NATURAL GAS IN AFRICA AMID A GLOBAL LOW-CARBON ENERGY TRANSITION

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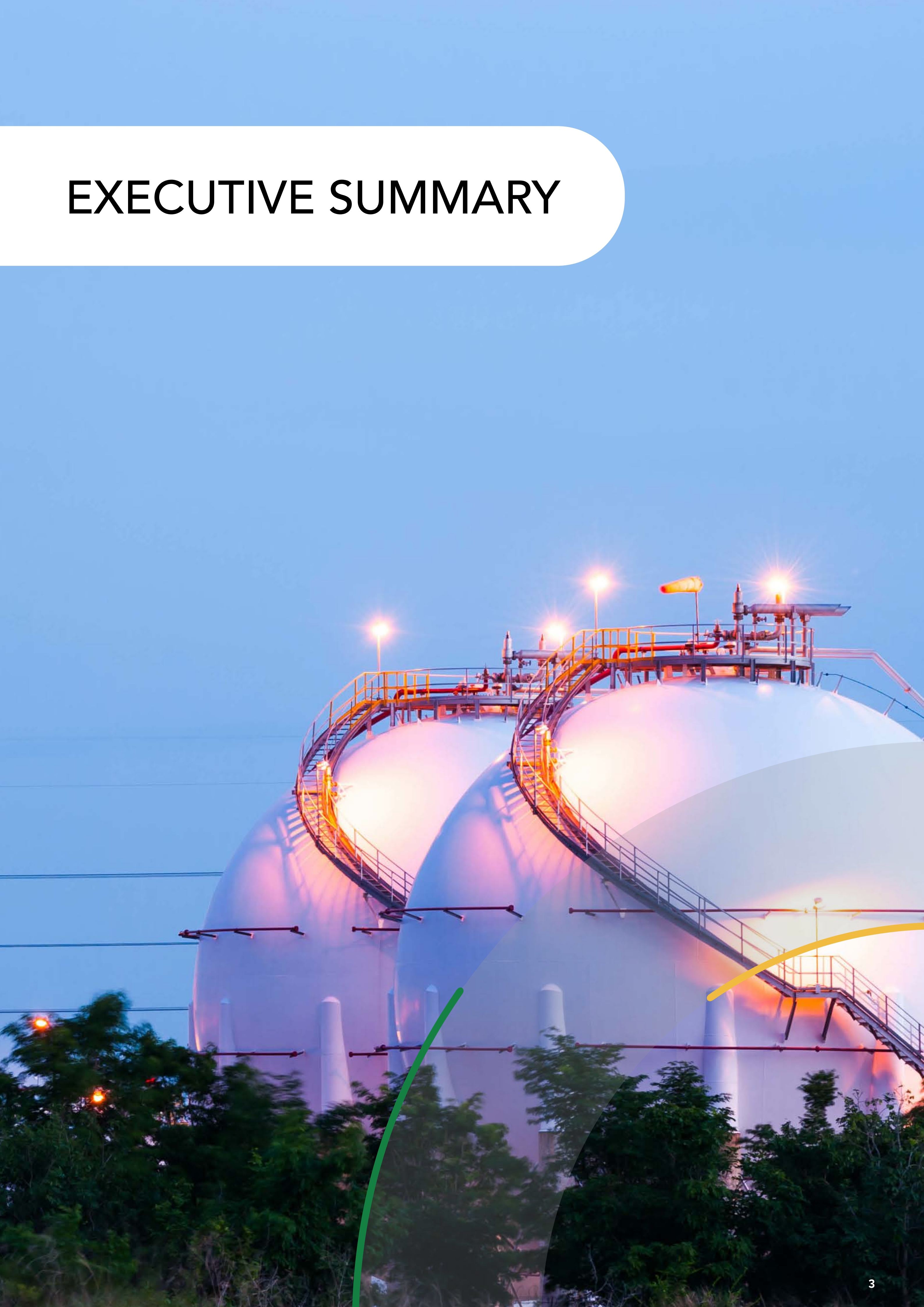
EXECUTIVE SUMMARY



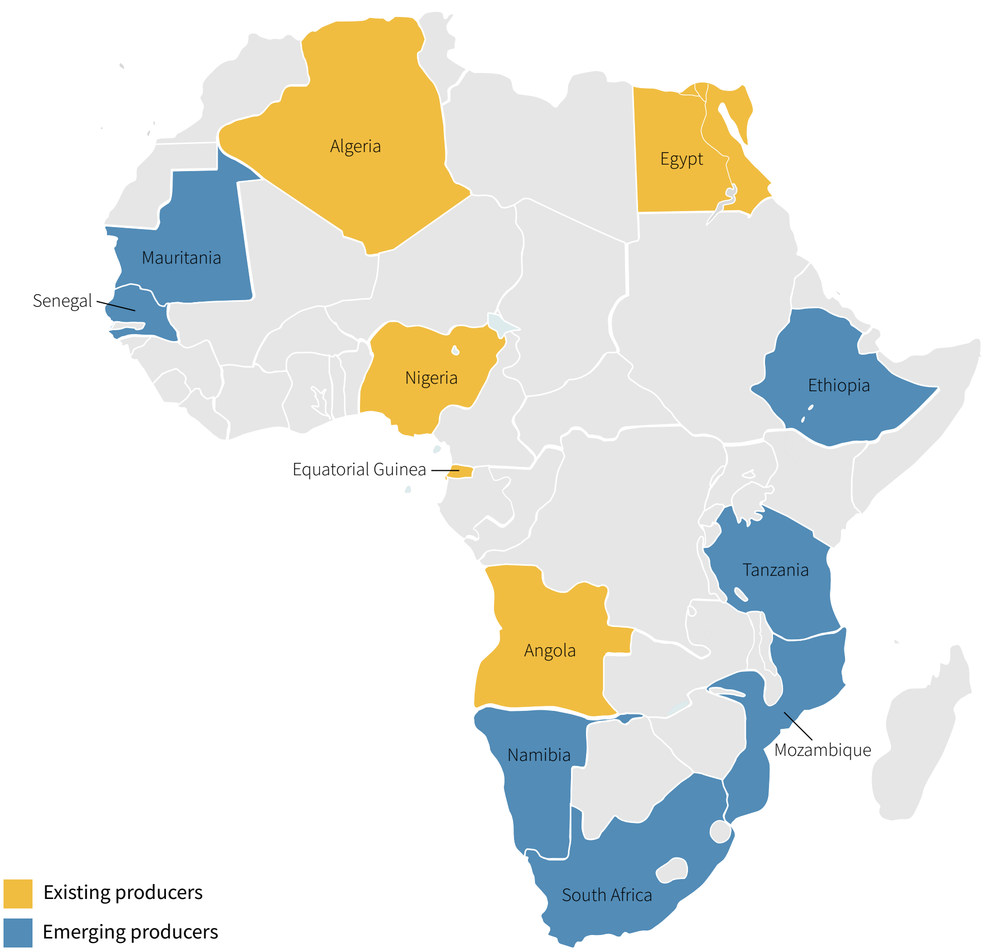
Countries in Africa could become increasingly important players in the world's natural gas markets, especially in the global liquified natural gas (LNG) trade. In the last decade, there have been major natural gas resource discoveries across the continent, adding to the reserves already held by the large incumbent producers in West Africa and North Africa.

The African Climate Foundation commissioned Willis Towers Watson (WTW) to help to develop a body of work around natural gas on the African continent, particularly regarding the factors, incentives, and transitions that will shape the future of gas in Africa. This study, which is the outcome of that work, explores key themes and issues around natural gas development on the continent, specifically in relation to the impacts of global climate transitions on the viability of gas investments (Figure E1).

The report splits African gas producers into two archetypes – existing and emerging – defined by the factors that help shape the predominant challenges these nations face in developing their natural gas endowments. These include the maturity of respective gas markets (whether the country is an existing major producer or new emerging producer) and the degree to which each country is facing challenges with meeting demand from a growing domestic base or maintaining natural gas export potential.

The analysis quantifies the economic value of natural gas production in each country in a range of global climate transition scenarios, each of which represents different speeds of potential decarbonisation globally. These range from "No Holds Barred" (NHB) as the slowest decarbonisation trajectory, to a global 1.5°C "Net Zero Emissions" (NZE) scenario as the fastest decarbonisation trajectory. This report summarises the current gas landscape in Africa across ten of the 12 countries and explores their domestic challenges. It also provides a high-level assessment of climate transition risk on any LNG-related export industry. A second report, published alongside this one, develops a deeper analysis of how climate transition risk could affect Mozambique and Tanzania's nascent LNG export industries specifically.

Figure E1: Scope of analysis



KEY FINDINGS

- **All African gas producers face material exposure to “external” climate transition risk**

  In scenarios with faster global decarbonisation, lower natural gas demand and lower long-term prices will reduce the value of existing African natural gas industries and damage the economic viability of future LNG projects. The economic viability of gas resources targeted at domestic demand could also be impacted, depending on the requirements of investors in those resources. These risks from structural changes occurring at the global level are termed “external” climate transition risk.

- **Domestic demand is unlikely to be a viable anchor for investments in new gas resources as domestic gas prices are often significantly below LNG prices**

  For investors in new gas resources, growing domestic or regional demand as a hedge against an uncertain outlook for exports is unlikely to be viable, as gas prices in African markets tend to be lower than gas prices in increasingly globalised LNG markets. African natural gas prices are often capped or regulated to encourage growth in gas uptake or because of the low ability to pay in countries where natural gas is used. This may mean that revenues from servicing domestic or regional demand are unlikely to be a sustainable substitute for dollar-denominated export revenues.

- **Growing domestic markets may lock in additional domestic transition risk**

  Investments in the upstream and midstream infrastructure required to enable growth in domestic or regional demand will add further transition risk to African economies, this time in relation to their own transitions. Increased competition from low-carbon alternatives and rising long-run gas prices are likely to lead to gas becoming uncompetitive before the end of those infrastructure assets’ lives.

- **Emerging producers exhibit lower starting levels of economic resilience**

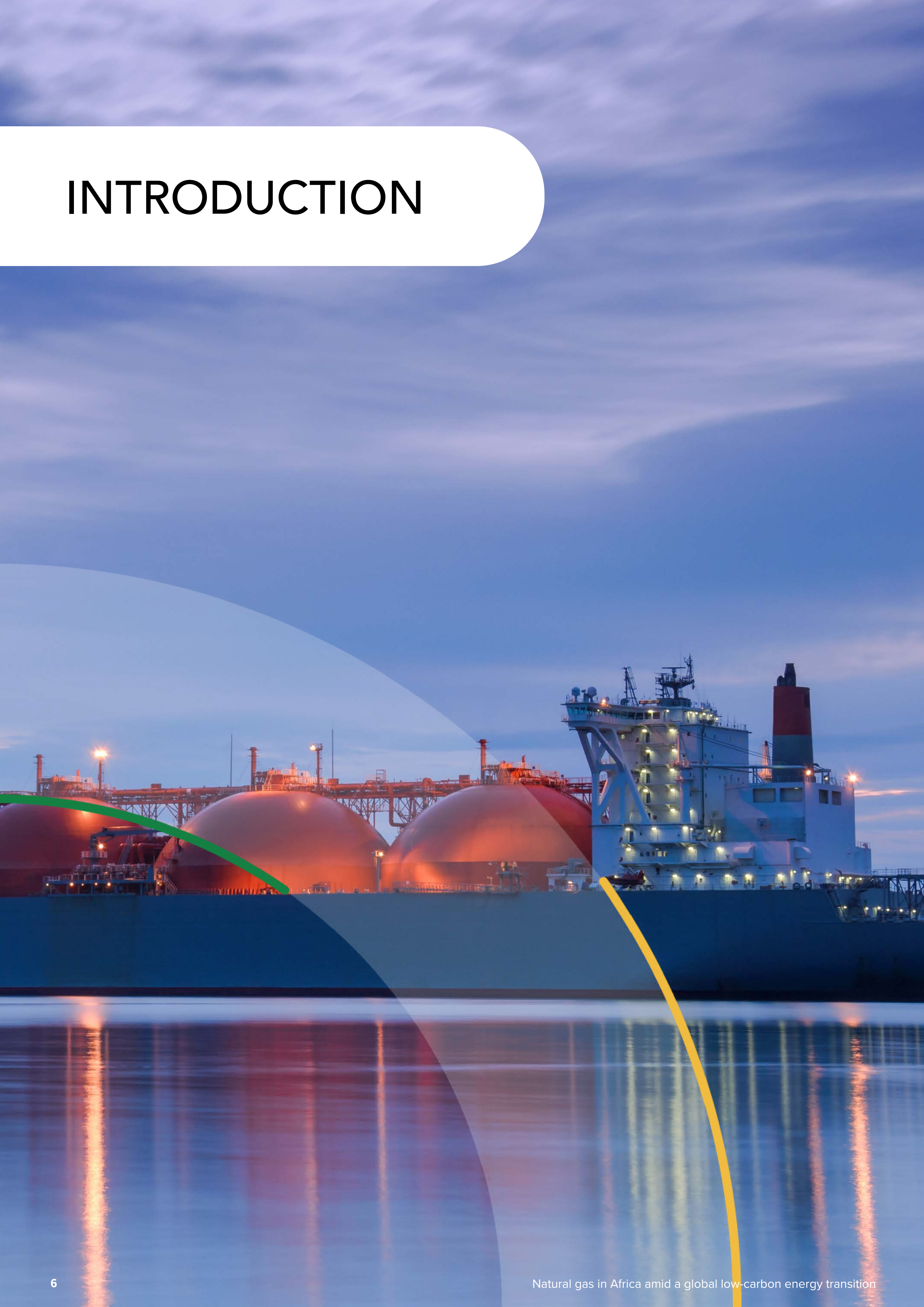
  Many future or “emerging” African natural gas producers (other than South Africa and Namibia) are relatively less developed than existing producers and have weaker sovereign credit ratings, with public finances less suited to absorbing the impacts of climate risk (physical or transition).[1] These countries also face more transition risk than existing producers – this is because investments in developing new resources are generally subject to more downside risk than those in resource bases already in production. Payback on investments on long-life infrastructure for new resources may not be complete before the global shift away from gas to meet the Paris Agreement targets begins.

- **The war in Ukraine and its impact on gas global markets could potentially expose producers to many more severe long-term risks**

  The war in Ukraine has caused global LNG prices to shoot upwards. If investors and host governments fast track new developments with the aim to capture short-term gains (from higher short-term global LNG prices), they expose themselves potentially to many more severe long-term risks in the process, because of the much bigger gap between artificially elevated valuations today and valuations in a 1.5°C scenario. Given the limited capacity of countries (especially emerging producers) to bear economic and financial risk, it is now even more important to assess transition risks before investment decisions are made.

[1] As indicated by Moody’s sovereign credit ratings in Figure 4.

INTRODUCTION



The global gas industry

The long-term prospects for natural gas demand have shifted significantly in recent years. Once widely seen as a "transition fuel" in the power sector, expected future growth in global gas demand has moderated over the last decade as prices for importing countries have risen. This has made gas increasingly uncompetitive in power generation compared with internationally traded coal, as well as wind and solar power (whose costs have fallen dramatically).[2] Gas' environmental credentials versus coal's have also come under scrutiny with evidence to suggest that fugitive emissions from gas wells and methane leaks in natural gas infrastructure are much higher than previously believed.[3]

Away from power generation, gas demand has grown within many emerging markets as a cleaner alternative (in the sense of air pollution) to oil in transport and biomass in residential heating and cooking. The use of natural gas also continues to grow in the chemical industry, particularly as a feedstock for the production of ammonia, itself a key component of nitrogen fertilisers.

The structure of natural gas markets has also been changing. Over the last decade, the share of natural gas transported as LNG has grown as the market has globalised, with LNG-regasification capacity growing fast in countries without access to large-scale pipeline networks and those with declining domestic supplies. A range of new sources of supply has also entered the market (Figure 1). Notable here is the United States, which first exported LNG in 2016 and in 2022 became the largest supplier of LNG globally, following an increase in demand from Europe due to the war in Ukraine.

Box 1: Gas types, transportation, and use

Two broad types of gas exist: natural gas (NG), a fossil fuel that is extracted from under the land or sea (and is the primary focus of this report), and petroleum gas (PG) that is produced as a by-product of crude oil refining and during extraction of natural gas.

Natural gas transported by ship, road, or rail is placed under very low temperatures and high pressures to liquify it into liquefied natural gas (LNG). Natural gas transported by pipeline is typically transported at higher temperatures but still under pressure, in the form of compressed natural gas (CNG). Liquefaction can either take place on land or, alternatively, when gas is extracted from the ocean bed, it can be liquefied in an installation known as a floating liquefied natural gas (FLNG) unit. Installations known as floating storage and regasification units (FSRUs) are often then used to convert LNG that has arrived at a port into CNG to feed into a pipeline to transport it to the location where it will be used.

Petroleum gas is usually distributed as a liquid called liquefied petroleum gas or LPG.

Both types of gas are used in transport, household heating, and cooking applications. LNG is also widely used as a feedstock in industry and for power generation.

Gas in Africa

Countries in Africa could become increasingly important players in the world's natural gas market, especially in the global LNG trade (Figure 2). In the last decade, there have been major natural gas resource discoveries across the continent, adding to the reserves already held by the large incumbent producers in West and North Africa.

Apart from Namibia and South Africa[4], existing producers largely perform better in terms of economic development and financial resilience, as indicated by GDP per capita and sovereign credit rating (Figure 4). However, these indicators do not present a complete picture of development and resilience, with some resource-rich emerging economies experiencing lower levels of economic and political stability than other countries with more limited resources. This is attributed to factors broadly described as the "resource curse" or "Dutch disease".[5]

[2] "Scale-up of Solar and Wind Put Existing Coal, Gas at Risk," BloombergNEF, blogpost, April 28, 2020.
[3] Natural gas emissions.
[4] South Africa, despite not being a large player in natural gas relative to other countries in the continent, has been a significant commodity exporter across key market such as coal, iron, and precious metals and minerals.
[5] "The Resource Curse," National Resource Governance Institute, March 2015.

Figure 1: LNG exports from 2000-2020 by major exporting country

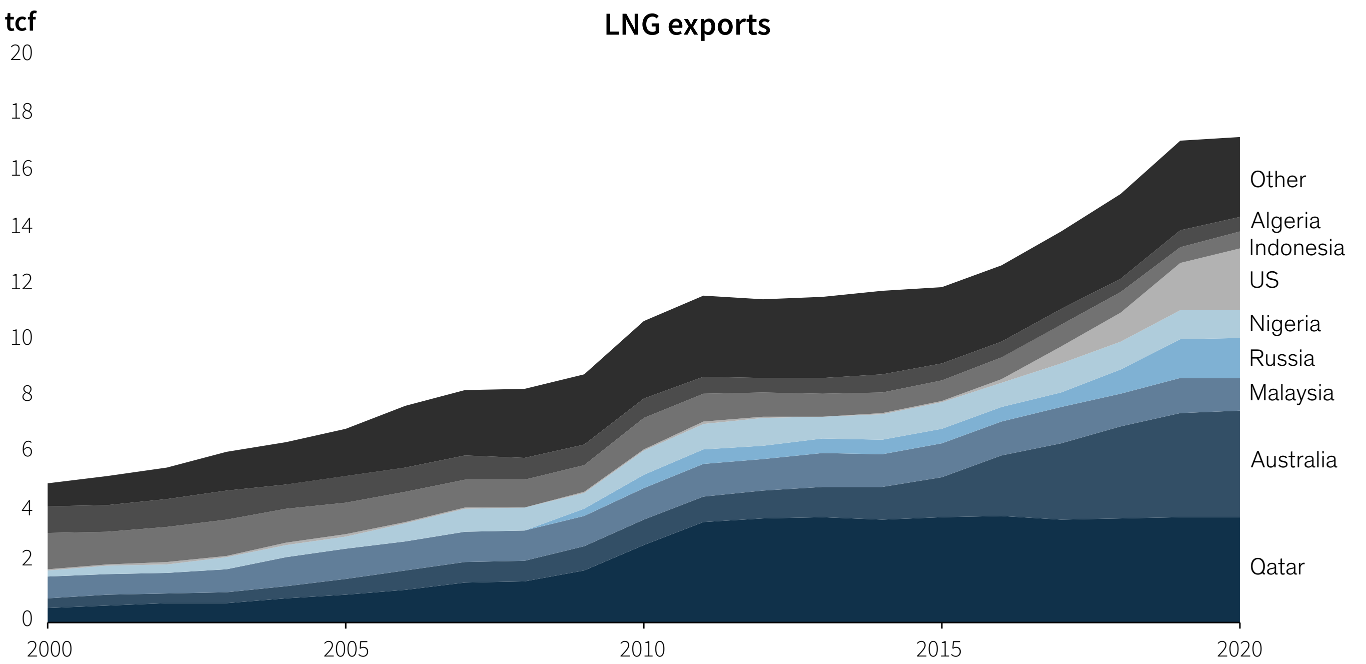
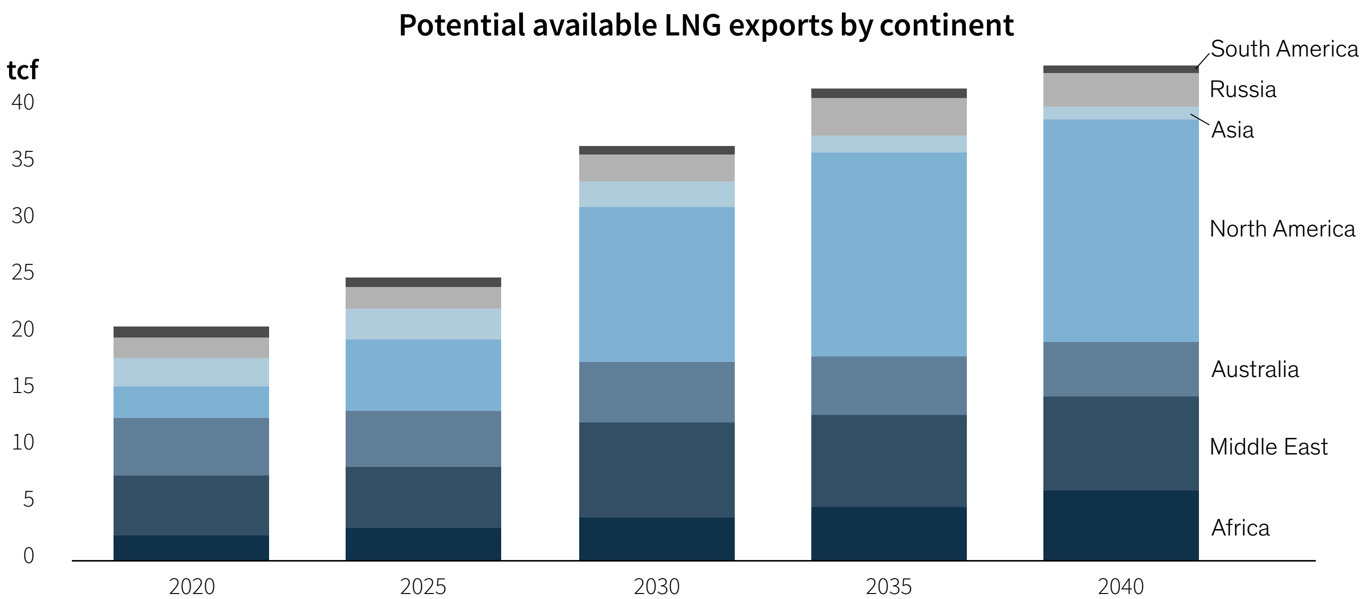
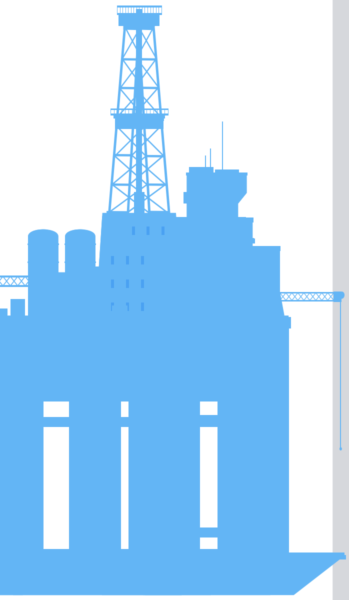


Figure 2: Potential LNG exports by continent[1]



[1]The volumes represent the potential supply that could enter the supply curve. Detailed modelling across a range of respective demand scenarios would be required to understand how much of this supply would be viable.

There are effectively two options for African countries to utilise their resources, if developed at all. The first is to use natural gas "endowments" to build export-orientated industries that would help supply growing gas demand across the world, especially in Asia. Proponents of such an option point to the potential flow of foreign direct investment (FDI) and a steady stream of foreign exchange and government fiscal revenues that could be used to fund development spending. This could be especially transformative in countries with limited or unreliable access to global capital markets, such as Mozambique. The second option is to leverage large domestic resource finds to help bridge the electricity access gap in many parts of sub-Saharan Africa, or to help build domestic gas-based industrial value chains, especially in the fertiliser industry – this would reduce import dependency on products and commodities that are usually some of the largest contributors to trade deficits. In reality, these options are not mutually exclusive and the ultimate balance, if developments are pursued, will be determined by a series of domestic and external factors facing each country, examined across this report.



Box 2: Dynamics of gas pricing and implications for its role as a transition fuel

LNG has traditionally been traded globally in long-term supply contracts (20 to 25 years) with many fixed-price contracts being linked to or "indexed" against the oil price. In recent years, however, growing volumes of gas have been traded on a spot basis, which has increased price volatility (Figure 3). There has also been a shift away from indexing against oil toward gas-on-gas (GOG) linked pricing.

The price paid for LNG often sets the marginal gas price in importing countries, with exporters receiving the price paid by the importer after subtracting shipping costs. As LNG demand grows over time, gas prices are likely to rise to cover the cost of building new LNG infrastructure. Furthermore, LNG prices have recently been impacted by the war in Ukraine and sanctions on Russia to a much greater degree than many other commodities. This is principally because of the importance of Russia as the largest global producer of natural gas, as well as the central role that Russia's key gas customers (within Europe and East Asia) play in global LNG consumption.

Rising gas prices, both in the short and longer term, could limit its value as a transition fuel, including in many industrial sectors such as hydrogen production and steel production, as the cost of low-carbon alternatives will likely continue to fall. This cost reduction will be supported by falling renewable energy prices and economies of scale in the manufacture of low-emission technologies, such as electrolysers.

Figure 3: LNG prices represented by TTF spot prices Europe

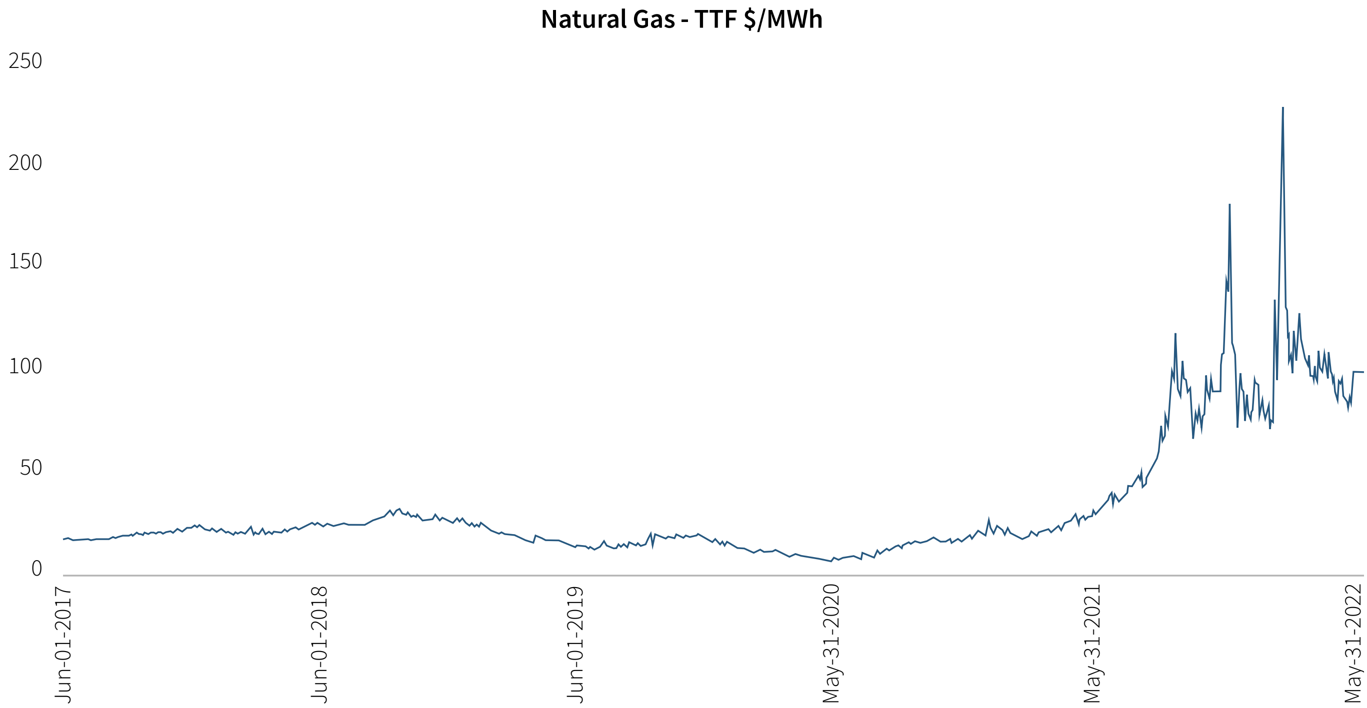
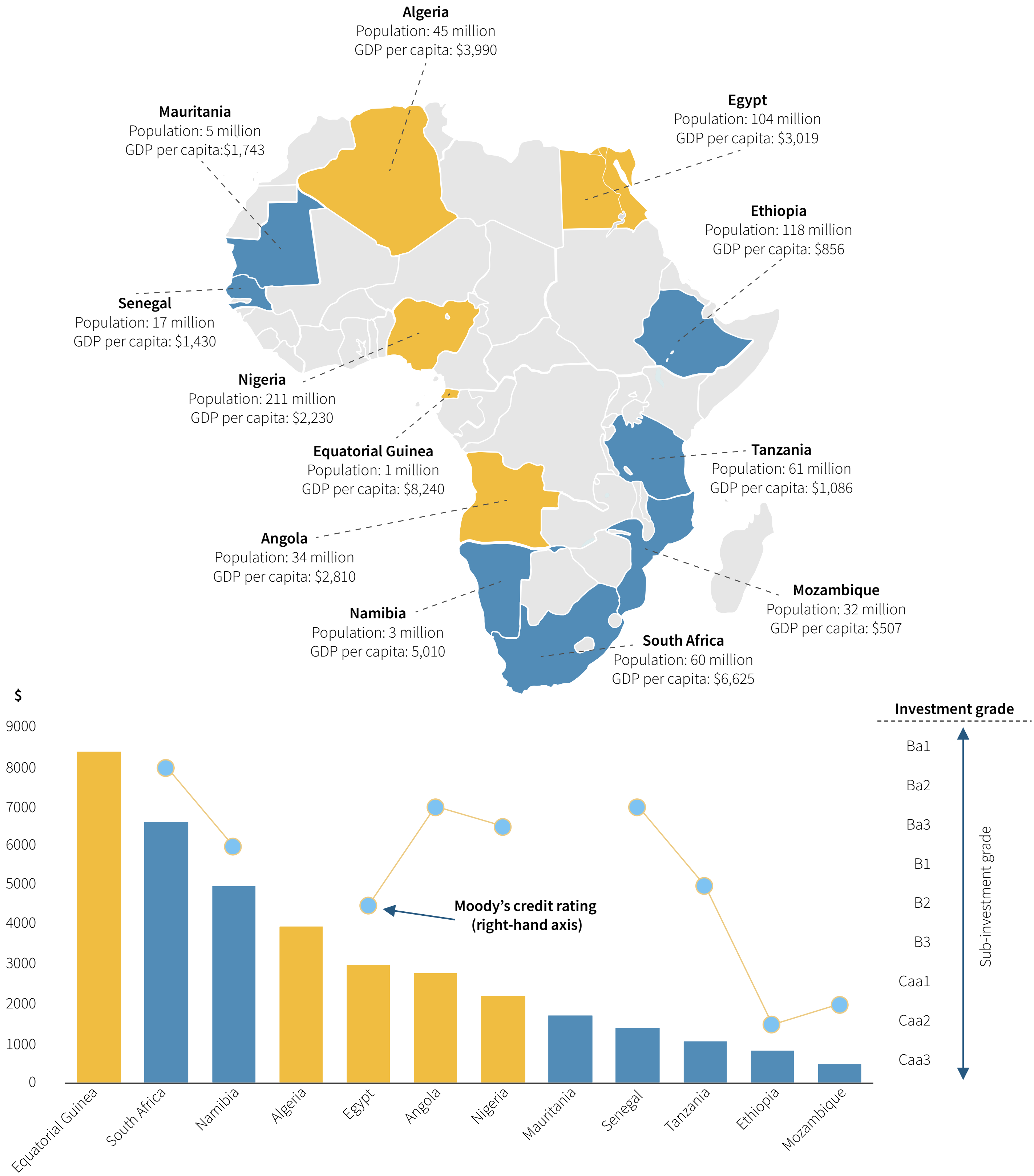


Figure 4: Existing and emerging gas producers analysed in this study



Climate transition risk

One of the most crucial factors outside African governments' control is the speed and shape of the structural changes taking place as a result of the global low-carbon energy transition. These changes will cause increasing economic and financial risk – often known as "climate transition risk" – to economic and financial stability. Climate transition risk is a concept that, over the last five years, has become very well known among the world's central bankers and financial supervisors. However, climate transition risk and physical climate risk, (together referred to as "climate-related financial risks") are difficult to measure and consequently are poorly managed in most parts of the world and ignored in some. The consequences of failing to manage them effectively could pose threats to global financial stability [6] and, implicitly, also to the world's ability to mobilise capital to meet Paris Agreement goals at reasonable cost.

There has been a long-running debate in global climate change negotiations about who bears responsibility for global warming and who should pay for its costs. If developing countries (such as those in Africa) bear less responsibility than developed countries,[7] then why should they pursue deep decarbonisation (typically formulated as "net zero" targets) today, and put their own economic development at risk? In recent years, an increasing body of analysis – including by the authors of this report[8] – has begun to show that, while the equity questions of climate action and climate finance are critical and cannot be ignored, the economic arguments and analyses set out by many developing countries in favour of very gradual domestic transitions are underestimating two very important factors.

Firstly, national low-carbon transitions do not happen in a vacuum. As countries start to reduce their greenhouse-gas emissions, they do so amidst an accelerating series of structural changes happening at different speeds, in different parts of the world, and in different industrial sectors (for example, the decline in the use of coal in power stations is likely to happen earlier than in cement production). These structural changes in demand will have a range of impacts on the largest global commodity markets and global trade more broadly, affecting all countries – exporters and importers.

Secondly, an overwhelming majority of the capital required to fund climate change mitigation and adaptation action across the world is concentrated in the developed world, in jurisdictions leading the conceptualisation and integration of climate risk (both physical and transition risk) into financial supervision. As developed world financial institutions increasingly start to factor climate transition risk into investment decisions, investment will increasingly shift from industries facing long-term decline to those with more robust long-term growth prospects. This may mean that capital may become harder to attract for countries seen as decarbonisation "laggards".

Box 3: Defining climate-related financial risks

The Task Force on Climate-Related Financial Disclosure (TCFD) was established in 2015 to provide recommendations on how the financial sector could incorporate climate-related risks and opportunities in decision making. Its disclosure framework has been widely adopted around the world. The TCFD highlights two types of climate-related financial risks:

Climate transition risk refers to risks associated with changing markets, technologies, and policy as the world transitions to a low-carbon future, as well as the associated legal and reputational risk.

Physical climate risk refers to the physical impacts that result as a result of climate change. These risks are highly location specific.

[6] "The Green Swan: Central banking and financial stability in the age of climate change," BIS, January 2020.
[7] "Analysis: Which countries are historically responsible for climate change?" Carbon Brief, October 5, 2021.
[8] This methodology has been developed and elaborated on in previous reports including: "Understanding the impact of a low carbon transition in South Africa," March 2019; "Understanding the impact of a low carbon transition on Uganda's planned oil industry," December 2, 2020.

Study scope and methodology

This report presents the findings of a study that assessed the current gas landscape in Africa across 12 countries, exploring common and country-specific themes and challenges, as well as the potential future impacts of climate transitions, for their gas industries. The Willis Towers Watson (WTW) global LNG model was used to generate the data used in the analysis, with full details of the model and methodology underpinning the work presented the Appendix.

Box 4: Framing the study using scenarios

The WTW global LNG model provides future projections of gas production, consumption, and prices between today and 2050 under different scenarios. Different climate scenarios are used to reflect potential global responses to the climate challenge. Four scenarios were considered here:

No Holds Barred (NHB), where the world continues along its present path, without any additional changes in policy, beyond what has already been implemented.

Business as Usual (BAU), which reflects all of today's announced policy intentions and targets, insofar as they are backed up by detailed measures for their implementation.

Well Below 2 Degrees Centigrade (WB2C), which is aligned with the Paris Agreement target of holding the rise in global temperatures to well below 2°C above pre-industrial levels.

Net Zero Emissions by 2050 (NZE), where net-zero CO_2 emissions are achieved in the energy sector by 2050. This scenario aligns broadly with a target of temperature increases remaining below 1.5°C above pre-industrial levels.

AFRICAN LNG VIABILITY UNDER DIFFERENT CLIMATE TRANSITION SCENARIOS

The LNG market has grown considerably over the past couple of decades, with strong growth outlooks across all but the more extreme 1.5°C-compliant climate scenarios. The largest driver of LNG demand is coal-to-gas switching in Asian power generation. By 2050, however, the outlook varies significantly across the various climate transition scenarios. In a NZE scenario, LNG demand could be 60% lower than current levels, as more rapid and geographically widespread decarbonisation leaves no room for unabated natural gas consumption in power generation or industry (Figure 5).

For African producers, this means operating in a more competitive market, with only the most economic or cost-efficient LNG assets in operation. This could lead to stranded capacity in the continent, but even more widespread would be the amount of stranded value (lower levels of revenue) that will affect even those assets still active in the market in a NZE scenario. Figure 6 shows how far revenues, across all African LNG assets, could fall in a climate transition, in comparison to BAU expectations.

Figure 5: Global LNG demand under different climate scenarios

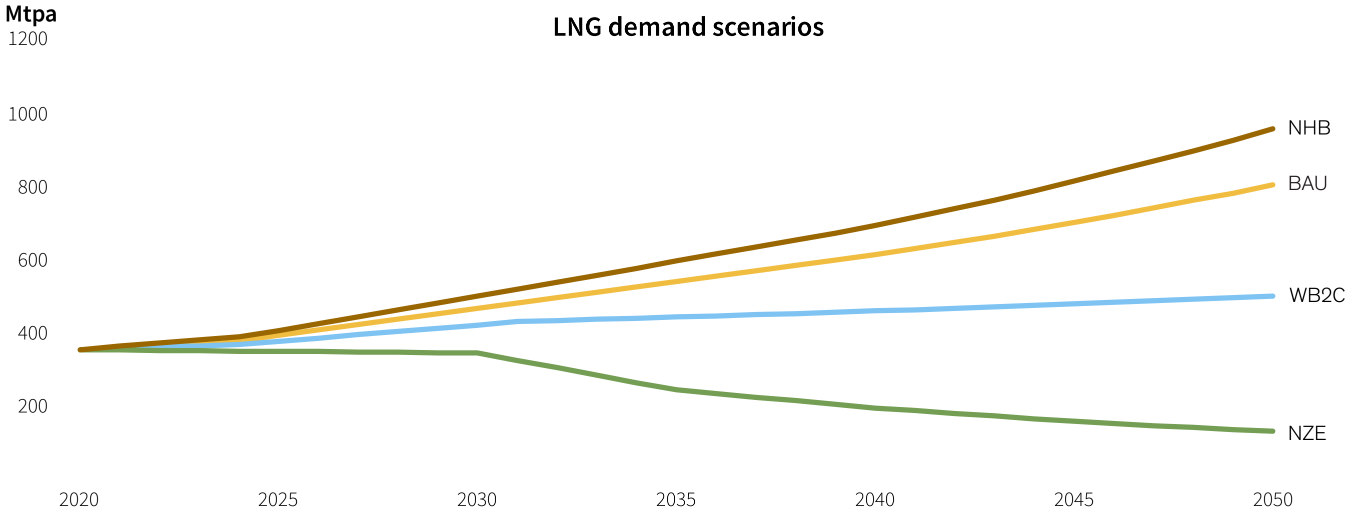
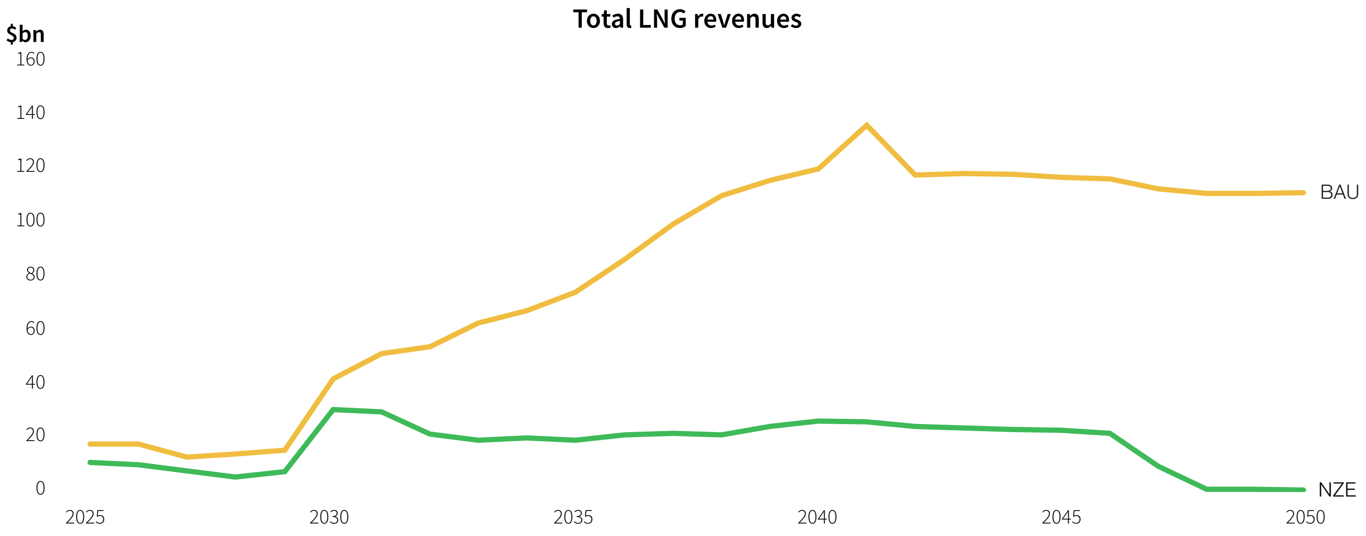


Figure 6: Total LNG revenues across Africa in BAU and NZE scenarios



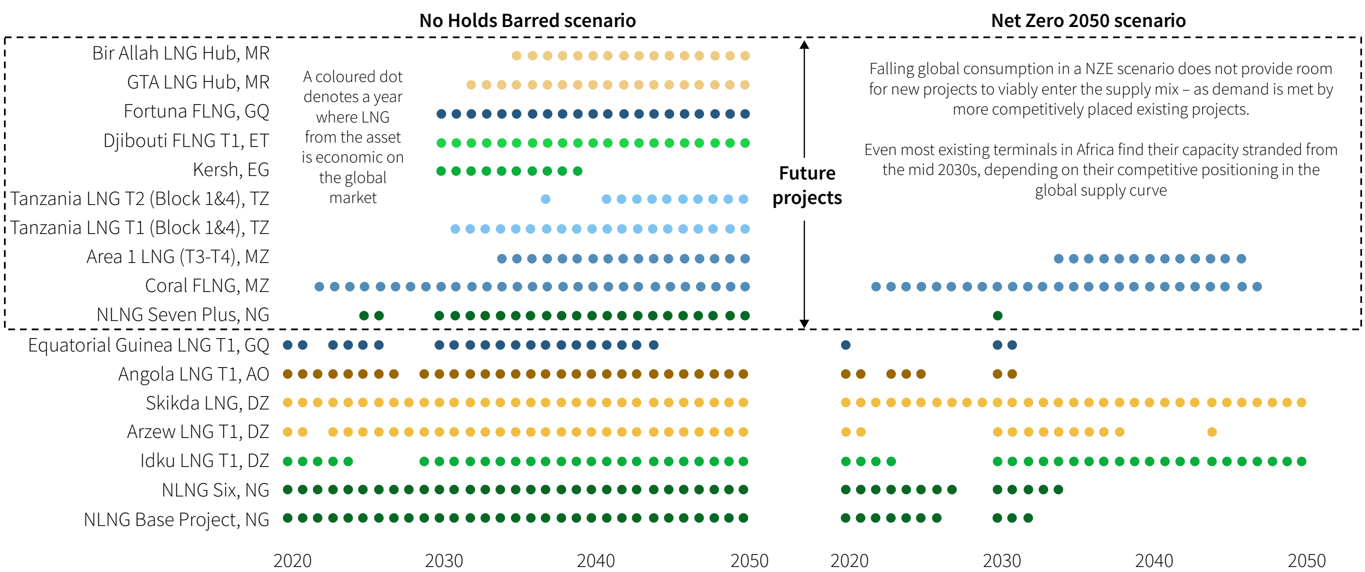
This transition will not affect all assets equally. Those positioned more competitively on the global cost curve will be better placed to remain economic on the spot market or negotiate viable long-term contracts at lower prices. Assets that have been producing for longer may be able to trade at lower market prices than newer assets that are yet to be built, because their development costs will already have been "sunk" and possibly fully depreciated. Yet-to-be-built newer assets will require prices that are high enough to provide investors returns on investment, in addition to covering asset running costs. Figure 7 graphically demonstrates how a selection of future and existing assets could fare differently in a NZE scenario versus a NHB or BAU scenario.

There is also a clear distinction between the impacts on existing and emerging producers. As emerging producers have a greater share of potential export value from future assets, they will have higher exposure to climate transition risk than existing producers. Figure 8 shows the total value of LNG revenues to 2050 for existing and emerging producing countries in the BAU and NZE scenarios. In a NZE scenario, the five existing producers and seven emerging producers earn similar amounts of total value between them. However, under a BAU scenario, the value of LNG revenues could be over double the NZE scenario for existing producers, but four times the value for emerging producers – providing an indication of the risk (particularly to new investments) as the world decarbonises. In other words, while existing producers collectively face transition risks, the combined risks to emerging producers are significantly higher (73% of BAU value).

The above quantification of high-level climate transition risk across the continent's gas producers paints a stark picture of how, in many cases, already economically vulnerable economies could be locking in new sources of climate transition risk by venturing into the LNG export industry. Those advocating for new gas project development argue that there are still billions of dollars of present value accessible to some countries, which could be realised even under the NZE scenario. However, if stakeholders and host governments do not plan future public investment and spending based on well-informed and stress-tested estimates of future revenues – taking all the risks into consideration – then development gains could fall well short of expectations and/or public debt could rise sharply, potentially destabilising countries' economies.

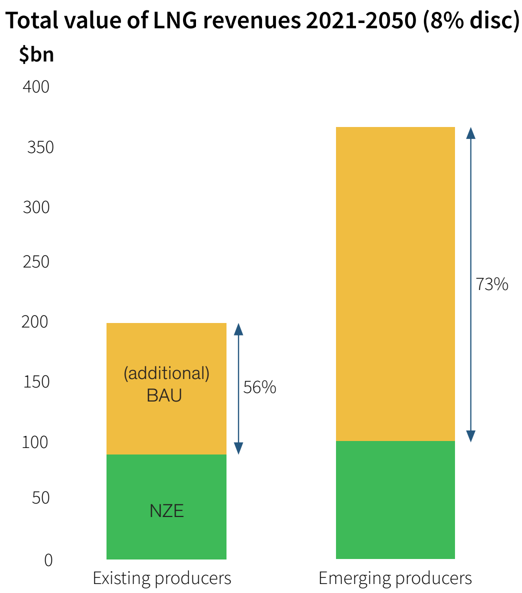
There are many historic examples of governments frontloading development expenditure, based on an expectation of uncertain future resource revenues that are then delayed or otherwise do not materialise.[9] Recent geopolitical events and structural shifts in the LNG market, related to the war in Ukraine, could exacerbate this. If investors and host governments fast track new developments with the aim of capturing short-term gains (from higher short-term global LNG prices), they expose themselves to many more severe long-term risks in the process.

Figure 7: Existing and future LNG asset competitiveness illustrated across BAU and NZE scenarios



[9] A recent parliamentary statement by a Ugandan finance minister confirmed, "There isn't any money in the Petroleum Fund, we appropriated it last year, what there was, so now we can't get what isn't there." Parliament Watch.

Figure 8: The total value of LNG revenues across country archetypes and scenarios



Box 5: Greenhouse-gas emissions along the natural gas value chain

The composition of natural gas varies around the world. Its primary constituent is methane, with ethane, propane, and butane typically being found in smaller proportions. It also has a number of trace constituents.

When the gas is burned in an efficient burner, these constituents are converted to carbon dioxide (CO_2), which is a greenhouse gas. Burning of coal also gives rise to CO_2, although the emissions from burning gas are substantially lower than coal per unit of energy recovered.

While gas is a preferred fuel to coal for power generation at the point of use, there is potential for the release of methane and other natural gas constituents directly into the atmosphere (known as fugitive emissions) during the extraction and transport of natural gas. Methane has a global warming potential of almost 30 times CO_2, according to the Intergovernmental Panel on Climate Change's (IPCC) latest assessment report. The release of these emissions increases the total life cycle greenhouse-gas footprint of natural gas.

BALANCING EXPORTS AND DOMESTIC USE

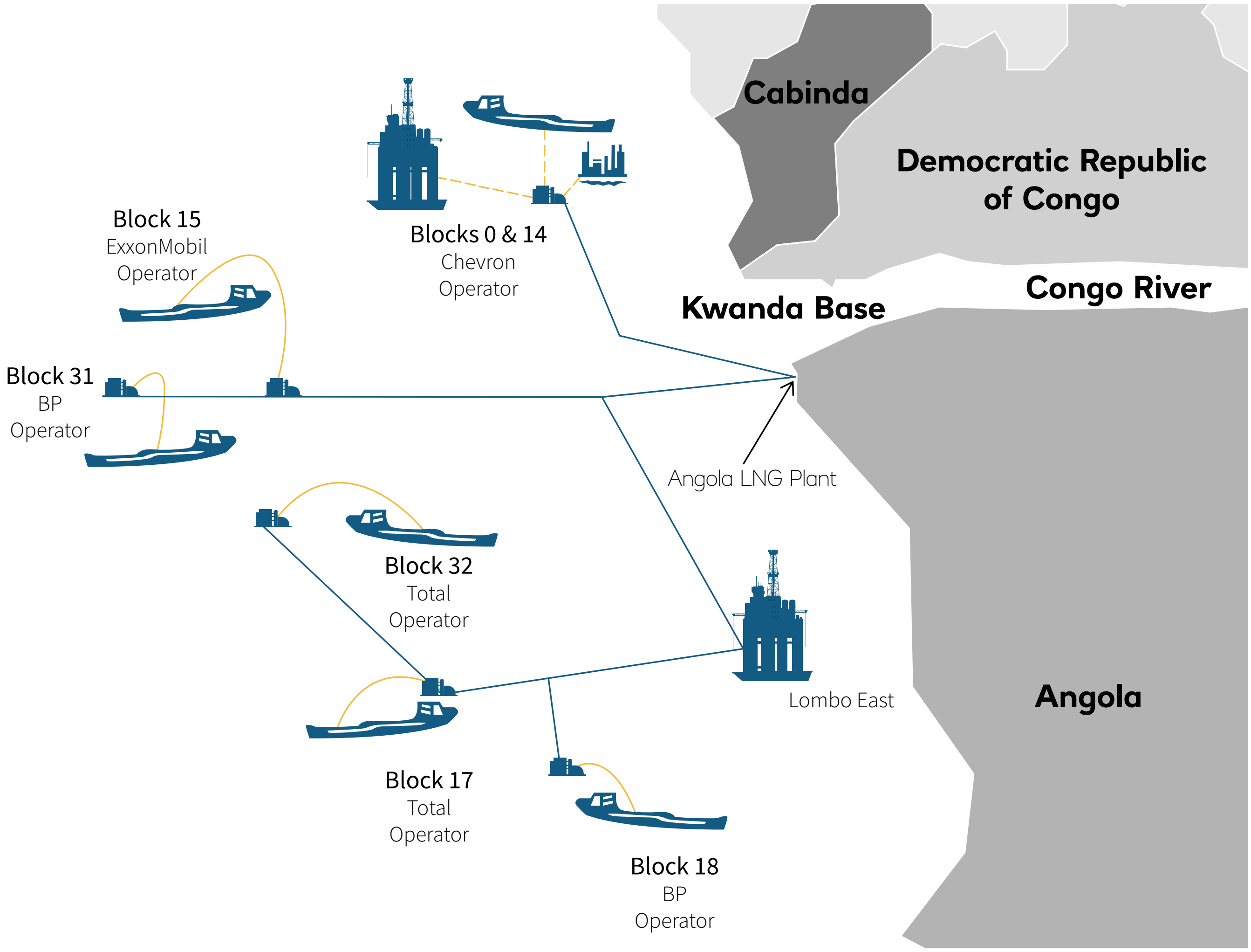
Growing exports

Developing export-orientated infrastructure to sell gas to international customers is often the quickest way to commercialise resources, especially in countries without appropriately sized existing domestic natural gas markets. Angola and Equatorial Guinea are the two established producers most focussed on maximising the value of their gas reserves through the export of LNG as opposed to growing domestic demand. Mauritania, Ethiopia, Tanzania, and Namibia[10] are likely to do the same, albeit through assets that are yet to begin producing. For Equatorial Guinea, Mauritania, and Namibia, relatively small populations limit the scope for growing domestic demand, meaning that economically viable gas industries are particularly dependent on exports. In Ethiopia and Tanzania, large populations hold out prospects of growing domestic demand, but gas in these countries would only likely be affordable with significant government subsidies.

Looking ahead, Angolan domestic gas demand is expected to remain relatively stagnant, even in optimistic economic growth scenarios, due to a lack of domestic pipeline gas infrastructure, coupled with a power system already dominated by hydroelectric power and cheap supplies of furnace oil. Angola's LNG supply comes exclusively from offshore oil developments, west of the Congo River estuary (Figure 9), which produce associated gas volumes that could otherwise have been wasted through flaring. This use of LNG infrastructure to commercialise associated gas is unique in Africa – and could present a way to curtail flaring any under-utilised gas production in other African countries.

Equatorial Guinea holds significant gas resources and existing LNG liquefaction capacity of 3.7 million tonnes per annum around the Bioko Island in the Gulf of Guinea. These gas developments are also

Figure 9: Angolan offshore infrastructure map



Source: "Gas supply"

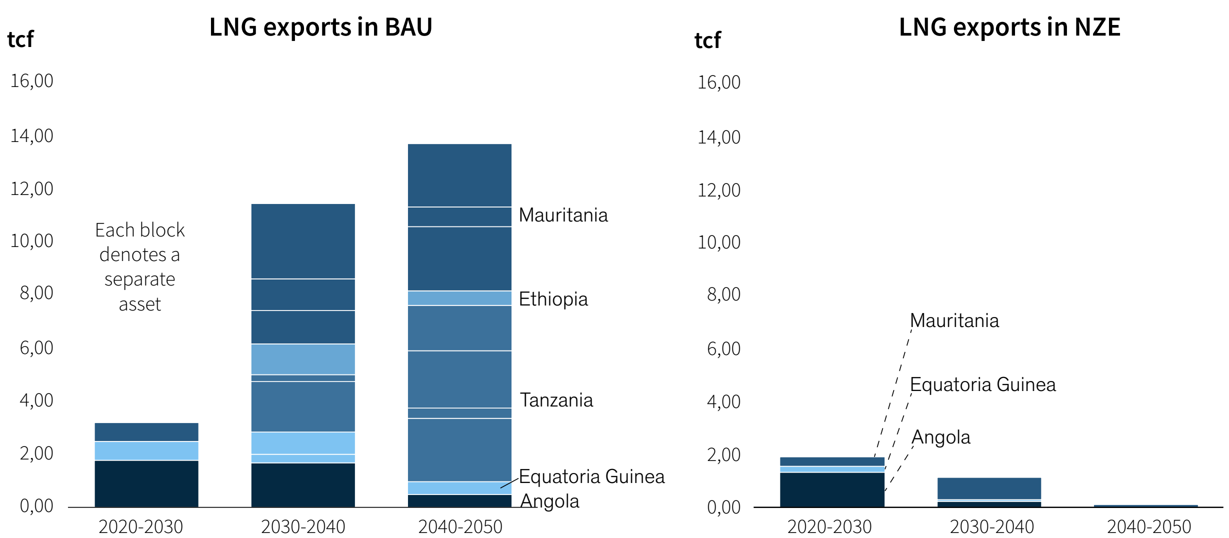
[10] Namibian exports would likely flow via electrons, rather than gas molecules, as gas could be fed to new combined cycle gas turbine plants (CCGTs) in the country and exported to South Africa using existing transmission lines.

sandwiched between larger undeveloped finds in the area that straddle the borders between Cameroon and Nigeria. The three governments are looking to leverage existing gas infrastructure on Bioko Island to commercialise these previously stranded basins and export the gas as LNG, a project being dubbed the “Gas Mega Hub”. As such, significant new investments are planned to potentially double export capacity by 2030.

Ethiopia has a strong reliance on hydropower capacity for power generation, with significant capacity additions planned over the coming decades. Without significant power demand around which to anchor infrastructure investments, the use of gas in cooking and industry is expected to remain limited. Ethiopia’s gas developments are another example of cross-border cooperation, as they involve the landlocked country accessing the port at Djibouti via a new gas pipeline, linking the finds in the country’s interior to the world’s LNG markets. With the lack of any viable and scaled domestic industry, these countries will be dependent on global markets and the LNG trade to deliver the revenues required to successfully commercialise their gas reserves.

Figure 10 shows the export potential for a selection of these countries. In a BAU scenario, the LNG export potential is very high, with Mauritanian and Tanzanian capacity dwarfing the current exports of the incumbent established export-orientated producers within two decades. In a NZE scenario, only the floating LNG terminal in the Mauritanian “Greater Tortue Ahyemin” (GTA) remains viable in the countries shown (Figure 11). In the absence of any other (unlikely) domestic policy options to commercialise the gas, most new LNG investments (particularly in infrastructure) in these countries would face stranding in a NZE scenario, driven by a global energy transition outside each host country’s control. It is therefore critical that stress testing new investments against a range of climate transition and price scenarios is carried out to ensure that countries do not take on unmanageable transition risks that will impact public finances.

Figure 10 and 11: Total LNG exports in each decade in a BAU and NZE scenario[1,2]



[1] In a BAU scenario, emerging export-orientated producers can grow their exports significantly as they bring new LNG capacity online, while existing producers are able to maintain exports for the next two decades before declining profiles start to take effect.

[2] In a NZE scenario, all new assets would be unviable, apart from the initial Mauritanian FLNG development, with existing producers also seeing exports beginning to fall before the end of the current decade.

Growing domestic demand

One option for governments to help partially mitigate exposure to external climate transition risk is to reduce reliance on markets where prices are set by globalised or regional trends. Domestic gas demand could potentially be an anchor for new gas investments while alleviating energy access constraints. The potential value of any such approach will, however, depend on the competitiveness of alternative sources of energy as renewable electricity and other low-carbon technology costs continue to fall.

Today, Africa's largest gas producers – Nigeria, Algeria, and Egypt – are not only some of Africa's largest countries by population and GDP, but also some of the world's largest gas producers. Having supplied global markets for decades, they have also begun to rely on gas use domestically to power their economies and industries. Egypt is even experiencing a period of net imports in recent years as production growth could not keep up with domestic demand growth. However, all three countries face challenges with inefficient production methods, meaning a significant amount of gas is still wasted through flaring.

Emerging producers looking to expand domestic gas consumption, are less easy to group. South Africa has historically used domestic and regional[11] gas supplies to feed industrial demand, primarily in gas-to liquid (GTL) and coal-to-liquid (CTL) refineries, but is exploring the potential for gas to replace the dominant dispatchable coal-fired power generation capacity in its domestic grid. Senegal's demand is also centred on power demand, but this is more to do with fulfilling rapid demand growth, without any relevant historic uses of natural gas. Mozambique, in a BAU scenario, is expected to become Africa's largest LNG exporter. However, the government has been keen to link any assets earmarked for LNG exports to domestic gas led industrialisation, with domestic supply obligations as high as 20% being negotiated. These volumes are earmarked for new power, GTL, and fertiliser industries.

Box 6: What are Domestic Supply Obligations?

To address tensions between exports and local demand, and support domestic utilisation, some countries have introduced or are considering legislation that requires a certain percentage of gas production to be sold on the local market, otherwise known as Domestic Supply Obligations (DSOs). DSOs often are not met due to a lack of effective enforcement mechanisms. Furthermore, because DSOs are placed on exporting assets, they can end up eroding the viability of LNG developments and increase the transition risks for these assets.

Existing producers

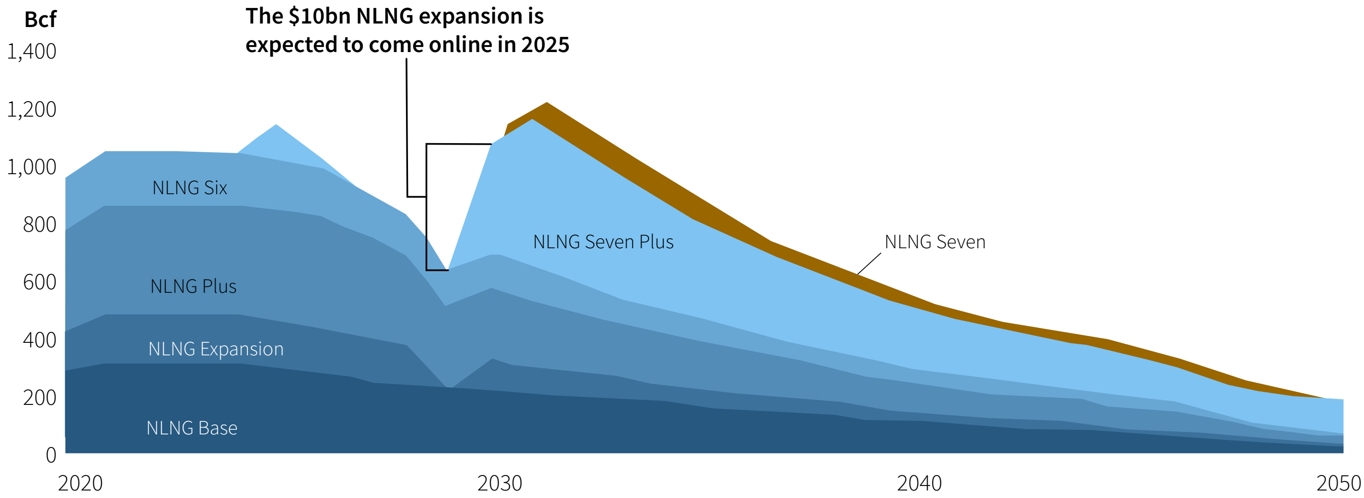
Natural gas exports have historically been extremely important for generating foreign exchange reserves and vital current account inflows for Nigeria, Algeria, and Egypt (Figure 12). However, even in a BAU scenario, long-term projections for exports (both LNG and pipeline[12]) from each of these countries is on a downward trend, as declining production coupled with growing domestic demand means that there is progressively less gas available for exports.

What this means is that the amount of commercially competitive gas being produced over time is unlikely to be sufficient to cover both long-term domestic demand and maintain export capacity. These dynamics could be particularly stark in Egypt, while in Nigeria and Algeria, growing domestic demand in the future could apply pressure on supply in the long run (Figure 13).

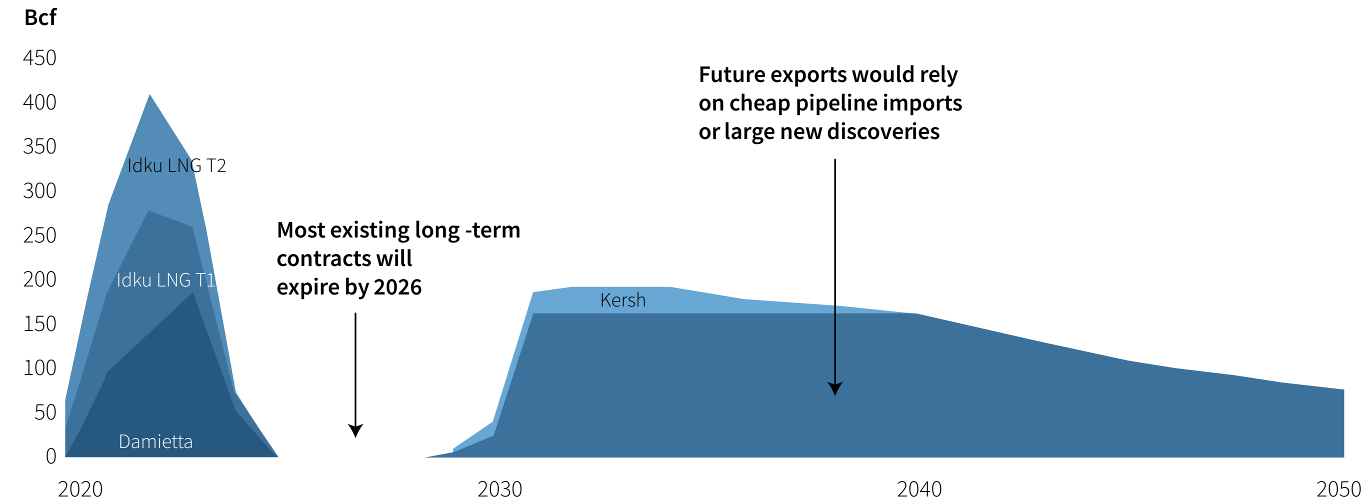
[11] The Pande and Temane fields in southern Mozambique, accessed via the Sasol owned ROMPCO pipeline.
[12] Nigeria exports via the pipeline through the West African Gas Pipeline (WAGP) network: wagp.com; Algeria exports via the pipeline to Italy through the Galsi and Trans-Mediterranean pipelines (via Tunisia) and to Spain directly through the Medgaz pipeline: "ENTSOG publishes its Transmission Capacity map 2021," ENTSOG, November 5, 2021.

Figure 12: LNG exports by country in a BAU scenario (coloured areas denote different assets)

Nigeria LNG exports (WTW model BAU)



Egypt LNG exports (WTW model BAU)



Algeria LNG exports (WTW model BAU)

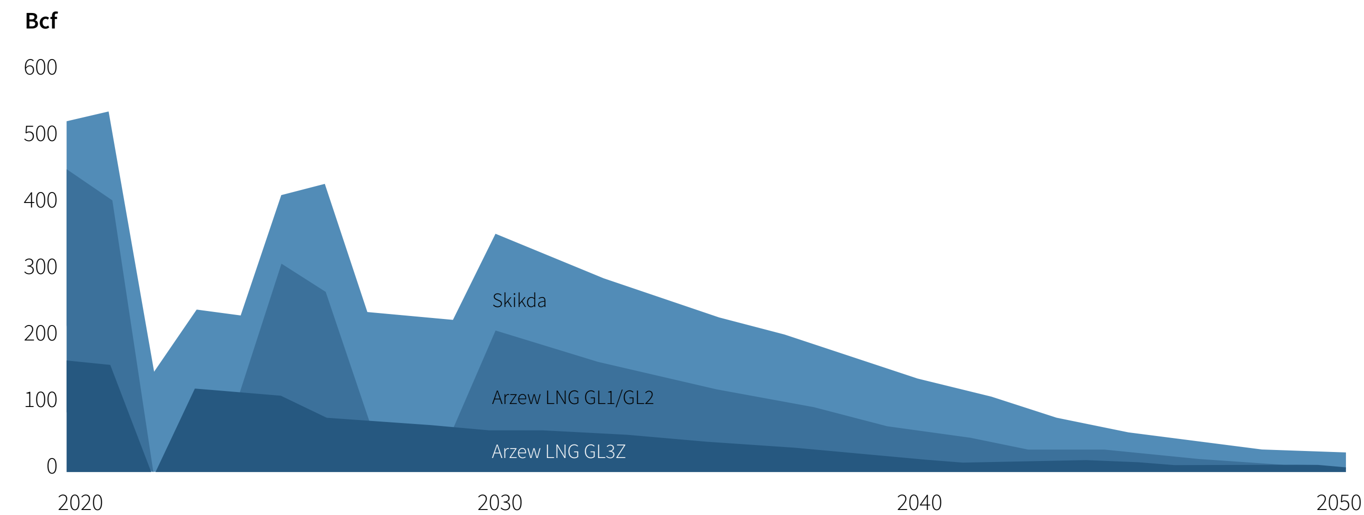
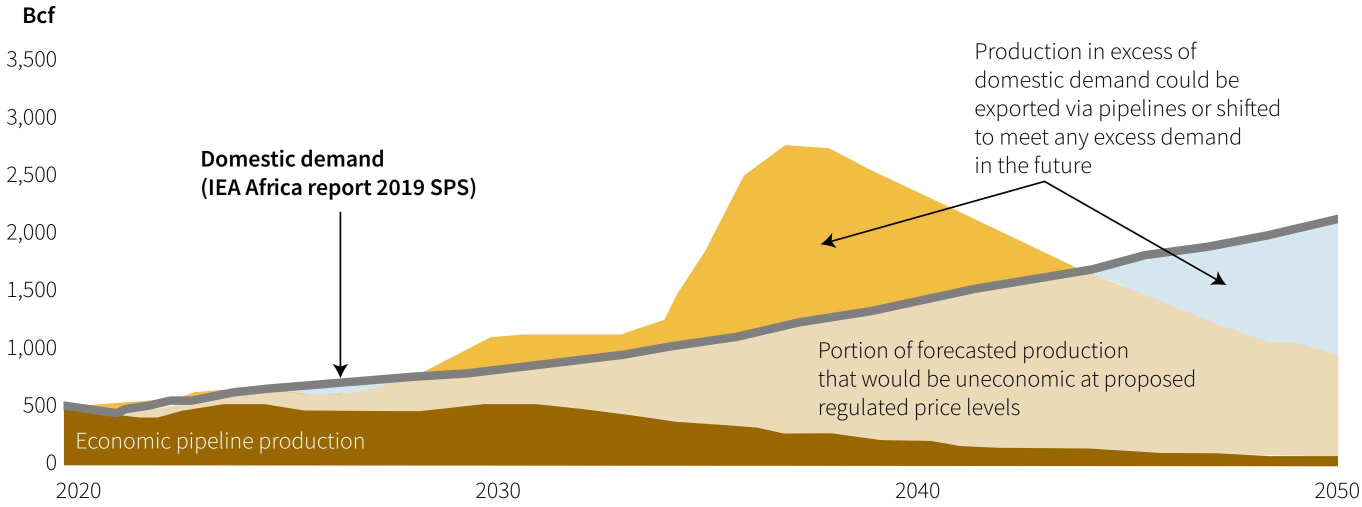
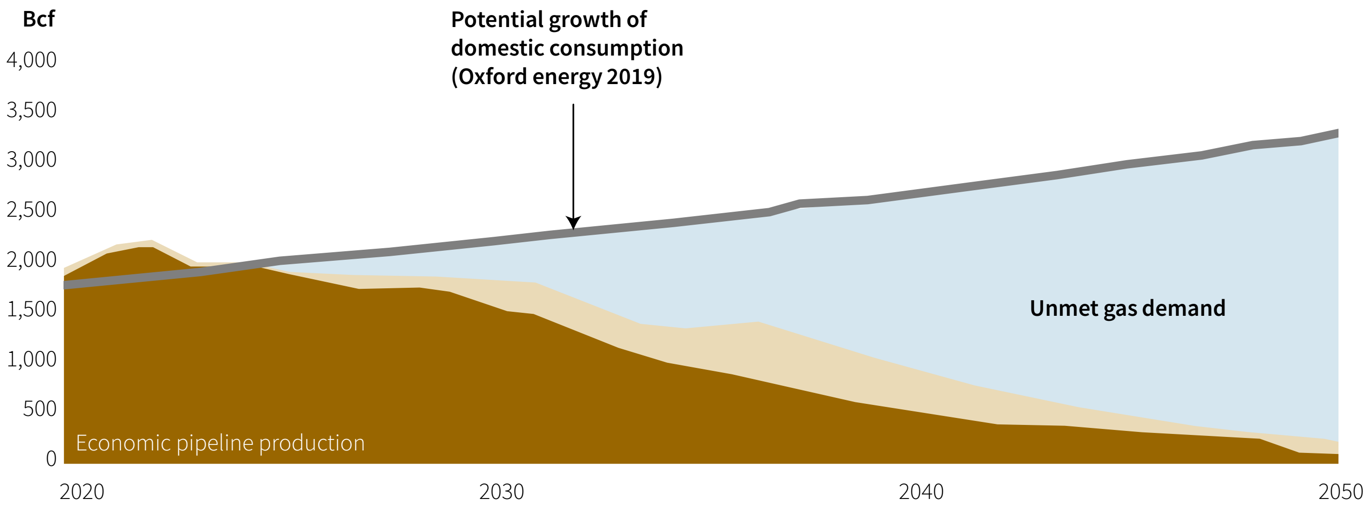


Figure 13: Supply and demand balance for domestic demand and pipeline export – excludes volumes destined for LNG[1]

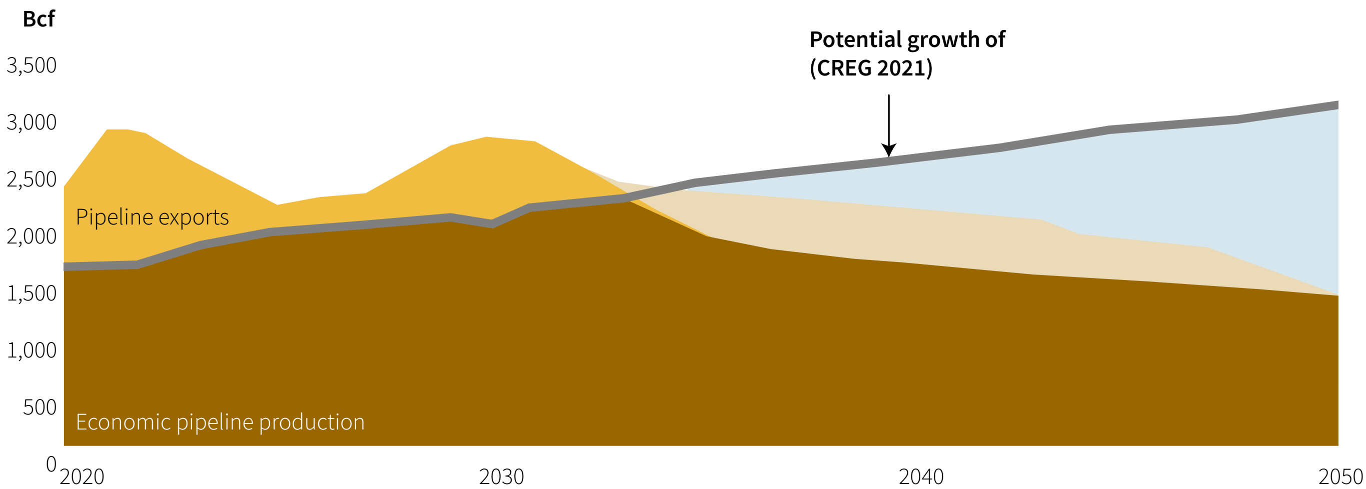
Nigeria



Egypt



Algeria



[1]For Egypt and Nigeria, the dark brown indicates supply that is viable according to current domestic price regulation, with light brown showing the additional available supply, unviable according to regulation. For Algeria, pipeline export prices linked to Europe are used to determine viability, rather than any domestic regulation.

One potential solution for addressing the supply-demand gap would be to capture a higher proportion of the gas that is produced. Nigeria is a good example of a country that has reduced flaring by 70% over the last two decades and is targeting the end of flaring completely by 2025.[13] Currently, Nigerian producers flare just less than 10% of total gas production, with a further 25% re-injected and used during the production of oil. However, previous targets have not been met, largely due to challenges in awarding contracts to capture and sell flared gas, as well as the declining gas volumes as fields are depleted. In contrast, Algeria is the world fifth largest gas flarer. Historically, there has been limited commercial incentive for Sonatrach (the Algerian National Oil Company [NOC]) to reduce flaring, which is largely from production in older fields with less participation from foreign investors.[14]

Low (subsidised) domestic prices can be a key constraint for developing underutilised gas reserves as they may not provide sufficient returns for the investment in gas and infrastructure for volumes that are destined for the domestic market. In Nigeria, for example, despite recent market reforms, prices may be high enough to enable access to gas supplies in the short run – but they may not be sufficient to encourage the investments needed now to begin developing resources that could meet growing domestic demand in the medium and longer term or encourage investment in capturing flared gas.[15] Egypt also has low, regulated gas prices (although these are linked to oil markets[16]). In contrast, although Algeria keeps prices low for domestic consumers through large subsidies, higher export-linked pipeline prices can provide more of an incentive for the development of gas production in Algeria. Figure 14 shows how these prices compare with the marginal breakeven gas price required in each country to develop discovered sources of domestic gas supplies.

A global low-carbon energy transition would not only cause global gas prices to rise slower in relation to BAU, but also reduce the costs of competing technologies, such as electrolysers for hydrogen production, battery technology for power system flexibility, and renewable solar and wind, to name just a few. Box 7 details how historic gas prices paid by CCGTs in Nigeria are too low to incentivise new resource development, while in many cases renewable sources of power are already competitive with these CCGTs that are buying gas at low prices. Current policies aimed at increasing domestic use of natural gas, at the expense of export capacity, may therefore already be misplaced in the power sector.

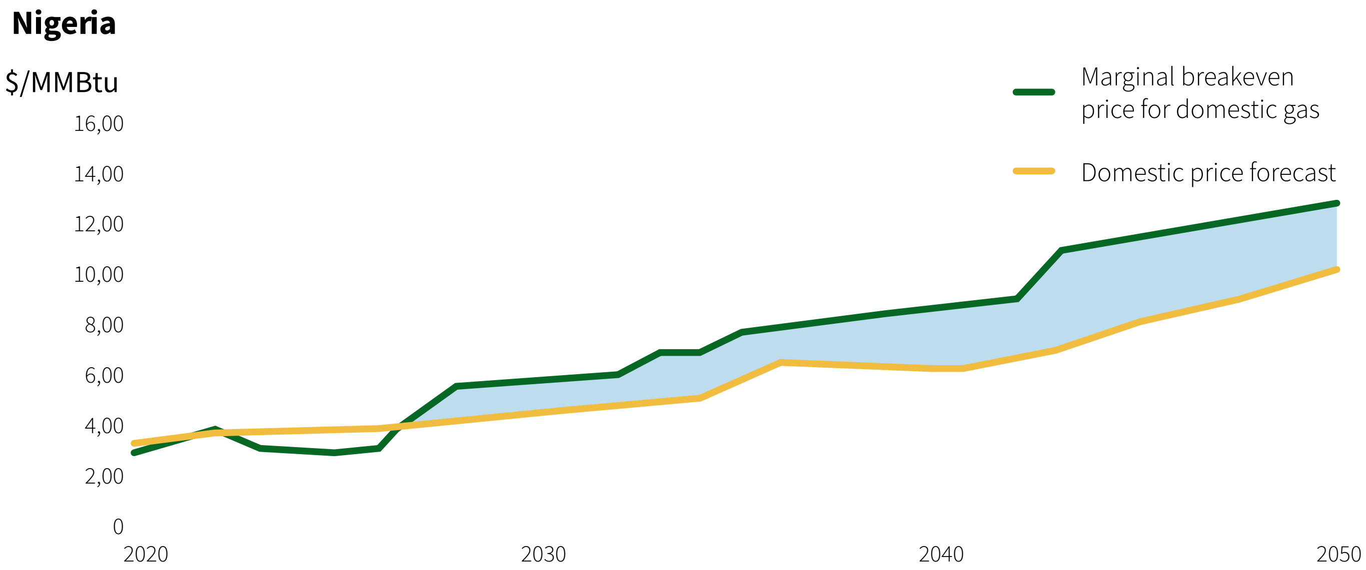
Box 7: Gas versus renewables in Nigeria

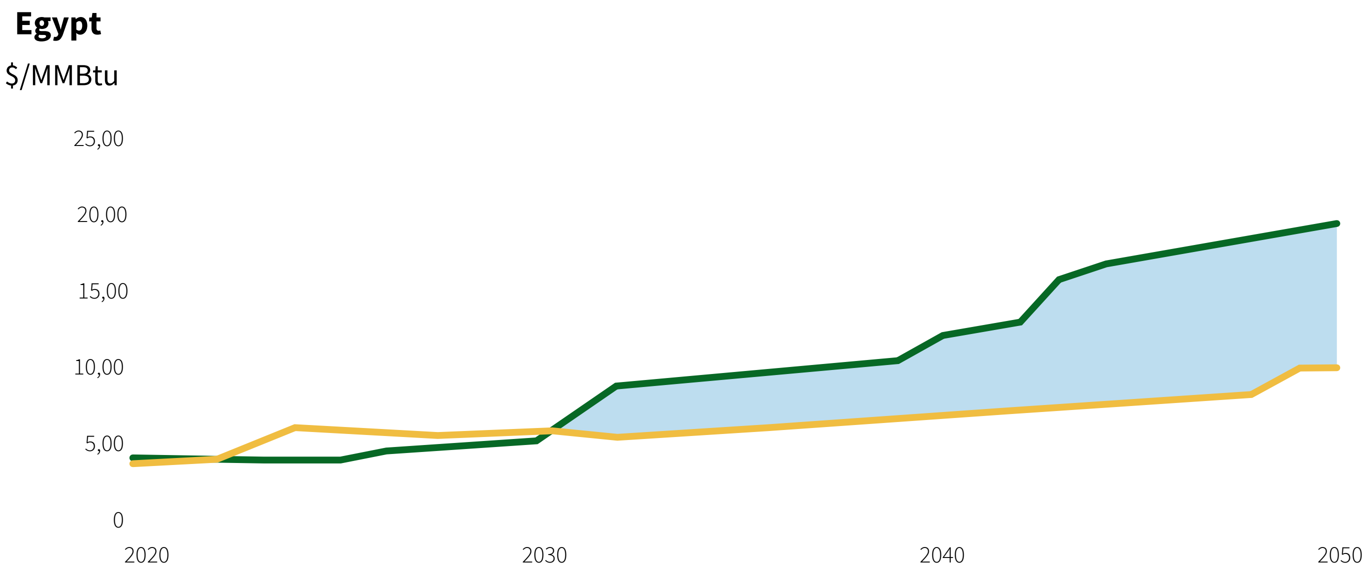
The recent Azura gas power plant power purchase agreement (PPA) has been signed at prices in the region of 10c/kWh – linked to low domestically regulated prices of around $2.2 per MMBtu. A price that would offer sufficient value to domestic producers in 2030 would be more than $6/MMBtu. It is clear that there will be upward pressure on LCOEs. Main grid solar projects sell their power to NBET, thanks to PPAs, at $0.075/kWh, declining from $0.115/kWh in line with solar costs and comparable projects in countries, such as Senegal at $0.05/kWh and Zambia at $0.06/kWh (lower than building new CCGTs in Nigeria at today's low gas prices). **New renewables are already competitive with new gas in today's markets – and gas LCOEs could trend upward while the cost of renewables continues to decline in the future.**

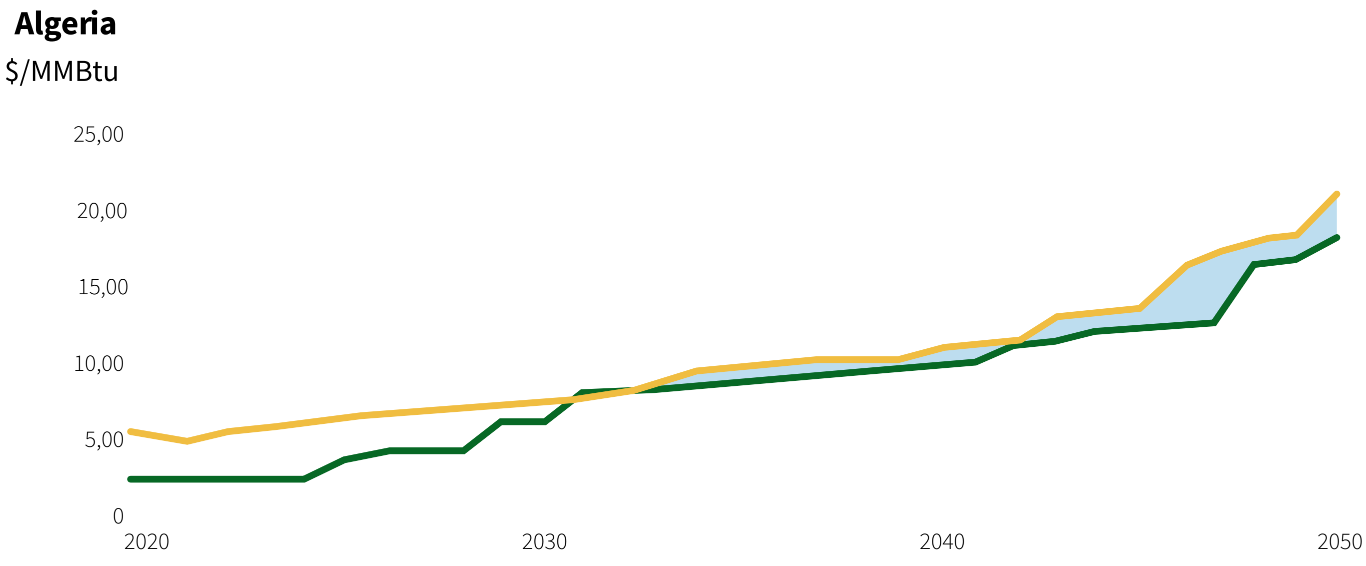
Solar mini-grid tariffs in Nigeria range between $0.4–$0.6/KWh. Developing mini grids has been touted as a key strategy in tackling energy access issues in Nigeria. In comparing mini-grid prices and new CCGT prices, the additional transmission infrastructure investments must also be accounted for.

[13] According to the International Energy Agency, the reduction of flaring is the result of a combination of tougher penalties and greater incentives to capture and sell the gas.
[14] Historically, flaring has not constrained exports or domestic supplies, in contrast to our future forecasts.
[15] "Petroleum Industry Bill (PIB) 2020 – a Game Changer?" KPMG, June 2021.
[16] Egyptian gas prices are linked to oil, in a range between a price ceiling and price floor: "Egypt – a return to a balanced gas market?" The Oxford Institute for Energy Studies, June 2018.

Figure 14: Domestic price projections based on current market regulation, compared with marginal break-even prices for discovered sources of domestic gas supplies







Emerging producers

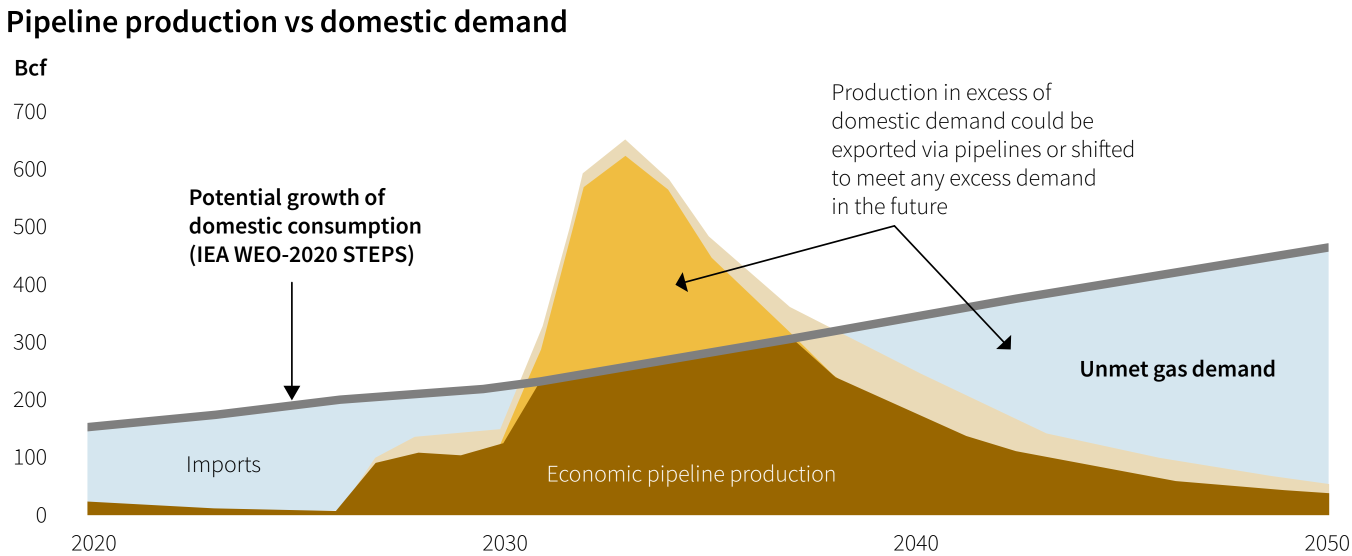
Various emerging producers are exploring expanding domestic demand as a part of their strategies to leverage their gas resources. Mozambique, which is one of the most interesting examples of how domestic policy is attempting to drive gas-led domestic industrialisation, is explored in greater detail in an accompanying report.

Senegal and South Africa are two emerging (non-producing) countries that have made significant gas finds in recent years and have big plans to expand domestic usage over the long run, as well as to supply export markets. In Senegal, recent efforts to expand electricity access in the country along with accompanying economic growth have bolstered power demand. Senegal commissioned its first major gas-to-power project with the arrival of the first floating regasification terminal in Dakar this year, which will use imported LNG to run a floating power plant owned by the Turkish energy firm, Karadeniz. This marks the beginning of what is expected to be increased gas use in power generation, as the country looks to build power capacity and increase electricity access from current levels of around 70% of the total population. When Senegal does begin exporting, it will be via terminals built across the border in Mauritania – another example of how new cross-border cooperation on the continent is being used to maximise gas development. Coupled with a desire to move away from expensive and inefficient furnace oil thermal power generation, and with a pipeline of new gas to power projects in the works, Senegal will actually require imports to satisfy demand over the coming decade, given the time it will take to develop its own LNG assets.

South Africa's gas consumption has historically largely been linked to industry, such as the use of Mozambican gas in Sasol's chemical operations around Secunda and the use of some domestic resources off the coast of Mossel Bay, primarily in GTL operations. South Africa could source more gas for power generation in the future, but there is an ongoing debate as to whether gas is needed for the country to transition away from coal.[17] TotalEnergies has made large recent offshore discoveries in the Brulpadda and Luiperd fields, close to the gas-producing basin near Mossel Bay. These finds raise the possibility of South Africa becoming an LNG exporter for the best part of the decade between 2030 and 2040, but could also have their capacity capped to feed growing domestic gas demand over the longer term, as showing in Figure 15.

While South Africa is expected to transition away from coal even faster in a climate transition scenario, the pace of renewable energy additions may not be enough for it to meet power demand, increasing its reliance on electricity imports to as much as 20% of total demand by 2040.[18]

Figure 15: South African production available to consumers[1]



[1]See split between production viable under current market regulations and compared against IEA domestic demand profiles.

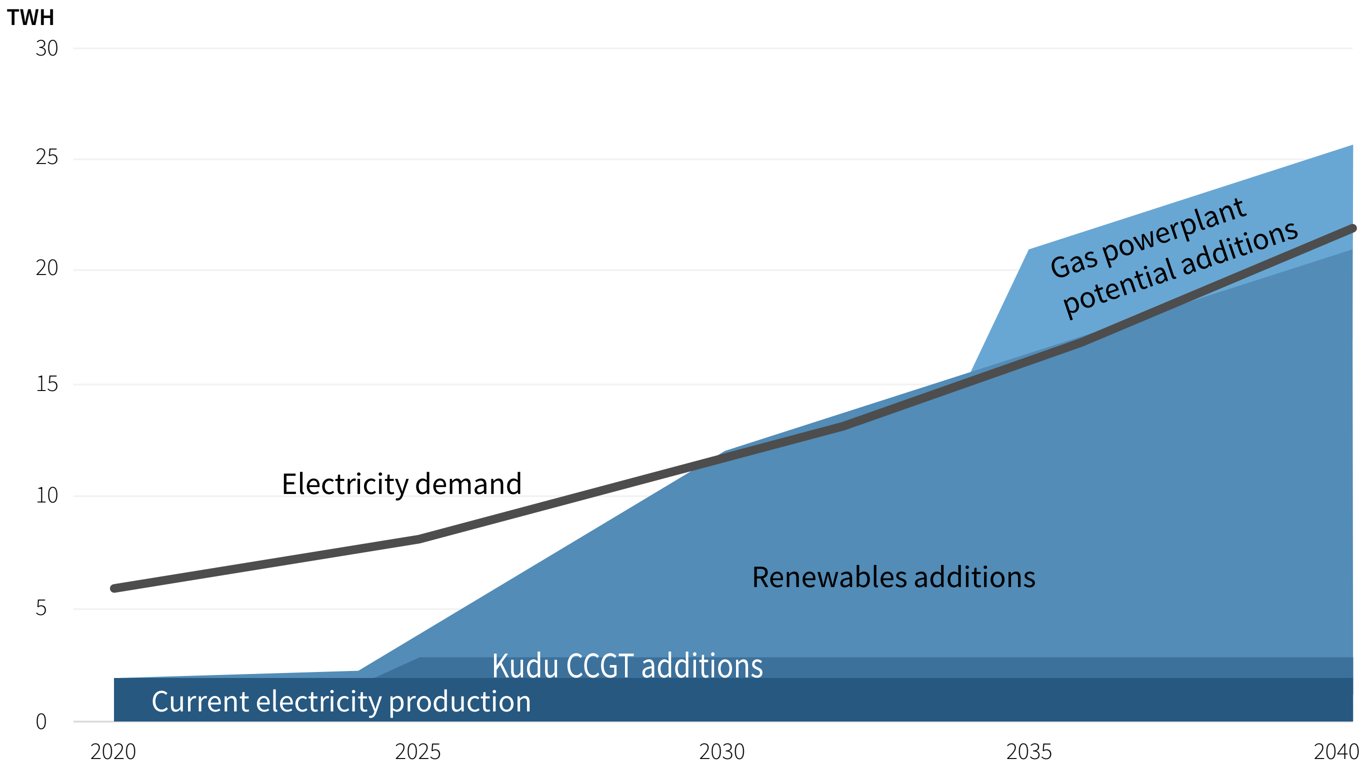
[17] "Hot air about gas," Meridian Economics, June 2022; "The impact of stranding power sector assets in SA: Using a linked power model to understand economic-wide implications," Academia, June 2016.
[18] "World Energy Outlook 2021 scenarios for South Africa – Annex A," IEA, October 2021.

Neighbouring countries, such as Namibia, could stand to benefit from such structural changes in southern African power systems, which have historically seen electrons flowing in the opposite direction.[19] The long-delayed Kudu gas development, off the coast of Namibia, is now undergoing FID and is expected to allow Namibia to feed a dedicated power plant of the same name to supply domestic energy needs and eventually start exporting power to South Africa, toward the end of the decade (See Box 8)

This may point to gas consumption being embedded over the long term in the southern African region, however gas from Kudu and Mossel Bay will only supply a fraction of the region's power needs going forward. Namibia expects to ramp up renewable capacity additions so much that it may not need any future extensions of the Kudu gas power project and will be able to cement itself as a South African main foreign supplier of electricity.

Figure 16, inspired by projections in the Harambee Prosperity Plan II (HPII)[20], shows how much of the electricity exports to South Africa (over and above the Namibian electricity demand projection) would come from renewables, with additional extensions to Kudu potentially providing just surplus to actual requirements. In addition, Namibia's efforts to position itself as a regional green hydrogen hub (with a $9.4 billion green hydrogen project already in the works)[21], could displace gas from South African industry[22], as electrolyser and renewable costs continue to fall. These developments serve to highlight the same domestic transition patterns identified for the emerging producers, with low-carbon substitutes becoming increasingly competitive with natural gas usage in power and industry.

Figure 16: Namibia electricity supply and demand forecast



[19] The Southern African Power Pool (SAPP) electricity market, established in 1995, includes several other countries in the region that currently rely on electricity imports, mainly supply by South Africa – examples include Botswana, Zimbabwe, DRC, and Malawi: https://www.sapp.co.zw/sites/default/files/Statistics%20 2019-20.pdf

[20] "Harambee Prosperity Plan II 2021 – 2025," Republic of Namibia.

[21] Edna Schutz, "The African nation aiming to be a hydrogen superpower," BBC News, December 28, 2021.

[22] This assumes that Namibian hydrogen plus transport costs would be competitive against South African hydrogen.

Box 8: Kudu project timeline[23]

The Kudu gas reserves were originally discovered in 1974 by Chevron. Since then, development of the project has stalled several times:

1976: Chevron pulled out of the country two years later after the United Nations imposed sanctions on South West Africa (SWA)

1993: Shell took over with plans to feed a gas-fired power station in Cape Town via **FLNG** – plans fell through due to the disappointing performance of appraisal wells

2003: Energy Africa took over and the first gas was targeted in 2008 with output flowing to an **800 MW power plant at Oranjemund**, a facility whose capacity was planned to be doubled if additional gas could be established in and around Kudu.

2004: The majority of Energy Africa's board of directors accepted a $500 million bid from Tullow Oil – but development stalled

2007: Itochu assessed a potential LNG project in Namibia after buying a 20% stake in the Kudu gas field. A 5 mtpa Namibian liquefaction plant was scheduled to come on-line by 2012 at a cost of about $6 billion. However, additional drilling indicated that there **were not sufficient reserves to support an LNG project.**

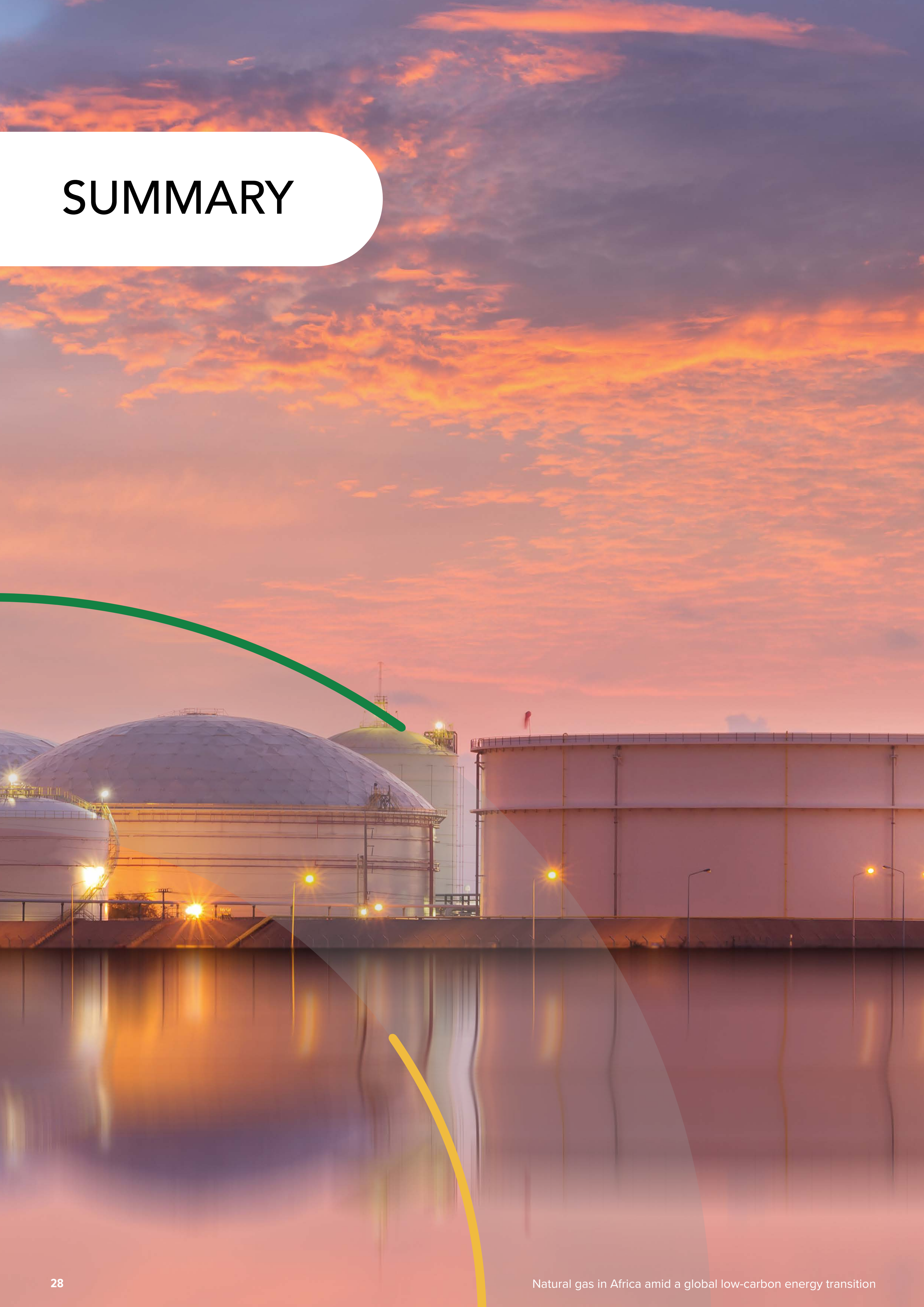
2014: Tullow Oil finally suspended contracting activities on its long-stalled Kudu gas project off Namibia, with Namcor (Namibian NOC) assuming 100% control of the project.

2017: BW Offshore acquired an operating stake in the Kudu gas field. FID has been delayed after the power plant was downsized from the original 800 MW to around 400 MW

2021: A farm-in agreement between BW offshore and Namcor has been signed, raising the operators' share from 56% to 95% - allowing the developer greater control over development plans and gas sale agreements, opening the way for FID

[23] "History," Namcor.com.

SUMMARY



For export-orientated producers, the most obvious challenges pertaining to their natural gas industries come from the potential global transition away from natural gas, forcing down long-term gas prices and damaging the economic viability of future LNG projects. Anchoring gas commercialisation around domestic demand is unlikely to be a viable way of mitigating this risk, even for those countries with the economic potential and political ambition required to drive strong domestic gas consumption growth. The regulated nature of established gas markets in Africa may appear to actually insulate these countries from some external transition risk (emanating from falling global gas demand and prices), however increased competition from low-carbon alternatives and rising domestic gas prices could, in fact, lead to additional transition risk (this time domestic) being locked in over the long term. This is especially true for the kinds of long-term investments in upstream and midstream infrastructure required to increase domestic gas utilisation.

Future (emerging) producers, other than South Africa and Namibia, are generally less economically developed, with public finances less suited to absorbing the impacts of global transitions.[24] These countries are also more exposed to a transition, given that the timelines for development coincide with global shifts away from natural gas consumption. Future producers leading with policies emphasising rapid growth in domestic consumption – in parallel to developing export capacity – could also be inherently locking in additional external transition risk, given the impacts of domestic supply obligations (with sub-economic prices) on the economics of major LNG developments.

[24] As indicated by Moody's sovereign credit ratings in Figure 4.

KEY CONSIDERATIONS FOR AFRICAN PRODUCERS

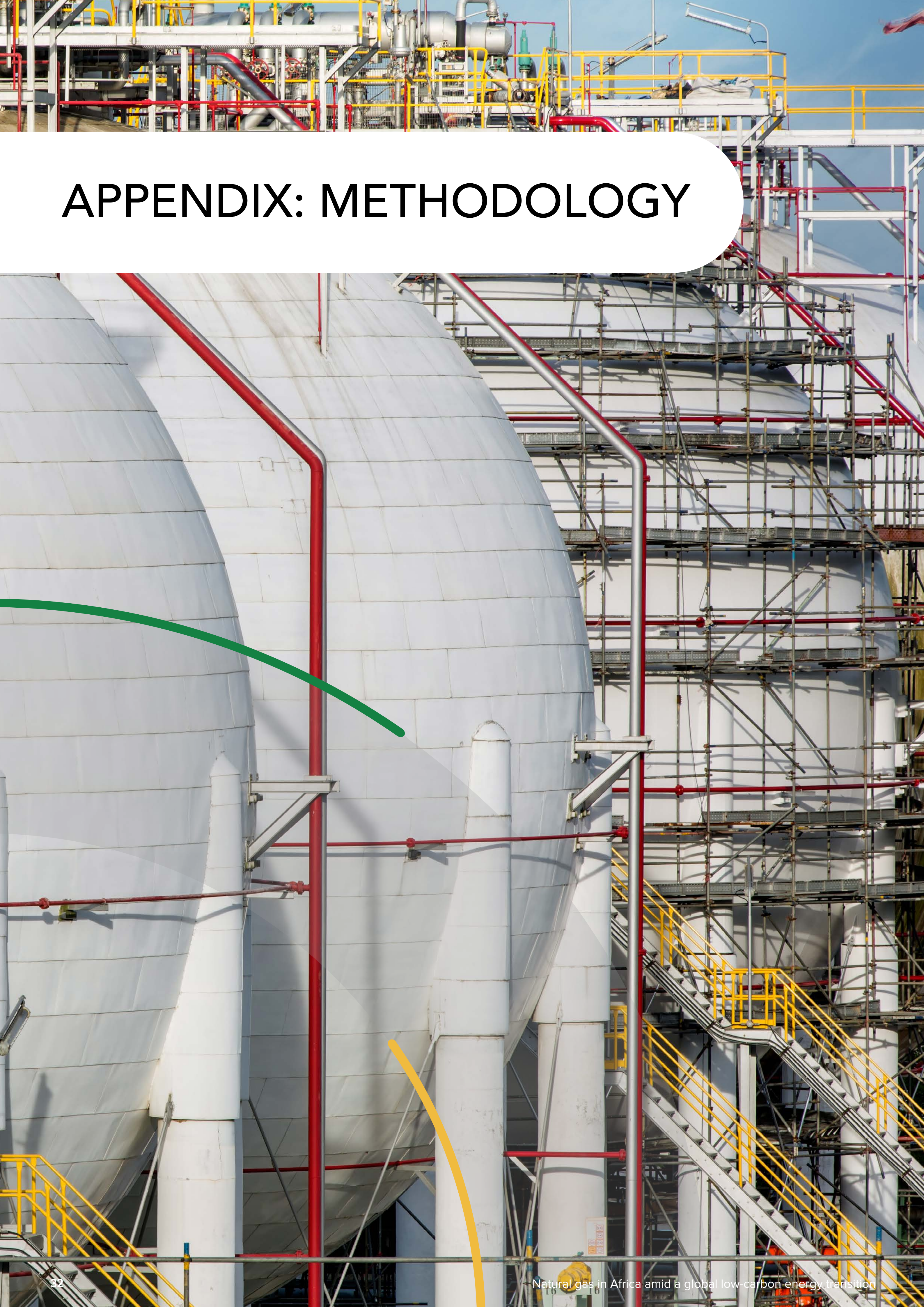
EXISTING PRODUCERS

- Climate transition risks must be factored into negotiations with commercial partners, co-investors, and lenders.
- The future cost of gas should be accurately reflected in market modelling, rather than relying on the current price environment in domestic power planning.
- The future cost of gas should be accurately reflected in financial modelling, rather than using the current price environment in planning large export infrastructure.
- An earlier and more rapid transition in oil markets will likely necessitate a move away from oil-linked gas pricing.
- Planned regulated prices for domestic consumption will need to be tested against the costs of investing in new infrastructure and the returns likely to be required by international investors.

EMERGING PRODUCERS

- Climate transition risks must be factored into negotiations with commercial partners, co-investors, and lenders.
- Government revenues should be stress tested against climate transition scenarios.
- Forecasts of future revenues should be thoroughly stress tested if sovereign debt is raised.
- Any future LNG contract negotiations should be based on gas price linkage, rather than oil.
- Standards and processes for methane and CO_2 emissions tracking and mitigation should be factored into any developments.
- Gas revenue management should be implemented to ensure that the threshold of revenue saving builds resilience to transition risk.
- The competitiveness of alternatives should be assessed when proceeding with domestic-gas-led industrialisation.

APPENDIX: METHODOLOGY



The approach used in the study is described here. As indicated in the main body of the text, outputs from the WTW global LNG model were used to provide the data for the analysis. The Appendix begins by defining the scenarios explored in the study, then describes the global LNG model, and finally concludes with a description of the analytical approach that underpins the narrative.

Global climate transition scenarios

The analysis used in this report considers four scenarios. Each scenario is a profile of future global LNG demand in line with a world constrained by a specific carbon budget, or total greenhouse-gas emissions that can be emitted over a fixed period. The scenarios outlined below are specific to gas, but they are modelled to be consistent with WTW in-house scenarios for all principal sources of primary energy (for example, oil, gas, coal, renewables, hydrogen, etcetera). All scenarios extend to 2050.

No Holds Barred (NHB) shows what happens if the world continues along its present path, without any additional changes in policy, beyond what has already been implemented. This means that the effects of country pledges or announcements are not considered unless they are enshrined in legislation.

Business as Usual (BAU) reflects all of today's announced policy intentions and targets, insofar as they are backed up by detailed measures for their realisation. This scenario is used to quantify the status quo value of natural gas across all 12 countries.

Well Below 2 Degrees Centigrade (WB2C) maps out a way to meet decarbonisation goals, requiring rapid and widespread changes across all parts of the energy system. This scenario charts a path aligned with the Paris Agreement by holding the rise in global temperatures to well below 2°C above pre-industrial levels.

Net Zero Emissions by 2050 (NZE) sets out a narrow but achievable pathway for the global energy sector to achieve net-zero CO_2 emissions by 2050. This represents a best estimate of a scenario aligned with a global temperature increase limited to 1.5°C.

Global LNG model

WTW's global LNG model is used to forecast LNG production, consumption, and prices between today and 2050 by balancing the regional LNG demand scenarios with asset level data for all the global LNG liquefaction assets and their upstream sources of supply. To produce these outputs, the model does not just simply balance demand and supply at the global level but does so while optimising trade flows between demand regions and producing assets. Annual demand is split between various regions (see, for example, the regional split for 2021 in Figure 17).

Over 160 LNG assets are included in the model, across all continents, ranging from those that are yet to be approved to those that have been producing for decades. Data summarising the production capacity and costs of supplying LNG to the market is included for each asset, in each year, thereby providing a global LNG supply cost curve. The raw data used in these calculations is largely sourced from the well-renowned global energy data provider, Rystad Energy. Each supply curve is correct for total costs at the point of export, or "free-on-board" (FOB) costs. LNG shipping costs, including charter rates and fuel and canal costs, are then calculated for each potential trade flow between supplying asset and demand region, to complete the total supply cost profile, specific to every potential combination of exporter and importer.

This cost matrix provides a key input to an optimisation routine, which seeks to provide the supply and demand combinations that satisfy the demand of each region, in each year, simultaneously in such a way as to minimise total costs. Based on the principle of marginal supply pricing, the most expensive supply segment used to meet demand in each region sets the clearing price in each region. These clearing prices are then organised into regional time series to produce the final price forecasts for each climate transition scenario. Figure 18 shows summarised trade flows between exporting regions and demand regions, across two scenarios, in 2025.[25] Figure 19 displays the resulting price forecasts for two of these demand regions, across the time horizon of the model.

[25] Asset level flows from exporting countries are grouped at the regional level in Figure 18, for illustrative purposes

Figure 17: LNG demand split between regions in 2021

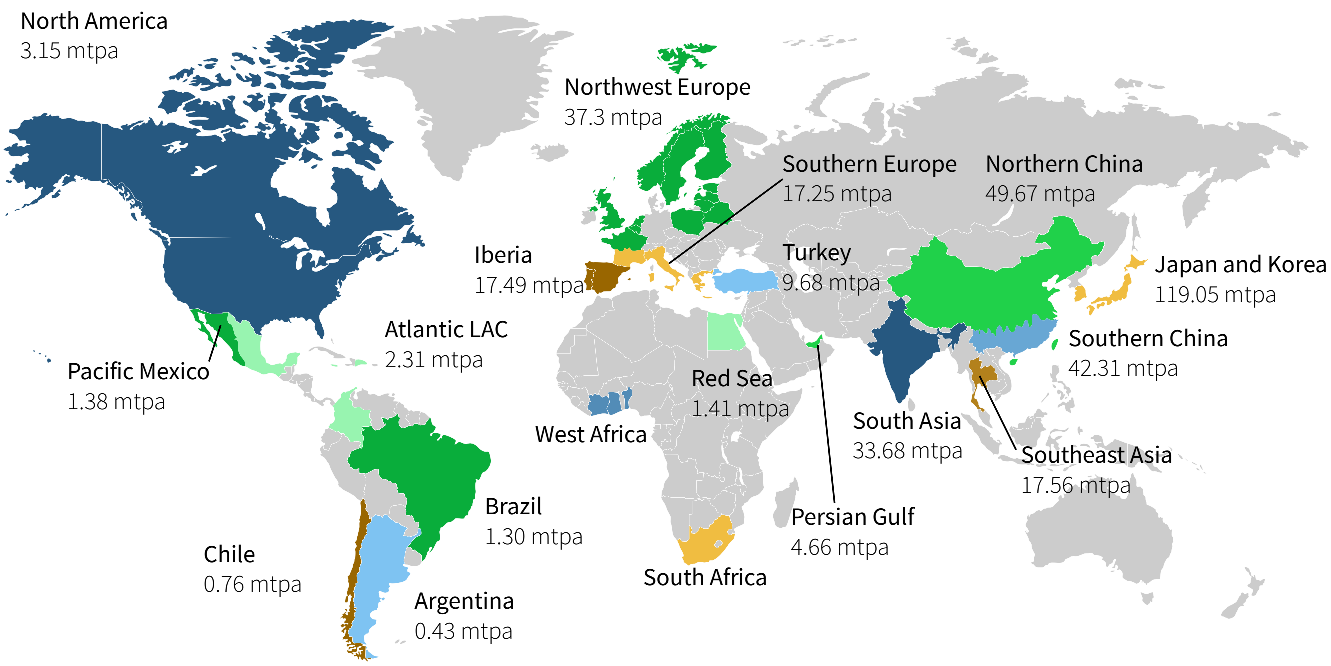
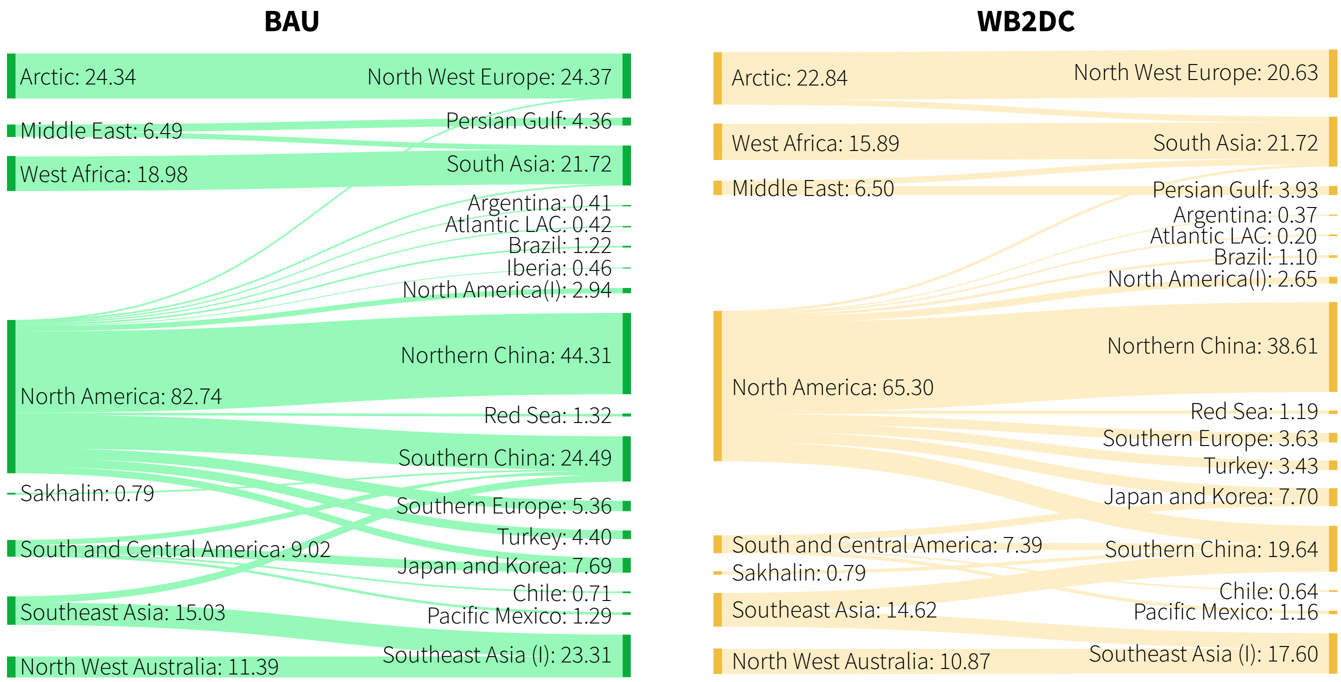
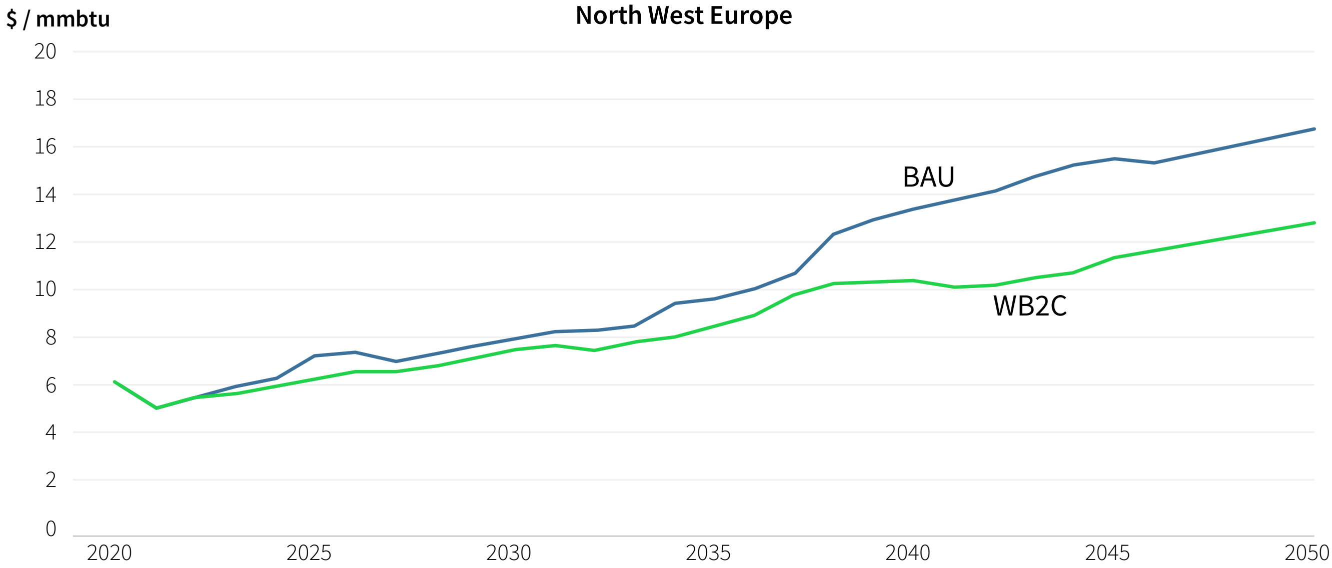


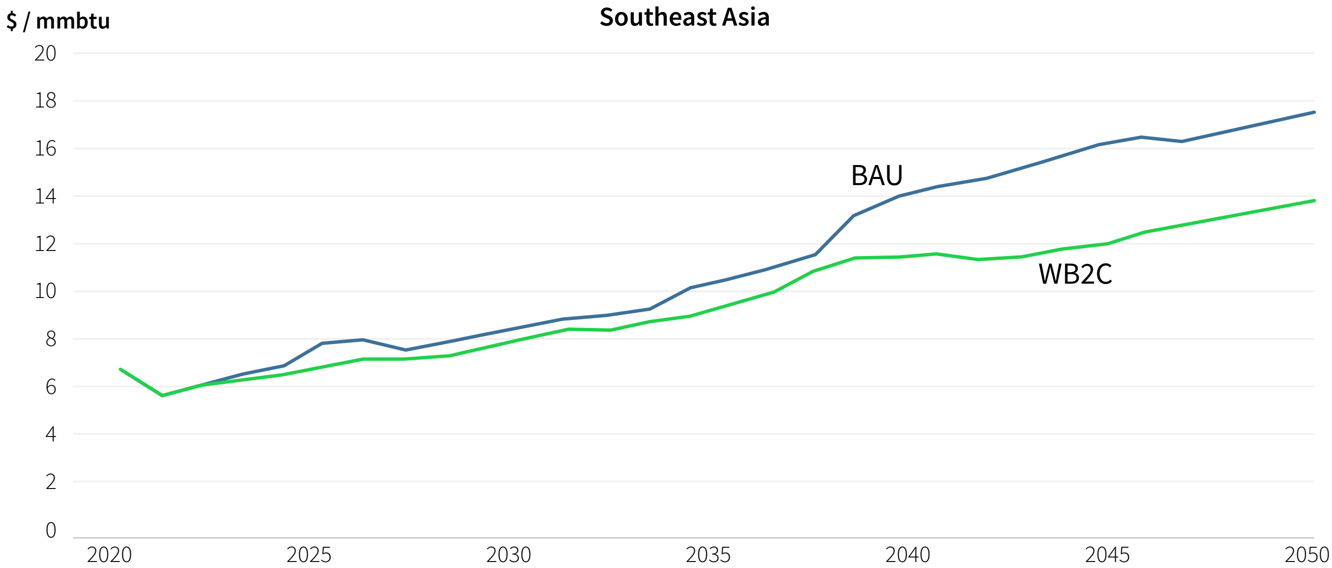
Figure 18: Trade flows in 2025 across two demand scenarios



The analysis presented in this report was conducted prior to the Russian invasion of Ukraine. It is too early to predict whether the resulting price shocks will continue into the long term in a BAU scenario. However, there is confidence that the modelling of orderly transition to WB2C globally will still produce price forecasts at a similar level to the WB2C shown above. As for BAU, it is expected that a more bullish outlook will be observed in the short to medium term, as Europe seeks to diversify away its gas supply from Russian pipeline imports, increasing European LNG demand.

Figure 19: BAU and WB2C scenarios price forecasts, for North West Europe and Southeast Asia





Analytical approach

The study covers 12 existing and potential future natural gas producers in Africa. They span both North Africa and sub-Saharan Africa and include countries with different levels of wealth and economic strength.

The status quo production was assessed for each country by forecasting production profiles based on all known natural gas finds, split by project or license area. These profiles are first assessed based on technical feasibility, then on economic feasibility – or whether BAU export revenues along with any domestic regulated revenues would be sufficient to generate returns sufficient to attract investment the gas resources. The raw data (potential production volumes and detailed economics for each asset) was obtained from Rystad Energy. Domestic demand trajectories for each country are sourced from publicly available material and reflect BAU demand profiles. The value of gas production to the country was then calculated based on the net present value of total gas revenues (export and domestic), using a common discount rate of 8% being used across the entire study.[26]

All LNG export assets (both future and current) across the 12 countries were assessed, testing them across the BAU and NZE LNG demand scenarios to determine whether each terminal would be viable in each scenario.

[26] The 8% discount rate, as an approximation, reflects the typical weighted average cost of capital (WACC) for oil and gas companies over the past couple of decades.

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