expenditure on the back of the LNG facilities expected to be constructed towards 2025 (Figure 6.10). The relative worst performing sector across the periods is drilling contractors. This segment benefited

from high activity and high contract rates from 2010 to 2014 while subsequent years saw a reduction in both activity and rates. The segment is also adversely impacted by the large share of gas developments towards 2025 as gas projects are a lot less drilling intensive than oil projects.

Figure 6.9: African upstream capital expenditure per service segment
Billion USD Nominal

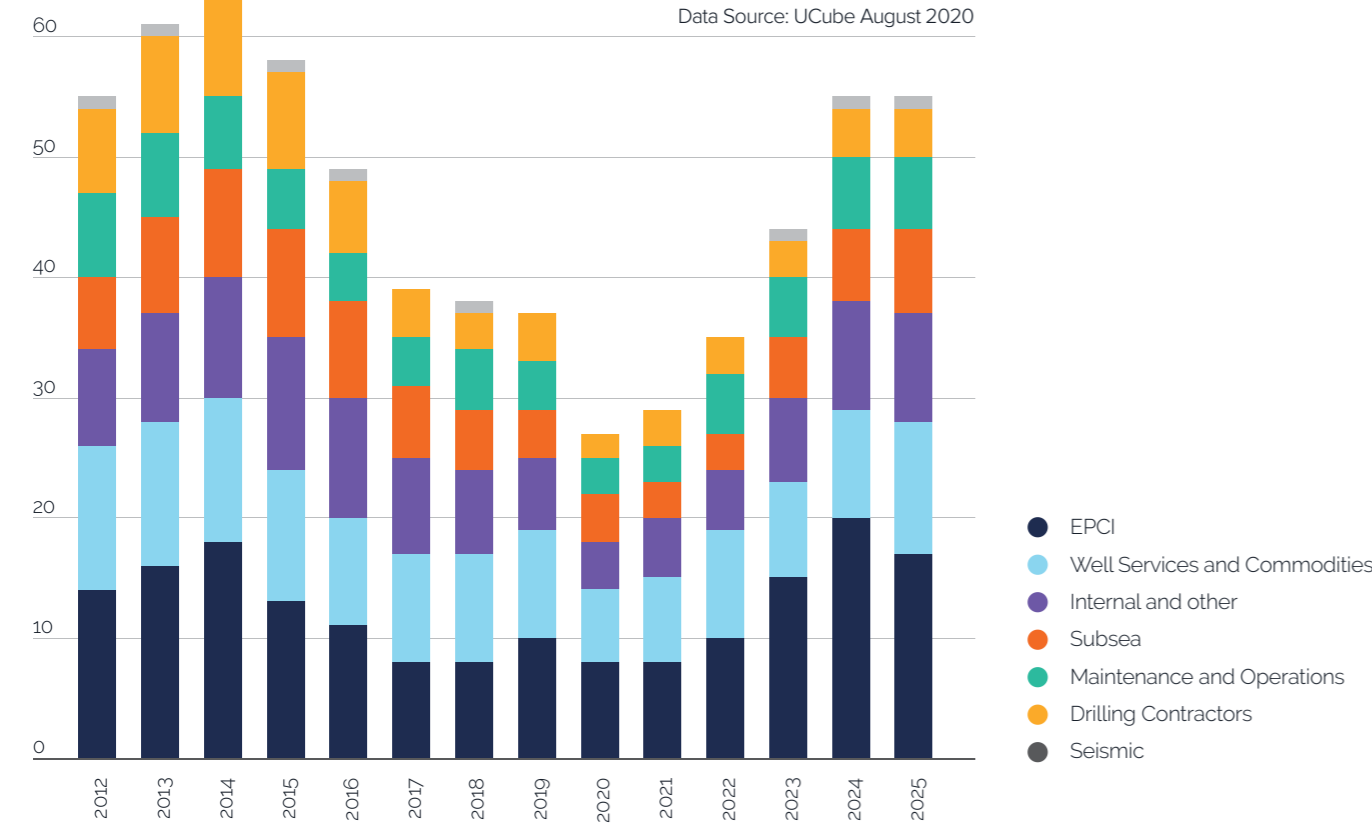
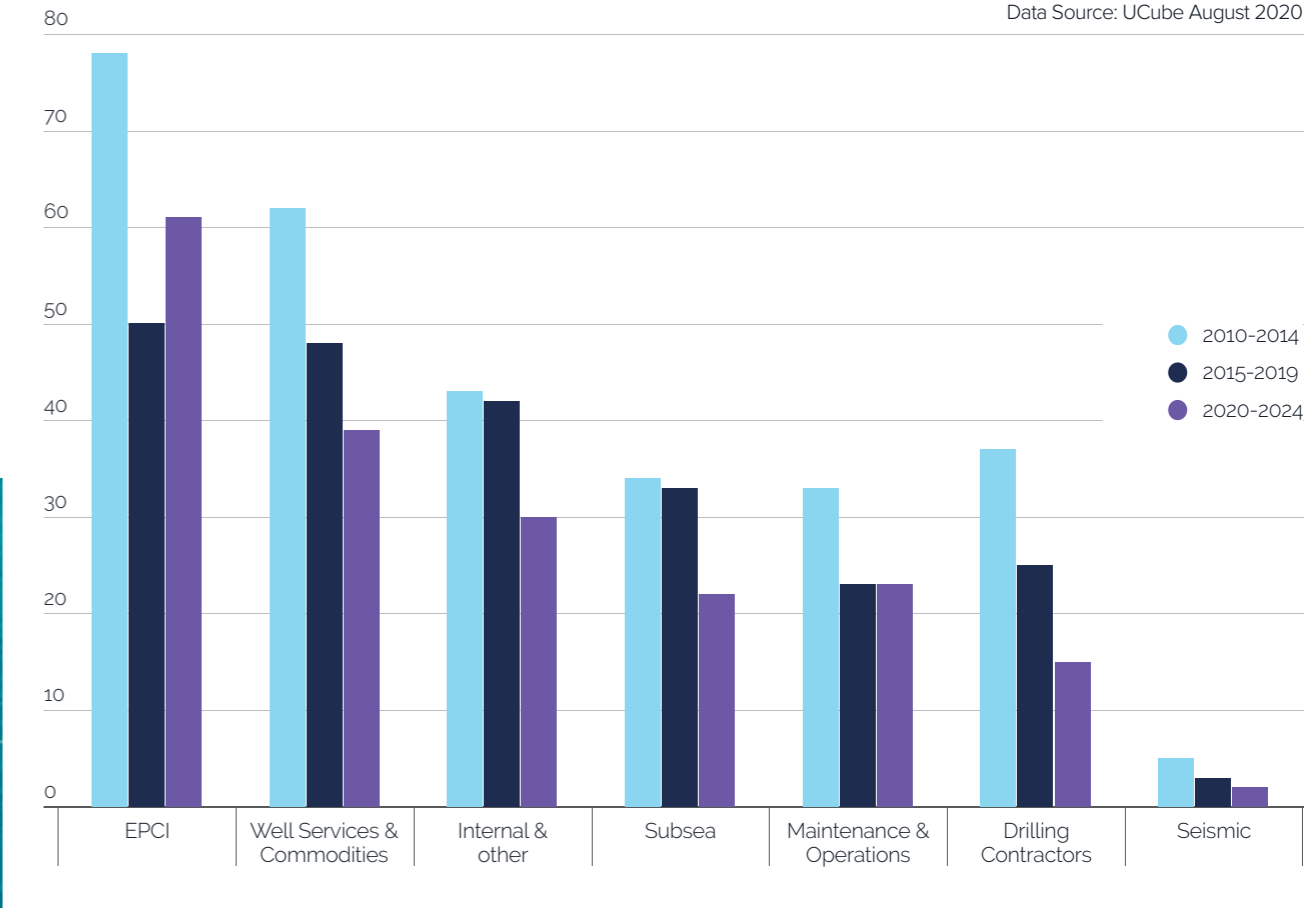


Figure 6.10: Cumulative capital expenditure per period
Billion USD Nominal



New market realities for 2021 expected to drive reviews of fiscal terms to improve competitiveness

Projected market conditions for 2021 do not indicate a return to high commodity prices, implying that the super profit era of petroleum is over.

The industry cost base has been adjusted, but African fiscal regimes are often lagging behind and remain uncompetitive in this new environment.

Many African governments will take steps to adjust the fiscal regimes in 2021 to improve competitiveness.

Using a UK-type fiscal regime can help unlock \$100 billion investments in a \$50/bbl scenario.

The end of the super-profit era?

Petroleum resources and the extraordinary profit they have typically generated in the past have resulted in various fiscal regimes. The fiscal regimes are designed in some way or another to ensure that part of this profit is collected by the state. Depending on the rules of the fiscal regime, there might be impacts on the investment metrics used by private companies on executing new projects.

A common example of such a metric is breakeven, or what revenue is required, as a function of quantity and price, to cover all cost, pay all government take and generate sufficient return. Ideally this breakeven should be as low as possible to improve the likelihood of the project generating positive financial returns.

As such, the rules and parameters of the fiscal regime is often very important, per-

haps even more important than the actual resource base created by nature, in terms of influencing the FID of a new project. When the oil price was above \$100/bbl, these fiscal regime rules could be favorable towards the state as the breakeven would in any case be low enough to secure an investment decision. However, with an oil price at \$50/bbl and below, the surplus that can be distributed is likely much smaller. From a post-tax point of view, it may then be difficult to justify new investments as the fiscal regime is too strict to make the project commercially viable even if the intrinsic value of the resource base would otherwise imply so.

The result is therefore a pressure on cost compression in fiscal terms similar to what the industry has experienced with investments and operational expenditure in order to unlock new potential projects.

With better fiscal regimes, Africa could unlock \$100bn in investment and 1 million bpd in additional output by 2030

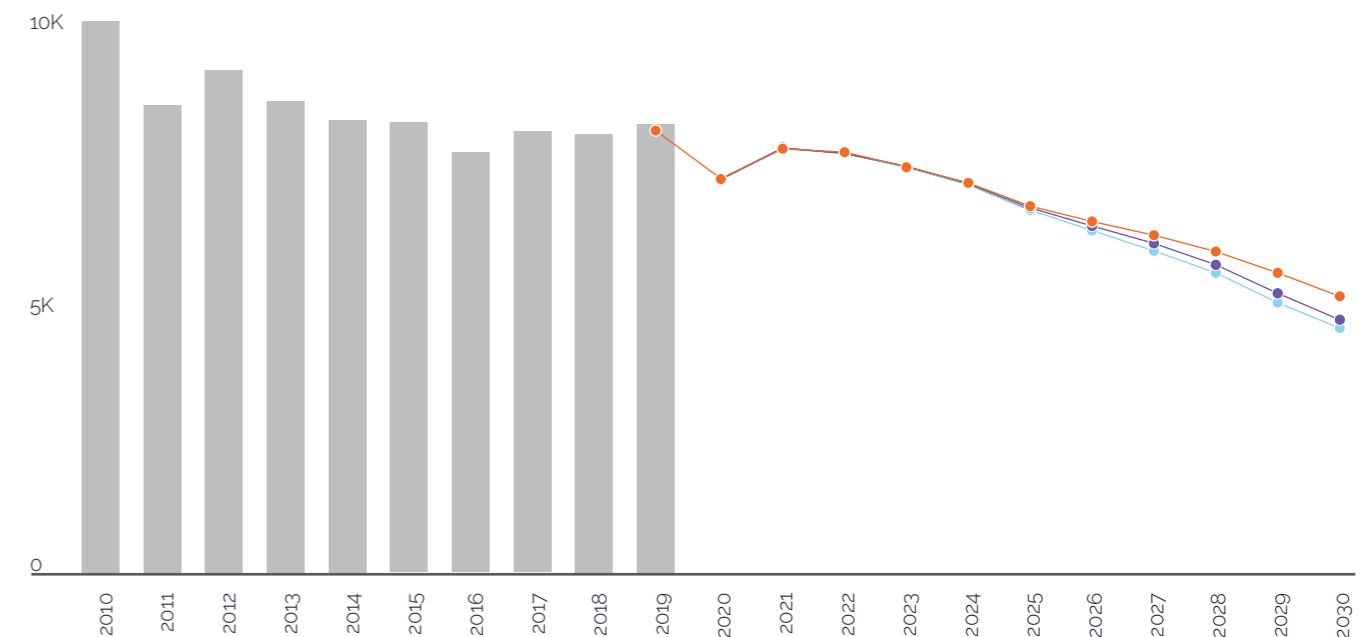
To investigate the potential on African production and investments from altering fiscal regimes, a simulation has been made whereby all projects with an expected FID by 2026 are subject to both their original fiscal regime as well as the United Kingdom's (UK) fiscal

regime, regarded as one of the most favorable globally.

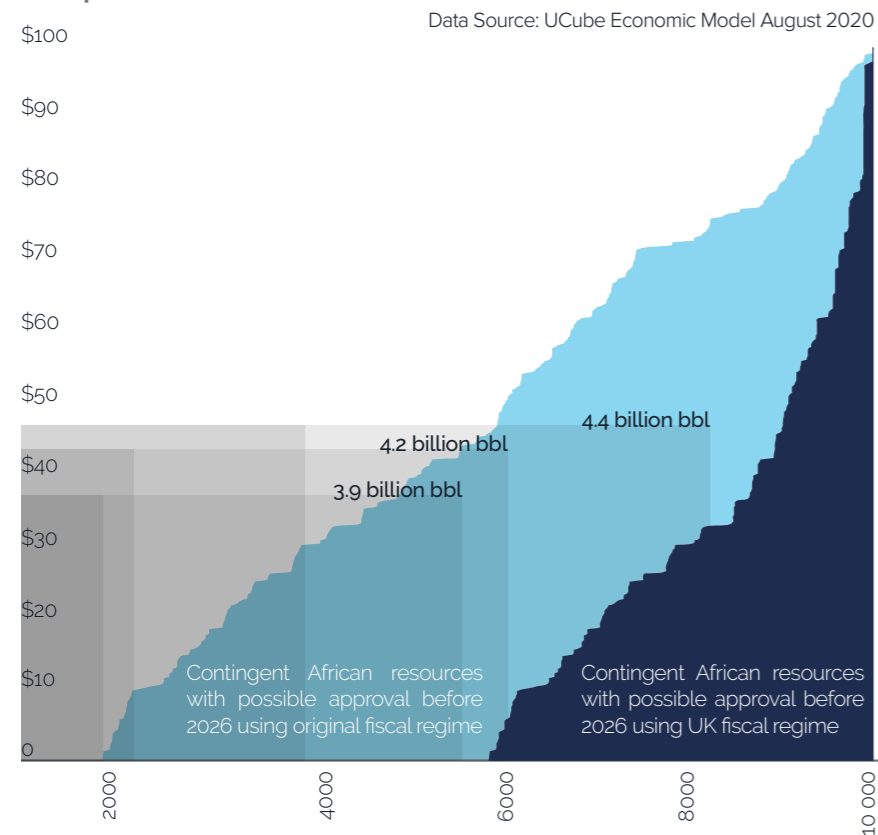
Figure 7.1 illustrates African liquids production towards 2030 under different breakeven thresholds. The thresholds imply that any pre-FID project with a

breakeven higher than the threshold will not be allowed to reach production. The difference between the \$35/bbl threshold and the \$50/bbl threshold is therefore all projects that can contribute with production with a breakeven between \$35 and \$50 /bbl.

Figure 7.1: African liquids production at different BE cutoffs
Million bbls/day

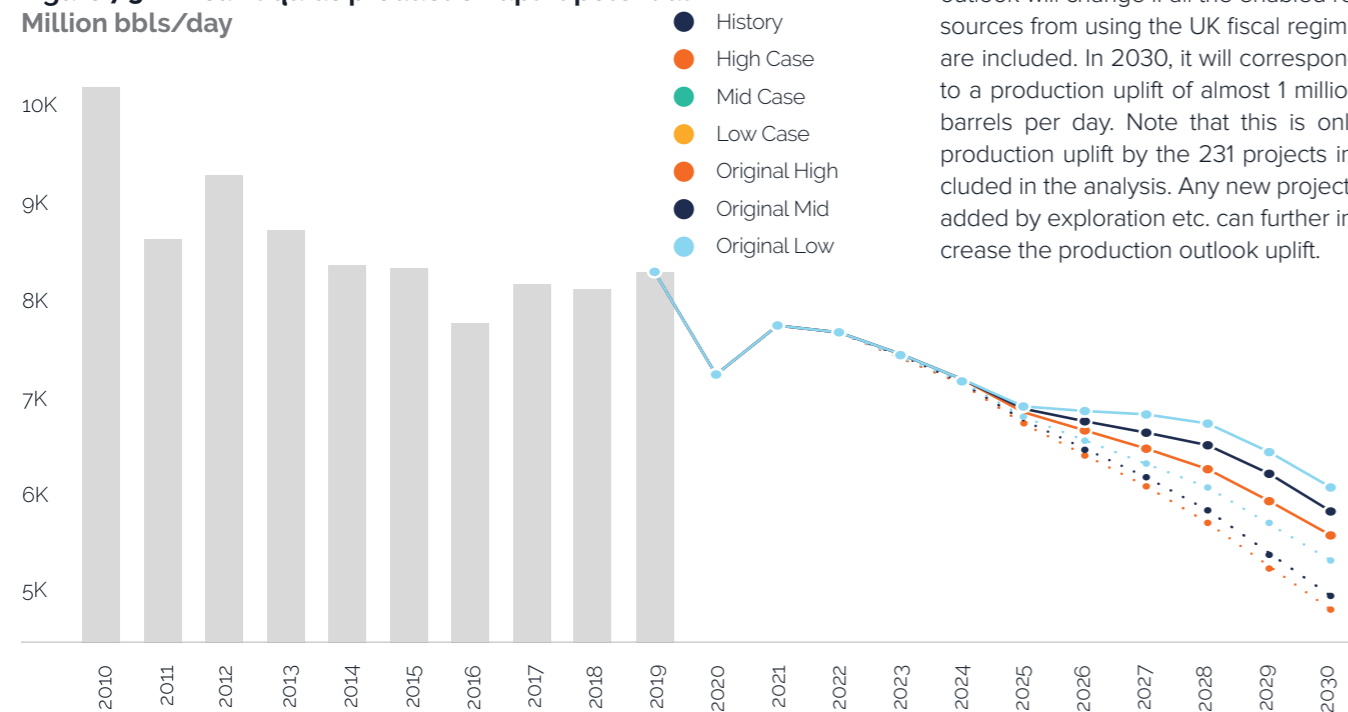


Data Source: UCube

Figure 7.2: Cost of Supply implication of fiscal changes
USD per barrel

By sorting and stacking all projects according to their breakeven on the Y axis and the resource base on the X axis, the cost of supply can be determined. This is illustrated in figure 7.2 where all 231 projects with an approval date before 2026 are sorted by their breakeven and add up to a cumulative 8 billion barrels of liquids. The sorting and stacking can also be done for all the projects in the theoretical situation where the UK fiscal regime is applied instead. The cost of supply curve will thereby shift down as lower break evens are generated via the terms in the UK fiscal regime versus the original fiscal regime.

By then adding horizontal lines according to the breakeven values of \$35, \$40 and \$50 /bbl on the Y axis, it is possible to assess how much of the resource potential on the X axis that will be added as you move from the original fiscal regime to the simulated UK fiscal regime. For the \$35, \$40 and \$50 /bbl thresholds this corresponds to enabling 3.9 billion barrels of liquids, 4.2 billion barrels of liquids and 4.4 billion barrels of liquids respectively of additional resources.

Figure 7.3: African liquids production uplift potential
Million bbls/day

Data Source: UCube

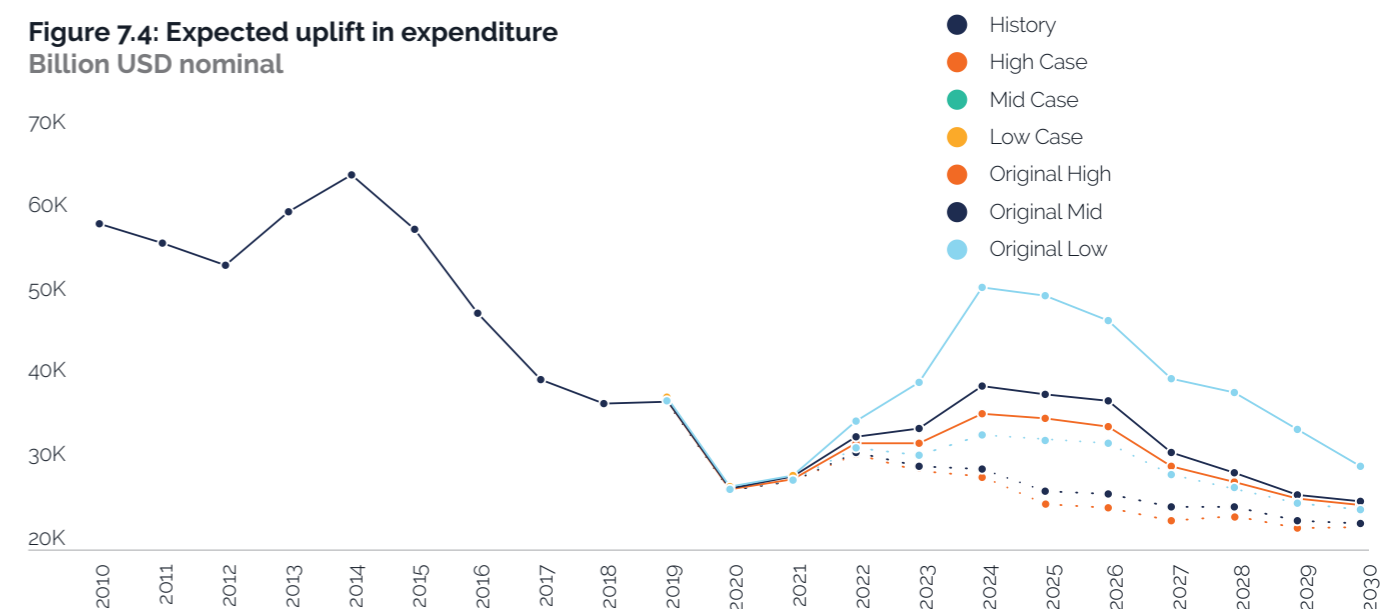
Figure 7.3 illustrates how production outlook will change if all the enabled resources from using the UK fiscal regime are included. In 2030, it will correspond to a production uplift of almost 1 million barrels per day. Note that this is only production uplift by the 231 projects included in the analysis. Any new projects added by exploration etc. can further increase the production outlook uplift.



Production does not come for free however, figure 7.4 illustrates how much more capital expenditure that will be enabled in order to support the projects unlocked by using the UK fiscal regime. Over the 2020-2030 period, the additional capital expenditure is estimated at \$49 billion at the \$35 /bbl threshold increasing towards \$100 billion as the \$50/bbl threshold is approached.

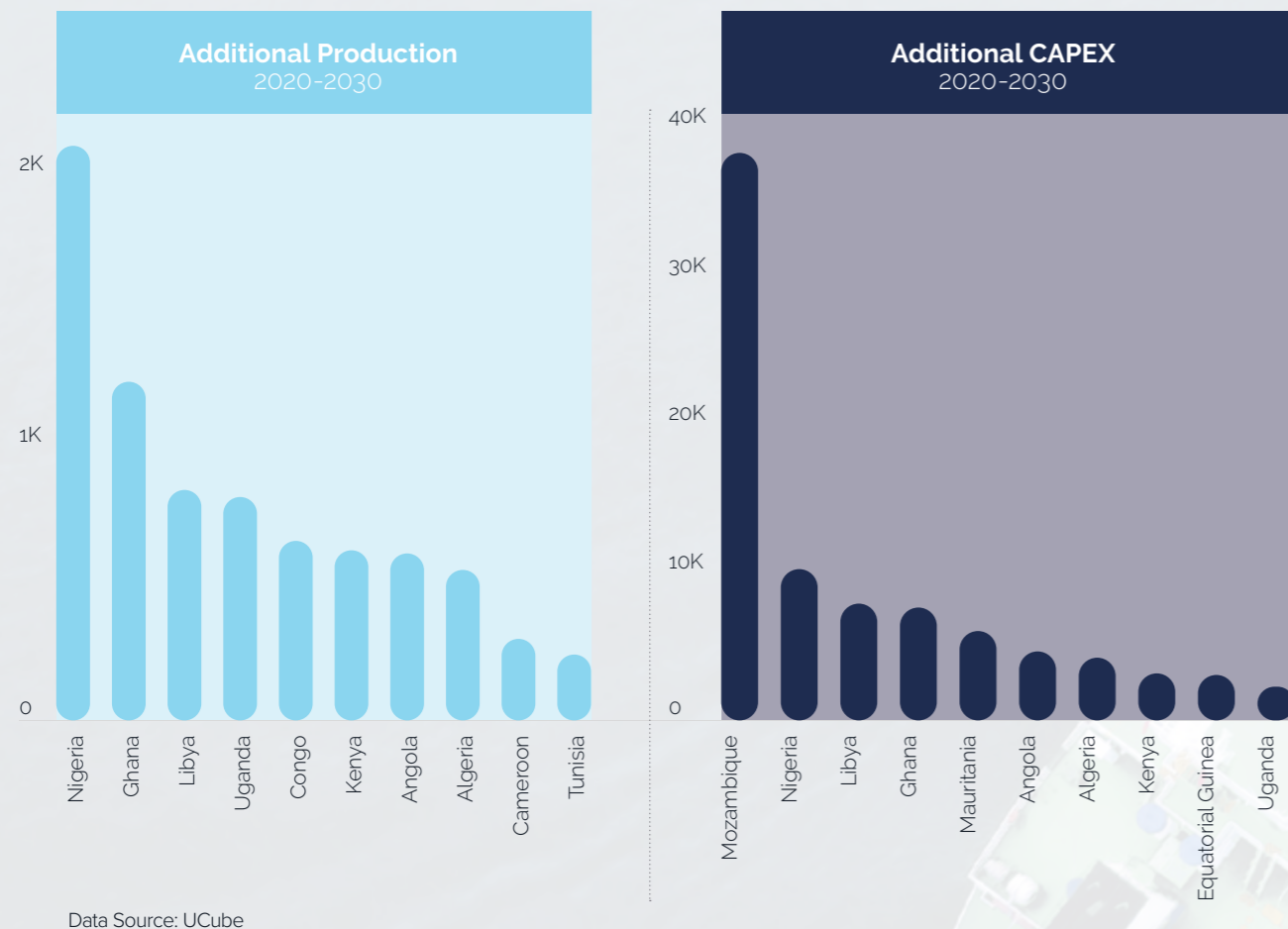
Breaking down the uplift in additional resources produced and the additional capital expenditure unlocked reveals Nigeria as the country with most potential. Figure 7.5 illustrates the additional barrels of liquids produced and capital expenditure spent between 2020 and 2030 in a \$50/bbl threshold scenario. Nigeria will effectively be able to produce about 2 billion barrels more than otherwise while justifying \$10 billion more investments.

Mozambique is an outlier in terms of investments as most of the capital expenditure will enable the LNG production with only a fraction of the resource base representing liquids and thereby not driving Mozambique to top 10 on additional liquids production. The same concept nevertheless applies that fiscal terms is a method that can be deployed to make resources more competitive.

Figure 7.4: Expected uplift in expenditure
Billion USD nominal

Data Source: UCube

Figure 7.5: Top 10 countries in a 50 USD/bbl threshold scenario
Million bbl



Bottom line for Africa: It is time for bold fiscal reforms

Most African producers understand the challenges posed by their existing fiscal regimes in the current price environment and are currently engaged in making amendments accordingly. Africa's largest oil producer Nigeria, is currently in the final stages of passing its Petroleum Industry Bill.

The bill will replace the current petroleum profit tax with a Nigerian Hydrocarbon Tax (NHT). The NHT rates are 50 percent for petroleum operations onshore and in shallow waters and 25 percent for off-shore operations. Companies involved in upstream operations are also expected to pay an income tax rate of 30 percent. Most importantly, it is hoped that this new bill will usher in transparency, simplicity, reduce disputes between companies and the government and ultimately lead to a spike in upstream activity in Nigeria. Africa's second largest producer Angola

is also expected to follow suit. Angola's National Oil, Gas and Biofuel's Agency (ANPG) is currently undergoing a review of its fiscal terms vis-a-vis other major producers with a view of enacting changes that will encourage more drilling in Angola from 2021 onwards.

Changing fiscal regimes do however come with challenges. It causes uncertainty, it distorts the expected revenue profile for the state, and it is hard to arrive at what the fiscal parameters should be. Capital is nevertheless fungible and to attract capital to possible future projects, African nations with petroleum resources will most likely have to adapt their fiscal regimes similar to how other nations have adapted them in light of the new era with more supply and less demand. Failing to do so can lead to stranded resources and out-competed projects.

COVID-19 in the short term and **energy transition** in the long term are the **most significant determinants** of the **industry outlook**

COVID-19 is undoubtedly perhaps the biggest shock in the history of the oil and gas sector.

Demand collapse has caused investments of \$690bn to disappear globally

The impact of the energy transition on long-term demand outlook colors capital allocation and decision-making today.

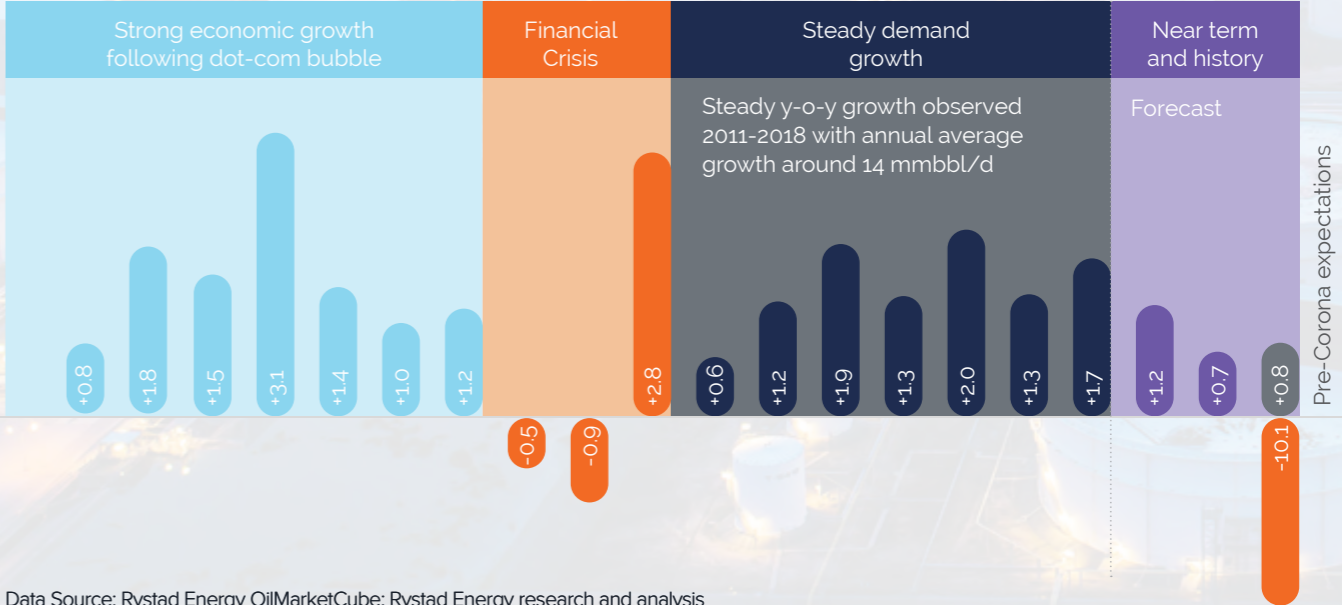
2020 has likely challenged the industry unlike any year in its history. A relatively stable growth in liquids demand has indeed been observed over the last 20 years. Even during the financial meltdown in 2008 and 2009, the demand overall was very resilient. In 2020 however, demand is currently expected to be about 10 million barrels of liquids less per day than pre-COVID-19 expectations (Figure 8.1).

Intra year, this difference is even more extreme as the brunt of this reduction occurred during the widespread lockdown in the second quarter to halt the coronavirus outbreak.

Such a dramatic change to demand created shockwaves into the markets by putting enormous negative pressure on prices. Most notably, the West Texas Intermediary reference price even ended up trading at negative levels as there simply was no ability to store more oil. The market forces therefore led to widespread production shut ins in North America as well as an OPEC agreement to cut production by about 10 million barrels per day.

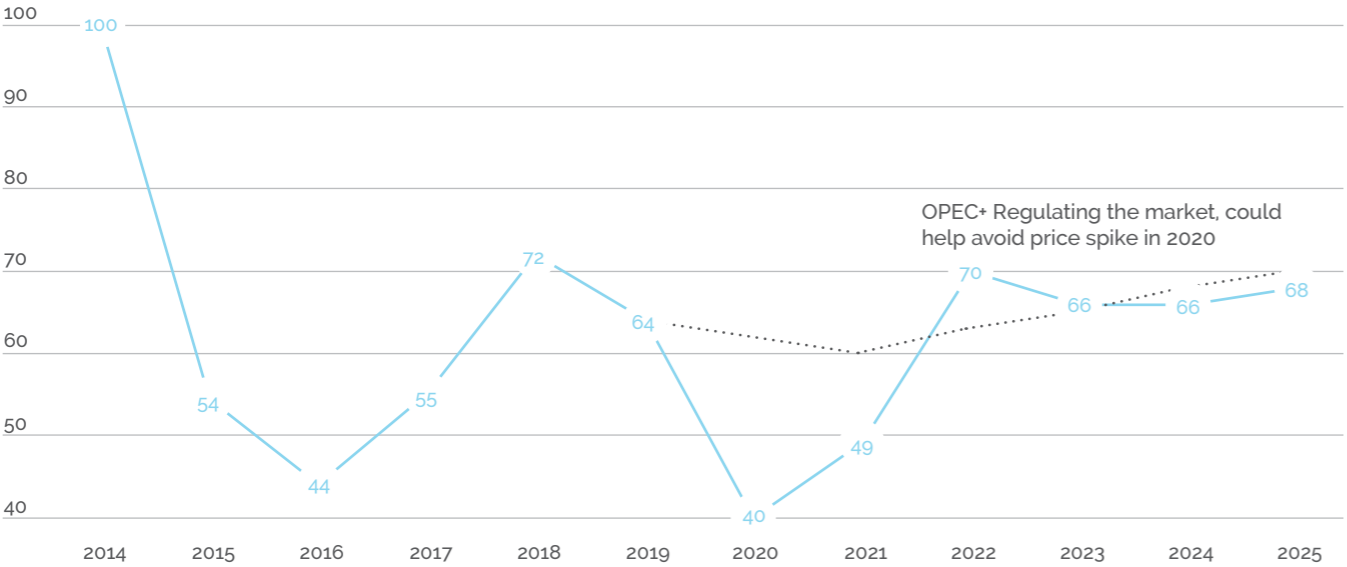
COVID-19 in the short term and energy transition in the long term are the most significant determinants of the industry outlook

Figure 8.1: The demand recovery that didn't come: We expected +0.8mmbbl/d in 2020, but will get -12



Data Source: Rystad Energy OilMarketCube; Rystad Energy research and analysis

Figure 8.2: Changes to oil price expectations since February 2020



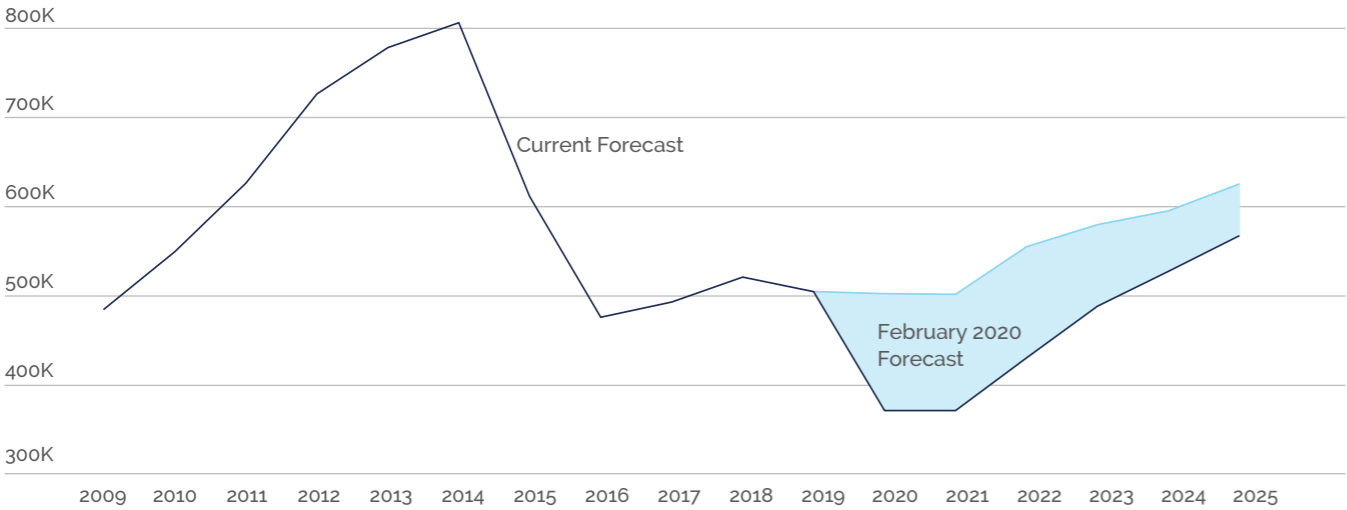
Data Source: UCube, Rystad Energy

As such, the oil markets have now re-balanced but with significant available capacity offline. COVID-19 has triggered a big short-term negative revision in oil price expectation while the mid to long term outlook still points to an oil price at least north of \$50/bbl (Figure 8.2), based on the assumption that a solution will be

found to the current COVID-19 pandemic, pushing global economic activity towards pre-COVID-19 levels. As a consequence of less revenue, the various operators in the world have also slashed their investment outlooks considerably. The combined reduction for 2020 to 2025 in expected global upstream CAPEX is

of \$690 billion compared to the initial expectation in February 2020 before COVID-19 was declared a pandemic (Figure 8.3). The reduction is front loaded implying that it is 2020 and 2021 where one should expect to see the biggest changes with almost 30 percent lower spend than pre-COVID-19 expectations.

Figure 8.3: A stable investment outlook has turned into two years of capex contraction



Data Source: Rystad Energy UCube August 2020

In absolute terms, it is conventional on-shore activity that is expected to see the biggest reduction with about \$115 billion removed from the 2020 and 2021 period (Figure 8.4). On a relative basis however, it is shale that is expected to see the biggest reduction with about 40 percent across 2020 and 2021. This outcome is consistent with shale's short cycle nature and continuous reliance on drilling implying that activity can be rapidly curtailed or boosted. Offshore is typically more influenced by multi-year capital programs that are inflexible and hence short-term changes should be more muted.

Beyond the calamity created by COVID-19 in the short-term outlook, perhaps the in-

dustry's biggest challenge and opportunity is the outlook on liquids demand as well as the drive to curb carbon emissions. Demand and emissions are ultimately linked, and is expected to be main structural driver over the mid to long term.

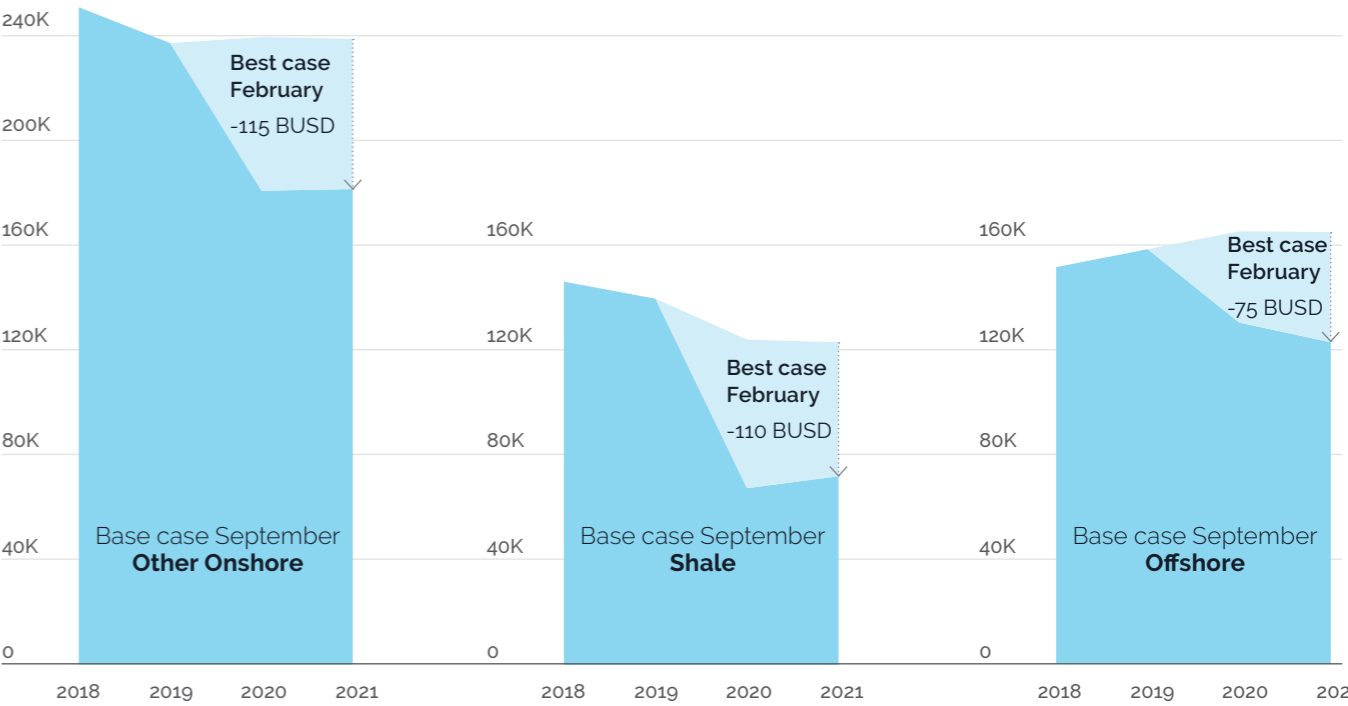
For the industry, where you have to make decision on capital allocation that may have a 20-year horizon, it is very important to have a view on the outlook. The lowest demand scenarios effectively imply that no additional exploration is required and only the most competitive projects will be allowed to mature to production. Should the demand trajectory move similar to the pace observed over the last 20 years implying continued growth of north of 1 mil-

lion barrels per day, the business case for exploration and maturing less competitive resources is much more compelling.

What nevertheless is a trend that has gained traction over the last year is the view that the corporate strategy has to move toward energy transition. So far, this has manifested itself particularly in the European majors allocating capital to renewable energy projects such as offshore wind and solar as well as committing to reduction of net emissions.









This trend was further reinforced in Q2 2020 when impairments were taken on the back of revised outlooks for commodity prices (Table 8.5).

Figure 8.4: Upstream capex by sensitivity to oil price
Billion USD, real



Data Source: Rystad Energy ServiceDemandCube February and August releases

Figure 8.5: The Europeans have started the energy transition, while the Americans are lagging behind

								
Renewables								
Renewable mentioned in annual report	141	148	358	42	2	2	116	71
Renewable capacity goal	Target for installed renewable power generation to 50 GW by 2030	Interest in wind energy with capacity 9 GW. No communicated renewable goal	Target for installed renewable power generation to >25 GW by 2025	Increase renewable power capacity to 5 GW by 2025	No communicated renewable goal	No communicated renewable goal	Increase renewable power capacity tenfold to 4-6 GW by 2026	Increase capacity in “low carbon power” to 7.5 GW by 2025
Quote	We have been investing in renewables for many years. Our focus is on biofuels, biopower, wind energy and solar energy .	We invest in low-carbon energy solutions such as biofuels, hydrogen, wind and solar power , and in other opportunities linked to the energy transition.	The Group has diversified its activities and is positioning itself in solar and wind power, sustainable biofuels and electricity .	Eni's decarbonization strategies are the growth of low carbon sources, an increase of the zero emission sources and a circular approach which maximizes waste...	Today, our world faces a dual challenge : meeting growing demand for energy while also reducing environmental impacts... ExxonMobil is committed to doing our part.	Chevron continues its commitment to understanding and evaluating the economic viability of renewable-energy sources, including solar, wind, geothermal and biofuels.	...there will have to be significant changes in the energy markets, and our portfolio will change accordingly to remain competitive.	We are positioning ourselves in the new, low-emission energy market with renewable energies and natural gas combined cycles.
Emissions								
CO2 mentioned in annual report	168	155	261	212	14	10	86	183
GHG emission reduction goal	Net zero by 2050	Net zero by 2050	Net zero by 2050	Net zero by 2030 Scope 1, upstream	No GHG goal. Communicated methane and flaring goals	No GHG goal. Communicated methane and flaring goals	Net zero by 2030	20% by 2030 Net zero by 2050
Quote	BP is working with peers on a range of fronts, in particular to tackle methane emissions and create opportunities for carbon capture, utilization and storage .	We are seeking cost-effective ways to manage GHG emissions... Such as Carbon capture and Storage, replace coal by natural gas, developing new fuels for transport .	The Group aims to both reduce the environmental footprint and the CO2 emissions of its operations	Ambition to lead the company to become carbon neutral in the long term by maximizing efficiency, reduce direct emissions through the compensation of residual emission	By applying advanced analytics to this abundance of data, we can identify new approaches to run sites more efficiently and potentially with fewer emissions .	100 million fund that does investments on electric vehicle charging network, novel battery technology and direct capture of carbon dioxide from the air .	The ambition to reduce net carbon intensity by at least 50% by 2050 takes into account scope 1,2 and 3 emissions, from initial production to final consumption.	Repsol will reinforce its strategy to reduce its carbon footprint , enabling us to reduce CO2 emissions by 2.1 million tons in 2020, compared to 2014 levels.

Data Source: Rystad Energy research and analysis; ServiceDemandCube; Operators' annual reports and websites

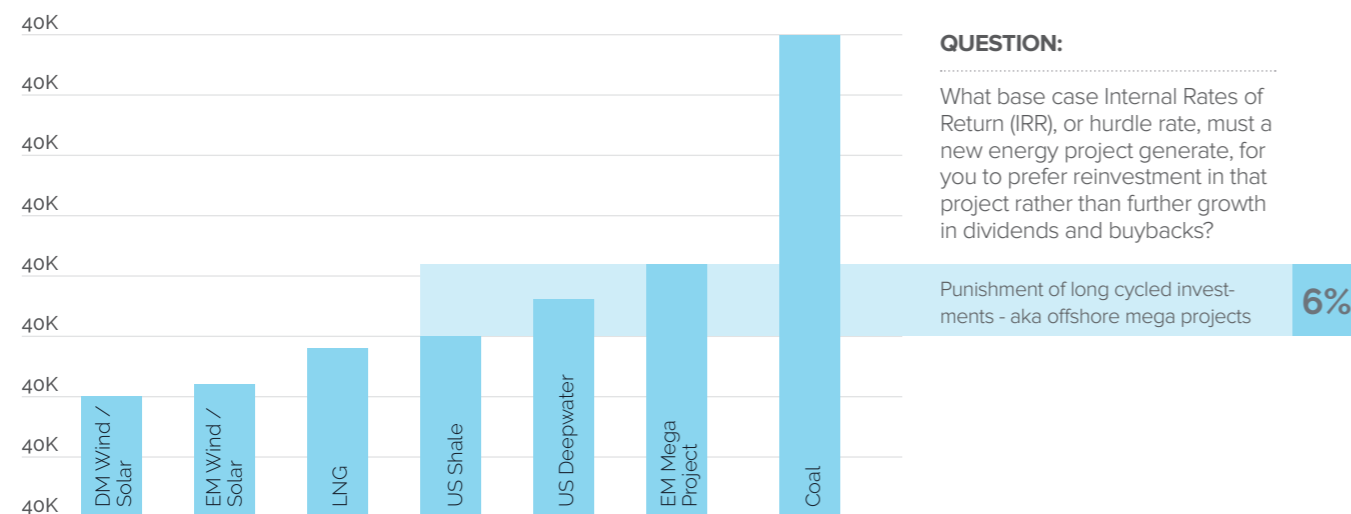
American, Russian and big NOCs are typically less clear on their energy transition strategy, with no clear target for renewable capacity and emission reductions. A potential reason for this different approach versus the European companies could be the access to resources. Americans have better and more access to the vast shale resources in North America while the NOCs in

Russia and the Middle East still have a vast potential in its competitive conventional petroleum resources.

Capital markets are also influencing how the companies are behaving. According to a study by the Oxford Institute for Energy Studies, investors are putting a higher premium on fossil fuel developments than renewables as il-

lustrated in Figure 8.6. In particular, long-cycle fossil fuel developments command a higher risk premium. Everything else equal this change in risk premium improves the competitive position of renewables and short-cycle fossil fuel projects and deteriorates the competitive position of long-cycle fossil fuel projects, thereby also influencing how capital is allocated.

Figure 8.6: Indications that long cycle projects are at risk of discrimination versus short cycle projects
Required Hurdle rate from investors to invest in project IRR



Data Source: Oxford Institute for Energy Studies

Africa is a Powerhouse

Join us at the forefront of the African energy industry.

We draw on the experience, expertise and collective strength of our members to actively lead on shaping policies, sharing best practice and using resources to create value for Africans.

Together, we can shape Africa's energy future.

Pre-Covid projects and ongoing **East African LNG** terminals expected to **prevent** massive **job destruction**

Inflexible capital programs help sustain overall employment through COVID-19.

Mega-LNG projects in East Africa are particularly important to support jobs creation in the industry.

Job creation potential greatest if Africa can harness its natural gas and downstream industrial potential by transforming and monetizing its resources at home.

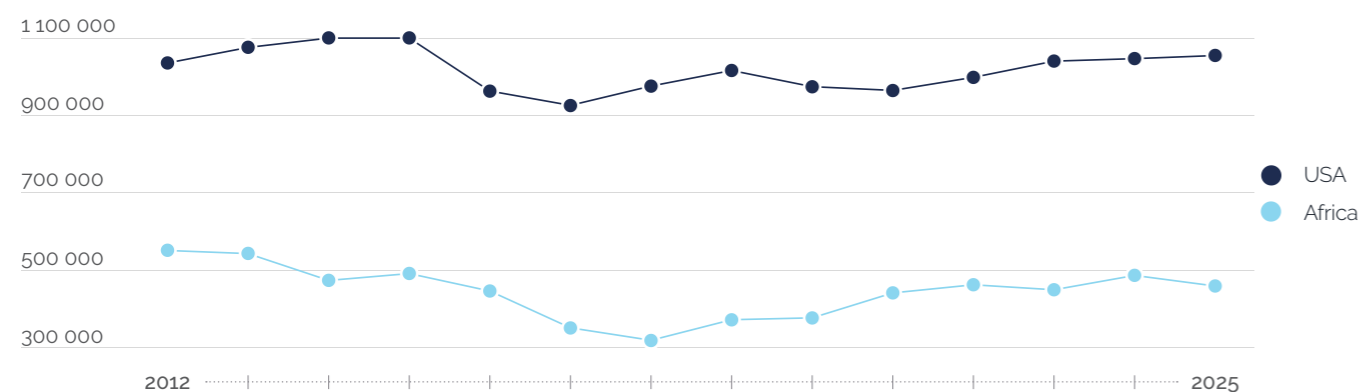
To arrive at an estimate for the numbers of jobs supported by the African upstream industry, the relationship between spend on petroleum activity and hard labor data in the United States has been used as a proxy. Figure 9.1 illustrates both American and African number of jobs as a result of the mixture of spend segments driving jobs and what their labor intensity is in the American market.

The African numbers point to a reduction of jobs from the peak in 2012 of about 550 000 until the trough of about 300 000 jobs in 2018. The reduction

is on the back of big capital program being completed and construction sites being demobilized. The production phase of these projects only has a fraction of the labor requirement of the development phase. For the same reason, African job numbers do not appear to see big immediate impact from COVID-19 in 2020 and 2021 as the initiated capital programs in 2018 and 2019 are ongoing and ramping up activity.

This is in particularly the case for the mega greenfield projects in Mozambique requiring north of 10 000 employees.

Figure 9.1: Africa upstream employees
Number of full time equivalents



Data Source: BLS, UCube August 2020

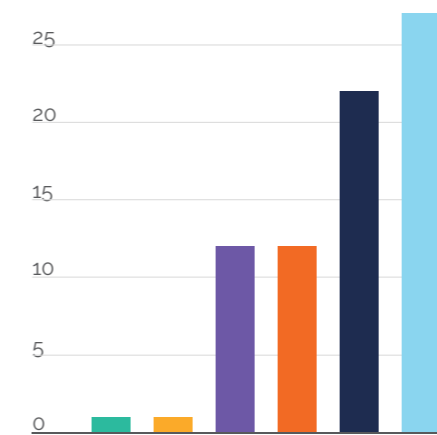


Figure 9.2: Number of jobs per Million Dollar of output



Data Source: Bureau of Labor Statistics 2012

Towards 2025, the numbers of jobs are expected to decline again on the back of new projects in 2020 and 2021 not being sanctioned due to COVID-19.

The American numbers have a different pattern in 2020 and 2021 as a function of the short-cycle nature of shale which means that activity and consequently employment can be much faster adjusted to market conditions than the mega-projects more prominent in Africa.

The jobs created by the petroleum industry have been an attractive secondary effect that has helped boost communities around the globe. The pattern for jobs in the petroleum industry follows that of other primary industries in that activity is more capital intensive than labor intensive.

As such, the amount of jobs created directly related to the upstream activity is

relatively limited versus the jobs created as tertiary effects on the services around the upstream jobs.

Figure 9.2 illustrates the estimate from the American Bureau of Labor Statistics on job creation per million dollar of output in different economic sectors. While petroleum activity is only expected to generate around one job per million dollars, the education sector is producing north of 25 jobs.

This is one of the drivers for many Persian Gulf and African countries to expand their economies beyond just oil and gas extraction for subsequent export as the job creation is effectively exported as well.

Using the stimulus afforded by the natural resources to stimulate jobs in other economic sectors with higher labor intensity is where a significant amount of jobs can be created.

Relentless work required to keep African resources competitive

Africa's share of global production is declining while share of spend remain stable, indicating lost competitiveness.

Africa is not insulated from global turmoil, investments of \$80 billion could be deferred or lost by 2025.

Africa's exposure to increasing long-cycle risk premiums is mitigated by a high share of gas resources.

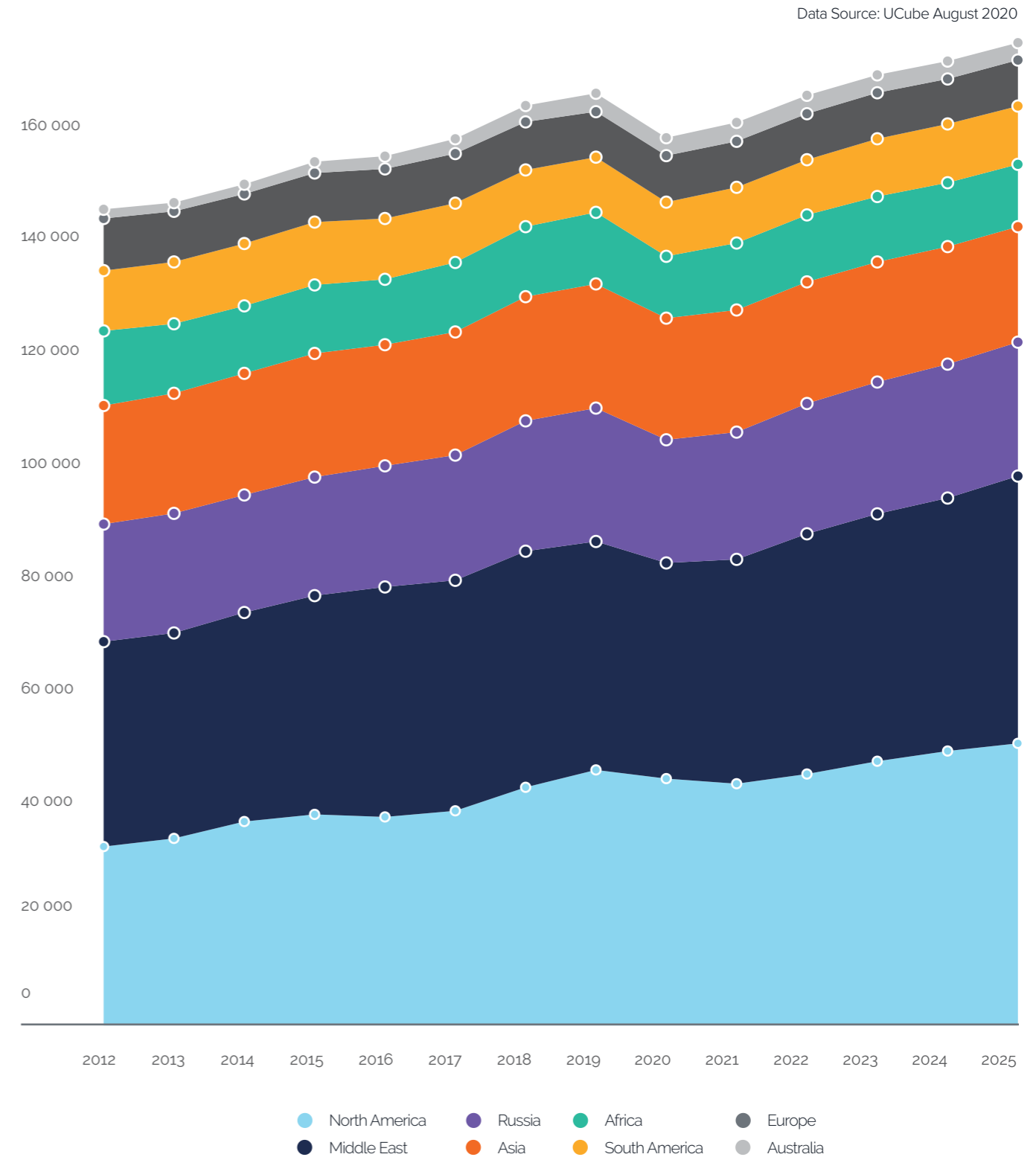
The outlook in the energy sector points to short-term difficulties created by COVID-19 and long-term sustainability questions raised by energy transition and carbon emission requirements. The African oil and gas sector is not insulated to these trends and must learn to evolve and stay competitive within new and shifting global dynamics for investment and capital allocation.

Africa's share of global production has declined and is expected to continue its decline towards 2025 (Figure 10.1). Strong growth in North America

through its unconventional resource base is the main reason for the reduced production share. Another explanation is the continued policy uncertainty that has plagued most African producing nations for year: while some have made remarkable efforts to provide an enabling environment for investors, others remain marked by red tape and never-ending policy debates. Without strong political will and policy reforms, Africa's share of global oil and gas production will continue its steady decline, and ultimately limit economic growth and jobs creation on the continent.

Relentless work required to keep African resources competitive

Figure 10.1: Global petroleum production per continent
Million boe/d



From a spend perspective, that is all money spent on investments and operations, we can expect a more stable outlook for Africa's share (Figure 10.2). While Africa is projected to consistently represents about 8-9 percent of the global spend between 2012 and 2025, its share of global production is also expected to decline over the same period.

Unfortunately, the only conclusion to be drawn from such facts is once again that of a deteriorating competitive position for African petroleum resources. With the exception of a few jurisdictions, producing a barrel of oil from African soil remains less competitive than producing the same barrel elsewhere.

The detrimental impact of COVID-19 on global energy markets is also expected to have an impact on African activity. Compared to pre-COVID19 expectation, about \$80 billion less investments are expected in Africa towards 2025, with the years 2020 to 2022 carrying the brunt of the difference (Figure 10.3).

Figure 10.2: Global upstream spend per continent
Million boe/d

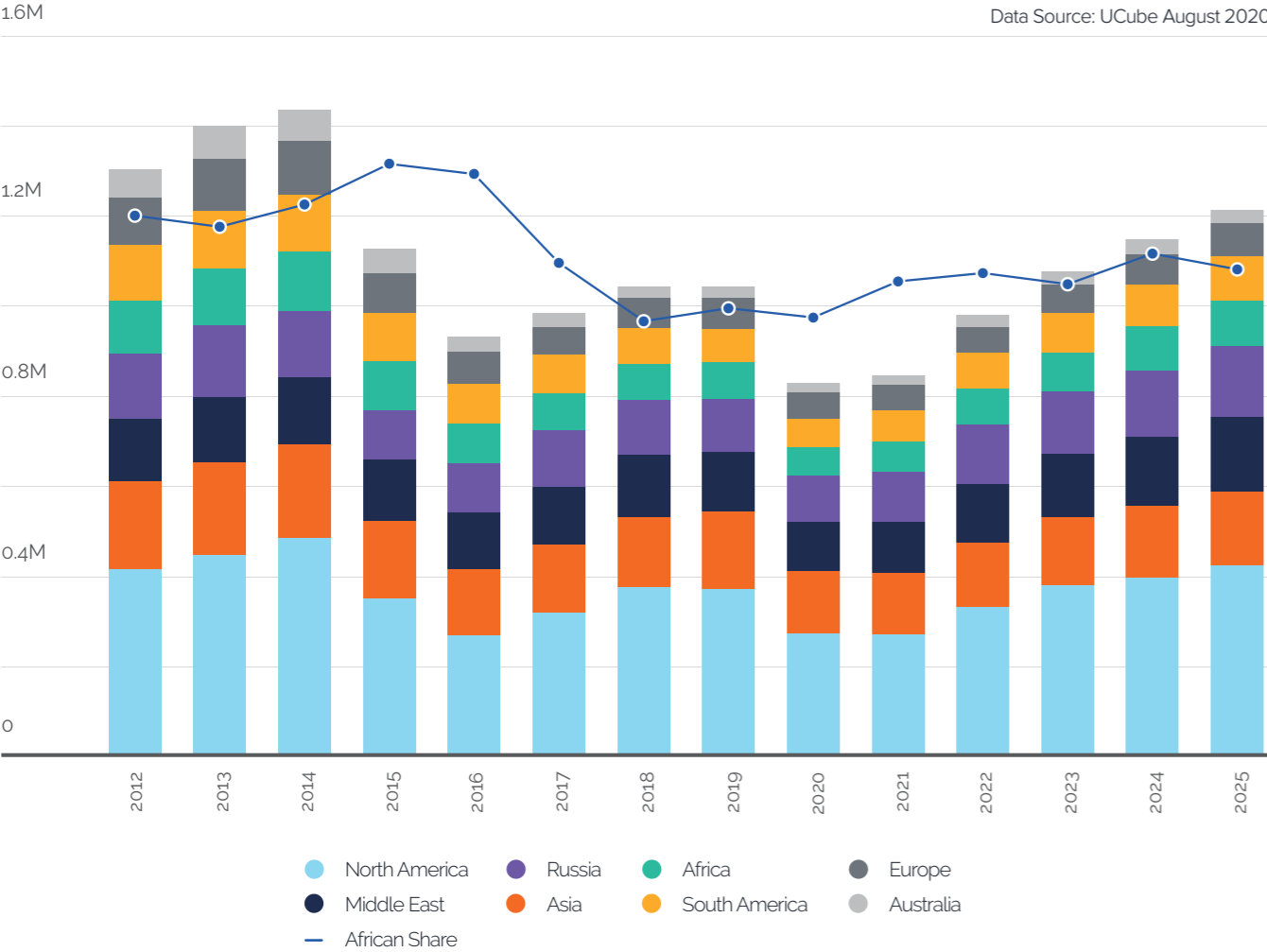


Figure 10.3: Contraction in African investment outlook
Billion USD, nominal

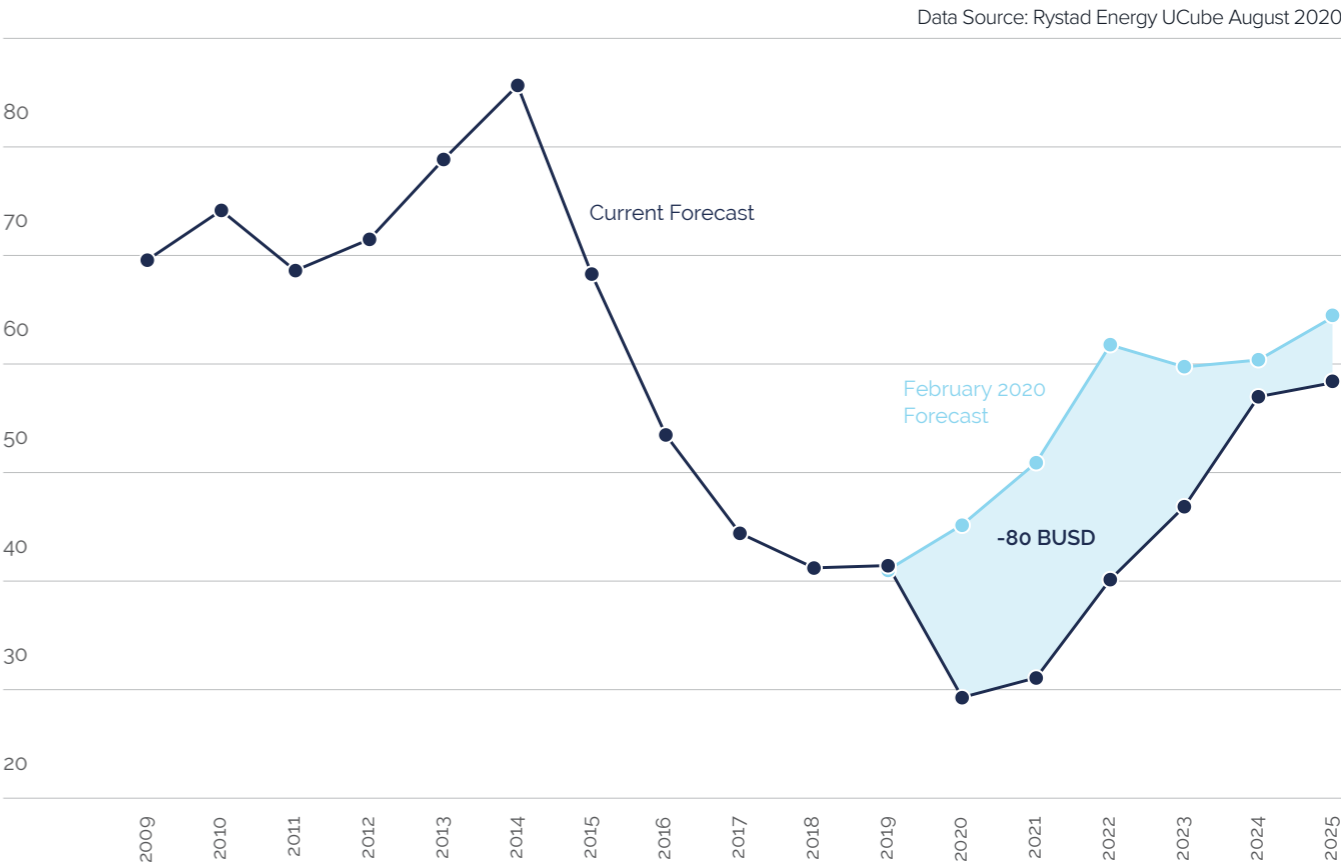
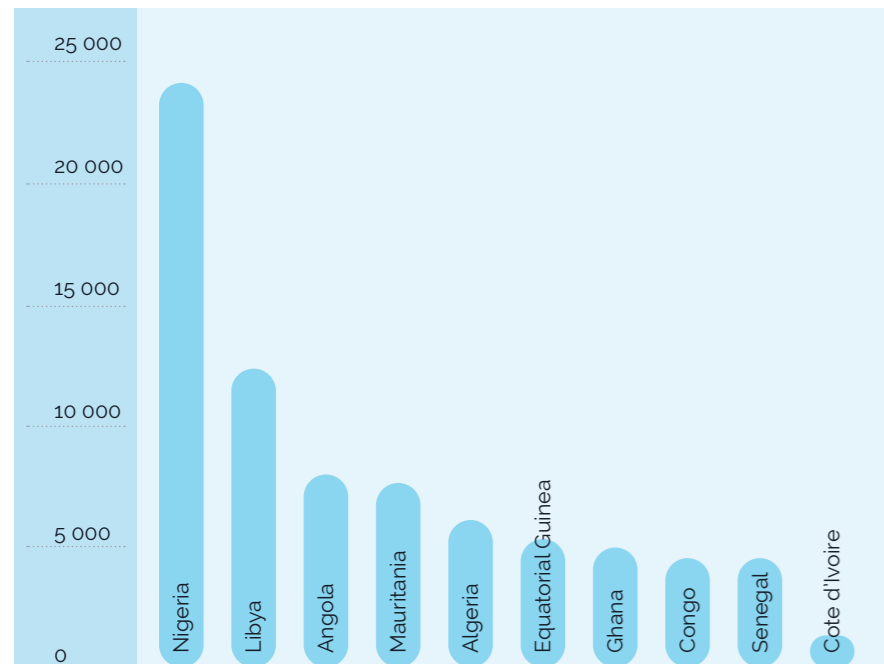
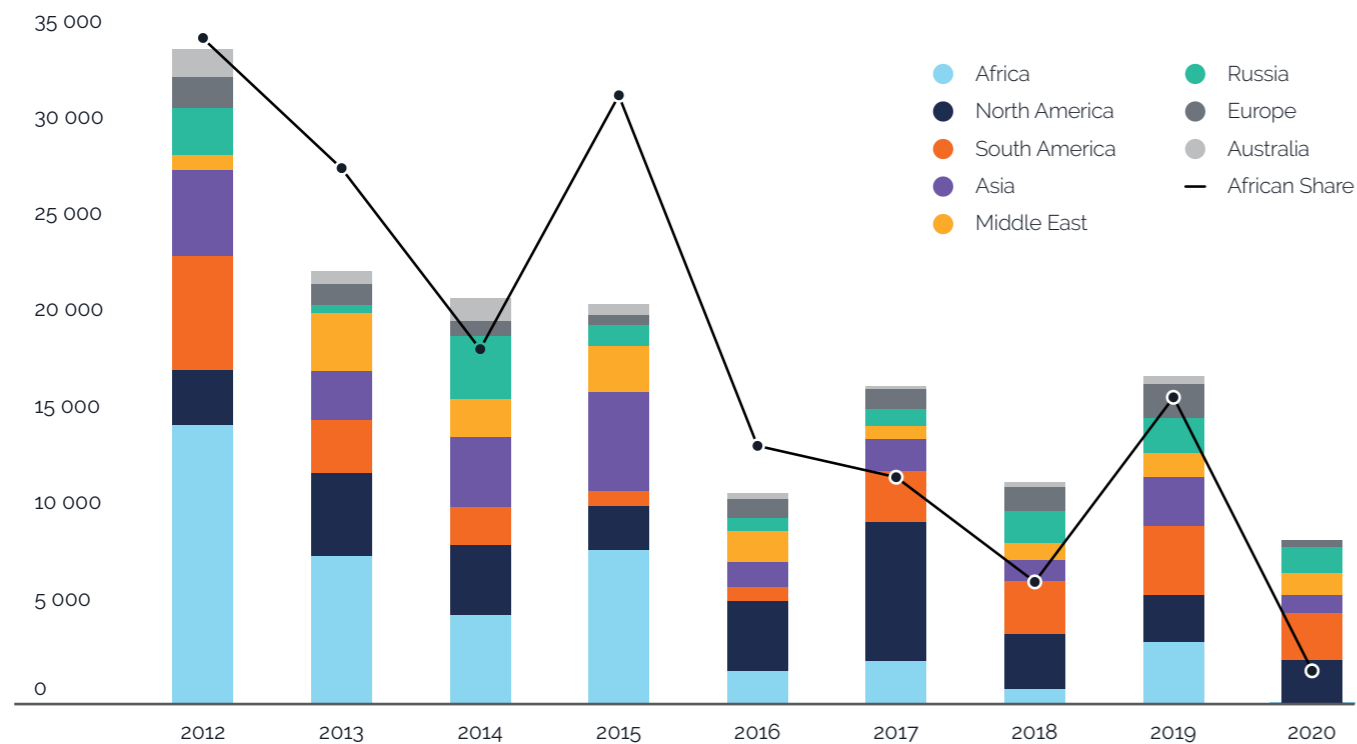


Figure 10.4: Top 10 lost upstream investment vs. pre-COVID
Billion USD nominal



Data Source: UCube August 2020

Figure 10.4: Discovered conventional resources per continent
Million USD nominal



Data Source: UCube August 2020

Out of these \$80 billions, Nigeria is by far the most adverse impacted country with about \$24 billion moving out of the 2020-2025 window (Figure 10.4).

Where Africa has performed well over the last years is in exploration. In particular, gas has been discovered in vast quantities outside Mozambique, Egypt, Senegal, Mauritania and South Africa. Together, these discoveries are sufficient to put Africa at the top spot in terms of discovered conventional resources per continent (Figure 10.5).

It was in particular for the period 2012 to 2015 that relatively big discoveries were made, while 2020 so far has failed to extend previous performance. Between 2012 and 2015, the amount of resources discovered in Africa averaged over 34

percent of all resources discovered globally over the same period. Reduced exploration activity as a function of lost cash flow can partly explain this outcome. There are also high impact wells expected to be completed before the end of 2020 that may turn around the current situation, especially in South Western Africa.

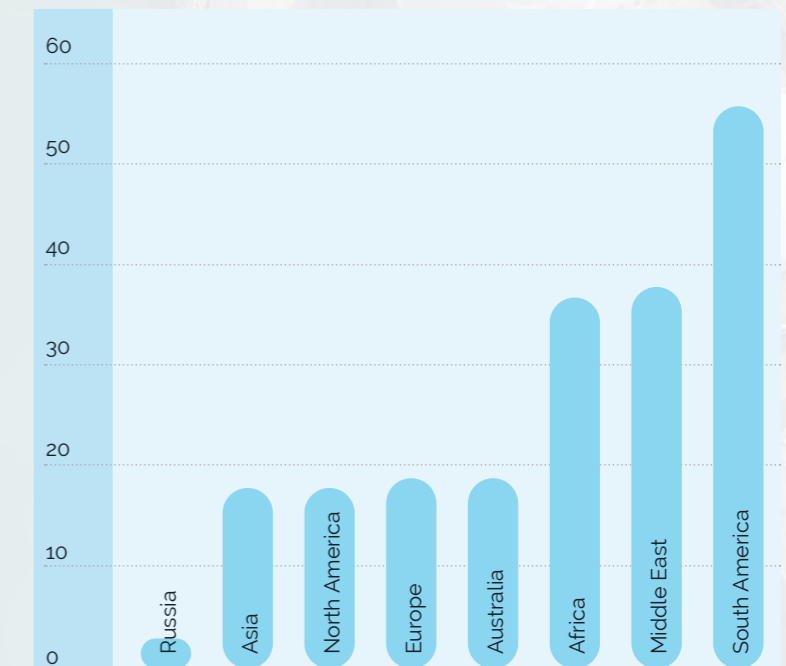
On a longer-term perspective, the energy transition and reported higher premium put on long-cycle projects may be detrimental the competitiveness of such projects, which typically include new platforms, FPSO, LNG facilities etc. South America has the highest share of these long cycle projects on the back of the vast resource base in Brazil's pre-salt reservoirs and the emerging Guyana basin.

The Middle East technically also has a big share of long cycle projects, but these projects are typically additional phases of existing mega fields with highly competitive positions.

On its side, Africa also has a large share of its contingent resources in long cycle projects which ultimately is a result of the exploration success experienced earlier in the decade, similar to the South American situation (Figure 10.6). There is a risk that these projects may have to sustain a higher risk premium this decade than the previous decade on the back of the long-term trends previously discussed.

However, a risk mitigating factor for Africa is the high share of gas resources which does not share the

Figure 10.6: Share of contingent resources in long cycle projects
Billion USD nominal



Data Source: UCube August 2020

same immediate deteriorating demand outlook as many of the liquids scenario outlooks are projecting. In other words, the aforementioned risk premium is more relevant to liquids rich projects rather than new gas developments. Africa's relatively high gas share of contingent resources gives it an edge over other regions with similar or higher contingent resources such as South America.

We cannot repeat it enough: it's time for Africa to fully develop and harness its natural gas potential!

Regional Production Review

Production Outlook

2021 overall hydrocarbons output expected at a slightly higher level than 2020 as OPEC's sanctions ease on the member nations, domestic struggle in Libya becomes less intense, and Algeria and Egypt see an increased level of natural gas output

Post the 2021 increase, liquids output currently estimated to decline down to 2020 levels and back again by 2025

Natural gas production is expected to stay roughly flat going into mid-2020s, after an expected increase in 2021

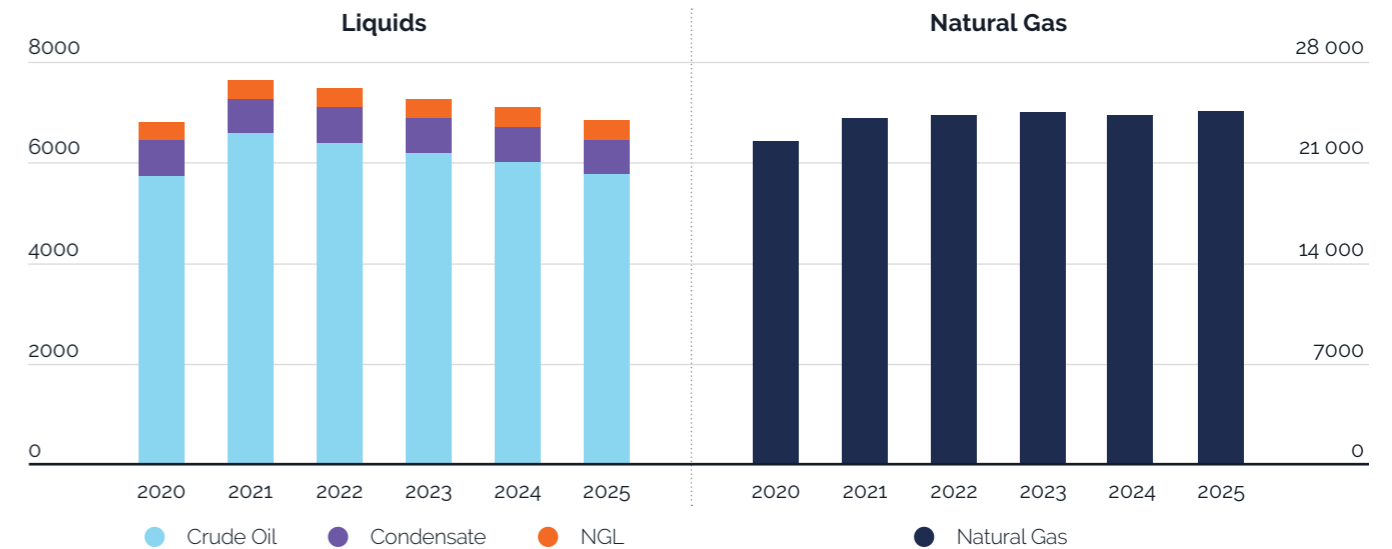
Sub-Saharan African countries vs North African hydrocarbon split expected to reverse from 55%-45% in 2020 to 45%-55% in 2025

Africa's 2020 hydrocarbons production is estimated at about 10.456 million barrels of oil equivalent per day (boepd), including 65% liquids and 35% of natural gas, with crude oil output only estimated at close to 5.74 million barrels per day (bpd).

As OPEC+' production sanctions on the member nations are lifted, sub-Saharan African (SSA) countries and Libya will pick up crude oil production, and 2021 crude oil output can be anticipated at a higher level of 6.6 million bpd, with overall output forecast at 11.55 million boepd (66% liquids – 34% natural gas). As a result of this, the overall liquids production is expected to increase from 6.8 million bpd in 2020 to a much higher 7.645 million bpd in 2021.

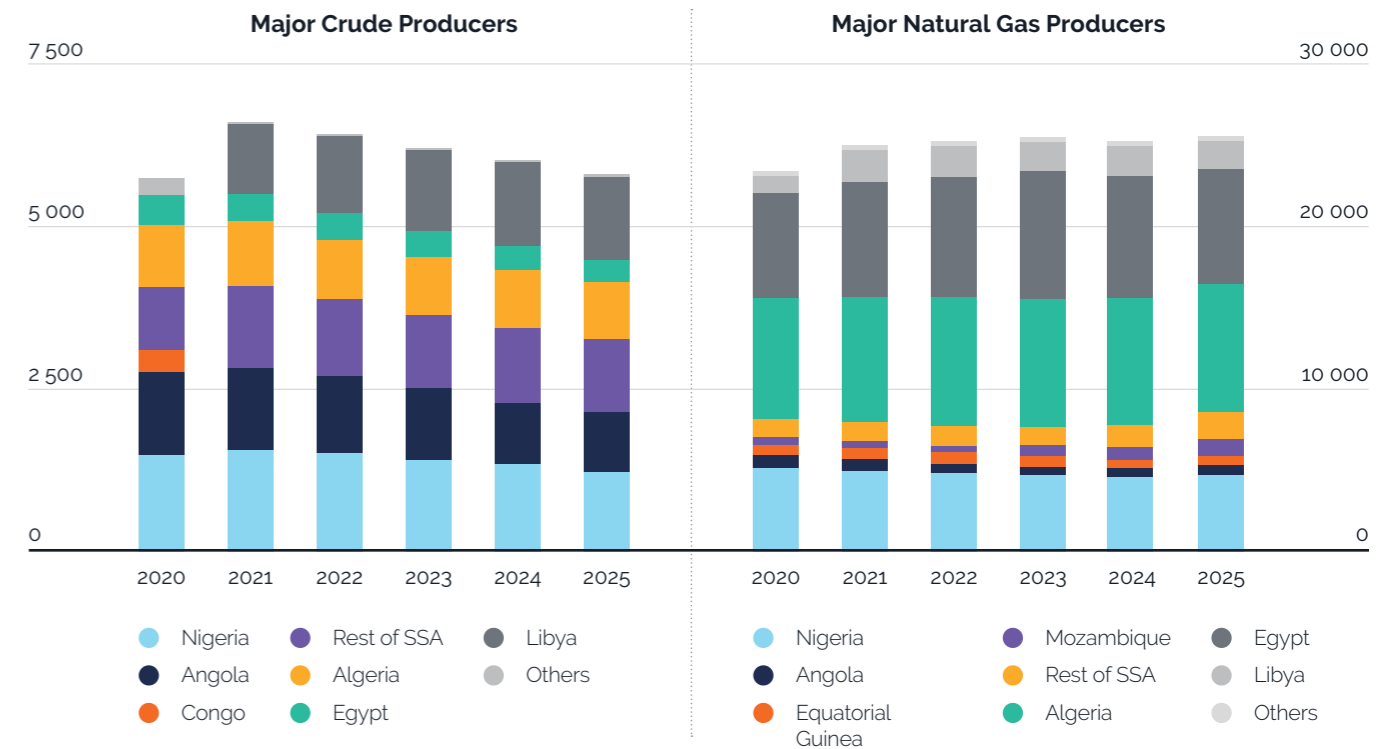
However, as natural decline takes its course and projects get pushed out, the liquids output from Africa is expected to gradually decrease to 2020 levels of 6.84 million bpd by 2025. 2020 natural gas production from the entire continent is estimated at close to 620 million cubic meters per day (mmcm/d). As the output from Algeria, Egypt and Libya settles at a higher rate going into 2020s, the overall natural gas production from the continent is estimated to hit 663 mmcm/d in 2021 and average output for the years 2021 – 2025 is expected at 671 mmcm/d.

Fig. 1: Africa | Liquids declining into 2020s with natural gas output expected to stay flatts
Liquids: Thousand barrels per day | Natural Gas: Million cubic meters per day



Data Source: Rystad Energy UCube

Fig. 2: Overall overview of Africa hydrocarbon output.
West African producers decline while North African countries ramp up
Liquids: Thousand barrels per day | Natural Gas: Million cubic meters per day



Data Source: Rystad Energy UCube

Figure 3:
SSA vs Rest of Africa

Production split to be reversed from 2020 to 2025 as Nigeria and Angola decline, and Algeria, Libya and Egypt projects take majority share.

The overall hydrocarbons production split between the SSA countries and North Africa reverses from 2020 to 2025. The SSA countries contributed to close to 55% of the overall continent's output in 2020, while the North African countries are estimated to contribute to close to 55% of the production by 2025. The main reasons for this trend reversal are:

Declining production from the major producers in SSA

Libya expected to recover from the ongoing civil war and produce a larger chunk of the overall crude production from the continent

Higher natural gas output from Algeria and Egypt



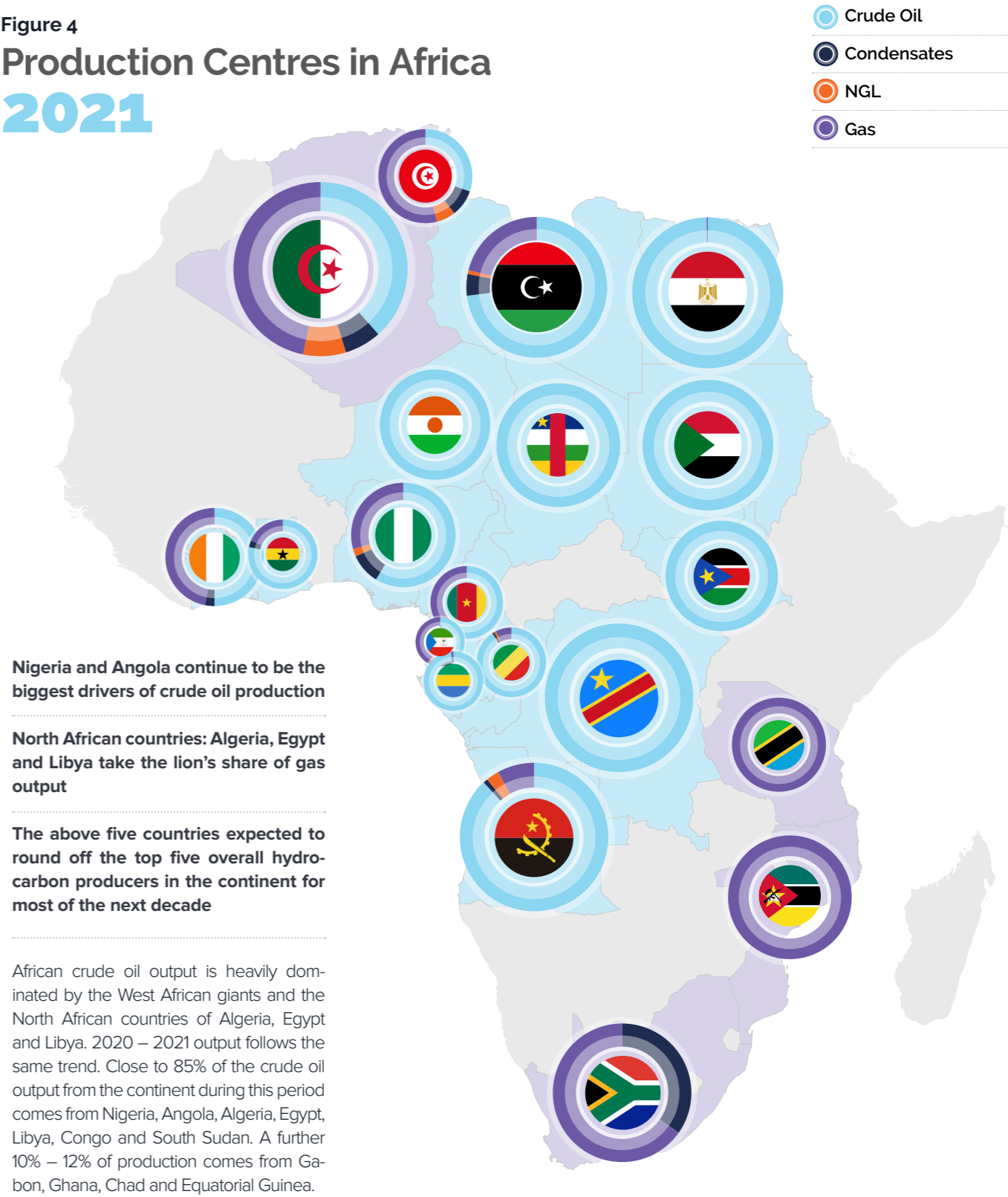
Data Source: Rystand Energy UCube

Figure 4
Production Centres in Africa
2020/2021 In thousand barrels per day
Heavily dominated by West and North Africa

<div>Algeria</div> <div>'20'21</div> <div>Crude Oil949985</div> <div>Condensates180176</div> <div>NGL211203</div> <div>Gas11611199</div>	<div>Tunisia</div> <div>'20'21</div> <div>Crude Oil2624</div> <div>Condensates78</div> <div>NGL46</div> <div>Gas4141</div>	<div>Libya</div> <div>'20'21</div> <div>Crude Oil2281075</div> <div>Condensates4674</div> <div>NGL914</div> <div>Gas164311</div>	<div>Egypt</div> <div>'20'21</div> <div>Crude Oil464426</div> <div>Condensates114116</div> <div>NGL1010</div> <div>Gas10091103</div>
<div>Niger</div> <div>'20'21</div> <div>Crude Oil65</div> <div>Condensates00</div> <div>NGL00</div> <div>Gas00</div>	<div>Chad</div> <div>'20'21</div> <div>Crude Oil116111</div> <div>Condensates00</div> <div>NGL00</div> <div>Gas00</div>	<div>Sudan</div> <div>'20'21</div> <div>Crude Oil6777</div> <div>Condensates00</div> <div>NGL00</div> <div>Gas00</div>	<div>South Sudan</div> <div>'20'21</div> <div>Crude Oil181212</div> <div>Condensates00</div> <div>NGL00</div> <div>Gas00</div>
<div>Côte d'Ivoire</div> <div>'20'21</div> <div>Crude Oil3733</div> <div>Condensates12</div> <div>NGL10</div> <div>Gas3231</div>	<div>Ghana</div> <div>'20'21</div> <div>Crude Oil176175</div> <div>Condensates38</div> <div>NGL00</div> <div>Gas3642</div>	<div>Nigeria</div> <div>'20'21</div> <div>Crude Oil14991558</div> <div>Condensates300252</div> <div>NGL6464</div> <div>Gas809778</div>	<div>Equatorial Guinea</div> <div>'20'21</div> <div>Crude Oil10994</div> <div>Condensates3330</div> <div>NGL1619</div> <div>Gas102106</div>
<div>Cameroon</div> <div>'20'21</div> <div>Crude Oil6356</div> <div>Condensates22</div> <div>NGL00</div> <div>Gas3433</div>	<div>Gabon</div> <div>'20'21</div> <div>Crude Oil190175</div> <div>Condensates00</div> <div>NGL00</div> <div>Gas32</div>	<div>Republic of Congo</div> <div>'20'21</div> <div>Crude Oil337305</div> <div>Condensates33</div> <div>NGL23</div> <div>Gas2726</div>	<div>DRC</div> <div>'20'21</div> <div>Crude Oil2422</div> <div>Condensates00</div> <div>NGL00</div> <div>Gas00</div>
<div>Angola</div> <div>'20'21</div> <div>Crude Oil12701265</div> <div>Condensates1614</div> <div>NGL4042</div> <div>Gas115115</div>	<div>Tanzania</div> <div>'20'21</div> <div>Crude Oil00</div> <div>Condensates00</div> <div>NGL00</div> <div>Gas3436</div>	<div>Mozambique</div> <div>'20'21</div> <div>Crude Oil00</div> <div>Condensates00</div> <div>NGL00</div> <div>Gas7267</div>	<div>South Africa</div> <div>'20'21</div> <div>Crude Oil00</div> <div>Condensates00</div> <div>NGL00</div> <div>Gas1715</div>

Data Source: Rystand Energy UCube

Figure 4
Production Centres in Africa
2021



These countries are expected to continue to be the crude oil power houses in the continent. Nigeria and Angola are expected to remain the top 2 crude oil producers in Africa, despite the OPEC-imposed production cuts. However, as the internal tensions subside and production picks up, Libya is expected to displace Algeria as the third largest crude oil producer in 2021. At the current assumptions which include the impact of COVID-19 on the global supply and demand of crude oil and project delays, wherever applicable, only Libya is expected to see growth in crude

oil output in Africa as it recovers from domestic conflicts. The rest of Africa is currently expected to decline in production going into mid-2020s. The same top 5 crude oil producers – Nigeria and Angola from the west; and, Algeria, Egypt and Libya from North Africa complete the top 5 natural gas producers for 2020 and 2021. These five countries contribute to about 90% of the overall natural gas output from the continent for both the years and the expected forecast suggests their shares

will remain the same going into the mid-2020s. Equatorial Guinea remains an important contributor throughout the period and Mozambique is expected to break into the scene by 2025 – 2026. The west African nations of Senegal and Mauritania housing huge volumes of recoverable natural gas are currently only developing 2.5 mtpa of LNG export capacity and are not estimated to bring on-line their LNG hubs (up to 30 mtpa) before later in the next decade as these projects are hit by delays in the post-pandemic era.



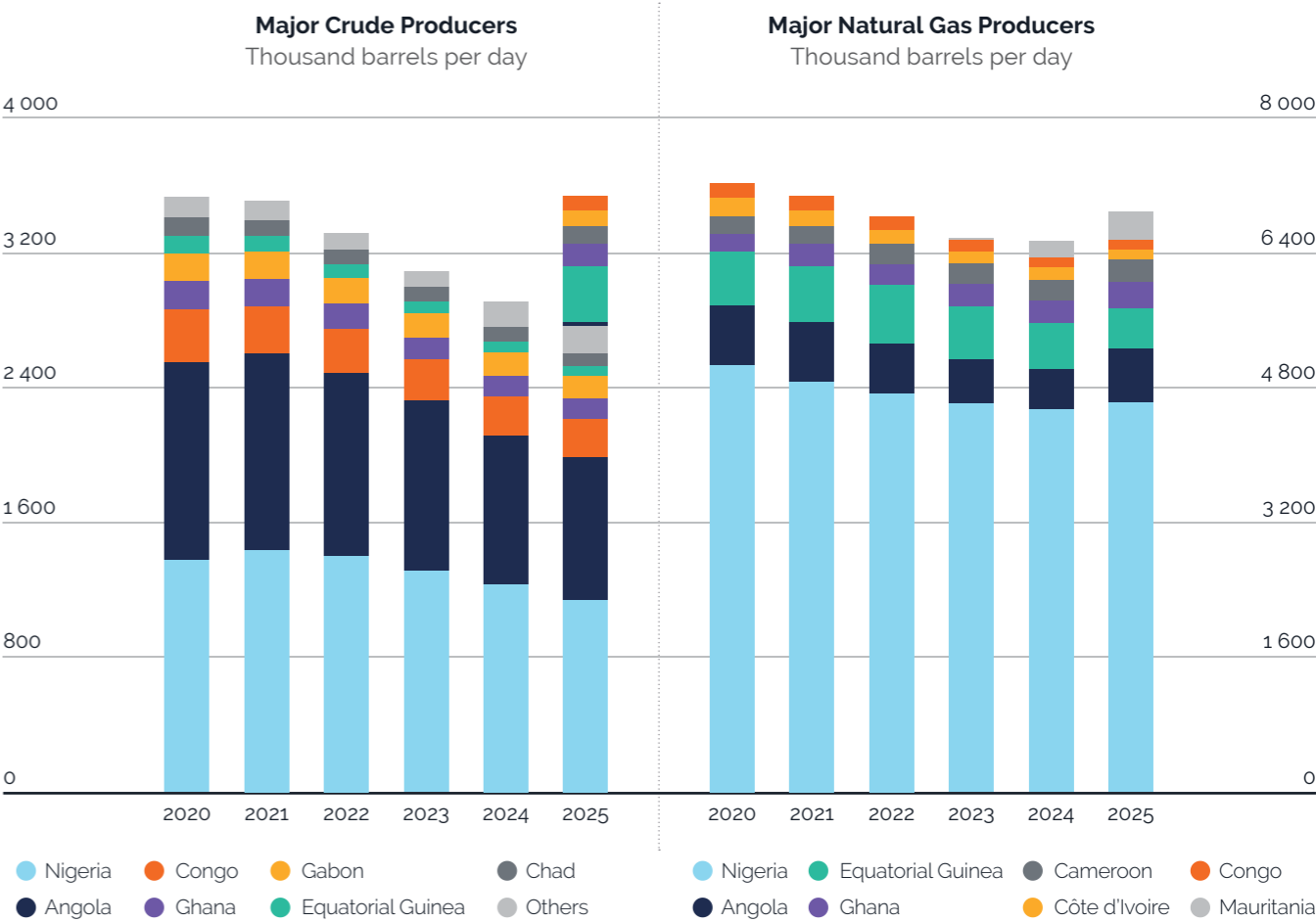
Declining crude output owing to declining reservoirs and lack of new start-ups.

Majority of the crude output driven by Nigeria and Angola.

Increased focus on monetization of natural gas hoping to reap rewards in the longer term.

Nigeria driving majority of the natural gas production from the region while the Senegal – Mauritania gas hubs currently face headwinds.

Fig. 5: West Africa
Nigeria and Angola, although declining continue to be major producers



Data Source: Rystand Energy UCube

Nigeria

Largest crude oil and natural gas producer in the region and expected to retain this status for a long period

2020 crude oil output plagued by production cuts imposed by OPEC while 2021 crude production expected at a higher level as OPEC sanctions ease down, but declining going forward

COVID-19 led capital expenditure cuts and revised crude price forecasts from operators leading to a large number of offshore project delays

Marginal fields bidding round garnering a lot of interest and impact to be seen in the next few months

PIB/PIGB saga still an ongoing process even after a decade

Nigeria, a member of both OPEC and the Gas Exporting Countries Forum (GECF), is currently the largest crude oil producer in Africa. 2020 overall oil and gas output is estimated at 2.67 million boepd, out of which liquids production expected to be 1.862 million bpd and crude oil production 1.5 million bopd. Crude oil output is expected to slightly increase to 1.56 million bopd in 2021 but this increase will be short-lived, and Nigeria’s oil output is estimated to decline to 1.235 million bopd by 2025.

Similarly, 2020 natural gas output is estimated at 137 mmcm/d and is estimated to drop down to 132 mmcm/d in 2021. Efforts are being put into place to increase monetization of gas, but new developments are clearly required to reverse the declining natural gas output. 65% of the 2020 crude oil production comes from offshore projects and in contrary, 75% of the year’s natural gas output comes from onshore fields. Post approval of NLNG Train 7

in 2019, no major projects were sanctioned for development in 2020. The First E&P-operated Anyala–Madu project on OMLs 83 and 85 has been the year’s major start-up, apart from the Seplat-operated Sapele Shallow development on OML 41.

No significant projects are expected to be approved or come online in Nigeia in 2021, as the country has taken a hard hit due to the COVID-19 pandemic and the subsequent global crude oil demand drop and crude price crash that came with it. Many high profile projects like the Shell-operated Bonga North and Bonga Southwest–Aparo deepwater developments, and the Eni-operated Etan–Zabazaba project, also in deepwater, are now expected to be delayed further as such investment intensive projects have come on the chopping block as IOCs and operators across the world are now focused on cutting down investments and delaying projects with a high breakeven oil price.

The petroleum industry in Nigeria was already plagued with existing issues like the long-delayed Petroleum Industry Bill (PIB), which later transformed into the Petroleum Industry Governance Bill (PIGB). In September 2020, President Buhari resubmitted the bill to the National Assembly, hoping to pass it by the end of 2020, although when or if this action will occur is unclear. To add to this, Nigeria also passed in late 2019 a revision to the 1993 deep water PSCs which increases the royalties on deep water fields from existing 0% to a possible 12.5% at current oil price.

While few other West African countries are taking initiatives to provide fiscal incentives to bring in and retain long-term investments in deep water projects, Nigeria has taken a step in another direction in a gamble to increase government revenues, but in doing so, has created an unattractive fiscal environment for upstream investors.

The latest development in Nigeria’s upstream sector has been the announcement of the 2020 Marginal Fields Bidding Round for which as many as 57 marginal fields are up for bidding. The round includes:

22 fields wrested from concessions held by Shell Petroleum Development Company (SPDC)

12 fields left dormant by Chevron

11 fields held by ExxonMobil now wrested

Five fields held by Total now wrested

Two fields under concession by ENI

An additional five more have been added to those offered by the Department of Petroleum Resources (DPR)

The entire process right from registration to award is expected to be done electronically, due to the coronavirus outbreak. All the technical and commercial bids were expected to be submitted by August 2020. Under the DPR Guidelines, the entire process is not expected to take longer than six months, from date of announcement and commencement to signing of Farm-out agreement with the OML holders. Meanwhile, there is dissent building up in the host communities with Indigenous Ijaw rights activists saying that a minimum of 25% equity stake in upcoming marginal field awards has to be allocated to host and transit communities in the oil producing Edo and Delta States. Some militant bodies have warned any award arising from the 2020 Marginal Field Licensing Round that fails to consider the interest of host communities will be an exercise in futility as farm-in allottees will not be allowed access. While the decision to conduct the bid-round is a step in the right direction and has generated a lot of buzz, the development of these oil fields in a post COVID-19 world may be challenging, given the oil price collapse in the international market, and the unfavourable fiscal regime for marginal field operations in the country.

Senegal | Mauritania

Made large scale natural discoveries which put the region on the global hydrocarbons map

Aspirations to set up 30 million tonnes per annum (mtpa) LNG capacity through three hubs, and also power the gas-to-power industry in Senegal

Facing headwinds due to COVID-19, leading to revisions in strategies by the partners of the gas hubs

Long-term LNG plans now facing uncertainty while domestic supply plans are expected to face delays

The West African countries of Senegal and Mauritania saw many discoveries during the years 2014, 2015 and 2016. The Ahmeyim – Yakaar – Teranga discoveries turned heads with huge volumes of gas discovered in the years 2015 to 2017 and are gearing up to put the region on the global LNG map along with the Bir Allah (Marsouin) find and the recent 2019 Orca discovery. Senegal also saw the FAN and SNE crude oil discoveries during the same period. These exploration successes are finally seeing the light of development. The phase 1 of the Greater Tortue Ahmeyim (GTA) FLNG project was approved in 2018 and the 2.45 mtpa project is expected to see a delayed start-up by 2023 due to the ongoing coronavirus pandemic. The GTA LNG hub, along with the Bir Allah LNG hub in Mauritania and the Yakaar–Teranga LNG hub in Senegal are expected to be developed in the zone, and could ultimately reach a cumulative export

capacity of 30 mtpa. This development is expected to see some delays as Kosmos now aims to decrease its stakes in the long-term LNG developments, and as BP revises its global investment strategy to become net zero by 2050. On the crude oil side, the first phase of the Sangomar (SNE) offshore oil project was approved earlier this year and the start-up is now expected by 2023. The later phases are expected to be developed post the start-up of phase-1.

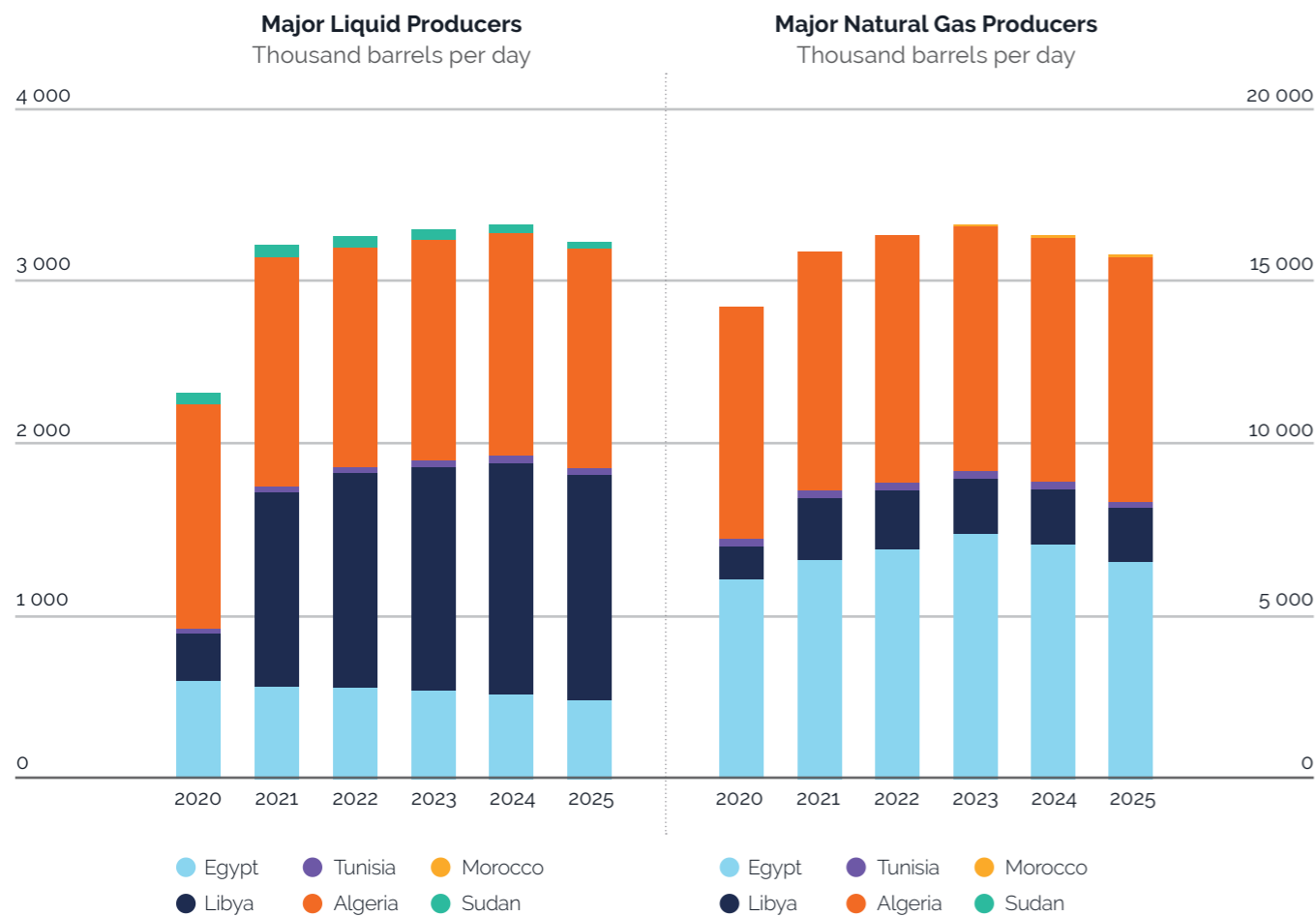
Being minnows in the region in terms of oil and gas production, both countries have been hit hard by the ongoing COVID-19 pandemic and the future of their mega LNG hubs is highly dependent on the operators’ decisions. With the long-lasting changes that the coronavirus has brought in the oil and gas market, the future of these LNG hubs and the natural gas aspirations of both Mauritania and Senegal seem to be facing very strong headwinds.



North Africa

Algeria and Egypt quietly taking over the continent's output while Libya has the capacity to become one of the largest crude oil producers if the civil war is resolved

Fig. 6: North Africa
Algeria, Egypt and Libya driving the production



Data Source: Rystand Energy UCube

Libya

A member of OPEC and GECF, Libya in 2011 was cruising towards raising its daily production above the 2 million threshold. But as General Gaddafi's regime ended and civil war broke out throughout the country, it has been unable to even maintain a sustainable oil production capacity around 1 million bpd. With continued civil unrest, force majeure has been imposed on oil exports in the country from January 2020. Due to this, Libya's oil production has currently plummeted to almost 10% of

its capacity. Prior to January 2020, Libya had been able to recover from lows of 600–800,000 bpd and was maintaining its oil production over 1.1m bpd.

Talks had started to initiate new major oil and gas projects like the development of the offshore structure A&E in Block NC-041 which was pegged at producing 30 to 35,000 bpd of condensate and 19.8 to 20 mmcm/d of gas at its plateau. Investment scenario was also getting better with IOCs like Total, BP, and ENI increasing their investment in the Libyan E&P sector. Currently, Libya is struggling

hard to bring back its offline capacity which would itself require \$600 to \$800m just to restore production back to January 2020 capacity and further billions of dollars to start ramping up its capacity and raise it to 2 million bpd. But given the current situation, IOCs are reluctant to invest in Libya, which is further putting more pressure on the already cash-strapped Libyan National Oil Company. In the current scenario, the 2020 crude oil output is estimated close to 230,000 bpd and 2021 production is expected to surpass 1 million bpd, providing the situation does not deteriorate.

Egypt

Egypt became self-sufficient in meeting its gas consumption in 2018, after projects like ENI's Zohr and BP's West Nile Delta (WND) started contributing to domestic gas production. The country not only met its growing domestic gas needs, but also exported 4 billion cubic meters of LNG in 2019 from its Idku LNG plant. Egypt's domestic gas production reached 68 billion cubic meters in 2019, the highest in this decade. However, the global drop in gas prices have drastically reduced 2020 LNG export volumes and the Covid-19 pandemic has exacerbated the problem by reducing domestic demand as well, leading to production caps on many projects. Zohr, the country's largest offshore project, is expected to pro-

duce way below its nameplate capacity of 84 million cubic meters per day as the nation faces a supply surplus. Current estimate is for Egypt to produce 62 billion cubic meters of gas in 2020, out of which only 1-2 billion cubic meters might be exported as LNG. In terms of upcoming projects, Raven, part of the third phase of BP's WND project, is expected to commence production next year. Based on current supply demand balances, Egypt is expected to experience a gas deficit post 2024, when the domestic consumption outpaces the local production again. The country has been actively planning new licensing rounds to discover more resources. Recently, the results were declared for the Red Sea round, while those for the West Mediterranean round are yet to be announced. Majors are likely to be awarded concessions as the sector is

frontier, and the nation hoping to discover another Zohr.

Although Egypt has been able reverse the direction of its gas output, the story is not the same when it comes to crude, as it struggles to discover more oil. The country's crude oil output remains on a decline, with major production coming from the Western Desert and the Gulf of Suez. The country is estimated to have produced ~490,000 bpd of crude oil in 2019, and continues to import what it needs to meet its domestic demand. The 2018 Licensing Round resulted in many concessions being awarded in Western Desert to international majors and independents, but it is yet to be seen if the concessions offered will result in additional discoveries.

Algeria

Algeria, an OPEC as well as GECF member, is a major African crude oil and gas exporter. The country produces close to 1 million bpd, although recent cuts in line with the OPEC+ deal have led to output falling below 850,000 bpd. The country has suffered a huge blow as the oil export revenue has dropped drastically due to the oil price cash. The impact of this is quite significant as Algeria depends heavily on oil and gas export revenue to support its state budget. Algeria is also a major pipeline gas exporter to Europe and LNG exporter

to East Asian and European markets. Current estimates are for the country to export 37 billion cubic meters of gas, out of which 15 billion cubic meters would be LNG exports. Algeria is estimated to have produced 86 billion cubic meters of gas in 2019.

Spain and Italy are the major importers of Algerian pipeline gas, although due to reduced gas demand as a consequence of the pandemic and lower gas prices, pipeline exports have also been reduced in 2020. This is on top of yet another drop from 2019 levels of 26 billion cubic meters compared to 39 billion cubic meters of pipeline gas ex-

ports in 2018. The country also had to signed new export contracts last year which expired recently. These new contracts were signed with lower volumes, as Algeria might struggle to maintain its short-term gas exports as its domestic gas consumption increases. With no major discoveries being witnessed, the country also introduced a new hydrocarbon law, hoping to attract further investments by foreign companies. This has led to Sonatrach to sign several MoUs related to exploration opportunities under the new law with majors and independents including ExxonMobil, Chevron, ENI, OMV, Cepsa, Lukoil, TPAO and Zarubezhneft.



East & South Africa

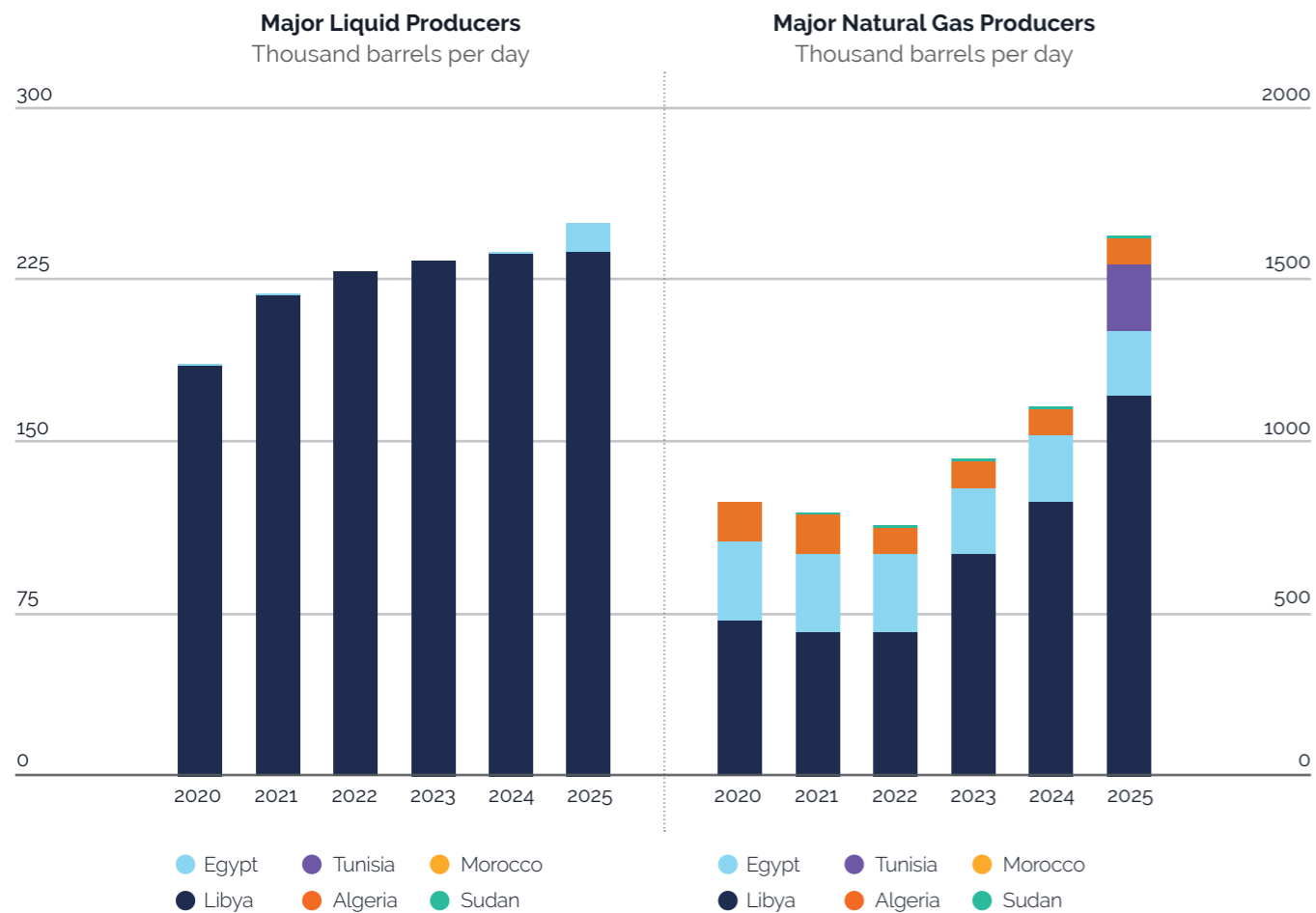
Most of current liquids production comes from South Sudan

The Region includes potential upcoming natural gas hubs catering to both domestic and export markets in Mozambique, Ethiopia, South Africa and Tanzania

Mozambique could overtake Nigeria in the next decade as Africa's biggest LNG exporter

Fig. 7: South & East Africa

South Sudan remains the crude oil producers as Natural gas projects in Mozambique, Tanzania and South Africa start ramping up



Data Source: Rystand Energy UCube

Mozambique

Mozambique had an amazing beginning of the decade with a successful exploration campaign during the period 2010 – 2014. The country reported many discoveries like the Golfinho, Atum, Coral, Windjammer, or Mamba South finds which

resulted in the conceptualization of new LNG hubs in the country. The ENI-operated 3.4 mtpa Coral FLNG development (Area 4) was approved in 2017 and is expected to come online by 2023. The first two trains of the onshore Mozambique LNG project, headed by Total in Area 1, were approved last year and are expected to bring online 12.88 mtpa of LNG output

in 2025. ExxonMobil is also expected to approve the development of the first two trains of its Rovuma LNG project in 2022 (Area 4). These two trains are expected to bring online a peak output of 15.2 MMtpa of LNG. Future phases operated by these majors could come online at a later timeline, with Total's Area 1 alone able to support 43 mtpa of LNG export capacity.

South Sudan

Before South Sudan gained independence in 2011, its combined oil production with Sudan was around 450 to 480,000 bpd. Years of unrest and civil war have damaged wells and production facilities and South Sudan currently produces around 280,000 bpd

with a target of bringing back output to 350,000 bpd. The country still relies on its northern neighbour's oil export infrastructure to monetize its reserves. After independence, Sudan started charging South Sudan in per barrel terms to facilitate oil export, and this oil revenue sharing has always remained an unsolved issue between these two nations. As part of OPEC+ group both Sudan and

South Sudan have pledged to cut down their oil production. Sudan seems to be adhering to their quota, but South Sudan has not been compliant throughout the cuts and is now expected to further ramp-up its production by Q4 2020. On the exploration front, South Sudan has started to pick some momentum and is expected to relaunch its bidding round initially planned for 2020 in Q1 2021

Rest of East & South Africa

Other countries in the South and Eastern regions of Africa are awaiting the approval of their upcoming projects or kick starting their exploration campaigns. Uganda's Tilenga project is one of them, with Total expecting to take a final investment decision (FID) in the near future. The sanctioning of the project has slipped into 2021, and first oil is expected by 2024-2025. Similarly, the South Lokichar development onshore Kenya has now slipped into 2023 as impact of

COVID-19 and fiscal framework issues have led Tullow Oil to call force majeure on the project for several weeks in 2020. In the landlocked nation of Ethiopia, the PolyGCL-operated Calub-Hilala fields' development, from where natural gas is planned to be piped off to a FLNG unit offshore Djibouti is expected to be approved in 2022 with start-up expected by the middle of the decade.

Offshore South Africa, French major Total has started an exploration campaign close to its Brulpadda gas and condensate discovery with the spudding of the Luiperd-1X well in late August 2020. August 2020, and announced a signif-

icant gas discovery a few months later. Somalia also launched its first offshore licensing round. The round initially included 15 blocks, but was reduced to seven – Block 204 off Kismayo, contiguous blocks 177 and 178 off Mogadishu and neighbouring blocks 165 and 153 off the coastal towns of Cadale and Ceeldheere. The process is expected to be completed by March 2021. However, significant challenges still remain as the province of Puntland, the state of Jubaland and the Republic of Somaliland have not agreed to legitimise the licensing exercise and have denied the revised Petroleum law or the control of the Somali Petroleum Authority (SPA).

The mid-level producers of Africa

Congo, Gabon, Ghana, Equatorial Guinea, Chad and Cameroon constitute a strong group of mid to low level African producers

Congo's crude oil exports have been hit by the cuts imposed on OPEC member nations but Equatorial Guinea and Gabon remain unaffected as the production levels are already low

Majors including Total, Chevron, Eni and ExxonMobil, and independents including Tullow Oil and Perenco drive majority of the output in these countries

In a new normal COVID-19 hit world, these countries fight their own battles to stabilize their respective oil and gas industry situation

These set of sub-Saharan African countries along with their much bigger hydrocarbon producing counterparts are heading towards a transformation, driven by possible divestments from majors with the aim of decarbonising their portfolios and positioning themselves for the energy transition

Congo

Largest crude oil producer in this group of mid to low level hydrocarbon producers and the third-largest oil producer in sub-Saharan Africa after Nigeria and Angola

Most of the production comes from the offshore projects operated by majors and independents

Being an OPEC member, the country's 2020 crude exports have been impacted by the OPEC+ agreement cuts

Production going forward is expected to decline but the Government aspires to drill 125 wells in the next three years – most of them in low-cost-intensive shallow-water or onshore locations

Congo has crude oil reserves of more than 3 billion barrels and gas reserves of about 400bn cubic metres, according to the government. The country's crude oil production increased from about 256,000 bpd in 2015 to a peak of almost 370,000 bpd last year, making it one of the few African countries with rising production among sub-Saha-

ran African oil producers. The OPEC+ sanctions put the country's 2020 crude oil output at about 335,000 bpd and 2021 production is expected to fall to 305,000 bpd. Congo is indeed facing a steep production decline as the past five years of exploration have failed to turn up any viable discoveries and near-future developments have been delayed due to the low oil price environment and the COVID-19 pandemic. The decline means Congo's production will be back at pre-2015 levels by the mid-2020s and will have dropped by more than 40% from last year's peak by the early 2030s.

Congo's economy is highly dependent on the oil industry, which accounts for 55% of gross domestic product (GDP), 85% of exports and 80% of tax revenue. Before the pandemic, Congo's GDP was projected to increase by around 4.6% this year – now it is instead expected to enter recession with a 7.2% GDP contraction in 2020. Considering the central role of oil and gas in the country's economy, the government has little choice but to focus on mitigating the production decline through new developments and discoveries in a bid to shore up its national finances.

Equatorial Guinea

Equatorial Guinea has a balanced liquid – natural gas production, with 2020 output at liquids 60% – 40% natural gas ratio

2020 crude oil output already below the target production post OPEC+ cuts

Close to 80% of the 2020 crude oil output comes from matured declining fields, and the production forecast is expected to continue to decline

2020 crude oil production is expected at approximately 110,000 bpd with the overall liquids output including condensates and Natural Gas Liquids (NGLs) estimated at 160,000 bpd. 2021 overall liquids output is expected to marginally decline to 150,000 bpd with crude oil output at 100,000 bopd. The country's 2020 natural gas output, including export volumes, is estimated at 100,000 boepd and 2021 output is expected to stay flat at these levels. The country, via the Alen monetization project and the development of an offshore gas megahub,

aspires to become the intra-African gas export hub. ExxonMobil, Marathon Oil, Noble Energy (now owned by Chevron) and Trident Energy produce all of the hydrocarbons from the country for both 2020 and 2021.

All of the production comes from offshore fields and gas is piped to the onshore EG LNG plant and Punta Europa complex. COVID-19 led to project delays and expected divestments like ExxonMobil's possible exit are the current setbacks that the country is battling.

Ghana

ENI and Tullow Oil remain Ghana's only two producers : all the production comes from the Tullow-operated TEN and Jubilee projects and the Eni-operated Offshore Cape Three Points (OCTP) project

Liquids output expected to stay relatively flat during the years 2020 – 2021 after a marginal drop from 2019 levels

Natural gas output expected to gradually increase

No new oil and gas industry-related reforms announced by the government, but the country is historically known for making more attractive tax agreements with operators

2020 crude oil output from Ghana is estimated at close to 180,000 bpd and 2021 levels are expected to be at similar levels of 175,000 bpd. The production is expected to gradually decline until 2025. But as some high profile discoveries like Aker Energy's Pecan, Springfield's Afina and ENI's Akoma fields come online during the later part of the decade, the production is expected to increase during the second half of the 2020s. To be noted, the existing production and most of the future output in the next decade is expected from cost-intensive deep water projects.

As Tullow Oil fights its financial troubles and ENI goes through its new carbon neutral direction, Ghana will be hoping its offshore projects do not become the collateral. Although the country's current fiscal agreements with existing operators are more contractor-friendly, the post

pandemic world of low crude price forecast might demand more from the administration to keep the presence and development from these operators to go on.



Gabon

55% of the 2020 crude output comes from offshore shelf fields and the rest from onshore fields, with 3/4th of overall production coming from matured declining fields

French major Total, independent Perenco and Carlyle Group-backed Assala Energy produce close to 70% of current output

Gabon's 2020 crude oil production is expected at 190,000 bpd, and is estimated to drop marginally to 180,000 bpd in 2021. The country is hardly impacted by the OPEC+ cuts as the 2020 output is already close to the target output post the cuts. Gabon is heavily reliant on its oil exports and the petroleum industry accounts for 30% of GDP, 79% of exports and 36% of government budget revenue. Before the pandemic and the associated oil price crash, Gabon's GDP was projected to increase by around 3.7% this year – now it is instead expected to enter a recession with a 3.8% GDP contraction

in 2020 and a further 1.4% reduction in 2021. Counter measures to the declining oil output and COVID-19 pandemic include extension on the closing date for the ongoing 12th Licensing Round. The authorities are also offering more than 65 000 square kilometres of 3D seismic and over 21 000 kilometres of 2D seismic data along with available well-specific data for 167 wells across the 35 offered blocks. This will provide a further opportunity for potential bidders to integrate new data into their evaluation of open blocks and help in the assessment of prospectivity and play potential.

Chad

The landlocked country of Chad is expected to produce close to 110,000 bpd of crude oil in 2020 and the production levels are expected to remain at this level in 2021 as well.

Most of the current production comes from the CNPC-operated Permit H (Area I, II and III); and the Chad Export Project on the Chari block and Mangara – Badila block operated by ExxonMobil and Glencore respectively. The country does not have many upcoming projects in the pipeline and the production is ex-

pected to be driven by the existing producing fields through the next decade. As a result, it is expected to gradually decline to half the current levels by the end of the next decade. A potential exit of ExxonMobil from the country is on the cards as the US major is trying to divest its 40% stake in the Chari block.

Cameroon

Cameroon is the smallest producer among this group of countries with mid to low level hydrocarbon output in Africa. 2020 crude oil production is expected to be about 65,000 bpd and to marginally drop to 55,000 bpd day in 2021. The country also produces natural gas from its Golar Kribi FLNG, Sanaga Sud and Logbaba fields. 2020 – 2021 natural gas output

is expected to stay flat at about 35,000 boepd. Perenco is the leading producer in the country and is expected to retain that position as the top producing operator through the next decade.

All of Cameroon's production comes from its offshore projects in shelf water depths. As no new major crude oil developments are expected to come online in the next decade, the country's crude oil output is expected to gradually decline to less

than 20,000 bpd going into the early 2030s. The natural gas output, however, is expected to average a relatively higher level of about 40,000 boepd through the 2020s as few projects like the Victoria Oil and Gas' Logababa Phase 2 and Noble Energy's YoYo come online.

The major upcoming project in the country is New Age-operated Isongo Marine, but this is plagued with a few issues and the start-up currently delayed.

Putting Power at the Centre of Africa's Economic and Industrial Revival

A bold and ambitious post-COVID recovery plan involving significant investments in Africa's electricity sector is needed as part of the policy responses by governments and the private sector to the pandemic.

Energy-intensive industrial activities such as value-additive mining will serve as key drivers of demand growth, accounting for 45 percent of total consumption by 2030. The African Energy Chamber forecasts that electricity generation on the continent will increase by 25 percent, 55 percent and 141 percent of 2020 baseline levels to reach 1,057, 1,138 and 2,047

terawatt-hours (TWh) by 2025, 2035 and 2040 respectively.

The Chamber assesses natural gas use in power generation is likely to increase in several African countries like Nigeria, as supporting infrastructure and monetisation options continue to grow.

SDG 7 goal which seeks to ensure "access to affordable, reliable, sustainable and modern energy for all" has produced modest gains in electricity access in Africa. Nonetheless, 565 million people still lack access to electricity on the continent, mostly in Sub-Saharan Africa.

Africa's energy transition is likely to emphasise energy security (access) and energy poverty (affordability), resulting in an increasing use of natural gas for domestic power generation and LNG exports, an increase in the share of renewable energy within the continent's generation mix, and an increased focus on decentralised off-grid energy initiatives for remote communities.

Climate change considerations in Africa have to take into consideration the equally important energy poverty and associated economic challenges that are of major concern to Africans

Africa's rapid economic development is directly linked to the reliable modern energy services provision, primarily electricity. However, access to reliable power is consistently identified as one of the most significant constraints to doing business on the continent (Figure 1 – Getting electricity indicators). The continent's rapid economic growth since 2010 has been driven by the expansion of the services and extractives sectors. This development has been catalysed by rising electricity demand, which is estimated to be growing at between 3-5 percent per annum.

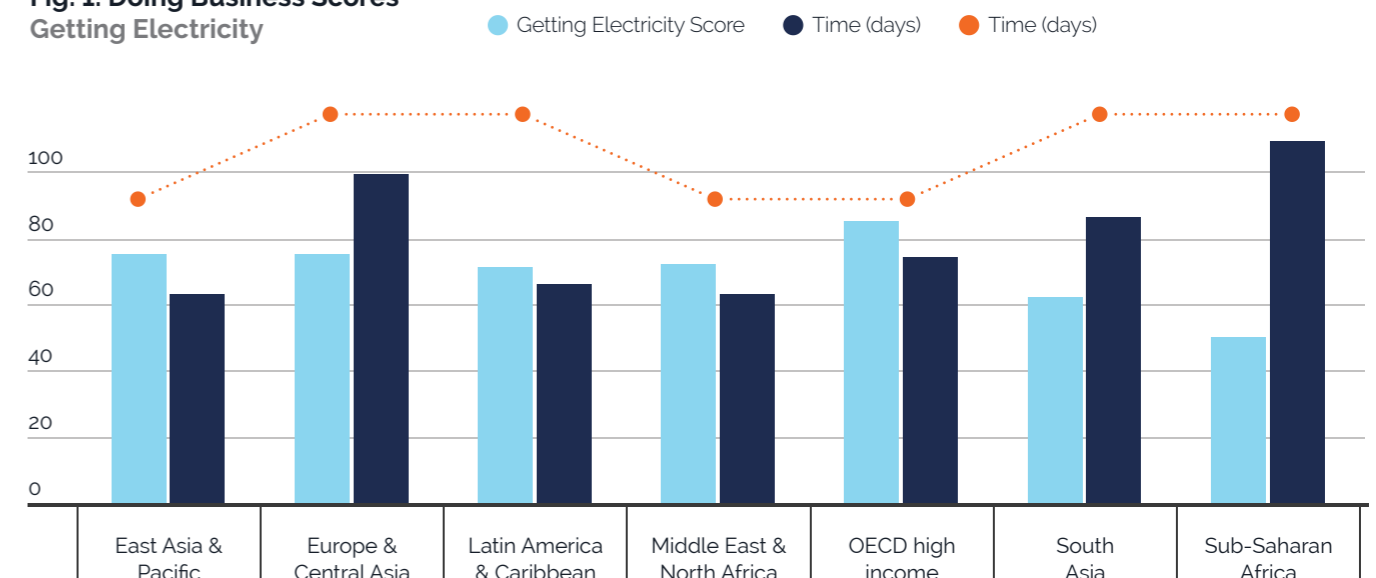
The African Energy Chamber firmly believes in the continent's potential, especially the opportunities that a post-COVID economic recovery presents for Africa's rapid industrialisation. This will increase domestic production and consumption, boost intra-regional trade through the African Continental Free Trade Area (AfCTA) and develop regional value chains.

All these, of course, catalysed by the continent's young and dynamic population as well as increasing digitalisation

(formalisation) of several economic sectors and government services.

For example, a 5 percent economic growth between 2020 and 2040 will increase the continent's economic output by 922 percent from the current US\$1.76 trillion to US\$18 trillion in 2040 with manufacturing making up 24 percent of value-added from the current 19 percent, according to EIA forecasts. Attaining these lofty benchmarks will require the availability of affordable and reliable energy, particularly electricity.

Fig. 1: Doing Business Scores
Getting Electricity



Data source: World Bank 2020 Doing Business Indicators

Africa's Electricity Sector in 2021

African Power Demand to Keep Rising Between 4-5%/y

Total electricity generation in Africa stood at 870 terawatt-hours (TWh) in 2019, an increase of 2.9 percent from 846 TWh in 2018. Africa's electricity generation capacity has grown at an average of 4.8 percent per annum since 2008, compared to 2.7 percent globally. Nonetheless, Africa's share of global electricity generation has been around 3 percent since 2000.

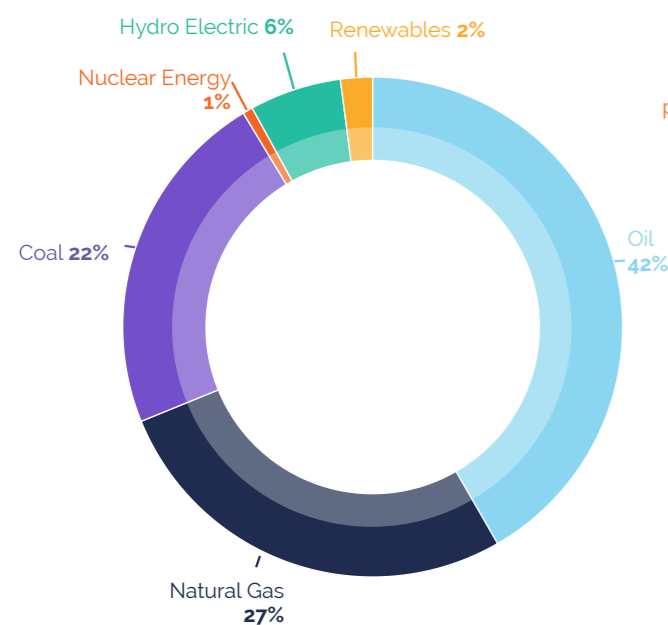
The African Energy Chamber forecasts that 2021 generation is likely to range between 870-900 TWh if demand

picks up aggressively throughout the year following the gradual removal of COVID-19 lockdown restrictions and economies opening more fully to international trade. Our base case forecast using a conservative 4.5 percent yearly growth (current stated policies) shows that electricity generation on the continent will increase by 25 percent, 55 percent and 141 percent of 2020 baseline levels to reach 1,057, 1,138 and 2,047 TWh by 2025, 2035 and 2040 respectively. This increases to 1,520 in 2030 and 2,700 TWh in 2040 in a more

aggressive push to expand capacity at 6 percent per annum (Dashboard 1 – electricity indicators).

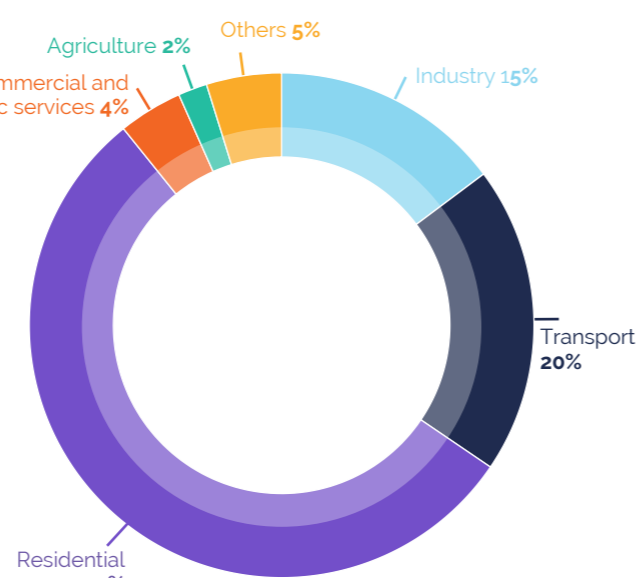
The latter assessment is premised on Africa aggressively pushing to expand electricity supply and modern energy services within the framework of the Africa Agenda 2063 on energy and infrastructure development. This will ensure that generation expansion will outpace population growth on the continent (Africa will have 1.8 and 2.45 billion people by 2040 and 2050).

Dashboard 1: Africa's total primary energy consumption (TPEC) by fuel

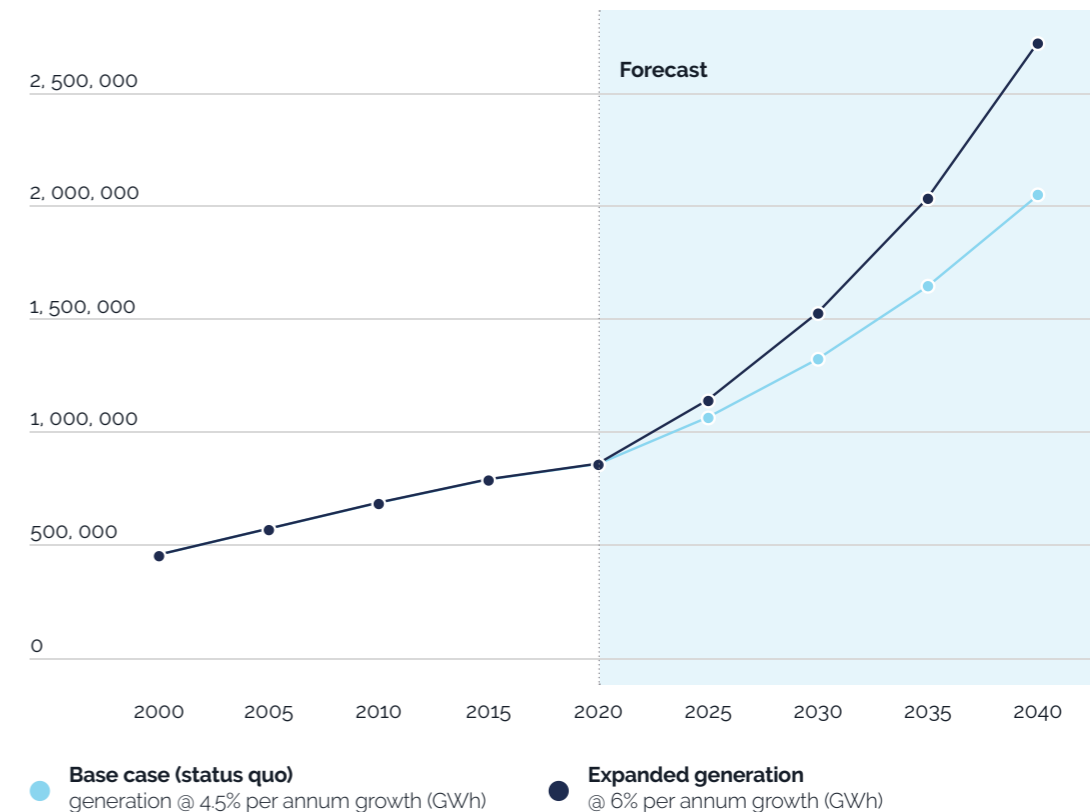


Data Source: IEA

Dashboard 1: Africa's total primary energy consumption (TPEC) by sector



Dashboard 1: Electricity generation in Africa by scenario, 2018-2040



Historical data source: IEA; Forecasts independently produced

Regarding the supply mix, natural gas (39 percent) constitutes the largest element in Africa's electricity generation mix, followed by coal (29 percent), hydro (15 percent) and oil (10 percent). While nuclear energy accounted for another 2 percent, the share of renewables (RE) in Africa's generation mix is growing, albeit at a lower pace than in other regions (5 percent). Most of the RE growth comes from solar, wind and geothermal power plants, and this expected to continue into 2030. Africa generated 830 megawatts (MW), 5,748 MW and 7,236 MW of geothermal, wind and solar installed capacity in 2019, signifying growth rates of 17.4 percent, 26.1 percent and 60.2 percent respectively since 2010. Nonetheless, most of these RE developments on the continent are limited primarily to Northern (Morocco,

Egypt) and South-Eastern Africa (South Africa, Kenya). Given the declining costs of key RE technologies along with rising concerns over CO₂ emissions, the level of renewables deployment, particularly solar and wind energy is expected to increase by 1.5 percent annually over the next decade to 2030.

Regarding sectoral electricity consumption, the industrial sector remains the continent's largest user (41 percent) followed by residential (33 percent), commercial and public services (18 percent) and agriculture (4 percent). Transport consumes a small proportion (approximately 1 percent) while the remaining 3 percent was accounted for by other sectors. At a sub-regional level, North Africa and South Africa account for more than 70 percent of Africa's electricity demand.

Sub-Saharan Africa's per capita electricity consumption has decreased by more than 4 percent since 2010 to around 486 kWh per capita, over six times lower than the global average of 3,133 kWh per capita. The value is much lower in most parts of Africa – for example, below 100 kWh per capita in Niger, Ethiopia and Benin. Further compounding these are the high electricity transmission and distribution losses in many countries due to derelict infrastructure from years of underinvestment. Transmission and distribution losses range from about 21 percent in DR Congo, Ghana (23 percent), Gabon (28 percent), Namibia (36 percent), Niger (42 percent) to as high as 70 percent in Libya and Togo, according to EIA and World Bank statistics; this compares to a global average of 8 percent.

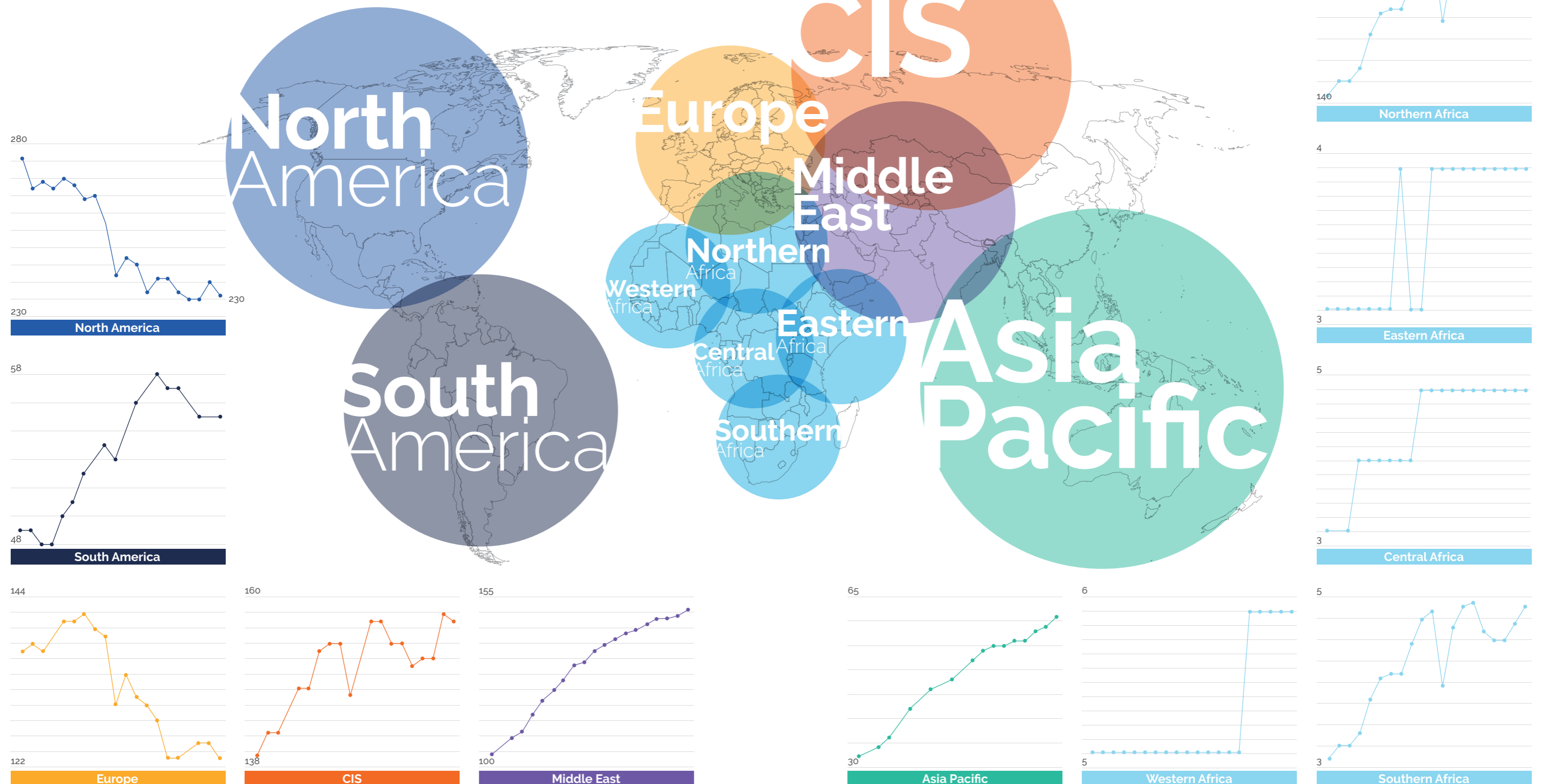
Dashboard 1:

World Energy Consumption per Capita

2000 - 2009

Gigajoule (GJ) per Capita

Data Source: IEA



Fighting Energy Poverty
is a Necessity

Despite the continent's enormous energy resources, access to modern energy services in Africa remains limited. Almost 600 million of the continent's population (almost 46 percent of the population)

lack access to electricity and about 730 million lack access to clean fuels and facilities for cooking, according to IEA and World Bank statistics. There is, however, a varied regional picture: while North Africa

has 99 percent electricity access rate, the situation by far remains low in West Africa (52 percent), Southern Africa (48 percent), East Africa (37 percent) and Central Africa (27 percent) as of 2018. As at the end of

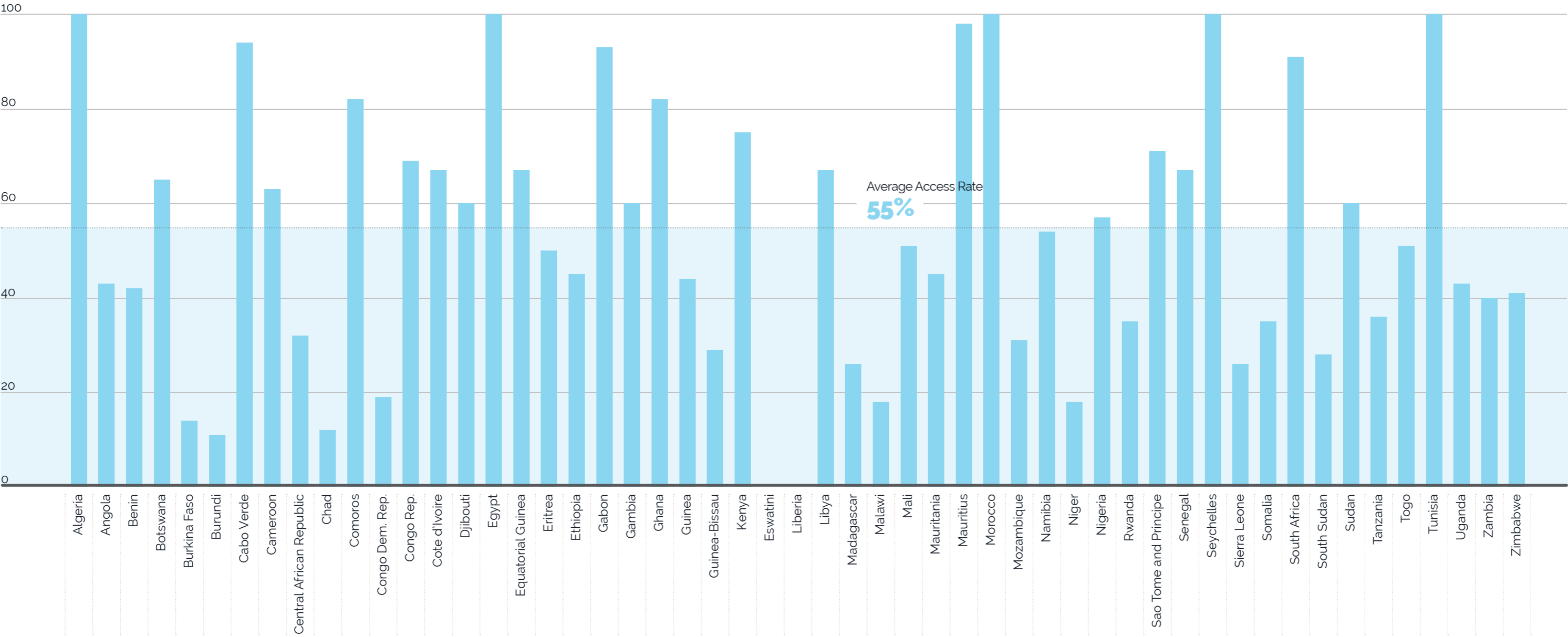
2019, the electrification rate in some African countries, including Chad, Burundi, Liberia, Niger, DR Congo and Malawi was as low as 10–20 percent (Figure 2: population access to electricity). In addition, most of the rural

population in Africa continues to rely on traditional biomass and waste (principally firewood, charcoal, and crop residues) for meeting their domestic needs, deepening energy poverty and health inequalities.

This is a challenge that the continent must adequately address to lift people out of poverty by creating sustainable livelihood opportunities, catalysed by the availability of cleaner forms of energy and natural gas.

Figure 2: Population access to electricity, 2018
% of population

Data source: World Bank 2020



Climate Change Poses a Threat to Baseload Hydropower

Africa remains among the least CO₂ (and other greenhouse gases) emitters in the world. The continent emitted 1,308 Million tonnes of CO₂ in 2019, representing a 2 percent growth in the decade between 2008-18, and representing only 2 percent to the global energy-stimulated CO₂ emissions. However, the impacts of climate change are being felt, and they are unevenly distributed across the continent in the form of drought-induced conditions and reduced rainfall for hydroelectric power generation, among others.

Already, some variations in rainfall patterns have altered the viability of installed hydropower plants in several countries, notably Zambia and Zimbabwe. Hydro-based electricity generation has provided base-load power with low running costs for many countries in Africa over the years. In about 11 countries, large hy-

dro (at least 50MW capacity) has accounted for about 50 percent total installed generation.

As we advance, the Chamber notes that hydropower capacity factors will be impacted by climate change, making it a serious concern for the reliability of electricity supply. Studies indicate that hydropower plants in Ethiopia, Ghana, Sudan, Morocco and Egypt will experience fluctuations for decades even after 2050. However, the degree of variability or change is linked to the GHG concentrations and will vary across countries, requiring a tailored approach in each state. As a result, we still note several ongoing and planned hydropower projects (estimated at more than 15 GW). Along with a commitment to low-carbon transitions and universal energy access, the share of hydro is predicted to increase by 7.5 percent (by 2025) and reach 23 percent share by 2040.

Gas-to-Power is Key to Unlocking Africa's Industrialization

Africa's gas industry holds enormous potential. The continent was estimated to have between 527-558 trillion cubic feet (Tcf) of gas as at the end of 2019, making Africa the fourth-largest gas reserves holder in the world after North America (7.5 percent of proven global reserves), according to BP and OPEC statistics. Over 90 percent of all recent gas discoveries in Africa were made by nascent players like Mozambique, Tanzania, Mauritania and Senegal. The Chamber believes that these changes highlight a potential new age for gas supply diversification in Africa as several new producers come on board.

Gas-to-Power: the Ideal Pillar to Africa's Energy Transition

This decline in consumption is, however, not the case in Africa as increased gas discoveries and lower production costs will make gas the primary fuel of choice in power generation. The continent has embraced natural gas as a primary fuel for electricity generation. The Chamber assesses this trend is likely to continue until the 2030s, subject to the availability of supporting infrastructure and monetisation options in several countries. A closer look at Africa's electricity generation mix over the past five years shows a dominant and strong appeal for natural gas as the preferred fuel for electricity generation.

With an expanded pipeline network in West, East and Southern Africa, regional gas movements could more than double by 2030, further displacing coal in some

markets. Although the continent's 'old guards' in the hydrocarbon industry like Algeria (159 Tcf), Egypt (78 Tcf), Libya (53 Tcf) and Nigeria (203Tcf) still account for significant (89 percent) gas reserves, it is worth noting that discoveries from the new entrants ('new guards') would potentially account for a more significant share of actual usage by 2030. Of all gas produced in Africa in 2019, 3.6 Tcf (40 percent) was exported while another 5.3 Tcf (60 percent) was consumed domestically, mostly for power production. The largest consumption (demand) countries are Algeria, Egypt, Nigeria and South Africa and significant scope remains to increase gas demand across sub-Saharan Africa.

The main challenge for Africa in the next decade is its ability to increase gas supply as the primary fuel in electricity generation to increase electricity access and productive economic uses of electricity. Ensuring the reliability of power supply and reducing electricity generation costs depends mainly on Africa's ability to navigate infrastructure and affordability challenges. For example, South Africa's state utility ESKOM will require a reliable and constant supply of gas, most likely from Mozambique or newly-discovered domestic fields, as it plans to phase out coal power and resolve electricity challenges that have led to crippling load shedding in the country. In West Africa, Nigeria can export additional gas to several coastal countries in the Gulf of Guinea region up to Cote d'Ivoire if the West African Gas Pipeline (WAGP) is extended beyond Takoradi in Ghana.

Dashboard 2:
World Natural Gas
2000-2019
Reserves, production, export,
import and demand

Data Source: IEA

Key

- World proven natural gas reserves by geographical grouping (Tcf)
- World marketed production of natural gas by geographical grouping (Bcf)
- World natural gas exports by geographical grouping (Bcf)
- World natural gas imports by geographical grouping (Bcf)
- World natural gas demand by geographical grouping (Bcf)

Regulatory Reforms and Regionalisation Must Become Priorities

African reforms continue to face internal and external threats

Regulatory reforms aim to ensure quality and reliable power supply, improve the financial and operational performance of utilities in the sector and ensure private sector participation. Most African countries have established independent energy sector regulators. In 2019, the average Electricity Regulatory Index (ERI) score was 0.572 for thirty-four African countries, indicating a medium level of regulatory development. That is, there exists a supportive regulatory framework, but implementation is constrained by legal and institutional gaps, including low regulatory capacity. At a respective country level, Uganda had the highest ERI score of 0.748 while Liberia scored the lowest ERI score of 0.267. However,

no country in Africa has so far reached a score of 0.8, which is the optimal level.

Key threats in the regulatory reform are shown in the figure below. Internally, (1) the unpredictability of the tariffs and non-reflective end-user tariffs in the overall transmission investment portfolio leads to a considerable sector cash deficit; (2) some regulatory reforms create room for renegotiation of concessions contract and often cause undue pressure on independent power producers, curtailing further investment; and (3) poor governance, pressure from labour unions and macroeconomic issues have hindered critical energy sector reforms in several African countries.

Externally, climate change, a non-Africa centric demand for energy transition and extreme weather events pose a growing threat to the continents power market, making it increasingly vulnerable regarding the security of supply. Access to finance is another major threat to the power sector in Africa.

Lack of access to funding such concessional loans to meet the needs of universal energy access delays the development of infrastructure. Similarly, political instability delays the development of regional markets, regional regulators, power pools and cooperation amongst the member countries in initiating cross-border projects.

Internal Threats

Non-cost reflective end-user tariffs in the overall transmission investment portfolio leads to a considerable sector cash deficit

Regulatory reforms create room for renegotiation of concessions and may sometimes cause undue-fiscal burden on IPPs

Standard reforms models do not explicitly link the provision of electricity to economic welfare needs

External Threats

Climate change

Access to adequate finance

Inadequate infrastructure

Slow development of regional regulatorsand regional power pools

non-Africa centric demand for energy transition

Regional Cooperation is Key to Electrifying Africa

The development of regional electricity markets has been a challenge worldwide. In Africa, with many small countries, trade in electricity would bring many benefits provided that the hard infrastructure is at scale and functioning and that the soft infrastructure (governance) is trustworthy.

Several projects have been initiated to ensure a single African power market

is realised. These projects could make it easier to trade power across regions and countries through novel designs which are regulated by regional regulators and supported by the initiative put forward through the AfCFTA. The operationalisation of continental power trade, catalysed by the AfCFTA, will inevitably increase energy access and improve social-economic welfare. The interconnections linking the South Af-

rican Power Pool (SAPP), West Africa Power Pool (WAPP), and Eastern African Power Pool (SAPP) provide numerous opportunity to establish the expected the African Single Electricity Market (AfSEM).

The AfCFTA aims to accelerate intra-African trade and boosting Africa's trading position in the global market by strengthening Africa's common voice

and policy space in international trade negotiations. The agreement also aims to remove non-tariff barriers by creating a single market of about 1.2 billion persons for trading in goods and service. AfCTA encompasses both top-bottom and bottom-up approach in supporting regulation at the regional level. Through its support, coordination of policies, harmonisation of regulations and, to the extent possible, harmonisation

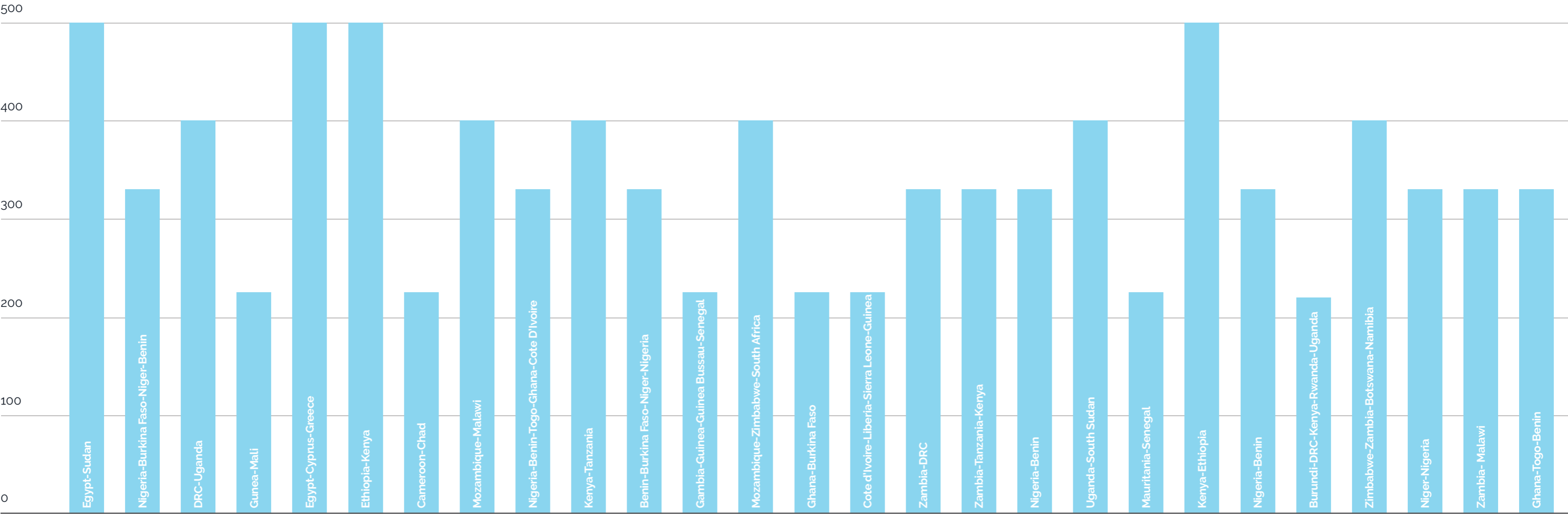
of legal institutions can be realised, hence deepening regional integration.

Through the AfCFTA, cross-border power trade can be enhanced through the effort made to spearhead the development of a regulatory and legal framework to establish a single and liberalised market for goods, persons, capital and services. This also opens opportunities for innovative ways to

finance cross-border power transmission infrastructure. One such novel approach could be to introduce public-private partnerships (PPPs) in financing cross-country and cross-regional transmission networks. These models, though new in Africa, could significantly contribute to the faster development of power markets and give opportunities to the private sector to participate in the otherwise monopoly subsector.

Figure 3: Crossborder Transmission Infrastructure Projects in Africa

Data Source: IEA



Adressing Africa's Growing
Funding Requirements

Africa's power markets have been funded by varied sources. These include equity-debt mix linked to contractual offtake arrangements, non-recourse debt, credit enhancement schemes, and developer technical assistance, among others. Other sources of funding power infrastructure include Sovereign wealth funds,

Africa50	Two transmission projects totalling 500 kilometres in Africa
African Development Bank	US\$4.5 billion to advance power generation investment and transmission. It is also supporting policy reforms, advisory services and providing financial guarantees for power projects on the continent.
ATI African Trade Insurance Agency	Developing 400 MW energy generation in 13 ATI members countries
Eastern and Southern Africa Trade & Development Bank	Providing US\$400 million power sector investments in the COMESA region
World Bank Group	Investing US\$5 billion in the energy sector by 2024 as follows: <ul style="list-style-type: none">Adding 3.3 GW-hours of energy storage;Supporting 60 million new connections by 2030;Adding 5,000 kilometres (km) of transmission line infrastructure constructed or rehabilitated by 2030Supporting 30,000 MW of new energy generation by 2030.
Canada	Pledge of US\$150 million and deepen coordination on the implementation of commitments under the Africa Renewable Energy Initiative (AREI).
EU	€2.5 billion (US\$2.8 billion) of financing for sustainable energy activities by 2025.
France	US\$2.15 billion funding in support of Power Africa through the Africa Renewable Energy Initiative (AREI).
Japan	Finance 1,000 km of transmission lines.

pension funds and international bond markets. In the past few years, other innovative infrastructure financing schemes such as puttable bonds have been proposed by investors and financiers. These bonds are designed to mobilise pension and life insurance funds and can be applied to greenfield projects.

Development Bank of Southern Africa	Finance 3,000 MW of new energy capacity.
China	<p>Sub-Saharan Africa's energy sector has received loans worth US\$ 17.5 billion from Chinese lenders since 2014, while oil and gas have received US\$3.2 billion. Focus areas include Nigeria's Mambila hydropower plant, Kenya's Lamu Coal-Fired power plant, South Africa's Medupi coal-fired power plant and Zambia's Kafue Gorge Lower hydropower plant.</p> <p>Other renewable projects include:</p> <ul style="list-style-type: none">an additional 200-MW solar farm in Ghana244.5 MW De Aar wind farm South Africaa 100 MW Gwanda Solar Power Plant in Zimbabwe1650 MWp Benban solar farm in Egypt (US\$ 4billion).
USA Power Africa	<p>Power Africa draws its funds from 12 US Government agencies and 19 development partners to support African government partners in seeking to increase energy access and improve the economic welfare of Africa. It has a presence in over 20 countries.</p> <p>Some of the notable projects include:</p> <ul style="list-style-type: none">US\$22 million in Sierra Leone to implement policy reforms strengthen institutional capacity and governance in the electricity sector.US\$257 million Liberia Power Compact to strengthen the power sector through policy reforms and infrastructure investment.US\$498 million in Ghana under Power Compact to implement necessary reforms to make the power sector sustainable and financially sound.US\$351 million under the Malawi Power Compact to increase the capacity and stability of the national electricity grid.US\$375 million under the Benin Power Compact to improve access to electricity.

What the Energy Transition Means for Africa's Power Sector

The energy transition refers to the transformation of the global energy sector from fossil-based production and consumption of fuels such as oil, natural gas and coal to zero-carbon emission fuels by 2050. This is primarily driven by the need to reduce CO2 emissions from energy sources or decarbonising the energy sector to contain the negative impacts of climate change. It entails increasing renewable and clean energy sources such as solar, wind, geothermal and water, among others into the energy supply mix. At the core is a need limit the increase in global average temperatures to well below 2°C above pre-industrial levels while pursuing efforts to limit global warming to 1.5°C above pre-industrial levels. This, encapsulated in the Paris Agreement, was adopted by 195 nations at the 21st Conference of the Parties (COP21) in December 2015.

CO2 emissions from energy sources including from power generation, have risen by an average of 1 percent per annum since 2010, according to IRENA data. This is notwithstanding the fact that the COVID-19 pandemic and associated economic slump temporarily suppressed emissions in 2020. Global emissions are forecasted to rebound over the medium term from 2021 as several economies open once again on the prospect of a COVID-19 vaccine becoming widely available for the global population. It remains likely that the world may not be able to meet the minimum

2°C pathway by 2050 if the current business-as-usual or stated policies scenario, are continued without radical or aggressive change in approach. The primary enablers or drivers for the energy transition at a global level will be increasing renewable energy supply, electrification and improvements in energy storage, all geared towards significantly cutting CO2 emissions. IRENA's forecasts indicate that about 65 percent of total final energy use will be met by renewables in 2050 while about 86 percent of electricity generation will also come from RE sources of which 60 percent of electricity to be supplied by solar PV and wind.

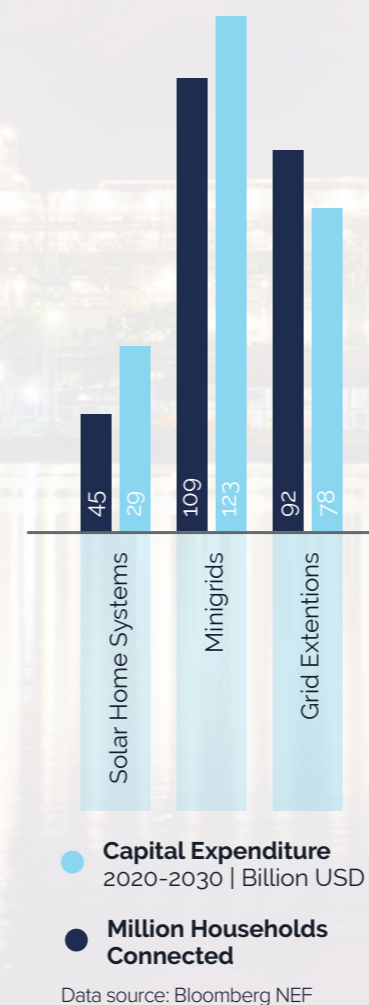
Energy Transition presents challenges as well as opportunities for Africa. One challenge is that several of Africa's hydrocarbon resources, particularly oil, are unlikely to be developed as initially planned. Many international banks for example, in response to pressure groups promoting an aggressive decarbonization push are retreating from financing the development of oil and gas projects in Africa. This would significantly reduce government revenues, especially for the less diversified commodity-dependent economies. This is also due to the declining share of oil in the global energy demand by 2050 (decarbonised world) if the 2°C pathway is aggressively pursued. On the other hand, the energy transition in Africa presents an opportunity to emphasise energy security (ac-

cess) and energy poverty (affordability). This encompasses: (1) increasing the use of Africa's natural gas for domestic power generation and LNG exports given the potential declining share of oil in global energy demand by 2050; (2) increasing the RE share of the generation mix; and (3) pursuing decentralised off-grid energy initiatives. Hence, policy responses by governments and investment inflows into the continent's power sector will be driven by these considerations in addition to others such as post-pandemic economic diversification.

To bridge the energy access gap in Africa, governments will require a successful mix of strategies that integrate grid extension and improvement, mini-grids and standalone generating systems. Kenya for example, has announced grid extensions to provide 299,601 connections at the cost of US\$382 million by 2022 when the country plans to achieve universal access.

Off-grid renewable energy options, notably standalone systems and mini-grids are projected to see strong sustained growth in the coming decade, in response to demand for energy in areas unlikely to be serviced by national grids. Towards 2030, standalone systems and mini grids could provide almost 50 percent of the new electricity access as this represents the least cost solution to connect about 450 million (41 percent of the population) people on the continent.

Figure 4: Technology use and capital expenditure to attain universal access by 2030



The relevance of mini grids in addressing the access challenge is spurred on by the increasing competitiveness of solar and battery storage, not forgetting improved energy efficiency of appliances. Key markets for mini-grid development include Ethiopia, Nigeria, Tanzania, Uganda and Kenya.

Undoubtedly, the post-COVID economic environment globally further complicates the access to finance challenge. Owing to the heightened importance that the COVID-19 pandemic has put on access to affordable and reliable energy, short to medium term recovery planning by most governments is highly likely to prioritise expanding access to areas the grid is yet to reach to reduce vulnerability and improve resilience. For example, Nigeria's government has detailed in its 2020 Economic Sustainability Plan a solar power strategy that it seeks to install five (5) million solar-home systems and mini-grids for communities and health clinics. The recovery plan also states a commitment to support private installers with low-cost financing and a requirement for solar equipment manufacturers to create additional job opportunities by setting up production facilities in Nigeria.

Emerging disruptor technologies

Technology will continue to play an increasingly important role in the African

energy sector. Digital technologies like the internet of things (IoT), artificial intelligence (AI), big data, and blockchain are being developed globally to meet specific demands imposed by an increasingly complex future power system. These digital technologies are expected to affect how power is consumed and supplied globally, including in Africa. The granularity of information available to organisations such as utilities will increasingly be used in fashioning how goods and services are produced and marketed to consumers. For the power sector in Africa, these technologies have the potential to enhance the economics of off-grid solutions, inform infrastructure planning and support grid operations.

In Africa, mobile connectivity, coupled with the use of mobile money, has created opportunities to improve electricity access by leveraging mobile IoT. At present, providers of electricity via solar home systems and microgrids leverage mobile IoT for accurate metering and billing of consumers as well as collecting data about power supply and demand. The use of mobile IoT is likely to grow as millions gain access to electricity towards 2030. Although many African countries acknowledge the importance of modernising the grid and improving system flexibility through smart grids, the high costs and degree of market development will be a barrier in the next decade.

Power Sector Investment Outlook

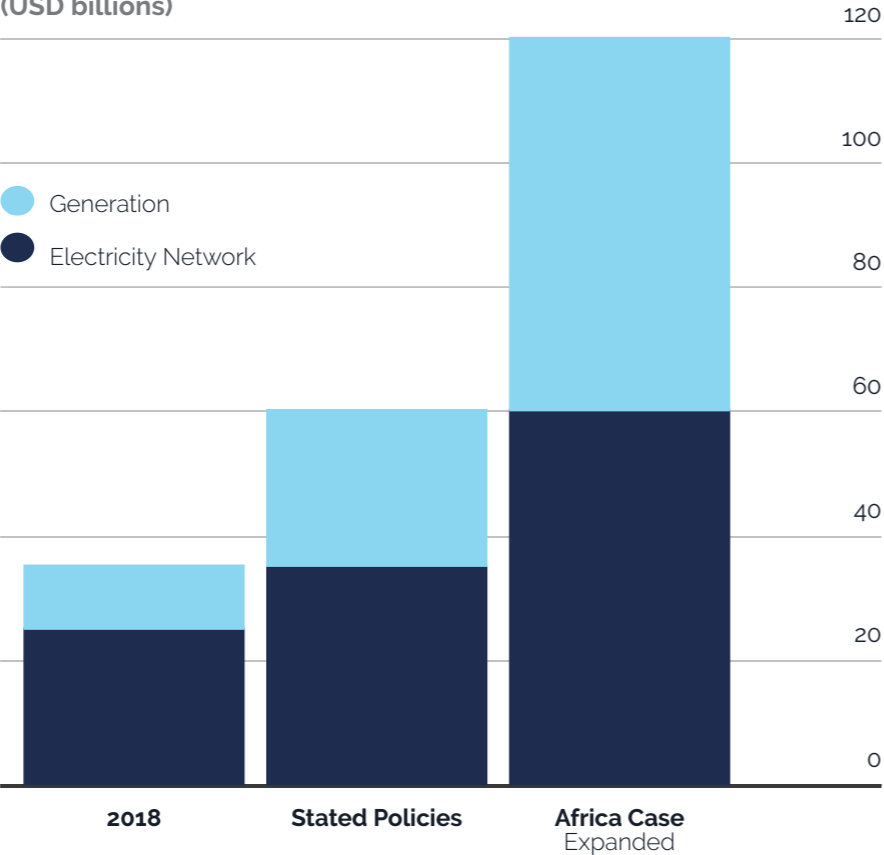
The EIA estimates indicate that annual energy investment needs in Africa will have to increase by 100 percent from the current USD 60 billion per annum (1.8 percent of the continents GDP) to USD 120 billion (2.4 percent of GDP) in order to attain universal access (Dashboard 3). This will go into both expanding generation capacity and upgrading the electricity network. This is corroborated by the IEA estimates, which indicate that annual power supply investments would need to increase to USD 120 billion per year until 2040.

COVID-19 has negatively impacted African economies across the board; this includes both commodities exporting ones and largely diversified ones. One impact of COVID-19 is the decline in electricity demand due to decreased industrial activity. Additional responses undertaken to mitigate the impact of the pandemic on the continent include the provision of free electricity, waiver of bill payments, and VAT exemptions on electricity bills, among others.

However, the Chamber assesses these measures to be short termist, and the focus should be on the economic stimulus that would propel the investment in the power sector. Indicators such as the reopening of several economies point to the fact that investment flows are highly likely to pick up in 2021 driven by the fundamental need to electrify the continent which will, in turn, deepen energy access, and reduce poverty and inequality.

African countries have a historical opportunity to coordinate their post-pan-

Africa annual power investment needs (USD billions)



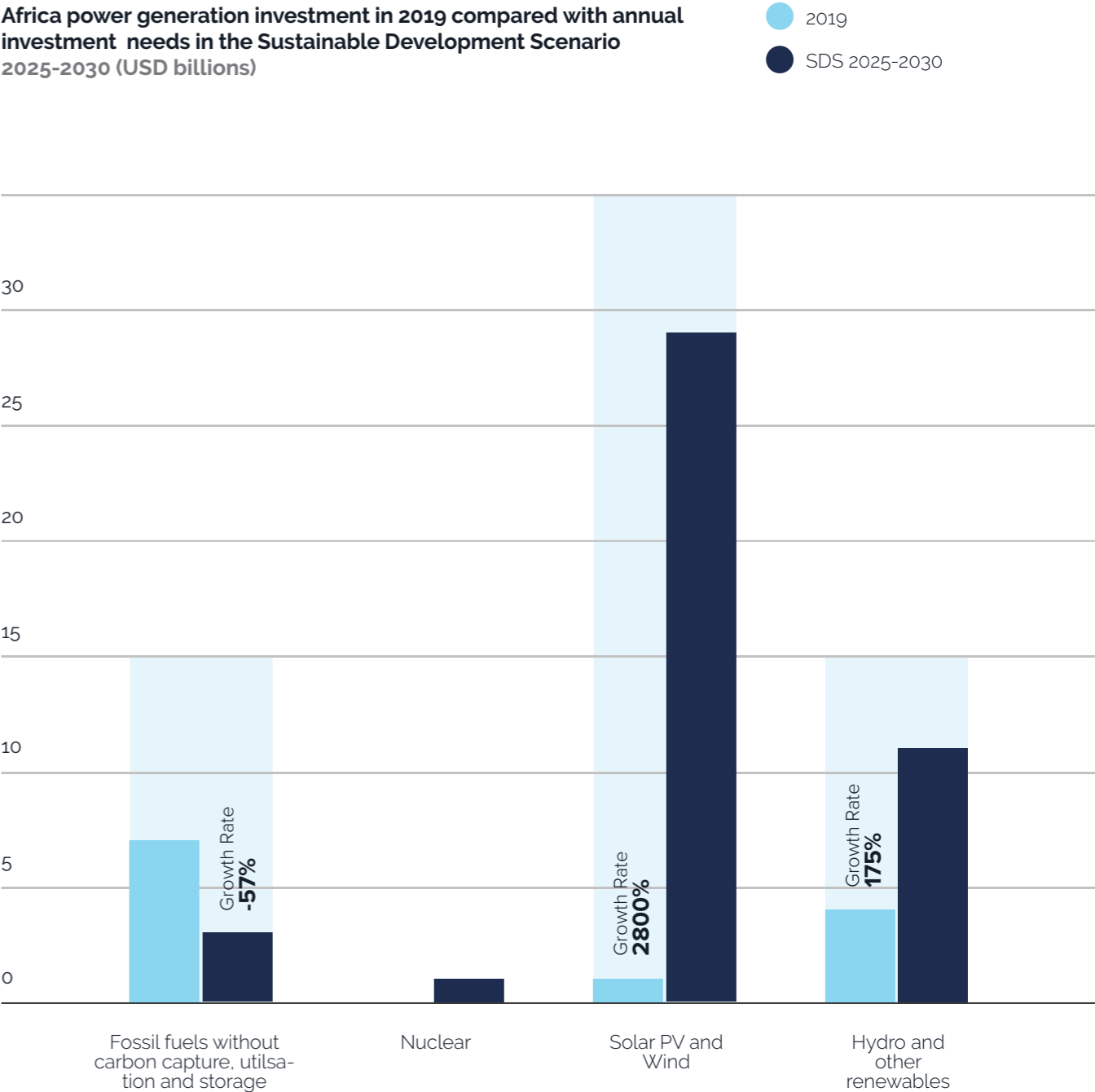
Data Source: EIA 2018

demic recovery initiatives to increase their efforts in achieving SDG 7 goals. This implies building more robust and efficient energy infrastructure systems as well as implementing decentralised energy solutions using both natural gas and renewable energy sources. Natural gas has the ability not only to meet baseload capacity needs of the region but also as a complement to hydro in the short term. However, because the cost advantage of gas as a natural baseload for power generation depends entirely on the location

of gas power generation and its distance from gas supplies, investments in pipeline infrastructure are very much needed.

Some of the key measures to mitigate the impact of COVID-19 and to initiate a robust recovery plan include prioritising the development of natural gas and renewable energy, the adoption of realistic market driven and cost reflective tariffs, and the leveraging the AfCTA so the private sector can invest in the regional power projects and pools.

Africa power generation investment in 2019 compared with annual investment needs in the Sustainable Development Scenario 2025-2030 (USD billions)



Data Source: IEA 2019



**African
Energy
Chamber**

www.energychamber.org

At the African Energy Chamber, we believe that deal-making is all about relationships. The Chamber boasts an unmatched capability to bring together key stakeholders in industry, government and with a clear focus on forging new ground in africa's energy sector. in this feature, we profile some of the key individuals and organisations that we expect to see at the forefront of our industry in 2021.



1.

NICOLAS TERRAZ

President for Africa
Total Exploration & production

In charge of Total's upstream portfolio across Africa, Nicolas Terraz is expected to deliver on a lot of historic firsts for the continent, including bringing Uganda's Tilenga project to financial close and to first oil, building a 1,443km pipeline to Tanzania, and ensuring that the continent's biggest ongoing LNG project gets executed on time and on budget in Mozambique. Meanwhile, Total is anticipated to deliver on three high-impact wells in South Africa, Namibia and Angola. Will he be able to face current headwinds and deliver on expectations in each of these frontier markets?



**African
Energy
Chamber**

25

**Movers
& Shakers** to Watch

2.**MUHAMMADU
BUHARI**President
Federal
Republic
of Nigeria

When he assented to the Deep Off-shore and Inland Basin Production Sharing Contract (Amendment) Act in late 2019, President Muhammadu Buhari put in jeopardy billions of dollars of investments into Nigerian deep water fields. However, strong political will to support the Nigerian economic recovery could translate in 2021 into the passing, adoption and signing of the long-awaited Petroleum Industry Bill (PIB). As a result, President Buhari's ability to rally stakeholders and push for much-needed reforms could actually inaugurate the start of a new era for Nigeria's energy industry in 2021.

3.**YURY
SENTURYIN**
Secretary-General
GECF

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4.**GUIDO
BRUSCO**
Upstream Director
Eni

Eni's former Executive Vice President for Sub-Saharan Africa now manages the global upstream portfolio of the Italian major and will have strategic decisions to make on rationalising the company's upstream spend. From Egypt all the way down to Angola, Eni is one of Africa's major international player and sits on strategic fields and acreages from Zohr in Egypt, OCTP in Ghana, Area 4 in Mozambique, onshore gas-rich licenses in Nigeria and Block 15/06 in Angola. As the company enters the global energy transition, the impact the move has on its upstream developments in Africa could shape the continent's E&P industry for years.

8.**JOÃO
LOURENÇO**
President
Republic
of Angola

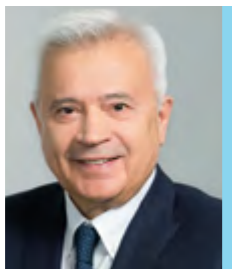
President João Lourenço's direct involvement in reforming and reviving Angola's oil & gas sector is bearing fruits. His presidential decrees have made lots of difference over the past three years for operators and investors, and provided the right enabling environment to make Angola a competitive African jurisdiction to invest in. As Angola recovers from the Covid-19 pandemic and yet another economic crisis, President Lourenço's leadership is more important than ever to further support sector recovery and boost local content development.

9.**ABBAS
MAHAMAT TOLLI**
Governor
Bank of the
Central African
States (BEAC)

Abbas Mahamat Tolli oversees the monetary policy over Central African states, including Cameroon, Central African Republic, Congo-Brazzaville, Gabon, Equatorial Guinea and Chad. All these nations are heavily dependent on oil & gas to fuel economic recovery post-Covid19. However, strict foreign exchange regulations imposed by the Bank of the Central African States (BEAC) have severely and negatively impacted the attractiveness of these countries for foreign investment. Will Abbas Mahamat Tolli open up to public and private sector calls to reform the region's foreign exchange policy and bring back much-needed investors in the region?

10.**MELE KOLO
KYARI**
Group Managing
Director,
Nigerian National
Petroleum
Corporation (NNPC)

At the head of one of Africa's biggest national oil companies, Mele Kolo Kyari is expected to remain one of the industry's leading figures in 2021 and beyond. As the Nigerian National Petroleum Corporation (NNPC) embarks on several strategic programmes and projects to boost refining capacity, cut upstream operational costs, develop energy infrastructure and unlock Nigeria's gas potential, Mele Kolo Kyari's actions and decisions can profoundly impact the short and medium-term outlook for Africa's biggest oil & gas producing country.

5.**VAGIT
ALEKPEROV**
President
and CEO
PJSC LUKOIL

LUKOIL is one of Russia's most international energy companies with investments all across the world and a growing investment portfolio in Africa. As Russia commits to grow its presence across the continent, LUKOIL could be a next major investor for Africa's upstream and infrastructure industries. The company is already participating in key projects such as Cameroon's Etinde development, and its recent acquisition of Cairn Energy's stake in Senegal's Sangomar oil project, though unsuccessful, showed a strong appetite for investing in African hydrocarbons. Where will Vagit Alekperov invest next?

6.**FÉLIX ANTOINE
TSHISEKEDI
TSHILOMBO**
President
Democratic
Republic of Congo

In charge of Total's upstream portfolio across Africa, Nicolas Terraz is expected to deliver on a lot of historic firsts for the continent, including bringing Uganda's Tilenga project to financial close and to first oil, building a 1,443km pipeline to Tanzania, and ensuring that the continent's biggest ongoing LNG project gets executed on time and on budget in Mozambique. Meanwhile, Total is anticipated to deliver on three high-impact wells in South Africa, Namibia and Angola. Will he be able to face current headwinds and deliver on expectations in each of these frontier markets?

7.**TONY
ATTAH**
Managing
Director/CEO
Nigeria LNG

As the head of Nigeria LNG, Tony Attah is currently piloting one of Africa's most strategic liquefied natural gas (LNG) projects, NLNGSevenPlus. Its plans notably include a \$6.5bn project consisting of a new 4.2 mtpa Train 7 and the debottlenecking of existing trains to add a further 3.4 mtpa of LNG liquefaction and export capacity to sub-Saharan Africa's biggest LNG export terminal. The execution of the project has the power to support Nigeria's economic recovery and local content development, while further positioning NLNG as an African gas success story.

11.**HRH PRINCE
ABDUL AZIZ BIN
SALMAN**
Minister of Energy
Head of OPEC
Delegation

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12.**BENOÎT DE LA
FOUCHARDIÈRE**
CEO
Perenco

While relatively discrete, the French-British independent Perenco pilots strategic assets and projects across Central Africa. More importantly, the company's focus on strategic gas developments in countries such as Cameroon, Gabon or the Democratic Republic of Congo could just be what the region need to diversify away from oil and develop a robust natural gas value chain. Benoît de la Fouchardière's leadership will thus have long-term implications for the gas and LNG industry of Central Africa: can Perenco become the investor the region needs to unlock its natural gas potential?

13.**REBECCA MIANO**
CEO
Kenya Electricity
Generating
Company PLC
(KenGen)

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14.**DAMILOLA OGUNBIYI**

CEO and Special Representative of the UN Secretary-General for Sustainable Energy for All and Co-Chair of UN-Energy



As a strong African energy advocate, Damilola Ogunbiyi has become a key figure of the global fight against energy poverty. Her ability to bridge gaps, form new partnerships and scale up private sector involvement around key issues such as energy access, off-grid renewables and LPG promotion could go a long way in supporting Africans' access to clean and affordable energy. As CEO and Special Representative of the UN Secretary-General for Sustainable Energy for All and Co-Chair of UN-Energy, Damilola's work has the power to transform the way Africans access and consume energy.

15.**HEATHER K. LANIGAN**

Regional Director, sub-Saharan Africa, U.S. Trade and Development Agency



At the head of the USDA's Africa operations, Heather is piloting several US investments supporting key gas and energy projects on the continent, especially in the areas of midstream gas infrastructure and gas-to-power. As the continent further puts natural gas at the forefront of industrialisation and economic growth priorities, Heather can become a pillar of a renewed and successful US-African energy cooperation that supports capital and technology transfers across Africa's natural gas value chain.

16.**HU XIAO LIAN**Chairwoman
The Export-Import Bank of China

China's EXIM Bank is one of the most significant investors in African energy infrastructure projects, especially when it comes to the financing of power generation facilities. In a post Covid-19 era, what strategic direction and guidance will Hu give the bank in Africa? Several massive African energy projects are already in negotiations with the bank across energy sources, and their sanctioning could significantly contribute to increasing power generation capacities across the continent and further support industrialisation.

20.**VIBHUTI JAIN**Regional Director for Africa
U.S. International Development Finance Corporation

As the United States increases its investment in Africa, key government agencies such as the U.S. International Development Finance Corporation (DFC) will be playing a key role in securing the capital and investment Africa needs to expand its energy infrastructure. Set up to replace the Overseas Private Investment Corporation (OPIC), the DFC has launched a regional team in Africa, headed by Vibhuti Jain. The DFC is a powerful partner for Africa to have as it seeks to attract the best capital and technology partners it needs to fight energy poverty. Will be the DFC's future strategic investments in Africa successfully address the continent's energy needs?

21.**ONYECHE TIFASE**Managing Director and CEO
Siemens Nigeria

To find a long-lasting solution to its never-ending power crisis, Nigeria has formed in 2018 the Presidential Power Initiative in partnership with Germany, and to be executed by Siemens. As the programme kicks off, Siemens' ability to execute it will now determine the future of investments into Nigeria's power industry. Heading Siemens' operations in Nigeria, Onyeché Tifase is now in charge of rolling out an ambitious project to upgrade the country's transmission and distribution systems, increasing the overall national system's capacity from 5 to 7 GW first, before ramping up to 11 GW and ultimately 25 GW.

22.**FOUMAKOYE GADO**Minister of Petroleum
Niger

Niger remains one of Africa's most attractive onshore energy frontiers, significantly de-risked by previous exploration programmes carried out by Chinese operators. The ongoing construction of the Niger-Benin oil export pipeline will be opening up a new route to monetize such reserves and could result in a profound transformation of Niger's economy by as soon as 2025. Can Minister Gado manage the execution of the pipeline and deliver on promises of an oil boom?

17.**AMINA BENKHADRA**Director General
National Office of Hydrocarbons and Mines (ONHYM)

Morocco is at strategic cross roads as it massively increases renewable energy generation while securing domestic gas to become self-sufficient and develop its first ever liquefied natural gas (LNG) export and import projects. As the Director General of the National Office of Hydrocarbons and Mines (ONHYM), Amina Benkhadra is spearheading the country's efforts to reach self sufficiency in gas and decrease the country's overall carbon footprint. Her guidance and support will tell if Morocco is able to succeed in its journey to build a vibrant domestic gas industry.

18.**KHADIIJA AMOAH**Country Director
Aker Energy Ghana

In Ghana, Khadija Amoah is piloting one of the country's most strategic upstream ventures, the development of the Pecan field. Discovered in the early 2010s by American independent Hess Corporation, Pecan is now operated by Aker Energy and will be Ghana's next major offshore oil & gas project, with an expected peak of 110,000 bopd. With Covid-19 putting initial development plans in jeopardy, can Khadija work on a new solution for the field's development and carry it through to final investment decision (FID)?

19.**MARY GORETTI KITUTU**Minister of Energy and Mineral Development,
Uganda

As Minister of Energy and Mineral Development, Mary Goretti Kitutu is directing Uganda's energy sector at a crucial time for the country. After several years of delay, the Tilenga oil project operated by Total, and the Kingfisher one operated by CNOOC, are set to move forward and produce first oil before 2030. Both are set to be developed along with a 60,000 bpd refinery and a 1,443km export pipeline to Tanzania. With multi-billion dollar investments taking shape in Uganda, how will she manage to support the execution of multi-billion dollars projects while ensuring they benefits to the local economy?

23.**BERNARD LOONEY**

CEO, BP



BP's new charismatic CEO has made it clear he intends to take BP into the global energy transition by setting an ambition for net zero by 2050. This notably includes achieving net zero on carbon in BP's oil and gas production on an absolute basis by 2050 or sooner, a 50% cut in the carbon intensity of products BP sells by 2050 or sooner, and an increase in the company's proportion of investment into non-oil and gas businesses over time. Can Bernard Looney leverage on the organisation's new energy transition strategy to reinvent itself in Africa?

24.**GWEDE MANTASHE**Minister of Mineral and Energy Resources
South Africa

Hit hard by the Covid-19 pandemic, South Africa's economy is in desperate need of a strong recovery agenda backed up by private sector investment. Its energy industry has been identified as a key pillar of the country's economic recovery moving forward, and Minister Gwede Mantashe will be expected to pilot several strategic programmes to boost investment and further diversity the country's energy mix. Chief amongst them is the launch and execution of the long-delayed fifth window of the Renewable Energy Independent Power Producer Procurement (REIPPP) programme. Can he carry it through to aid economic recovery while supporting upcoming upstream and midstream gas developments in the country?

25.**ERNESTO MAX ELIAS TONELA**Minister of Energy and Mineral Resources,
Mozambique

As Mozambique prepares to ship its first cargoes of liquefied natural gas (LNG) to global markets in a few years, the country's Minister of Energy and Mineral Resources, Ernesto Elias Tonela, has strategic decisions ahead of him. Between preparing the domestic market for a gas revolution and ensuring local content development and jobs creation don't get lost in the process, he oversees Mozambique's energy sector at a crucial time in the country's history. His leadership and guidance will be central to turning Mozambique's resources into economic growth.



African Energy Chamber

**For more information on the
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