OIL AND GAS FORECAST TO 2050

Energy Transition Outlook 2017

SAFER, SMARTER, GREENER

FOREWORD

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The world's energy system is going through a transition. Over the next thirty years it will change significantly in its composition as it decouples from carbon, population and economic growth.

DNV GL's Energy Transition Outlook seeks to understand the nature and pace of this change. We have created an independent forecast of what we believe to be the most likely energy future. It will inform our own strategic choices over the years to come, and we hope it will also provide useful insight to our customers, partners and other stakeholders.

We forecast energy demand to flatten, mainly due to increased efficiencies in the use of energy, after 2030. Industry across energy sources and throughout the energy value chain will continue to make energy available, affordable and clean.

There won't be a 'silver bullet' for sustainable energy production; instead the world will benefit from a portfolio of technically sophisticated and cost-effective energy. The oil and gas industry will continue to play an important role in this portfolio and hydrocarbons will account for 44% of the total energy mix in 2050. Key areas of demand for fossil fuels will be within heavy

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Increased dialogue and collaboration is required to drive the energy transition transportation, air and shipping. Gas is predicted to become the largest energy carrier from 2033 to the end of our forecast period.

Tomorrow's energy system will be characterized by enhanced efficiency with reduced waste of energy, cost and resources in all stages of the value chain. For oil and gas this not only means enhanced recovery and cost efficiency, but also the use of each energy source and carrier where it is most effective. A plateau in demand and cheaper resources will lead to tough competition between energy sources where supply exceeds demand. There will be an increased need and opportunity to serve energy systems with a flexible mix of sources and carriers, and to identify and exploit synergies between these.

This transition does not come by itself, and the details of the energy system will vary significantly between regions and countries. Increased dialogue and collaboration is required to drive the transition: between industry, policymakers and regulators, between various parts of the energy industry and between countries and regions.

We hope that this report can trigger and support this dialogue.

ELISABETH TØRSTAD

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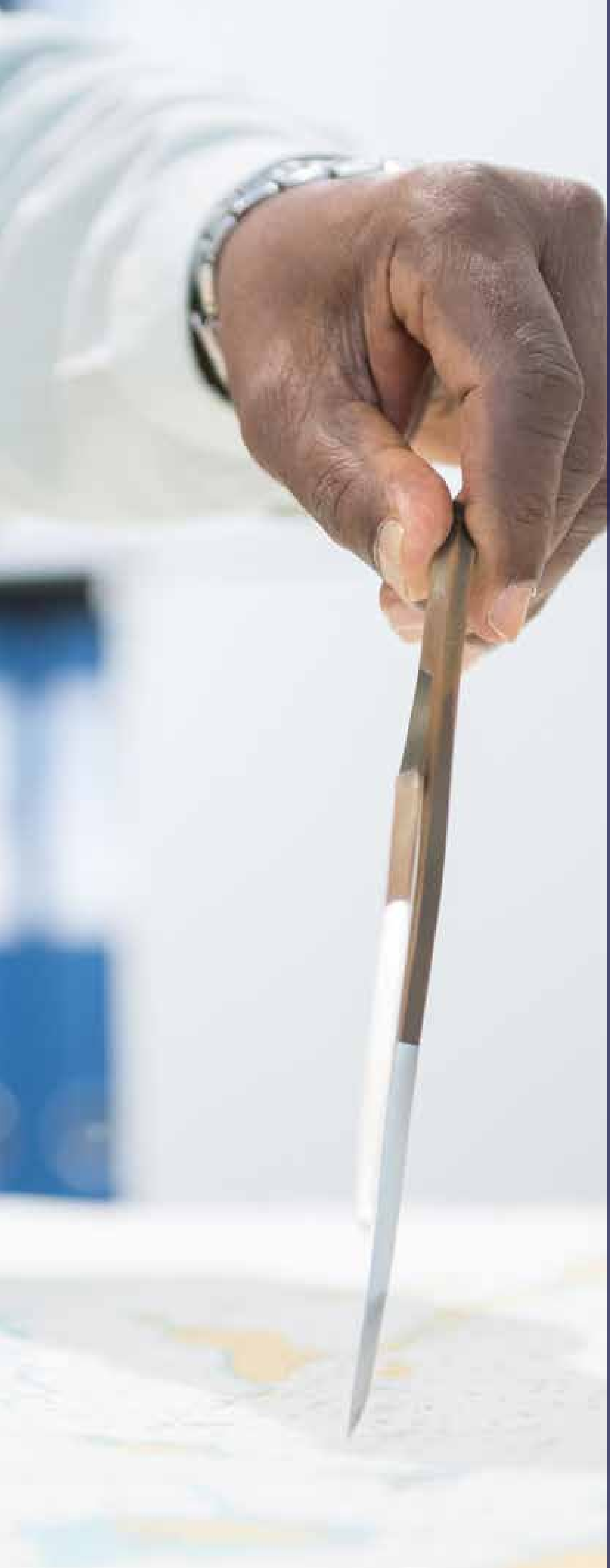
HISTORICAL DATA

CONTENTS



1

EXECUTIVE SUMMARY

1. EXECUTIVE SUMMARY

The energy transition will be characterized by many sub-transitions in the next three decades. Based on the DNV GL model of the world energy system, we forecast that global final energy demand will flatten at 430 exajoules (EJ) from 2030 onwards (7% higher than 2015), reflecting accelerating improvement in global energy efficiency, driven largely by the electrification of the world's energy system and an increased share of renewables.

Oil and gas will play a very important role in the energy mix throughout our forecasting period. Although we expect renewable energy sources to take an increasing share of this mix, we forecast oil and gas to account for 44% of the world's primary energy supply in 2050, down from 53% today. Investment will be needed to add new oil and gas production capacity, and to operate existing assets safely and sustainably over this period, to deliver output levels that can meet predicted demand.

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The oil and gas industry will play a very important role in the energy mix throughout our forecasting period

The stage is set for gas to become the world's primary energy source towards 2050, and the last of the fossil fuels to experience peak demand, which will occur in 2035 according to our model. Gas can play a central role in supporting energy security alongside variable renewables during the transition. There are opportunities to improve its carbon footprint by curtailing methane emissions from its value chain and through improving the economics of large-scale carbon capture and storage (CCS) for gas-fuelled power generation. We expect demand for oil to be at its maximum in 2022 and the high point for coal has already passed.

The growing role of gas, and declining demand for coal and oil will reduce the carbon intensity of fossil fuel use, as oil and gas majors continue to focus on reducing the carbon footprint of their business portfolios. However, our model forecasts that global warming will likely reach 2.5 degrees Celsius (°C) above pre-industrial levels. This is not in line with the COP 21 Paris Agreement on climate change, which aims to keep global warming to 'well below 2°C'.

Against this background, this report provides an in-depth analysis of the implications of our model across the oil and gas value chain.

UPSTREAM

Conventional oil production will play an important role in the global energy mix for decades to come. Conventional onshore oil production will decline 1.4% per year on average until 2050, but will still account for more than 50% of all oil production by then.

Unconventional onshore oil production will roughly double to around 22 million barrels per day (Mbpd) by 2035 when it will have nearly a 30% share of all global crude oil production.

Offshore oil production will still be important in 2050, but it is set to more than halve from today's 30Mbpd.

Conventional onshore gas production will start declining from about 2020 along with offshore gas production while unconventional onshore gas rises to a plateau. Conventional onshore gas production will fall strongly in North America while rising in North East Eurasia, and Middle East and North Africa. Production will remain high throughout the period to 2050.

Unconventional onshore gas will retain an important share of gas supply in North America with production increasing towards 2025 and then declining slightly until 2050.

Technologies such as subsea processing and unmanned tiebacks will improve the economics of oil and gas production from deepwater and/or harsh environment offshore fields. Adopting industry-wide standards can reduce scope inflation, which contributed to compound annual growth of more than 10% in capital expenditure (capex) per barrel of oil between 1999 and 2013.[1] Enhanced intra-sector collaboration can reduce inefficiencies at interfaces along the supply chain. Increased use of digitalization and automation will also play a leading role in keeping production costs down, and aligns with our forecast of a slowly reducing cost base.

MIDSTREAM

Gas trade forecasts and other results from our model support the requirement for: new pipelines including those for cross-border transmission; and liquefied natural gas (LNG) terminals of varying scale. We predict an average 1.8% annual increase in seaborne natural gas trade (LNG and liquefied petroleum gas (LPG) combined) from 340 million tonnes per annum (Mtpa) today to around 640Mtpa in 2050. Gas transport trends will drive globalization of markets for gas trading. »

With gas demand set to persist until at least 2050, there will be increased costs and activity on older pipeline systems in world regions (see *References*) such as North America, Europe, North East Eurasia and the Middle East and North Africa. In North America in particular, pipeline systems continue to be repurposed and undergo change of service due to shifts in where gas is produced and consumed, and LNG exports being allowed.

Leading gas transmission system operators will progressively incorporate advances in artificial intelligence, augmented reality, the industrial Internet of Things and machine learning into systems and processes. This will assist them to maintain, repair and operate networks safely and cost-efficiently, and provide customers, regulators and partners with tailored analyses of large volumes of data.

DOWNSTREAM

Increasingly, customers will buy units of 'energy' rather than volumes of a fuel. More accurate and consistent measurement of the 'energy value' delivered will be required. Greater computing power and more advanced data analytics will allow gas distribution system operators to manage more complex data and customize the results for internal and external stakeholders.

Global refinery oil demand will reach a high by 2022 at only 2% above 2017 levels, followed by a 39% decline by 2050, due largely to significantly reduced transport sector oil demand. We expect greater focus in mature markets on producing cleaner, higher-grade transport fuels. Indian and Sub-Saharan Africa markets will likely concentrate on building scalable and operationally flexible refinery capacity.

We predict a 30% decline in petrochemicals production levels over 30 years, driven by regional transitions in product demand and in feedstock supply, which will show increasing gas reliance as oil consumption declines. Globally, we foresee a drive, aided by greater and more sophisticated digitalization, to optimize lifecycle performance for existing and new-build facilities throughout the refining and petrochemicals sectors. ■

> The stage is set for gas to become the world's primary energy source towards 2050


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2

INTRODUCTION

2. INTRODUCTION

Driven by our purpose of safeguarding life, property and the environment, DNV GL enables organizations to advance the safety and sustainability of their businesses.

Around 70% of our business is energy-related. We provide classification, technical assurance, software and independent expert advisory services to the maritime, oil and gas, and the power and renewable energy industries. We also provide certification services to customers across a wide range of industries.

Based on the insights and knowledge of these industries, we have now made an independent forecast of what the world's energy future will look like and how the energy transition may unfold. We share with stakeholders and customers our foresight on supply and demand trends, and our high-level analyses of these.

This publication is one part of DNV GL's new suite of Energy Transition Outlook (ETO) reports. In all, four publications provide predictions through to 2050 for the entire world energy system. The outlooks are based on our own independent energy model, which tracks and forecasts regional energy demand and supply, as well as energy transport between regions.

Alongside the company's main outlook[2], the suite includes three reports discussing implications for separate industries: oil and gas[3]; power and renewables[4]; and maritime.*

Our core ETO model is a system dynamics feedback model, implemented with the Stella modelling tool. It models energy demand, and the energy supply required to meet it. Key demand sectors such as buildings, manufacturing and transportation (air, maritime, rail and road) are analysed in detail.

In a somewhat crowded field of energy forecasting, our work seeks to create value by:

— Source-to-sink treatment of the entire energy system, including for example the impact of increased global transport of liquefied natural gas (LNG) on emissions from ships
— Focus on technology trends and needs for the future
— Focus on the ongoing transition, rather than the status quo of the energy system.

In this publication for the oil and gas industry, the energy requirements of key demand sectors that we have modelled are translated into trends we expect to see across the value chain. We discuss in detail how the oil and gas energy system will meet this demand from existing and new conventional and unconventional production capacity onshore and offshore. We also consider the implications for LNG and pipelines. The enabling roles of digitalization and emerging technologies are also considered.

DNV GL's model includes forecasting of the energy transition in 10 global regions (see page 73). Some key predicted regional trends and analyses are included in this publication. More detailed analysis is available from DNV GL. We can also tailor such content to the needs of individual organizations and companies.

Our outlooks, including that for oil and gas, present our independent view of what we consider to be the most likely future amid the energy transitions unfolding around us.

We also stress that we present only one 'most likely' future, not a collection of scenarios. The coming decades to 2050 hold significant uncertainties, notably in areas such as future energy policies, human behaviour and reaction to policies, added to the pace of technological progress, and trends in the pricing of existing and new technologies. A full analysis of sensitivities related to our energy system modelling is available in our main report.

It should also be noted that we have modelled oil and gas production independently of each other. In reality, these are connected. This limitation should be considered when reviewing the results. ■

**Our main outlook report, oil and gas report, and power and renewables report were published in September 2017. Our maritime report will be published later in the year.*

3

OIL AND GAS DEMAND FORECAST

3. OIL AND GAS DEMAND FORECAST

We see a world where, for the first time since at least the industrial revolution, global energy demand is likely to peak. In 2015, total global final energy demand was 400EJ—equivalent to 9,600 million (m) tons of oil—and will increase to 430EJ in 2050, according to our model.

Final energy demand has risen 35% over the past 15 years, but we expect it to increase by only 7% between 2015 and 2030. Thereafter, it will become virtually flat, because of slower growth in productivity and global population, and continuous increases in energy efficiency.

We forecast that gas, followed by oil, will be the two largest energy sources at the end of the forecast period (figure 1). Continued investment will be needed over this time to maintain production at levels required to meet demand.

However, the mix and contribution of renewables will increase, driven by strong growth in solar and wind. Our ETO main report provides detailed analysis of estimated consumption across all energy sources in the lead-up to 2050.

ENERGY CONVERSION

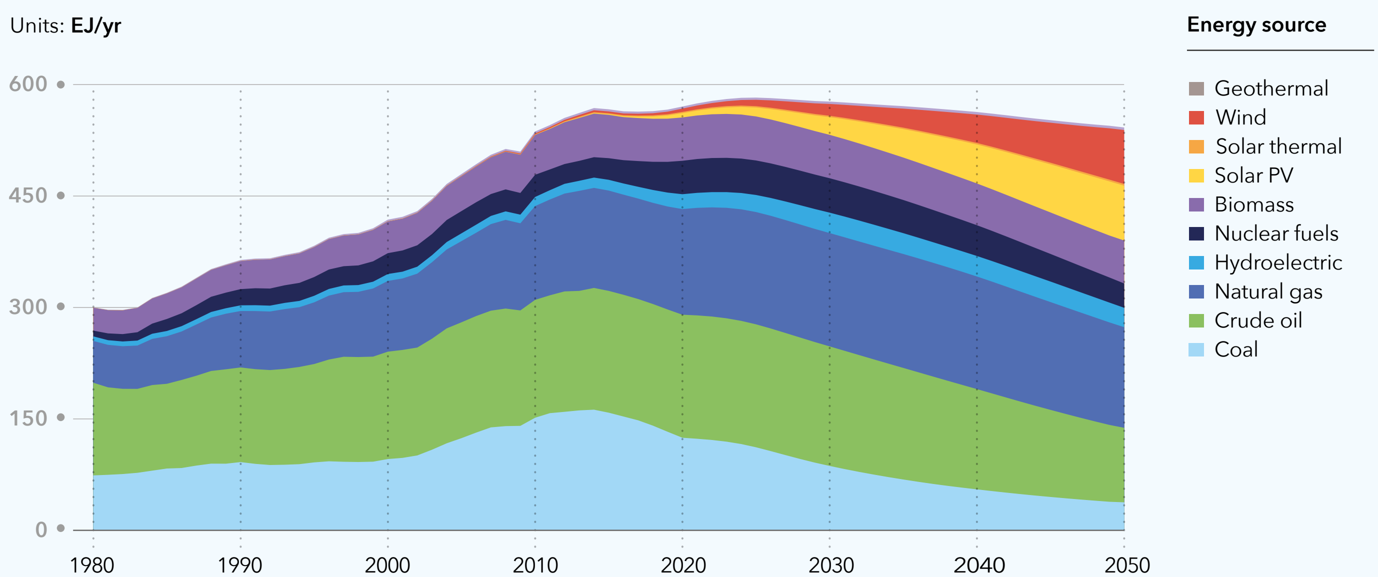
EJ, TWh or Mtoe?
The oil and gas industry normally presents its energy figures in million tons of oil equivalents (Mtoe), while the power industry is used to terawatt hours (TWh). The International System of Units' principal measure for energy, however, is joules, or rather exajoules (EJ) when it comes to global production. This is the unit we have chosen in our outlook.

SOME SIMPLE CONVERSION FACTORS

23.88Mtoe = 1EJ

277.8TWh = 1EJ

WORLD PRIMARY ENERGY SUPPLY BY SOURCE (FIG 1)



OIL DEMAND

Our model forecasts almost flat oil demand over the coming 15 years, with the peak coming as early as 2022 (figure 2).

Demand growth is expected to come from emerging economies, with the largest growth markets being China, India, South East Asia and Sub-Saharan Africa.

A decline in demand will begin, with significant decreases in North America, Europe, Pacific OECD, and later in China. This is driven largely by changes in the transport market, resulting from a shift to electrifying domestic and commercial transport, and the increased efficiency of next-generation engines fuelled by petroleum and diesel.

While transport remains the main source of oil demand throughout the period, reliance on oil for this purpose will reduce from 104EJ/yr in 2030 to 51EJ/yr by 2050. The growing use of electric vehicles will influence this significantly. Non-oil energy sources accounted for 9% of energy use in transportation in 2016; we forecast this to increase to 50% in 2050.

Direct oil demand in manufacturing and buildings is relatively small, but is expected to reduce somewhat in both those sectors over the forecast period, reaching 9EJ/yr (manufacturing) and 2EJ/yr (buildings). The power sector will also demand around 8EJ/yr of oil, down from 10EJ/yr today.

GAS DEMAND

Global demand for gas has more than doubled in the past 30 years. It will increase for another two decades, according to our model, peaking in 2035 at just below 160EJ: 14% higher than today (figure 3). Thereafter, gas consumption will go into moderate decline. »

In Europe, demand peaked in 2010 at little more than 20EJ/yr. Pacific OECD followed suit above 8EJ/yr in 2015. For North America, we expect a high approaching 35EJ/yr in 2020.

Demand will continue increasing over an extended period in other regions, with the high points, rounded to the nearest whole number, being: Latin America, 10EJ/yr (2030); China, 20EJ/yr (2034); North East Eurasia, 36EJ/yr (2039); South East Asia, 8EJ/yr (2035); Middle East and North Africa, 26EJ/yr (2042). Demand on the Indian Subcontinent and in Sub-Saharan Africa will rise all the way to 2050 to reach 13EJ/yr and 7EJ/yr respectively.

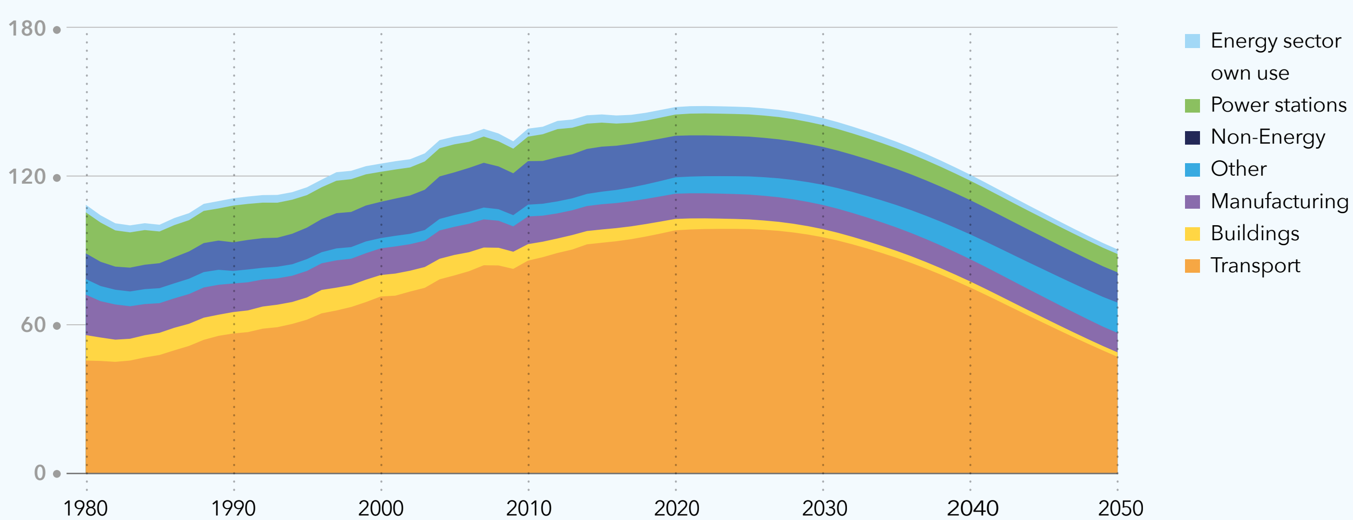
The power generation sector will be the principal consumer of gas in most regions, challenged only by the manufacturing sector in India, China and Latin America. Gas use in power generation will increase sharply over the next 15 years, before levelling off and then declining relatively steeply towards the end of the forecast period when wind and solar start to dominate power supply.

Global gas consumption for the buildings sector remains stable over the forecast period, although we see decline in North America, Europe and Pacific OECD, and a strong increase in consumption in Sub-Saharan Africa. Global gas consumption in manufacturing increases slightly in both relative and absolute terms. Gas use in transport will increase, notably in shipping, where gas use will represent 30% of all energy use in 2050.[5]

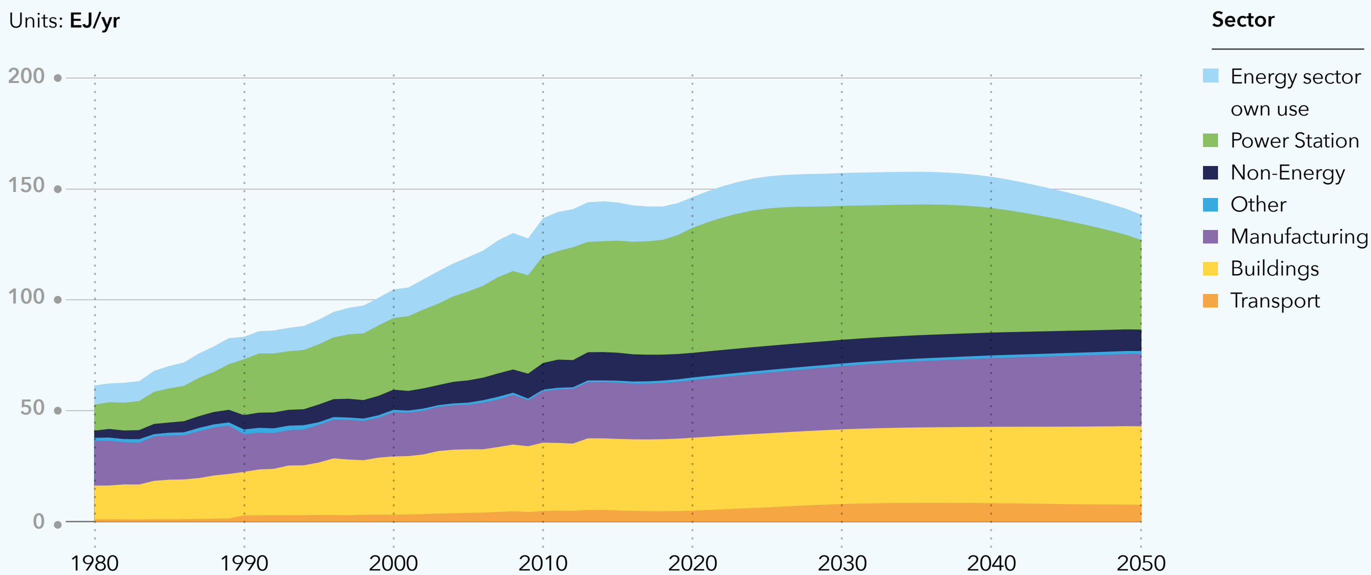
> Continued investment will be needed to maintain production at levels required to meet demand

WORLD OIL DEMAND BY SECTOR (FIG 2)

Units: **EJ/yr**



WORLD GAS DEMAND BY SECTOR (FIG 3)



4

TRENDS AND IMPLICATIONS

4.1 ONSHORE AND OFFSHORE OIL EXPLORATION AND PRODUCTION

ONSHORE OIL EXPLORATION AND PRODUCTION

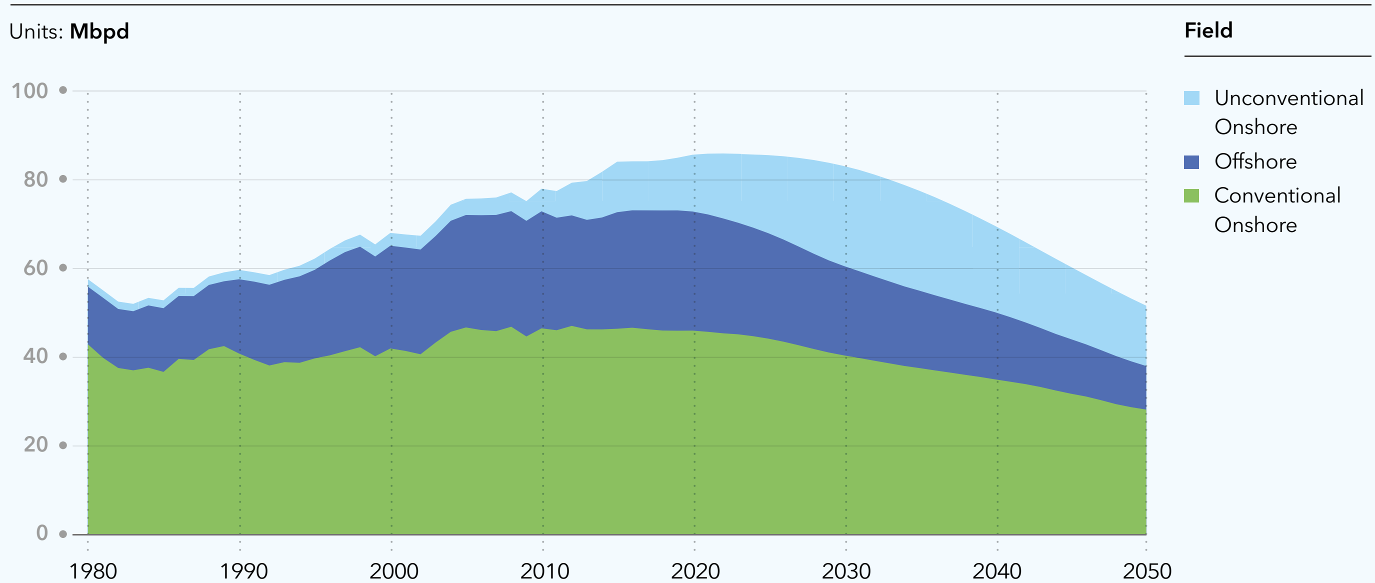
Our model predicts continued, substantial but declining global crude oil production between now and 2050 (figure 4). The forecast curve is for production to rise from nearly 82 million barrels per day (Mbpd) in 2015 (excluding NGLs and other liquids) to a high of 83Mbpd in 2022 before declining, slowly at first then more quickly, to hit 50Mbpd in 2050.

Conventional onshore oil will continue to provide the major and most stable share of total oil production. It will still account for more than 50% of the global figure by 2050, though we forecast a steady decline in production level averaging 1.4% per year over the forecast period.

Unconventional onshore oil production, meanwhile, will double to around 22Mbpd by 2035, when it will account for nearly 30% of all global crude oil production.

CRUDE OIL PRODUCTION BY FIELD TYPE (FIG 4)

Units: **Mbpd**



Offshore oil production will still be operational in 2050 but is set to more than halve from 30Mbpd in 2015.

More than half of conventional onshore oil production will likely come from the Middle East and North Africa by 2050, followed by North East Eurasia, including Russia (figure 5). Production from North East Eurasia will decline significantly from 2020, but it will still be the second largest producing region. Latin America will move into a clear, though distant, third place as output from China declines.

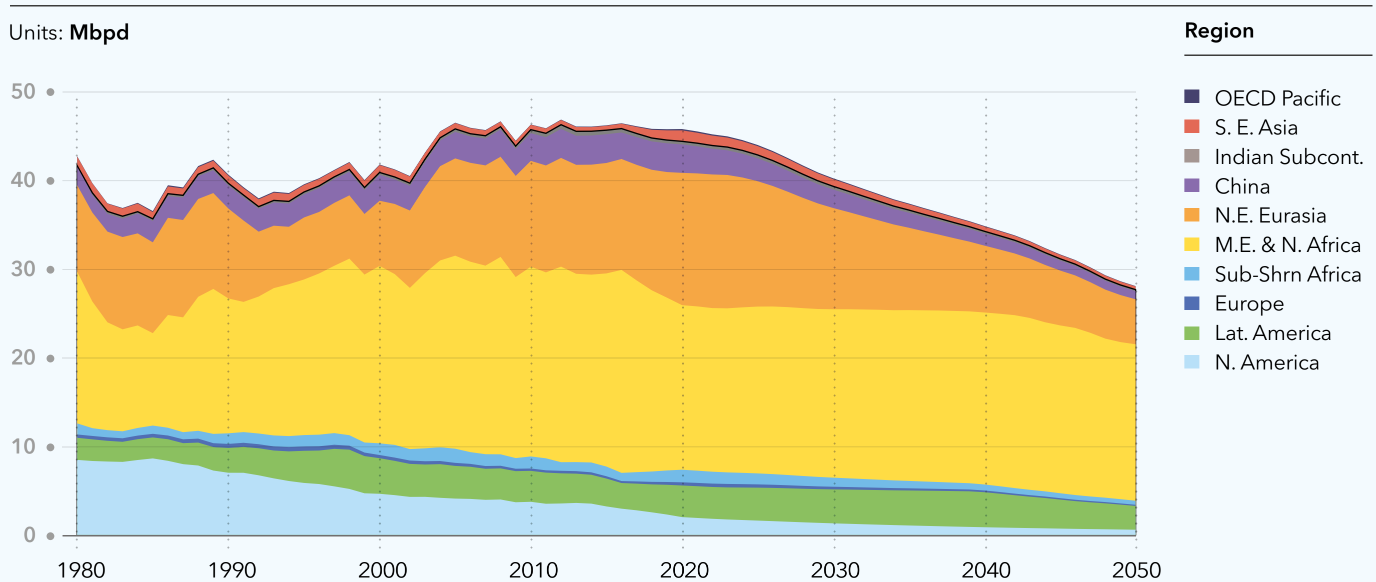
This underlines the continued importance in the future of Middle East and North Africa, and its geopolitics, in oil production. Our model assumes that regional supply increases are driven by large-scale, low-cost oil resources, especially in the Middle East and North Africa, as producers respond to growing abundance by asserting competitive advantage.

CAPACITY ADDITIONS: CONVENTIONAL ONSHORE OIL

To ensure both short-, mid- and long-term supplies of energy, our model forecasts the production capacity addition required to compensate for energy sources depletion. To meet predicted oil demand, the industry needs to add capacity as fields deplete, and assets retire after their lifetime. »

> Conventional onshore oil will continue to provide the major and most stable share of total oil production

CONVENTIONAL ONSHORE OIL PRODUCTION BY REGION (FIG 5)



The model predicts that the world's annual need for new conventional onshore oil capacity additions will reduce by nearly three-quarters by 2050 (figure 6).

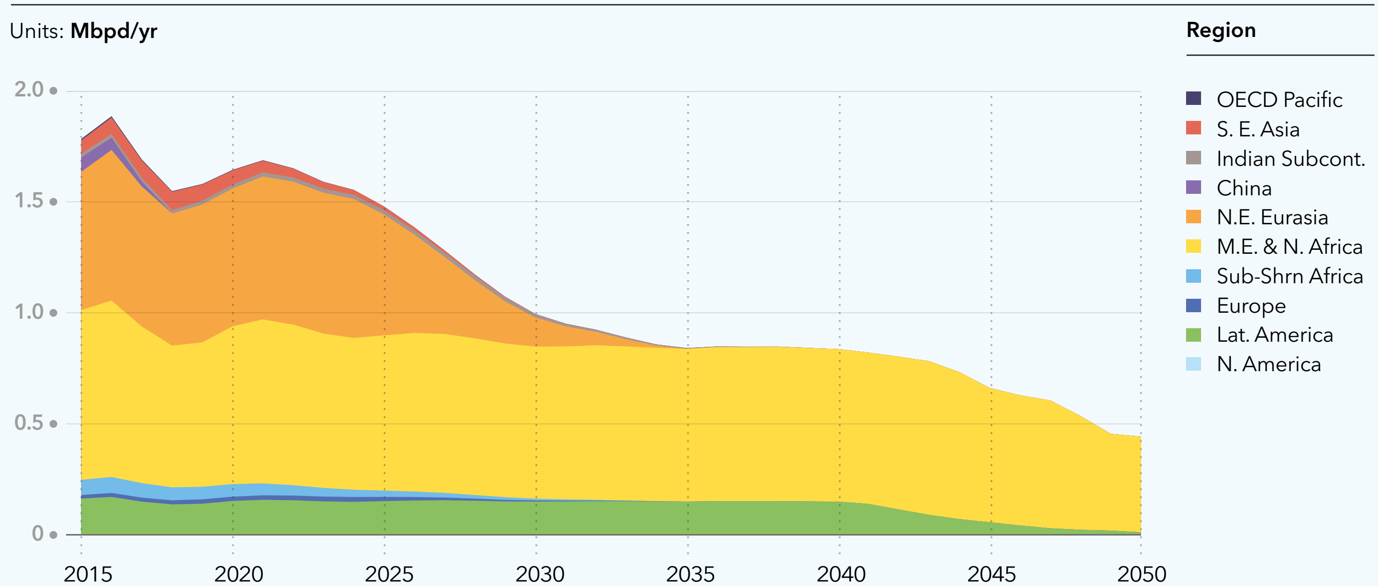
Production capacity additions in Europe, North East Eurasia, South East Asia and Sub-Saharan Africa are set to become practically negligible by the mid-2030s. Over this period and beyond, Middle East and North Africa will assume ever-increasing importance as the main centre of additional conventional onshore oil production, maintaining this status until at least mid-century.

Given the rise of unconventional onshore oil in North America, our model does not predict any new additions to conventional onshore production there between 2018 and 2050. The same applies to China as it pursues decarbonization policies that will be centred on renewables and gas. New capacity additions in Latin America are predicted to remain stable to 2040 before reducing to practically zero in 2050.

Regions that will require the greatest capital (capex) and operational (opex) expenditure for conventional onshore oil production to meet predicted demand (figure 7) are Middle East and North Africa and North East Eurasia, including Russia. These two regions will consistently attract the most investment between now and 2050, with China, India, Latin America and South East Asia also seeing substantial spend, either capex or opex, over various periods within that timeframe. »

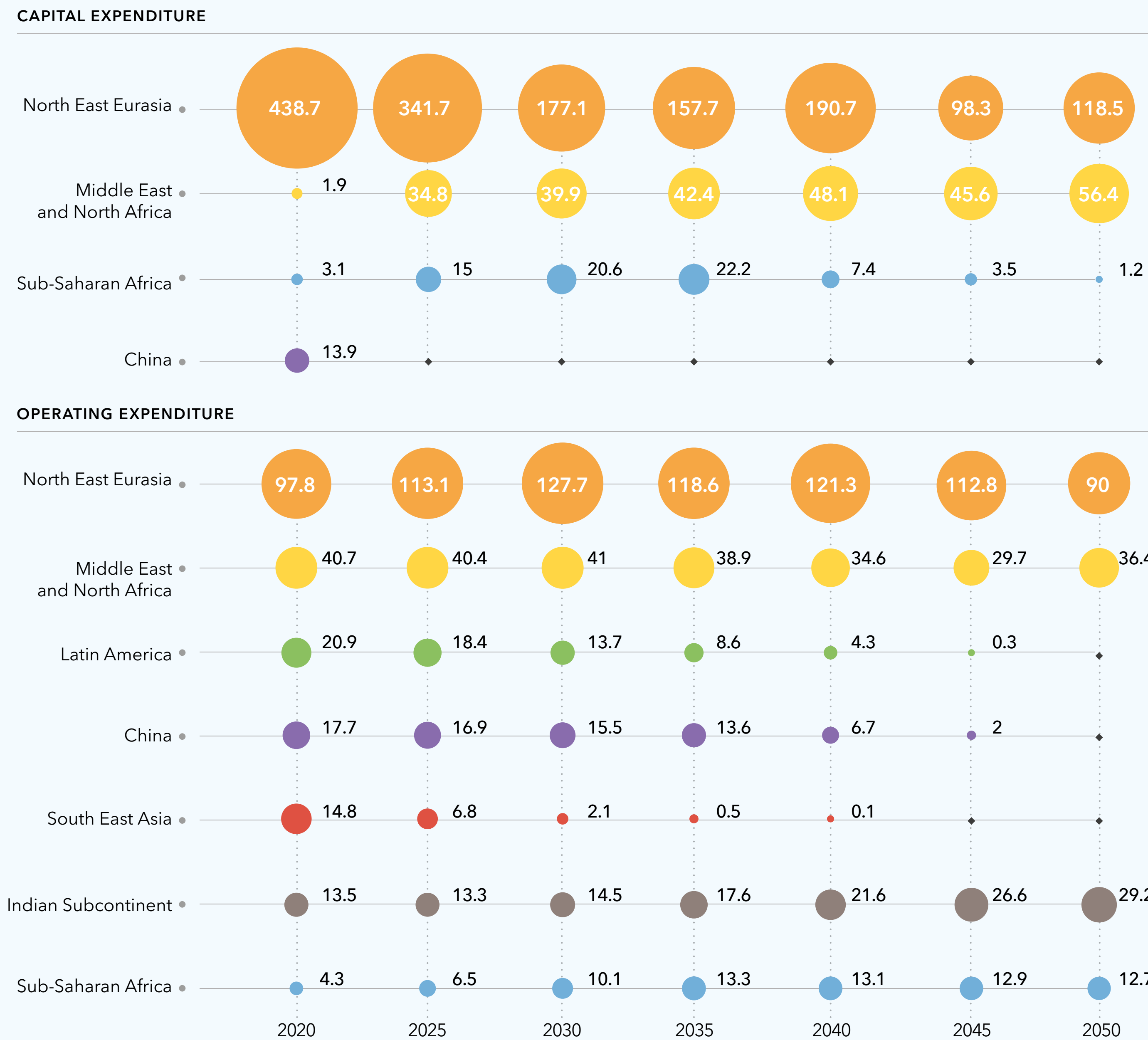
> The world's annual need for new conventional onshore oil capacity additions will reduce by nearly three-quarters

WORLD CONVENTIONAL ONSHORE OIL PRODUCTION CAPACITY ADDITIONS BY REGION (FIG 6)



INVESTMENT (USD BN) REQUIRED FOR CONVENTIONAL ONSHORE OIL PRODUCTION 2020-2050 (FIG 7)

Units: **USD bn/yr**



Beyond the resource availability and lower cost of capex and opex, the principal reasons for further investments in conventional onshore oil in the Middle East and North Africa, and North East Eurasia include: security of supply; protecting independence; reducing external pressure on local gross domestic product (GDP); and enhancing political and social stability through investment in local employment.

BLURRING LINES BETWEEN CONVENTIONAL AND UNCONVENTIONAL OIL

As we see in our model (figure 4), increasing volumes of accessible unconventionals could add significantly to oil supply, reducing the distinction between conventional and unconventional oil.

This trend is explained not just by improving technical innovations unlocking access to unconventional oil pools previously rendered unviable. Historically, major oil pools have been developed by conventional methods. Recognition of the limited availability of such resources—such as onshore the Middle East and North Africa, in the North Sea and in the Gulf of Mexico—and of the need to enhance security of supply, sparked development of alternative drilling and production techniques often described as unconventional.

Discussion about conventional and unconventional oil developments can lead to a misunderstanding that these techniques rival each other, or are mutually exclusive. The opposite is true; the method can change for a given location, on- or offshore. Once conventional oil can no longer be extracted, switching to unconventional methods can extend field life and restore production rates, for example.

One notable feature of the recent lower oil demand environment is that we now see clear evidence of the impact of the two different production techniques in oil markets. In the conventional oil production model, the Organization of the Petroleum Exporting Countries (OPEC) would traditionally restrict production to raise prices for its members. After a period during which supply and demand rebalanced, markets would stabilize at a new, higher price, at which point OPEC would turn on the taps again.

Now, when OPEC cuts production, unconventional producers who are efficient enough to be profitable at an oil price of USD50-55 per barrel, and probably even lower in the future, can respond rapidly at that trigger point with production increases that defeat OPEC efforts to raise prices. Because they are not bound by OPEC agreements, unconventional producers can do this every time, creating a situation where large conventional field operators will always be beaten to the rewards of dearer oil before prices are forced down again by rising supply.

This is set to create a medium-term supply challenge because operators are reluctant to invest in large conventional field developments while oil prices are low. While our model is not built to forecast short- and medium-term trends, oil production shortages seem likely if production from conventional fields declines faster than output from unconventionals grows.

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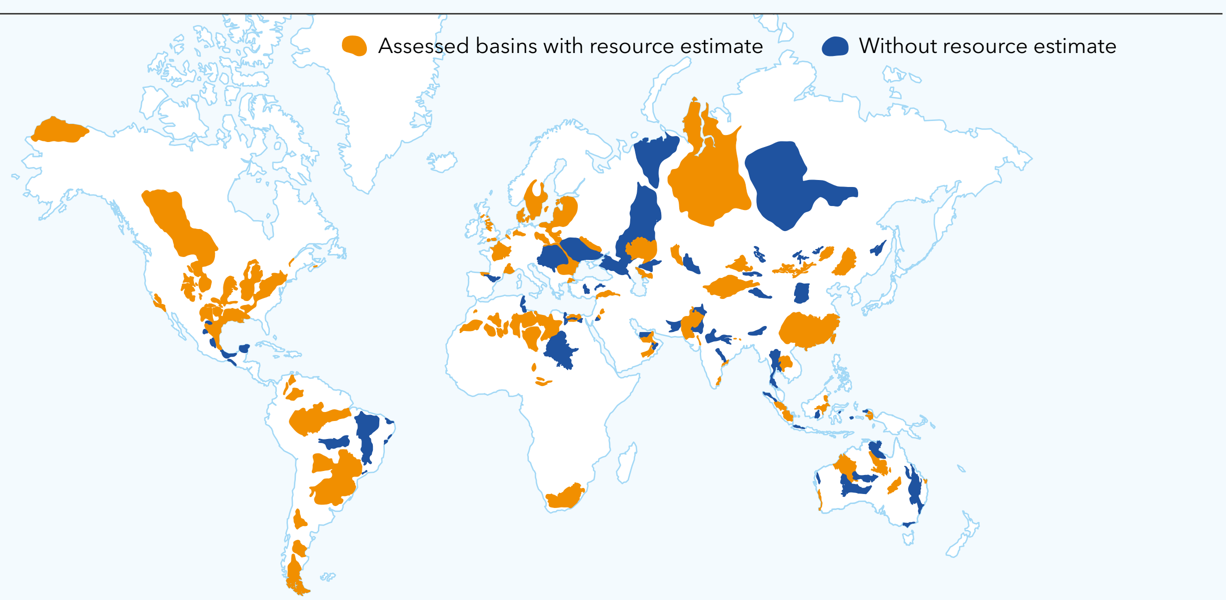
Increasing volumes of accessible unconventionals could add significantly to oil supply, reducing the distinction between conventional and unconventional oil

GLOBAL IMPACT: UNCONVENTIONAL OIL PRODUCTION BEYOND THE AMERICAS

Continual additions to estimated reserves have delineated 137 shale formations in 41 countries in recent years (figure 8). Global unconventional recoverable oil reserves are estimated between 500 billion (bn) and more than one trillion (tn) barrels. North America and Latin America dominate production, but other regions such as China and North East Eurasia will feature as technology, infrastructure, regulation, public acceptance and oil demand evolve. More rapid production growth outside the Americas will not happen for another five to 10 years however.

The recent identification and development of unconventional oil resources creates potential positive impacts on energy supply. With its ability to rapidly turn unconventional production up and down, the US shale industry has arguably become the world's new swing producer, at least for the short term. For the foreseeable future, major shale oil developments will be centred in the Americas, and will continue to have an impact on oil supply and therefore oil prices in the near term. »

GLOBAL UNCONVENTIONAL OIL AND GAS RESOURCES (FIG 8)



Source: U.S. basins from U.S. Energy Information Administration and United States Geological Survey; other basins from Advanced Resources International (ARI) based on data from various published studies

Our model predicts that, at current production rates, North American shale oil output will resume growth from 2020 to top out at around 14Mbpd by 2034 (figure 9). Latin America can expect sustained growth in unconventional onshore production from less than 2Mbpd now to nearly 7Mbpd in 2031 before declining from the mid-2030s. If there is significant development in North America and the average price falls across all regions and for both sands and shale, utilization of unconventional oil in the energy marketplace could extend further into this century.

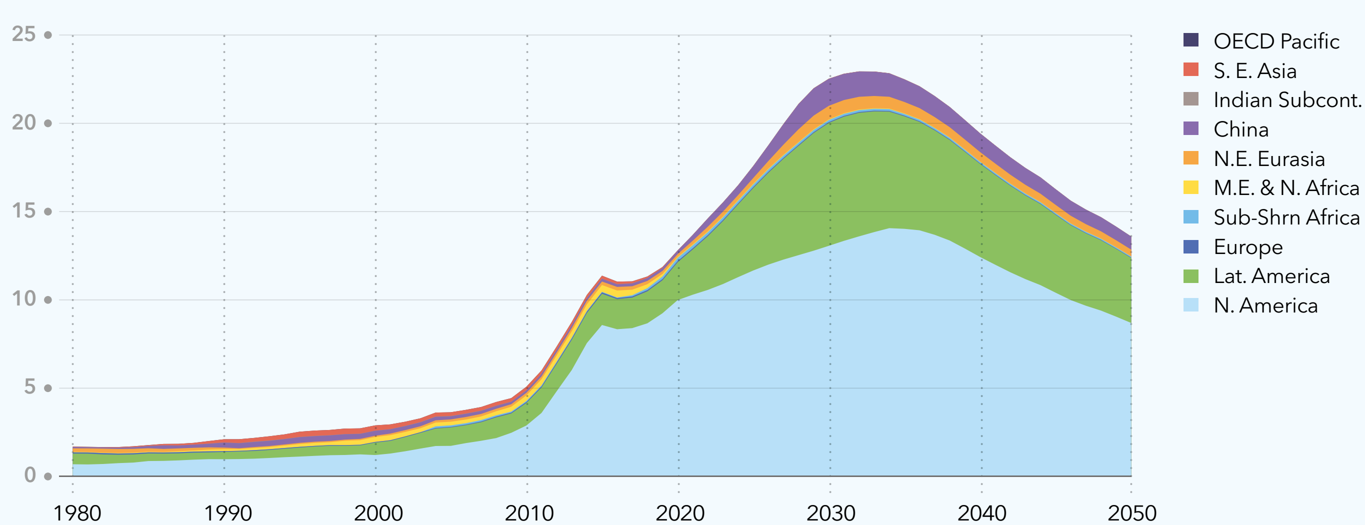
To fully realize the economic benefits of developing unconventional oil resources outside the Americas, countries must address several key challenges. They need: access to drilling rigs and equipment; efficient horizontal drilling and hydraulic fracturing technologies (see section 4.5: *Digitalization and automation*); enough trained workers with the right skills; new or upgraded pipelines and roads to the many unconventional oil resources that are in remote areas; and, not least, public acceptance of developments.

If these challenges can be met, then depending on the development of regional policy frameworks, demand, price and the level of renewables development, unconventional oil has the potential to play a significant transitional role in providing energy until mid-century. Our model results indicate that the shale revolution will not be global, but that the effects of it will be.

In Europe, for example, current policies for oil and gas exploration will remain important in investment decisions. In the longer term, further policies on decarbonization will likely result in tougher planning approval and permitting processes for new developments onshore.

UNCONVENTIONAL ONSHORE OIL PRODUCTION BY REGION (FIG 9)

Units: **Mbpd**



CAPACITY ADDITIONS: UNCONVENTIONAL ONSHORE OIL

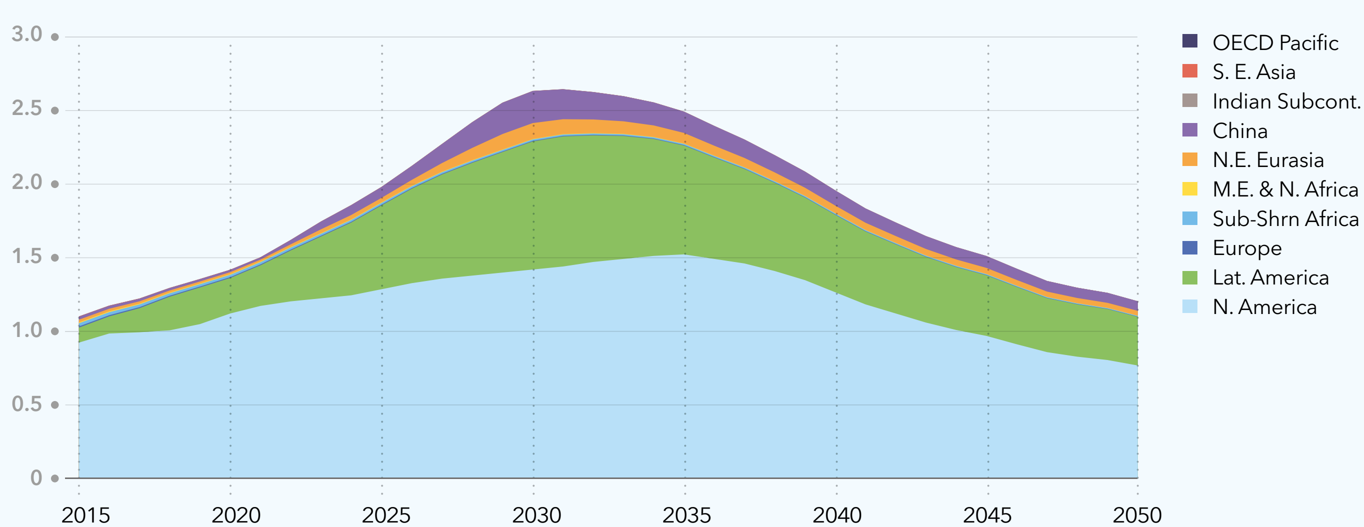
Globally, the annual rate at which new production capacity is being added for unconventional onshore oil is predicted to rise from around 1Mbpd/yr in 2015 to a high of nearly 3Mbpd/yr in 2031 (figure 10). A near-eightfold increase of the rate in Latin America between 2015 and a regional high of almost 1Mbpd/yr in 2031 is a notable feature.

North America is set to remain the largest regional provider of new production capacity throughout the entire forecasting period from 2015-2050, accounting for 83% of the global total in 2015, a low of 55% in 2031, and 64% in 2050. The region's huge unconventional oil reserves could, if required, sustain the rate of capacity additions predicted for 2035 well beyond that point. Beyond the sheer scale of recoverable reserves, digitalization and data analytics—which lie at the heart of targeting the most productive parts of reservoirs in unconventional oil plays—will enable increasing production efficiencies and recovery rates. Forecasting a peak in new production capacity for North America instead reflects declining global demand for liquids, a rising preference for gas over oil, and increasing exploitation of unconventional oil resources in other regions. ■

> North America is set to remain the largest regional provider of new unconventional onshore oil production capacity

UNCONVENTIONAL ONSHORE OIL PRODUCTION CAPACITY ADDITIONS BY REGION (FIG 10)

Units: **Mbpd/yr**



OFFSHORE OIL EXPLORATION AND PRODUCTION

Our model forecasts almost flat oil demand in the coming 15 years, with an eventual high in 2022. Offshore oil production is likely to gradually decline over the forecast period, from today's level at 26Mbpd to less than half that amount in 2030 (figure 11). The Middle East and North Africa is the only region for which our model predicts anything approaching a more-or-less sustained level of offshore oil production beyond 2020.

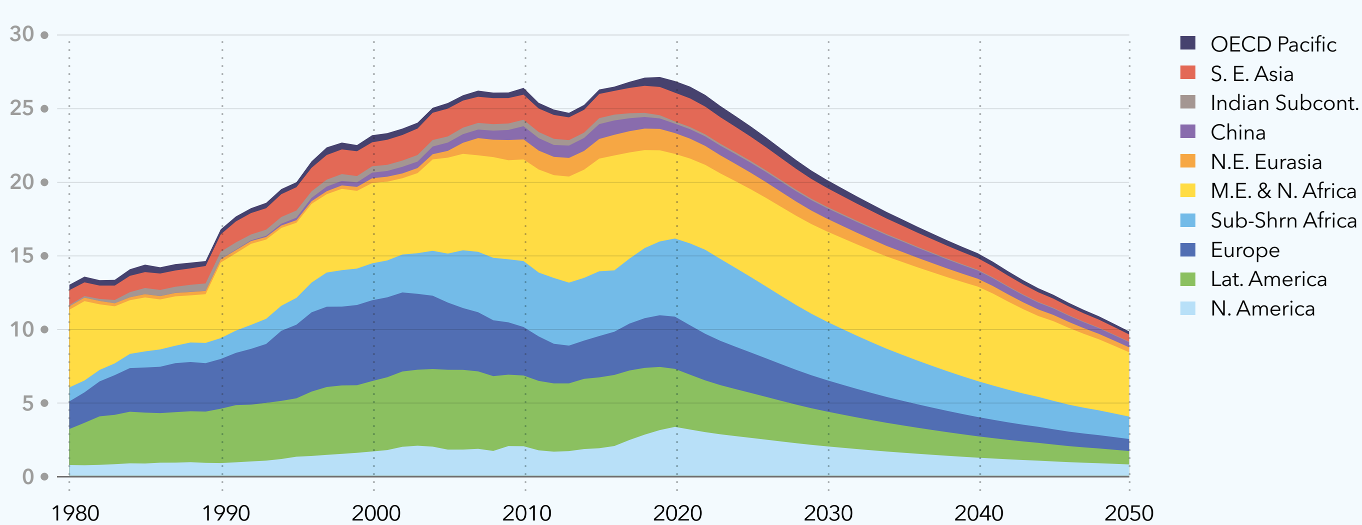
Interest in deepwater and harsh environment projects is reviving as technology and leaner field development options improve the economic case for making positive final investment decisions.[6]

Breakeven costs for deepwater developments dropped from an average of about USD75 per barrel in 2014 to USD62 in the first half of 2016 and USD55 in Q1 2017. If oil remains priced at around USD50 a barrel it could initiate development of several deepwater projects as early as 2018 because current industry expectations foresee prices rising to the USD60-70 range around 2020-2021 when any development projects started next year will start producing.

Day rates for harsh environment drilling rigs have halved in the past few years, but rig operators have also managed to achieve impressive cost savings. Several rigs have been scrapped, which has helped to restore positive operating margins for those remaining. A fleet of 125 drill ships and 188 semi-submersible drilling rigs were in operation worldwide at the end of 2015. While no new build semi-submersible drilling rigs and drill ships were ordered in that year, or indeed since, we expect demand to return slowly over the next three to five years. The deepwater new build market will take longer to recover.

OFFSHORE OIL PRODUCTION BY REGION (FIG 11)

Units: **Mbpd**



COST IMPLICATIONS

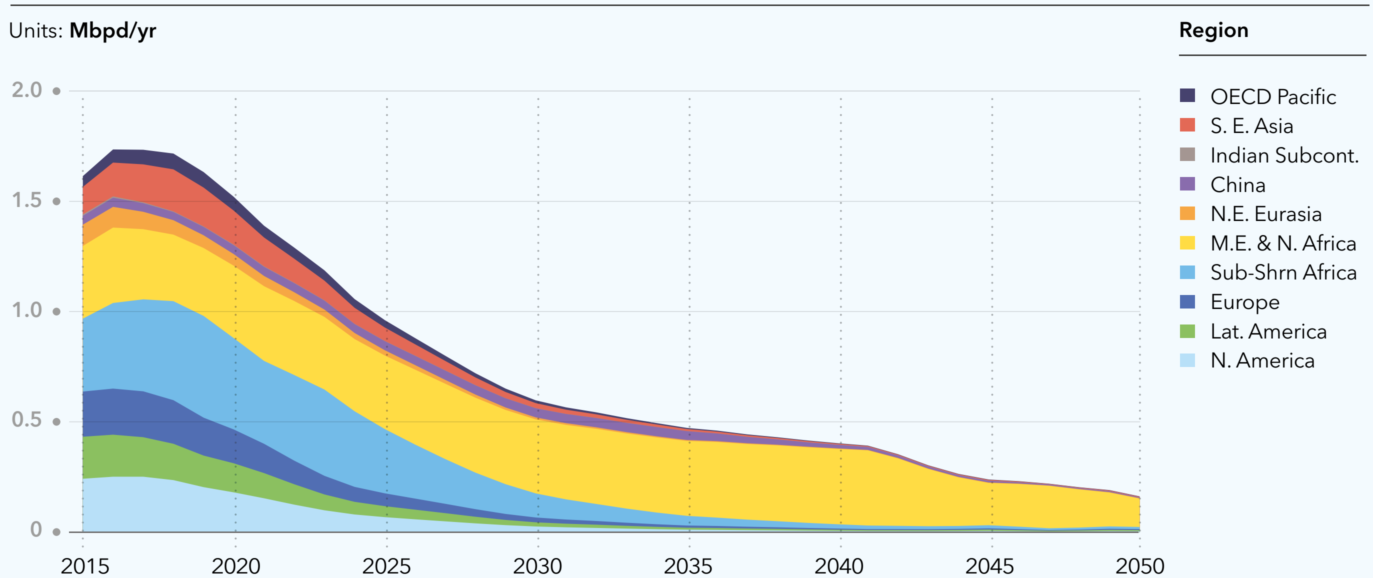
The industry has reduced offshore development and production costs by between 30% and 40% in the past three years. These reductions have been achieved through a series of measures such as commercial pressure on the supply chain, rapid technology implementation allowing improved design concepts for new development fields, and increased standardization.

We have seen a shift from fixed installations to floating production systems, even in shallower water. New developments in drilling and well design have allowed existing reservoirs to be further exploited. New, previously marginally economic reservoirs, or 'small pools', are now becoming viable. The emergence of subsea processing, which directly exports hydrocarbons to shore without a surface facility, or reusable spars and buoys to exploit a series of smaller, previously 'stranded' fields, are two examples of how innovation can extend field lives and lower costs.

Our model forecasts a continued decline in production costs. Given the predicted decrease in demand for oil over the forecast period, we believe that there is unlikely to be a rapid rise in oil prices, such as those witnessed in previous, cyclical market changes. While we do not model energy prices we do model costs, and our assumption is that in the long run prices will follow costs.

We are now heading for a peak in oil demand rather than supply. Consequently, we expect oil prices to stabilize. Shorter spikes may still happen, and these shorter cycles are not part of our forecast, but the longer-term trend is towards lower costs. »

WORLD OFFSHORE OIL PRODUCTION CAPACITY ADDITIONS BY REGION (FIG 12)



We expect the industry will turn to innovations in facility design, operating models and contracting strategies to maintain or improve operating margins. Increased digitalization, standardization and remote or autonomous operations will continue to bring cost savings to the industry and support developments in a lower oil demand environment (see section 4.5: *Digitalization and automation*).

CAPACITY ADDITIONS: OFFSHORE OIL

The rate at which new capacity is added annually to global offshore oil production is set to slow by 92% between now and 2050, according to our model (figure 12). It predicts an initially shallow short-term decline from close to 2Mbpd/yr in 2017, before a steep, decade-long fall from 2020 to 2030, then a more gradual downward path.

Drivers of decline will include: demand for oil falling steadily beyond 2022; substitution of gas for oil as a result of carbon reduction strategies in oil companies' business portfolios and in the global energy mix; the relatively high cost per barrel of developing offshore versus onshore oil in general (and unconventional oil in particular); and, the increasingly tough challenge to produce and transport oil from deeper and harsher climatic and metocean environments as the era of 'easy' offshore oil becomes a distant memory.

On average, the Middle East and North Africa has the lowest development costs and will see steady or increasing annual additions to offshore oil production capacity until the early 2040s. Sub-Saharan Africa will exceed these, but only until the mid-2020s. Every other region will see investment in new capacity of this kind declining from now, and at a rapid pace until 2030. ■

> We expect the industry will turn to innovations in facility design, operating models and contracting strategies to maintain or improve operating margins

4.2 ONSHORE AND OFFSHORE GAS EXPLORATION AND PRODUCTION

ONSHORE GAS EXPLORATION AND PRODUCTION

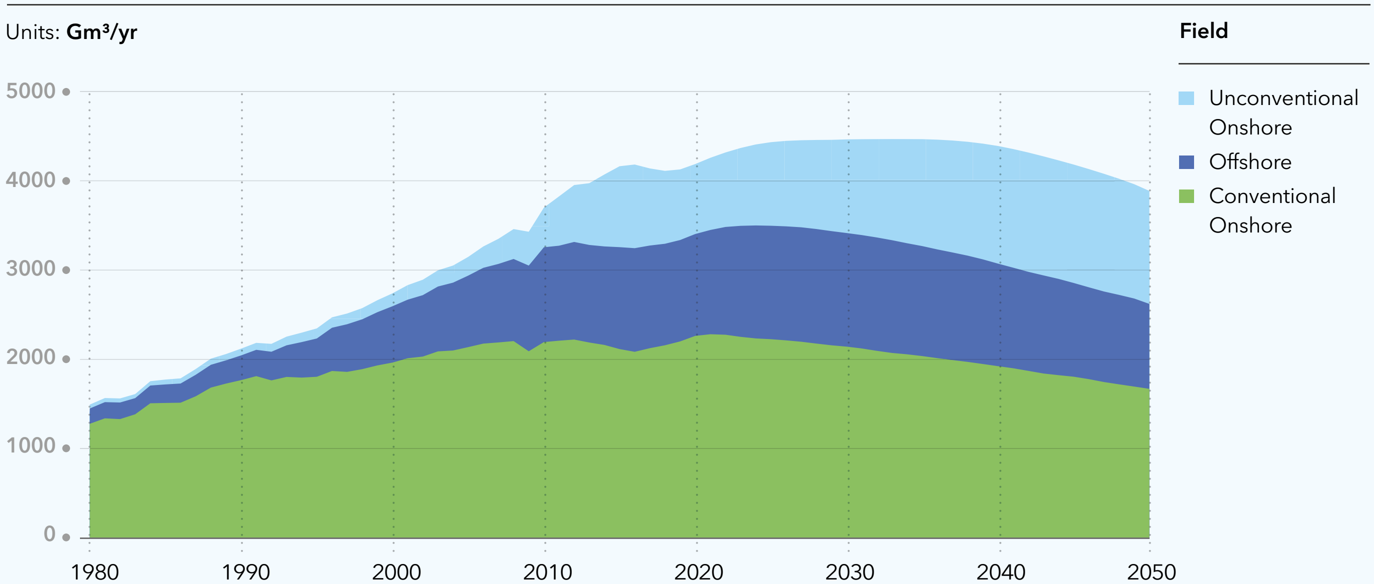
Conventional onshore gas production will start declining from about 2020 along with offshore gas production while unconventional onshore gas rises to a plateau, according to our model (figure 13).

Conventional onshore gas production will fall strongly in North America while rising in North East Eurasia. Middle East and North Africa production will remain high throughout the forecast period (figure 14).

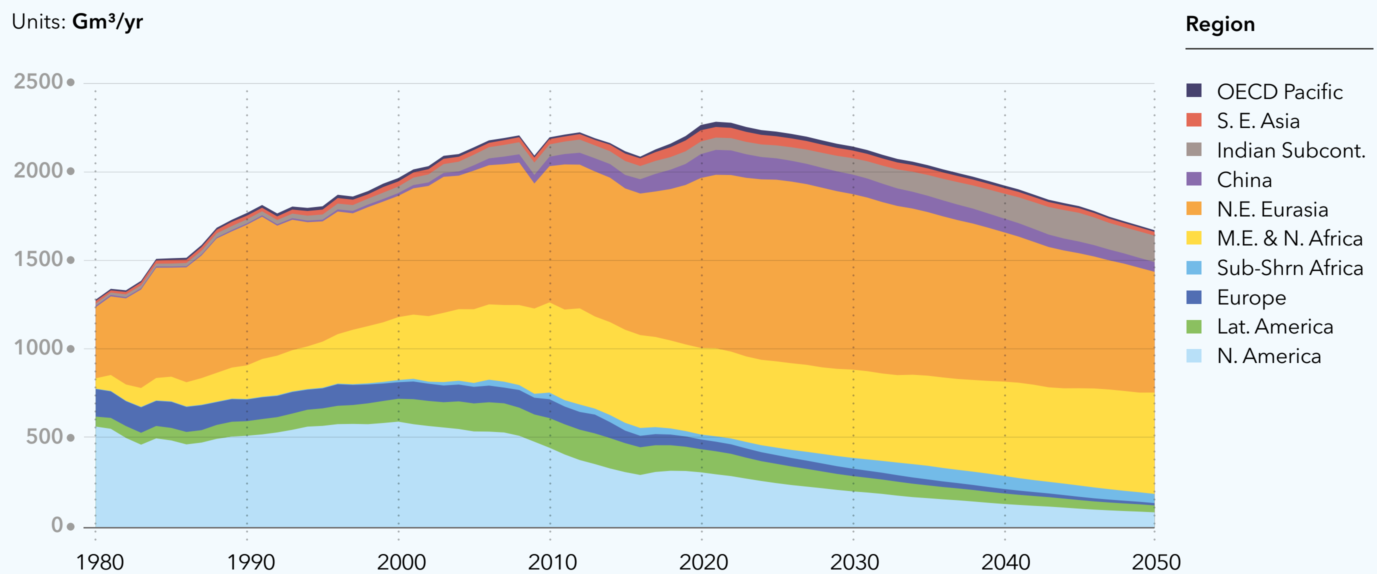
CAPACITY ADDITIONS: CONVENTIONAL ONSHORE GAS

The rate at which new capacity is added annually to global conventional gas production is set to rebound nearly 15% from nearly 63 billion cubic metres per year (Gm^3/yr) in 2017 to $72Gm^3/yr$ in 2022, according to our model (figure 15).

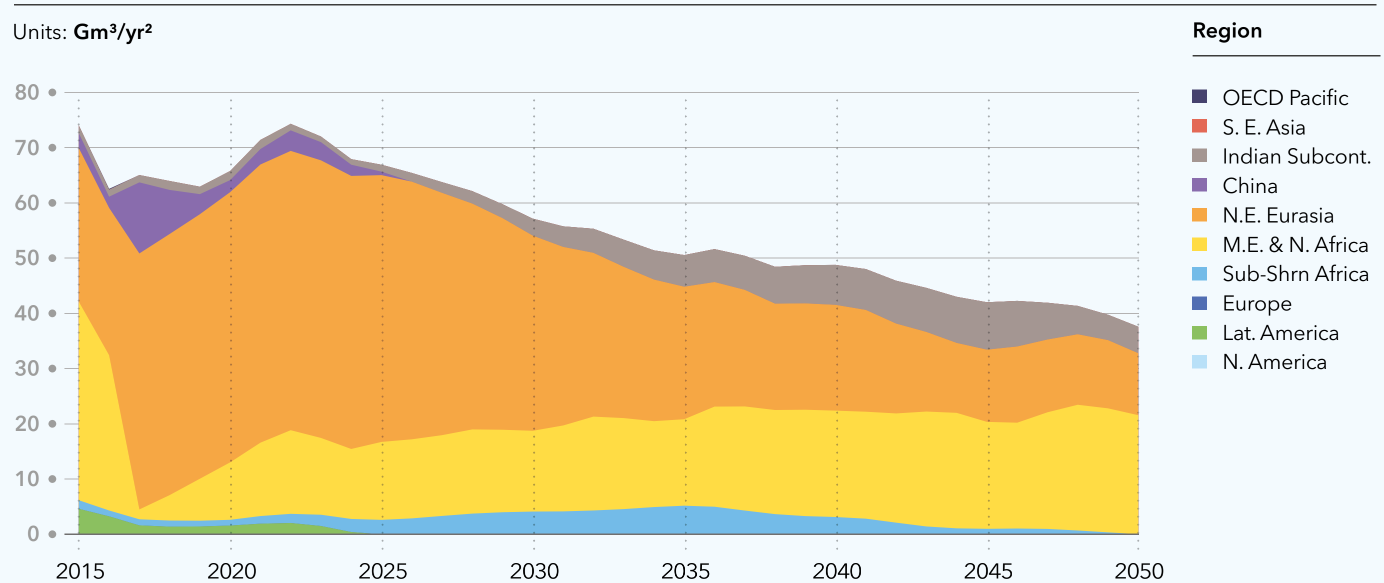
GAS PRODUCTION BY FIELD TYPE (FIG 13)



CONVENTIONAL ONSHORE GAS PRODUCTION BY REGION (FIG 14)



WORLD CONVENTIONAL ONSHORE GAS PRODUCTION CAPACITY ADDITIONS BY REGION (FIG 15)



Developments in North East Eurasia, including Russia, and in Middle East and North Africa, will account for most of this surge, but only Middle East and North Africa will increase or largely sustain the rate at which it adds capacity over the entire forecasting cycle.

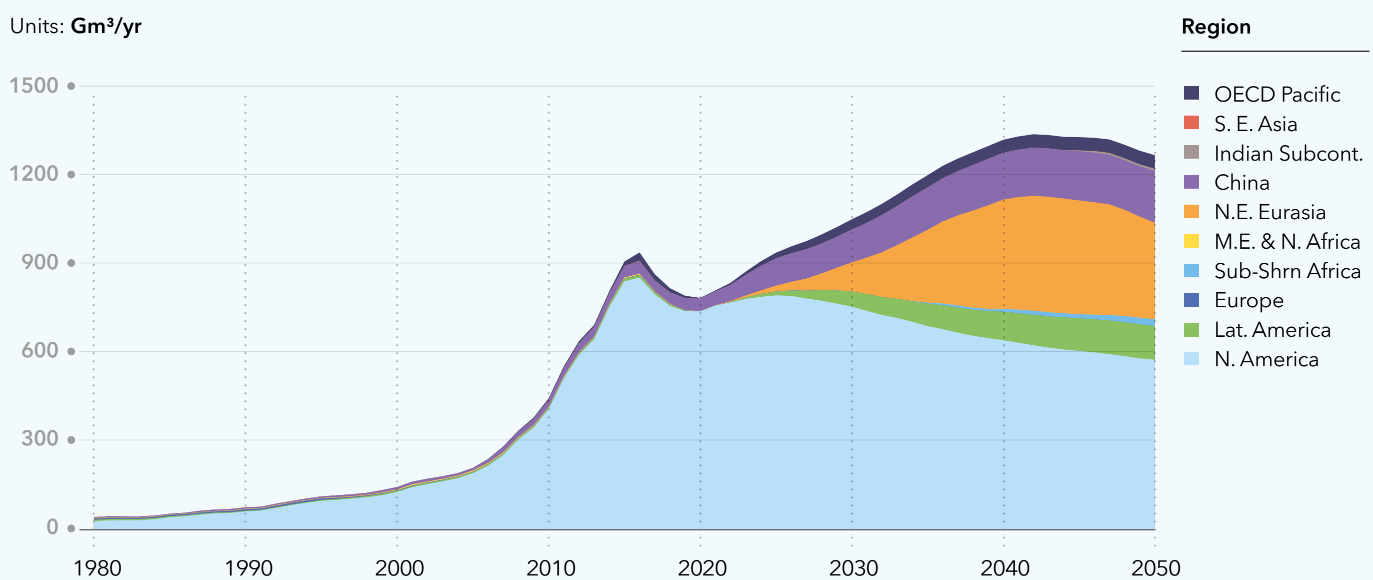
Other notable predictions include a continued sharp tail-off mid term in new Chinese capacity, and the Indian Subcontinent adding capacity at a gradually increasing rate for almost two decades from the mid-2020s as population, economic and industrial growth sustain demand for domestic gas production alongside piped or LNG imports. Sub-Saharan Africa looks set to follow the Indian Subcontinent's pattern of capacity additions, at least until about 2035, and on a more modest scale.

Unconventional onshore gas production peaked in 2016 (830Gm³/yr), but will retain an important share of gas supply in North America, according to our model. After a dip in 2019, production here will increase towards a peak of 800Gm³/yr in 2025 then decline gradually at a rate of -1.4% per annum towards 570Gm³/yr in 2050, when it will still be robust (figure 16). By then, such resources are expected to account for 85% of US domestic gas supply, with 68% of this originating from gas-bearing shales.

Continued robust production from existing and emerging unconventional oil and gas plays will clearly remain critical to US domestic energy security. Furthermore, unconventional gas will be the primary source for North American LNG exports.

> Conventional onshore gas production will start declining from about 2020 along with offshore gas production

UNCONVENTIONAL ONSHORE GAS PRODUCTION BY REGION (FIG 16)



Production will rise steeply with a compound annual growth rate (CAGR) of 12% in China towards 2030, before levelling out and then falling slightly after 2040. In Latin America, unconventional gas production will race ahead from 2030 with a CAGR of 17% towards 2050. In North East Eurasia, production will increase rapidly from 2025 onwards. Under our model's current assumptions, unconventional gas will not play any important role in other regions.

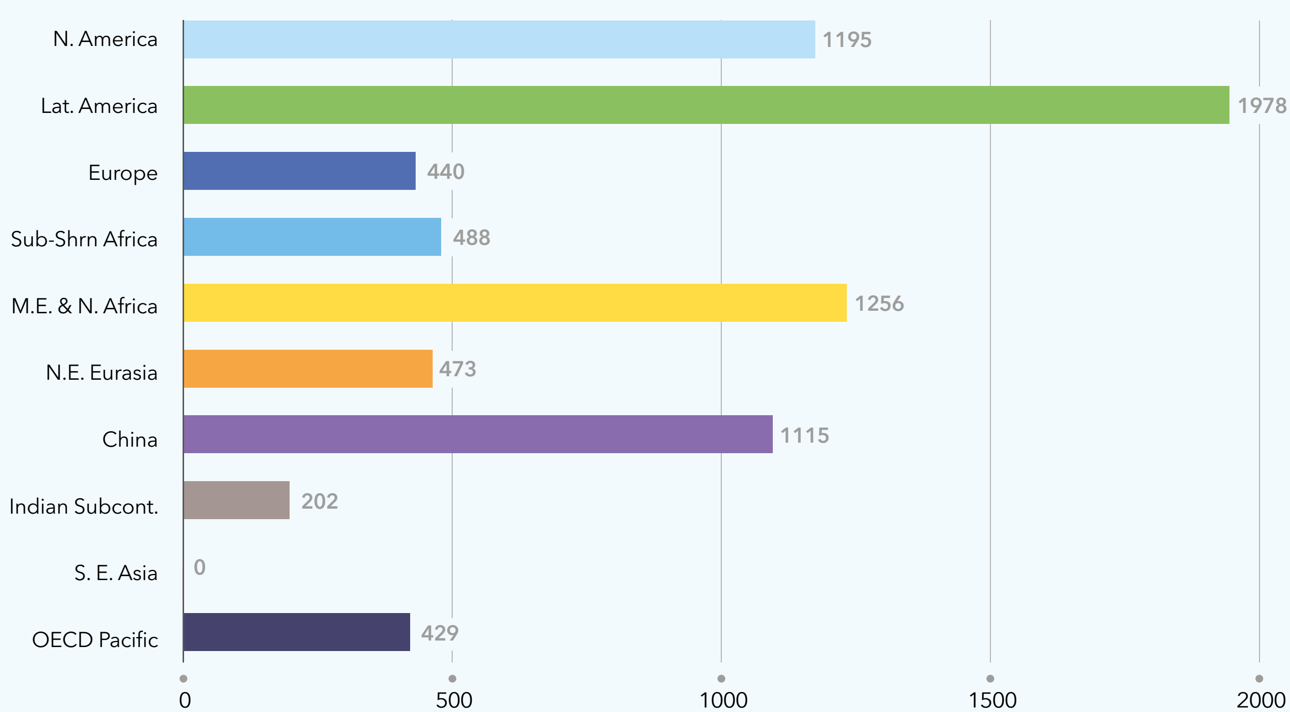
North America, Latin America, Middle East and North Africa, and China hold the largest estimated recoverable shale gas resources, according to the US Energy Information Administration (figure 17).

The Western Hemisphere accounts for more than 42% of gas reserves, compared with a little below 23% for the large producers of conventional gas: Middle East and North Africa, and North East Eurasia. China alone holds around 15%.

The distribution and production of resources may shift in the future to create new dynamics in geopolitics. However, when we compare technically recoverable resources with our model results, we see that not all regions will succeed in developing their unconventional gas industry for cost and market capacity reasons. »

TECHNICALLY RECOVERABLE SHALE GAS (FIG 17)

Units: **Tcf**



Source: World shale resource assessments - attachment A: size of assessed shale gas and shale oil resources, at basin- and formation-levels (last updated 12/29/2014)', EIA, September 24, 2015

While unconventional gas is becoming increasingly conventional in North America, other regions are lagging in developing their resources. Some simply do not need to, while others have concerns over water usage and environmental threats. Bulgaria, France, The Netherlands, the Northern Territory in Australia and some US states, counties and cities have bans in place.

In most regions, the debate continues with advocates of hydraulic fracturing stressing potential economic benefits and gas supply security. South Africa is an example of a nation that has lifted its ban on hydraulic fracturing.

CAPACITY ADDITIONS: UNCONVENTIONAL ONSHORE GAS

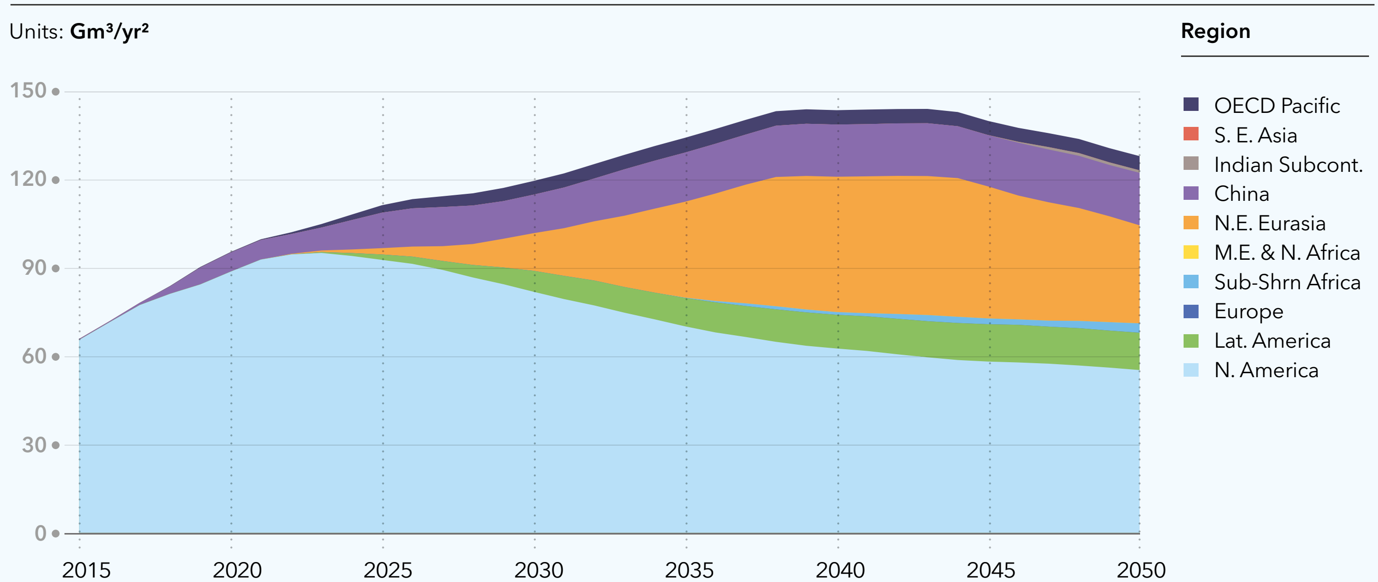
An acceleration in additions to unconventional onshore gas production capacity in North East Eurasia (principally Russia), China and Latin America, in that order, will more than compensate for a decline in the annual rate of additions in North America beyond 2021 (figure 18). Our model predicts that, globally, such additions will more than double from 64Gm^3/yr in 2015 to 140Gm^3/yr in 2041.

In 2015, North America accounted for almost 100% of additions. By 2041, it will have a predicted 42% share of the global total. Despite this, it will remain the main single source of new capacity over the forecasting period to 2050.

FUTURE DEVELOPMENT SOLUTIONS

As we discuss in section 4.1: *Onshore and offshore oil exploration and production*, shale oil and gas producers have significantly lowered breakeven production costs since 2012 by applying lean engineering and increasingly efficient technologies. Continued innovation in drilling technology will decrease the number of wells and surface area required for hydraulic fracturing to develop shale gas resources in a given location.

WORLD UNCONVENTIONAL ONSHORE GAS PRODUCTION CAPACITY ADDITIONS BY REGION (FIG 18)



The technique will also become more efficient, less toxic and less water-intensive by reusing water or using high-pressure nitrogen and/or carbon dioxide (CO_2) gas streams to boost production.

Our model predicts that, in the long term, average onshore oil and gas production costs will remain stable or decrease slightly in most regions. Unconventional oil and gas production costs are expected to fall rapidly, as technology cost learning curves fall rapidly in a much less mature industry. For analysis of emerging onshore unconventional gas sources, see section 4.4: *Emerging and enabling technologies for decarbonization.* ■

GAS: THE BROAD PICTURE

Gas will continue to play a key role alongside renewables in helping to meet future, lower-carbon, energy requirements. We expect to see increased interest in the fuel as 'oil' majors reduce the carbon impact of their business portfolios.

BP, Chevron, ExxonMobil, Shell and Total have all signalled intent to increase the share of gas in their reserves. Shell's acquisition of BG Group is a clear example of how the acquirer is seeking to increase and improve its gas supply opportunities.

The world has plenty of natural gas resources: 530 trillion cubic metres (Tm^3), of which around a third (180Tm^3) is identified, proven conventional reserves, and 350Tm^3 are other gas resources, such as unconventional and hydrate sources.

North East Eurasia and the Middle East and North Africa will increase gas output towards at least 2040, according to our model. These regions will overtake North America, currently the world's largest gas producer, where gas production is essentially flat for the next decade. Our model also predicts a decline in European gas production.

Production is forecast to rise in South East Asia, China and the Indian Subcontinent, where it will more than double in the latter two regions. We forecast a doubling of gas production in Sub-Saharan Africa, though absolute levels will remain relatively modest.

That said, there are challenges to the market position of gas as regulatory issues—such as carbon pricing, emission caps and pollution regulation—could pose risks to the future share of gas in the global power generation mix.

Gas competes with coal on availability and affordability. While coal-to-gas switching will continue, coal is easier to transport and import, two reasons why we have seen lower uptake of gas in Europe and Asia.

Combusting gas generates less carbon than burning an equivalent amount of coal or oil, but gas must also compete with cleaner renewables. Carbon capture and storage (CCS) is part of the solution to this, and could further reduce the carbon footprint of gas. However, our model results indicate that CCS uptake will be low, at least for the first 20 years (see section 4.4: *Emerging and enabling technologies for decarbonization*.)

Methane emissions along the gas value chain are another headwind that needs addressing if gas is to play a truly significant role in reducing the carbon impact of international oil companies' activity.

OFFSHORE GAS EXPLORATION AND PRODUCTION

Offshore gas production volumes will increase by approximately 20% by 2030, according to our model, with growth principally coming from the Middle East and North Africa region, and South East Asia. Production will decline slowly thereafter (figure 19).

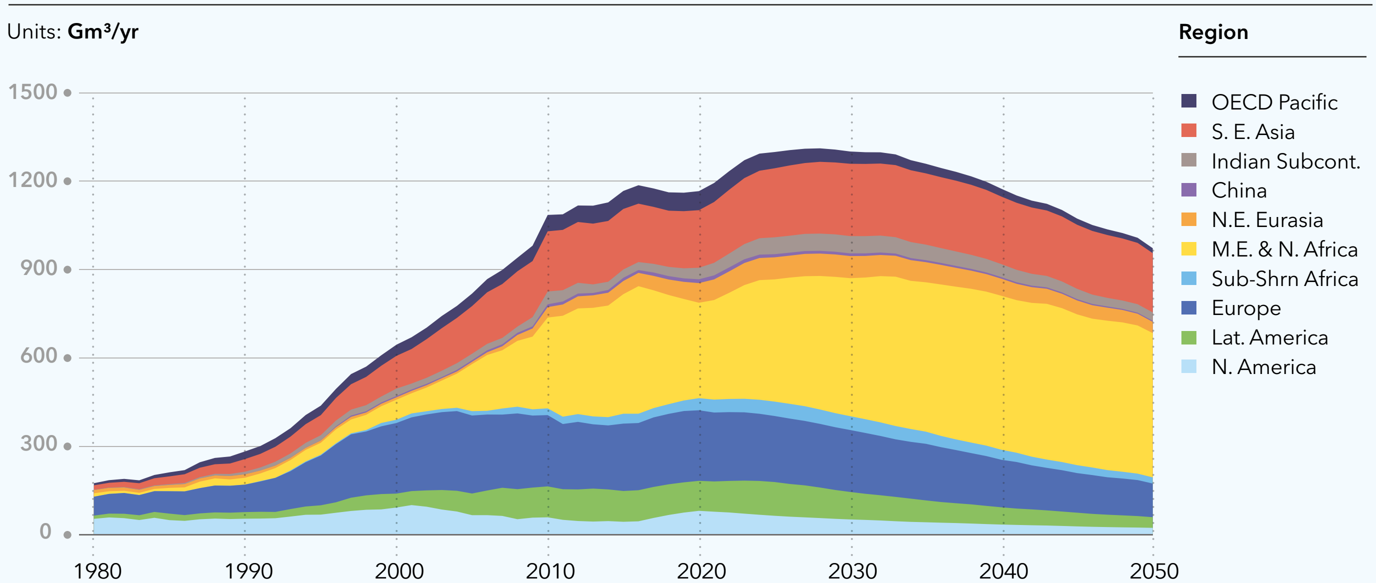
Europe will continue to be a significant source of offshore gas during the forecast period, but production will slowly decline. The region's primary challenge will be reserves replacement. Eni's Zohr project, offshore Egypt, and Total's deepwater gas prospect in Block 11, offshore Cyprus, also provide new potential gas sources for Europe.

CAPACITY ADDITIONS: OFFSHORE GAS
The strong role that we predict for gas in the future, and the gas-for-coal/oil substitution story, is reflected in our model's outlook for new capacity additions to global offshore gas production, at least in the short term (figure 20). It predicts recovery from a forecast 68Gm³/yr in 2017 to 77Gm³/yr in 2025, then a more-or-less steady rate of decline to 36Gm³/yr in 2050. Over the period 2017-2050, the annual rate of new additions to offshore gas production capacity will fall by 46%, half the percentage predicted for offshore oil.

The availability of production solutions such as Floating LNG (FLNG) allowing LNG transport will also assist in making the case for continued new development of offshore gas resources over the forecasting period.

The Middle East and North Africa will continue to see the highest annual rate of new production capacity for offshore gas from now until at least 2050.

OFFSHORE GAS PRODUCTION BY REGION (FIG 19)



ENABLING GREATER USE OF STRANDED OFFSHORE GAS

Offshore gas producers face a significant challenge in some of the world's largest natural gas resources being found at great distance from the biggest gas markets and without access to export infrastructure routes.

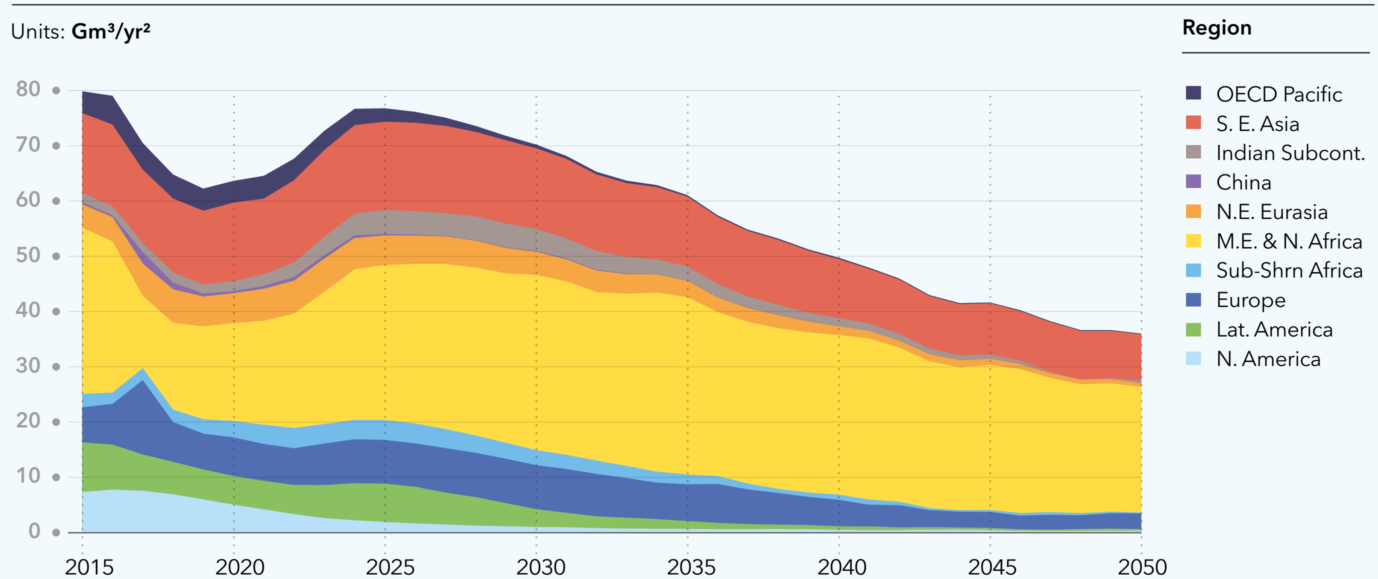
Substantial growth in the proposed use of FLNG technology offers a solution to unlock development of previously stranded offshore gas assets from which production can be exported by LNG carrier rather than uneconomic pipelines. In some locations, companies may prefer to send LNG direct to the final market's entry point rather than processing gas onshore.

FLNG was conceived for large gas fields such as Shell's Prelude offshore Western Australia. However, the arrival of the technology, and the cost reductions that it has so far achieved, have also promoted the development of smaller FLNG designs such as Petronas' FLNG1 (also known as the PFLNG Satu). Prelude FLNG is expected to produce 5.3 million tons per annum (Mtpa) of liquid and condensate.

This includes 3.6Mtpa of LNG, 1.3Mtpa of condensate and 0.4Mtpa of liquefied petroleum gas (LPG).
In contrast, PFLNG Satu, which has entered production ahead of Prelude, will produce only 1.2Mtpa of LNG per year.

It is likely that we will see the development of smaller and medium-size FLNGs, but it is doubtful whether another Prelude-sized vessel will be commissioned. The latest FLNG project to reach a final investment decision is the Eni Coral FLNG, which will be located offshore Mozambique with a production capacity of more than 3.3Mtpa. »

WORLD OFFSHORE GAS PRODUCTION CAPACITY ADDITIONS BY REGION (FIG 20)



Significant investments will be required to develop new gas supply resources such as those served by FLNG. A recent report[7] by the Gas Exporting Countries Forum (GECF) estimates that the cumulative investment needed for upstream and gas transportation systems between 2015 and 2040 is USD8tn. GECF forecasts that the upstream supply element alone will require almost USD7.5tn of this, with the remainder being needed for liquefaction, regasification, shipping and pipeline projects.

As we discuss in section 4.3: *Mid- and downstream technologies*, the challenge of finding markets and export routes for gas sales remains, but GECF forecasts global LNG export capacity will increase by 45% between 2017 and 2022. It also predicts that 90% of this capacity will originate from projects already sanctioned in the US and Australia. There is an oversupply in global LNG markets, which leads to fierce competition between US and Qatari exports to deliver to European and Asian customers in particular.

COST IMPLICATIONS

Breakeven costs for deepwater developments dropped from an average price of about USD75 per barrel of oil equivalent in 2014 to USD62 in the first half of 2016, and to USD55 in the first quarter of 2017. As we discuss in section 4.1: *Onshore and offshore oil exploration and production*, the costs of offshore gas drilling have also dropped dramatically over the past three years, and rig supply is expected to exceed demand for the next few years, keeping rig prices lower. The industry has reduced development and production costs by 30-40% over this time.

Beyond cost, we have seen greater demand for gas in domestic applications in emerging markets. This is notable in African nations, some of which see greater value in using some of their gas resources for economic and social development rather than all production being exported. Our model predicts that demand for natural gas for residential and commercial buildings in Sub-Saharan Africa will grow forty-fold to a little more than 4EJ/y in 2050 as the region rises from tenth to fifth in the geographical ranking for this parameter.

The availability of gas for power generation, and for conversion into useful products such as fertilizers, chemicals and plastics has created new opportunities for nearshore gas developments to bring gas to onshore terminals for processing, rather than just being deployed for export.

TECHNOLOGY DEVELOPMENTS

As we discuss in section 4.1: *Onshore and offshore oil exploration and production*, we believe that the offshore gas industry will continue to seek new innovations in facility design, operating models and contracting strategies to maintain or improve operating margins. Increased digitalization, standardization, and use of remote or autonomous operations will continue to bring cost savings to the industry.

We have seen a shift from fixed installations to FLNGs, even in shallower water, while new developments in drilling and well design have allowed existing reservoirs to be further exploited, with new, previously marginally economic reservoirs, now becoming viable. The emergence of innovations in FLNG design, such as DNV GL's Solitude design concept for an unmanned and autonomous FLNG vessel, shows how the industry is continuing to challenge the status quo when it comes to novel concepts (see section 4.5: *Digitalization and automation* for more).

In another area of innovation, huge amounts of methane hydrate have been found beneath Arctic permafrost, beneath Antarctic ice and in sedimentary deposits along continental margins worldwide. In some parts of the world these deposits are much closer to high-population areas than any current natural gas field.

These deposits might allow countries that currently import natural gas to become self-sufficient. The current challenge is to inventory this resource and to find safe, economical ways to develop it. One alternative being explored by Japan and the US is to inject CO_2 into the hydrate formation to warm it and release the methane, thereby producing a valuable resource whilst trapping an environmentally damaging one. ■

> “Offshore gas production volumes will increase by approximately 20%

4.3 MID- AND DOWNSTREAM TECHNOLOGIES

TRANSMISSION SYSTEMS

Our model predicts strongly increased gas demand in countries that have less well-established gas infrastructure, such as China and India. This leads to a need for imports in these regions as shown in figure 21. For instance, in the period 2015 to 2025, our model predicts a doubling of gas trade between North East Eurasia and China to just under 160Gm^3/yr. Seaborne gas trade from North America to China will grow to more than 85Gm^3/yr from today's level of approximately 30Gm^3/yr. We expect an increase in gas trade from Sub-Saharan Africa, mainly to India and South East Asia, of about 25Gm^3/yr in 2050.

As we discuss in section 4.2: *Onshore and offshore gas exploration and production*, unconventional gas will retain an important share of gas supply in North America, with production rising towards 2020, and remaining relatively stable until 2040. We also expect increases in unconventional gas production in China and Latin America over the outlook period.

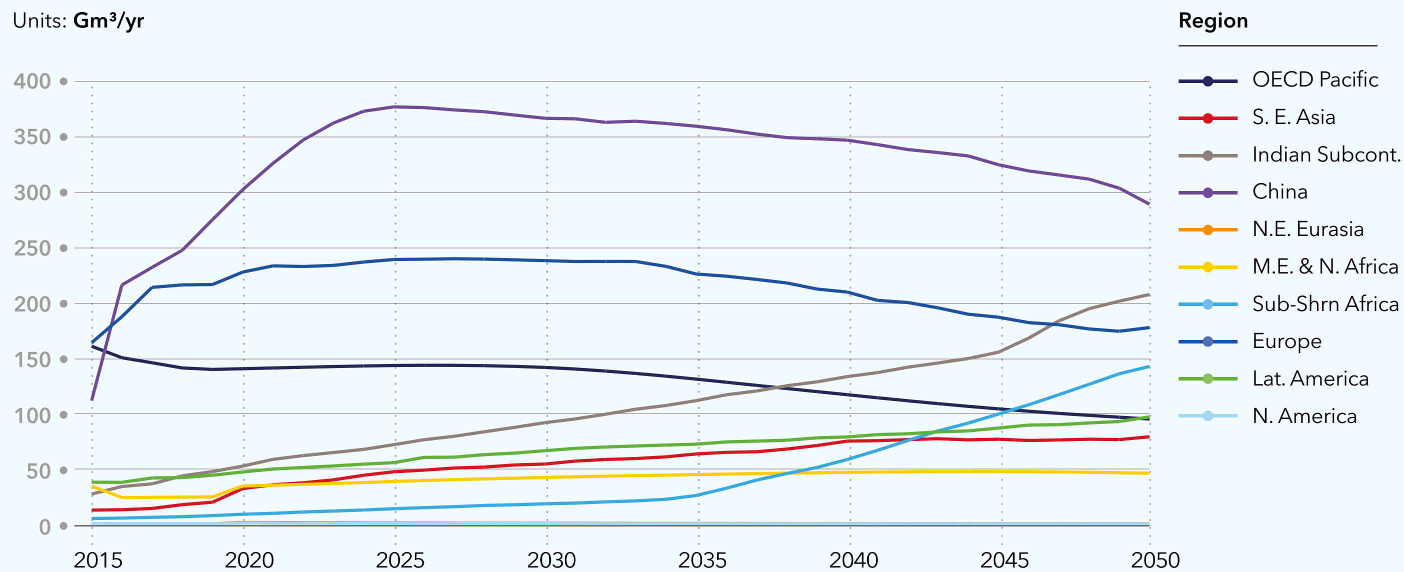
Based on such assumptions, our model predicts an average 1.8% annual rise in global seaborne natural gas trade (LNG and LPG combined) from 340Mtpa today to around 640Mtpa in 2050; and growth in maritime industry demand for LNG for fuel use from around 16Mtpa today to 85Mtpa in 2050.

These trends in demand and trade could drive a further surge, beyond the current construction, of new cross-border and national transmission pipelines, LNG export and receiving terminals, and LNG carriers. However, it should be stressed that substantial risks to gas supply remain, which create uncertainty about the future mix, location and scale of gas transport projects in the future.

Geopolitics and national economic and social development agendas figure prominently among these uncertainties. For example, the European Union (EU) supports development and expansion of LNG-import facilities in addition to related downstream onshore gas infrastructure throughout Eastern Europe. This is to improve security of supply for countries in this region, which would otherwise rely heavily on pipelines from sole source suppliers such as Russia. The EU also supports pipelines from new sources of supply such as the Mediterranean and Caspian regions as indigenous production in historical demand centres such as North West Europe declines. This requires gas to be transported across longer distances in high-pressure, large-diameter pipelines.

For new supply regions, LNG provides a viable route to monetize large gas reserves in remote locations such as Sub-Saharan Africa which have no significant markets nearby, and only limited connectivity to existing demand centres. That said, new pipeline systems in underdeveloped gas markets could align with existing and potential national and local government plans to use some gas to stimulate their own economies.

GAS IMPORTS BY REGION, 2015-2050 (FIG 21)



GECF estimates that almost 15% of current LNG export facilities are operating below capacity today due to outages, security concerns, losses or lack of feed gas. Falling offshore gas project investments will exacerbate feed gas issues.

Once demand for natural gas/LNG increases and/or current LNG supply capacity is more fully utilized, some new LNG export projects will be sanctioned. If gas prices to customers remain in the range of USD8 to USD12 per million British thermal units (MMBtu), and upstream operators can deliver gas into pipelines or LNG liquefaction facilities at prices around USD4 per MMBtu, several large, new gas projects could be initiated as early as 2020. Concerns about gas supply security will re-emerge in the medium term, and will consequently drive another investment cycle. Amongst projects that stand to benefit from this are FLNG solutions that are already creating a renewal of interest in deepwater and harsh environment gas previously viewed as too far from shore to be developed economically.

According to Business Monitor International, transport of gas as LNG is expected to exceed pipeline gas transportation by 2035. This may support an increase in the global market for gas trading, with consumers no longer locked into a pipeline route. »

> Demand and trade trends could drive a further surge in the construction of new pipelines

COST IMPLICATIONS

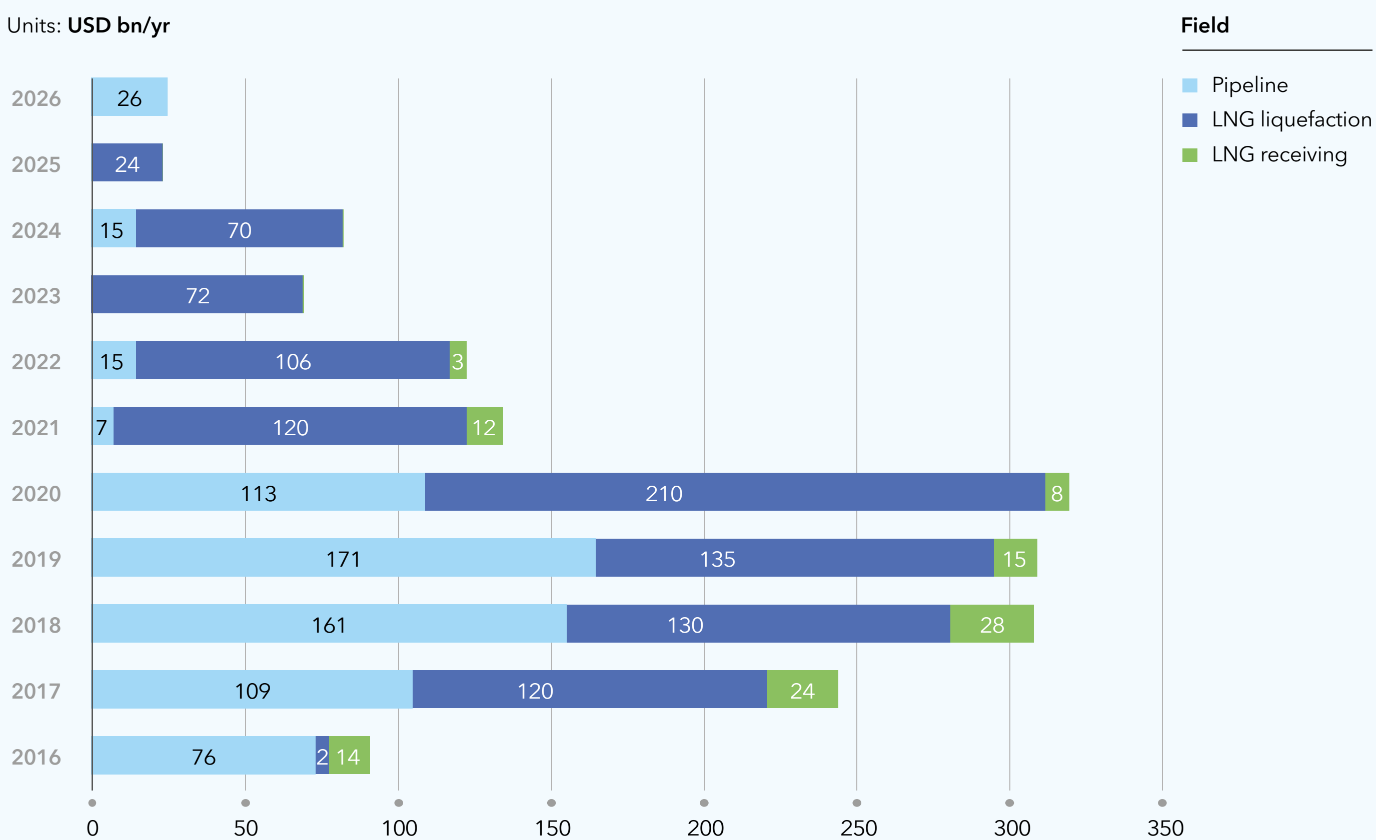
While our model does not predict pipeline costs or investments, the GECF forecasts that cumulative investment in new pipelines and additional LNG liquefaction and regasification terminals will reach USD1.8tn in the decade to the end of 2026, with pipelines (USD0.7tn) and LNG liquefaction (USD1tn) dominant. Figure 22 shows investment by asset type and year, and includes plans in various stages of development. Some may not come to fruition.

Pipelines are generally inspected and repaired until it is no longer safe or economically viable to keep them in operation. Timely replacement of old assets is important to stakeholders focused on safety and security of gas transport supply.

With gas demand set to persist until at the least the end of our modelling horizon, it seems inevitable that there will be an increase in costs for replacement and

INVESTMENT IN PIPELINES, LNG LIQUEFACTION, AND LNG RECEIVING (FIG 22)

Units: **USD bn/yr**



Source: Energy Industries Council (EIC) Datastream refurbishment of older pipeline systems in regions such as Europe, Middle East and North Africa, North East Eurasia and North America.

More than half of US pipelines were constructed in the 1950s and 1960s, and some even earlier, for example. Though lifetimes may exceed 100 years, we expect a continued and likely increasing effort in asset lifetime extension for these regions.[8]

REGULATORY IMPLICATIONS

Governments play a crucial role in legislating and assuring compliance to mitigate risk of incidents in the oil and gas industry. It is good practice for lawmakers to define independent licensing authorities to conduct oversight at all stages of new projects. With our model indicating that more LNG terminals and pipelines – some crossing national borders and more challenging environments – should be built to link fresh supply regions with new demand centres, the application and oversight of regulations will become increasingly important.

We expect a continued and likely increasing effort in asset lifetime extension

REFINERIES

Our model for the refinery industry forecasts limited global growth in mature regions and a 25% decline in industry oil demand over the next 30 years. This is due to paradigm transitions in regional energy consumption and sector demand. Globally, refinery oil demand is predicted to rise 7% between 2017 and 2030, followed by a 30% decline by 2050 to refinery processing levels last seen in the 1980s. This will largely be because of significant global reduction in oil demand from the global transport sector from 2025 onwards.

Regionally, our model predicts refinery demand growth only in the Indian Subcontinent and Sub-Saharan Africa: the former in the near term and the latter predominantly post-2030. The Indian Subcontinent's need for refinery-processed oil is expected to double over the next 15 years. This will be driven by a doubling in its transport sector's demand for oil by the time it peaks, with the next 30 years indicating a sustained three-fold increase in demand from the region's indigenous manufacturing and power sectors. Sub-Saharan Africa's three-fold increase in refinery demand by 2040 will largely be driven by a doubling in regional transport oil demand, and ten-fold growth in oil consumption for power generation.

We forecast that mature refining markets, including North America, Europe and the Pacific OECD, will shrink by 2050 to refinery processing levels equivalent to a half to a third of 2017 activity. This is proportionate to ongoing declines in each market's transport sector's energy demand.

We predict that global refineries output, which was around 30,000 million barrels per year (Mbbl/yr) in 2015, will be roughly the same in 2020, 2025 and 2030 before subsiding to 27,500Mbbl/yr in 2035; 24,600Mbbl/yr in 2040; 21,500Mbbl/yr in 2045; and 18,400Mbbl/yr in 2050.

China, currently the second-largest refined oil producer after North America, is expected to cut its overall oil demand by 2050 to 80% of 2017 levels. During this period, we expect oil demand from the country's power sector to be phased out. We forecast that transport oil demand will double by 2030 then return to 2017 levels by 2050. We expect other regions' refinery oil demand to be driven largely by similar policy and technology shifts in the transport and buildings sectors.

Looking to the future, there are three key refinery technology shifts: in mature markets, a focus on producing cleaner, higher-grade transport fuels; in the growing Indian and Sub-Saharan Africa markets, a focus on building scalable, operationally flexible refinery capacity; and, in all markets, a focus on optimizing lifecycle performance for existing and new-build facilities. ■

> Our model predicts refinery demand growth only in the Indian Subcontinent and Sub-Saharan Africa

PETROCHEMICALS

Our model predicts a 30% decline in refining production levels over 30 years, driven by regional transitions in feedstock supply and product demand. It projects growth only in the Indian Subcontinent, where petrochemicals output is set to double by 2050. Globally, our model forecasts a transition in the industry's feed mix from 60% oil/34% gas to 56% oil/40% gas over this time. This demonstrates increasing gas reliance against a backdrop of declining oil consumption.

For the largest modern petrochemicals regions, our model anticipates significant reductions in global market share by 2050, ultimately within a much smaller market. The forecasts are:

- China: from 25% today down to 20%
- North America: a fall from 20% to 15%
- Europe: a halving of global market share to 6%, driven by pronounced declines in oil use over the next 30 years.

Notably, the industry's 6% balance of coal-derived feed in 2017, popular only in China, represents a larger level of supply than the Indian Subcontinent's total pre-growth demand. All other regions are expected to remain generally unchanged in size and feed mix through to 2050.

Based on the results of our model, we expect to see some key technology shifts in the petrochemicals industry of the future. In declining mature markets, there will be a focus on energy efficiency and product innovation. In growing Indian markets, the trend will be towards building petrochemicals capacity in integrated refinery and industrial complexes. There will be a global emphasis on optimizing lifecycle performance for existing and new build facilities. ■

> Our model anticipates significant reductions in global market share by 2050

GAS TERMINALS

Our model's prediction of robust and increasing global demand for natural gas (see section 3: *Oil and gas demand forecast*) suggests continued complementary growth in gas processing: the link between production and transportation to market. Gas processing separates natural gas liquids (NGL) from natural gas, and often performs other functions such as dehydration, contaminant removal and fractionation.

Demand for ethane, propane and butane are other growth drivers for the processing market. Some 60% of propane is recovered during extraction of natural gas and oil; the remaining 40% being produced during refining of crude oil. NGLs such as propane can add value based on the difference between prices for the individual liquids and the market value of unprocessed natural gas.

Globally, there are more than 1,800 gas processing plants in operation today, and investment in such facilities is dictated by unique supply and demand circumstances in different geographies.

The re-entry of Iran to global oil and gas markets will spark large investments in production and processing. Russia, currently the world's leading gas supplier, may also spur growth in processing when it starts delivering even more gas to Asia. Due to declining gas production, we do not see Europe experiencing any growth in processing.

Gas processing plants operate at about 68% of capacity on average, for reasons including transportation constraints, varying input supplied from gas wells, and regional economics. Current low oil and gas prices have motivated natural gas industry participants to find innovative ways to meet rising demand while lowering production costs. Operations and maintenance improvements are the most common strategy for maximizing production from current assets.

However, while current low oil and gas prices have slowed investment in gas field development – therefore delaying processing projects – wider global demand for gas over the coming decades may mean that new processing capacity is delayed rather than cancelled.

World gas demand has doubled in the past 30 years. Our model predicts that growth will continue for another two decades, hitting a high in 2035 at a level 14% greater than in 2017 before going into moderate decline as renewables take an ever-increasing share of the electricity market. ■

> Increasing global demand for natural gas suggests continued complementary growth in gas processing


LNG

4.4 EMERGING AND ENABLING TECHNOLOGIES FOR DECARBONIZATION

CARBON CAPTURE AND STORAGE

Carbon capture and storage (CCS) is a mitigation technology. It reduces emissions from large point sources in energy production from fossil fuels and from other sectors with high CO2 emissions from production, such as in the production of ammonia, cement, iron and steel.

THE CCS MARKET

The greatest deployment of CCS today is in North America, where captured CO_2 from hydrocarbon processing and energy production is used for enhanced oil recovery (EOR). Captured CO_2 is re-injected into reservoirs to increase field pressure and ease extraction of gas and oil. Nearly all CO_2-EOR projects have viable business cases. They are based on the availability of a high-purity CO_2 stream, which is purchased and transported to the EOR site at the buyer's expense.

Power generation CCS and aquifer storage projects generally receive government capital funding. Exceptions include the Sleipner and Snøhvit storage projects offshore Norway, which are incentivized by a Norwegian CO_2 tax. Elsewhere, the Gorgon project in Australia committed to store produced CO_2 as a criterion for permission to site the LNG facility on Barrow Island.

As the cost of using renewable energy for power generation rapidly decreases, questions are being raised as to whether the use of CCS in coal and gas plants can be competitive in the future. This will be dependent on climate and policy, and their resultant incentives and regulations. Current sentiment in the CCS community is that more effort should be placed on CO_2 capture in industries where the gas is an unavoidable by-product.

As part of its climate policy, Norway has supported feasibility studies for three capture concepts in the cement, waste processing, and ammonia industries. The country's government is expected to support front-end engineering design (FEED) studies for all these concepts in 2017. The aim is to have at least one full-scale CCS value chain in operation by 2022.

ADDRESSING COST

We have assumed in our model that CCS will follow a similar learning curve to other technologies (figure 23), where increasing knowledge about its development and deployment incrementally reduces cost.

CCS will require an initial push in the form of support to piloting installations. As noted earlier in this report, these pilots are in development and we expect a dozen or so to come to fruition by 2035. We expect average carbon prices to increase across all regions – as much as USD60/ton in Europe in 2050 – but they will still be much lower than real lifecycle emission costs. Consequently, CCS will not take off rapidly, but the technology will start gaining momentum towards the end of the outlook period. The sooner CCS is deployed, the more important the role it will play in decarbonization.

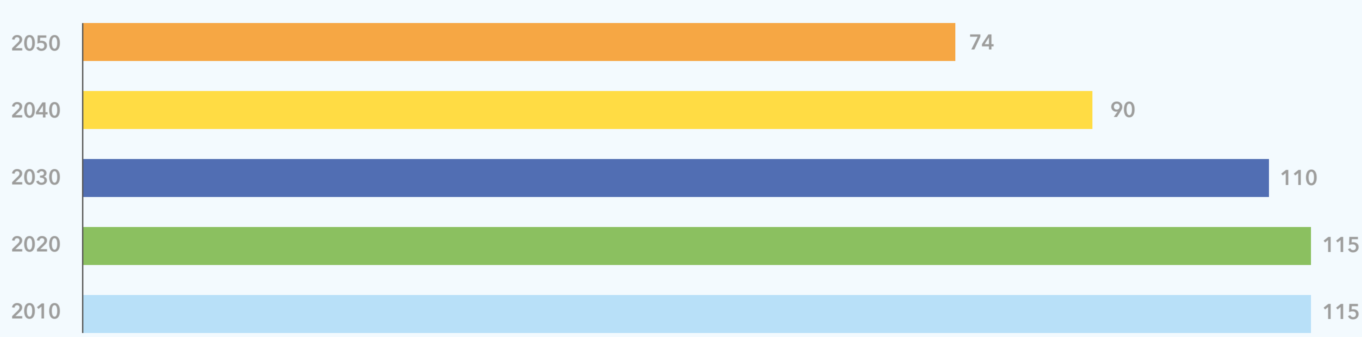
Beyond EOR, CCS is a political tool to reduce emissions, since the non-abated alternative will always be cheaper. The balance between the carbon cost and the 'abatement cost' is therefore highly sensitive to both when and how fast CCS can be deployed.

This is also reflected in some of our sensitivity studies. When the carbon cost is increased by 50%, we see CCS uptake grow tenfold and playing a much more important role in curbing emissions. From a purely economic point of view, a higher cost of carbon is critical for the role that CCS can play in the mitigation of climate change. This means that if policy helps to increase the cost of carbon, we can expect higher and faster deployment than shown in our model. ■

> CCS technology will start gaining momentum towards the end of the outlook period

CCS MITIGATION COST PER TONNE OF CO_2 ASSUMING LIMITED UPTAKE OF THIS TECHNOLOGY (FIG 23)

Units: **USD/tonne of CO_2**



BIOGAS

Biogas, produced from natural anaerobic degradation of varying biomass sources, mostly waste, can be used to generate heat and electricity. Consisting mainly of methane (50-65%) and CO_2 (35-50%), it may be upgraded by removing the CO_2 to leave almost pure biomethane, a natural gas substitute for use in power plants and ordinary gas appliances for residential heating. Biomethane can also be an industrial feedstock, an energy carrier, or a fuel in the transportation sector.

Biogas generation will mainly be located close to the origin of residual streams because transportation of high-moisture content biomass is expensive. Part of the biogas produced will likely be used as process energy for treatment processes. Another part will not be used directly onsite, but for electricity and heat generation, functioning to some extent as a controllable load. We also expect an increase in biogas upgrading to biomethane for production of bio-compressed natural gas and bio-LNG for the transportation sector.

BIOMETHANE

We expect biomethane to be a transition fuel for residential heating. Existing homes with gas connections will gradually shift to electric or hybrid heating systems, leading to lower gas demand. In the longer term, therefore, biomethane will play a negligible role in heating houses. Instead, our model predicts that biomethane will predominantly be used as a biofuel in transportation, contributing to the 6EJ/yr of bioenergy use in this sector by 2050.

As the resource is scarce, and extensive production of biomethane may compete with agriculture and other land use, the fuel is likely to be prioritized in sectors whether there are few or no low-carbon options, such as aviation and long-distance shipping. In regions with well-developed natural gas infrastructure, an increasing number of biomethane injection plants supply industries and/or back-up gas-fired power plants with a renewable feedstock/fuel.

USES OF BIOMASS

A back story to this concerns how biomass will be used over time amid competition for it as a starting point for food, feed, fuels and biochemicals. While our model sees higher value applications for biomass increasing in the future, a fraction will always remain as a waste stream from which energy can be generated. This is particularly true for wet biomass streams, such as municipal organic waste, sewage sludge and manure.

Anaerobic digesters that convert these streams into biogas are generally dispersed and small, with capacities ranging from a few dozen kilowatts up to a few megawatts. Avoiding methane emissions into the atmosphere is one main driver for anaerobic digestion technologies. ■

> We expect biomethane to be a transition fuel for residential heating

HYDROGEN

Hydrogen (H_2) is one of the great unknown variables of our model. It has the potential to become a major energy carrier and may have a significant presence in our energy future, but the extent of this is very uncertain. Our model assumes further action will be taken to reduce CO_2 emissions and meet objectives of the COP21 Paris Agreement, and our main report discusses this in further detail. Our model also predicts increasing use of gaseous fuels in manufacturing, particularly for high-temperature processes.

Decarbonizing industry will boost the development and deployment of multi-fuel burners and engines suited for H_2 or mixtures containing it. Meanwhile, domestic appliances and small fuel cells can be modified to run on H_2 in regions that historically use natural gas heating.

THE BENEFITS OF HYDROGEN

Hydrogen does not emit greenhouse gases (GHGs) during processing, and when burned. In fuel cells, it can store renewable solar and wind energy, both of which are intermittent in generation and vary seasonally. It is the intermediate between electricity and gaseous fuels, with the capacity to de-complicate an all-electric society; a phenomenon emerging in areas where green electricity is reaching double-digit market shares.

H_2 can support the transition to a sustainable energy industry by enabling the use of remaining natural gas (and oil) reserves through applying methane steam reforming combined with CCS. Hydrogen therefore becomes a stepping stone for oil and gas companies and developing countries to progress into a fully-green future.

It can assist several sectors to convert to a zero-carbon future involving: specific high-temperature processes; reduction processes such as in brickworks and in the steel industry by replacing blast furnaces; aviation, navigation, rail and road transport fueled directly with H_2 or with the next generation of fuels derived from it.

DECARBONIZING DISTRIBUTION GRIDS

In Europe and North America, where gas has been used extensively for decades to heat buildings, existing distribution grids must be maintained or prepared for changing gas composition.

The challenge is to decarbonize gas systems by adding biogas or H_2 to natural gas while making safe, efficient use of existing assets. Amid the switch to an all-electric distribution grid, investment decisions in coming years will factor in further integration of power and gas infrastructure.

Industry applications for gas are mainly in high-temperature processes. Existing and new industries in China and India benefit from more efficient burner technologies, for example. With decarbonization in mind, these processes should be able to accommodate other gaseous fuels such as mixtures containing hydrogen.

A TRANSPORT REVOLUTION?

Reducing GHGs and emissions from heavy-duty transportation can drive H_2 use in mobility. Our model forecasts a rapid uptake of light electric vehicles, but clean gas or liquid fuels remain the choice for heavy duty transportation until battery capacity is further developed, which is expected towards the end of the forecast period. The first H_2-powered buses, trucks, trains and ships are already available, and fueling infrastructure is developing in various EU countries, the US and Japan.

Existing gas infrastructure can be re-used for transporting mixtures containing H_2: an attractive option from both cost and technical perspectives. Moreover, hydrogen can be transported by ship in large quantities at high pressure (350–700 bar) or in liquefied form at -252°C .

The first R&D studies are finalized; pilot projects are deployed and guidelines on the consequences are being drafted. Comparable to LNG, this can open a global market for hydrogen. Underground storage, for example in salt caverns, has potential for large-scale, high capacity and long term storage of energy.

THE CHALLENGES FOR HYDROGEN

There are currently several uncertain factors surrounding the use of hydrogen. These include technology learning curves, future cost developments and the strength of policy support. Hydrogen currently lags behind several of the other new technologies entering the energy future. In a competitive situation, its success is unclear. Should H_2 achieve significant scaling in one sector, it would have important spillover effects on competitiveness in other sectors.

Hydrogen's high diffusion rate and flammability require additional attention to fully understand and reduce risks as it gains traction in markets. In our model, therefore, the use of H_2 is not specifically quantified. The potential remains, but scaling is highly uncertain. ■

> The potential for hydrogen remains, but scaling is highly uncertain

POWER-TO-GAS AND ENERGY STORAGE

The function of storage in the energy system is to provide flexibility to match energy demand and supply, covering imbalances ranging from milliseconds to several months. As our model forecasts, large-scale energy storage will become increasingly important in regions with high penetration of variable renewable energy sources and strongly seasonal energy demand patterns.

The transition towards renewable energy sources calls for innovation to enable a supply-driven electricity system. The low capacity factors of solar (around 18%) and wind power plants (around 35% for onshore and 45% for offshore) require large installed capacities leading to periodic surplus electricity generation. We believe that this will happen periodically for a while, and then massively from 2030 onwards.

ENERGY STORAGE

Rather than waste it, surplus energy can be stored for later use. Underground gas storage (UGS) and pumped hydro energy storage (PHES) are important current options to achieve this on a large scale and for longer periods of weeks to seasons (figure 24). Europe's UGS facilities can theoretically store nearly 900TWh of power whereas PHES, located mainly in Norway and Turkey, has a maximum storage capacity of 70TWh.

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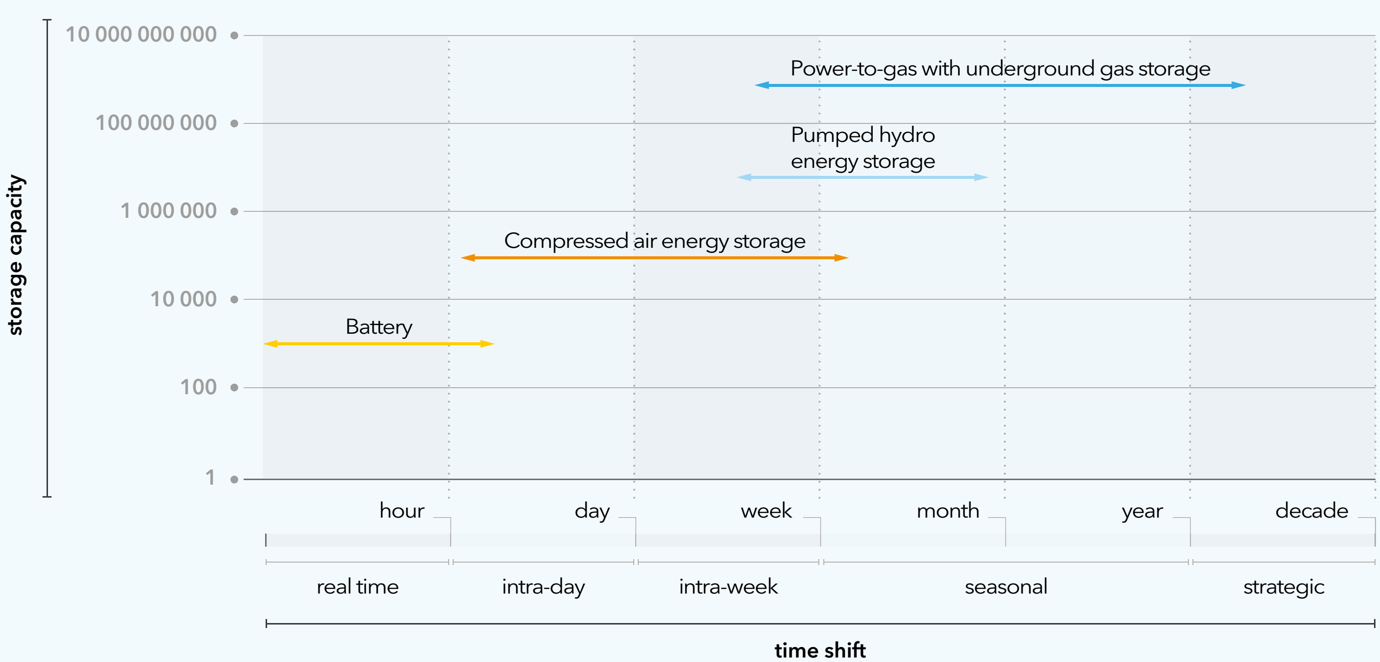
TYPICAL (UNIT) STORAGE CAPACITIES OF DIFFERENT NETWORK-SCALE STORAGE TECHNOLOGIES AND THEIR TYPICAL TIME-SHIFT (FIG 24)

Units: **Kilowatt hours** (values are not in scale)



In principle, storage could be achieved by the traditional, larger-scale, solutions such as PHES and, in the future, compressed air storage units. However, neither option currently suffices for currently fast-growing surplus electricity.

Power-to-gas is an alternative to storing this surplus energy more economically than batteries, although each technology is expected to develop over different time horizons. Storage takes place in an electrolysis cell where water molecules are split into hydrogen and oxygen by applying an electric current. Next to the electrolysis cells, electrolyser units comprise auxiliary equipment such as a water demineralization unit, a water pump, a converter, a cooling system, a hydrogen purifier and instrumentation.

Alongside UGS, power-to-gas could facilitate large-scale, long-term energy storage by transforming surplus electricity from renewables into a storable energy carrier – H_2 or methane – and using existing pipelines to transport the gas.

We calculate that to become economically competitive by 2030, system costs for PHES, especially electrolysers, need to be reduced by half in the interim period to store energy for up to two weeks.

Power-to-gas as a chemical storage system opens up new markets for surplus electricity by producing a carbon-free energy carrier and intermediate chemical product which can be applied outside of the power sector (figure 25). The sustainably produced H_2 can be used directly in the industrial or transportation sector, transported through the natural gas grid via blending (and stored in gas storages), or further converted to methane via a methanation process. Hydrogen can also be combined with carbon dioxide and nitrogen to produce sustainable products such as methanol, ethylene, and ammonia, which can be used in the chemical industry. ■

METHANE LEAKAGES

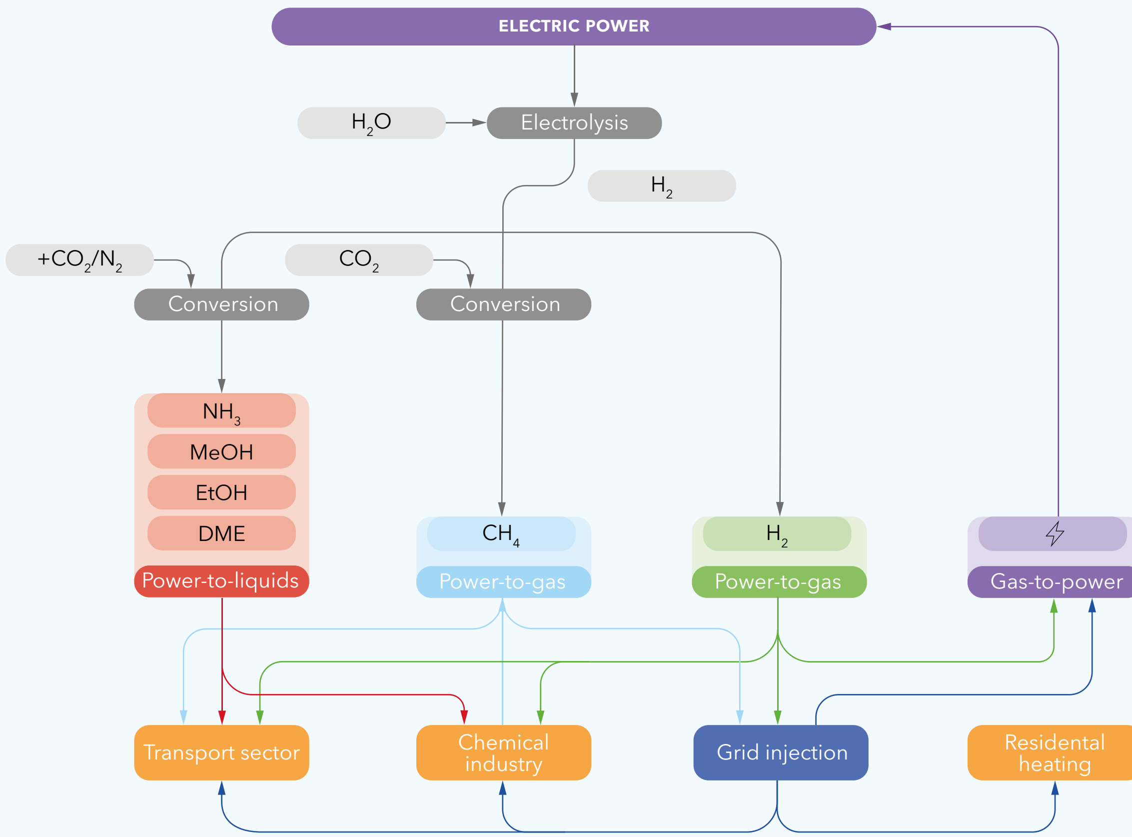
It is important that the oil and gas industry maintains focus on reducing methane (CH_4) leakages. This potent greenhouse gas is emitted in the value chain through energy use, venting and flaring, and fugitive emissions. The global warming potential GWP (the globally averaged radiative forcing impacts relative to CO_2) is 84 in a 20-year perspective and 28 in a 100-year perspective. In analyses, 100-year GWP values are most commonly used.

The International Association of Oil and Gas Producers (IOGP) has found that the oil and gas industry accounts for 54% of total methane emissions.[9] Of this, 44% was from venting, vessel-loading and tank storage; 25% was from fugitive losses; 25% from flaring; and 6% from energy use. The IOGP also reports that onshore activity has more than twice the methane intensity of offshore activity.

Regional averages for emissions varied significantly from 0.14–2.41 tonnes of CH_4 per 1,000 tonnes of hydrocarbon production in 2014, according to IOGP. This is due to the varying state of transmission and distribution infrastructures by region. Additionally, unconventional shale gas developments produce more CH_4 per unit of production than natural gas.[9]

The data available on methane is less robust than other greenhouse gasses, such as CO_2. Different studies produce divergent results, and this variation in statistics illustrates large potential for sharing best practice technologies that can be adopted to lower CH_4 emissions and to close gaps between local GHG abatement performances.

POWER-TO-GAS THROUGH CHEMICAL STORAGE OPENS NEW MARKETS FOR SURPLUS ELECTRICITY (FIG 25)



Abbreviations

H_2O	water
H_2	hydrogen
CO_2	carbon dioxide
N_2	nitrogen
NH_3	ammonia
MeOH	methanol
EtOH	ethanol
DME	dimethyl ether
CH_4	methane

4.5 DIGITALIZATION AND AUTOMATION

The oil and gas industry faces broad challenges in maintaining a sharp focus on cost efficiency, safety and sustainability for hydrocarbons to make a positive contribution to the energy transition.

A SMARTER WAY OF WORKING

Digital technologies and smarter use of data can assist in meeting these challenges. Digitalization will play a primary role in containing costs while improving safety by enabling reduced downtime, predictive maintenance, performance forecasting, real-time risk management and energy efficiency.

Across industries in general, collecting, moving, analysing and interpreting data is becoming progressively easier and cheaper through the impact of remote sensing, automation, augmented reality, the industrial Internet of Things (IoT) and other advances in information and communication technology (ICT).

Cloud-based digital twins represent an opportunity for greater operational and cost efficiencies in future oil and gas operations, for example. Imagine a 30,000-ton rig rendered perfectly and dynamically in virtual reality throughout its lifecycle. Analysing sensor data from a corporate IoT, digital twins can provide easy-to-understand dynamic updates on asset condition and operational parameter states, helping to optimize scheduling of costly inspection and maintenance regimes.

UPSTREAM BENEFITS

Digitalization, on- and offshore, has high potential for better reservoir asset optimization and improved operational performance. On the Norwegian Continental Shelf alone, operators could save some USD4bn through advanced analytics, process digitalization, robotic process automation, and through connecting and sensing technology. Extrapolated, this figure rises to USD60bn globally, with the greatest opportunities for gains in the drilling and wells, and production sectors.

Data analytics and digitalization can optimize subsurface mapping of the best drilling locations; indicate how and where to steer the drill bit; and, suggest the best way to stimulate the unconventional reservoir. Drilling automation has shown it can raise performance and reduce risk and maintenance costs from crown block to downhole.[10] Greater gains will come through wider deployment of wired drill pipes that report downhole conditions via fast, reliable telemetry. Robotic drilling systems that respond to downhole data are on the way and will increase the flexibility of drilling operations.

A growing trend towards moving offshore operations from platform to seabed in some environments will entail new ICT coupled with process automation, analytics for failure prediction and intelligent sensors.

Beyond efficiency considerations, concepts such as dynamic barrier management utilizing sensors, ICT and data analytics to detect, analyse, interpret and predict health, safety and environmental (HSE) risks in real or near-real time can be a bulwark against reputational, financial, environmental and societal damage.

Enhanced mobile computing, assisted by app-centric analytics, can increase uptime, improve productivity and reduce margins of errors.

MIDSTREAM AND DOWNSTREAM APPLICATIONS

Midstream and downstream, greater computational power and more sophisticated software are enabling strategic responses to market demand and regulation, and to energy policy and decarbonization targets, driving energy transitions.

Data is a strategic asset for gas transmission and distribution system operators (TSOs and DSOs). For both, customers increasingly demand shorter delivery times and energy use information that is dynamic and up-to-date.

For TSOs, one driver of demand for data is that balancing transmission networks is becoming more sophisticated. Some DSOs are meanwhile piloting real-time, smart networks as they prepare to operate using mixed gas sources such as natural gas, re-gasified LNG, biomethane and hydrogen in their systems. The heating value of each gas varies by type and source, posing questions about what is priced.

Oil and gas will sell into markets that increasingly buy units of 'energy' rather than oil, gas, coal, renewable power and so on. This creates a need for more accurate and consistent measurement of what is delivered.

Greater computational capabilities and more powerful software will allow operators to manage a larger volume of data and increase its value by interpreting it in ways tailored to the needs of external and internal audiences.

Leading gas network operators anticipate a data-driven future, which will progressively incorporate advances in artificial intelligence, augmented reality, industrial IoT and machine learning.

Some are already starting or plan to integrate such advances into their systems and processes through more sophisticated data gathering, analysis and visualization systems to maintain, repair and operate networks. Their goals are to optimize internal efficiency and to deliver an effective service and information to clients.

CHANGE MANAGEMENT AND COLLABORATION

Leadership is essential to fully exploit the digital opportunities that we foresee for the oil and gas industry as it contributes to the energy transformations predicted by our model. Breaking down functional silos is vital as the depth, pace and success of change rests on asset and operations managers embracing it as much as top management.

There is significant potential for the industry to become more accustomed to openly sharing data across projects and operations, integrating supply chains and creating transparency to increase trust and raise efficiency.

Similarly, using data to increase visibility of key aspects of multi-year, multi-stakeholder construction projects in oil and gas to all relevant parties can identify cost savings. »

As the recipient of large volumes of data on oil and gas production, regulators have scope to work more closely with the industry to produce insights for improving efficiency and health, safety and environmental performance, as well as security.

Across the value chain, the recent industry challenges resulting from oil price reductions have highlighted the value of sharing data to accelerate understanding of efficiency and sustainability challenges.

For pipelines, collaboration is key to a sustainable industry, for example. Pooling inline inspection data can lead to better predictive tools for risk and asset integrity management.

The most powerful impact on projects and operations, comes when leading subject matter expertise is combined with data analytics, information management and software. With meaningful analytics, digitalization has the potential to significantly enhance safety, efficiency and sustainability. ■

SOLITUDE: AUTONOMOUS FLOATING LNG

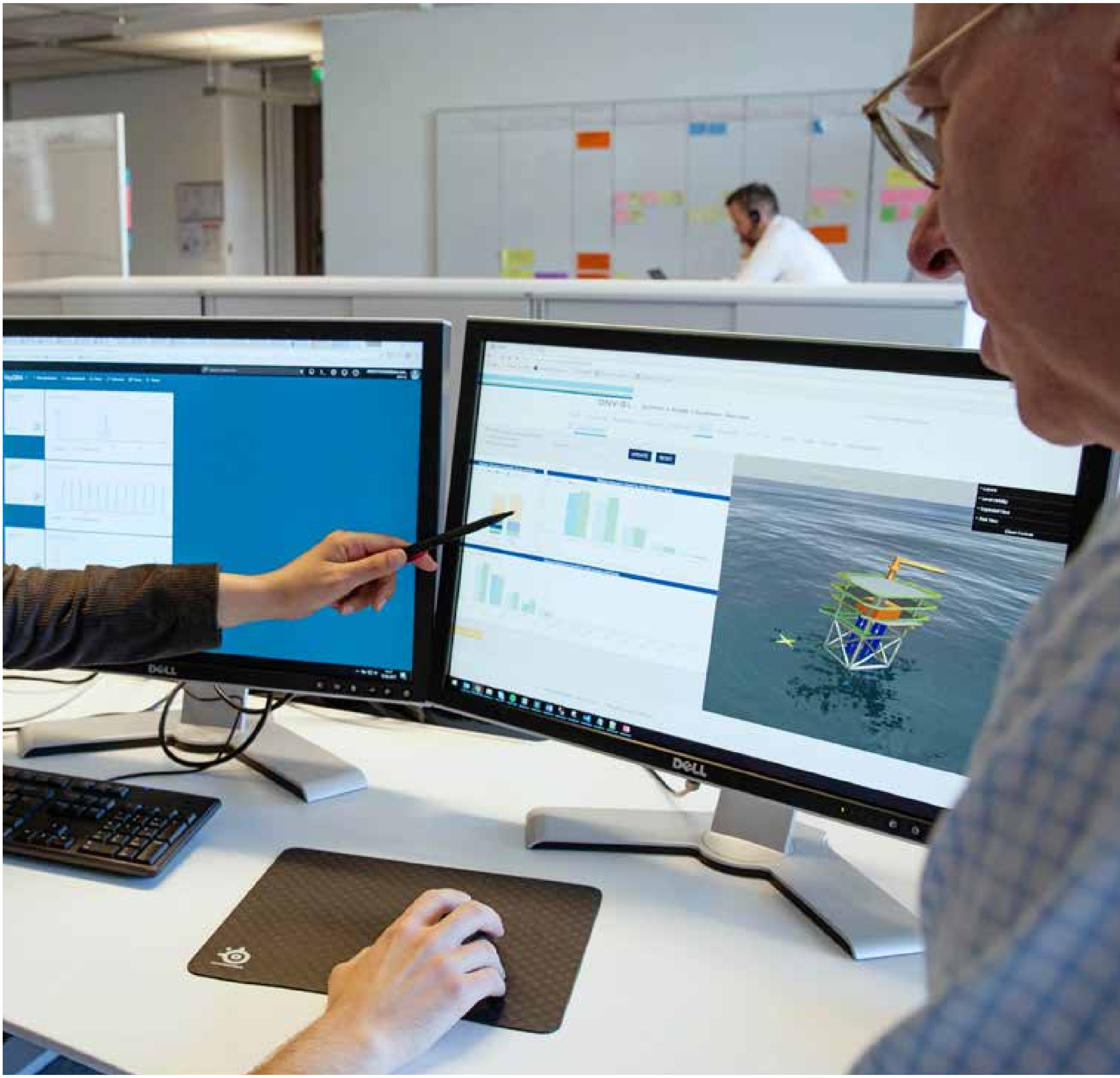
The increased use of digitalization and of remote or autonomous operations will bring essential cost savings to the oil and gas industry. DNV GL's unmanned floating LNG concept, Solitude, demonstrates how technological advances can be combined into a solution that offers some 20% reduction in annual opex, while only adding a few percent increase in capex and increasing overall safety levels.

Most of the technology included in the concept is already within reach. Power that would otherwise be generated by high maintenance gas turbines can be generated by fuel cells, improving power generation reliability and reducing environmental footprint.

Equipment is modularized and monitored from shore with much of the routine maintenance and fault correction carried out by self-programming autonomous inspection and maintenance units. Wireless sensor networks act as eyes, ears and noses, feeding information to a condition monitoring system that oversees fault detection, proactive maintenance and repair planning.

As there will be no one living onboard or working on the topside during normal operation, the associated personal safety risks are eliminated. When people do enter for large maintenance campaigns, the topside would be prepared for a safe working environment.

For more information, visit: dnvgl.com/solitude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THE NEXT FIVE YEARS

5. THE NEXT FIVE YEARS

Understanding how the oil and gas industry will be transformed by 2050 is part number crunching and part informed speculation, though our model identifies impacts of key long-term energy trends such as decarbonization and growing electrification.

Most oil and gas majors are guided by five-year strategies updated on a rolling, five-year basis, which with the help of our model, provides some pointers to what to expect across the value chain short- to midterm.

Given the general market outlook on price, we expect oil and gas companies to maintain a sharp focus on capital and operational expenditure across the value chain from wellhead to end-user over the next five years. They will pursue strategies promoting lean financial performance without compromising safety and production.

Against this background, these are some of our key expectations between now and 2022.

COST CONTROL WILL REMAIN IMPORTANT

Opinion research[10] supports our view that the industry accepts it is now in a 'new normal' oil price environment, and will continue to innovate in facility design, operating models and contracting strategies to maintain or improve operating margins. While we do not model energy prices we do model costs, and our assumption is that in the long run prices will follow costs.

Offshore, the sector has reduced development and production costs by 30-40% since 2014. US producers of shale oil have also managed large cost reductions per barrel. However, our model predicts almost flat oil demand in the coming 15 years, so what happens next will determine what health the industry is in to adapt to significant long-term energy transition trends that we have identified.

Cost reduction has been achieved through a series of measures, and there is now a bias towards shorter-term, more flexible new field developments. Technology developments are reviving interest in deepwater and harsh environment projects, however. Average breakeven costs for deep water fell about 7% to USD55 per barrel (bbl) between 2014 and early 2017. If oil holds around USD50/bbl, several deepwater projects could launch in 2018.

In addition, oil and gas executives believe collaboration with other industry players is the primary way to maintain innovation amid cost pressures.[11] We expect increased collaboration, standardization and digitalization over the next five years to lay foundations for consistently lower capital and operational expenditure.

DIGITALIZATION AND AUTOMATION WILL CUT COSTS AND ENHANCE SAFETY

Our model forecasts a continued decline in production costs. We expect increasing uptake of digitalization and automation to make a significant contribution to this trend over the next five years. Half (49%) of senior oil and gas professionals already believe that greater use of digitalization is needed to increase profitability in 2017.[11]

Digitalization will contain costs while improving safety by enabling reduced downtime, predictive maintenance, performance forecasting, real-time risk management and energy efficiency. As we discuss in this report, operators could save nearly USD60bn globally through advanced analytics, process digitalization, robotic process automation, and connecting and sensing technology.

A growing trend towards locating offshore operations on the seabed in some environments will entail new ICT coupled with process automation, analytics for failure prediction and intelligent sensors. Cloud-based digital twins are meanwhile moving from concept towards reality and will represent an opportunity for greater operational and cost efficiencies in future oil and gas operations.

US UNCONVENTIONALS BECOME CONVENTIONAL

Unconventional oil and gas can already claim to be the new 'conventional' in North America, where their share of production will continue to grow. This trend will continue over the next five years. Our model predicts that, at current production rates, North American shale oil output will resume growth from 2020, peaking in 2040. For the next few years at least, the US shale industry may continue to be the world's new swing producer thanks to its ability to ramp production up and down more nimbly than producers of conventional oil and gas.

US producers have reduced drilling costs, improved drilling efficiency and applied innovative completion approaches; resulting in more oil at less cost. Further efficiency-boosting innovation based on advances in geomechanics is on the way.[12] Already producing at below USD40/bbl, US shale production is challenging new field developments in conventional onshore and offshore oil to also drive costs down further. Our model indicates costs continuing to fall over its forecasting horizon, but makes no predictions about the trajectory in the short term.

It also predicts that larger-scale production of unconventionals will start in Latin America within five years. It anticipates greater output in China; oil prices and cost per barrel will determine whether this happens.

FOCUS WILL INCREASE ON GAS

The stage is set for gas to become the largest primary energy source in 2034. It will also be the last of the fossil fuels to experience peak demand, which will occur 2035 according to our model. Gas will continue to play a key role alongside renewables in helping to meet future, lower-carbon, energy requirements. Major oil companies intend to increase the share of gas in their reserves, and we expect even more such interest by 2022 as they decarbonize business portfolios.

North East Eurasia and the Middle East and North Africa will increase gas output towards at least 2040 and outstrip North America, the world's largest gas producer, but where gas production looks essentially flat for the next decade. We also predict continued decline in European gas production.

Regulatory change such as carbon pricing, emission caps and pollution laws could pose a risk to our expectations for gas in the energy mix. However, there are opportunities to improve the carbon footprint of gas by curtailing methane emissions from its value chain and through improving the economics of large-scale carbon capture and storage (CCS) for gas-fuelled power generation.

Based on current political, industry and research initiatives, we expect significant curtailing of methane emissions from now on. However, our model does not see average prices for emitting carbon rising to more than a fraction of the cost of carbon capture. Without higher carbon prices and supportive finance from governments, we do not expect large-scale CCS to take off rapidly any time soon.

Economically-viable CCS is also needed to decarbonize large-scale production of hydrogen (H_2) which, with biogas or its upgraded form biomethane, stand to take an increasing, albeit minor, share of a changing gas fuel mix; particularly in end-use and transport.

Gas network operators are already pursuing plans to accommodate this. Ongoing research and pilot projects could lead to greater commercial use of both H_2 and biomethane within the next five years to decarbonize distribution systems and compensate for declining production of natural gas in some regions.[13,14] The question is whether H_2 will have a significant presence in our energy future. Today this is unclear.

NEW SUPPLY AND DEMAND MARKETS NEED CONNECTING

More than 276,000 kilometres of onshore pipelines will have been installed globally between 2017 and 2021.[15] Our model suggests that the pace of new midstream projects will increase to meet demand for connecting changing supply and demand geographies. Demand is already growing for natural gas in China and its continuation in our model implies greater imports of liquefied natural gas (LNG) and/or piped natural gas from Russia, for example.

India, another nation with less well-established gas infrastructure, is also set to take more gas from now on. We see the bulk of the next decade's investment in pipelines, natural gas liquefaction and LNG-receiving plants coming in the period up to and including 2020, with some spill-over into 2021–22 for LNG production projects.

Based partly on our assumptions of growth in unconventional gas supply in North America, Latin America and China, we predict a near-continuous 3% per annum increase in seaborne LNG trade from 282Mtpa today to 660Mtpa in 2050.

Among end users, refineries will focus in the next five years on more economic cracking techniques and increased production of aviation fuels. In Indian and Sub-Saharan African markets, expect: a focus on cracking refineries capable of supporting production of transport-grade fuel to feed into new local pipelines; and investments in coking technology supported by coke-fuelled power generation co-developed by associated power producers.

We anticipate integration of crude oil supply purchase between refineries and petrochemical producers. The latter will look increasingly to reduce baseload energy costs while enabling market access. This could see them merging with power producers which have a footprint in renewables, or finding support from associated gas in markets such as India, where it is usually flared.

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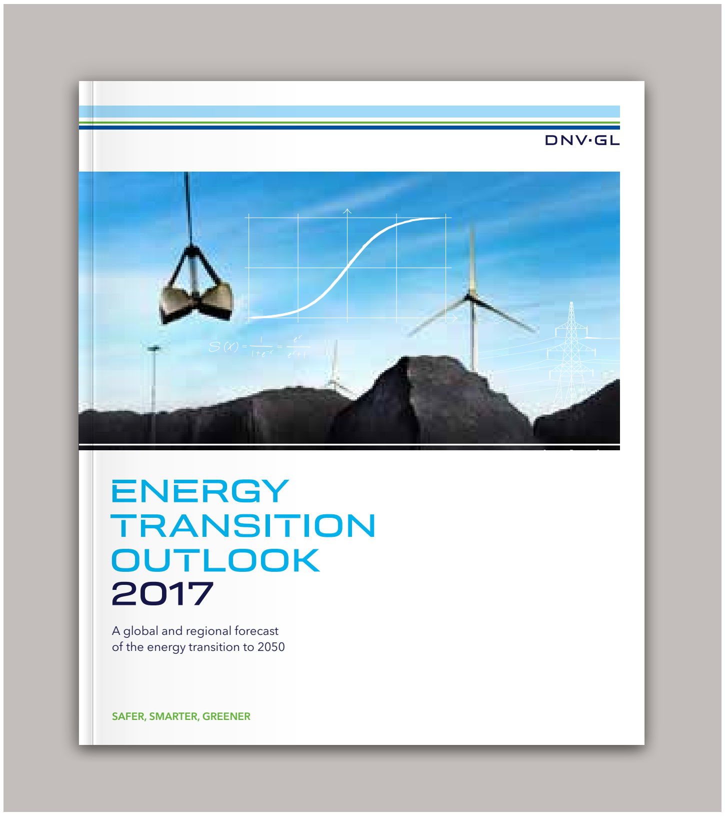
KEY TO WORLD REGIONS COVERED IN OUR MODEL

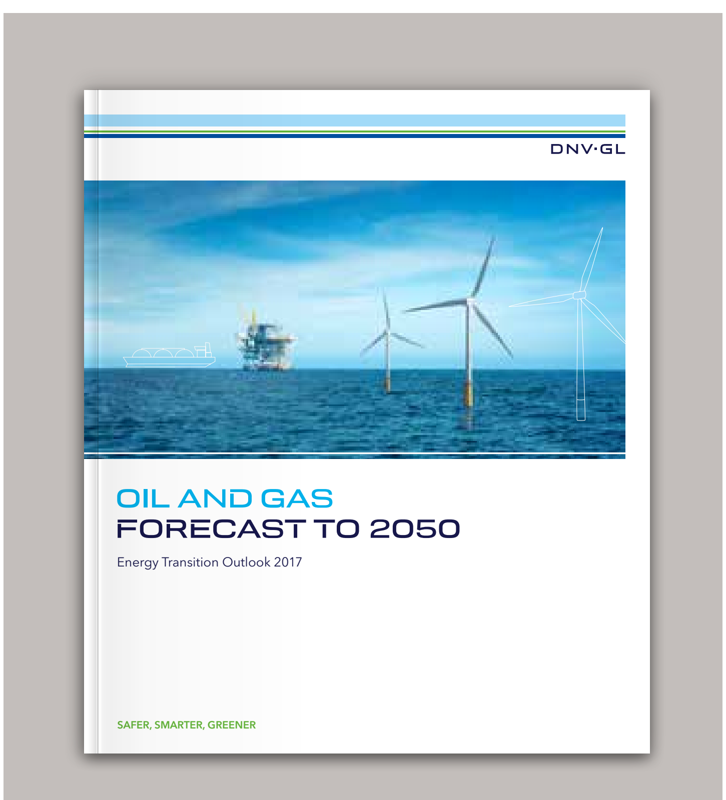
REGION	TERRITORIES
N. America	Canada and the United States.
Lat. America	All nations from Mexico to the southern tip of South America, and including the Caribbean.
Europe	All European countries including the Baltics. Excludes Russia, all former Soviet Union republics, and Turkey.
Sub-Shrn Africa	All African countries except Algeria, Egypt, Libya, Morocco and Tunisia.
M. E. & N. Africa	Stretching from Morocco to Iran. Includes Turkey and the Arabian Peninsula.
N. E. Eurasia	Russia and neighbouring countries including all former Soviet Union states except the Baltics. Includes Mongolia and North Korea.
China	The People's Republic of China, and Taiwan.
Indian Subcont.	India, Pakistan, Bangladesh, Sri Lanka, Afghanistan, Nepal, Bhutan, Maldives.
S. E. Asia	Stretches from Myanmar to Papua New Guinea. Includes many smaller island states in the Pacific Ocean. Indonesia is the largest country.
OECD Pacific	Japan, Republic of Korea ('South Korea'), Australia and New Zealand.



ENERGY TRANSITION OUTLOOK

Our main publication deals with our model-based forecast of the world's energy system through to 2050. It gives our independent view of what we consider 'a most likely future', or a central case, for the coming energy transition. The report covers:

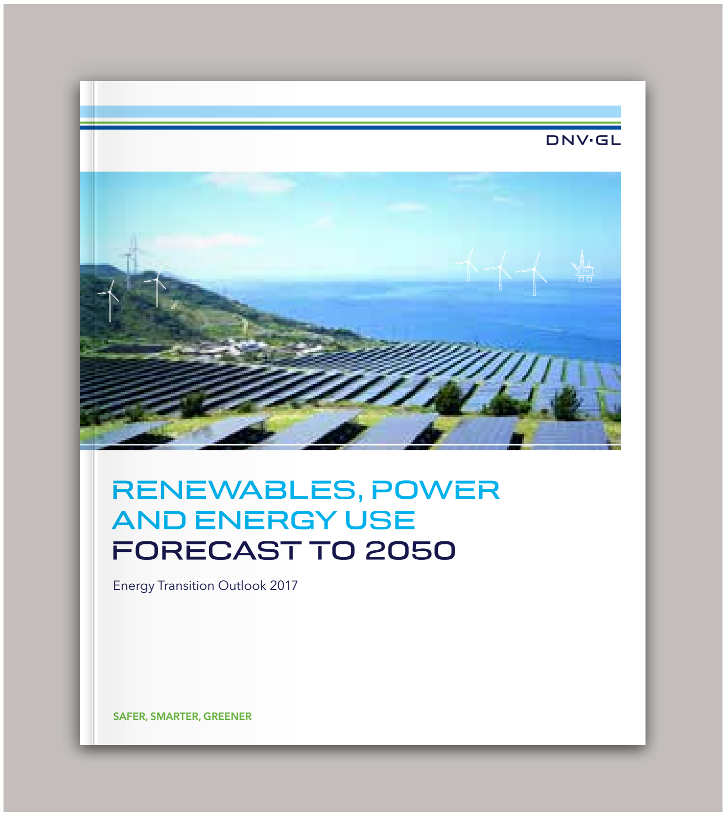
- Our main assumptions, on population, productivity, technology, costs and the role of governments
- The model behind our forecast results
- Our findings on global energy supply, demand and each of the energy carriers – and a sensitivity analysis.
- Energy forecasts for each of our 10 world regions
- Issues to watch in the next 5 years
- The climate implications of our outlook
- Highlights from our supplementary reports.



OIL AND GAS FORECAST TO 2050

Oil and gas will be crucial components of the world's energy future. While renewable energy will increase its share of the energy mix, oil and gas will account for 44% of world energy supply in 2050, compared to 53% today.

In our oil and gas report, we have translated the energy requirements of key demand sectors into the trends we expect to see across the value chain. We discuss how the oil and gas energy system will meet this demand from existing and new production capacity. We also consider implications for LNG and pipelines, and the roles digitalization and emerging technologies will play across the value chain.



RENEWABLES, POWER AND ENERGY USE FORECAST TO 2050

This report presents implications of our energy forecast for key stakeholders including electricity generation, including renewables; electricity transmission and distribution; and energy use.
The report covers:

- Key conclusions from our model
- Key technologies and systems, focusing on results from the model and on the expected key developments. The technologies and systems considered include: onshore and offshore wind; solar; hydropower; biomass; nuclear; coal; transmission grids and system operation; distribution grids; off-grid and micro-grids; electrification of energy use; buildings and their energy efficiency; energy efficiency in manufacturing industry; and storage.
- Takeaways for specific types of stakeholders
- Important issues to monitor over the next five years

MARITIME FORECAST TO 2050

Forthcoming: our Maritime energy outlook will be published towards the end of 2017. It will explore the implications of our forecast for the shipping industry. The expected focus areas include the contribution of shipping to the decarbonization of the world's energy system and the impact of shifts in the energy mix on the demand and usage of vessel types and trading patterns. The forces driving this shift are not limited to emission regulations and physical risks to assets, but also changes in consumer preferences, new technologies, and the supply of energy, all of which will have an impact on shipping.

SAFER, SMARTER, GREENER

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DNV GL is a quality assurance and risk management company. Driven by our purpose of safeguarding life, property and the environment, we enable organizations to advance the safety and sustainability of their business. Operating in more than 100 countries, our professionals are dedicated to helping customers in the maritime, oil & gas, power and renewables and other industries to make the world safer, smarter and greener.

DNV GL is the technical advisor to the oil and gas industry. We bring a broader view to complex business and technology risks in global and local markets. Providing a neutral ground for industry cooperation, we create and share knowledge with our customers, setting standards for technology development and implementation. From project initiation to decommissioning, our independent experts enable companies to make the right choices for a safer, smarter and greener future.

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