The Oil and Gas Industry in Energy Transitions

Insights from IEA analysis

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Introduction

The oil and gas industry is facing increasing demands to clarify the implications of energy transitions for their operations and business models, and to explain the contributions that they can make to reducing greenhouse gas (GHG) emissions and to achieving the goals of the Paris Agreement.

The increasing social and environmental pressures on many oil and gas companies raise complex questions about the role of these fuels in a changing energy economy, and the position of these companies in the societies in which they operate.

But the core question, against a backdrop of rising GHG emissions, is a relatively simple one: should today's oil and gas companies be viewed only as part of the problem, or could they also be crucial in solving it?

This is the topic taken up by the International Energy Agency (IEA) in this report, which builds on a multi-year programme of analysis on the future of oil and gas in the IEA *World Energy Outlook* (*WEO*) series.

This report does not aim to provide definitive answers, not least because of the wide diversity of oil and gas companies and company strategies around the world. It does aim to map out the risks facing different parts of the industry, as well as the range of options and responses.

Three considerations provide the boundaries for this analysis. First, the prospect of rising demand for the services that energy provides due to a growing global population – some of whom remain without access to modern energy – and an expanding global economy.

Second, the recognition that oil and natural gas play critical roles in today's energy and economic systems, and that affordable, reliable supplies of liquids and gases (of different types) are necessary parts of a vision of the future.

And last but far from least, the imperative to reduce energy-related emissions in line with international climate targets.

These elements may appear to be in contradiction with one another, but this is not necessarily the case. The *WEO* Sustainable Development Scenario (SDS) charts a path fully consistent with the Paris Agreement by holding the rise in global temperatures to "well below 2°C … and pursuing efforts to limit [it] to 1.5°C", and meets objectives related to universal energy access and cleaner air. The SDS and the range of technologies that are required to achieve it provide a benchmark for the discussion throughout this report.

The other scenario referenced in the analysis is the Stated Policies Scenario (STEPS), which provides an indication of where today's policy ambitions and plans would lead the energy sector. These outcomes fall far short of the world's shared sustainability goals.

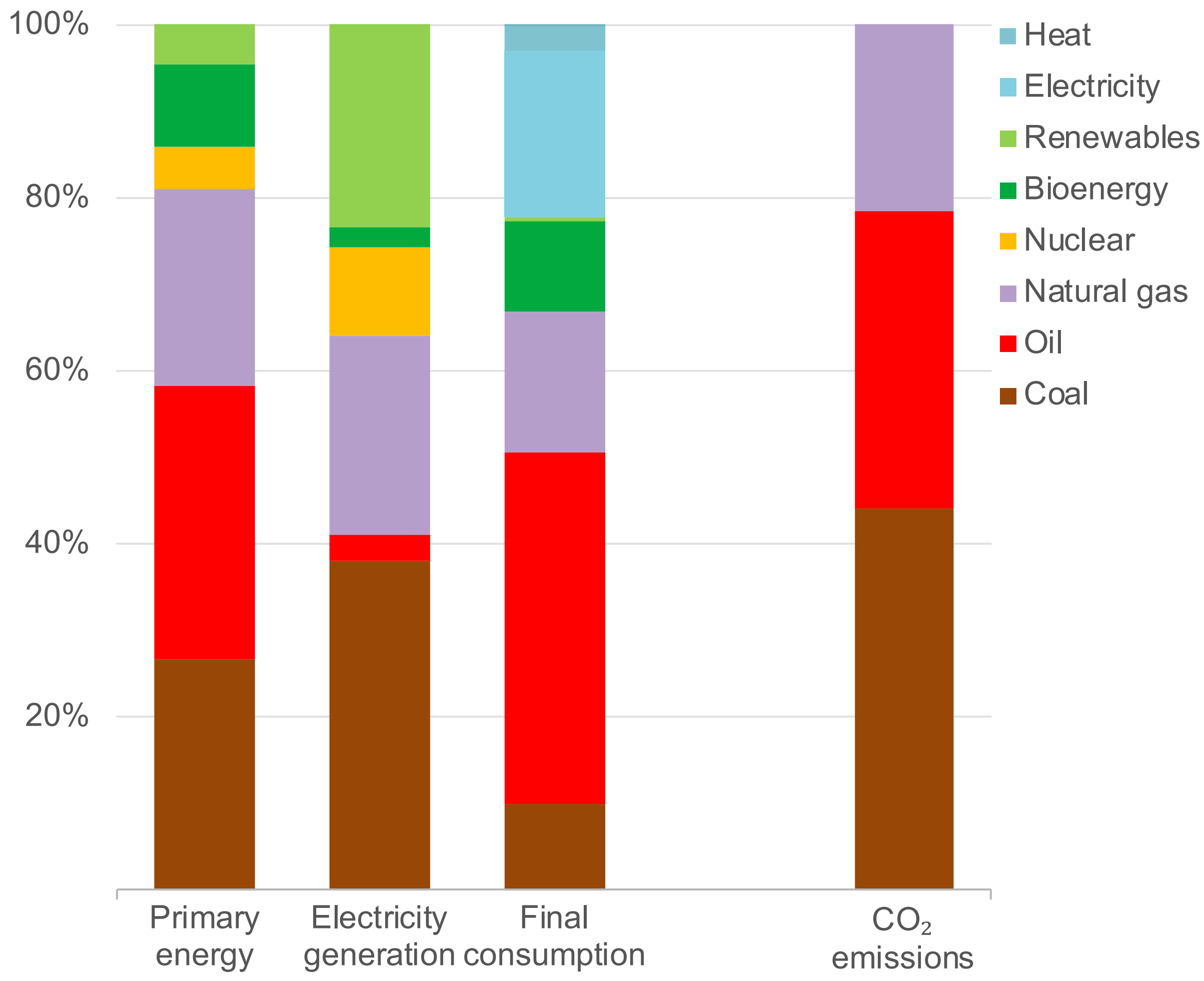
The focus of this report is therefore on accelerated energy transitions, the forces that could bring them about – whether from society, policy makers, technology, investors or the industry itself – and the implications that this would have for different parts of today's oil and gas industry.

Key findings

1. The oil and gas industry faces the strategic challenge of balancing short-term returns with its long-term licence to operate

Societies are simultaneously demanding energy services and also reductions in emissions. Oil and gas companies have been proficient at delivering the fuels that form the bedrock of today's energy system; the question that they now face is whether they can help deliver climate solutions. The analysis in this report highlights that this could be possible if the oil and gas industry takes the necessary steps. As such, it opens a way – which some companies are already following – for the oil and gas industry to engage with the "grand coalition" that the IEA considers essential to tackle climate change. This effort would be greatly enhanced if more oil and gas companies were firmly and fully onboard. The costs of developing low-carbon technologies represent an investment in companies' ability to prosper over the long term.

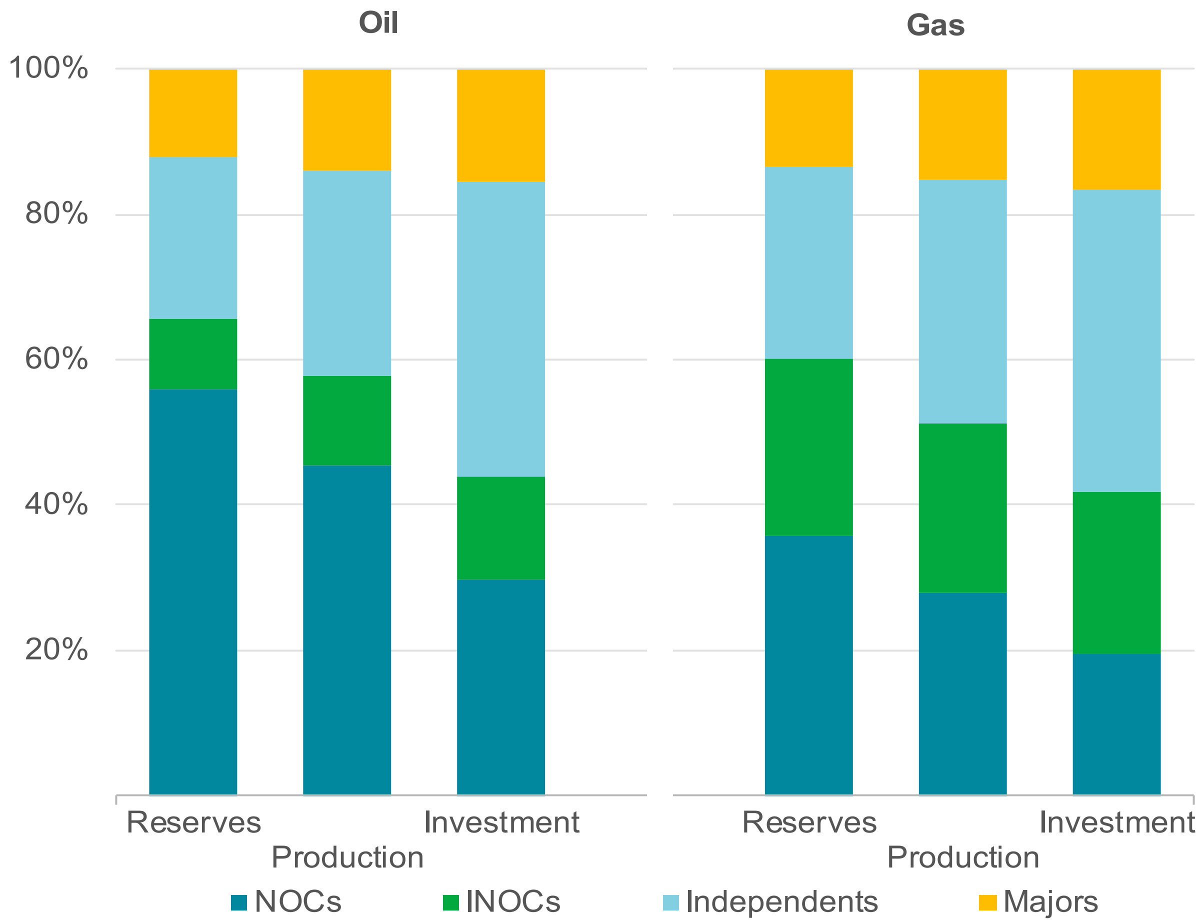
Overview of the global energy system, 2018



2. No oil and gas company will be unaffected by clean energy transitions, so every part of the industry needs to consider how to respond

The industry landscape is diverse and there is no single strategic response that will make sense for all. Attention often focuses on the Majors, seven large integrated oil and gas companies that have an outsized influence on industry practices and direction. But the industry is much larger: the Majors account for 12% of oil and gas reserves, 15% of production and 10% of estimated emissions from industry operations. National oil companies (NOCs) – fully or majority-owned by national governments – account for well over half of global production and an even larger share of reserves. There are some high-performing NOCs, but many are poorly positioned to adapt to changes in global energy dynamics.

Ownership of oil and gas reserves, production and upstream investment by company type, 2018

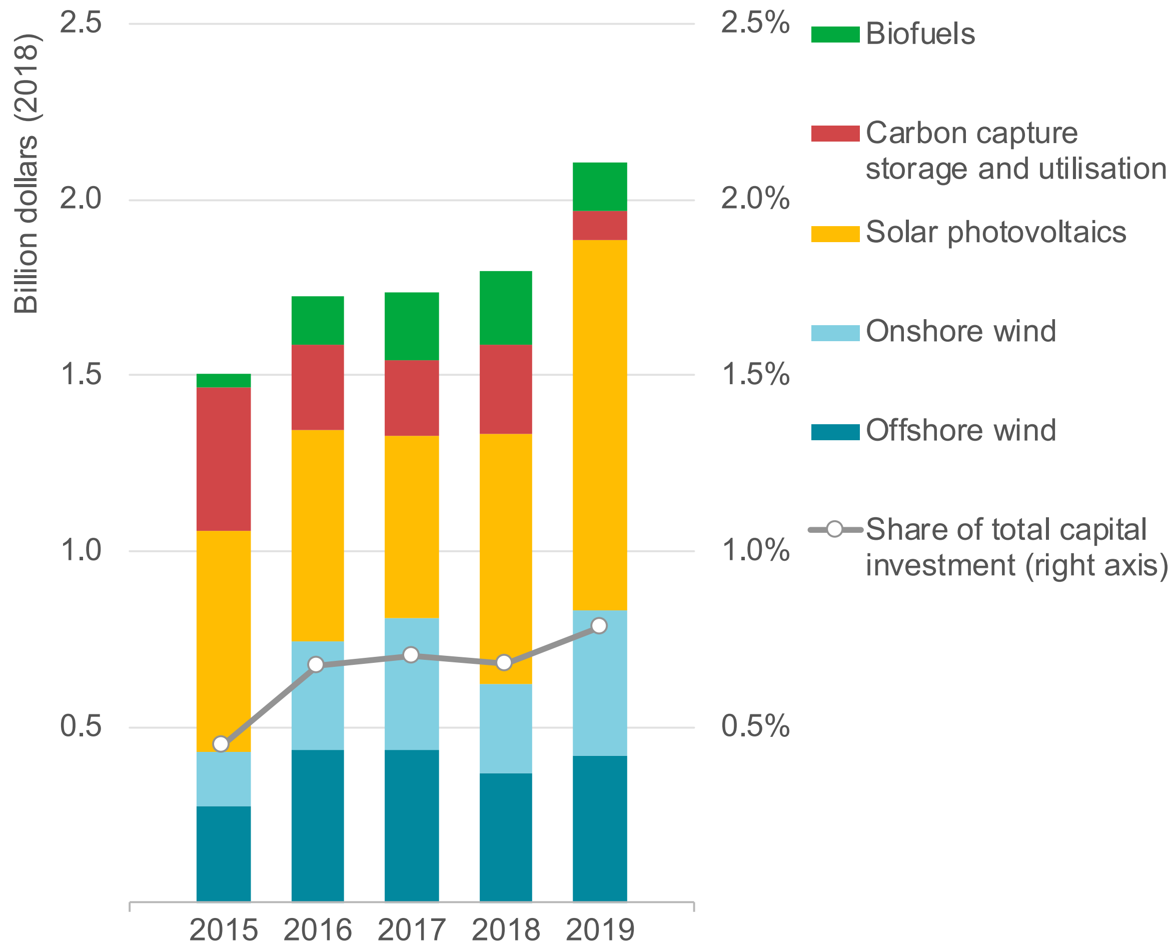


Note: NOCs = national oil companies; INOCs = international national oil companies.

3. So far, investment by oil and gas companies outside their core business areas has been less than 1% of total capital expenditure

For the moment, there are few signs of a major change in company investment spending. For those companies looking to diversify their energy operations, redeploying capital towards low-carbon businesses requires attractive investment opportunities in the new energy markets as well as new capabilities within the companies. As things stand, leading individual companies spend around 5% on average on projects outside core oil and gas supply, with the largest outlays in solar PV and wind. Some oil and gas companies have also moved into new areas by acquiring existing non-core businesses, for example in electricity distribution, electric vehicle charging and batteries, while stepping up research and development activity. A much more significant change in overall capital allocation would be required to accelerate energy transitions.

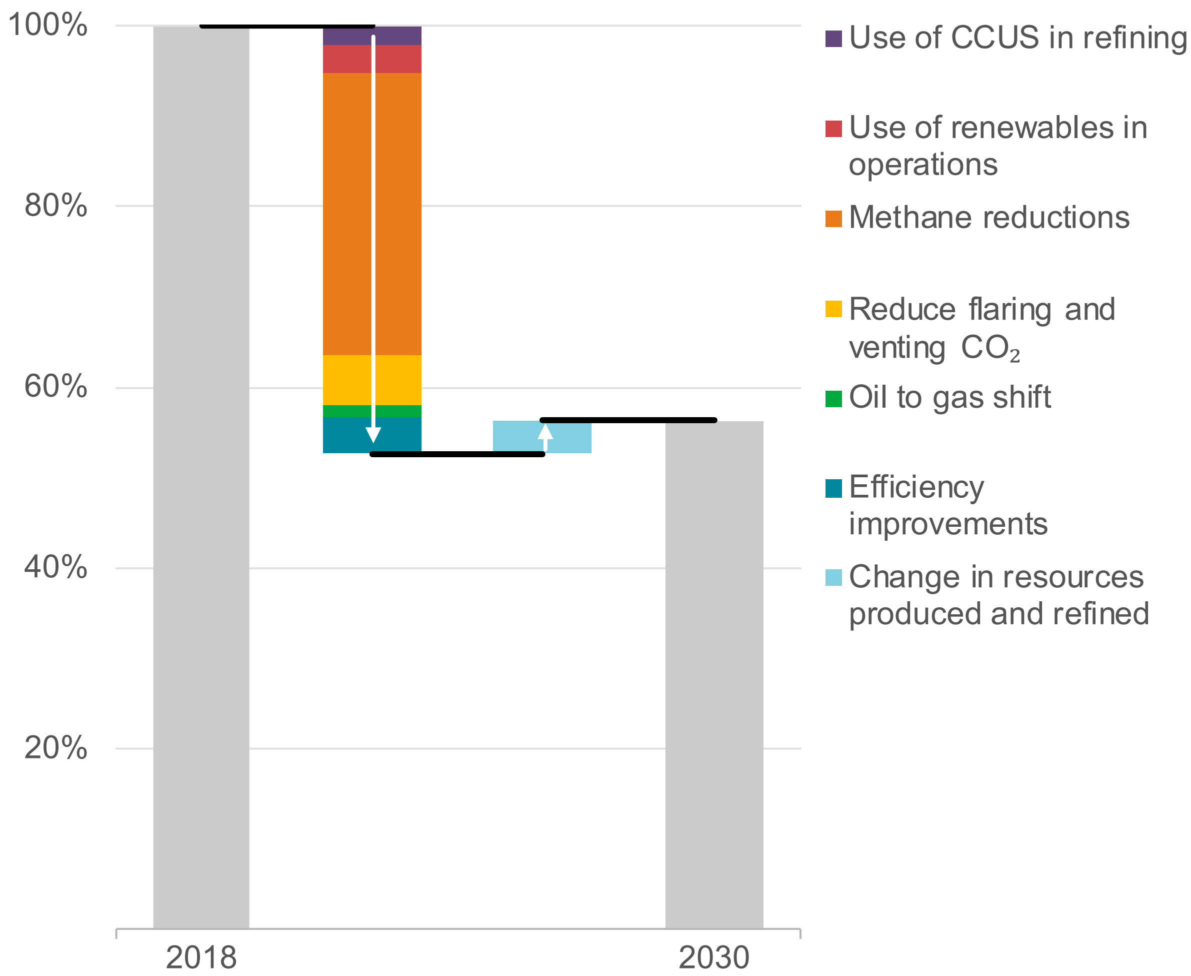
Capital investment by large oil and gas companies in new projects outside oil and gas supply



4. There is a lot that the industry could do today to reduce the environmental footprint of its own operations

Uncertainty about the future is a key challenge facing the industry, but this is no reason for companies to "wait and see" as they consider their strategic choices. Minimising emissions from core oil and gas operations should be a first-order priority for all, whatever the transition pathway. There are ample, cost-effective opportunities to bring down the emissions intensity of delivered oil and gas by minimising flaring of associated gas and venting of CO_2, tackling methane emissions, and integrating renewables and low-carbon electricity into new upstream and liquefied natural gas (LNG) developments. As of today, 15% of global energy-related GHG emissions come from the process of getting oil and gas out of the ground and to consumers. Reducing methane leaks to the atmosphere is the single most important and cost-effective way for the industry to bring down these emissions.

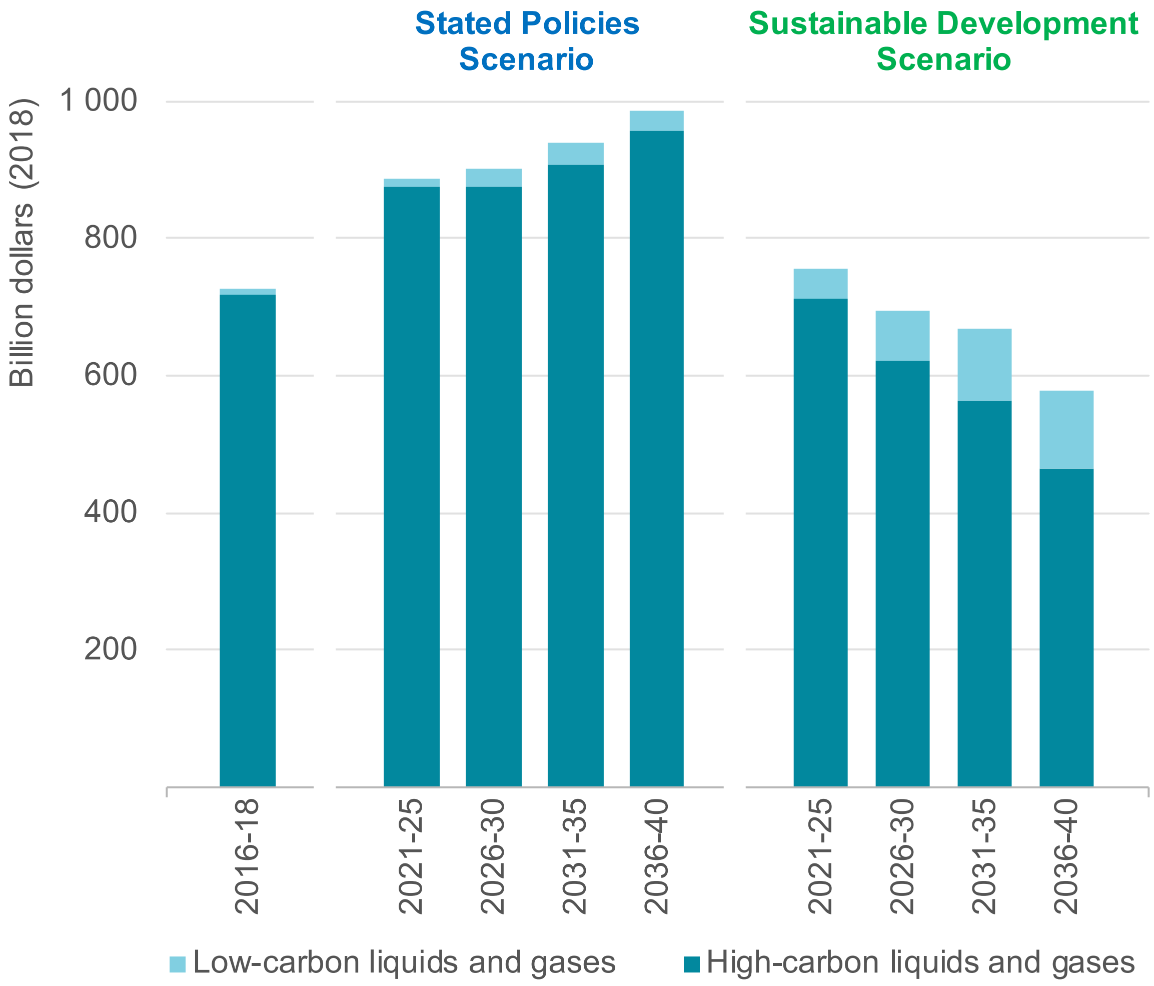
Changes in the average global emissions intensity of oil and natural gas operations in the SDS



5. Electricity cannot be the only vector for the energy sector's transformation

A commitment by oil and gas companies to provide clean fuels to the world's consumers is critical to the prospects for reducing emissions. The 20% share of electricity in global final consumption is growing, but electricity cannot carry energy transitions on its own against a backdrop of rising demand for energy services. Bringing down emissions from core oil and gas operations is a key step in helping countries to get environmental gains from using less emissions-intensive fuels. However, it is also vital for companies to step up investment in low-carbon hydrogen, biomethane and advanced biofuels, as these can deliver the energy system benefits of hydrocarbons without net carbon emissions. Within ten years, these low-carbon fuels would need to account for around 15% of overall investment in fuel supply.

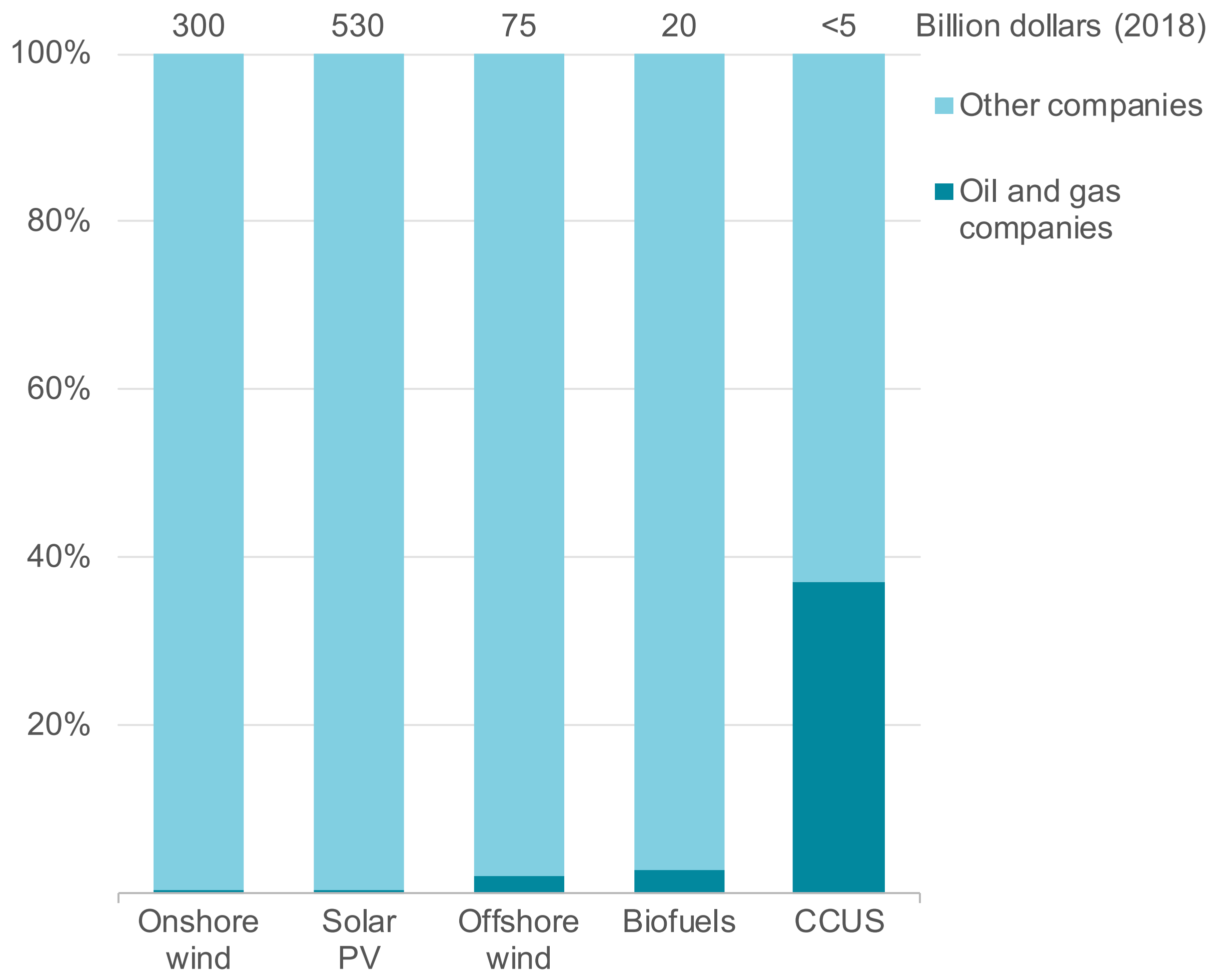
Capital investment in liquids and gases by scenario



6. The oil and gas industry will be critical for some key capital-intensive clean energy technologies to reach maturity

The resources and skills of the industry can play a central role in helping to tackle emissions from some of the hardest-to-abate sectors. This includes the development of carbon capture storage and utilisation (CCUS), low-carbon hydrogen, biofuels, and offshore wind. Scaling up these technologies and bringing down their costs will rely on large-scale engineering and project management capabilities, qualities that are a good match to those of large oil and gas companies. For CCUS, three-quarters of the CO_2 captured today in large-scale facilities is from oil and gas operations, and the industry accounts for more than one-third of overall spending on CCUS projects. If the industry can partner with governments and other stakeholders to create viable business models for large-scale investment, this could provide a major boost to deployment.

Global capital investment in selected low-carbon technologies (2015-18)

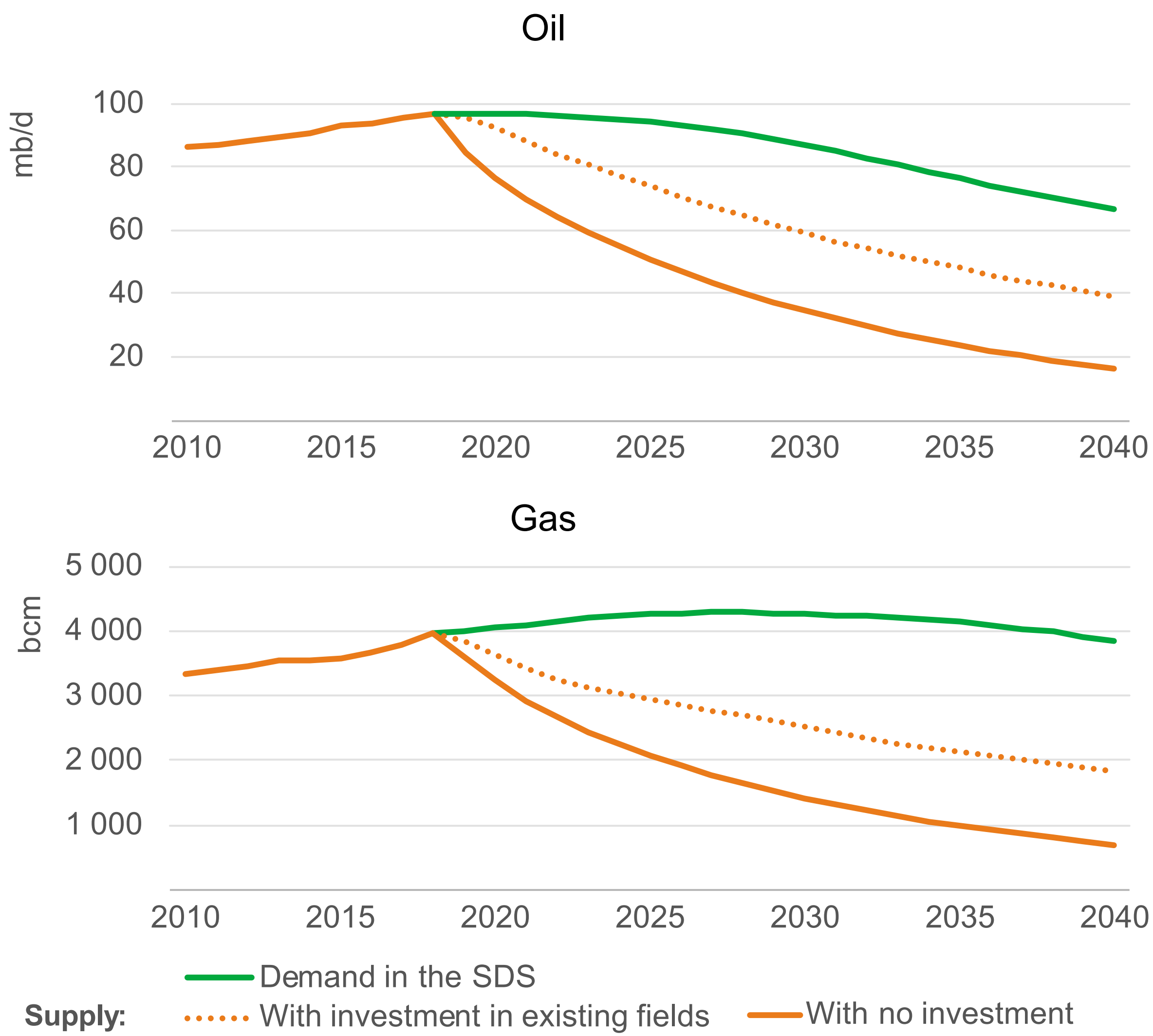


Note: CCUS only includes large-scale facilities.

7. A fast-moving energy sector would change the game for upstream investment

Investment in upstream projects is still needed even in rapid transitions, but the type of resources that are developed, and how they are produced, changes substantially. Production from existing fields declines at a rate of roughly 8% per year in the absence of any investment, larger than any plausible fall in global demand. Consequently, investment in existing and some new fields remains part of the picture. But as overall investment falls back and markets become increasingly competitive, only those with low-cost resources and tight control of costs and environmental performance would be in a position to benefit.

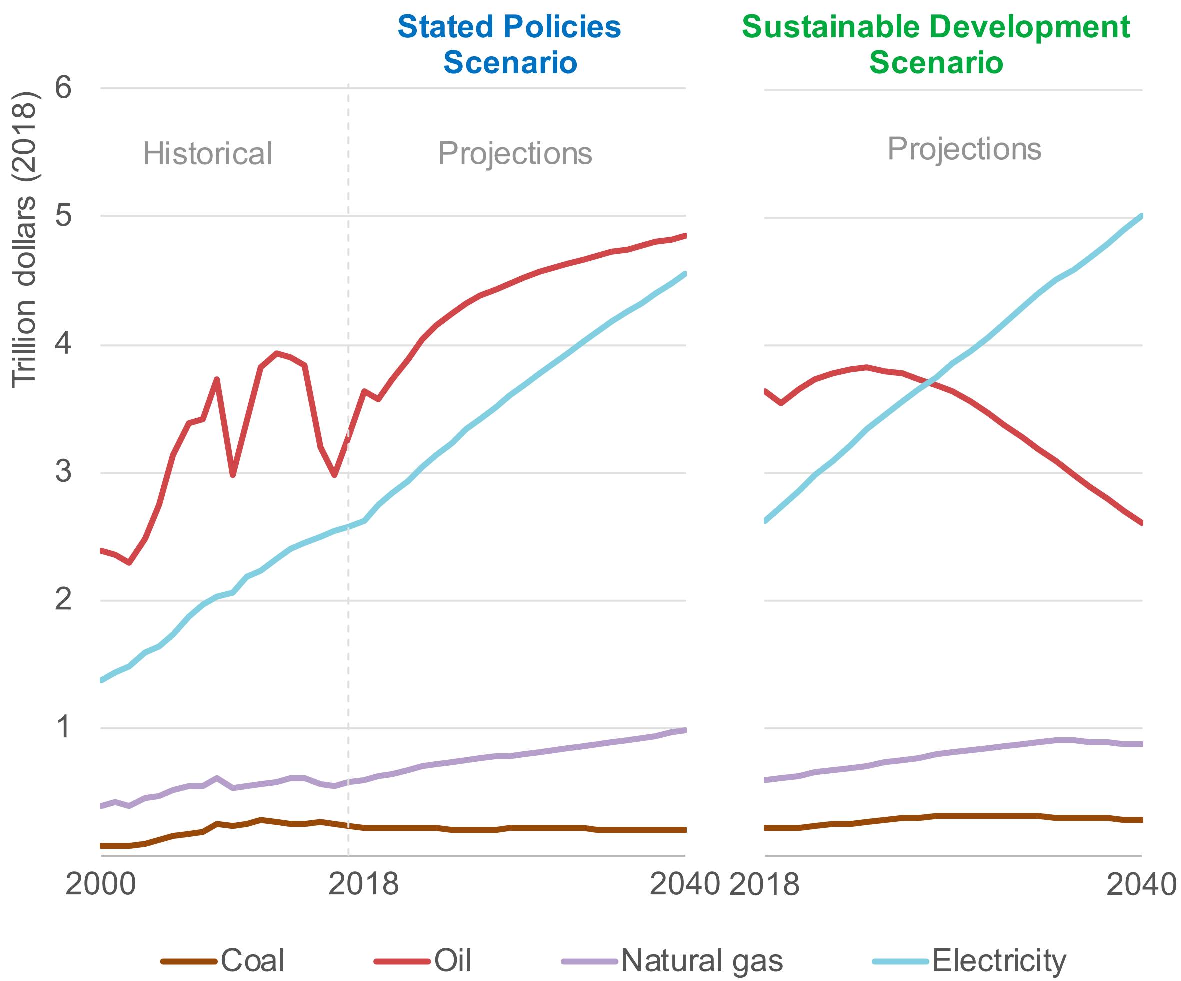
Global demand in the SDS and decline in supply from 2019



8. A shift from "oil and gas" to "energy" takes companies out of their comfort zone, but provides a way to manage transition risks

Some large oil and gas companies are set to make a switch to "energy" companies that supply a diverse range of fuels, electricity and other energy services to consumers. This means moving into sectors, notably electricity, where there is already a large range of specialised actors and where the financial characteristics and scale of most low-carbon investment opportunities are (with the partial exception of offshore wind) a long way from traditional oil and gas projects. Electricity provides long-term opportunities for growth, given that it overtakes oil in accelerated energy transitions as the main element in consumer spending on energy. It also opens the door to larger and broader reductions in company emissions, relieving social pressures along the way, although investors will watch carefully the industry's ability to balance diversification with expected returns and dividends.

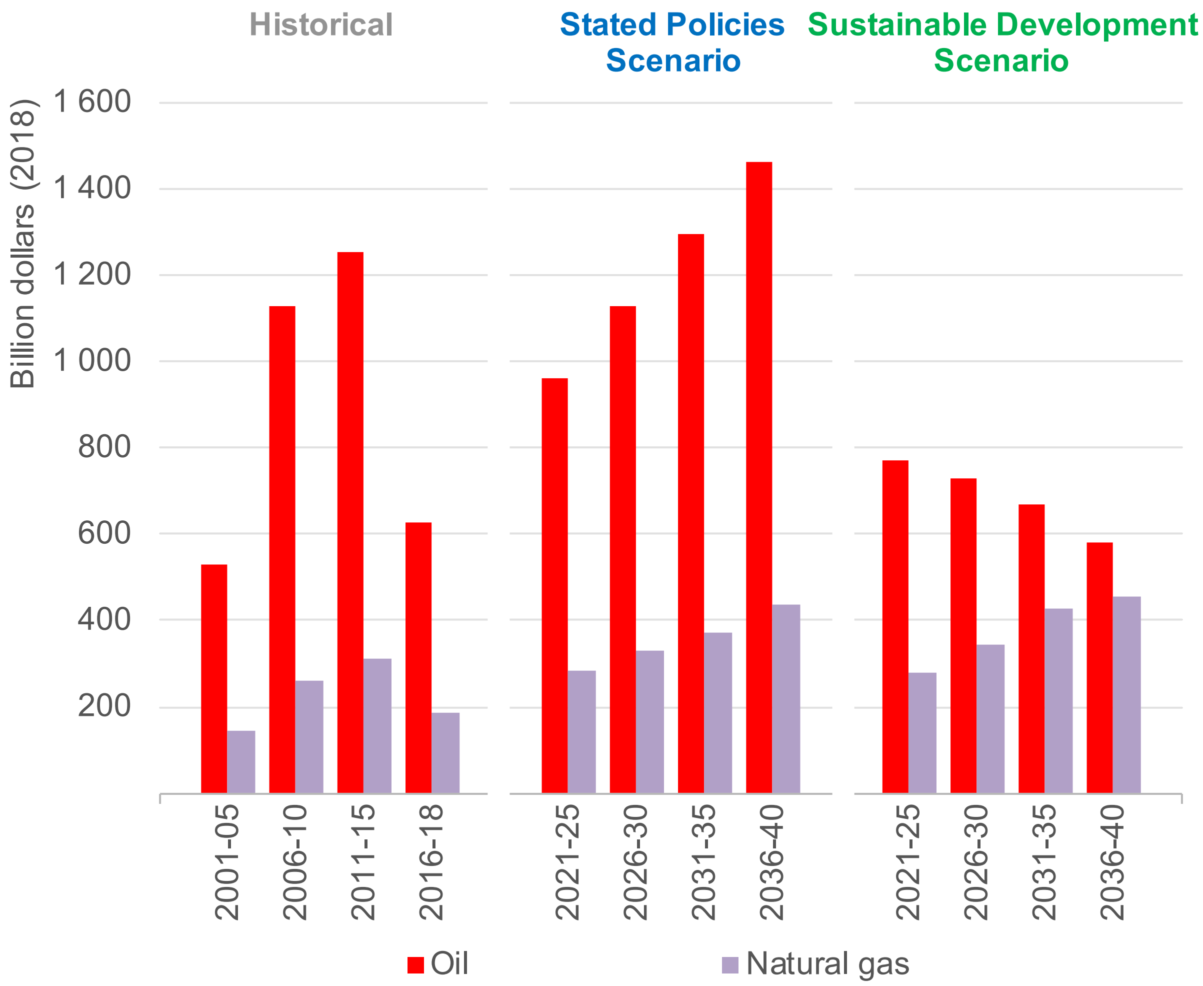
Global end-user energy spending by scenario



9. NOCs face some particular challenges, as do their host governments

The stakes are high for NOCs that are charged with the stewardship of national hydrocarbon resources, and for their host governments and societies that often rely heavily on the associated oil income. Changing energy dynamics have prompted a number of countries to renew their commitment to reform and to diversify their economies; fundamental changes to the development model in many major resource holders look unavoidable. NOCs can provide important elements of stability for economies during this process, if they are operating effectively and alert to the risks and opportunities. Some leading NOCs are stepping up research efforts targeting models of resource development that are compatible with deep decarbonisation, e.g. via CCUS, trade in hydrogen or a focus on non-combustion uses of hydrocarbons.

Average annual net oil and gas income before tax of NOCs and INOCs, by scenario



10. The transformation of the energy sector can happen without the oil and gas industry, but it would be more difficult and more expensive

Oil and gas companies need to clarify the implications of energy transitions for their operations and business models, and to explain the contributions that they can make to accelerate the pace of change. This process has started and company commitments to reduce emissions or emissions intensities are becoming increasingly common. However, the industry can do much more to respond to the threat of climate change. Regardless of which pathway the world follows, climate impacts will become more visible and severe over the coming years, increasing the pressure on all elements of society to find solutions. These solutions cannot be found within today's oil and gas paradigm.

Section I

The oil and gas industry today

Mapping out the oil and gas industry: National oil companies

The oil and gas industry includes a very diverse mix of corporate structures and governance models, from small enterprises to some of the world's largest corporations. The risks and opportunities of energy transitions vary widely across this spectrum.

For the purposes of this analysis, oil and gas companies are grouped into four main categories: two of these categories cover companies that are fully or majority-owned by national governments and the other two relate to privately owned companies.

Among the former, this report distinguishes between national oil companies (NOCs) that concentrate on domestic production and a second group of international NOCs (INOCs) that have both domestic and significant international operations; the classification is done on the basis of upstream operations.

NOCs include the largest companies both in terms of production and in terms of reserve size. They have a mandate from their home government to develop national resources with a legally defined role in upstream development. Some NOCs are active in the downstream and even may operate outside their home country, but the home country upstream represents the vast majority of their asset base.

The largest of these NOCs are in the Middle East (notably Saudi Aramco, National Iranian Oil Company, Basra Oil Company, Qatar Petroleum), but there are also companies in this category in the Russian Federation ("Russia") and the Caspian (e.g. Rosneft, Uzbekneftegaz, SOCAR, KazMunayGaz), Latin America (Petrobras, PEMEX, Petróleos de Venezuela, S.A. [PDVSA]), and many parts of Africa (Nigeria National Petroleum Corporation [NNPC], Sonatrach, Sonangol).

INOCs are similar to NOCs in terms of governance and ownership but have large upstream investments outside the home country, usually in partnership with host NOCs or private companies. INOCs include large players in global gas markets.

For oil, in most cases INOC production is sold into the international market either by companies' own marketing arms or by the associated NOC. On rare occasions, it may be transported back to the home country if this makes sense economically. INOCs are often dominant in the refining sector of their home country.

Companies in this category include Equinor, the China National Petroleum Corporation (CNPC), Gazprom, Sinopec, the China National Offshore Oil Corporation (CNOOC), Petronas, India's Oil and Natural Gas Corporation (ONGC) and Thailand's PTTEP.

Mapping out the oil and gas industry: Privately owned companies

The "Majors" (sometimes referred to as international oil companies [IOCs]) are integrated companies listed on US and European stock markets. Their upstream division represents the majority of the financial value, but in physical terms most of these companies are net buyers of oil for their refining operations, where throughputs generally exceed the company's crude production. The decoupling of the marketing of their upstream production and supply to their refineries makes them active players in the international oil market.

They have historically focused on large, capital-intensive projects (often in partnership with other NOCs and INOCs), taking both market and project management risk, although many are increasingly investing in shorter-cycle investments. Natural gas, especially liquefied natural gas (LNG), represents an increasing share of their production and capital investment.

In this report's classification, the "Majors" grouping includes seven companies: BP, Chevron, ExxonMobil, Shell, Total, ConocoPhillips and Eni.

"Independents" are either fully integrated companies, similar to the Majors but smaller in size, or independent upstream operators. They may focus on assets of less interest to the Majors such as medium-size declining fields or frontier areas. As with the Majors, they often outsource drilling, well completion and logistics operations.

Independents encompass a wide range, including Russian companies such as Lukoil; Repsol in Europe; a large number of North American players such as Marathon, Apache and Hess; and diversified conglomerates with upstream activities, such as Mitsubishi Corp.

This group also includes North American shale independents, a relatively new group of companies that almost exclusively focus on developing shale gas and tight oil resources. These companies have a high reliance on debt finance and financial leverage.

In addition to these four categories (NOCs, INOCs, Majors and Independents), there are three other company types – typically private-owned – that play significant roles in the oil and gas industry, and whose response is important in energy transitions:

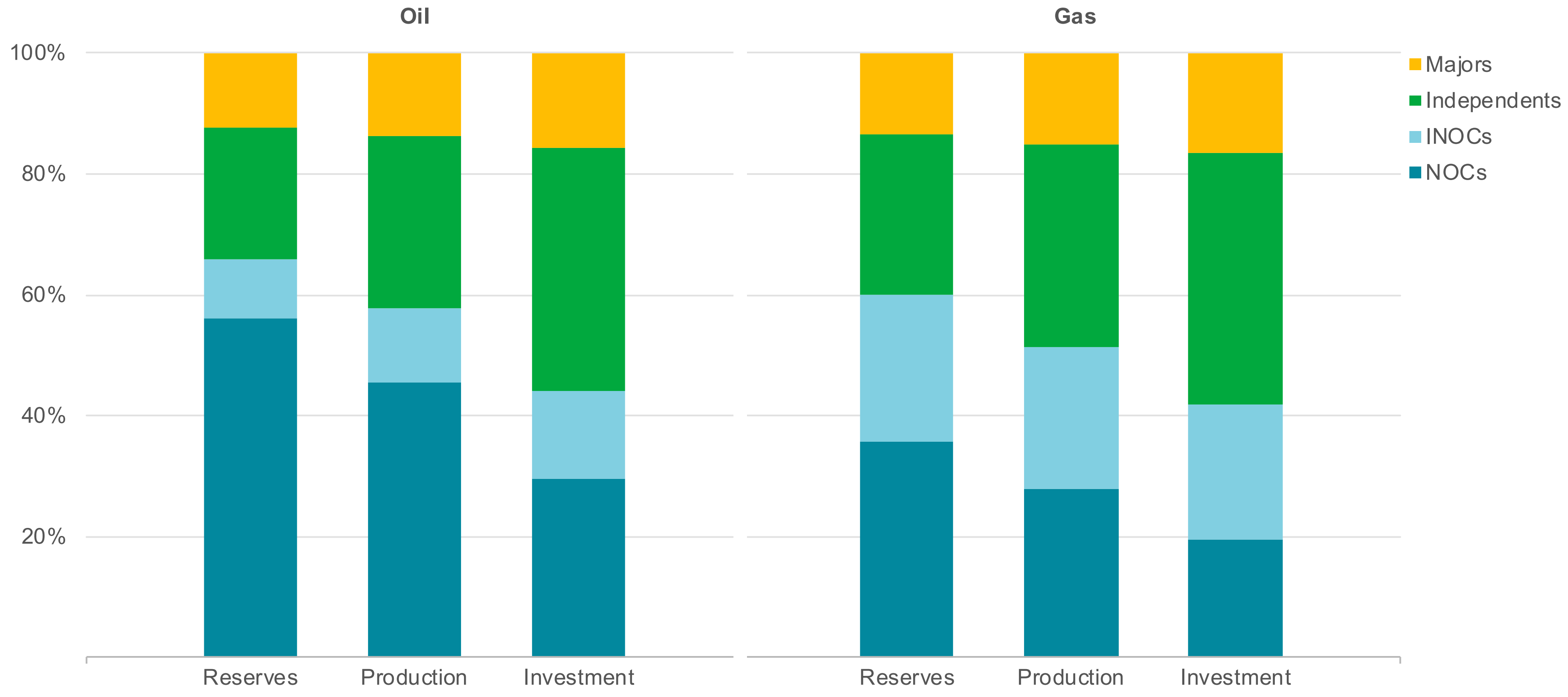
- **Service companies** (e.g. Schlumberger, Baker Hughes). Most oil and gas companies rely on specialist engineering services for drilling, reservoir management and construction of infrastructure. Some of the most important technological innovations unlocking new resources were developed by service companies. Service companies tend to be highly exposed to the cyclicality of capital spending.
- **Pure downstream companies** (e.g. Marathon Petroleum, Phillips 66). These are companies operating refineries and retail networks; their capitalisation and balance sheet position is usually considerably weaker than the Majors.
- **Trading companies** (e.g. Vitol, Glencore). Companies that are active in the physical trading of oil products and LNG. They sometimes invest in transport, refining, distribution and storage assets but their business models tend to rely on owning only those physical assets that help optimise their position in the market. They play a major role in ensuring the smooth, flexible functioning of markets.

Resources and production

Slides 18 - 26

How do the different company types compare in their ownership of oil and gas reserves, production and investment?

Ownership of oil and gas proven-plus-probable reserves, production and upstream investment by company type, 2018



Note: *Oil* includes crude oil, condensate and natural gas liquids (NGLs).

Source: IEA analysis based on the World Energy Model and Rystad Energy.

Most oil reserves are held by NOCs, whose lower-cost asset base means that they account for a smaller share of upstream investment

NOCs (including INOCs) control around two-thirds of the world's proven-plus-probable (2P) oil reserves, including both conventional and unconventional oil.

Remaining reserves are shared between the Independents (22%) and Majors (12%). The share of the Independents is boosted by major Russian non-state reserve-holders such as Lukoil and by companies that have stakes in the Canadian oil sands.

The majority of oil reserves in the Middle East and Latin America are held by the domestic NOCs, whereas in North America – with the exception of Mexico – this role is taken on by private companies. In Russia, there are some strong domestic, privately owned companies, but majority state-owned companies have been increasing their share and now control over 40% of Russian reserves.

Companies, often Majors, with their headquarters in Europe and North America are among the largest reserve-holders outside their home regions. Although Asian companies are currently among the most acquisitive internationally, their overseas holdings remain relatively small, in particular by comparison with the extent of their anticipated oil demand.

The share of 2P oil reserve holdings does not translate into a similar share of production today. For example, while NOCs hold 55% of global oil reserves, they account for only 45% of oil production (in large part because of the policy of market management pursued by many of their host governments).

NOCs control not only by far the largest portion of reserves, but also those with the lowest average development and production costs (although NOC assets are not exclusively low-cost). Furthermore, many of their assets have slow decline rates, meaning that relatively limited levels of capital spending, on a per barrel basis, are required to maintain production.

These factors mean that the share of NOCs' capital investment in upstream oil projects is much lower than their share of oil reserves. Conversely, Independents – and more recently, also the Majors – typically hold slightly higher-cost assets or projects with higher decline rates such as US tight oil and deepwater fields; together Independents (40% of the global total in 2018) and Majors (15%) account for well over half of today's upstream oil investment.

NOCs – including INOCs – also hold the largest share of natural gas reserves; the upstream ties between oil and gas are strong

Reserves of natural gas are more evenly distributed across the four company types than is the case for oil. However, while the share of NOCs is lower for gas than for oil, the share of INOCs – which include Russia's Gazprom – is significantly higher. As a result, the combined share of NOCs and INOCs in 2P reserves is broadly similar for both natural gas and oil.

Amongst the INOCs, Gazprom is the dominant reserve holder in Russia, while Chinese state-owned companies such as PetroChina and Sinopec hold the lion's share of gas reserves in the People's Republic of China ("China"). The Majors have the smallest share of global total (14%), but these have a broad geographic spread, with their largest holdings in the Middle East, North America, Australia and North Africa.

As with oil, the share of NOCs in both production and investment levels is much smaller than their share of reserves given their lower cost base. Their largest investments in 2018 were in the North Field in Qatar (Iran's share of this field is called South Pars), in fields in Turkmenistan and in gas processing facilities for the Ghawar field in Saudi Arabia. Given the distribution of INOC reserves, most of their investment took place in Russia and China.

The holdings of Independents are bolstered by their strong position in the United States, which holds the second-largest level of reserves after Russia. Nearly two-thirds of upstream investment by the Independents in 2018 was in North America.

The Majors display a geographically dispersed pattern in investment, including large-scale spending in Africa, in fields to supply new LNG facilities in Australia, and in shale gas plays in the United States.

It is not possible in practice to make a sharp distinction between oil and gas production and investment. This is because most wells that are drilled to target oil formations also yield a mixture of other hydrocarbons such as condensates, natural gas liquids and natural gas, and natural gas wells also produce quantities of liquids.

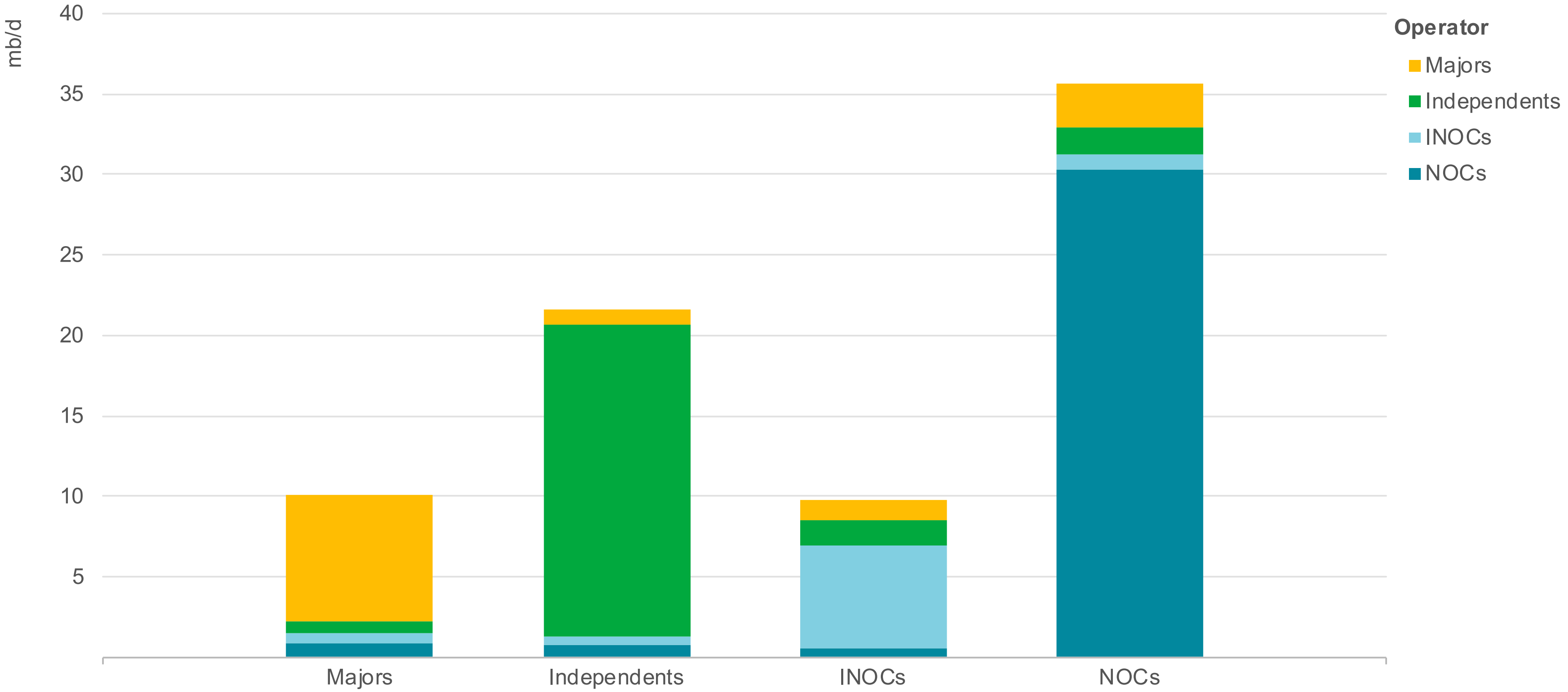
Some 850 bcm of associated gas (nearly one-quarter of global marketed production) was produced in 2018 as a by-product of oil output. Only around three-quarters of this total was used by the industry or brought to market.

Associated gas from oil fields is a main source of flaring as well as a major source of gas that is vented directly to the atmosphere. Some 140 bcm was flared and this report estimates that an additional 60 bcm was released directly into the atmosphere in 2018 (200 bcm is more than the annual LNG imports of Japan and China combined). This represents a major waste of resources as well as a significant source of GHG emissions.

In the case of oil, there were 17.3 mb/d of NGLs produced in 2018. Production of NGLs has almost doubled since 2000, as global gas production has risen.

Companies' production includes oil from both operated and non-operated assets. The Majors hold a relatively small share of total crude oil production globally…

Equity ownership of global crude oil production by company split by asset operator, 2018

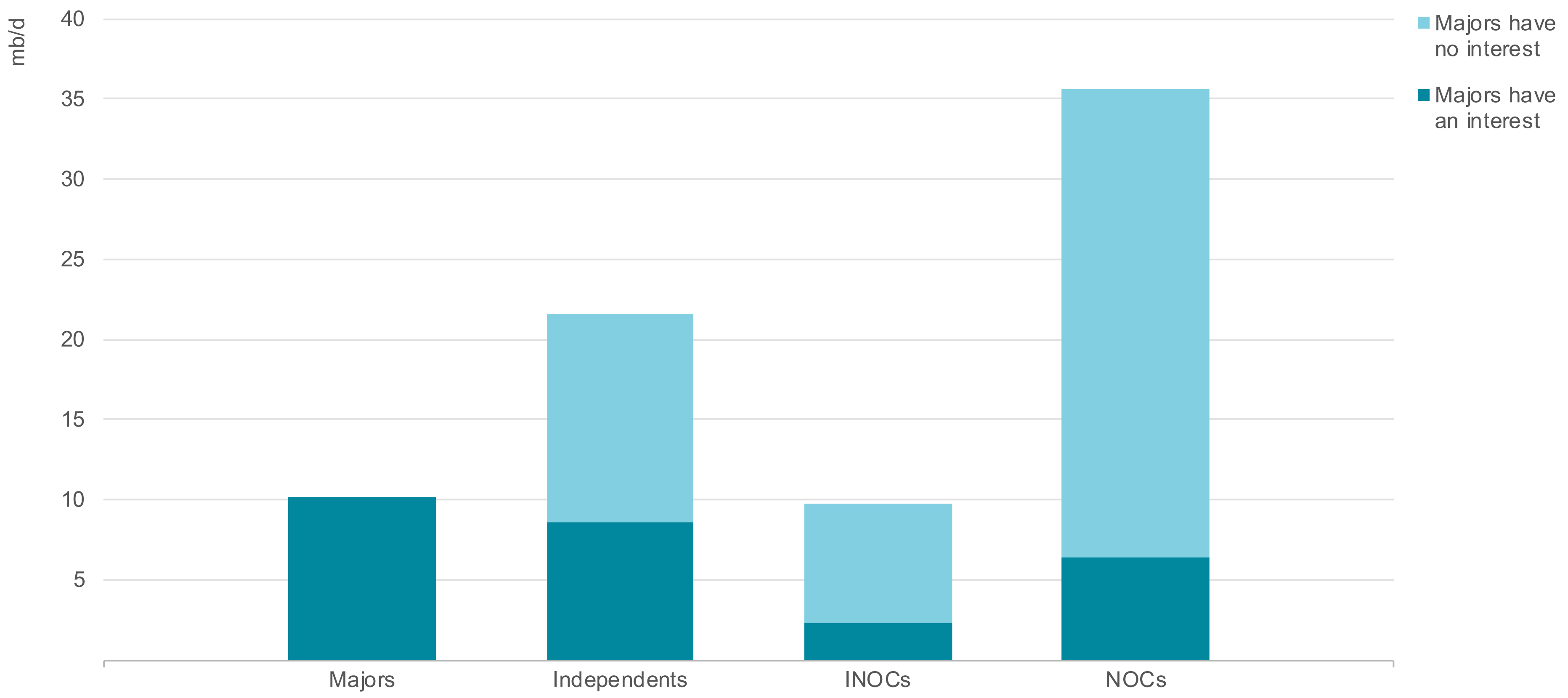


Note: Share of production in joint ventures is split according to the ownership of each company grouping in the joint venture.

Source: IEA analysis based on Rystad Energy.

…although the influence of the Majors extends well beyond their ownership of production

Equity ownership of crude oil production split by assets in which one of the Majors has any interest



Notes: Production from a project is assigned to “Majors have an interest” if one of the Majors has more than 1% equity ownership of output, irrespective of the project operator. Assessment examines production on a project-by-project basis.

Source: IEA analysis based on Rystad Energy.

Partnerships are prevalent across the upstream world

Just under 78 mb/d of crude oil is produced around the world today (a further 17 mb/d consists of NGLs, including condensates). The NOCs account for just under half of global crude oil production, followed by the Independents (28%), and Majors and INOCs (both 13%). These volumes include the equity ownership of each company type in upstream projects, even where another company type operates the field (i.e. takes care of day-to-day oilfield operations).

Exploration and new field development are risky and complex processes, so companies often split the equity ownership to spread the risk and reward and to encourage technical and operational collaboration; this arrangement also usually stipulates who will operate the field once it starts production. A common vehicle is for the interested parties to establish a joint venture: these can take many different forms but they generally aim to promote collaboration between the parties and spread the risk while maintaining some level of corporate independence.

A complicating factor when considering “ownership” of barrels is that tax regimes in some countries can transfer ownership of barrels that are produced to the host government, rather than apply a royalty of tax to financial flows. The equity ownership for companies can vary over the lifetime of a field or vary according to external factors such as the oil price.

In 2018, the Majors had equity ownership of around 10 mb/d of crude oil production, but they operated fields that produced around 13 mb/d. By contrast, the NOCs owned 36 mb/d of production, while they operated fields that produce around 32 mb/d crude oil.

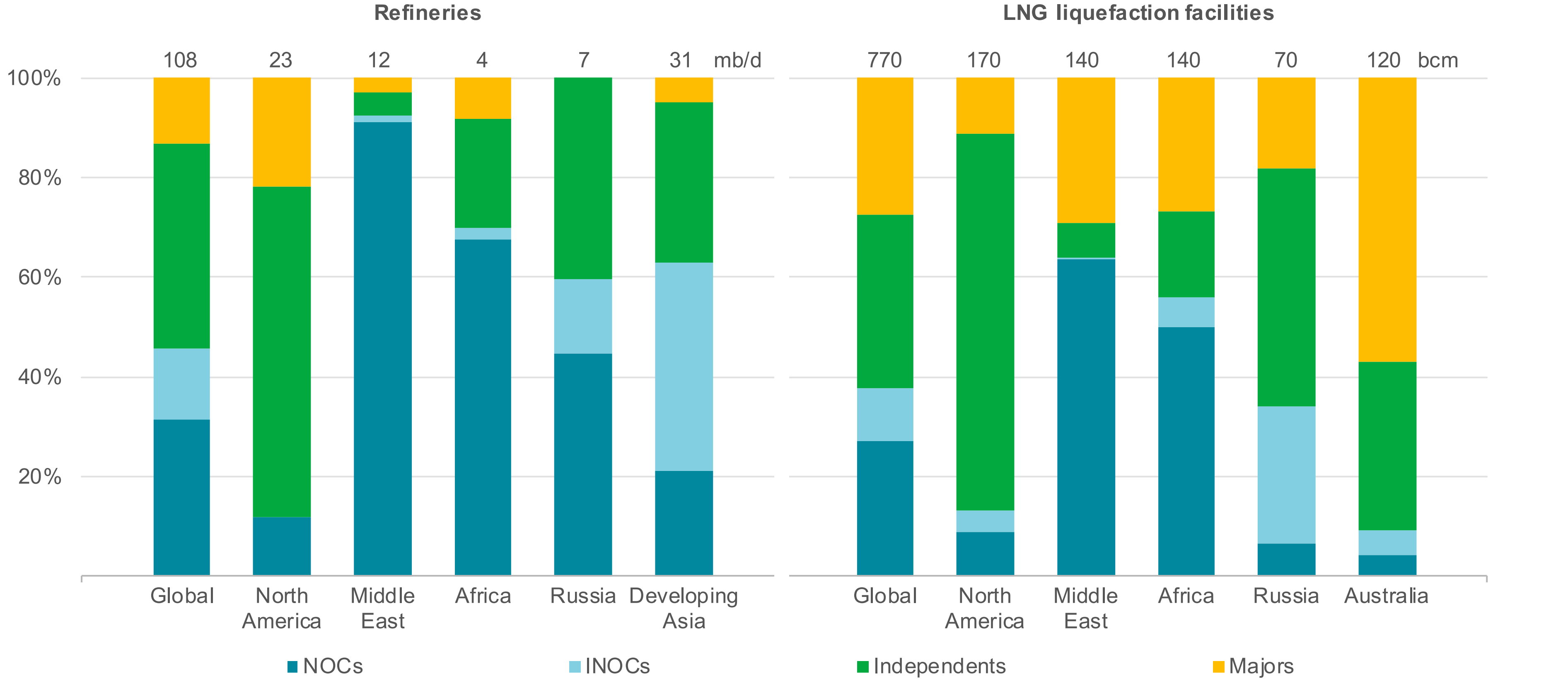
The prevalence of different types of partnerships in the oil and gas industry means that the influence of companies can spread much further than their equity ownership or direct operations. For example, the Majors hold stakes in fields that produce far more than the 10 mb/d crude oil that they own. Around 40% of oil production that is owned by Independents comes from fields in which one of the Majors holds a stake. The figures are lower for INOCs (24%) and NOCS (18%), but these still represent significant volumes.

In total, just under 30 mb/d of global production in 2018 came from fields in which the Majors held some sort of equity stake. In other words, Majors hold some level of influence over three times more global production than they directly own.

This has important potential implications for the Majors’ influence on upstream production practices. For example, co-ordination between the Majors and their partners at all fields in which the Majors have a stake, in favour of using certain practices or technologies, would impact almost three times more production than if they were to be instituted only at fields that the Majors directly own or operate.

Ownership of refinery and LNG assets varies across regions…

Composition of refinery and LNG asset ownership in selected regions, 2018



Note: Includes refineries and liquefaction facilities in operation and under construction.
Source: IEA (2019), *World Energy Outlook 2019*, www.iea.org/weo2019.

…with a major expansion of capacity bringing new players and regions to prominence

There is over 100 mb/d of refining capacity in operation or under construction today, 40% of which is in North America and Europe and another 40% in developing countries in Asia (where a host of new refining capacity is being built) and in the Middle East. Independents (both integrated players and pure downstream companies) hold the largest share of around 40%, followed by NOCs (31%), INOCs (14%) and the Majors (13%). There is also a small contribution from major trading companies.

The trend varies widely by region. In North America, Europe and advanced economies in Asia (where refining activities have traditionally taken place), refineries are largely owned by private companies. Independents and Majors own almost 90% of the refineries in this region, while NOCs have limited presence.

The picture is starkly different in the regions where a number of new refineries are being built. In the Middle East, 90% of the refineries are owned by NOCs. The participation of Independents and Majors has mostly taken place via joint ventures with NOCs. Similar trends are visible in Africa, where NOCs account for two-thirds of refinery ownership. NOCs and INOCs also have strong presence in developing countries in Asia, holding two-thirds of the region's refining capacity, but there is also a sizeable contribution from private companies.

The share of NOCs (and INOCs) in global refinery ownership and petrochemical units is set to increase in the coming decades. This is because most of the new refinery capacities are planned to be built in the Middle East and in developing countries in Asia and because many NOCs are pursuing a strategic expansion into the downstream.

Turning to LNG, there is currently some 570 bcm of liquefaction capacity in operation today and almost 200 bcm that is financially approved or under construction. The three largest LNG exporters – Australia, Qatar and the United States – account for around half of the world's operational capacity. Over the next few years, these three countries are set to jostle for the position of largest exporter. Canada and Mozambique are the major pending new entrants to the club of LNG producers, taking the total number of exporting countries to 23.

The capital and technical risks associated with developing LNG liquefaction terminals favour a relatively diversified ownership; globally, there is roughly a 60/40 split between Majors/Independents and NOC/INOCs. Independents hold the largest share of liquefaction capacity globally (35%) and dominate the picture in North America. NOCs are majority owners in the Middle East and Africa, frequently partnering with Majors to execute large, capital-intensive projects. Majors have the largest presence in Australia, which has seen some of the highest levels of spending on LNG mega-projects. Russian LNG has a more diversified ownership structure than in pipeline gas supply, drawing IOCs, NOCs and other external partners into large-scale Arctic, Yamal and Siberian projects.

The growth of LNG supply in the last decade has underpinned the emergence of LNG "portfolio players", large companies that hold a portfolio of LNG supply, liquefaction, shipping, storage and regasification assets in different regions. They can be Majors, NOCs or larger Independents and are distinguished by their size and presence across the value chain.

Environmental indicators

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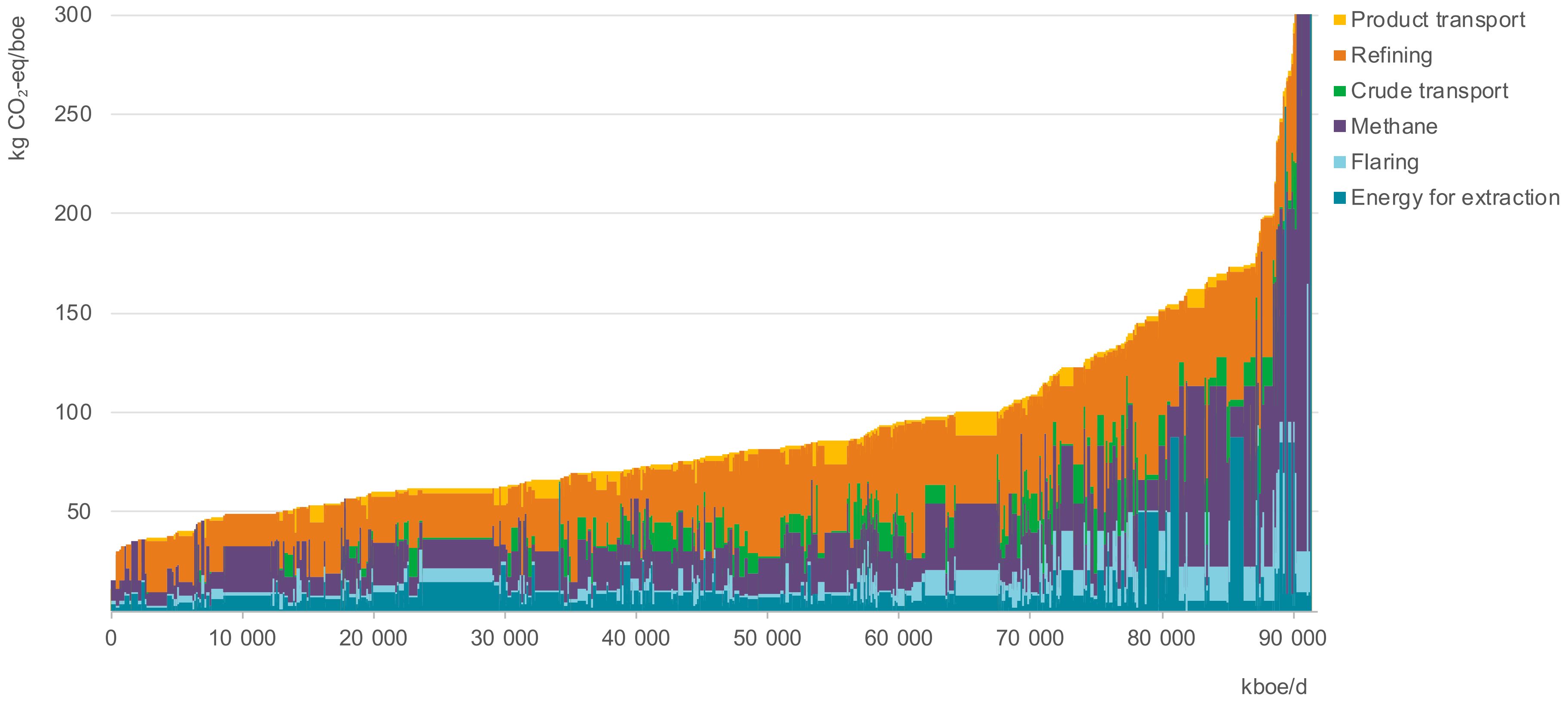
Not all oil is equal. Excluding final combustion emissions, there is a wide range of emissions intensities across different sources of production…

Estimated scope 1 and 2 emissions intensity of global crude oil, condensate and NGLs production, 2018

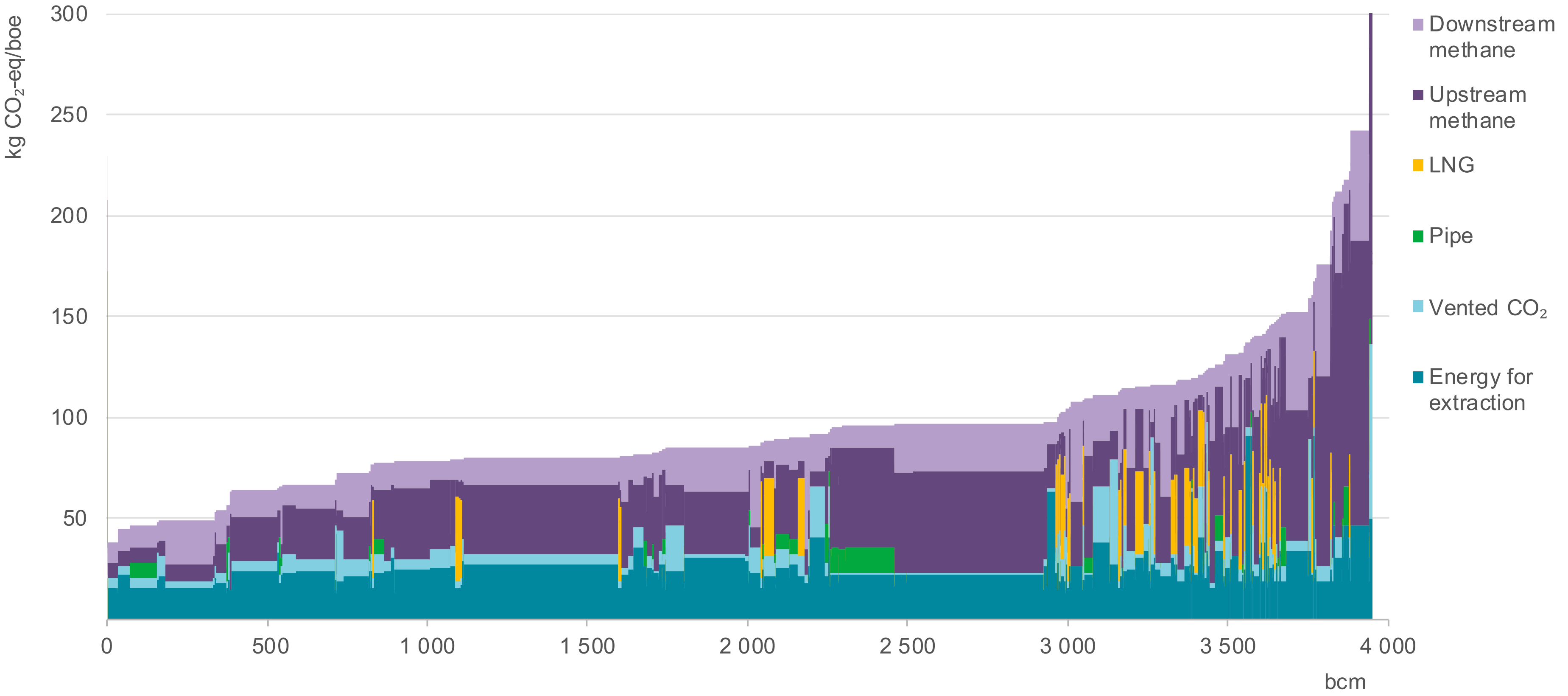


Notes: kg CO_2/boe = kilogrammes of CO_2 per barrel of oil equivalent; kboe/d = thousand barrels of oil equivalent per day. One tonne of methane is assumed to be equivalent to 30 tonnes of CO_2 (the 100-year "global warming potential"). Although not strictly an oil refining process, NGL fractionation is included within refining since it converts liquids into usable oil products.

Source: IEA (2018), *World Energy Outlook 2018*, www.iea.org/weo2018.

…and the same applies to natural gas: methane leaks to the atmosphere are by far the largest source of emissions on the journey from reservoir to consumer

Estimated scope 1 and 2 emissions intensity of global natural gas production, 2018



Note: kg CO_2/boe = kilogrammes of CO_2 per barrel of oil equivalent. Energy for extraction includes emissions from processing to remove impurities before transport. Upstream methane includes emissions from production, gathering and processing; downstream methane includes emissions from shipping (if applicable), transmission and distribution (see IEA [2017] for further details). One tonne of methane is assumed to be equivalent to 30 tonnes of CO_2 (the 100-year "global warming potential").

Source: IEA (2018), *World Energy Outlook 2018*, www.iea.org/weo2018.

Scoping out the emissions from oil and gas operations

Extracting oil and gas from the ground, processing it, and bringing it to consumers is an important component of global energy demand today. The process of getting these fuels to consumers is also an important source of global GHG emissions. These can be CO_2 emissions from the energy consumed along the oil and natural gas value chains as well as leaks of CO_2 and methane to the atmosphere.

These emissions associated with oil and natural gas are often divided into three different "scopes". Looking from the perspective of the oil and gas industry as a whole, while avoiding any double counting, this report approaches the issue as follows.

"Scope 1" emissions are emissions that come directly from the oil and gas industry itself. This includes, for example, emissions from powering the engines of drilling rigs, or from leaks of methane in the upstream or midstream, or emissions from ships used to transport oil or gas overseas.

"Scope 2" emissions arise from the generation of energy that is purchased by the oil and gas industry; for example from the generation of electricity taken from a centralised grid to power auxiliary services, or from the production of hydrogen purchased from an external supplier to be used in a refinery. The sum of scope 1 and 2 emissions is often referred to as the "well-to-tank" or "well-to-meter" emissions.

The IEA World Energy Model tracks a barrel of oil or cubic metre of natural gas from where it is produced to where it is refined or processed and finally consumed. As a result, this report can estimate total GHG emissions from the multitude of different production and trade routes that exist in global oil and gas markets today.

On this basis, it is estimated that 95 kilogrammes of CO_2 equivalent (kg CO_2-eq) is emitted in bringing an average barrel of oil to end-use consumers. There is a broad range of emissions for different types of oil. The lowest 10% production has an average emissions intensity of less than 45 kg CO_2-eq per barrel of oil equivalent, while the highest 10% has an emissions intensity of over 200 kg CO_2-eq/boe.

For natural gas, global average scope 1 and 2 emissions are around 100 kg CO_2-eq/boe. As with oil, there is a large spread between different sources of gas and different trade routes. The highest 10% of production is around four times more emissions-intensive than the lowest 10%.

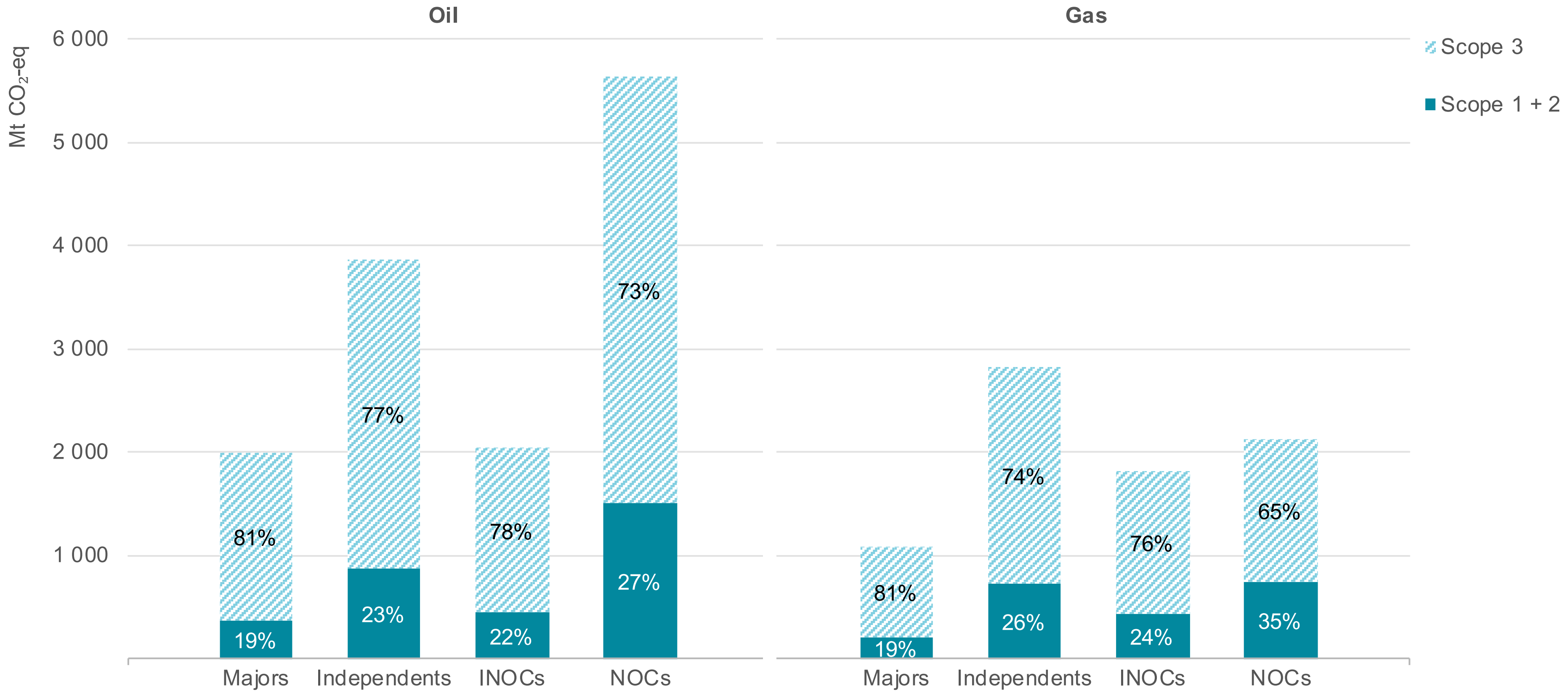
The main differences between resource types is a function of: the natural complexity and location of the resource, the technologies and engineering used, the age of assets, and the processes and measures in place to minimise flaring and methane emissions. For example, lower-emitting sources of oil tend to be easy to extract, have tight controls on methane leakage and flaring, are light oil or NGLs (which can be processed by simple refineries or bypass the refining sector entirely), and are refined and consumed close to where they are extracted.

"Scope 3" emissions occur during combustion of the fuel by end users. Scope 3 emissions from oil products can vary substantially: liquefied petroleum gases (LPGs) emit around 360 kg CO_2/boe, while heavy fuel oil emits around 440 kg CO_2/boe. The global average array of oil products produced from a barrel of crude oil equivalent in 2018 results in around 405 kg CO_2 when combusted. There is a much smaller degree of variation in CO_2 emissions from the combustion of natural gas, but on average, emissions are 320 kg CO_2/boe (average combustion emissions for coal, expressed on a comparable basis, are around 540 kg CO_2/boe).

On average, scope 1 and 2 emissions account for almost 20% of the full life-cycle emissions intensity of oil; for natural gas, scope 1 and 2 emissions account for around 25% of its full life-cycle emissions.

Scope 3 emissions from oil and gas are around three times scope 1 and 2 emissions but the shares vary between different companies and company types

Estimated annual scope 1, 2 and 3 GHG emissions from the full oil and gas supply chain according to company type, 2018



Note: Emissions are apportioned on an equity ownership basis.

There is increasing focus on emissions from oil and natural gas consumption as well as the emissions arising from oil and gas operations

Collectively, this report estimates that scope 1 and 2 emissions from the oil and gas sector are 5 300 million tonnes of CO_2 equivalent (Mt CO_2-eq) today. This is nearly 15% of global energy sector GHG emissions. Crucially, it is above-ground operational practices (namely methane emissions, venting CO_2 and flaring) that are responsible for the majority of GHG emissions from oil and gas operations worldwide, rather than the type of oil and gas that is produced and processed.

There is some variation in the share of scope 1 and 2 emissions in total emissions (i.e. of scope 1, 2 and 3 emissions) among the different companies and categories of companies. This reflects the complexity of the resources they produce, the design and efficiency of their operations, and the efforts that they take to minimise methane and other vented emissions. For NOCs, scope 1 and 2 emissions are around 30% of total emissions on average, whereas for the Majors the estimate is less than 20%. However, the oil and gas produced by some NOCs has some of the lowest emissions intensities in the world, while other NOCs perform very poorly.

A number of companies or institutions have announced targets, plans or commitments to reduce scope 1 and 2 emissions from their operations. These are specified either in terms of total reductions in scope 1 and 2 emissions or in reductions in the emissions intensity of operations. Announced plans vary in their scope and materiality, ranging from commitments that have been firmly incorporated into business plans to those that are more aspirational.

Individual company examples include BP's aim to reduce its scope 1 and 2 emissions by 3.5 Mt CO_2-eq between 2015 and 2025; Equinor aims to reduce emissions from its domestic operations by 40% by 2030, and to near-zero by 2050; Eni is targeting a 43% reduction in its upstream GHG emissions intensity between 2014 and 2025; and Chevron has a goal to reduce its GHG emission intensity of oil production by 5-10% and gas production by 2-5% between 2016 and 2023, including oil and gas produced from non-operated assets.

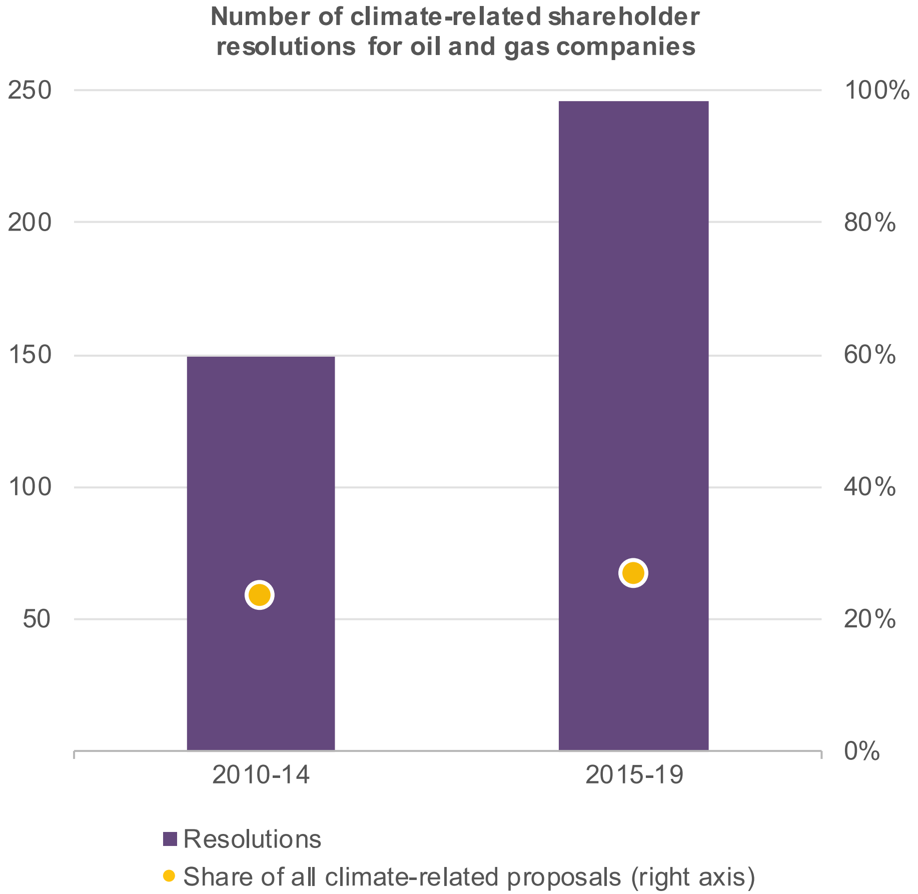
Scope 1 and 2 emissions are clearly a major source of GHG emissions, but it is the scope 3 emissions arising from the consumption of the oil and natural gas produced by the industry that account for the largest share of total emissions. Globally, scope 3 emissions today are around 16 billion tonnes of CO_2 equivalent, around three times the level of scope 1 and 2 emissions.

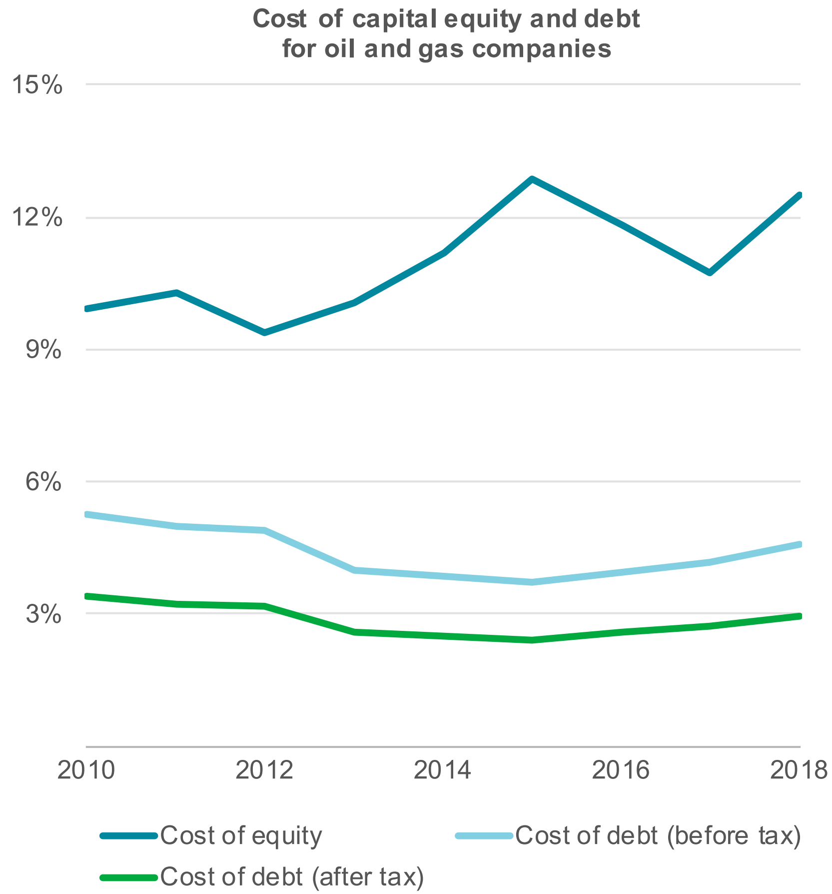
Responsibility for scope 3 emissions is a contentious topic. Scope 3 emissions from the combustion of oil and natural gas are typically attributed to end-use sectors (such as passenger cars, aviation or industry). Yet, responding to pressure from investors, some oil and gas companies have announced targets to reduce the full emissions intensity – including scope 1, 2 and 3 emissions – of the products they sell to consumers. For example, Repsol announced an aim to reduce its full emissions intensity from 2016 levels by 10% by 2025, 40% by 2040, and 100% by 2050; Shell aims to reduce its full emissions intensity by 20% by 2035 and around 50% by 2050, while Total aims to reduce its full emissions intensity from 2015 by 15% by 2030 and by 25-40% by 2040.

From a company perspective, there are a number of ways of reducing scope 3 emissions intensities (see Section IV). These include applying carbon capture, utilisation and storage (CCUS) to the use of the oil or gas, by increasing the share of low- or zero-carbon energy sources that are sold, or by purchasing or generating offsets in order to compensate.

Pressures from capital markets are focusing attention on climate-related risks

Investor engagement on climate (left) and evolution in the cost of equity and debt for oil and gas companies (right)





Note: Cost of capital analysis is based on the top 25 listed companies (in 2018) by oil and gas production. Companies based in China and Russia are excluded from the analysis. The weighted average cost of capital is expressed in nominal terms and measures the company's required return on equity and the after-tax cost of debt issuance, weighted according to its capital structure.

Source: Shareholder proposals data from Ceres (2019); calculations for cost of capital based on company data from Thomson Reuters Eikon (2019) and Bloomberg (2019).

Financial, social and political pressures on the industry are rising

The oil and gas industry requires social acceptance of its projects to be able to build and operate facilities. Social and environmental concerns about projects have traditionally focused on local impacts, including the potential for air pollution as well as for contamination of surface and groundwater. In recent years, rising global emissions have intensified scrutiny of the industry also on broader environmental grounds, especially in Europe and North America. This is also reflected in heightened engagement by investors in listed oil and gas companies on climate-related risks and restrictions in some areas on access to finance. The main pressure points are:

Capital markets. Over the past decade, climate-related shareholder resolutions, which commonly seek to improve disclosure or align the strategies of companies with a more sustainable pathway, have strongly increased while investor collaborations, such as the Climate Action 100+, increasingly seek to facilitate engagement on sustainability issues. Investors, through buying and selling of shares (i.e. supply of finance), have increased required rates of return on equity for the industry. Moreover, an increasing number of banks, pension funds, insurance companies, and institutional and private investors are limiting their exposure to certain types of fossil fuel projects: the primary focus has been on coal, but restrictions are increasingly seen on some oil and gas projects as well.

At the same time, there is growing appetite, and regulatory attention, towards sustainable finance, supported by the advent of green-labelled securities; increased pressure for disclosures of climate-related risks, as under the recommendations from the Task Force on Climate-related Financial Disclosures (TCFD); and, in Europe, a taxonomy to guide capital allocation towards sustainable activities.

Opposition to new infrastructure projects. A combination of local environment issues with a push to keep fossil fuels in the ground has increased opposition to new oil and gas infrastructure projects in some countries and regions. The result has been lengthy permitting procedures and litigation leading to project delays and cost overruns. In other cases, projects have been indefinitely postponed or cancelled. Infrastructure bottlenecks can create price discounts in local markets and serve as a major disincentive to new upstream investment.

Natural gas is typically more reliant on fixed grids than oil to reach consumers. In some jurisdictions such as the Netherlands, New York and California, climate concerns have led to bans or restrictions on connecting new consumers to the gas grid or expanding gas distribution infrastructure.

Fracking bans. With the emergence of shale, the large majority of the growth of global oil and gas production relies on hydraulic fracturing. Some of the most intense concerns are not directly climate-related, such as increased seismic activity and impact on water supplies. Nevertheless, fracking bans are very frequently discussed in the context of keeping fossil fuels underground and also preventing methane leakage. Fracking is either banned or impossible for all practical purposes in much of Europe; in New York, California and Quebec in North America; and in some states of Australia.

Investment

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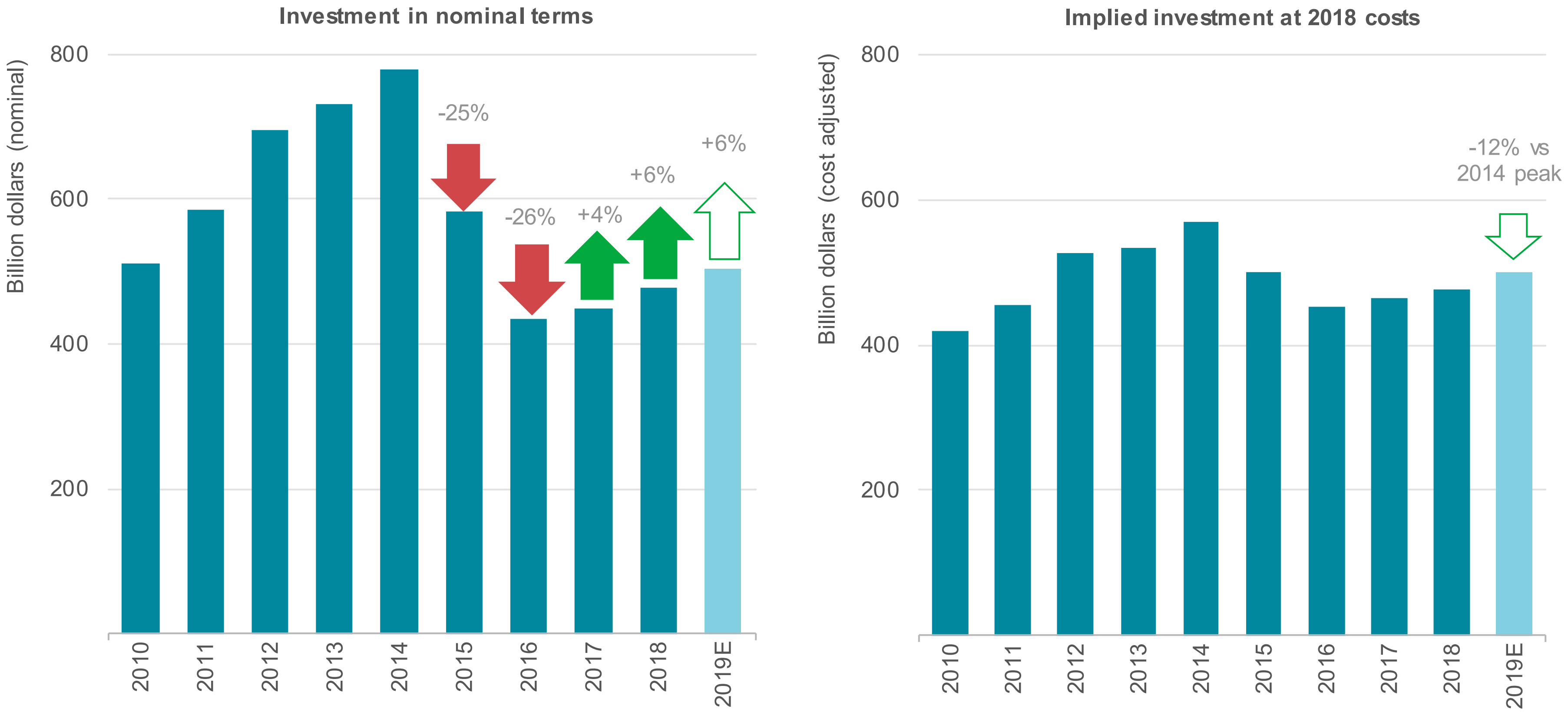
Upstream oil and gas investment is edging higher, but remains well below its 2014 peak

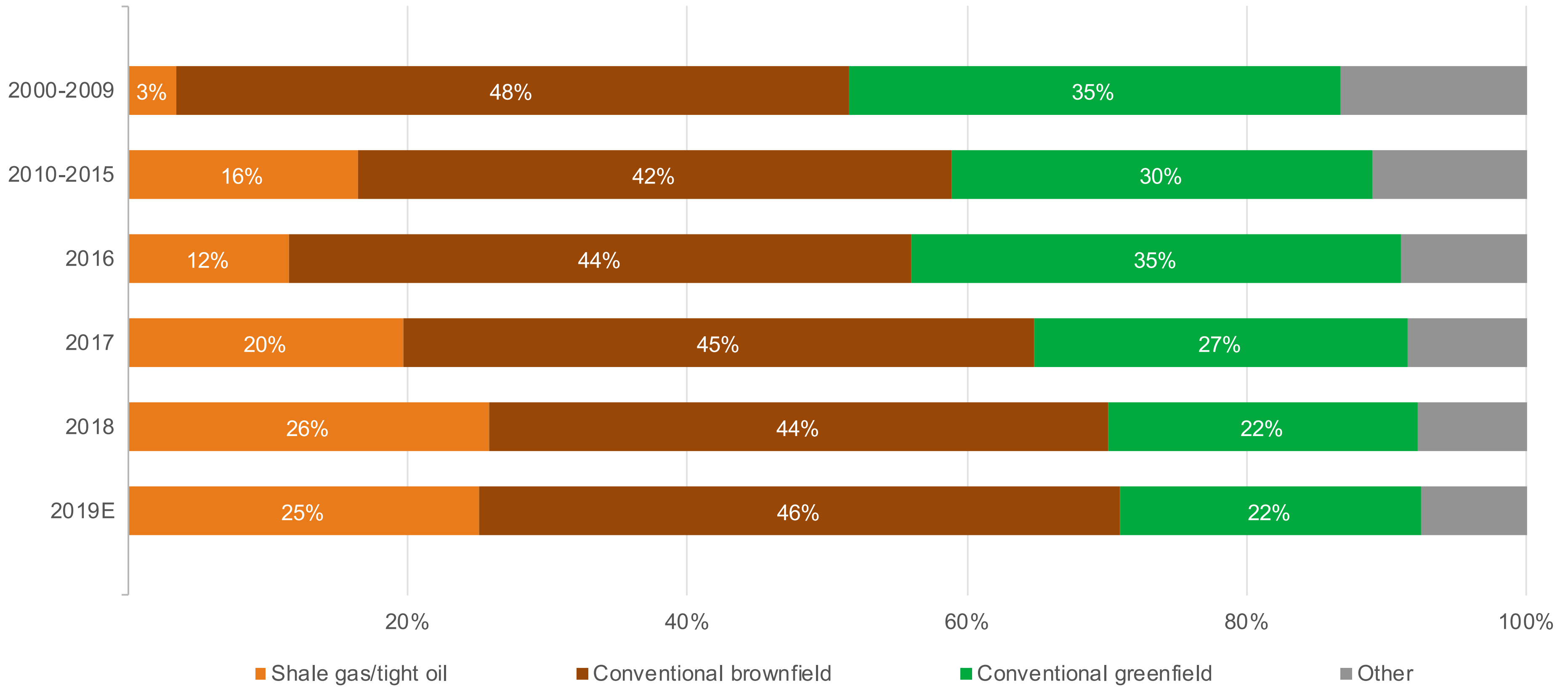
Global upstream oil and gas investment and cost-adjusted investment



Note: The cost-adjusted investment chart on the right estimates historical investment based on a constant level of 2018 capital costs over time based on the IEA Global Upstream Investment Cost Index (UICI) and US Shale Upstream Cost Index. When compared with the chart on the left, it shows the impact of cost-cutting measures and industry cost deflation on the overall investment trend.

Production spending has increasingly focused on shale and on existing fields

Share of global oil and gas development and production investment by asset type



Note: Production investment indicates capital spending in the upstream sector excluding exploration activities.

Source: IEA analysis based on Rystad Energy (2019), UCube (database).

Investment trends reflect capital discipline and more careful project selection

At nearly USD 480 billion in 2018 and with a rise expected in 2019, upstream oil and gas investment has edged higher over the past three years, but remains more than one-third below the peak level seen in 2014. The sharp decline reflects in part a slowdown in new field development amid a more challenging oil price environment, with low levels of new conventional oil and gas projects being sanctioned for development over 2016-18, alongside a collapse in exploration spending.

These investment trends also reflect renewed efforts by the industry to keep upstream costs under control. While recent increases in upstream activity have put some upward pressure on costs, a combination of continued overhang in the market for some services and equipment, consolidation in the service industry, and increased uptake of digital technologies to improve productivity has limited cost inflation in the sector. Adjusted for declining upstream costs, the overall reduction in investment activity is less stark – the 35% reduction in spending from 2014 to 2018 turns into a much smaller 12% fall in actual activity levels.

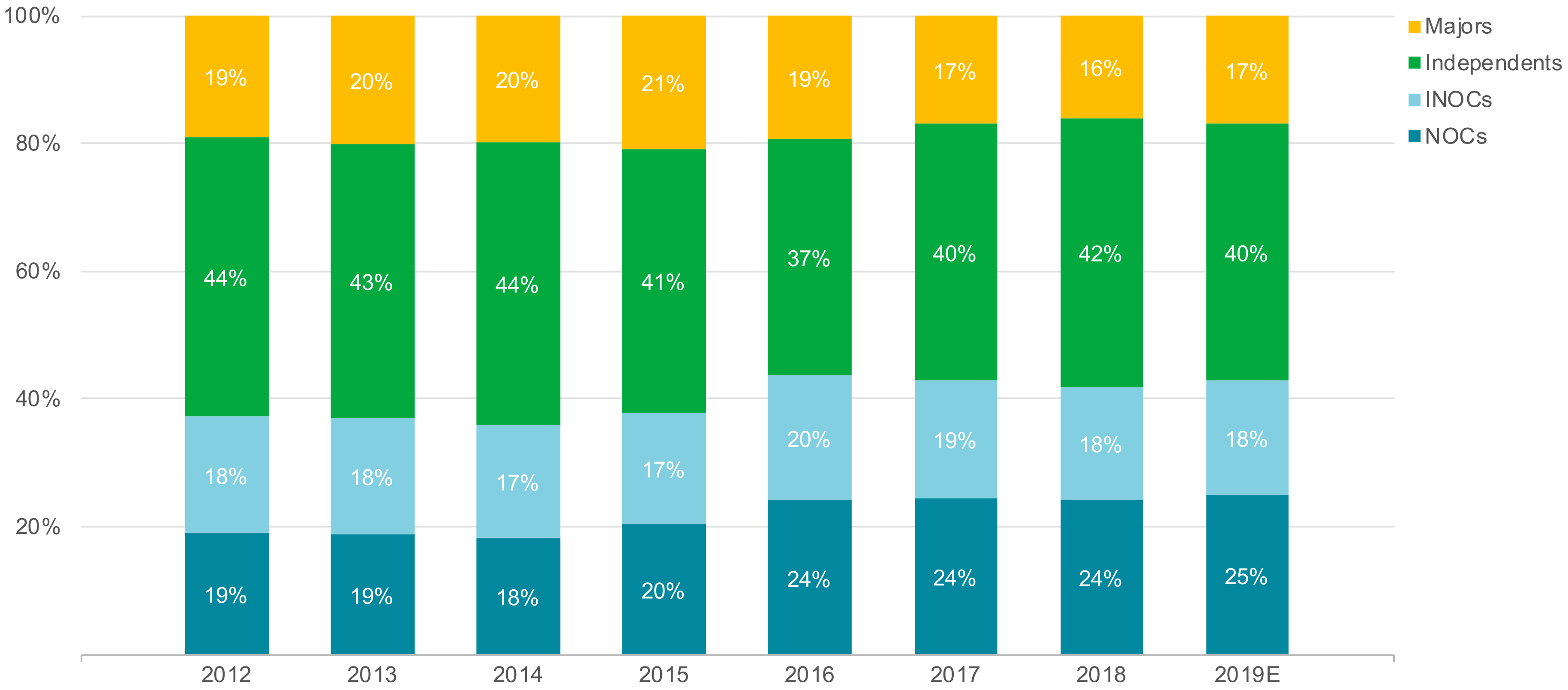
The new watchwords for the upstream industry are capital discipline and careful project selection. Break-even prices for sanctioned projects fell by almost 50% over 2014-18 (aided by cost deflation), before rebounding in 2019 by 15-20%, mainly due to more and larger projects, as well as more complex developments (e.g. offshore).

Offshore project approvals are making a comeback. After several years of final investment decisions for smaller-sized offshore projects, decisions in 2019 were oriented towards fields with larger reserves (the highest overall reserves approved since 2013) and higher peak production (also the highest since 2013). In addition, companies approved numerous small brownfield projects in 2018-19 at a low development cost, which will help sustain output from existing offshore facilities.

Companies continue to acquire and divest assets, optimising their portfolios in an effort to meet financial objectives and respond to pressures from investors. Generally, they have disposed of mature non-core assets or more “difficult” assets such as Alaskan reserves, Canadian oil sands or reserves with unfavourable fiscal terms.

The share of NOCs in upstream investment remains near record highs…

Global upstream oil and gas investment by company type

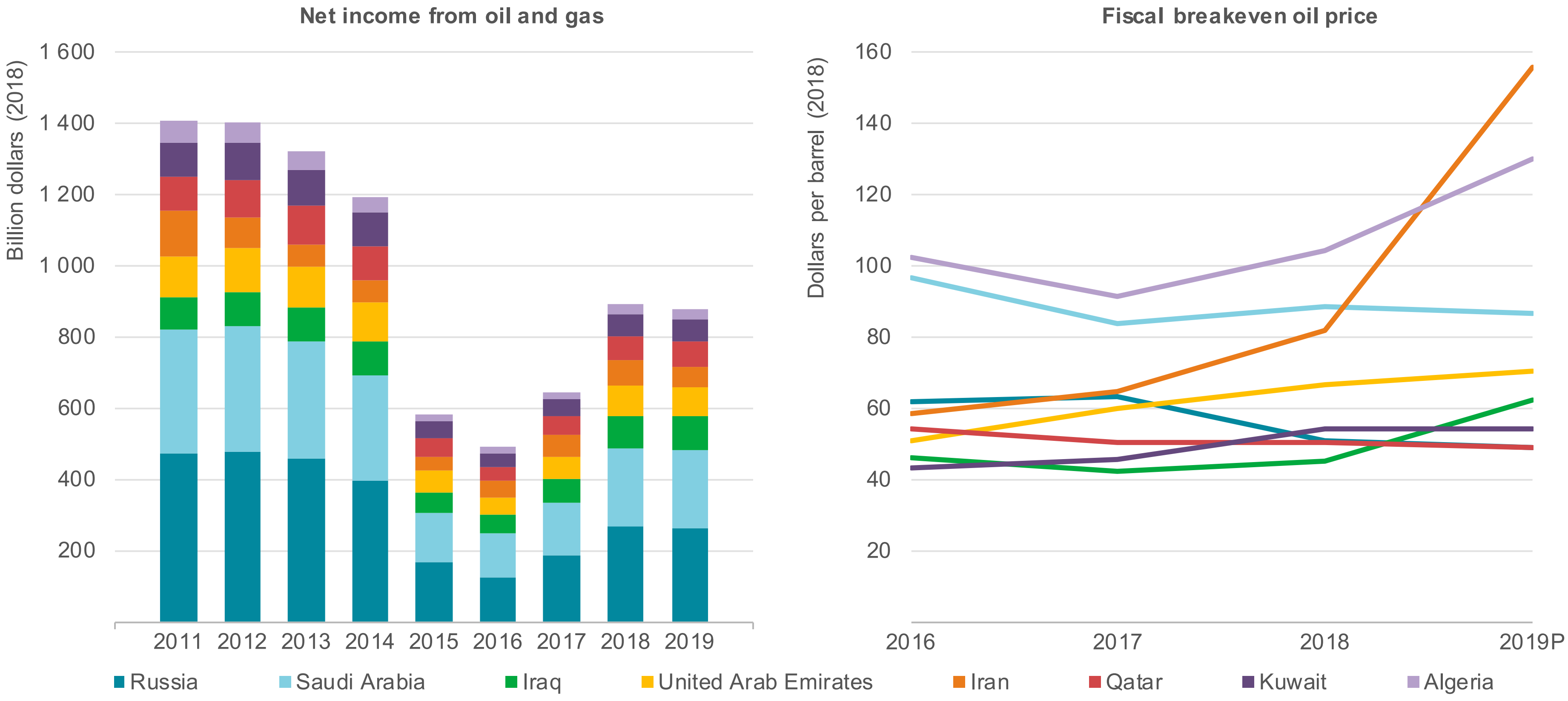


Note: Data for 2019 are IEA estimates based on company guidance, consultations with industry experts, and other sources.

Source: Analysis based on company reports and Rystad Energy (2019), UCube (database).

…although many resource-rich economies continue to face strong fiscal pressures

Net income from oil and gas and fiscal break-even oil price in selected producer economies



Notes: 2019P = projected for 2019. Fiscal break-even pertains to the oil price at which the national fiscal balance is zero.

Source: Fiscal break-even oil price data are based on IMF (2019) and Economic Expert Group (2019).

The rules of the investment game are changing

The investment environment for oil and gas projects is changing. The direction of change varies substantially in different parts of the world, but one common denominator is that this is becoming a game with slightly fewer players, and the ones that are left tend to be larger.

Even though many resource-rich countries have been under pressure in recent years following the downturn in the oil price in 2014, investment by NOCs has generally remained more resilient than that of the Majors. The NOC and INOC share of upstream spending has expanded in recent years to near 45%.

Among the Independents, some of the medium-sized and smaller companies that have been instrumental in leading the shale revolution are feeling the squeeze from tightening financial conditions. Medium-sized companies with international operations that are more exposed to debt markets have also been struggling to get projects off the ground.

All companies are facing demands to focus on capital discipline, improve free cash flow and pay down debt. As ever, though, national priorities continued to play an important role in determining investment strategies and flows among the NOCs. The international bond sale and then initial public offering of shares in Saudi Aramco in 2019 was a watershed moment for the transparency of company operations, as well as a strong statement of intent about the direction of economy-wide reforms. Many NOCs in the Middle East signalled intentions to step up upstream activity to sustain oil production and meet growing domestic gas needs. Investment by Chinese NOCs has also soared over the past two years in response to a government mandate to increase domestic production, despite a weakening earnings picture.

The legal, regulatory and fiscal conditions that shape the overall economics of the oil and gas business are also evolving. In some instances, conditions are becoming more restrictive, up to and including bans or moratoria on certain types of new projects. As discussed in more detail in Section III, countries including Belize, Costa Rica, Denmark, France, Ireland and New Zealand have introduced partial or total restrictions on certain types of new oil and gas developments; certain states or provinces in federal systems in North America have done likewise.

However, there are also jurisdictions that are responding to the rise of shale and the prospect of energy transitions by trying to make investment in their resource base more attractive, either by changing the terms or by stepping up licensing activity, or both.

Developing countries with oil and gas resources or energy security concerns are competing for upstream investment

Securing investment in oil and gas resources, as well as adequate revenues from these investments, remains a priority for many governments around the world. Globally, almost 90 licensing rounds are expected to occur over 2019-20, and recent reviews and changes of fiscal arrangements have the potential to shape investment activity in the years ahead.

In some instances, these have involved tightening the terms attached to the development of very prospective resources, in order to secure additional revenues for governments (Nigeria and Senegal are examples). More common has been a shift towards more favourable terms for investment, especially in less prospective regions and countries with concerns over stalling production or rising fuel imports. This is particularly visible in other parts of Africa and in Southeast Asia, where upstream investment has fallen sharply since 2015.

Many different considerations determine the sharing of project risk between companies and governments. These include the timing of revenue transfer by operators to host governments (e.g. front-loaded as signature bonuses or back-loaded as profit-based taxes when operating projects generate income) and the progressivity, or “regressivity”, of taxation with respect to changing oil and gas prices.

Some recent examples of changes in the regulatory or fiscal regimes include:

Nigeria: in November 2019, the government amended production agreements for future offshore oil production, adding a 10% royalty on deepwater projects and a 7.5% royalty on frontier and onshore basins. While the clarification of new terms has ended a period of investment uncertainty and creates new revenue streams for the government, it may also have the impact of increasing development costs and introducing production delays from new projects.

Algeria: in response to concerns that a slowdown in investment may result in future deficits for both domestic demand and exports, the government approved a new hydrocarbons law in November 2019. The law provides incentives (fiscal and contractual) for partnerships between the NOC (Sonatrach) and international companies. The new law still limits foreign ownership to 49%, introduces a local content clause and reinforces the role of Sonatrach as an operator.

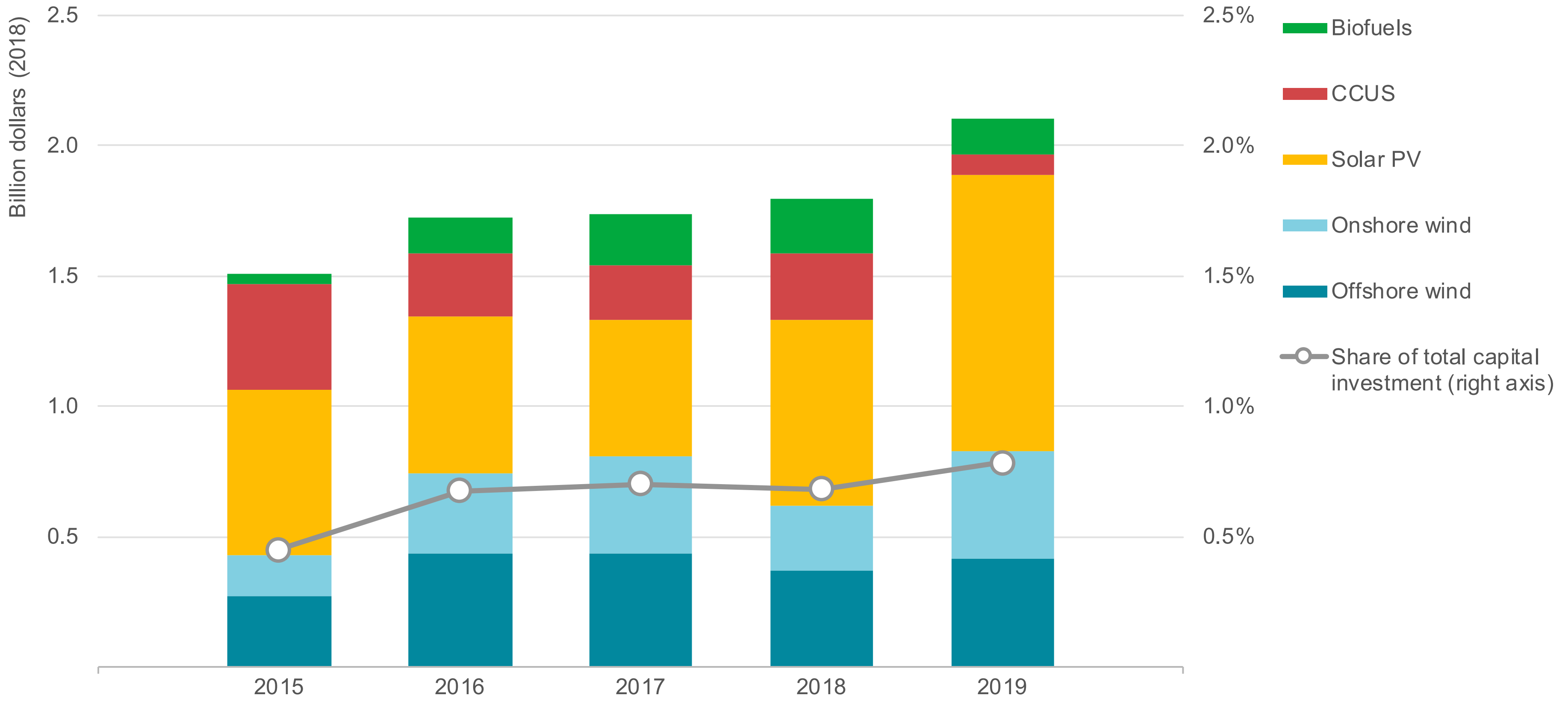
Angola: the government initiated an overhaul of its oil and gas sectors to stimulate investment, creating a new regulator, reorganising the role of Sonangol and simplifying investment procedures. This included a decree in May 2018 providing incentives for the development of marginal fields.

Malaysia: in November 2018, the NOC Petronas revised fiscal terms for new deepwater production-sharing contracts. The changes aim to attract more investment and open up new plays in Malaysia.

Indonesia: the government is seeking to stimulate upstream investments by improving the investment environment via fiscal incentives for oil and gas operators. In late 2017, it approved a new regulation revising the fiscal terms for conventional oil and gas contracts.

Investment by the oil and gas industry outside of core areas is growing, but remains a relatively small part of overall capital expenditure

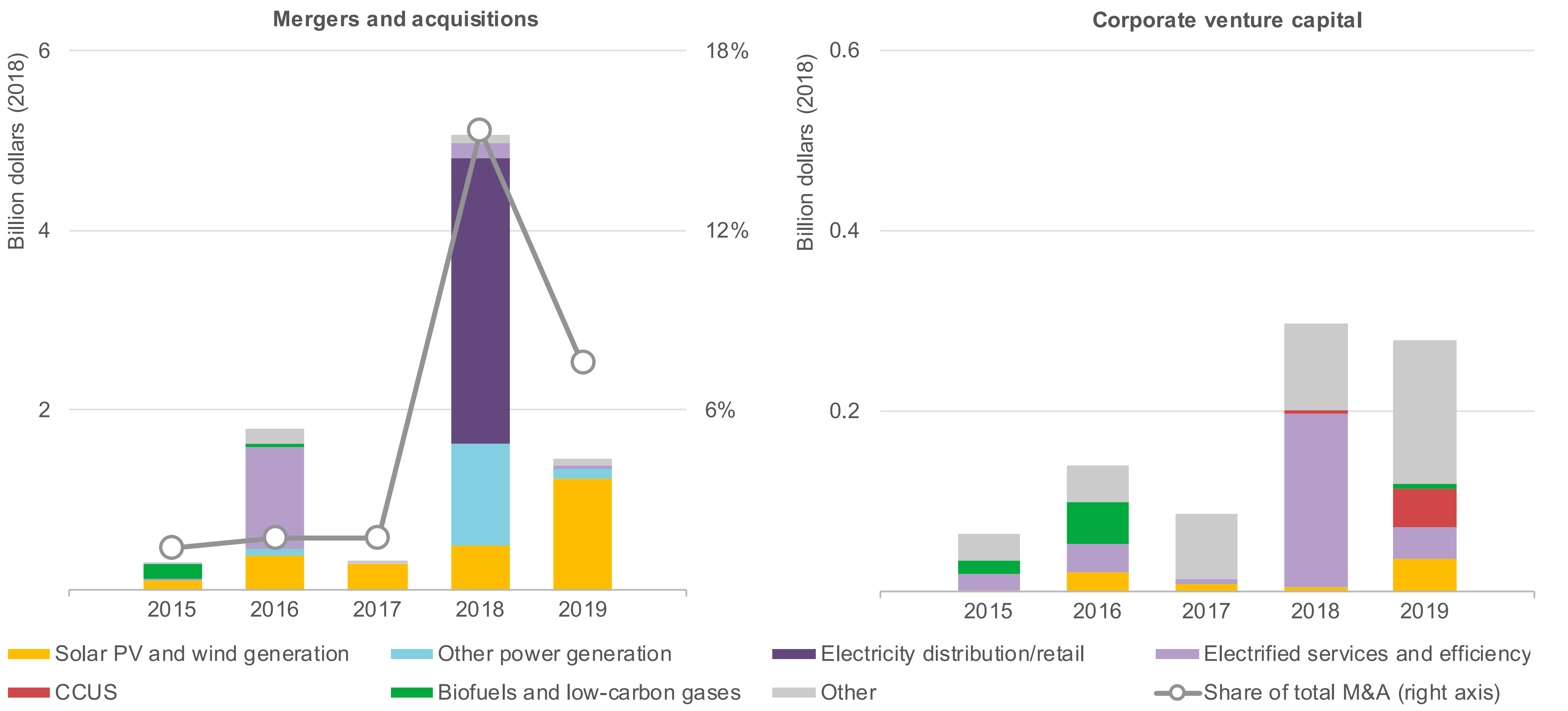
Capital investment by Majors and selected other companies in new projects outside oil and gas supply



Notes: Capital investment is measured as the ongoing capital spending in new capacity from when projects start construction and are based on the owner's share of the project. Companies include the Majors and selected others (ADNOC, CNPC, CNOOC, Equinor, Gazprom, Kuwait Petroleum Corporation, Lukoil, Petrobras, Repsol, Rosneft, Saudi Aramco, Sinopec, Sonatrach). CCUS investment is in large-scale facilities; it includes developments by independent oil and gas companies in Canada and China and capital spend undertaken with government funds.

A larger share of recent spend in new areas has come through M&A plus venture activity, focused on renewables, grids and electrified services such as mobility

M&A and corporate venture capital spending by Majors and selected other companies outside of core oil and gas supply



Notes: M&A = mergers and acquisitions; only transactions with disclosed values are included. *Electrified services* include battery storage and electric vehicle (EV) charging; *low-carbon gases* include low-carbon hydrogen and biomethane; *other* includes digital technologies, data analytics and mobility services. Companies include the Majors and selected others (ADNOC, CNPC, CNOOC, Equinor, Gazprom, Kuwait Petroleum Corporation, Lukoil, Petrobras, Repsol, Rosneft, Saudi Aramco, Sinopec, Sonatrach).

Shifts in business strategy vary considerably by company

Investment and strategic responses to energy transitions by selected companies (illustrative, based on 2015-19 activity)

Company	Enhancing traditional oil and gas operations			Deploying CCUS		Supplying liquids and gases for energy transitions		Transitioning from fuel to "energy companies"			
	Reducing methane emissions	Reducing CO_2 emissions	Sourcing renewable power	For centralised emissions	For EOR	Low-carbon gases	Advanced biofuels	Solar PV and wind generation	Other power generation	Electricity distribution/retail	Electrified services / efficiency
BP	●	●	◐	◐	◐	●	◐	●	◐	◐	●
Chevron	●	◐	●	●	◐	◐	◐	◐	○	○	◐
Eni	●	◐	●	◐	◐	◐	●	●	●	●	◐
ExxonMobil	●	◐	●	●	◐	◐	◐	○	○	○	○
Shell	●	●	●	●	◐	●	◐	●	●	●	●
Total	●	●	●	◐	◐	●	●	●	●	●	●
CNPC	◐	○	◐	◐	●	◐	◐	●	○	○	○
Equinor	●	●	●	●	◐	◐	◐	●	○	◐	◐
Petrobras	◐	◐	●	●	●	●	◐	◐	●	◐	○
Repsol	●	●	◐	◐	◐	◐	◐	●	●	●	◐

Notes: PV = photovoltaic. **Full circle** = growth area supported by observed strategic investments (e.g. M&A) and/or capital/operational expenditures in commercial-scale activities; **half circle** = announced strategy and/or minor investments, venture capital and/or research and development (R&D) spending; **empty circle**= limited evidence of investment activity. **For methane and CO_2 emissions**, which are not based on project and spending data, assessments reflect the presence and strength of methane reduction and emissions intensity targets, as well as evidence of their implementation, the emissions intensity trend of new investment, transparent reporting of absolute emissions and sources, and linking of executive and staff compensation to achieving goals. Power generation and efficiency investments in the Transitioning category pertain to projects destined for commercial sales (not own use). Electrified services include battery storage and EV charging. Low-carbon gases include low-carbon hydrogen and biomethane.

Accommodation with energy transitions is a work in progress

Some large oil and gas companies have made strategic and investment moves to diversify outside their core businesses of oil and gas supply, as well as to reduce the environmental footprint and enhance the efficiency of operations. Within the energy sector, these responses can be grouped into four areas: i) traditional oil and gas operations; ii) CCUS; iii) low-carbon liquids and gases; and iv) transitioning from "fuel" to "energy" companies; these options are further elaborated in Section IV.

Emissions reduction measures and targets feature prominently in the strategies of many large oil and gas companies. As noted above, these measures include efficiency improvements, choosing lower-carbon sources to supply those facilities, reduced flaring and reduced methane emissions.

However, for the moment, investments by oil and gas companies in non-core areas remain a minor part of their overall spending, and operational improvements vary in terms of their observed results.

As measured by the CO_2 intensity of invested capital, emission indicators for some companies (e.g. BP, Shell, Equinor) have improved by over 10% since 2015, while for several other companies they have worsened. Some players (e.g. ExxonMobil, Chevron, Eni) have become important off-takers of renewable power through corporate power purchase agreements.

Aggregate trends suggest that alignment by the industry with energy transitions is, at best, a work in progress. To a degree, this reflects broader policy and market signals, which in most parts of the world have not encouraged a wholesale change in company strategic priorities. But the bottom line remains that there are few signs of the significant reallocation of capital spending that would be required to meet the goals of the Paris Agreement.

The approach varies by company, but thus far less than 1% of industry capital expenditures is going to non-core areas

For the group of companies analysed, aggregate annual capital expenditures for projects outside core oil and gas supply averaged under USD 2 billion since 2015, less than 1% of the total capital expenditures by these companies, though some companies have spent up to an average of 5%, and the total topped USD 2 billion for the first time in 2019. Including spending on gas-fired power capacity (for commercial sales), spending has averaged over USD 2 billion since 2015.

Capital expenditures by the oil and gas industry in renewables have picked up gradually over time, reflecting the increasing availability of attractive projects. The largest outlays have been made in solar PV, with some companies (e.g. Eni, Shell) developing projects directly and others (e.g. BP, Total) owning major stakes in subsidiaries. Offshore wind is another growth area (e.g. Equinor, Shell, CNOOC) and benefits from considerable synergies – 40% of the full lifetime costs of a standard offshore wind project have overlap with the offshore oil and gas sector (IEA, 2019).

Oil and gas companies also have a significant profile in CCUS investments, marked by recent commissioned projects involving Chevron, CNPC, and Shell, and account for over 35% of overall CCUS capital expenditures, often backed by government funding (Section III). The cost challenge and business model complexity of CCUS have meant that relatively few large-scale facilities have been developed, though many oil and gas companies are involved in R&D, pilot project development and partnerships to advance applications. OGCI members recently announced a new initiative to spur large-scale CCUS investment at industrial hubs around the world.

Despite the affinity with company strengths, investment in low-carbon liquids and gases projects is relatively low, e.g. bio refineries, biogas processing and hydrogen production. This can largely be explained by challenging project economics. Most activity to date has come through R&D, though some players (e.g. Eni, Petrobras, Total) have developed commercial-scale plants.

M&A have provided the principal vehicle for diversification. Strategic investment associated with new energy areas accounted for around 5% of total M&A by these companies. Several large deals have shaped this picture, and acquisitions have been the primary means for oil and gas companies to enter consumer-facing fields such as electricity distribution (e.g. Total with Direct Energie), EV charging (e.g. BP with Chargemaster) and distributed battery storage (e.g. Shell with Sonnen).

Corporate venture capital activity, which represents a smaller outlay, but signals potential future growth areas, has risen in recent years, with a concentration in start-up investments for electric mobility, digital technologies and renewables. Many oil and gas companies also have large R&D activities in clean energy technologies – although R&D spending by oil and gas companies has not risen significantly as a share of revenue in recent years (IEA, 2019).

Looking ahead, a number of companies have announced plans to step up their spending in new energy areas in the coming years. Total, for example, has set an aim of 7 GW of renewables worldwide by 2025. Shell plans to spend nearly 10% of its capital expenditures on power by 2025 while Equinor sees itself devoting 15-20% of capital expenditures towards new energy solutions by 2030.

Section II

Oil and gas in energy transitions

Scenarios for the future of oil and gas

This section discusses the way that the outlook for oil and natural gas could be affected by an accelerated pace of energy transitions. There is a huge range of possible futures depending, for example, on the pace of technological innovation, the ambition of energy policies, market dynamics, societal trends and many other factors. The analysis refers to two scenarios included in the IEA *WEO*, but focuses mainly on the SDS and some sensitivity cases around this Scenario.

The **SDS** charts a pathway for the global energy sector fully aligned with the Paris Agreement by holding the rise in global temperatures to "well below 2°C … and pursuing efforts to limit [it] to 1.5°C". This requires rapid and widespread changes across all parts of the energy system.

The world is not on track to meet this Scenario. The IEA's assessment, based on the policies in place today as well as those that have been announced (the **STEPS**), is that the momentum behind clean energy transitions is not enough to offset the effects of an expanding global economy and growing population. The STEPS does not see a peak in global energy-related CO_2 emissions by 2040 – obviously far from the early peak and rapid subsequent decline in emissions targeted by the Paris Agreement.

This disparity between the direction in which the world appears to be heading, on the one hand, and the wealth of scientific evidence highlighting the need for ever-more-rapid cuts in GHG emissions, on the other, is a crucial fault line in global energy.

The projections in the STEPS suggest that, in the absence of more concerted policy action, demand for oil and (especially) gas would continue to grow to 2040, while coal demand would remain where it is today.

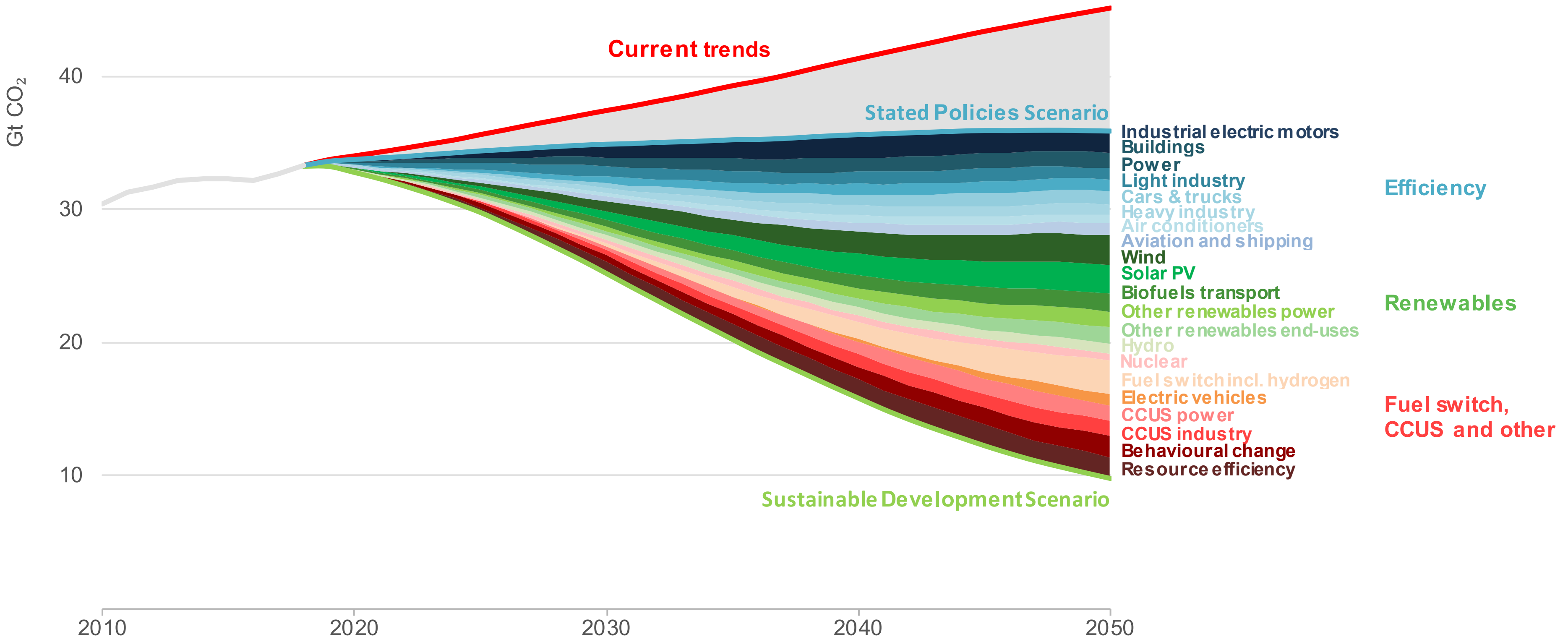
However, the emissions trends in the STEPS would imply a 50% probability of a 2.7°C stabilisation (or a 66% chance of limiting warming to 3.2°C) – not nearly enough to avoid severe effects from climate change.

Something has to give, and the pressure to act more forcefully on emissions is growing, visible in a groundswell of opinion in many countries in favour of aligning policy and investment decisions with a low-emissions future. This includes an increasing number of national and corporate commitments to net-zero emissions, typically by mid-century. In some sectors, notably electricity, this is enabled by ever-lower costs of some key renewable technologies.

The SDS provides a way to explore the consequences of these types of rapid transitions across the energy sector as a whole. While emissions reductions are central to its design, it is not solely a climate scenario. It reflects a broader range of imperatives facing policy makers by also meeting objectives related to universal energy access and cleaner air, while retaining a strong focus on energy security and affordability.

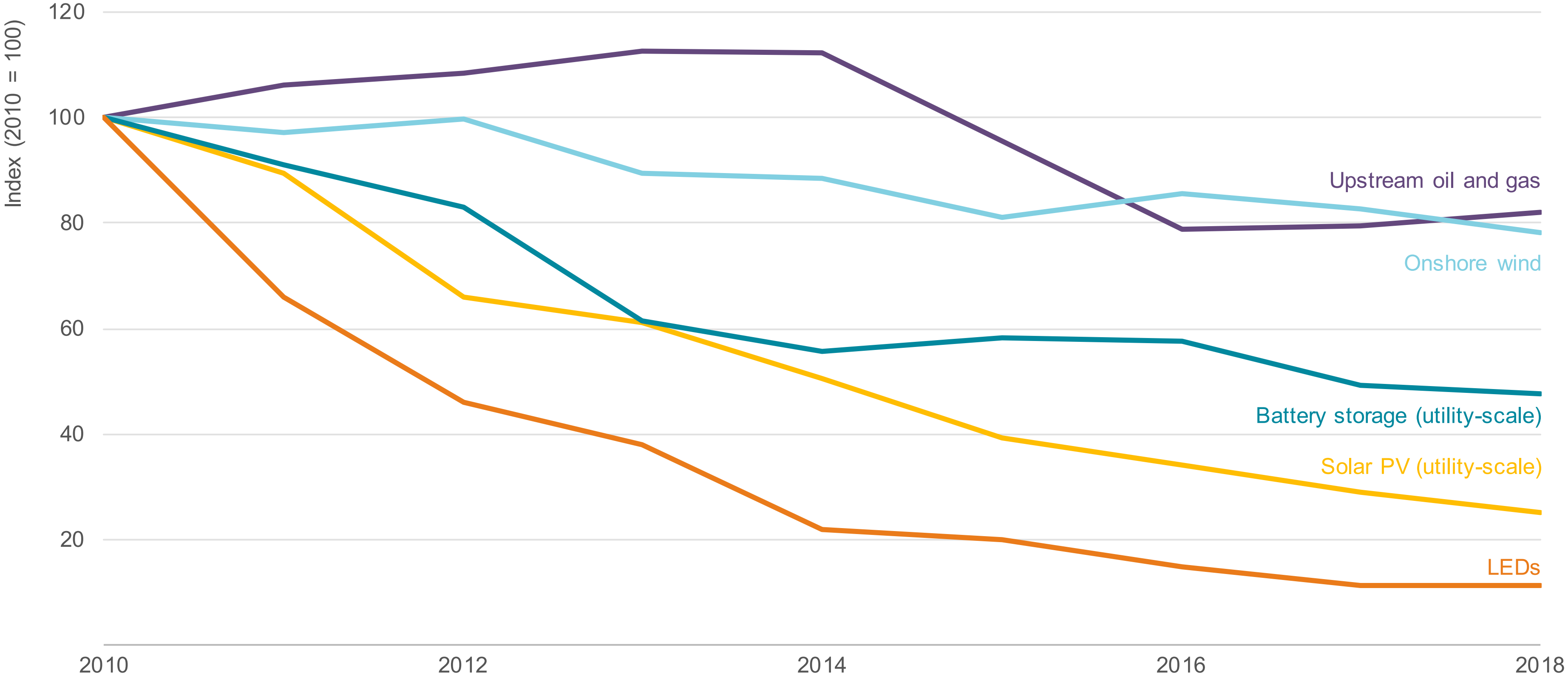
A wide range of approaches and technologies are required to achieve emissions reductions in the SDS

Energy-related CO_2 emissions and CO_2 emissions reductions by measure in the SDS



Changes in relative costs are creating strong competition for incumbent fuels

Capital cost index for selected energy-related technologies and sectors



Notes: LEDs = light-emitting diodes. Upstream oil and gas based on the IEA UICI. Capital costs for other technologies reflect the global weighted average costs of components for a given amount of energy service or of commissioned projects.

Source: IEA analysis with calculations for solar PV and wind costs based on IRENA (2019), *Renewable Cost* (dataset).

Low-carbon electricity and greater efficiency are central to efforts to reduce emissions, but there are no single or simple solutions to tackle climate change

A wide range of technologies and policies are required in clean energy transitions to bring down emissions.

In the SDS, improved energy efficiency is a key lever for change. Exploiting the full economic potential for efficiency improvement leads to the energy intensity of the global economy (the amount of energy used per unit of gross domestic product [GDP]) falling by over 3% per year to 2040. For comparison, this indicator showed only a 1.2% improvement in 2018.

There is also a step change in the pace at which increasingly cost-competitive renewable technologies are deployed. This is most visible in the power sector, where renewables provide two-thirds of electricity supply worldwide by 2040 (up from one-quarter today). Of this, solar PV and wind power together provide 40%, with a further 25% from dispatchable renewables including hydro and bioenergy.

The growth in low-carbon electricity is accompanied by the rising importance of electricity as an energy carrier. The share of electricity in global final consumption rises from 19% today to more than 30% by 2040. The increase in electricity demand in the SDS comes from a variety of sources; the largest is EVs.

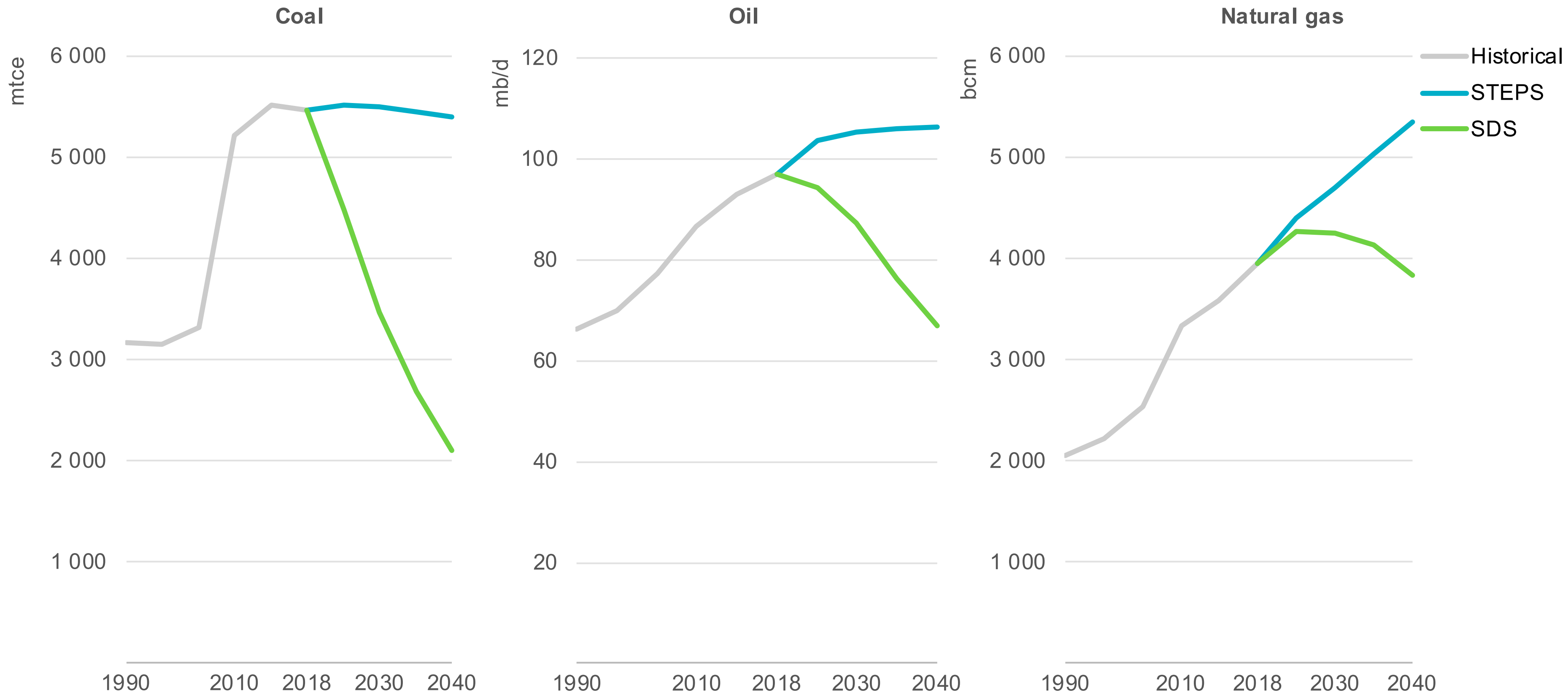
However, even with rapid growth in low-carbon electricity, more than two-thirds of final consumption in 2040 in the SDS comes from other sources, mainly from liquids and gases (the role of coal, examined in the next slide, declines rapidly).

And even if electricity use were to grow even faster and the complete technical potential for electrification were deployed, there would still be sectors requiring other energy sources (given today's technologies), with most of the world's shipping, aviation and certain industrial processes not yet "electric-ready".

This opens up a set of questions for energy transitions that are no less important to the prospects for emissions reduction than improvements in efficiency or the rise of low-carbon electricity. These concern the fuels that are used in the rest of the energy system, including the emissions intensities of the oil and natural gas that is consumed; the deployment of low-carbon fuels such as biofuels, synthetic fuels and renewable gases; alternative energy carriers such as hydrogen; and the possibilities to capture, utilise or store CO_2.

A rapid phase-out of unabated coal combustion is a major pillar of the SDS

Coal, oil and natural gas demand by scenario



Coal demand drops rapidly in all decarbonisation scenarios, but this decline cannot be taken for granted

Coal is the most carbon-intensive fuel and the majority of global coal consumption is in the electricity sector, where competition from renewables is strongest. As such, it is no surprise that unabated coal use comes under intense pressure in all decarbonisation scenarios.

In the SDS, global coal use is 60% lower by 2040 than in the STEPS. Coal demand for power generation is hit hardest, while coal use in the industrial sector is slightly more resilient because substitution possibilities are more limited. Overall, coal's share in the global primary energy mix falls towards 10%, from 27% today.

Such a dramatic change in coal's position in the global energy mix would not be simple to deliver. There are 2 080 GW of coal-fired power plants in operation worldwide and a further 170 GW under construction. Almost 60% of today's coal-fired fleet was built in the last 20 years, much of this in developing countries in Asia where the average age of existing plants is just 12 years old.

There are different options – explored in the *WEO 2019* – to bring down emissions from the existing stock of coal-fired plants: to retrofit them with CCUS or biomass co-firing equipment; to repurpose them to focus on providing system adequacy and flexibility while reducing operations; or to retire them early. In the SDS, most of the world's existing coal-fired capacity would be affected by one of these three options.

These solutions all involve financial or social costs. If they are not implemented, or pursued only in part, then many existing coal plants could expect to operate for decades to come. Emissions just from the continued operation of the existing global coal fleet would make sustainable energy targets very hard to reach.

This could imply additional pressure on other sources of emissions, i.e. oil and/or natural gas, as emissions from these sources would then need to fall even faster in order to be in line with international climate objectives.

For example, if coal demand were to remain as in the STEPS, then this would require dramatic adjustments in oil or natural gas use to keep cumulative emissions to 2040 within the levels of the SDS. In 2040, oil demand would need to fall to around 20 mb/d and gas demand to 1 500 bcm, i.e. both fuels would be around two-thirds lower than the levels projected for 2040 in the SDS.

Moreover, even without considering a hard carbon constraint, more robust coal demand in developing economies would deprive natural gas of some markets that it might otherwise be in a position to claim, notably the provision of process heat for industry.

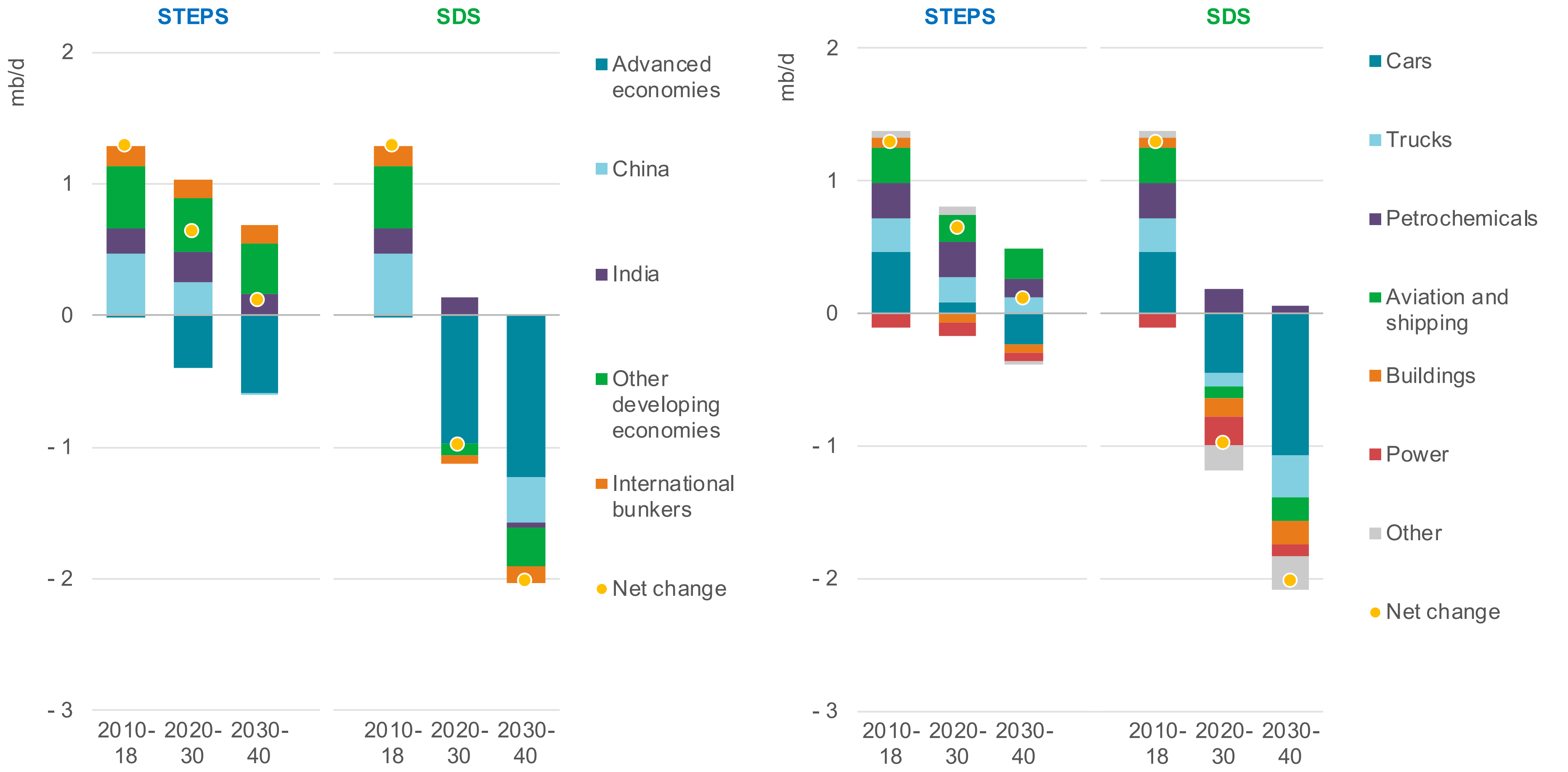
The oil and gas industry is often warned to watch out for the rise of electrification and renewables. But the discussion about the future of oil and gas in energy transitions also needs to take place with one eye on what happens to coal.

Oil in the Sustainable Development Scenario

Slides 55 - 63

Changing demands on oil

Average annual changes in oil demand by region (left) and sector (right)



Transitions away from oil happen at different speeds, depending on the segment of demand…

The headline difference in oil demand between the STEPS and the SDS is stark. While demand plateaus in the 2030s in STEPS, oil consumption is falling by around 2 mb/d each year by then in the SDS. Beneath the aggregate numbers, there are also significant variations across different segments of oil demand, depending on the ease with which oil can be substituted.

Passenger transport sees the most dramatic changes. Already in the STEPS, oil use in this segment is declining by the late 2020s but in the SDS, oil consumption for passenger transport plummets. By 2040 in this Scenario there are 900 million EVs (including electric cars, plug-in hybrids and fuel cell cars) on the road globally – around 50% of the global car fleet – and most of the world's urban buses are electric. There is also some modal shift from private vehicles to public transport, which means there are around 10% fewer cars on the road than in the STEPS in 2040.

Trucks have been one of the main sources of oil consumption growth in recent years, with demand rising by around 4 mb/d between 2000 and 2018. Global road freight activity nearly doubles between 2018 and 2040, with the expansion of online commerce boosting the amount of goods transportation undertaken by lighter vehicles (which are easier to electrify). In the SDS, there are enhanced efforts to decarbonise freight transport through systemic improvements in road freight operations and logistics, and a shift towards the use of alternative fuels and vehicles.

In the shipping sector, the optimisation of hull shapes, improvements in the efficiency of engines, air lubrication and wind assistance all help to curb overall energy use. There is also growth in the use of biofuels, electrification for some short-distance journeys, hydrogen along certain routes, and LNG (albeit to a limited extent). While the use of oil falls by around 30% between 2018 and 2040 in the SDS, it still makes up 70% of fuel consumption in shipping in 2040.

In aviation, the two main opportunities to reduce oil use are efficiency and biofuels. Oil use falls by just under 20% between 2018 and 2040, while the use of biofuels expands rapidly: in 2040, biofuels account for around one-quarter of fuel use in aviation.

The only sector to see demand growth in the SDS is petrochemicals. The rate of plastics recycling more than doubles from around 15% today to 35% in 2040, but oil use as a petrochemical feedstock still increases by almost 3 mb/d to 2040 (IEA, 2018). The use of bio-based feedstock offers one potential alternative to oil demand, but this remains a niche industry even in the SDS. This is partly due to the considerable cost gap that bio-based processes need to close in order to be competitive, but also it is because bio-based processes compete with other sectors where bioenergy enjoys stronger policy support.

…and there are also very significant variations by geography, with oil use in developing economies more robust

In Europe and in the advanced economies in the Asia Pacific region, more than 90% of car sales are electric in the SDS by 2040, and oil use in buildings is almost entirely eliminated. There is also a strong uptake of electric cars in the United States, although their share of new car sales is slightly lower (an average of around 50% during the 2030s), in part because of a preference for larger car sizes that are more difficult to electrify in full.

Oil use in petrochemicals in advanced economies falls by around 25% between 2018 and 2040. This occurs partly because of a shift in global refining and petrochemical activities towards emerging economies (which benefit from cheaper feedstock), and partly because of material efficiency improvements and enhanced recycling efforts that reduce the need for new plastic materials.

Oil demand continues to grow in some developing economies in the SDS. In China, oil demand peaks in 2025, and in India it peaks around 2030. But from 2030, oil demand is in decline across nearly all countries and regions; the only exception is some countries in sub-Saharan Africa, although growth there is relatively limited. In aggregate, oil demand in developing economies in 2040 is around 10% lower than today.

China is already a leader in electric mobility. There are over 25 million new passenger cars sold every year to 2040 and a rapidly expanding proportion of these are electric cars in the SDS (rising from 25% of sales in 2025 to over 90% by 2040). However, there is still an overall increase in oil use in passenger cars until around 2025. Oil use as a petrochemical feedstock also rises steadily in China between 2018 and 2040.

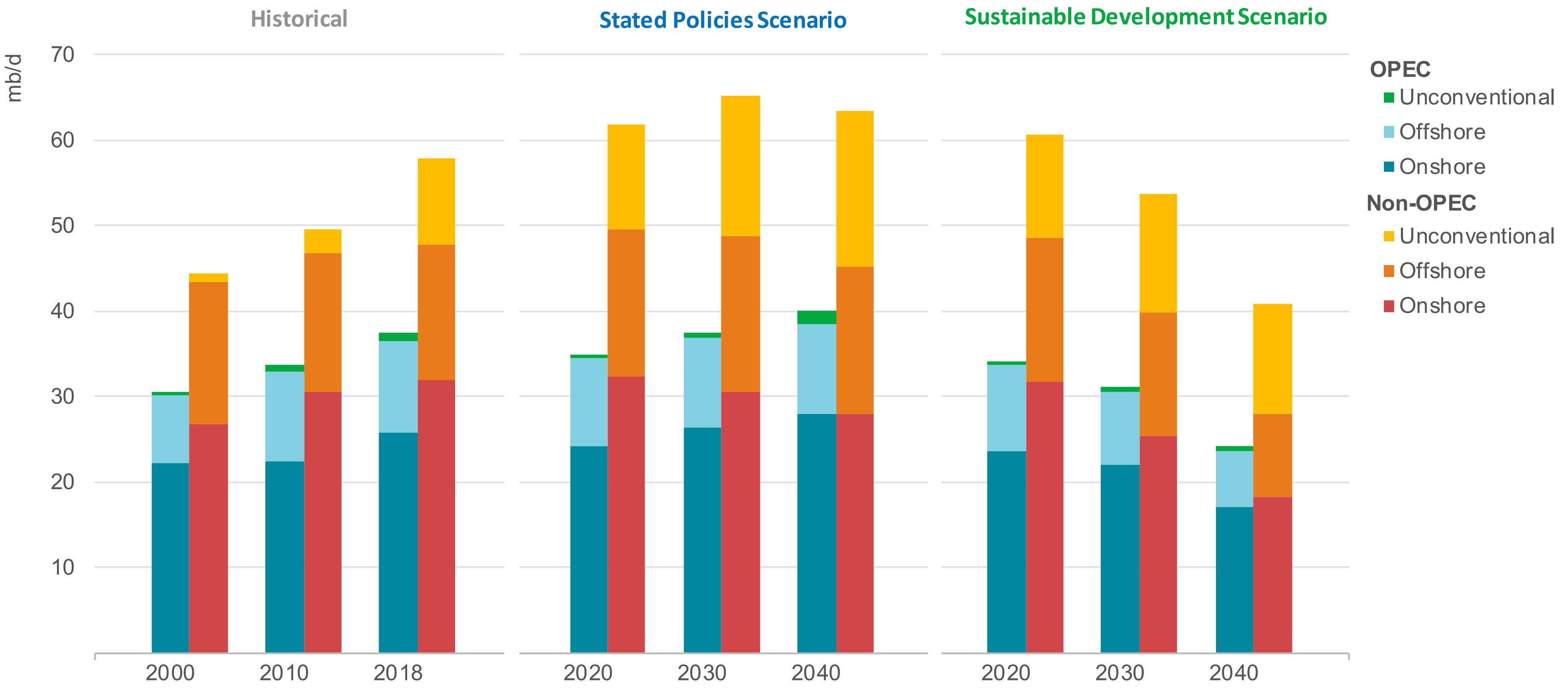
In India, there is a pronounced growth in passenger car sales from around 3 million in 2018 to over 16 million in 2040. Again, the proportion of electric cars sales expands rapidly in the SDS, and 90% of passenger car sales in 2040 are electric. Besides petrochemicals, there is also an increase in oil use in buildings in this scenario. LPG helps to provide clean cooking facilities to around 300 million people in rural locations in 2030 who would have otherwise relied on the traditional uses of biomass.

The population of sub-Saharan Africa grows by 70% between 2018 and 2040 and its economy almost triples in size; further, a key pillar of the SDS is that universal energy access is achieved by 2030. As a result, oil use grows across all sectors in sub-Saharan Africa over the period to 2040. Nonetheless, its per capita oil consumption in 2040 (0.6 barrels per person per year) remains only a fraction of the global average in this Scenario (2.7 barrels per person per year).

For comparison, average per capita consumption of oil today is 4.7 barrels per person per year, with average levels in the European Union (8 barrels) and North America (17 barrels) considerably higher. Nonetheless, this level of oil consumption in Africa in 2040 still brings a relatively high level of energy services because some possible uses for oil, such as heating, are not required and because there is a large potential for efficiency improvements.

A shrinking oil market in the SDS would change the supply landscape dramatically…

Oil production by region, type and scenario



...but would not remove the need for continued investment in the upstream

Oil demand in the SDS is falling by around 2.5% per year by the 2030s. However, even this rapid drop would be well short of the decline in production that would occur if all capital investment in currently producing fields were to cease immediately. This would lead to a loss of over 8% of supply each year. If investment were to continue in currently producing fields but no new fields were developed, then the average annual loss of supply would be around 4.5%.

Under these circumstances, as examined in more detail in Section III, continued investment in existing oil fields, as well as some new ones, remains a necessary part of the energy transitions envisaged in the SDS. What is much less clear is who would be making these investments, and where.

The answer to this question would be determined in large part by the approaches pursued by resource-holding governments and companies.

The strategies of the main, low-cost resource holders, notably those in the Middle East, are critical in this regard. In theory, given their place at the lower end of the supply cost curve, these countries would be in a position to satisfy a larger share of oil demand in such a scenario, with knock-on effects on price levels (a possibility examined in a sensitivity case at the end of this section).

In practice, the options open to these large producers would depend on their resilience to lower oil prices, i.e. the success or otherwise of efforts to diversify their economies and reduce reliance on hydrocarbon revenues. In the absence of concerted reforms, any attempt to maximise production and increase market share would bring down oil prices to levels that would cause profound fiscal difficulties, meaning that prices at these low levels could not in practice be maintained for long (as discussed in more detail below).

Policies in other countries would also play a role, notably if any governments decided either to restrict access to their resources ("keep them in the ground") or, alternatively, to incentivise their development by introducing more favourable fiscal terms.

Company strategies would also be influential in determining the kinds of investments that went ahead, as certain types of resources – offering lighter oil, or faster payback – might offer a balance of risk and reward that is better suited to this kind of scenario.

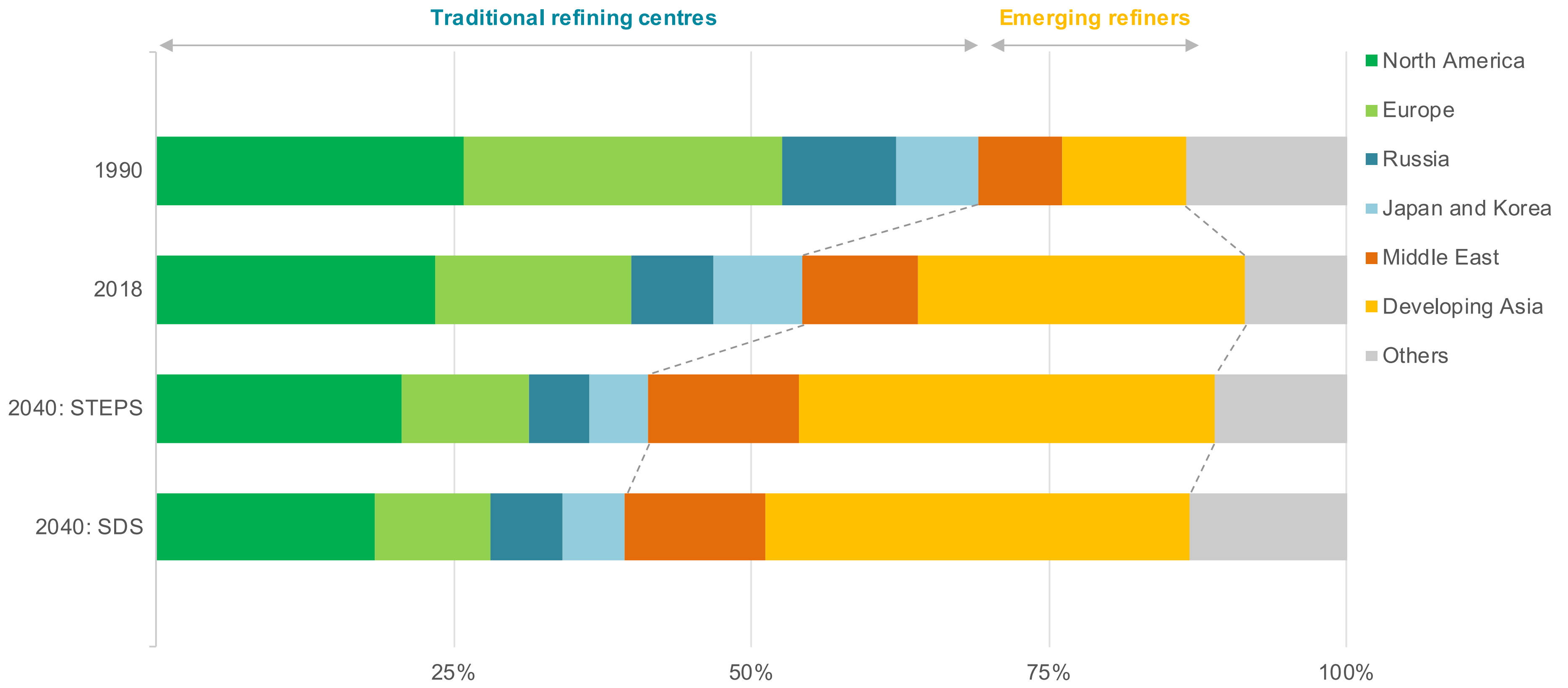
In the very challenging market conditions of the SDS, this report assumes that – either by design or by default – investment and production in major low-cost resource holders is limited in a way that maintains a floor under oil prices.

This allows some higher-cost non-OPEC supplies to find a place in the supply mix. It also means that tight oil production in the United States continues to grow into the 2020s; the short investment cycle of shale is also relatively well suited to the uncertainties of this Scenario.

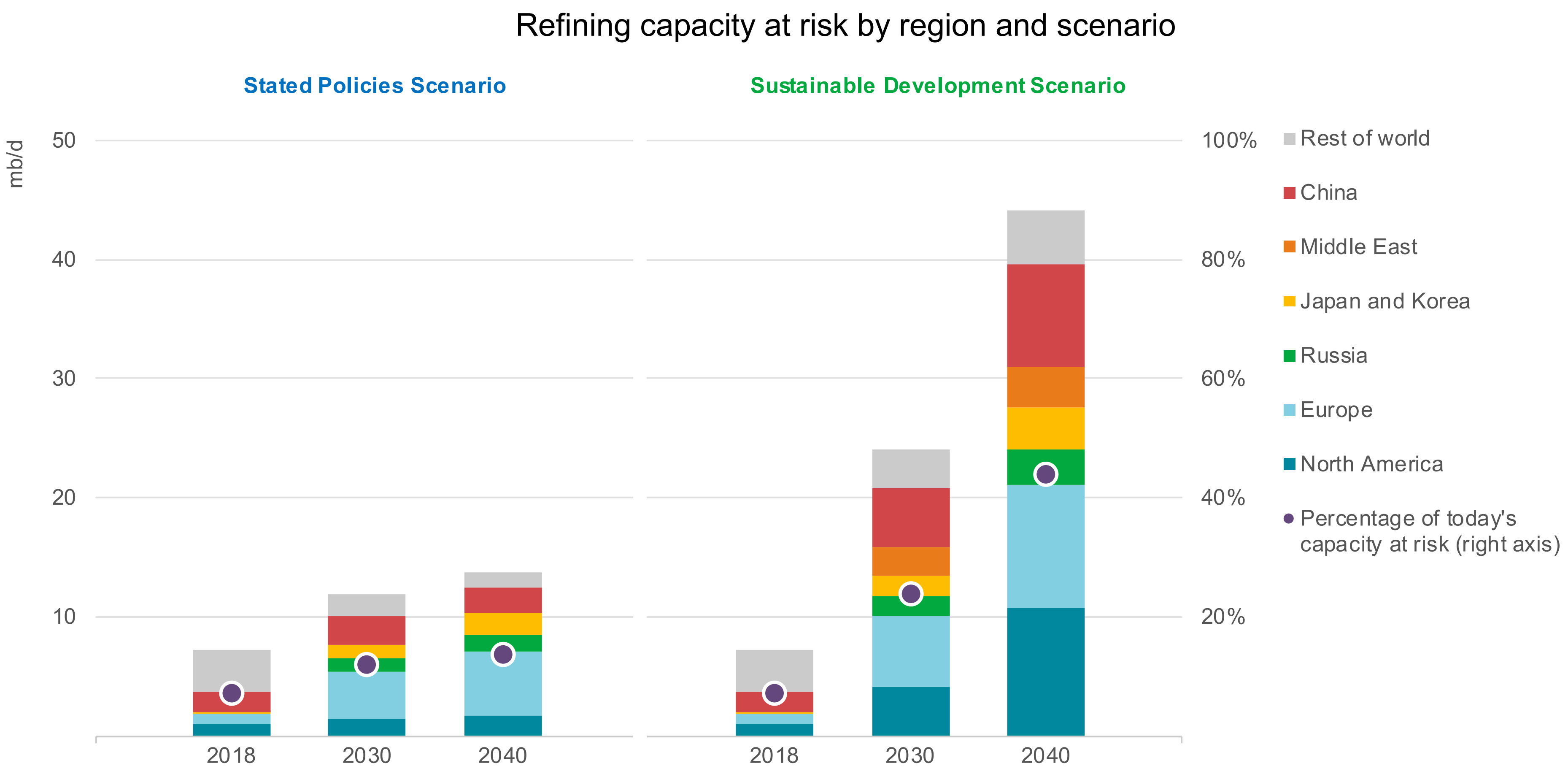
However, even with a larger share of shorter-cycle investments that are more reactive to prevailing market conditions, oil markets could well be in for a bumpy ride as and when energy transitions accelerate. There would be a greater number of factors with larger levels of uncertainty affecting the supply-demand balance: for this reason, the oil price in the SDS could well be more volatile.

Global refining activity continues to shift towards the regions benefiting from advantaged feedstock or proximity to growing demand

Share of global refinery runs by region and scenario



Demand trends in the SDS would put over 40% of today's refineries at risk of lower utilisation or closure



Changes in the amount, location and composition of demand create multiple challenges for the refining industry

Changing global energy dynamics pose multiple challenges for the global refining industry. The main difficulty arises from the prospect of falling oil demand (a much more serious challenge for the refining industry than for the upstream), but the range of regional shifts in consumption and changes in the composition of oil demand in favour of lighter products such as ethane, LPG and naphtha also pose major challenges.

The share of these lighter products in total oil demand rises from just under 20% today to 23% in 2040 in the STEPS and to 30% in the SDS. This is underpinned by rising demand for oil products as feedstocks for petrochemicals. On the other side of the ledger, transport fuels – notably gasoline – face headwinds from the rise of alternative fuels and efficiency improvements. Demand for heavy fuel oil also registers a notable decline.

This poses critical questions for traditional refining business models. Today, refiners typically earn most of their profit from selling road transport fuels such as gasoline and diesel. Prices for petrochemical feedstocks – the main sources of demand growth in both scenarios – often trend lower than crude oil prices.

Refiners are positioning themselves to meet these challenges by either processing growing volumes of lighter crude oils or deepening integration with petrochemical operations. Higher levels of integration would provide a hedge against a possible peak in demand for road transport fuels, bring operational synergies and enhance feedstock flexibility. There are even more ambitious schemes being pursued to bypass refining operations and produce chemicals directly from crude oil, which are likely to gain more traction in the case of accelerated energy transitions.

However, there is a risk that, in anticipation of weak oil demand growth in some sectors such as passenger transport, companies may overinvest in other sectors where sustained growth is expected, such as petrochemicals. Today, for example, many large oil companies have stated their intent to invest in petrochemicals, potentially creating an investment influx and capacity growth higher than the rate required by demand growth; this possibility is examined in Section III.

Yet another challenge comes from the refining industry itself. A wave of new refining investment is set to boost global capacity in the coming years. In the STEPS, some 15 mb/d of new capacity comes online between 2018 and 2040, primarily in developing economies in Asia and the Middle East – the regions benefiting from either advantaged feedstock or rising domestic demand. This would upend the traditional order of the global refining industry.

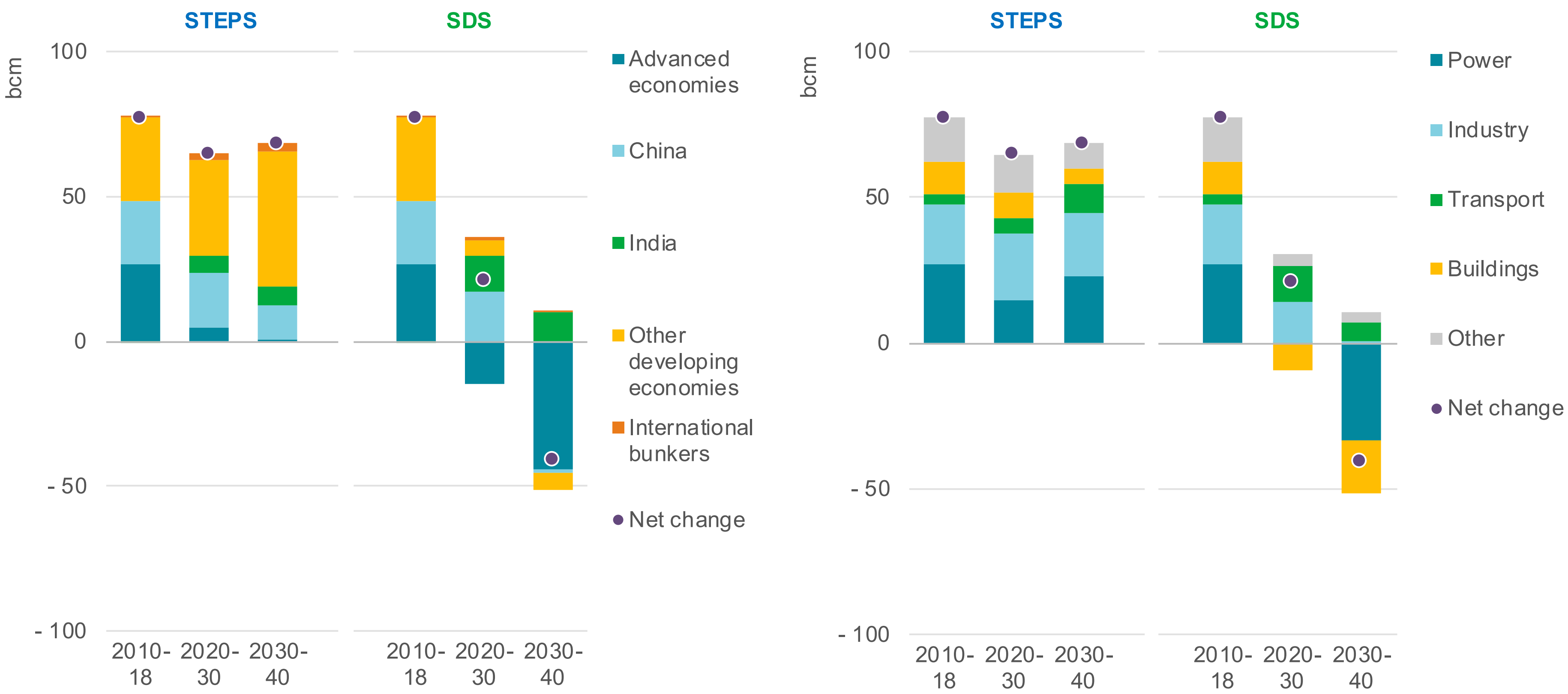
In the SDS, the reduction in oil demand intensifies the pressures across the industry, with only the most competitive assets set to thrive. Growing contributions from NGLs and biofuels-to-liquids demand create additional pressure. This report estimates that in this Scenario, more than 40% of today's existing refineries would face the risk of lower utilisation or closure by 2040.

Natural gas in the Sustainable Development Scenario

Slides 64 - 71

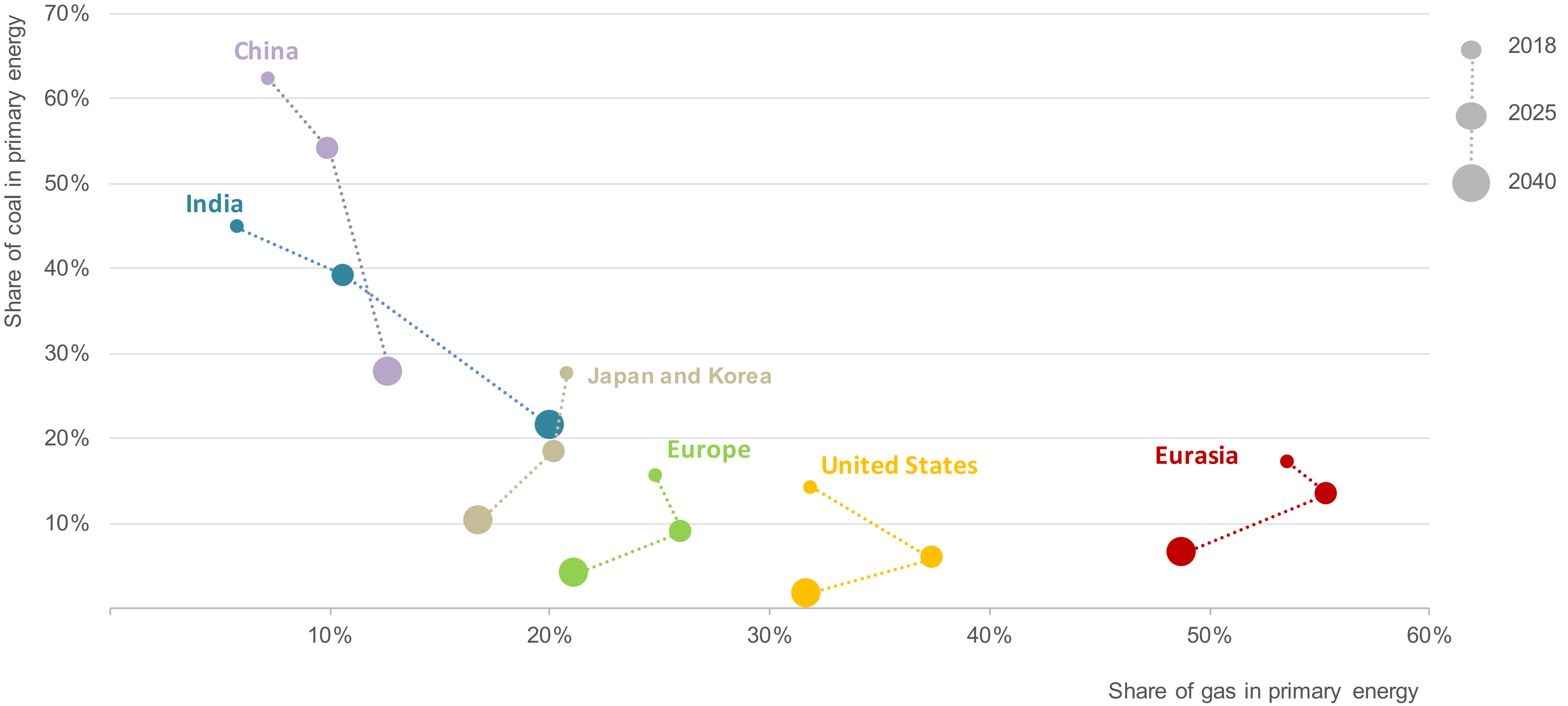
There is no single storyline about the role of natural gas in energy transitions

Average annual changes in natural gas demand by region (left) and sector (right)



The role of gas in helping to achieve the goals of the SDS varies widely, depending on starting points and carbon intensities

Share of coal and natural gas in primary energy demand in selected regions in the SDS



Policies, prices and infrastructure determine the prospects for gas in different countries and sectors

The oil market looks broadly the same from anywhere in the world; the same is not true for natural gas. Even as the market becomes more liquid and interconnected, relatively high costs of transportation mean that price levels can vary substantially between resource-rich, exporting regions and those that need to import gas.

The environmental credentials of gas also differ depending on the sector, country and time frame being considered.

In places where energy transitions are already quite advanced, or where gas already plays a large role in the energy mix, gas naturally becomes a target of decarbonisation policies.

The perspective is often different in some parts of the world that do not use much natural gas today. This includes, for example, the coal-dominated energy systems in many developing countries in Asia, and in countries with rapidly growing energy and infrastructure needs, as in many parts of Africa. For these countries, if gas is affordable and reliable, then it looks – together with renewables – like part of the solution over the period to 2040.

These varied perspectives come through clearly in the projections for the SDS, in which overall gas use rises until around 2030 before falling back to today's levels by 2040.

The window of opportunity in this Scenario for natural gas to play a role in the decarbonisation of advanced economies is narrow; by 2025, increased electrification of heat demand, greater penetration of renewables in the power sector and significant efficiency improvements begin to reduce natural gas consumption. By 2040, demand in advanced economies is one-third lower than today.

The decline in advanced economies is partially offset by continuing growth in developing markets in Asia, particularly China and India, where gas has a more prolonged role. New gas infrastructure is built to help displace more polluting fuels such as coal and oil in hard-to-abate sectors such as heavy industry (e.g. steel and petrochemicals). Nonetheless, to be compatible with a fully net-zero emissions global energy system, gas infrastructure will ultimately need to deliver truly low-carbon energy sources (as discussed below).

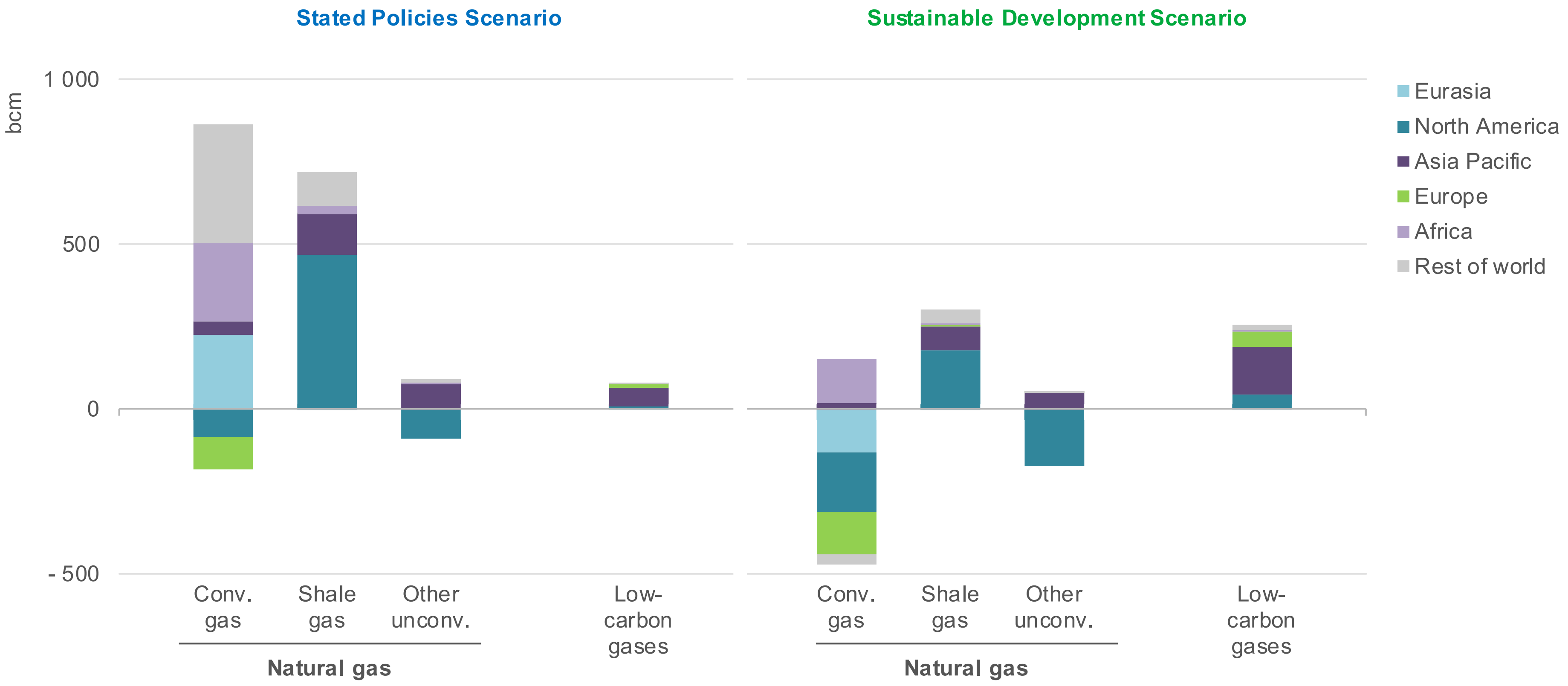
Increased gas use also plays a role in many country strategies to improve air quality, a consideration that brings it into play also for some parts of the transport sector where electrification is a less viable option, such as road freight.

The role of gas in the power sector in the SDS varies by country, depending on prevailing prices and policies, but there is a general shift towards the provision of balancing and flexibility functions for both seasonal and short-term variations in demand, rather than the provision of baseload or mid-merit power. As variable renewables scale up rapidly, gas infrastructure plays a crucial role in ensuring security of electricity supply. In countries with large, young gas-fired fleets – notably the United States – plants are also retrofitted in some cases with CCUS.

In the SDS, gas-related CO_2 emissions in 2040 drop 15% below today's levels, but make up a much larger share of total emissions, reaching almost 40% (up from 21% today), as coal use falls back.

The emissions intensities of different sources of gas supply come into focus and decarbonised gases start to make their mark

Change in gas production by region and scenario, 2018 versus 2040



Note: Other unconv. = tight gas and coalbed methane; low-carbon gases = biomethane and hydrogen injected into the gas grid.

Lower-emissions gases are critical to the long-term case for gas infrastructure

Natural gas production in the SDS has to accommodate changing patterns of demand, but it also has to adapt to higher expectations about the environmental footprint of the delivered gas. This is felt in two ways: increased differentiation between sources of natural gas based on their life-cycle emissions; and an enlarged role for low-carbon gases such as biomethane and low-carbon hydrogen.

The SDS requires a major reduction in the emissions arising from the extraction, processing and transportation of natural gas. Abatement of methane emissions along the gas supply chain is vital; this report's current estimate of worldwide methane emissions from natural gas operations corresponds to an emissions intensity of 1.7% (i.e. 1.7% of gas production is lost to the atmosphere). In the SDS this falls to 0.4%. In the absence of concerted actions to reach this level, there would be less room for natural gas to play a role in this Scenario.

Other options to reduce the emissions intensity of gas supply would also be in play, including for example the electrification of the LNG liquefaction process using zero-carbon electricity (rather than via combustion of natural gas) and increased deployment of CCUS.

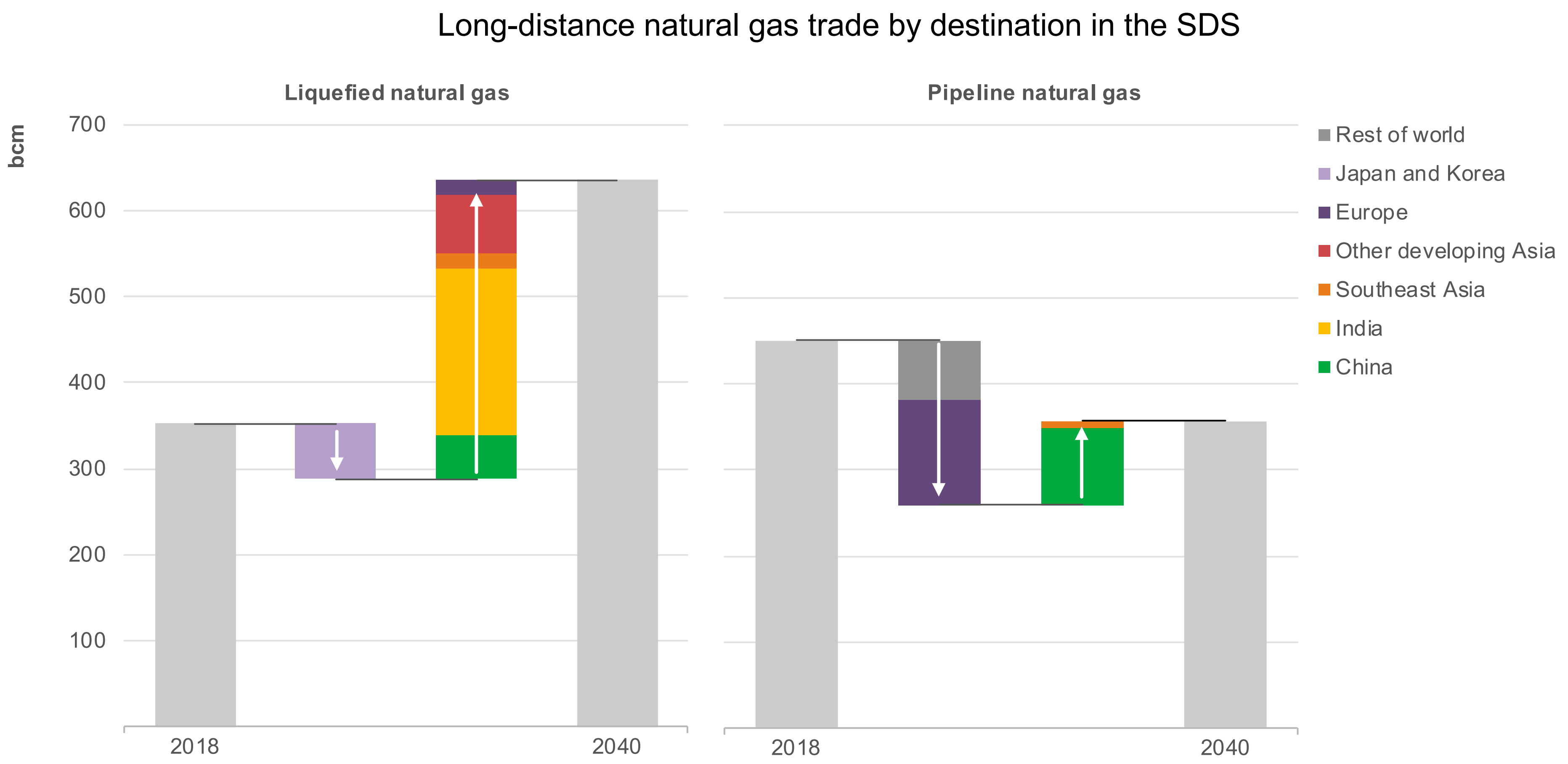
Supply of conventional natural gas declines by around 500 bcm to 2040, although it remains the largest source of global production. Some of this is a consequence of natural resource depletion in North America and Europe, but it also reflects a decline in Russian exports to Europe.

The main new arrivals on the supply side are low-carbon gases. By 2040, decarbonised gases are well established in the energy system of the SDS, making up 7% of total gas supply globally in 2040 (but more than double that share in some markets, such as Europe and China).

Of the options to produce decarbonised gases, low-carbon hydrogen is enjoying a wave of interest, although for the moment it is relatively expensive to produce. Blending it into gas networks would offer a way to scale up supply technologies and reduce costs. The assessment in *WEO 2019* of the sustainable potential for biomethane supply (produced from organic wastes and residues) suggests that it could cover some 20% of today's gas demand. Recognition of the value of avoided CO_2 and methane emissions would go a long way towards improving the cost-competitiveness of both options.

Gradually repurposing or retooling gas grids over time to deliver low-carbon energy helps to make the continued use of gas networks compatible with a low-emissions future. This is an important part of secure energy transitions in many countries. As noted above, there are limits to how quickly and extensively electrification can occur, and practical constraints on building out new electricity infrastructure. As things stand, gas grids typically deliver more energy to consumers than electricity networks and provide a valuable source of flexibility.

Long-distance gas trade, largely in the form of LNG, remains part of the picture in the SDS



Note: Declines in pipeline trade in the *Rest of world* are predominantly in North America.

The optionality and flexibility of LNG gives it the edge over pipeline supply

In the SDS, long-distance gas trade grows by up to 25% compared with today. The carbon-intensive developing economies, mostly in Asia, in which gas can play a role in energy transitions, are also short of abundant domestic gas resources. For this reason, even as they ramp up deployment of renewables at breakneck speed, they also increase imports of gas.

Most of these imports are in the form of LNG, as it is more suited to accommodate the changing geography of gas supply and demand. Especially in the uncertain policy and demand environment of the SDS, there is a preference for LNG's flexibility in seeking out the most advantageous destination markets, as opposed to the rigidity of pipeline routes.

In the SDS, demand for LNG remains robust until the late 2030s, largely due to demand from developing countries in Asia. There is also a plausible scenario (which would miss stringent climate targets) in which natural gas use gets squeezed between renewables and indigenous coal. However, where moving away from coal is an unambiguous priority, demand for LNG in Asia is robust and, in some countries such as India, actually higher in the SDS than in the STEPS.

By 2040, LNG demand is falling back in several Asian markets in the SDS. There is a risk, therefore, that some LNG export facilities are not fully utilised. New liquefaction capacity is capital-intensive, with investment decisions made on the basis of economic lifetimes of around 30 years.

If operators were to adjust the payback period of building a liquefaction terminal to half of the standard economic lifetime, i.e. to 15 years, then the delivered cost of LNG required to return the initial capital invested would increase by an average of USD 1.10/MBtu – undercutting the affordability of natural gas, which is a key variable in some very price-sensitive markets.

Long-distance pipeline trade ends up 20% below today's levels by 2040. The new Power of Siberia pipeline, which started gas deliveries in 2019, opens up a major new artery in gas trade between Russia and China. However, the steep decline in gas demand in Europe in the SDS reduces the call on pipeline imports from Russia, Norway, the Caspian and North Africa. Elsewhere in the world, the commercial case for building new pipelines is challenging, with a notable absence of large, creditworthy buyers willing to commit to long-term volumes to justify the financing and construction of large-scale pipeline projects.

Price trajectories and sensitivities

Slides 72 - 76

Exploring the implications of different long-term oil prices

The oil price is the intermediary between supply and demand: it ensures that new sources of oil supply steadily come online at the right time to meet changes in oil demand and to keep the system in equilibrium. The upward drift in oil prices in the STEPS reflects the large requirement for new resource development, while the steady fall in oil demand in the SDS limits the call on higher-cost oil to balance the market and so the price is lower.

Projections of future prices are of course subject to a high degree of uncertainty and this report's trajectories do not attempt to anticipate the fluctuations that characterise commodity markets in practice. Price levels in the scenarios reflect a dynamic, cyclical relationship between the oil price and the cost of oil and gas extraction, along with other factors such as depletion and technology learning.

As discussed above, another important assumption is that investment and production in major low-cost resource holders is limited in a way that maintains a floor under oil prices, e.g. by major resource-holders maintaining a strategy of market management. This means that the marginal project required to meet demand is more expensive than would be implied only by the global supply-cost curve.

However, faced with rapidly falling demand, major resource holders could choose an alternative strategy and look to ramp up production in an attempt to gain market share while there is still scope to do so. In this event, the combination of falling demand and increased availability of low-cost oil would undoubtedly lead to even lower prices.

This situation is modelled here in the Low Oil Price – SDS Case (LOP-SDS). In the early 2020s, large resource holders rapidly increase production by fully utilising all of their spare production capacity: this leads to an overhang of supply and a sudden drop in the oil price. Thereafter, these resource holders continue to grow production to force out higher-cost sources of supply and so increase their overall market share. In this case, the oil price suddenly drops to below USD 25/barrel and thereafter remains in a relatively tight band between USD 25/barrel and USD 35/barrel. (This case focuses on oil markets because demand trends, the more regional nature of natural gas markets and the absence of large levels of spare natural gas capacity make a similar case for gas somewhat less likely).

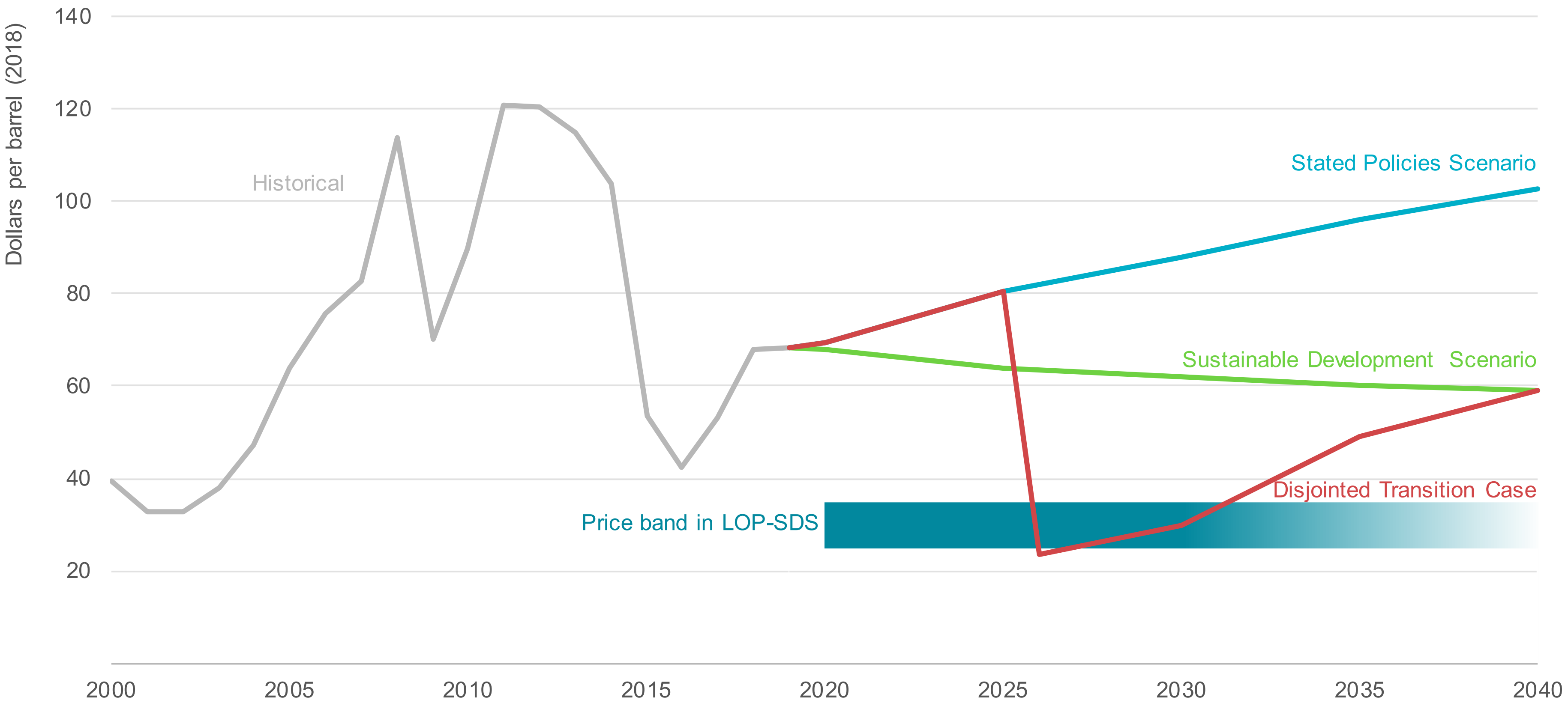
Despite the drop in the oil price, for the purposes of this case this report assumes that global oil demand remains identical to the levels projected in the SDS to ensure that emissions fall in line with the Paris Agreement. Keeping end-user prices the same as in the SDS would require even stronger policies and taxation on oil use to avoid any rebound in demand. The implications of this case are examined directly below.

Another possibility examined in this report is a Disjointed Transition Case. In this case, energy policies and markets initially follow the trends of the STEPS to 2025. This is followed by a sudden strengthening of energy policies, with oil and gas demand then dropping abruptly to the level of the SDS over the five-year period to 2030. Prior to 2025, operators invest on the assumption that prices and demand will continue to rise as in the STEPS, only to be faced with a sharp break in the trend.

The precipitous drop in oil demand in this case leads to a large surplus of supply and so there is again a sudden drop in the oil price. After 2030, oil demand follows the trend of the SDS and, as the surplus is slowly worked off, the oil price slowly recovers. Results from this case are examined in more detail in Section III.

The SDS has steady decline in oil prices but very different trajectories are possible, depending on producer or consumer actions

Oil price in the STEPS, SDS and two sensitivity cases

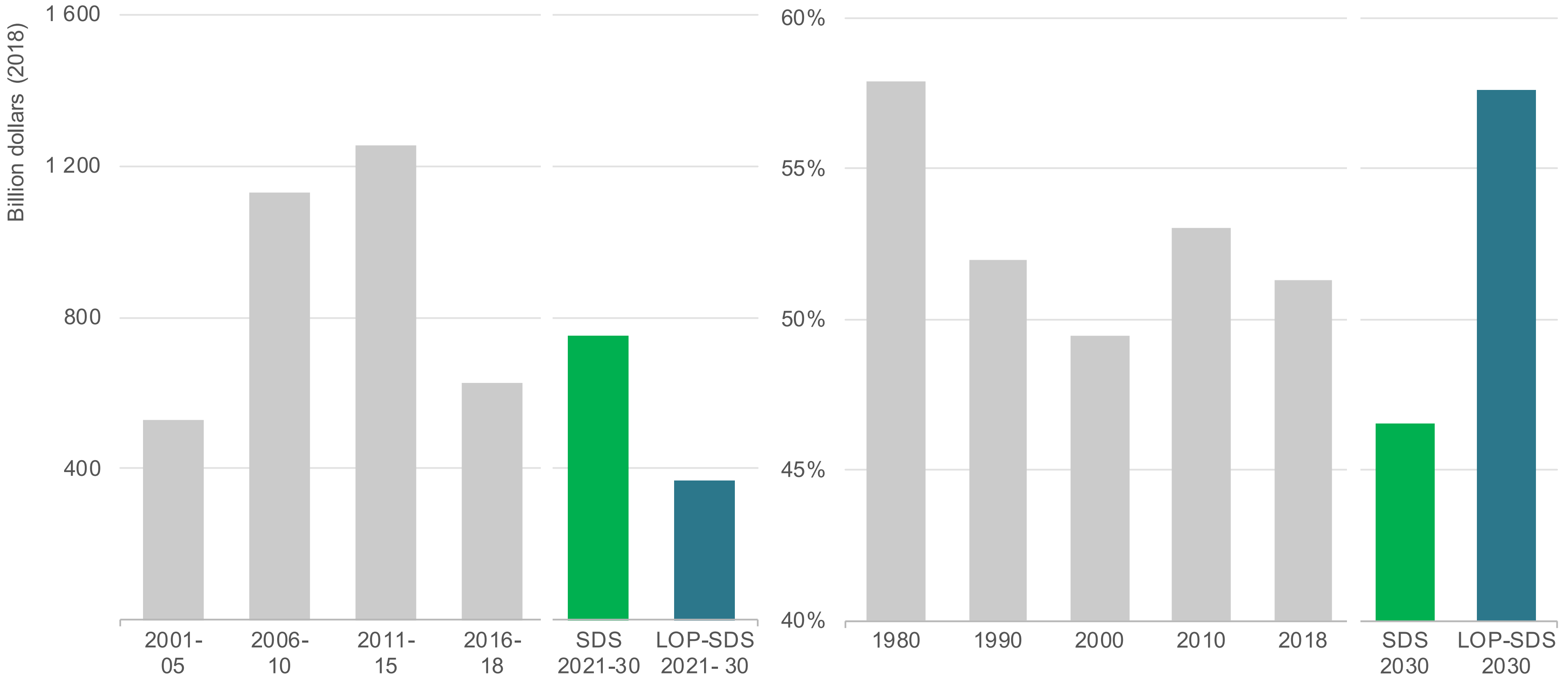


Notes: Prices are given in real 2018 US dollars. LOP-SDS price band reflects the range of the modelled oil price from the early 2020s.

Large resources holders could choose to gain market share in energy transitions, but would face the risk of a rapid fall in income from hydrocarbons…

NOC (including INOCs) net income before tax from oil sales

Share of OPEC and Russia in global oil production



Note: Net income before tax is total revenue from oil sales minus operating and finding and development costs; it is the rent that is available to NOCs and INOCs and their host governments.

…meaning that a very low oil price becomes less likely the longer it lasts

A situation where large resource holders prioritise market share would have strong implications for energy markets and energy transitions. With an oil price remaining below USD 35/barrel, most non-OPEC producers – as well as many of the higher-cost members of OPEC – would struggle to develop new upstream projects.

This would increasingly concentrate production in the lowest-cost producers: in the LOP-SDS, the members of OPEC and Russia would make up well over 55% of global oil production by 2030, a level not seen since the early 1980s. Production from members of OPEC and Russia in this case is 2 mb/d higher in 2030 than in 2018 even though global oil demand is 10 mb/d lower.

Such a drop in the oil price would make oil consumption more attractive to consumers, creating a dilemma for policy makers pursuing rapid energy transitions. On the other hand, it could also facilitate the removal of fossil fuel consumption subsidies and the introduction of an effective or actual price on CO_2 emissions, two measures that are widely implemented in the SDS.

It would also imply huge strains on the fiscal balances of many of the major producers, as the collapse in the oil price would bring hydrocarbon income in these countries down to near-historic lows.

In the wake of the oil price fall in 2014, the net income from oil sold by NOCs and INOCs (before tax and other transfers to governments) fell to less than USD 430 billion. In this LOP case, net income drops to a low of USD 210 billion and it averages only around USD 370 billion for the duration of the 2020s. In other words, the significant strains that were felt by producer economies in the immediate aftermath of the 2014 oil price crash would be much more severe and last for much longer.

The World Energy Model does find an equilibrium at these price levels, with sufficient supply available to meet the projected levels of demand. However, this outcome quickly runs into difficulties when considering its real-world implications.

The main one is that it would rely on very rapid and successful implementation of reforms to the producer economies in question (IEA, 2018). Without much more diversified economies and sources of tax revenue, revenue from hydrocarbons in such a low-price world would not be sufficient to finance essential areas such as education, health care, public sector employment and so on. This would make it unlikely in practice for prices at these low levels to be maintained. These social pressures could also mean much more limited funding available for continued investment in the upstream.

As a result, while periods of very low prices in the SDS cannot be ruled out, it is difficult see how they could be sustained for very long periods. If production from low-cost resource holders were to start to fall, this would inevitably place upward pressure on the oil price. An alternative case – as posited in the SDS – is for the major resource holders to restrict production by design, even as demand falls, to provide a higher floor under the oil price. This would be very challenging to realise in practice but could avoid some of the more disruptive economic and social impacts of a prolonged period of low oil prices.

Efforts to diversify and reform hydrocarbon-dependent economies are essential to the SDS. But a measured assessment of how quickly these can be achieved is a key reason why the oil price in the SDS remains in a higher band around USD 60/barrel.

Section III

Risks facing the industry

Introduction

Rising concentrations of GHGs in the atmosphere, changing energy dynamics, and growing social and environmental pressures represent huge challenges for the oil and gas industry.

The twin threats are a loss of financial profitability and a loss of social acceptability. There are already signs of both, whether in financial markets or in the reflexive antipathy towards fossil fuels that is increasingly visible in the public debate, at least in parts of Europe and North America.

Either of these threats would be sufficient to fundamentally change the relationship of oil and gas companies with the societies in which they operate. Together, they require a rethink of the way that the industry conducts its business. Climate change is not a problem that can be solved in the existing oil and gas paradigm.

This section examines some of the risks facing the industry in more detail, focusing on four issues:

- Investment strategies and the **risk of over- and/or under-investment** in ways that would have strong implications for markets and public policy. This report examines three possibilities:
  i. The industry overinvests in oil and/or natural gas.
  ii. It underinvests in oil or gas.
  iii. It underinvests in low-carbon alternatives to oil and gas.
- The risk of **stranded oil and gas assets** due to climate policy. This topic is also divided into three separate strands:
  i. stranded volumes (when resources slated for development remain in the ground)
  ii. stranded capital (when oil and gas projects don’t recover the capital invested in them)
  iii. stranded value (a reduction in company revenue from both lower production and lower prices).
- The **financial performance of NOCs and INOCs**. There are specific considerations that apply to these companies, given their critical roles in the economic life of their host states and the over-reliance, in many cases, of these states on revenues from hydrocarbons.
- The **financial performance of publicly traded companies**. Here we bring together different aspects of the debate for publicly traded companies, asking whether and how they can deliver the returns that the markets demand while also transforming themselves.

There are additional risks facing the industry that are not examined here, such as litigation related to its activities in some jurisdictions, or increased difficulty in recruiting new talent. This report has also not made an assessment of the physical risks that oil and gas companies might face in the coming decades, for example from extreme weather events. These risks are real, but for the next two decades they are already locked in; they do not vary by scenario over the period to 2040; longer-term physical risks will of course be shaped much more by the speed and depth of energy transitions.

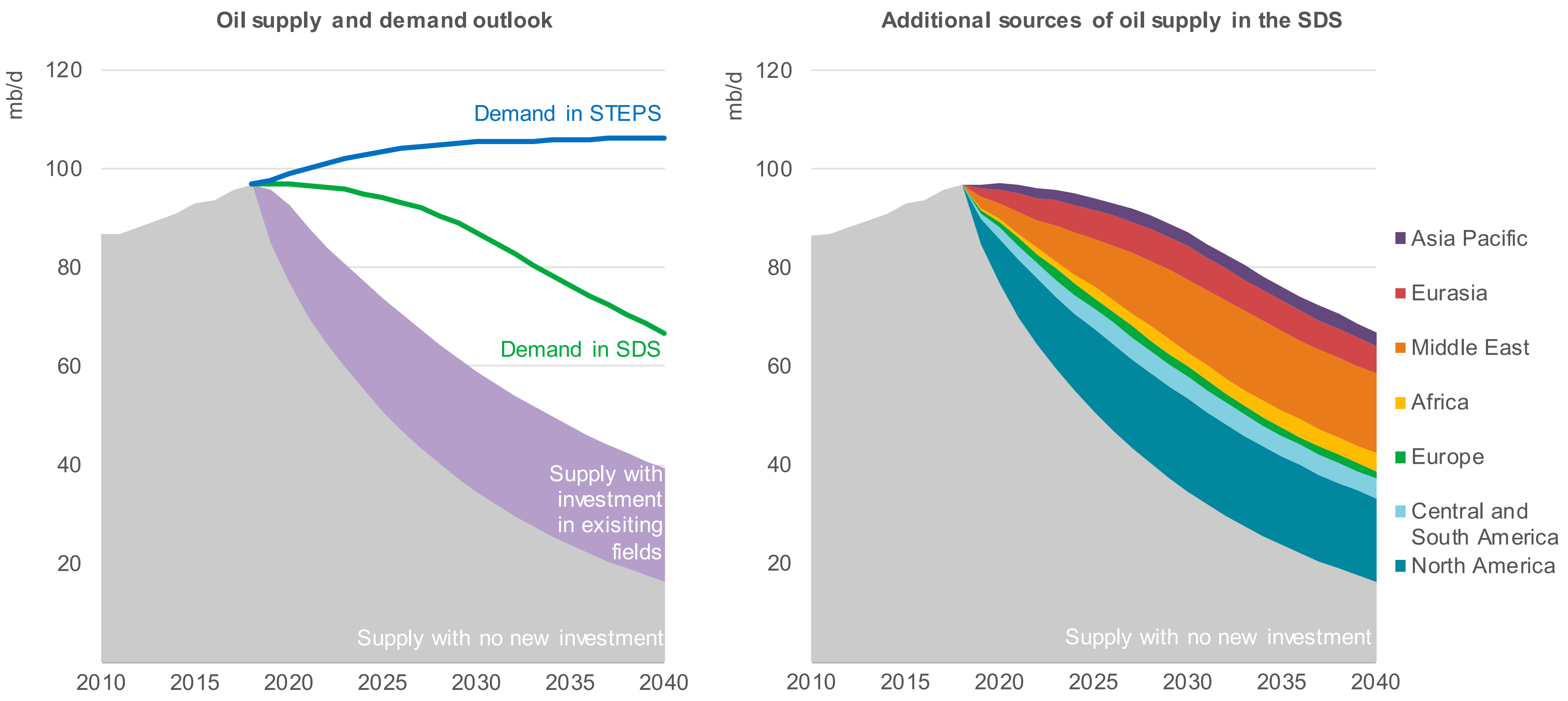
Increased evidence and incidence of physical risks is nonetheless relevant to this discussion, as they may well prompt additional climate policy actions, thereby increasing the “transition risks” facing traditional oil and gas actors and others.

The risk of over- and under-investment

Slides 79 - 94

Declining production from existing fields is the key determinant of future investment needs, both for oil…

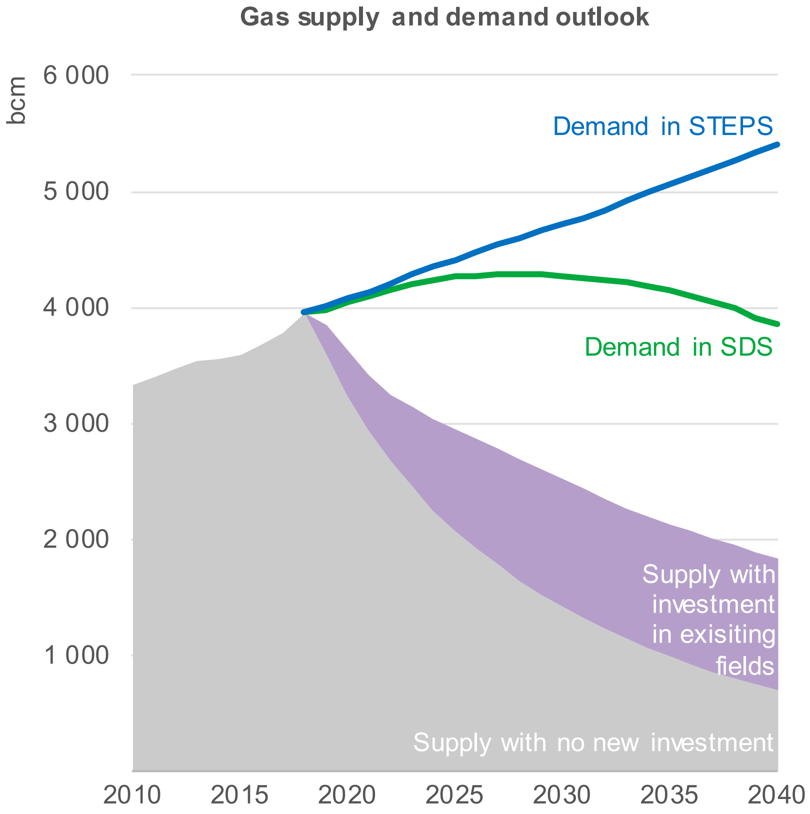
Global oil demand by scenario and declines in supply according to investment levels from 2019

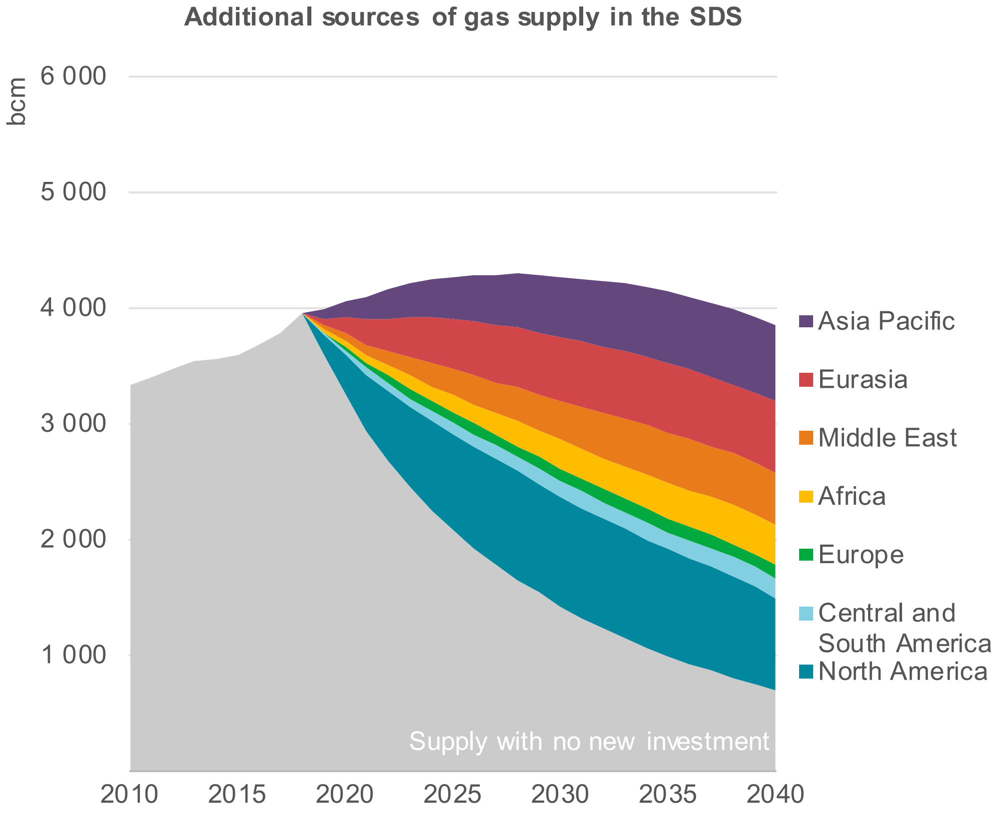


Note: With no investment, all sources of supply decline at their natural decline rates. With investment in existing fields only, all currently producing sources decline at the annual loss of supply. In both cases, no new fields are developed.

…and for natural gas

Global natural gas demand by scenario and declines in supply according to investment levels from 2019





Note: With no investment, all sources of supply decline at their natural decline rates. With investment in existing fields only, all currently producing sources decline at the annual loss of supply. In both cases, no new fields are developed.

Decline rates can vary substantially between different types of oil and gas field

A significant tranche of the oil and gas production over the period to 2040, in all scenarios, comes from the reserves in today's producing fields. These are the proven, developed reserves that are tapped by existing infrastructure. Production from these fields will decline in the future as the natural pressure in the reservoir starts to fall. This aggregate decline rate is likely the most important factor affecting future investment needs.

In general, a decline rate refers to the percentage reduction in actual production from an individual field or a group of fields over time. It can vary widely from field to field, according to their size, maturity, location, geology, geochemistry and development strategy. There are two main decline rates often reported. Our estimates for these decline rates are based on a detailed field-by-field decline rate analysis that takes into account the differences that exist across different field types, weighted by each field's cumulative production.

Natural decline rate: the drop in production from all currently producing fields that would occur if capital investment were to cease immediately. We estimate that the global annual average natural decline rate from all sources of oil production is around **8%**.

Observed post-peak decline rate: in practice, decline rates are generally much lower than the natural decline rate since there is continued investment in producing fields. The observed post-peak decline rate is the compound annual decline in production from existing crude oil fields whose production has already peaked, but with continued capital investment in these fields. We estimate that the global annual average observed post-peak decline for conventional crude oil today is around **6.1%**.

However, the observed post-peak decline rate still does not provide a robust description of the annual loss in production from the global oil balance, for a variety of reasons:

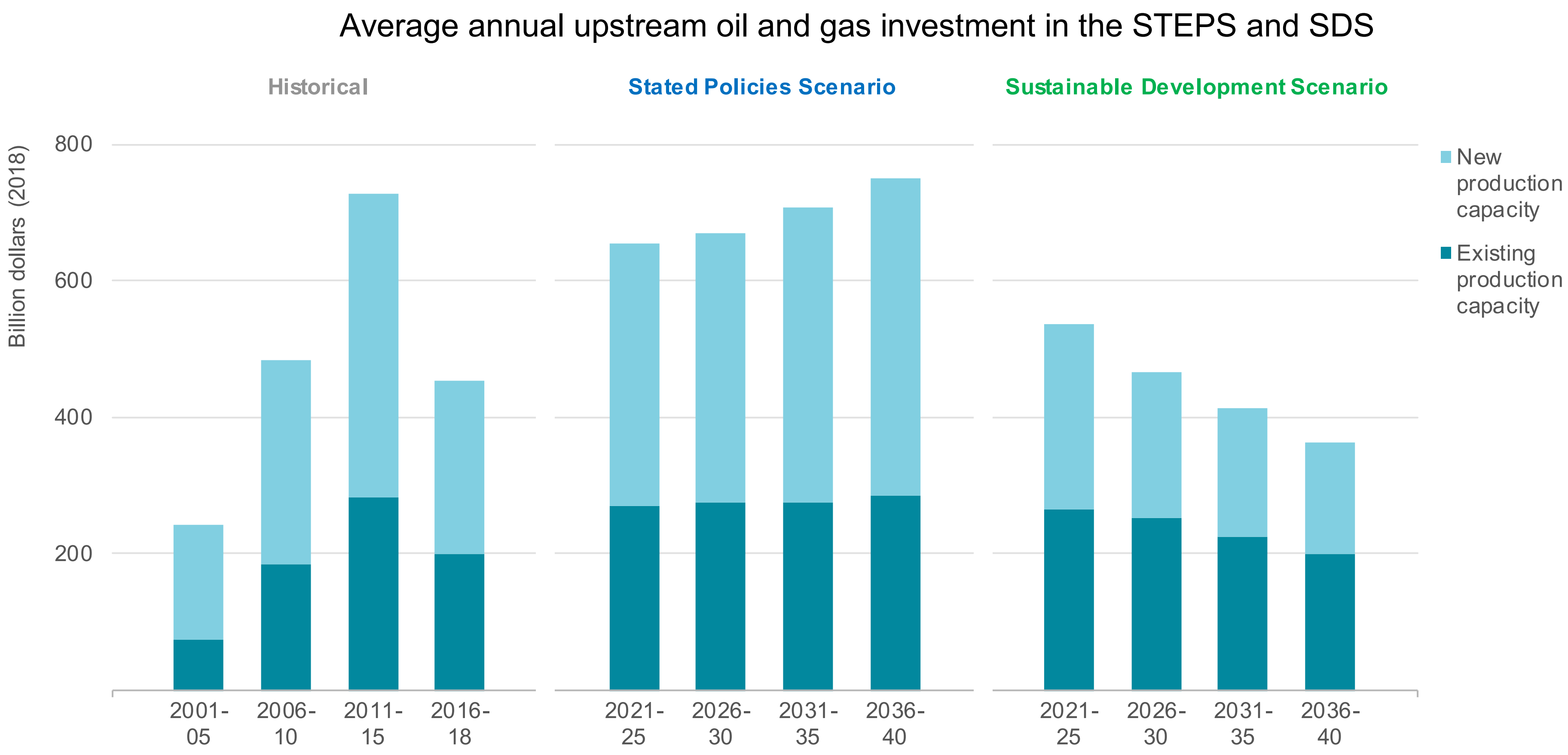
- The observed post-peak decline in fields producing in 2018 changes over time as fields become more mature.
- Less than 50% of global oil production today comes from post-peak conventional crude oil fields. The rest comes from conventional crude oil fields that have not yet reached their production peak, NGLs, tight oil, extra-heavy oil and bitumen, coal-to-liquids, gas-to-liquids and additives.
- There are fields being developed today that will soon come online.

Taking into consideration these factors, we estimate that if no new oil fields were to be approved beyond those already under development, the **average annual loss of supply** to 2040 would be around **4%.**

This annual loss of supply changes dynamically over time. For example, there are initially rapid declines in tight oil production, which are offset to some extent by increases in production from approved and ramp-up conventional crude oil fields. It then accelerates as more fields enter decline and as the pipeline of new projects begins to dry up. In later years, the annual loss of supply starts to drop slightly as it trends towards the average post-peak decline of large fields (which tend to decline more slowly than smaller fields) and as the initial decline in tight oil eases into a slower long-term decline rate.

The above figures are for changes in oil production, but the figures for natural gas are generally similar. We estimate that the natural decline rate for natural gas is around 7.5%, while the average annual loss of natural gas supply over the period to 2040 is 3.5%.

Upstream investment in oil and gas is needed – both in existing and in some new fields – in the SDS…



Note: *Existing production capacity* is measured from the start of each period and includes sources of supply that were brought into production in a previous year.

…because the fall in oil and gas demand is less than the annual loss of supply

In the SDS, oil demand peaks soon and falls at its fastest rate during the 2030s at around 2.5% per year. Natural gas demand peaks later, but demand falls by around 1% per year during the 2030s.

These declines are much lower than both the natural decline and the average annual loss of supply. As a result, investment in both new and existing sources of supply is needed. Investment in current sources of production slows the natural decline rate to the annual loss of supply (i.e. reduces the decline from 8% to 4%). Investment in new fields is then also required to ensure a smooth balance between supply and demand.

Around USD 510 billion is spent on average each year on existing and new fields between 2019 and 2030 in the SDS. This level falls over time as the declines in oil and gas demand accelerate, and averages around USD 390 billion between 2030 and 2040.

In the SDS, spending is also increasingly focused on maintaining production at existing assets rather than seeking or developing new projects. Today around 55% of upstream investment is spent developing new fields and the remainder on currently producing fields. In the 2020s, this proportion drops to 50% and to 45% in the 2030s.

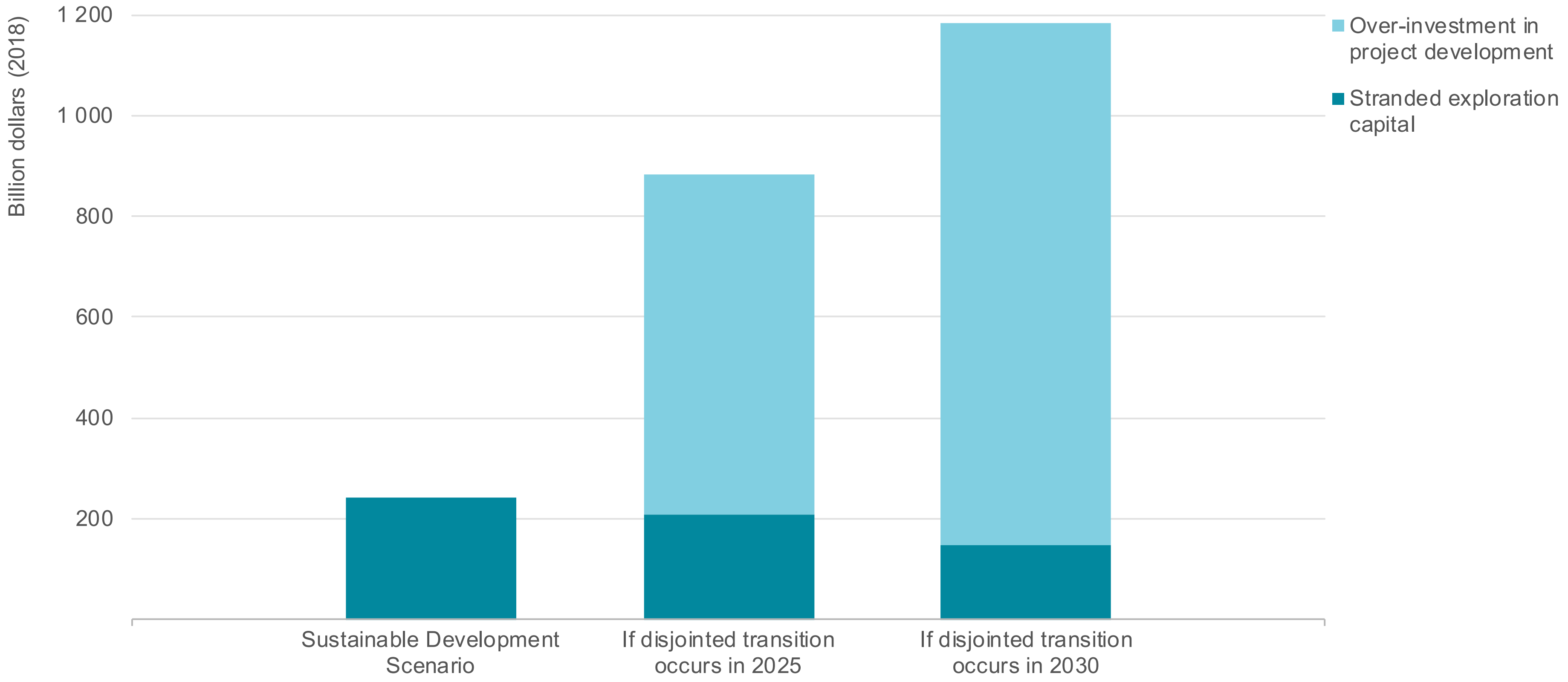
While investment in new and existing oil and gas fields is important to help ensure sufficient supply in the SDS, the level of investment needed is much lower than in the STEPS – by the 2030s, upstream spending in the SDS is around half that in the STEPS.

In addition to upstream spending, there is also some continued investment in mid- and downstream oil and gas infrastructure, albeit likewise at levels well below those projected in the STEPS. For oil, this ensures that the global refining capacity adapts to changes in the oil product mix, reduces the emissions intensity of refining processes, and ensures the integrity and adequacy of pipeline, storage and port infrastructure. Maintaining gas infrastructure is also important, not least because the composition of the gases transported through these networks starts to change with the uptake of low-carbon gases such as hydrogen and biomethane. On average there is around USD 150 billion invested each year in mid- and downstream oil and gas infrastructure between 2019 and 2040 in the SDS.

The following slides explore the potential for over- and underinvestment in oil and gas during energy transitions, and the potential implications. They also examine a case of underinvestment by the oil and gas industry in low-carbon alternatives to oil and gas.

i) Overinvestment in oil and gas: What if the industry invests for long-term growth in oil and gas but ends up in a different scenario?

Stranded capital to 2040 in the upstream oil sector in the SDS and Disjointed Transition Case



A disjointed transition, with a sudden surge in the intensity of climate policies, would shake the oil sector

Particularly in the early years of energy transitions, the oil and gas industry may be overly optimistic in its reading of the future in terms of either demand and investment needs or price levels. This may lead to overinvestment in assets that are not needed because demand turns out to be lower than expected. A similar outcome might be reached if there is a sharp discontinuity in policy, due to a sudden acceleration in the intensity of efforts to get the world on a trajectory consistent with international climate targets.

One way to assess the potential impacts of these cases is through the Disjointed Transition Case introduced in Section II. In this case, oil and gas demand follows the STEPS until 2025 but then drops abruptly to the level of the SDS over the five-year period to 2030. As a result, prior to 2025, operators invest based on price and demand levels from the STEPS, only to be faced with a sharp break in the trend.

Such a sharp switch in trajectory would be very difficult to do in practice, but it would represent a massive shock for oil markets. Oil demand would need to decline by some 3.5 mb/d each year for a five-year period, which leads to a large overhang in supply and a large drop in the oil price. Natural gas would also be affected, although the impact would be less disruptive: global demand would need to fall by around 30 bcm each year, less than the rate of decline seen in the 2030s in the SDS.

A significant part of the reduction in oil demand in this case would be absorbed by declining output from existing fields and the absence of production from new fields as investment dries up. Still, financial losses can arise for a number of reasons. Some projects developed to 2025 with price expectations oriented towards the STEPS would fail to recover their invested capital. In addition, a demand shock of this magnitude would require shutting in some old fields made uneconomic by the fall in prices. There would also be exploration capital that would be not recovered, as is the case in the SDS (see below).

Taken together, we estimate that balancing supply with reduced demand over this five-year period could mean that around USD 900 billion investment in upstream capital assets would not be recovered. For context, this is more than one-third of the upstream oil investment in the SDS in the period to 2025.

Moving this transition between scenarios so that the sudden switch takes place five years later (i.e. between 2030 and 2035) leads to a much larger shock because by then the gap between scenarios is that much larger. There would need to be an even more dramatic 6 mb/d annual decline in oil demand over a five-year period, and nearly USD 1 200 billion of above-ground stranded upstream capital. This type of scenario would also be very disruptive for mid-/downstream infrastructure, notably for refineries where there are no “decline rates” to absorb the shock.

The overall message is clear: the later energy transitions are deferred, the more difficult it is to get back on track. Though government policies can smooth transitions, stop-and-go cycles of policy volatility can have the opposite effect. The implications of such a disjointed effort would be very challenging for the oil industry, but there would also be major challenges for policy makers. In consuming countries, the sudden drop in the oil price could lead to a rebound in demand unless it is countered with policy efforts that would effectively prevent consumers from accessing these lower prices, e.g. via taxes or other duties. In producing countries, there would be severe and sudden loss of revenue.

The industry could also overinvest in the sectors that are deemed 'safe havens' in energy transitions, notably natural gas and petrochemicals

Another possibility of "overinvestment" is a rush to invest in sectors that are considered more resilient to energy transitions: natural gas (especially LNG) and petrochemicals. The opportunities here are clear (see Section II), but there are risks as well given that both sectors involve large, capital-intensive investments that require high levels of utilisation over time. Unlike the production declines in the upstream, there is no natural protection in these sectors against the risk of demand coming in below expectations.

A record 95 bcm of new liquefaction projects were given the green light for investment in 2019. Together with other projects under construction, this means that around 40% of the new LNG capacity projected in the SDS to 2040 has already been sanctioned or is under construction.

Thus far, the current situation of LNG oversupply has not led to lower liquefaction plant utilisation, as suppliers have continued to market LNG cargoes as long as they yield positive short-term cash flows. Long-term contracts that mandate minimum take-or-pay volumes and link the gas price to oil have also acted as a buffer shielding LNG suppliers from lower demand and lower spot prices.

However, a sustained period of oversupply would prolong downward pressure on natural gas prices and heighten the risk that LNG operators are unable to recover their long-run investment costs. It would also create significant buyer pressure to renegotiate contract terms, endangering some of the risk management strategies that currently safeguard the long-term financial health of LNG projects.

Cheaper LNG would provide an opening for gas to gain market share against coal in the power sector, and help gas to challenge oil in other sectors such as long-distance shipping and road freight. However, this could also lock in new gas infrastructure and the associated emissions, unless there is a credible plan to use this infrastructure to transition to low-carbon gases.

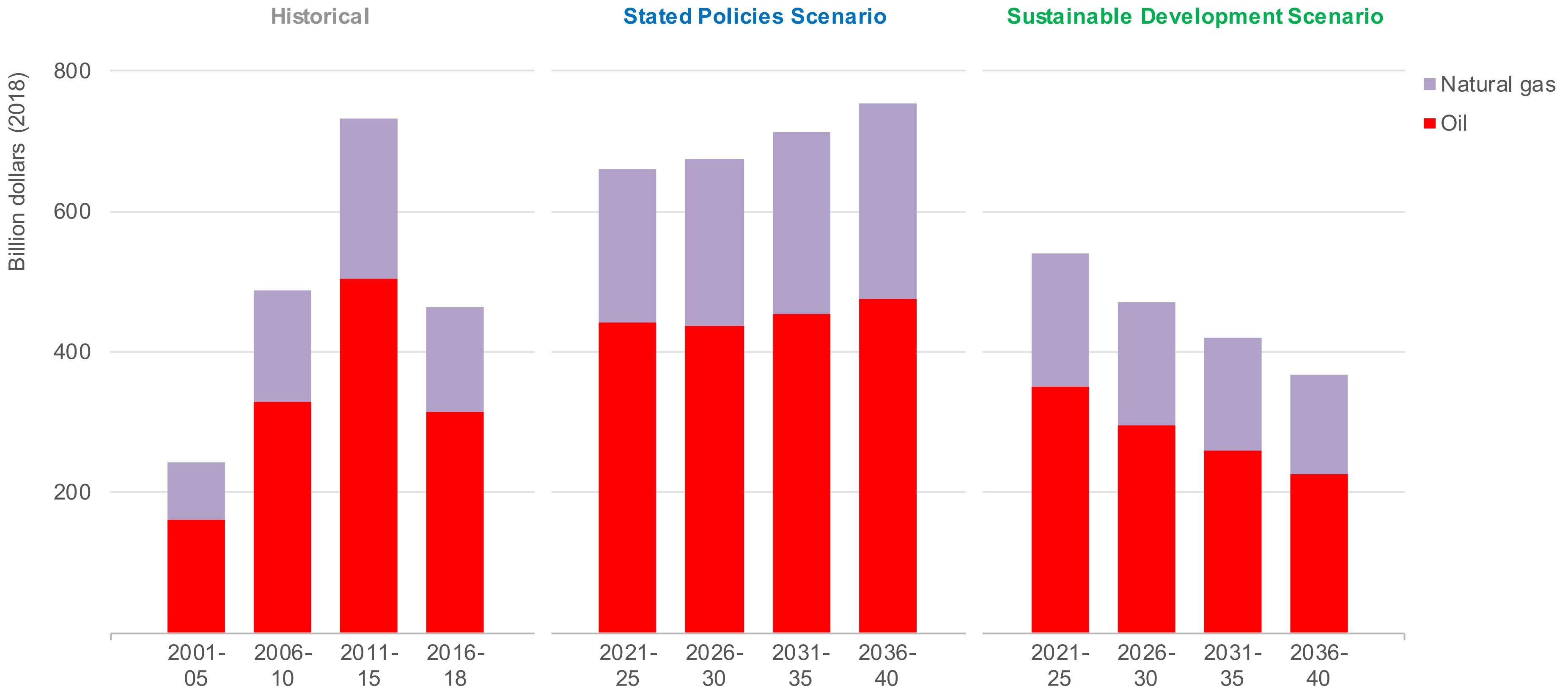
On the petrochemicals side, capital spending on new capacity has more than doubled since 2014. Demand for petrochemicals remains relatively robust, but the growth in production capacity is happening at a much faster pace. This was partly driven by efforts to leverage cheap NGL feedstocks in the United States, but also by companies' strategic movement to seek additional margins and to hedge against the risk of a slowdown in oil demand in other sectors.

As in the case of LNG, this is set to intensify competition, erode industry margins and weigh on high-cost producers in the years ahead. Significant margin erosion is already visible in some parts of the product chain such as para-xylene and polyamide, and many companies have seen declining profits since 2016.

Overinvestment in petrochemicals can also undermine efforts to minimise the negative environmental impacts of plastic consumption. For example, prices for recycled polyethylene terephthalate (PET) have traditionally been lower than those for virgin PET. But in the second half of 2019, European prices for virgin PET collapsed and trended lower than those of recycled PET, squeezing economic opportunities to switch to recycled plastics and making policy efforts to boost recycling more costly.

ii) Underinvestment in oil and gas: What if the supply side transitions faster than demand?

Average annual upstream oil and gas investment in the STEPS and SDS



Today's upstream trends are already closer to the SDS

Between 2016 and 2018, actual oil and gas upstream spending averaged around USD 460 billion each year, compared with an average of USD 730 billion for the years between 2011 and 2015. This retrenchment was caused by the sharp drop in the oil price in 2014 and needs to be seen alongside a significant reduction in upstream unit costs over this period. The reduction in activity levels has been significantly less than the headline reduction in spending. But it remains the case that there has been a material slowdown in upstream activity over the course of the 2010s.

Oil and gas markets appear well supplied for the moment, but there are few guarantees that such conditions will persist. Current investment spending in both the oil and gas sectors is reasonably well aligned with the near-term needs of the SDS. It would, though, need to pick up considerably to meet the higher demand outlook of the STEPS.

In other words, there is a risk of a mismatch between today's trends on the demand side, which point to robust growth in consumption, and investment dynamics on the supply side. Supply is being squeezed by tighter financial conditions, company strategies to limit investment only to the most favourable projects with low costs and risks, and (in some cases) by investor expectations.

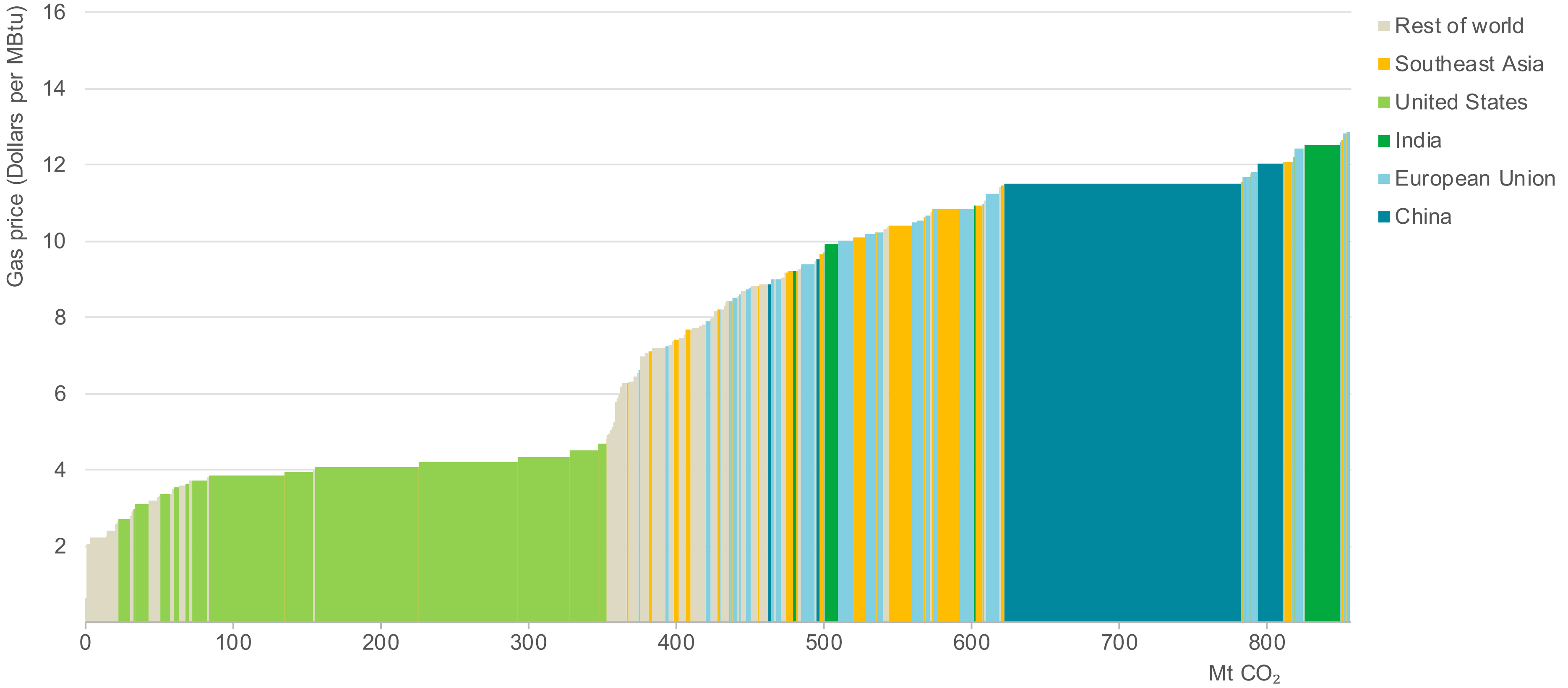
If this mismatch persists – and assuming that short-cycle shale cannot expand indefinitely to fill the gap – then the world could be looking at a material tightening in markets by the mid-2020s associated with higher and potentially more volatile prices. The risks in this respect appear to be higher for oil than for natural gas.

From the perspective of the oil and gas industry, and of energy transitions, such a market tightening would have important implications:

- When a price spike is caused by a supply-side shock, this penalises consumers of the fuel in question and hits the economies in countries that are net importers. For example, around 70% of oil consumed in China is imported, closer to 80% in India, and 100% in France, Japan and Korea. The oil import bill in many cases is equivalent to a sizeable share of GDP.
- Periods of high oil prices could accelerate the policy momentum and economic attractiveness of alternatives to oil, especially in some of the emerging demand giants in Asia that are particularly sensitive to price swings.
- Producers of oil would benefit from higher revenues: the key strategic and environmental question would be whether those revenues are reinvested in new oil and gas production, or whether they would provide a spur for more diversified spending on cleaner fuels and technologies.

A shortfall in oil and gas investment could give impetus to energy transitions, but could also open the door to coal

Possible additional CO_2 emissions from gas-to-coal switching in the power sector at higher natural gas prices



Notes: Coal price assumptions: China: USD 85/tonne; Europe: USD 85/t; India: USD 75/t; United States: USD 50/t; no CO_2 prices applied.

A variety of additional constraints could emerge to affect oil and gas investment and supply in the coming years

The possibility of underinvestment and price spikes could be heightened by new constraints on oil and gas supply, arising from geopolitics or from changing attitudes towards upstream oil and gas developments.

In recent months, a well-supplied oil market has been able to take deep geopolitical tensions and uncertainties in its stride, including a sharp reduction in exports from Iran, the decline in output from Venezuela and the attacks on oil facilities in Saudi Arabia.

For the moment, there appears to be ample capacity within the oil market to absorb such shocks, but this could steadily be eroded if there is a persistent mismatch between demand and supply trends (as described on the previous slide). Under these circumstances, further geopolitical tensions could be expected to provoke a much more significant market reaction.

The traditional focus when looking for constraints on upstream investment is on certain NOCs and INOCs, in part because of the membership of some of their host governments in OPEC. However, there are also rising pressures on the Majors and other independent oil and gas companies to limit their investment in new and existing assets.

This pressure is reflected in calls for policy makers to restrict new oil and gas developments, for example by raising fiscal terms or by introducing moratoria or bans. To date, countries including Belize, Costa Rica, Denmark, France, Ireland, and New Zealand have introduced partial or total restrictions on new oil and gas developments in specific areas (e.g. onshore developments) or for certain types of resources or production techniques (e.g. those involving hydraulic fracturing).

These countries account for only a fraction of oil and gas production globally today, and these pressures are offset by efforts in other countries to move in the opposite direction, i.e. to attract more upstream investment (see Section I). Nonetheless, these shifts could signal a wider change in attitudes towards upstream oil and gas development. At the very least, this would change the location of new investment and, at most, this could have significant impacts on markets.

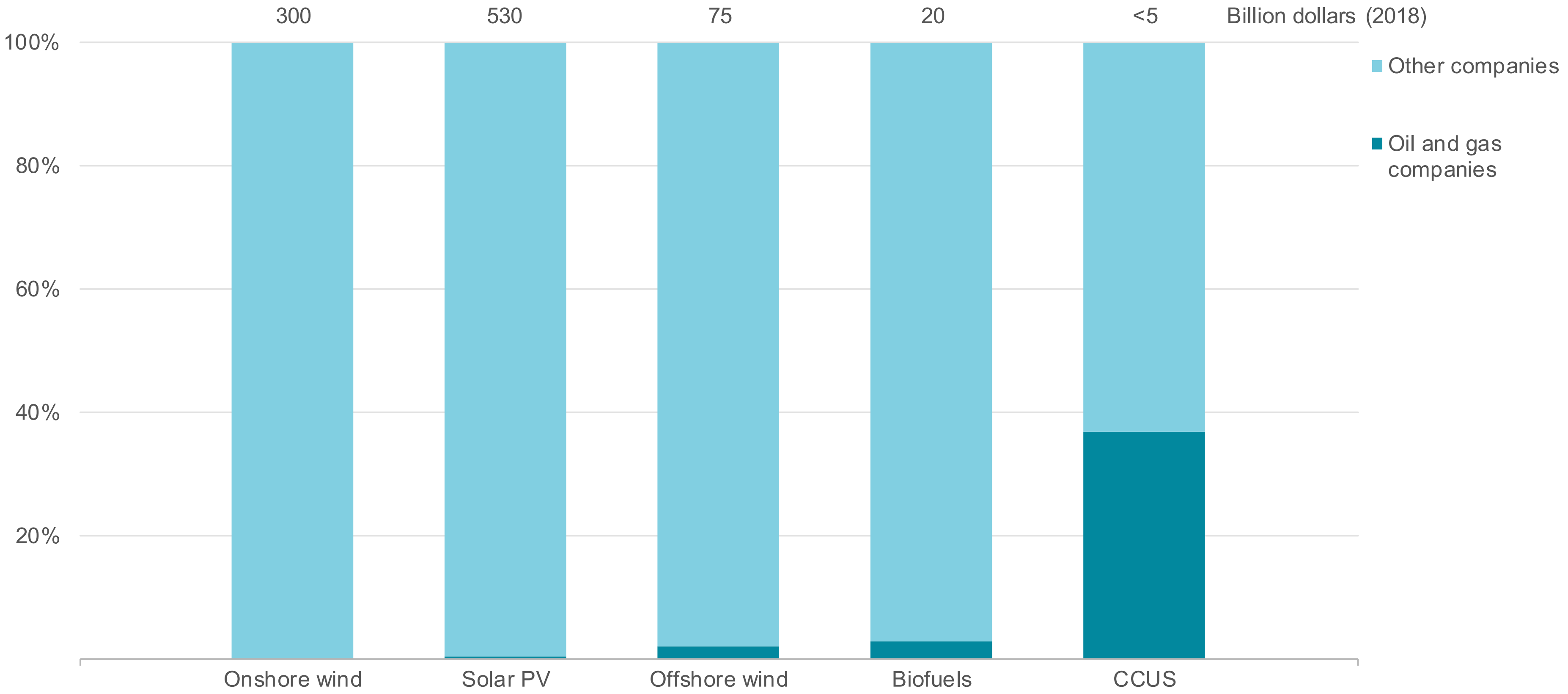
As noted above, any period of higher prices for oil and/or natural gas could accelerate the policy momentum and economic attractiveness of cleaner alternatives to hydrocarbons.

However, if natural gas prices were to rise, this could also provide a market signal to bring coal plants back into the mix. Some power markets are particularly sensitive to a change in gas prices. In the United States, a near-term rise in the Henry Hub price to USD 4.5/MBtu could see more than 300 Mt of CO_2 emissions from coal returning to replace gas (raising power sector emissions by nearly one-fifth). This outcome would also depend on the stringency of federal and state-level emissions standards.

In developing Asian markets, natural gas is increasingly imported in the form of LNG and is thus a much more expensive option than domestic coal. The example of record-high LNG prices during the period 2010-14 shows that they did contribute to improving efficiency and the competitiveness of renewables; however, they also resulted in an upswing in coal use. Only in Europe would a rebound in coal use appear unlikely, as a commitment to phase out coal is locked in by political commitments in many countries.

iii) If the oil and gas industry doesn’t invest in cleaner technologies, this could change the way that transitions evolve

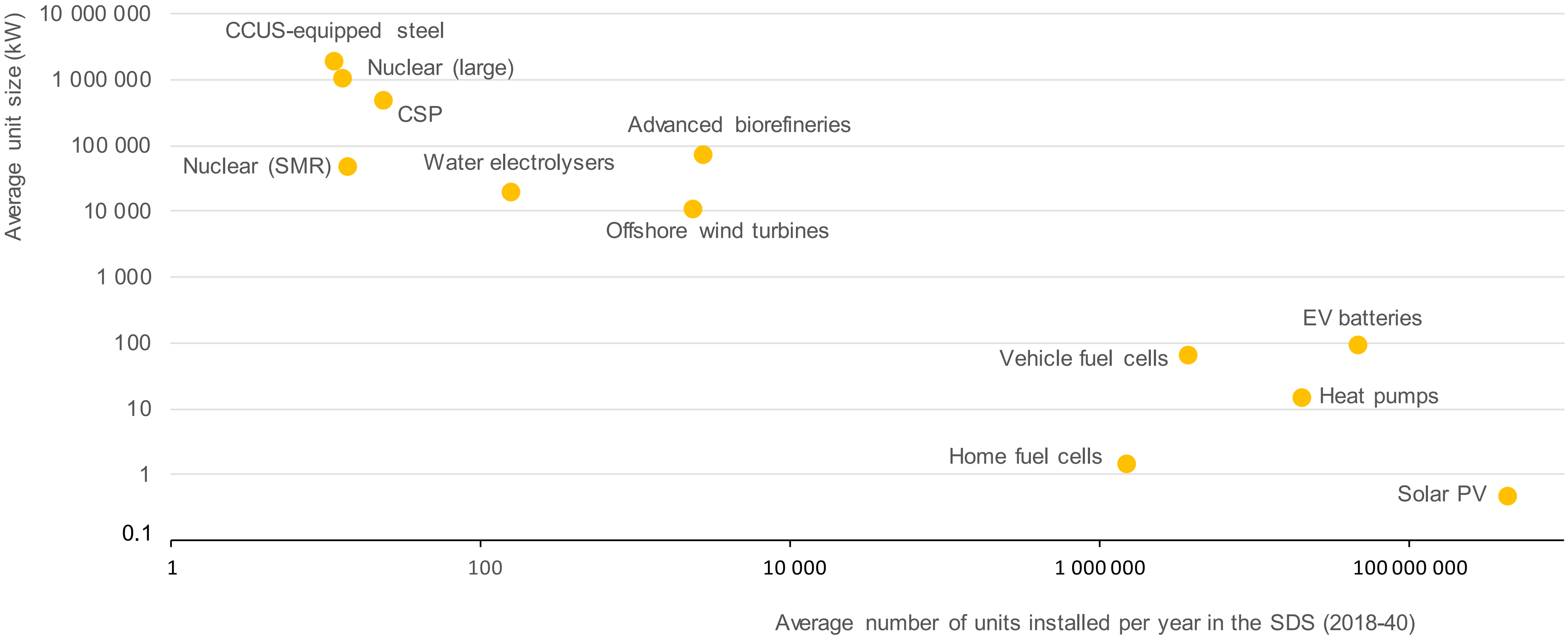
Capital investment by the Majors and selected other oil and gas companies in selected energy technologies, 2015-18



Note: Capital investment is measured as the ongoing capital spending in new capacity from when projects start construction and are based on the owner's share of the project. Companies include the Majors and selected others (ADNOC, CNPC, CNOOC, Equinor, Gazprom, Kuwait Petroleum Corporation, Lukoil, Petrobras, Repsol, Rosneft, Saudi Aramco, Sinopec, Sonatrach). CCUS investment is in large-scale facilities; it includes developments by independent oil and gas companies in Canada and China and capital spend undertaken with government funds.

A range of large unit-size technologies are required for broad energy transitions

Low-carbon technologies by unit size and average annual installations in the SDS



Notes: CSP = concentrating solar power; SMR = small modular reactor. Capacities refer to rated maximum energy output. For technologies that do not have output rated in energy terms, energy throughput for the relevant technology component is used.

Investment in some of these capital-intensive technologies could fall short if the oil and gas industry is not involved

The technologies that are needed for the deep decarbonisation of the SDS have very diverse characteristics. They range from the physical sizes of individual units and the types of owners or operators to the types of materials, engineering and financing involved.

A key vector for energy transitions thus far has been via technologies that have relatively small unit sizes and are capable of being mass-produced, such as solar panels, EV batteries and heat pumps. Mass diffusion and deployment of these technologies is essential to the design of the SDS.

However, cost-effective transitions also involve a range of larger unit-size technologies that require associated infrastructure and generally involve a higher degree of investment risk. CCUS, hydrogen and advanced bio-refineries are in this category because of their costs and complexity. Offshore wind projects also tend towards inclusion in this group (although deployment is already bringing down costs and investment risks) because of their size and the specialised expertise that is required to implement them.

These types of technologies require more capital to be put at risk in an early stage of the innovation chain, and they often face regulatory uncertainties. If these technologies are to thrive, governments around the world will have to take on a significant proportion of the risks of early commercial projects, sometimes for well over a decade, and provide strong signals that they will be supported in the future.

From the industry side, some of these types of technologies are also a good match for the oil and gas industry from an R&D, technical and project management perspective, and also because they require players with strong balance sheets to get projects moving.

For the moment, even though there is evidence of diversified spending (as seen in Section I), the oil and gas companies do not account for a significant share of overall investment in any major clean energy investment category, with the exception of CCUS, where overall spending is still low.

The positioning of the oil and gas industry matters much less for the outlook for solar PV and wind, but it could make or break the outlook for some of these more capital-intensive technologies. And if low-carbon fuels are not available at scale, then – however difficult it is in practice – it will be natural for policy makers and other stakeholders to seek to solve every transition problem with low-carbon electricity. The latter is an area where, with the exception of offshore wind and geothermal, there is little overlap with today’s industry strengths.

Stranded oil and gas assets

Slides 95 - 102

Where are the risks of stranded assets in the oil and gas sector?

A key question for the oil and gas industry is whether the lower oil and gas prices and lower volumes of oil and gas produced in the SDS, compared with the STEPS, are likely to lead to widespread losses.

There are multiple strands to this debate. While these are interrelated, they are too often conflated. This occurs partly as a result of loose terminology, and as a result there is a high degree of confusion surrounding discussions of the potential value of losses resulting from climate change policy. It is therefore useful to distinguish between different impacts and losses that could be incurred by the oil and gas industry. This report distinguishes among:

- **stranded volumes**: existing fossil fuel reserves that will be left unexploited as a result of climate policy
- **stranded capital**: capital investment in fossil fuel infrastructure which is not recovered over the operating lifetime of the asset because of reduced demand or reduced prices resulting from climate policy
- **stranded value**: a reduction in the future revenue generated by an asset or asset owner assessed at a given point in time because of reduced demand or reduced prices resulting from climate policy.

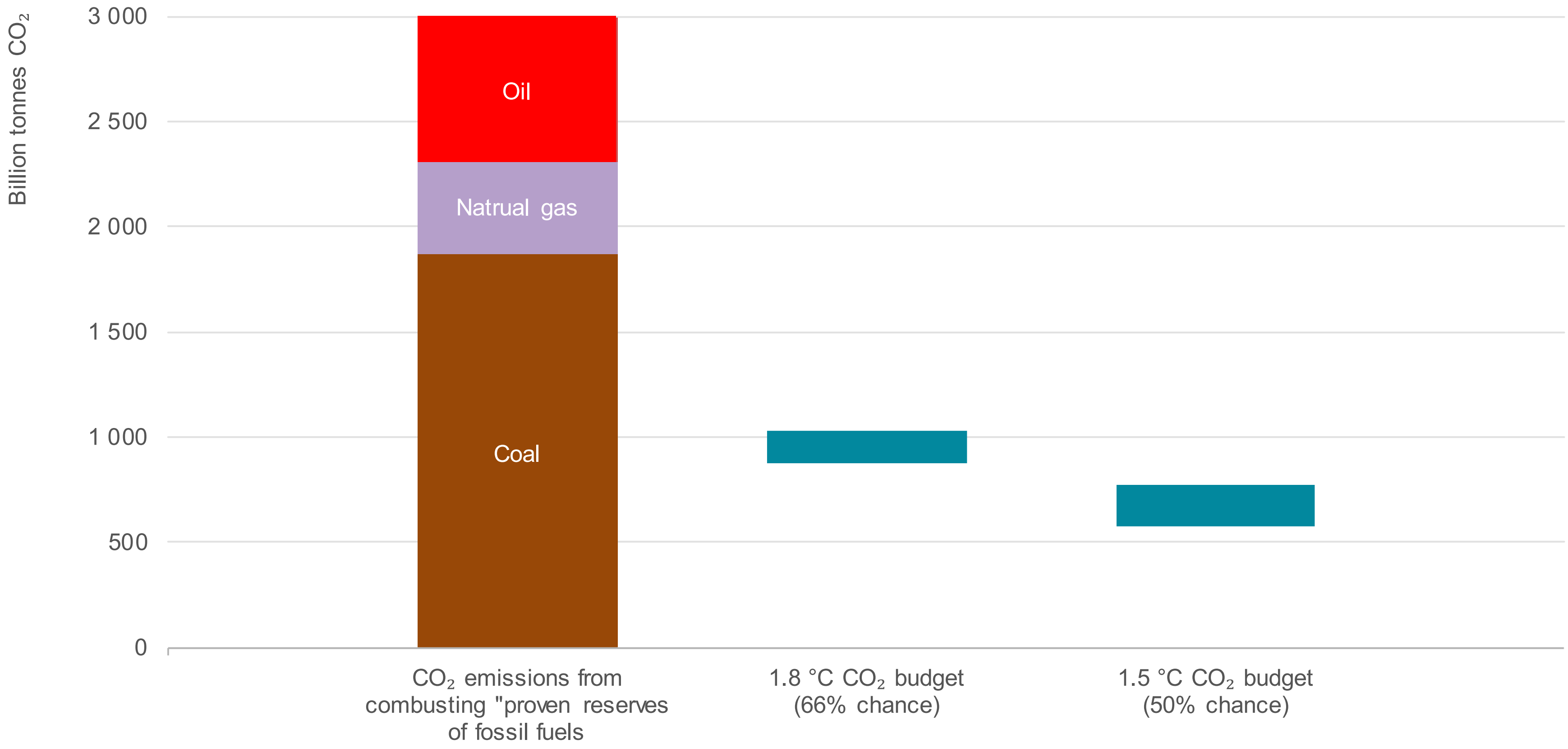
These different possible losses would pose different problems for the oil and gas industry and other market participants. For example, for stranded capital, if an asset is taken out of service before it has been able to recover the original investment, the parent company's total capital would be reduced, potentially lowering its ability to make future investments.

For stranded value, it is necessary to compare values between a scenario that contains strong climate policy and for one that does not. Estimates can be very sensitive to the specific "counterfactual" scenario chosen – the analysis below compares differences between the SDS and the STEPS.

Overall, we find that the risks of stranded assets in the oil and gas industry during energy transitions are not in the places or magnitudes that are often assumed. In particular, the risk of stranded volumes is significantly higher for NOCs than for the Majors or Independents. With regard to stranded value, the estimate of the present value of the long-term difference in net income (for privately traded companies) between the two scenarios is less than the drop in their value already seen in 2014-15. The risk of stranded value could, however, be larger in mid- and downstream assets as these tend to have long operating lifetimes.

i) Stranded volumes: Unabated combustion of all today's fossil fuel reserves would result in three times more CO_2 emissions than the remaining CO_2 budget

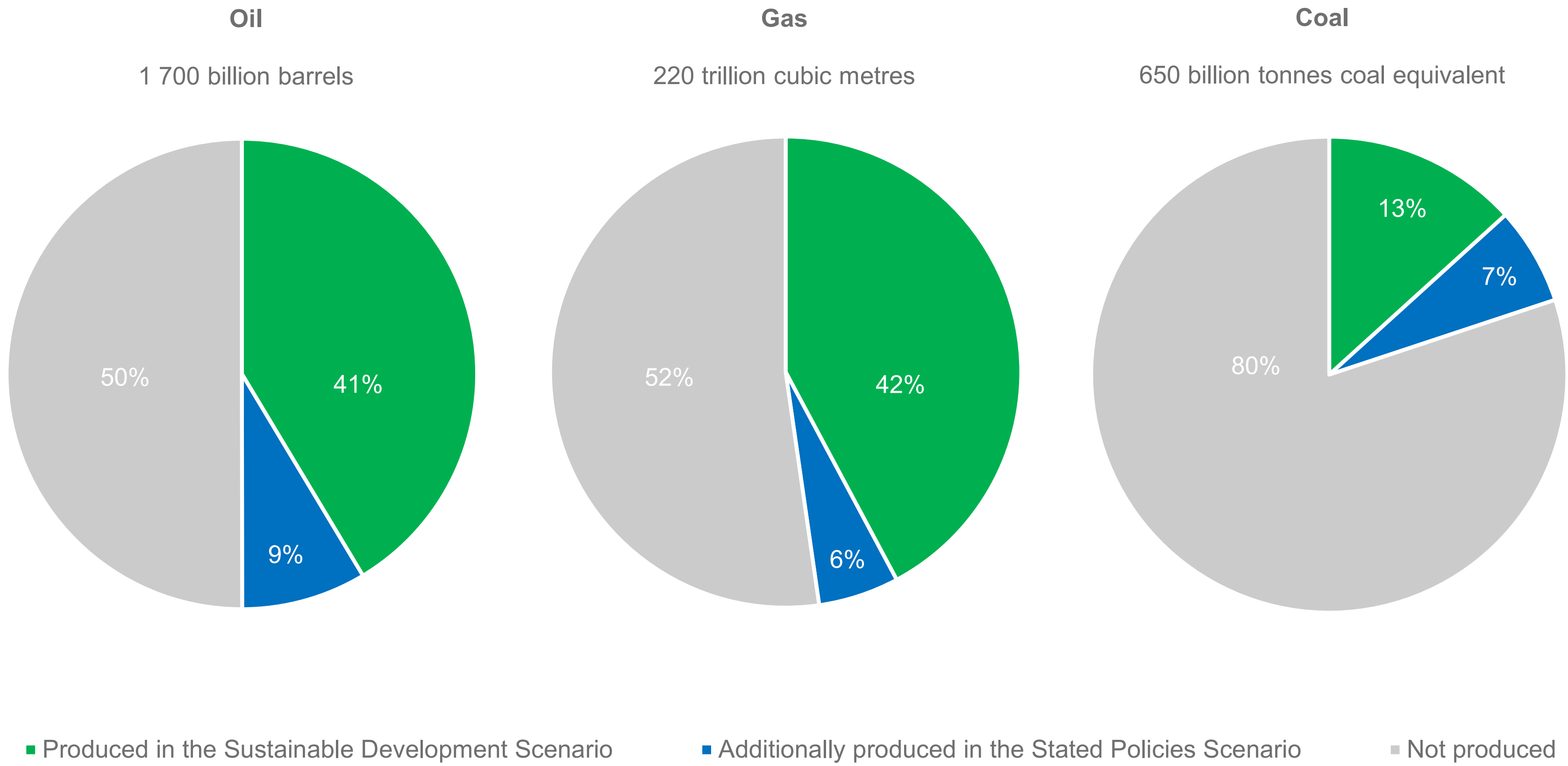
CO_2 emissions from combusting all "proven reserves" of coal, oil and natural gas compared with remaining CO_2 budgets



Notes: Reserves are the publicly reported level of "proven reserves", with 1 700 billion barrels of oil, 220 tcm of natural gas, and 650 billion tonnes of coal equivalent. CO_2 budgets are taken from the Intergovernmental Panel on Climate Change (IPCC) *Special Report on Global Warming of 1.5 °C* and are from the start of 2018. The different CO_2 budgets shown are associated with uncertainty in the temperature increase today relative to pre-industrial times. The SDS has a remaining CO_2 budget of 880 Gt CO_2.

Large volumes of reserves therefore need to be "kept in the ground", but many of these would not be produced before 2040 even in a higher-emissions pathway

Proportion of "proven reserves" produced in the STEPS and SDS, 2018-40



Note: To align with most discussion on stranded volumes, reserves stated are the publicly reported level of "proven reserves".

A more nuanced assessment is required to understand the implications of climate policy on fossil fuel reserves

The amount of CO_2 that would be released from combusting all publicly reported "proven reserves" of oil, gas and coal is at least three times the cumulative amount of CO_2 that can emitted while restricting the temperature rise in line with the Paris Agreement (this is just "proven reserves"; overall resources are considerably higher). This simple comparison has given rise to the idea that at least two-thirds of existing oil, gas and coal reserves will be "stranded" under deep decarbonisation scenarios.

It is undoubtedly correct that a very large proportion of existing fossil fuel reserves cannot be combusted while limiting the temperature rise. However, this does not necessarily mean that large volumes of reserves will be "stranded". Nor does it mean that exactly the same proportion of oil reserves, gas reserves and coal reserves would need to be "kept in the ground". There are a number of reasons for this:

- There are major differences between the fossil fuels. Oil has a high volumetric energy density while gas has the lowest combustion CO_2 emissions per unit of energy delivered. It is unreasonable to assume that equal proportions of oil, gas and coal reserves will be unused.
- Existing reserves are not the same as volumes that will be produced. For example, for natural gas, the equivalent of 42% of "proven reserves" are produced in the SDS between 2018 and 2040 and 48% of reserves are produced in the STEPS. In other words, even in the STEPS, more than half of proven natural gas reserves are unused before 2040.
- There is a wide spread in the quality and production costs of oil and gas in different countries. The geography of demand also affects which reserves are best placed to be produced. Volumes of reserves that are unused will also vary widely by country.
- Not all oil and gas is combusted when extracted or will result in CO_2 emissions to the atmosphere. Today around 15% of oil and 5% of natural gas are used as petrochemical feedstocks and in other non-combustion processes. Fossil fuels can also be used with CCUS. There would still be scope 1 and 2 emissions from their extraction, processing and transport, but scope 3 emissions, which represent the largest share of emissions, would be much lower in these cases.

Despite these reservations, there is still a large difference in fossil fuel use between the scenarios. There are 150 billion barrels fewer oil resources and 13 tcm fewer natural gas resources produced in the SDS than in the STEPS over the period to 2040. This differential would widen further after 2040 since the SDS is on track to achieve net-zero emissions by 2070.

The Majors and Independents generally aim to produce reserves on their books within the next 20-30 years, and so the risk to them of stranded volumes is likely to be relatively small. But for many of the large fossil fuel resource holders, and their NOCs and INOCs, there is a clear risk that some of their larger underlying resource holdings could become stranded in energy transitions. This explains the focus in some of these countries on reducing reliance on hydrocarbon income while also looking for ways to monetise these volumes without releasing emissions to the atmosphere (see Section IV).

Stranded capital: Around USD 250 billion has already been invested in oil and gas resources that would be at risk

Between 2019 and 2030, upstream investment in the SDS is around USD 1 600 billion less than in the STEPS. This USD 1 600 billion is sometimes reported as the level of "stranded capital" at risk in the SDS. As with stranded volumes, this is an overly simplistic interpretation of results.

This reading of stranded capital assumes that the oil and gas industry consistently invests for the next ten years on the basis of higher demand (as per the STEPS) while in fact being in a world of lower demand (as in the SDS). In practice, overinvestment on this scale would lead to a glut of oil and gas on the market and therefore a major drop in prices. In other words, this interpretation would require companies to be entirely blind to the evolving level of demand and prices in the world for a prolonged period. Such a situation is difficult to envisage.

A more realistic assessment of stranded capital is based on the resource development needs in the STEPS and SDS. In the STEPS, around 640 billion barrels of new oil resources are developed between 2018 and 2040, as are 115 tcm of natural gas resources. In the SDS, the corresponding figures are 390 billion barrels of oil and 85 tcm natural gas. Consequently, there is a 250 billion barrel and 30 tcm difference in new resource developments between the two scenarios. Investment in these resources is at most risk of becoming "stranded capital". There are two aspects.

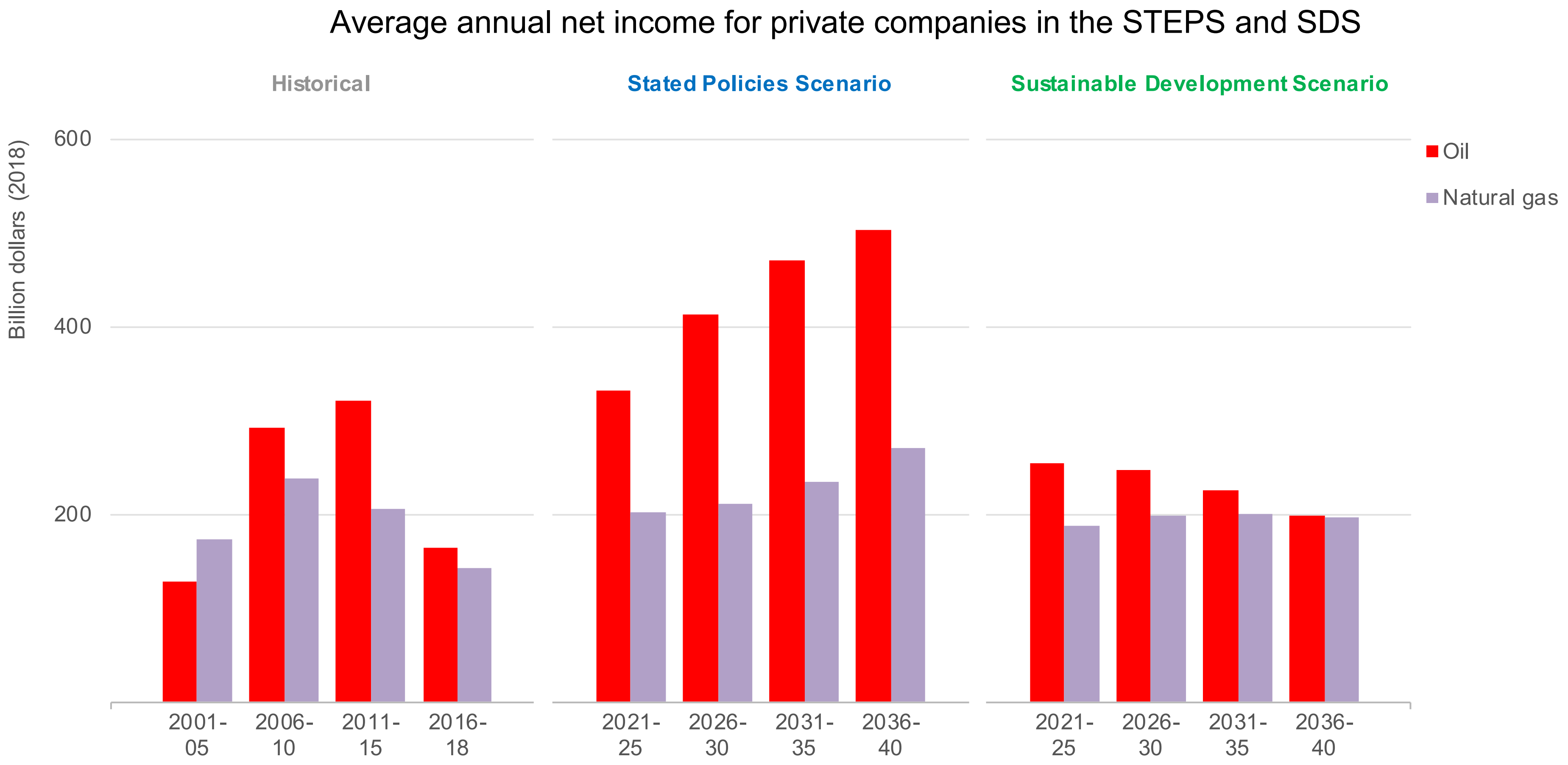
First, some of the resources that are not developed in the SDS have already had money spent on their discovery and appraisal. The capital already spent proving up these undeveloped resources – the exploration cost – is not recouped in the SDS before 2040. It is not simple to assign a value to this, particularly since the capital investment was often incurred many years ago, but we estimate it to be around USD 250 billion. This could be considered "stranded capital"; it is less than 3% of upstream capital investment made over the past 20 years.

Second, there is the possibility that companies decide to go ahead with new investment into new projects but end up with production potential that is not needed. These kinds of mistaken investment decisions cannot of course be ruled out, but they don't occur in the SDS. The path towards decarbonisation is assumed to be clear and visible to investors and so they do not develop new resources in the expectation of a much higher trajectory for demand and prices.

In other words, provided the transition is one in which a consistent and credible course towards decarbonisation is pursued and market participants fully integrate this into their resource development plans, there is no reason why other upstream capital, beyond the USD 250 billion of exploration capital, should become stranded.

However, if there is a delay in implementing emissions reductions, or if market participants do not fully take market signals on board, the level of stranded capital can escalate rapidly. As discussed above, in a disjointed transition occurring in 2025, stranded capital rises to around USD 950 billion; if the transition is delayed to 2030, it is USD 1 200 billion.

Stranded value: The net income of private oil and gas companies in the SDS is USD 400 billion lower in 2040 than in the STEPS



Notes: Net income is revenue minus finding and development costs, operating costs, and government taxes. Estimates are for all private oil and gas companies (Majors and Independents), and are derived from country-level data using a field-by-field database that classifies asset ownership by type of company along with assumptions about the ownership of future discoveries. Assumes no changes in fiscal terms.

The estimate for potential long-term stranded value is large, but less than the drop in the value of listed oil and gas companies already seen in 2014-15

The lower demand for oil and gas in the SDS, compared with the STEPS, would be felt by upstream companies as a reduction in revenue from both lower production and lower prices. This reduction in revenue because of more stringent climate policies could lead to potential “stranded value”. By 2040, this report estimates that the annual net income from oil and gas sales (i.e. revenue minus all costs and taxes) of private companies in the SDS is around USD 400 billion lower than in the STEPS.

The present value of the cumulative net income of private oil and gas companies in the STEPS to 2040 is just over USD 5.1 trillion (at a 10% discount rate); in the SDS, it is USD 3.8 trillion. There would be large variations between different types of companies, but the 25% difference between the two scenarios implies a risk of USD 1.4 trillion net present stranded value.

A 25% reduction in the present value of net income is large, but to put this in context, the drop in the oil price in 2014 and 2015 resulted in a 30% drop in the value of listed oil and gas companies.

Three factors keep this difference in check:

- Underlying declines mean that most investment goes to offset decline, so the differences in demand between the two scenarios has a smaller effect on the overall picture.
- There are only small differences in regional gas prices between the two scenarios. There is a larger difference in the oil price, but discounting means that even large variations in net income late in the projection period have only a relatively small impact on the calculation of net present value.
- Costs in the oil and gas industry are closely correlated to oil prices. For example, the oil price crash in 2014 led to a 30% reduction in upstream costs within two years. The lower price trajectory of the SDS relative to the STEPS means that companies incur lower costs and so spend less.

The risks of stranded value are much greater in some of the price sensitivity cases introduced in Section II. However, as argued above, it is unlikely in our view that there is a stable equilibrium between supply and demand for oil prices at the lower bounds considered in these cases.

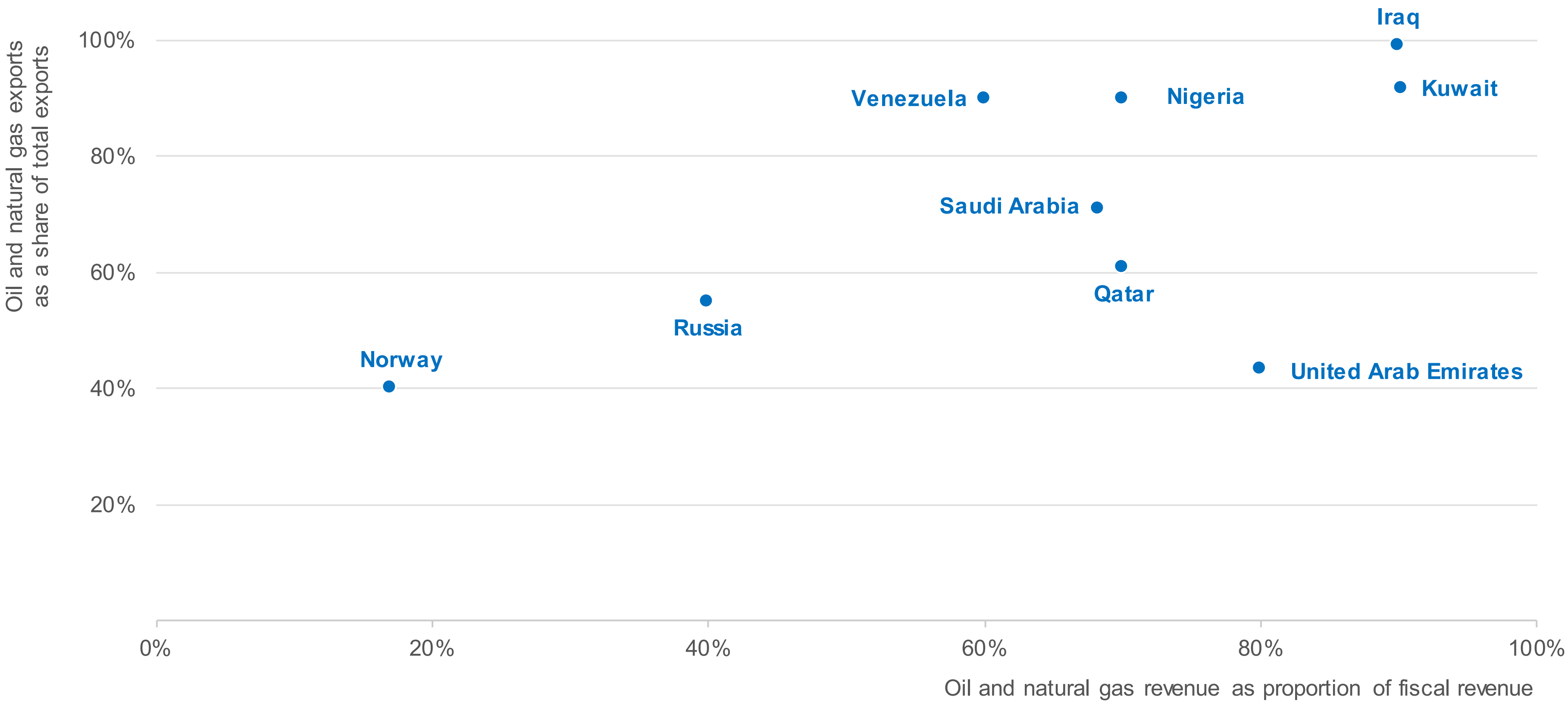
In a 1.5°C pathway with no or limited temperature overshoot, the impacts would likely be severe. We have not carried out detailed modelling of the price dynamics in this scenario, but the drop in demand would be sufficiently steep and dramatic that it would involve significant risk of asset stranding, not just in the oil and gas sector but also across wide sectors of the economy such as buildings, transport and industry.

Financial performance – national oil companies

Slides 103 - 110

Recent years have highlighted some structural vulnerabilities not only in some NOCs, but also in their host economies

Oil and gas as a share of total exports and as a share of total fiscal revenue in selected countries, 2017



Note: For Russia, the share of fiscal revenue refers to the federal budget (for consistency with other countries shown); revenues from oil and natural gas account for around 20% of Russia's consolidated budget, which includes revenues and expenditures in the Russian regions.

The pivotal role of NOCs and INOCs in the oil and gas landscape is sometimes overlooked

High dependence on oil export revenue has long been recognised as a strategic vulnerability for resource-rich economies. However, changes in the energy system, including the shale revolution in the United States as well as the gathering pace of energy transitions, are raising the stakes both for NOCs and INOCs, and their host countries.

The role and governance of each NOC and INOC vary widely, but they are nonetheless critically important stakeholders in their host countries and in the energy sector as a whole.

The typical mandate given to an NOC gives it a privileged position in its domestic upstream sector. On occasion, it is also given a role in seeking out profitable investment opportunities abroad (i.e. to act as an INOC). Some countries with modest reserves require their NOC to focus on the downstream sector, taking on the role of refiner or purchaser.

Many states rely heavily on the oil income from their NOCs or INOCs (which is usually far larger than the revenue from natural gas). This has financed a great deal of public spending, infrastructure and employment, but it is also associated with significant risks – especially if exports provide the main source of national revenue.

Domestic sources of revenue imply productive sectors of the national economy. External revenue, if large enough, however, can support an economy even without a strong productive domestic sector. Under these circumstances, there is a risk that the functioning of such states focuses more on the distribution and allocation of hydrocarbon income than on the creation of the conditions for enterprise, leading to a narrow and undiversified economic structure.

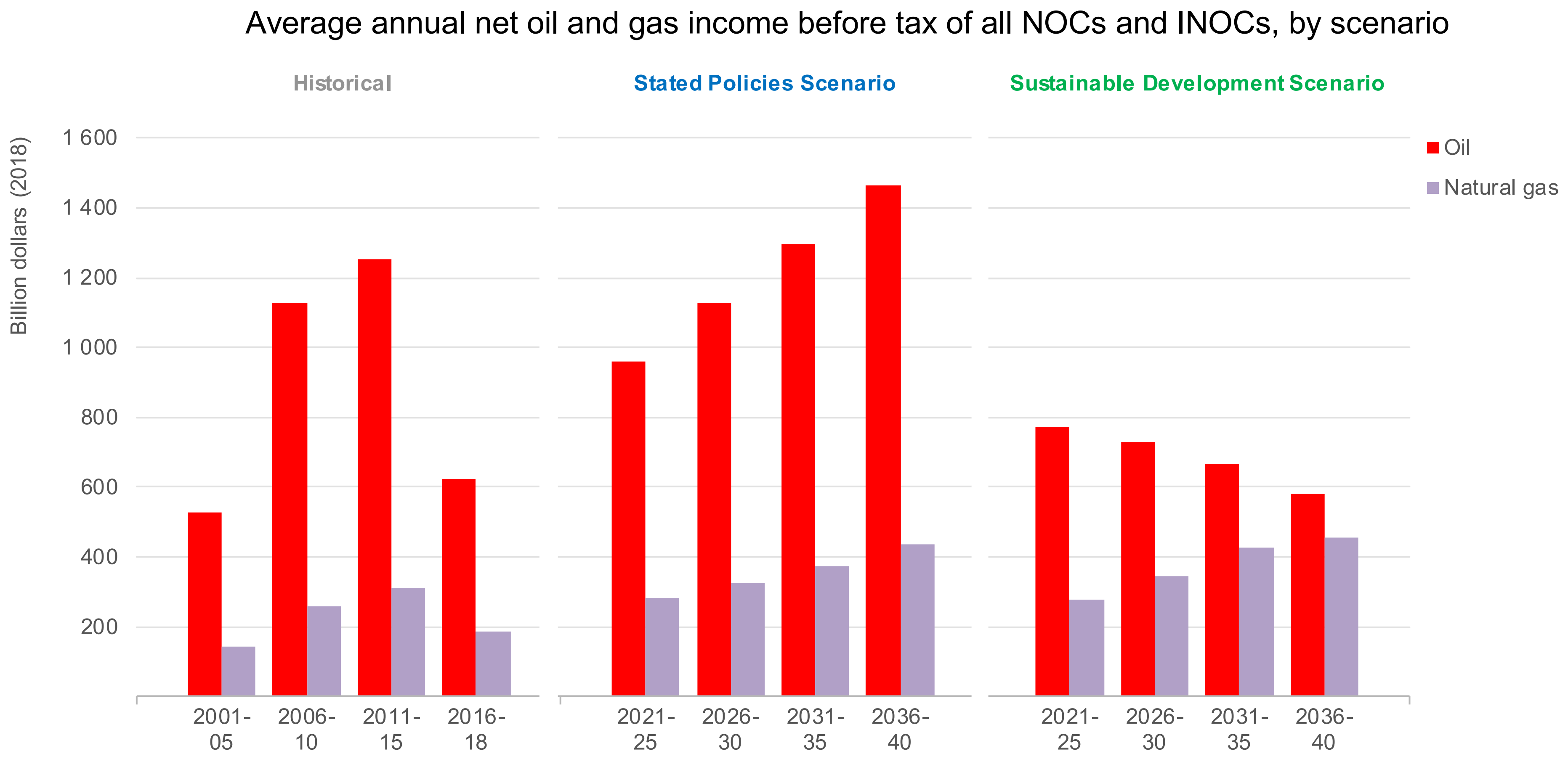
The roller coaster in oil and gas prices over the past decade illustrates the challenges. From a high point of USD 1 900 billion in 2012, we estimate that the net income generated by the world's NOCs and INOCs (before tax and other transfers to governments) fell by some 70% to USD 570 billion in 2016, then rebounded to USD 1 100 billion in 2018.

Major swings in hydrocarbon revenue can be deeply destabilising if finances and economies are not resilient, and NOCs play a huge role as conduits for these shocks to the system. Indeed, data collected by the Natural Resource Governance Institute show that after the oil price crash in 2014, the amounts transferred to governments by NOCs dropped even more sharply than overall revenues (NRGI, 2019).

The risks of high dependence on volatile oil and gas revenue have prompted a number of countries to renew their commitment to reform and diversify their economies. A well-performing NOC can provide an important element of stability for economies during this process.

By contrast, today's Venezuela provides a stark example of the potential risks. Despite having some of the largest hydrocarbon reserves in the world, the Venezuelan NOC, PDVSA, is caught in a vicious cycle of dwindling revenue, mounting debt, and falling investment and output. The company is desperately short of funds, not least because it has to supply almost one-quarter of its production to the domestic market at such a subsidised price that it barely recovers any revenue. Mismanagement of the oil and gas sector has accelerated the downward spiral of the economy as a whole.

Accelerated energy transitions would bring significant additional strains



Note: Net income before tax = revenue minus finding and development costs and operating costs.

Fiscal and demographic pressures are high and rising in many major traditional producers served by NOCs

Whichever way the energy system evolves, the arguments for economic diversification in major oil- and gas-producing countries are strong.

The traditional development model in many resource-rich countries has relied on recycling hydrocarbon revenues into public services and jobs; the record of private-sector job creation has been relatively weak. In Iraq, for example, the public sector has grown from 1.2 million employees in 2003 to around 3 million today.

Accelerated energy transitions would put further pressure on hydrocarbon volumes and prices, and consequently on hydrocarbon revenues. This would be a matter of particular concern for those producers, such as Iraq and Nigeria, which have large, growing and youthful populations and a pressing need to create new employment opportunities.

The transformation process promises to be complex, and even though the purpose is to reduce reliance on hydrocarbons, successful reforms will rely heavily on NOCs to provide revenue and, in some areas, expertise and innovation.

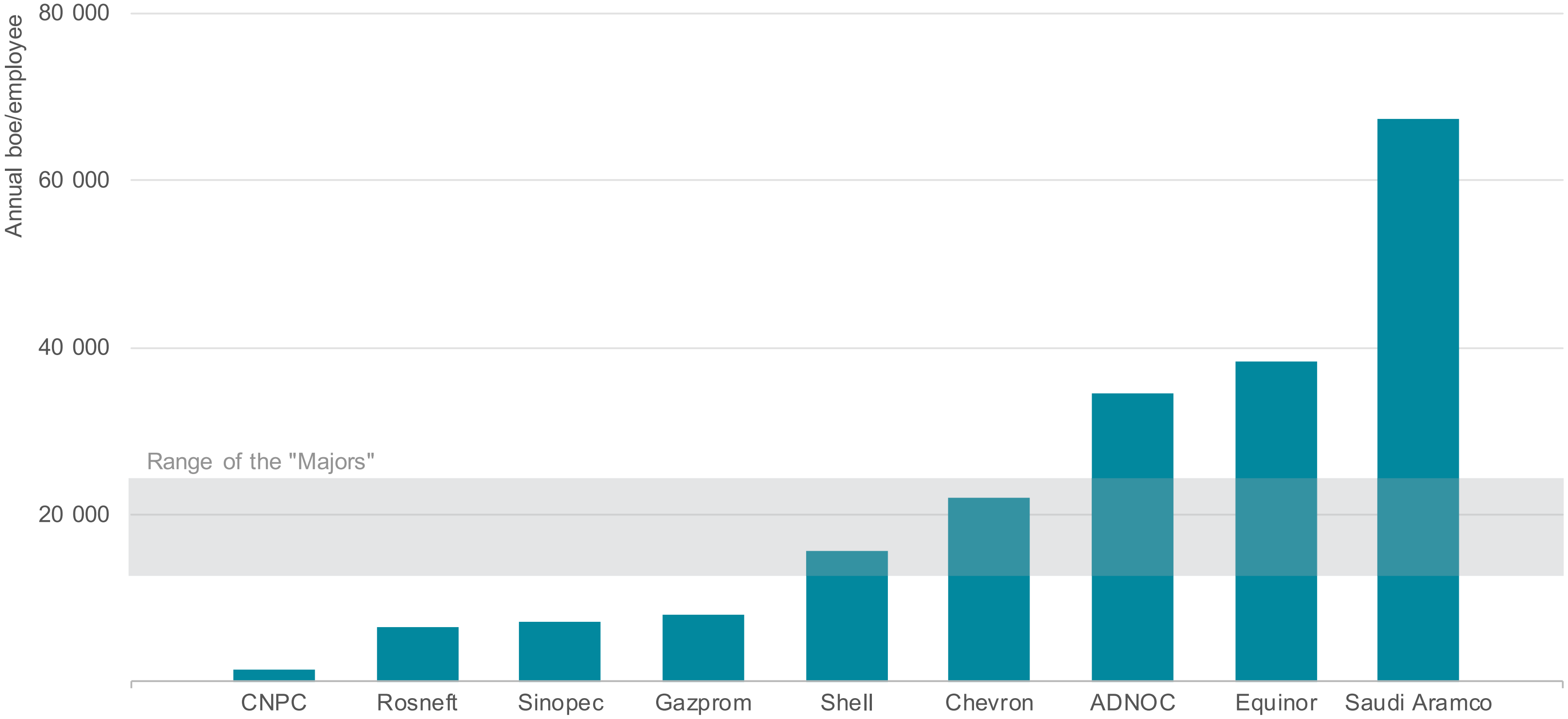
We have estimated total NOC net income before tax from oil and gas in the two scenarios. By the 2030s, the amount generated by NOCs in an average year is just over USD 1 000 billion per year in the SDS, compared with USD 1 800 billion in the STEPS. Oil accounts for the largest share of the total, but by the 2030s in the SDS the contributions of oil and gas are approaching parity (although the unequal distribution of oil and natural gas production across individual NOCs means this would differ between countries).

This estimate reflects the value of the produced oil and natural gas (accounting for subsidies that reduce the realised price of domestic sales), minus upstream capital and operating costs. It is not necessarily an indication of the revenue that is transferred to host governments, as there are typically other company operations, including downstream operations and the delivery of public services in some cases, which would affect these transfers. (Nor is it indicative of all the oil and gas revenue accruing to these host governments, as the total would include taxes and royalties paid by other companies operating in the country concerned).

In practice there are some NOCs whose financial performance already represents a significant risk for their host country economies. Many NOCs are heavily indebted; the Natural Resource Governance Institute has identified 18 companies with long-term liabilities equal to more than 5% of their country's GDP (NRGI, 2019). In extreme cases such as PDVSA, NOC debt has risen to more than 20% of GDP.

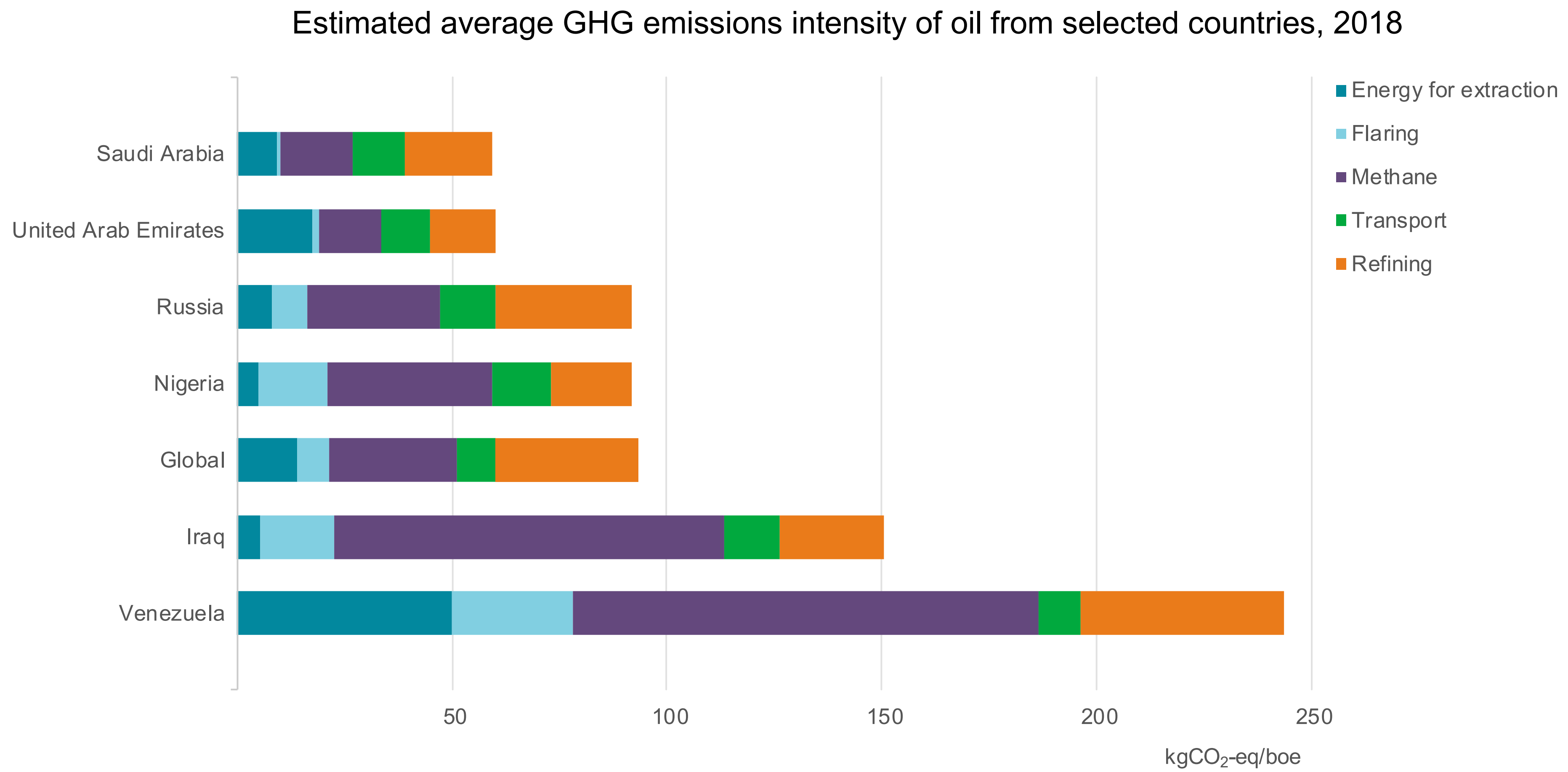
NOCs cover a broad spectrum of companies

Barrels of oil/gas equivalent output per employee for a range of NOCs



Notes: ADNOC = Abu Dhabi National Oil Company. Includes direct employees of companies only. This is not necessarily a proxy for efficiency or productivity, especially given different resource types and quality being developed and the different profiles of companies in upstream and downstream businesses; however, it does show that the range of NOCs according to this metric is much broader than for the Majors.

Performance on environmental indicators also varies widely



Note: For comparison, the CO_2 emissions from oil combustion (not included here) are around 405 kg CO_2-eq/boe. Refining refers to average emissions from refineries within each country (rather than emissions from refining total oil production from each country).

Source: IEA (2018), *World Energy Outlook 2019*, www.iea.org/weo2019.

There are some high-performing NOCs and INOCs, but many are poorly positioned to weather the storm that energy transitions could bring

Energy transitions are posing critical questions for NOCs, but it is not clear that many have prepared responses. According to a survey from IHS Markit (2019), 89% of global integrated oil companies use and disclose scenario-based climate strategies, but only 6% of NOCs.

There are many high-performing companies among the NOCs (including INOCs) and also some examples of more diversified investment strategies, motivated by a desire to position the companies well for changes in the energy sector.

Among the INOCs, examples include moves by Equinor and CNOOC into offshore wind, and by Petronas and CNPC into solar; both Equinor and Petronas are also supporting venture capital initiatives that support early-stage new energy technologies.

Among the NOCs, consideration of the risks and opportunities presented by energy transitions is being led by Saudi Aramco, along with companies such as ADNOC and the Kuwait Petroleum Corporation. However, for the moment, none of the large NOCs have been charged by their host governments with leadership roles in renewables or other non-core areas.

Seen through the lens of energy transitions, the role of NOCs as custodians of national hydrocarbon resources takes on some new dimensions. The traditional priority to deliver strong financial returns requires a firm focus on cost discipline and efficient operations. Competitive pressures in oil and gas markets, already strong today, intensify in the SDS, and many NOCs are also moving from "protected" domestic upstream sectors into more competitive downstream areas such as refining and petrochemicals.

With this in mind, host governments would need in many cases to prioritise much more transparent operation of their NOC; the prospects in energy transitions for NOCs characterised by poor governance or rent-seeking look extremely difficult.

Access to low-cost fuels – often delivered by NOCs – is deeply embedded in the social contract in many resource-rich economies. This contract would need to adapt over time, as pricing reform and the phase-out of fossil fuel consumption subsidies form part of the broader reform agenda.

NOC strategies would also need to reckon with the importance of environmental stewardship, recognising that many hydrocarbon-rich economies are among the most vulnerable to the physical impacts of climate change, including water and heat stress as well as increased incidences of extreme weather.

With regard to investment in low-carbon technologies, the predominant model thus far is for hydrocarbon-rich countries to create a specific company separate from the NOC (e.g. Masdar in the United Arab Emirates), leaving the NOC to focus on oil and gas. But it cannot be excluded that NOCs may also take on roles in relation to some low-carbon technologies, not least because of the possible synergies with their oil and gas operations.

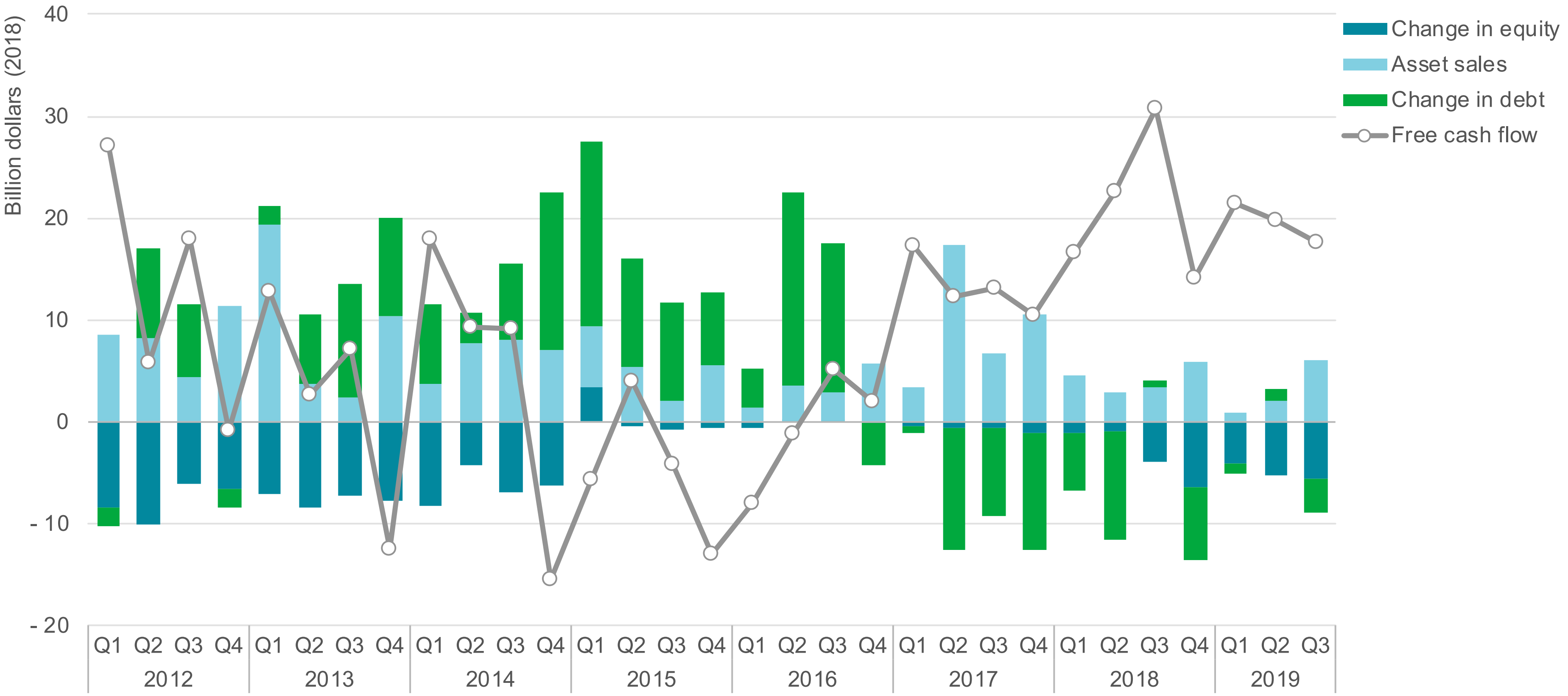
Already the most forward-leaning of the NOCs are accelerating research efforts targeting models of resource development that are compatible with deep decarbonisation. These cover a range of areas, including CCUS, hydrogen, and strategies to find and develop non-combustion uses for hydrocarbons. The focus on CCUS in industry may be a particularly productive avenue, given that the Middle East (and Russia) have cost-efficient carbon storage options, which would be an advantage given the need for heavy industry to move to low-carbon production processes.

Financial performance – publicly traded companies

Slides 111 - 119

Following strong improvement, the Majors' free cash flow levelled off the past year, as companies increased share buybacks and paid down debt

Sources of finance and free cash flow for the Majors

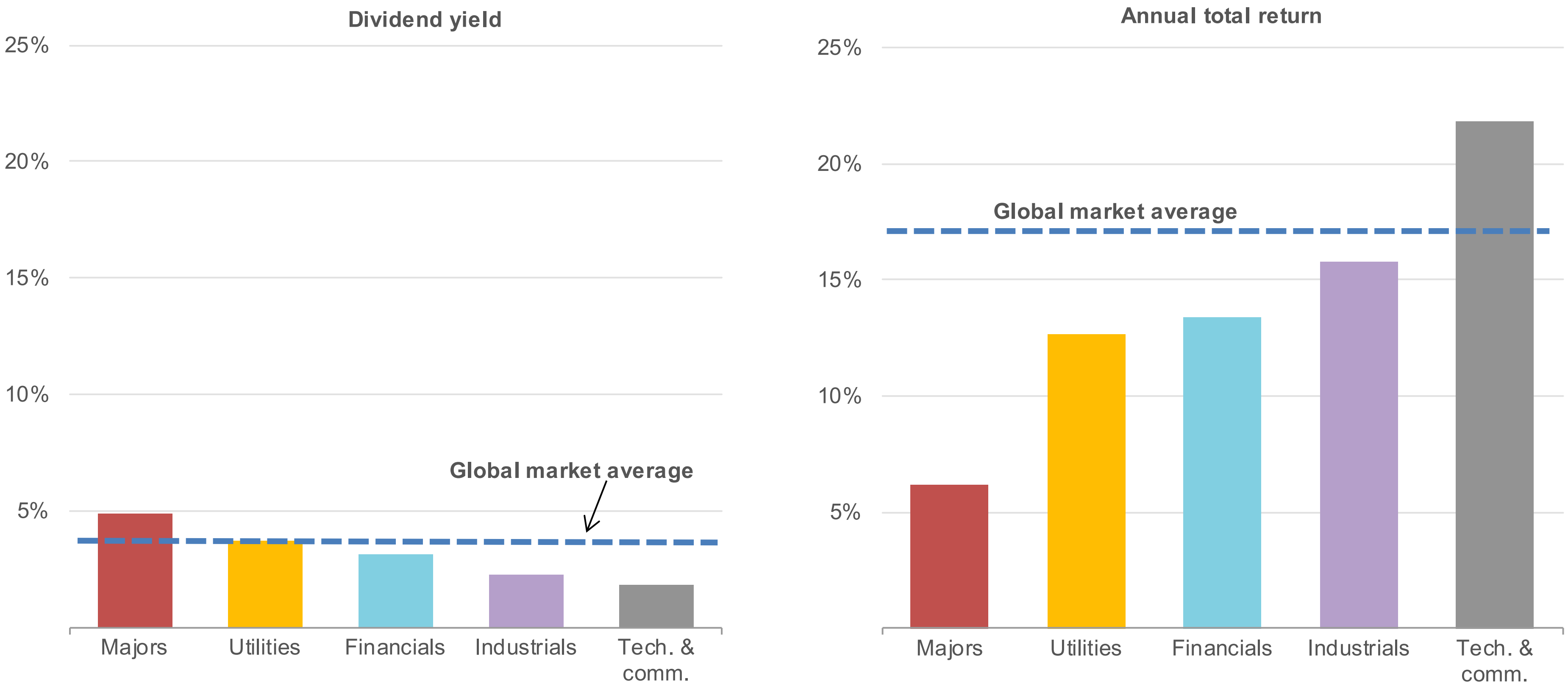


Note: Free cash flow = cash from operating activities less capital expenditure. It excludes changes in working capital.

Source: Calculations based on company filings and Bloomberg (2019), *Bloomberg Terminal*.

Dividend yields remain high, but total equity returns have underperformed

Equity performance of the Majors and global listed companies by selected sector (2015-19)



Notes: Tech. & comm. = technology and communications. The charts include all listed companies in the world with over USD 10 billion of market capitalisation as of 15 April. The dividend yield and annual total return by sector are the averages weighted with market capitalisation in each year. Annual total return = the sum of share price change and dividend during a given year divided by the share price at the beginning of the year.

Source: Calculations based on company filings and Bloomberg (2019), *Bloomberg Terminal*.

Finding the right balance between delivering oil and gas, maintaining capital discipline, returning cash to shareholders and investing for the future

The oil and gas business has traditionally generated a substantial economic surplus for resource owners and producers, characterised by economies of scale and barriers to entry that have tended to favour large companies with strong balance sheets. After covering expenses and salaries, income from oil and gas is primarily used to fund investments, provide financial returns and meet tax obligations. For investors and governments (in both producer and consumer economies), the industry has served as an important source of financial value.

However, publicly traded companies are facing growing pressure to optimise decision making across multiple priorities, including environmental and climate-related areas, which has implications for future business strategies and financial performance ahead.

Most upstream oil and gas investments are financed on balance sheets with equity from corporate retained earnings. Debt accounts for only around a quarter of the capital structure among top producers, and has been used sparingly in order to smooth investment and dividend payments during downturns, most recently in 2015-16. While project finance structures play a meaningful role in funding infrastructure, they are mainly relevant on the upstream side in large integrated projects such as LNG.

Over the past three years, the Majors have significantly improved their financial performance through a combination of cost reductions and operational efficiency, higher production, capital discipline and a higher oil price. Annual free cash flow reached almost USD 90 billion in 2018 and is on course to remain positive, albeit at stable levels, in 2019. This performance has enabled the Majors to pay down debt after a period of leveraging.

An important pillar of financial performance has been the maintenance of high dividend yields, at nearly double the market average. During the oil price downturn, Majors were willing to enact challenging internal measures and borrow heavily to avoid cutting dividends. Share buybacks are another channel to deliver value to investors. Outside of 2015-16, the industry has returned capital to equity markets and this practice has provided comfort to investors, even as calls for divestment have increased from some quarters.

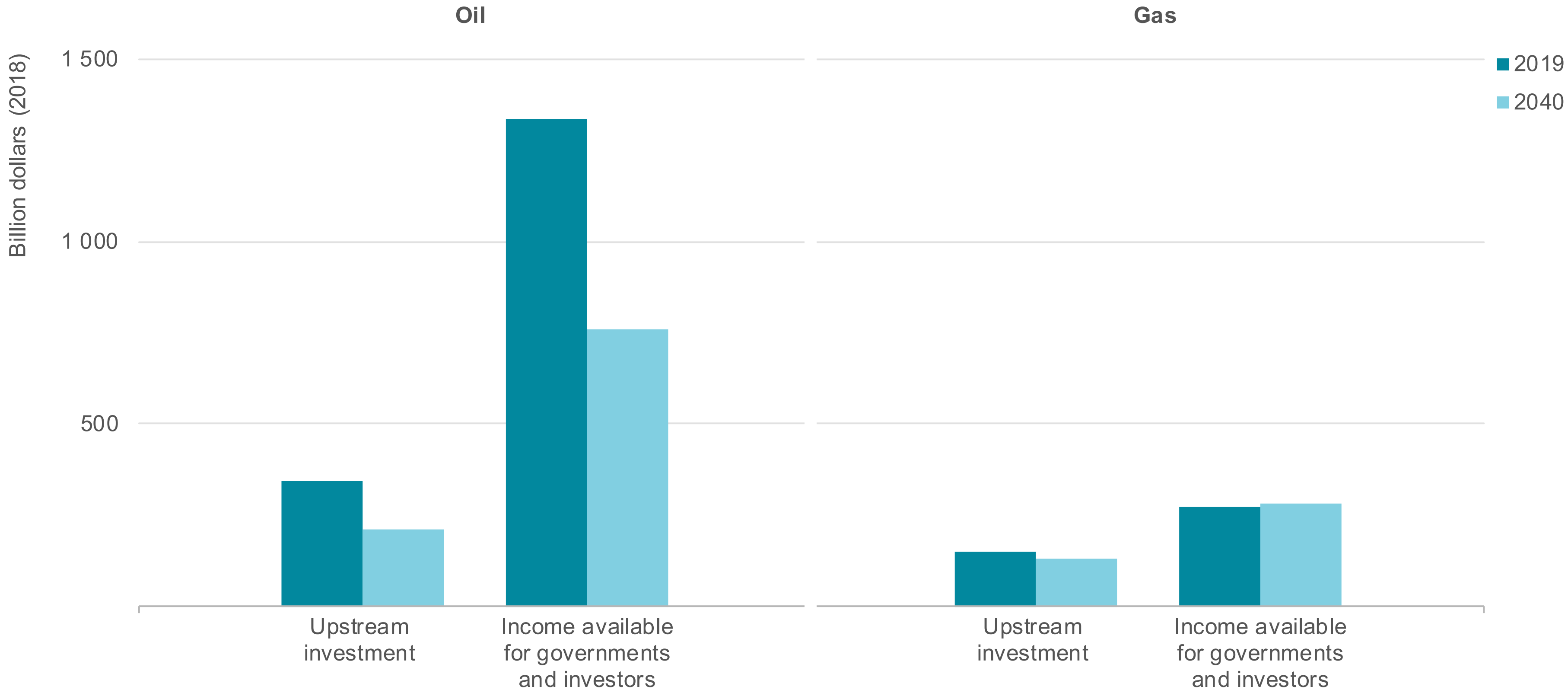
However, overall equity performance for the Majors has recently suffered and has trailed the broader market during the past five years. This partly reflects investor uncertainty over how well the industry can position itself in a changing market environment.

Smaller, independent players, e.g. US shale companies, also improved since 2016, but financial performance remains more tenuous. Independents have relied more on issuing new debt, selling assets or issuing new equity, though their call on external financing has fallen since 2016, thanks to operational efficiency, cost reductions, and a more disciplined approach to balancing the investment and cash flow generated by their own activities. While shale companies in aggregate overspent also in 2018, the ratio of capital expenditures to cash flow has constantly declined from almost 2 to 1 in 2015 to just over 1 to 1 in 2018. Furthermore, shale companies have paid back debt and begun to return cash to their shareholders via share repurchases.

Still, US shale companies have yet to turn the corner in terms of profitability. Despite a continuous strong increase in US shale oil production, capital markets have grown more wary of financing independents, as evidenced by rising bond yield spreads in 2019.

Oil income available to governments and investors shrinks in the SDS, but does not disappear

Oil and gas net income before tax in 2019 and in 2040 in the SDS



Notes: Income available for governments and investors = revenue minus finding and development costs and operating costs. Data include net income before tax for Majors, Independents, NOCs and INOCs.

Dividing up a smaller pot of hydrocarbon income will not be a simple task

A key financial issue facing the industry is whether the lower prices and production volumes of the SDS lead to a collapse in the income available from oil and gas, with potential implications for investments, returns and taxes.

In the SDS, there is a significant decline in net income from oil and gas in 2040 compared with today. This income also needs to cover the cost of any new upstream investment, with the remainder being available for governments and investors.

The fall in income relative to 2019 does not necessarily portend an investment crunch, as the requirement for upstream investment is significantly lower than today. Nevertheless, the pool of income available to share between governments and investors is around 40% lower in 2040.

This smaller pot of income would have impacts on the financial and industrial landscape for oil. Smaller independent companies may be challenged to stay in business, take on riskier new projects or face consolidation pressures from industry leaders. Average company size may rise. Shareholders are likely to prioritise total returns, but also increasingly focus on diversification and sustainability strategies (see discussion below). In the absence of credible moves to boost income (and returns) from newer energy areas, the industry may continue to face pressure to maintain a robust dividend yield and continuous share buybacks. The use of debt finance may also be constrained by the prospect of declining or more uncertain revenues.

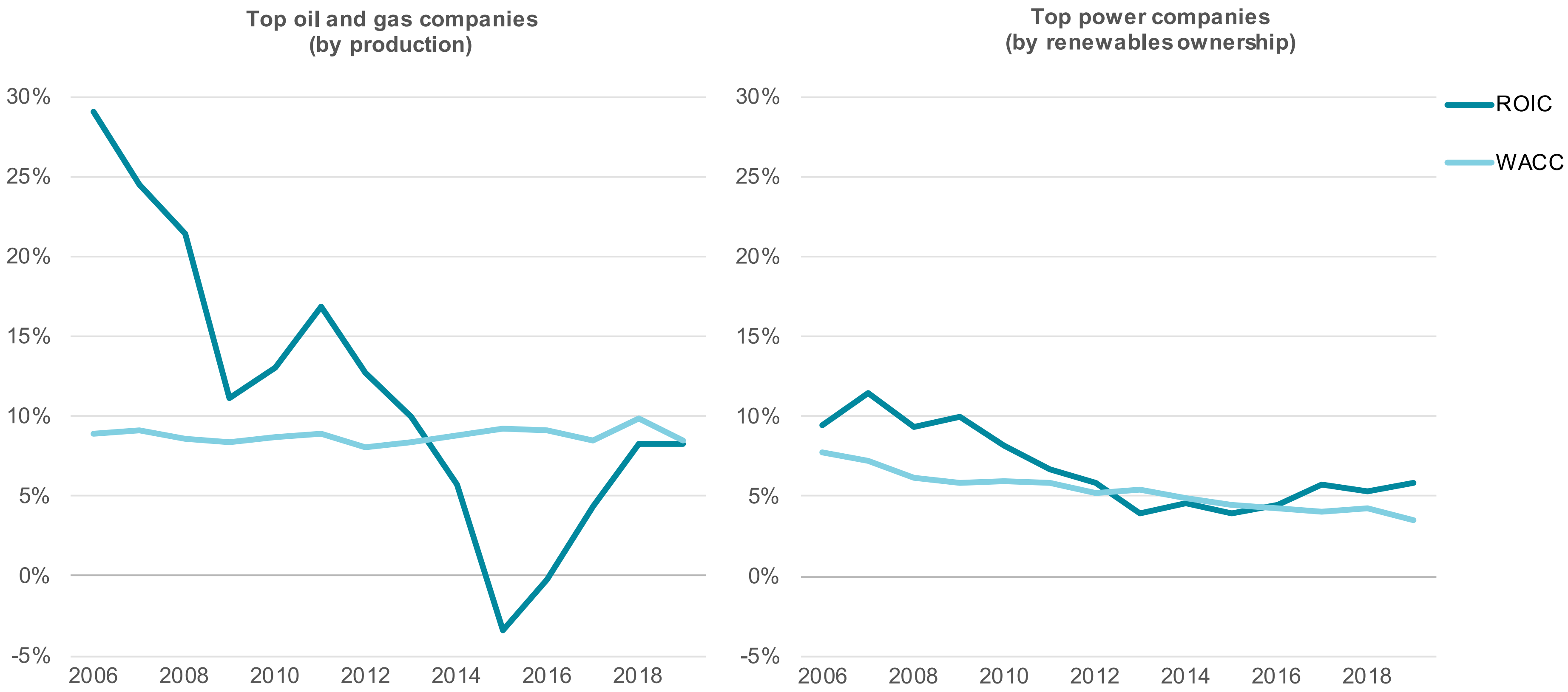
Income allocation between investors and governments is subject to complex dynamics as companies compete for resources and governments compete for investment. In energy transitions, some resource-rich countries may find themselves under pressure to bring in investors or face the possibility that national resources remain undeveloped forever, especially in a world where US shale output maintains a strong competitive presence in the market. The reviews of upstream fiscal and contractual terms prompted by the price downturn in 2014-15 could be a sign of things to come.

From an industry perspective, this analysis suggests that companies may be able to continue financing investment in core oil and gas areas to meet lower demand in the SDS, while maintaining an acceptable return for investors. However, a number of uncertainties may arise, such as market volatility or disruptive changes to policies or investor sentiment, which could result in adverse impacts on internal rates of return (IRRs).

The bottom line is that, as energy transitions progress, oil and eventually natural gas become smaller and more competitive spaces in which to operate. Reliance by companies on these investment opportunities and reliance by governments on the associated revenues become steadily more risky strategies. Both of these factors speak to the importance of diversification.

Different financial risk and return profiles between the fuel and power sectors

Average return on invested capital (ROIC) and after-tax weighted average cost of capital (WACC) for listed energy companies

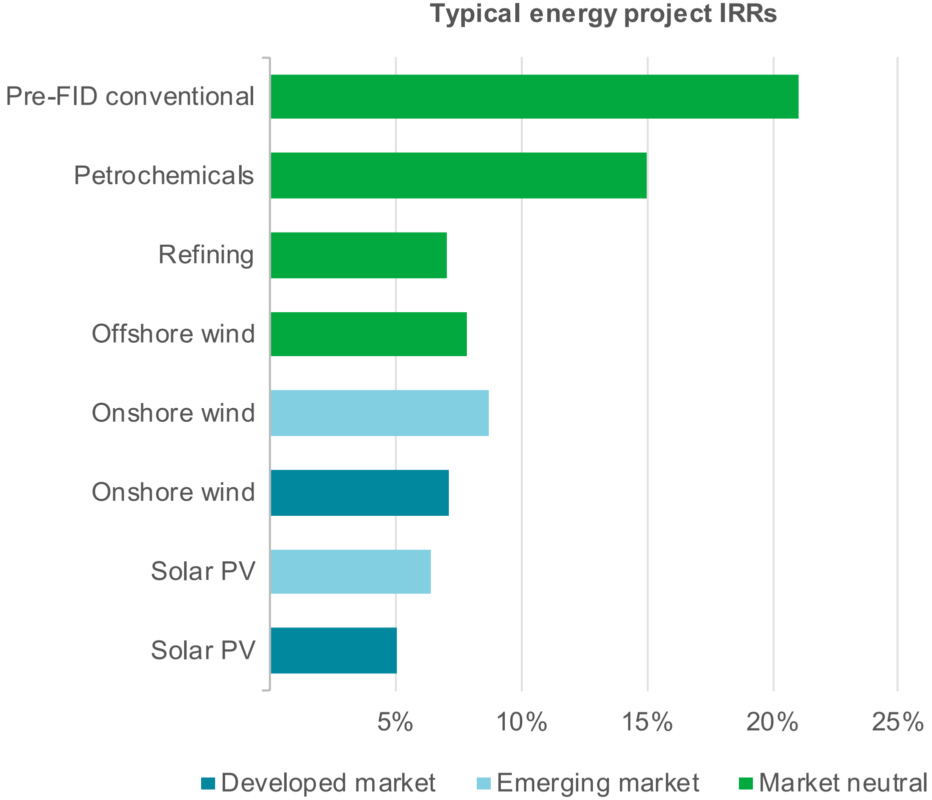


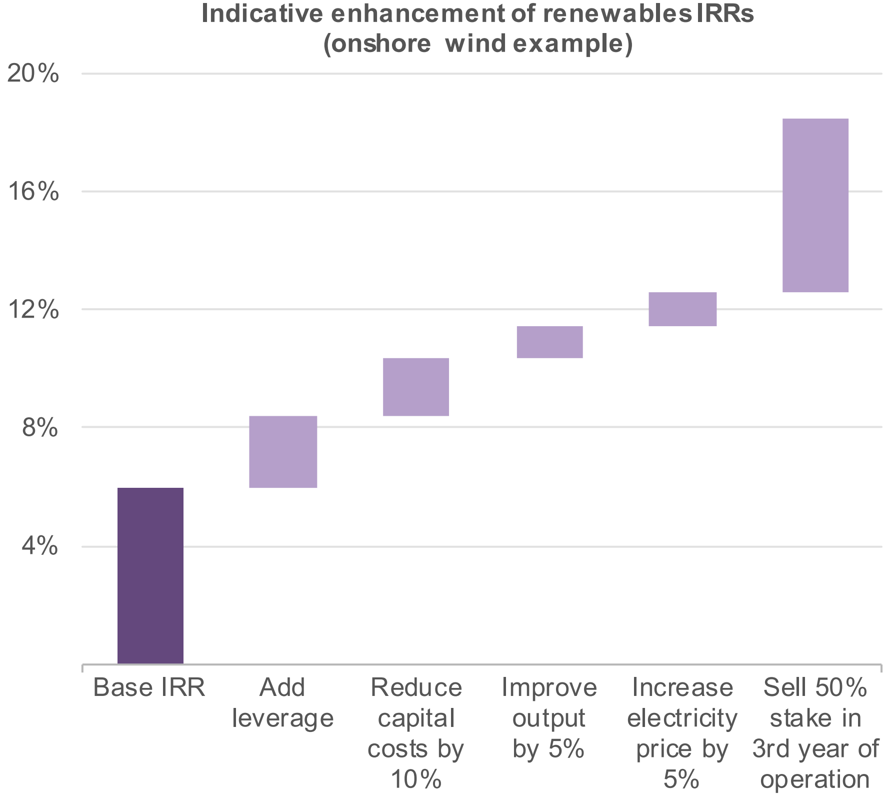
Notes: The samples contain the top 25 listed energy companies (in 2018) by oil and gas production and power companies by ownership of solar and wind capacity. Companies based in China and Russia are excluded from the analysis. Industrial conglomerates with large business lines outside of energy are also excluded. ROIC measures the ability of a company's core business investments to generate profits, expressed as operating income adjusted for taxes divided by invested capital. The WACC is expressed in nominal terms and measures the company's required return on equity and the after-tax cost of debt issuance, weighted according to its capital structure.

Source: Calculations based on company data from Thomson Reuters Eikon (2019) and Bloomberg (2019), *Bloomberg Terminal*.

What is the upside for risk-adjusted returns from low-carbon energy investment?

Typical energy project IRRs (left) and approaches to enhancing equity returns from renewables investments (right)





Notes: Pre-FID conventional = pre-final investment decision for conventional oil and gas project. Enhancement of renewables IRRs analysis is based on an indicative onshore wind farm in Europe with capital cost of USD 1 800/kW, capacity factor of 22%, added leverage of 60% and 50% equity stakes sold to a financial investor with return expectations of 5%.

Source: Left graph on typical energy project IRRs adapted from Wood Mackenzie (2019).

Potential financial opportunities and risks from shifting capital allocations

In response to market and financial pressures, some oil and gas companies have started to diversify their business strategies into new areas, ranging from reducing emissions in core activities to investing in low-carbon fuels and power (see Section I). This shift poses both opportunities and risks for financial performance, and has implications for the way that these companies finance their activities in the years ahead.

When looking at the financial risks and returns associated with different investment strategies, these dynamics point to a potential capital allocation dilemma for both industry and investors alike.

For example, ROICs for the oil and gas industry have historically exceeded those for power. At the same time, returns are typically more volatile in oil and gas (as evidenced by the recent downturn) than in power, with the latter benefiting more from assets with greater revenue certainty, e.g. renewables with long-term contracts. This contributes to higher risk and cost of equity for oil and gas, while power is more financed with debt, which supports its overall lower cost of capital. While indicators vary by company and market, the broad picture suggests potential trade-offs for profits, but also financing costs and risks, for investments in different energy areas.

Many oil and gas companies continue to see operational improvements and a focus on higher-return core assets as a better recipe for long-term profitability than investing elsewhere in energy. Evolving characteristics of newer energy investments also raise questions over their future risks and returns. For example, as incentives for renewables and market design shift in some jurisdictions, such as Europe, and flexible technologies, e.g. battery storage, come into play, companies and investors may need to grapple with new business models, more exposure to price risk, less cash flow certainty and changed financing costs.

Better project management and new financing models have the potential to support diversification and returns at the same time. Some renewables developers have enhanced equity IRRs through a combination of improving project output and reducing capital costs, employing greater leverage from banks and selling equity stakes in already developed projects to investors (e.g. pension funds) comfortable with lower returns from operational projects, enabling the original developer to recycle its capital into another investment opportunity. The considerable experience that oil and gas companies have in energy risk management, trading and marketing can create further synergies.

Financial performance for oil and gas companies may increasingly depend on the availability of appropriate financing mechanisms and partners to match a range of strategic choices. Increased climate-related scrutiny by investors may create challenges in financing traditional oil and gas, but raises questions over funding improvements in core areas that also have positive sustainability (and profitability) impacts.

Further efforts to develop so-called transition bonds and related instruments, which can fund new energy activities by traditional players, may help to fill potential financing gaps and provide more nuanced approaches to capital allocation. For example, Shell recently signed a USD 10 billion credit facility where interest payments are linked to progress in emissions reductions.

Section IV

Strategic responses

Introduction

Uncertainty has always been a key challenge facing the oil and gas industry. However, as analysis in previous sections has underlined, efforts to tackle climate change present a new and pervasive set of risks and uncertainties, meaning that there is no clear line of sight on how the energy sector of the future will look. The large range of possibilities complicates company deliberations about future returns and about strategic responses to energy transitions.

This leads to a justifiable call from parts of the industry – echoed in many respects by the IEA – for strong and unambiguous direction from policy makers. There is ample room for greater clarity on how energy and climate policies will evolve.

However, this uncertainty is not in itself a reason for oil and gas companies to "wait and see" when considering a response to new environmental imperatives and pressures, for three main reasons:

- Regardless of which pathway the world follows, climate impacts will become more visible and severe over the coming years, with knock-on effects on the public debate and on perceptions of the industry.
- Decision making in the oil and gas industry has always been subject to a large degree of uncertainty; managing this is not a new task for them, especially given that…
- …leading companies have a voice in the energy and climate policy debate: they have the capacity to push for some of the certainty that they are looking for in energy transitions, e.g. on carbon pricing, scaling up CCUS or markets for low-carbon fuels, and the ability to forge strong partnerships with governments, industry and society that give the process momentum.

A starting assumption for this section is that doing nothing is not an option. Energy transitions, however they proceed, require a strategic response from the oil and gas industry. Companies considering their long-term future need to develop strong and credible narratives about their role(s) in a changing energy market, and to justify their response to the challenges posed by climate change.

That said, there is no single response or business model that will be suitable for the wide range of companies active in the oil and gas sectors. This section does not attempt to be prescriptive; the owners of the companies will decide which strategies to follow, based on their assessment of the specific capabilities and strengths of the companies in question. In each case, the merits and risks attached to company strategies will be the subject of close scrutiny, as will the returns on proposed investments and the value proposition for shareholders and society.

The different elements described below do not represent a ladder of ambition that all companies need to climb, but rather a menu of options that an increasing number of companies are considering or acting on.

The strategic options

The responses outlined in this section are grouped into four areas:

- how **traditional oil and gas operations** look when viewed through the lens of accelerated energy transitions
- the use of **CCUS technologies** to bring down emissions
- The longer-term potential for the industry to supply **low-carbon liquids and gases** to consumers
- the **transition from "fuel" to "energy" companies**, which supply electricity and other energy services as part of a diversified offering.

As noted above, there are many examples of companies pursuing different elements included here. While there will, of course, be large differences between the decisions of different companies, it will be difficult for any company operating in the oil and gas business to avoid consideration of the first set of issues highlighted here. The areas highlighted in the other "baskets" offer ways for companies to make a positive contribution to long-term reductions in emissions. For some, this will involve their complete repositioning as "energy companies" rather than oil and gas companies.

However, it is not axiomatic that all of them will, or even that they should, follow this route. The activities of NOCs and many INOCs, for example, are typically set by their host states, and there is no guarantee that these companies will be charged with the development of other energy sources.

Other companies may also decide that their specialisation is in oil and/or natural gas (possibly shifting more towards the latter over time). As such, for as long as these fuels are in demand and returns on investment are sufficient, their strategic focus will be to supply them as cleanly and efficiently as possible – even if that risks a loss of "social licence" over time. A related possibility is for companies to decide that – rather than risking money on unfamiliar business areas – others may be better placed to allocate this capital to new activities. So their "investment" in transitions would consist of returning cash to shareholders.

The process of change is difficult for companies, and there is no single or sure recipe for success. Based on experience thus far, though, there are some indicative steps that form part of the company transformations that are under way today.

A crucial first step is to decide on the case for change – based in part on the risks arising from a "business-as-usual" pathway and also on a vision of the broad forces that are shaping the future of energy.

A next step is typically a mapping exercise: to assess the company's portfolio and its capabilities, responsibilities and competencies against this vision of the future and to seek out areas of competitive advantage. Our assessment is that there are significant areas of intersection between the expertise and capital of oil and gas companies and mission-critical elements of energy transitions.

Finally, there is the task of ensuring that key constituencies – both inside and outside the company – are aligned with the new strategic goals. Company culture often needs to adjust to make it more receptive to new business models, technologies and approaches. Clear communication, backed up by strong leadership, are particularly important in this phase; people inside and outside the company will be quick to detect mismatches between words and deeds.

The role of partnerships

Partnerships are an integral part of the operation of today's oil and gas industry. The industry tends to share risks in areas where the costs are higher, which is why there are typically many partners in large offshore oil fields or LNG terminals. It has also created numerous bodies to deal with industry-wide issues of environmental performance, such as the OGCI.

Existing partnerships and associations can play a role in promoting some of the strategic responses detailed in this section. For example, methane abatement is a main focus for the OGCI and for the signatories to the multi-stakeholder Methane Guiding Principles group.

There is also ample scope for existing partnerships to spread best production practices: the analysis in Section I underlines that the influence of companies can spread much further than their equity ownership or direct operations. The Majors, for example, hold some level of influence over three times more global oil production than they directly own.

The more testing questions about partnerships come in relation to the development of high-cost, infrastructure-intensive areas such as hydrogen and CCUS. The industry instinct to share risk across different partners is clearly relevant in these areas, but finding alignment among a group of oil and gas companies, on its own, is not going to be sufficient to move them forward. Getting a critical mass will require a broader group, not only from the end users that might use hydrogen or CCUS, but also from across governments, the financial community and society.

In discussions on how to accelerate energy transitions, these types of institutional questions are coming to the fore, especially for the "hard to abate" sectors such as steel, cement, plastics, heavy road transport, aviation and shipping (Victor et al., 2019). There is a clear case for co-ordinated action to steer and accelerate technological transitions in these sectors to break the current impasse, in which each set of actors is often looking to others to make the first move.

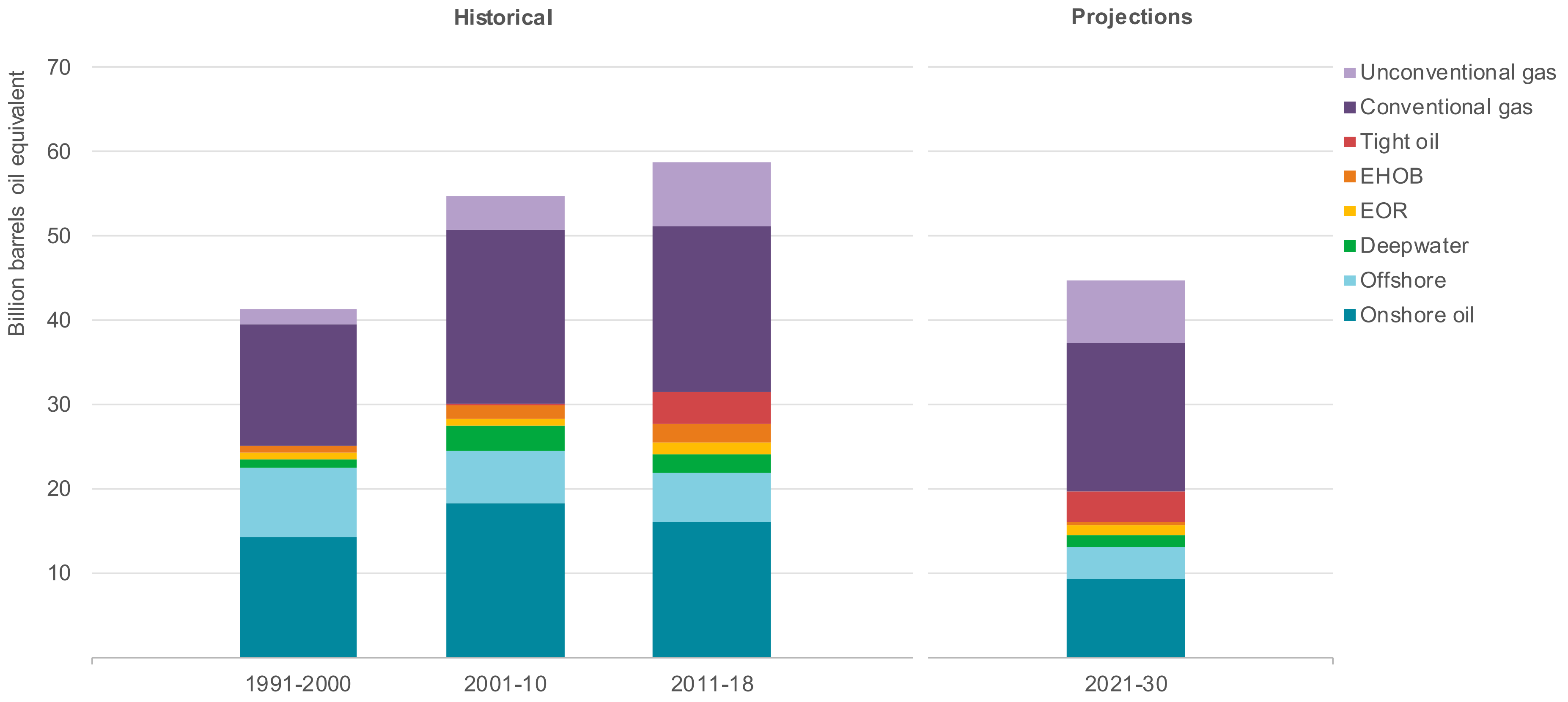
This is an area ripe for engagement by leading parts of the oil and gas industry. This is especially so, given that the most difficult sectors for energy transitions, listed above, are also the ones in which the oil and gas industry could be instrumental in delivering low-carbon solutions.

Traditional oil and gas operations

Slides 124 - 134

Energy transitions reshape which resources are developed and how they are produced

Average annual volumes of oil and natural gas resources developed historically and in the SDS



Note: EHOB = extra-heavy oil and bitumen.

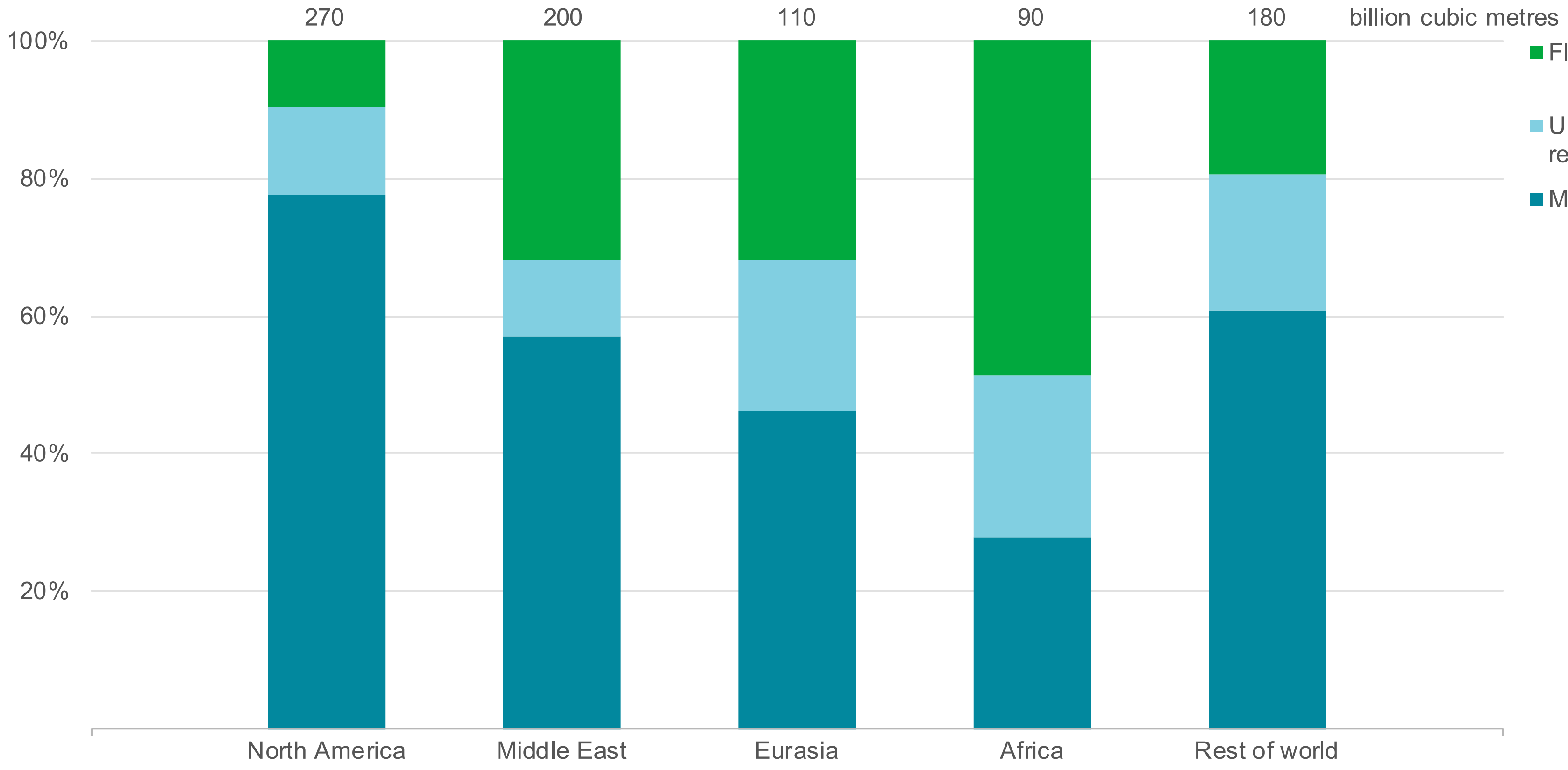
Which types of resources have the edge?

While both oil and natural gas demand peak in the SDS, both fuels continue to play a major role in the global energy mix for decades to come. In 2040, oil and natural gas still satisfy just under half of global energy demand in this scenario. As discussed in the previous section, the level of new oil and gas resources required remains significant, largely due to declining output from existing fields. But companies also face choices as to the types of resources that are considered for development in this Scenario:

- **Lower-cost resources** will naturally be favoured, regardless of the demand outlook. This suggests that the large resource holders, such as those in the Middle East and Russia, and companies that can keep a tight control on extraction costs could capture a greater share of the market. Efficiency and cost discipline are the watchwords. However, the profile and characteristics of oil and gas demand in the SDS suggest that the direct costs of extraction are not the only consideration.
- **Natural gas fares better than oil** in most energy transition outlooks, including the SDS. The profitability of gas supply is often more challenging than oil, but in recent years many companies have sought to increase the level of natural gas in their project portfolio. This is partly because of the greater number of development opportunities for natural gas, but is also a response to the better prospects for gas demand.
- **Lighter crude oils and natural gas liquids** are better suited to the demand environment of the SDS, and reduce the need for intensive refining.
- **Among existing projects, a search for additional low-cost barrels**. Some of the cheapest additional barrels, especially among established producers, are those available at existing producing fields or at satellite fields. Technologies and approaches that maximise recovery are likely to be favoured, especially if they have co-benefits for environmental performance, as with the use of CO_2 for EOR.
- **Among new projects, a preference for shorter payback periods**. An uncertain demand environment increases the implied discount rate for new projects, which penalises very capital-intensive investments and favours opportunities with shorter lead times between approval and first production. Shale investments fall into this category, and larger conventional projects (onshore and offshore) may increasingly be separated into multiple distinct phases for the same reason.
- **Among all projects, a focus on bringing down the emissions intensities along the value chain.** The emissions intensity of production is a function both of the natural complexity of the resource and of above-ground development and operational choices. Oil and natural gas with lower emissions intensities will be better positioned than higher-emitting sources, and would likely be increasingly preferred for development. Actions to reduce emissions from oil and gas operations include:
  - i. minimising flaring
  - ii. tackling methane emissions
  - iii. integrating renewables and low-carbon electricity into new upstream and LNG developments.

i) Minimise flaring: Flaring of associated gas is still widespread in many parts of the world

Use of associated gas by region, 2018



Source: IEA (2019), *World Energy Outlook 2019*, www.iea.org/weo2019.

In the SDS, the volume of flared gas drops dramatically over the coming decade

Most wells that are drilled to target oil formations also yield a mixture of other hydrocarbons such as condensates, NGLs and natural gas. Natural gas is known as “associated gas” and it has often been seen as an inconvenient by-product of oil production: it is generally less valuable than oil per unit of output and is costlier to transport and store.

Only 75% of the associated gas produced today around the world is put to some kind of productive use, either marketed directly to end consumers via gas grids, used on-site as a source of power or heat or reinjected into oil wells to create pressure for secondary liquids recovery.

The remainder (some 200 bcm in 2018) is either flared (140 bcm) or vented to the atmosphere (an estimated 60 bcm, including deliberate venting and unintentional fugitive emissions). “Routine” flaring typically occurs because of the remoteness of fields or the topography of the surrounding area, because the price of gas in accessible markets discourages operators from developing gas transportation infrastructure to reach existing or potential new markets, or because of the time lag between developing a new resource and connecting this to a gas pipeline.

Together, such non-productive uses of gas have significant and damaging environmental consequences. They make up around 40% of the scope 1 and 2 emissions associated with oil production. The flared volumes alone in 2018 were responsible for 270 Mt CO_2, as well as additional methane emissions to the atmosphere because of incomplete combustion (flares are rarely 100% efficient).

They also represent a wasted economic opportunity: the 200 bcm that was flared or escaped into the atmosphere or vented in 2018 was greater than the annual LNG imports of Japan and China combined.

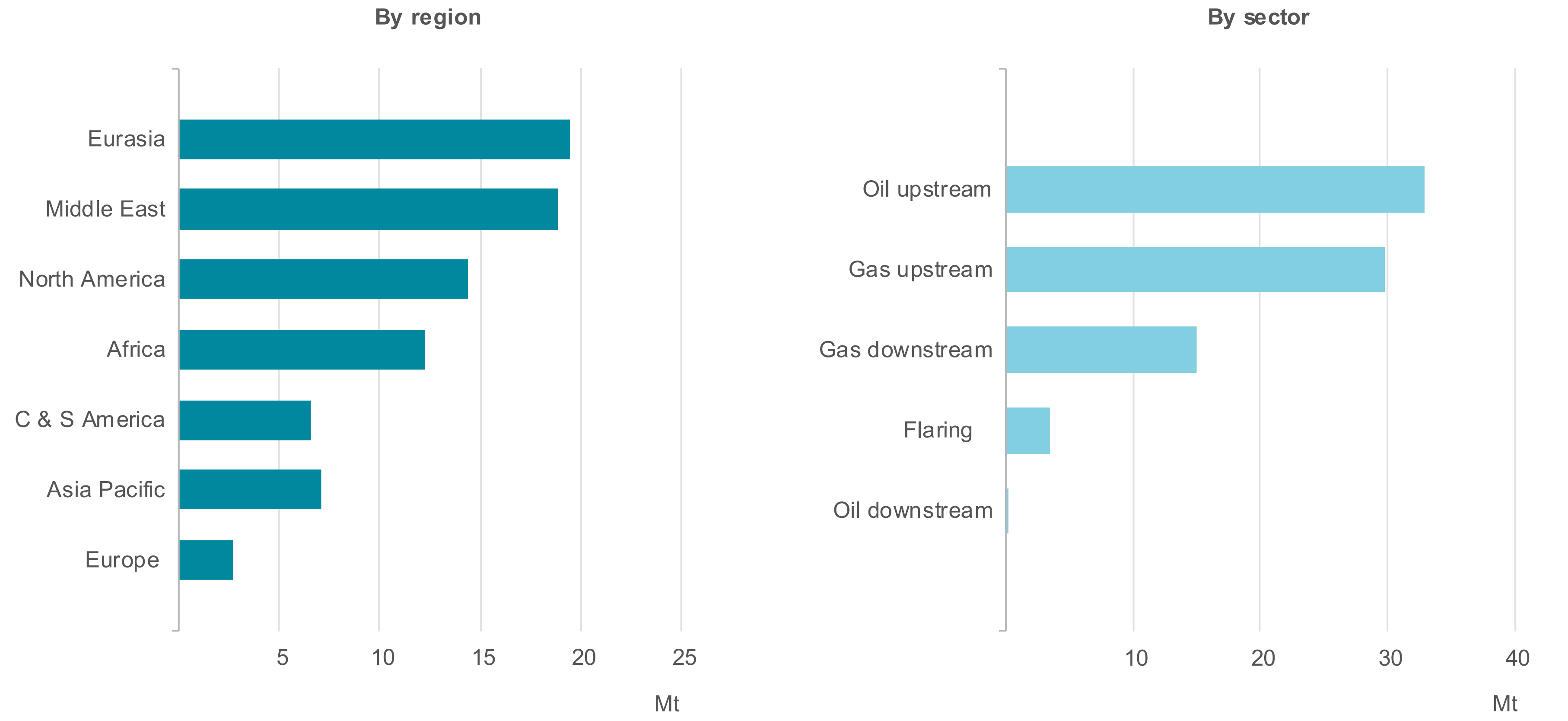
There are various initiatives under way to reduce flaring. For example, various energy companies, governments and institutions have endorsed the Zero Routine Flaring by 2030 initiative launched by the World Bank and the United Nations in 2015.

For new fields, operators should aim to develop plans to use or conserve all the field’s associated gas without routine flaring. At existing oil fields, operators are asked to eliminate routine flaring when it is economically viable as soon as possible, and no later than 2030.

Since it is a wasteful practice, flaring drops steadily over the period to 2040 in the STEPS. In the SDS, as a result of strong policy interventions and industry efforts, the volume of gas flared drops much more dramatically over the next decade. Flaring is soon eliminated in all but the most extreme cases, with less than 13 bcm flared from 2025 onwards, less than 10% of the 2018 level.

ii) Tackle methane emissions. Upstream activities are responsible for the majority of methane leaks from oil and gas operations today

Regional and sectoral breakdown of estimated methane emissions from oil and gas operations, 2018



Notes: C & S America = Central and South America.

Source: Based on IEA (2018), *World Energy Outlook 2018*, www.iea.org/weo2018. An interactive version of these data is available at https://www.iea.org/reports/methane-tracker/country-and-regional-estimates.

The precise level of methane emissions from oil and gas operations is uncertain, but enough is known to conclude that these emissions have to be tackled

Methane is a major GHG, much more potent than CO_2, which has important implications for climate change, particularly in the near term. The largest source of manmade methane emissions is agriculture, but the energy sector is not far behind.

It is important to tackle all sources of methane emissions arising from human activity, but there are reasons to focus on emissions from oil and gas operations. Although emissions also come from coal and bioenergy, we estimate that oil and gas operations are likely the largest source of emissions from the energy sector. Moreover, our analysis shows clear scope to reduce them cost-effectively (see next slide).

Methane emissions can be released at different points along the oil and gas value chains, from conventional and unconventional production, from the collection and processing of gas, as well as from its transmission and distribution to end-use consumers. Some emissions are accidental, for example because of a faulty seal or leaking valve (usually called "fugitive emissions"), while others are deliberate, often carried out for safety reasons or due to the design of the facility or equipment (usually called "vented emissions").

We estimate there were around 80 Mt of methane emissions from oil and gas operations in 2018, split in roughly equal parts between the two. This estimate is generally in line at the global level with other assessments.

However, there is a very large discrepancy with the emission intensities reported by a number of companies. For example, the 45 Mt emissions from natural gas correspond to a global average emissions intensity of just over 1.7%, while many major oil and gas companies report a global average emissions intensity for oil and gas production that is less than 0.1% (IOGP, 2015). There are a variety of possible explanations why such a gap exists.

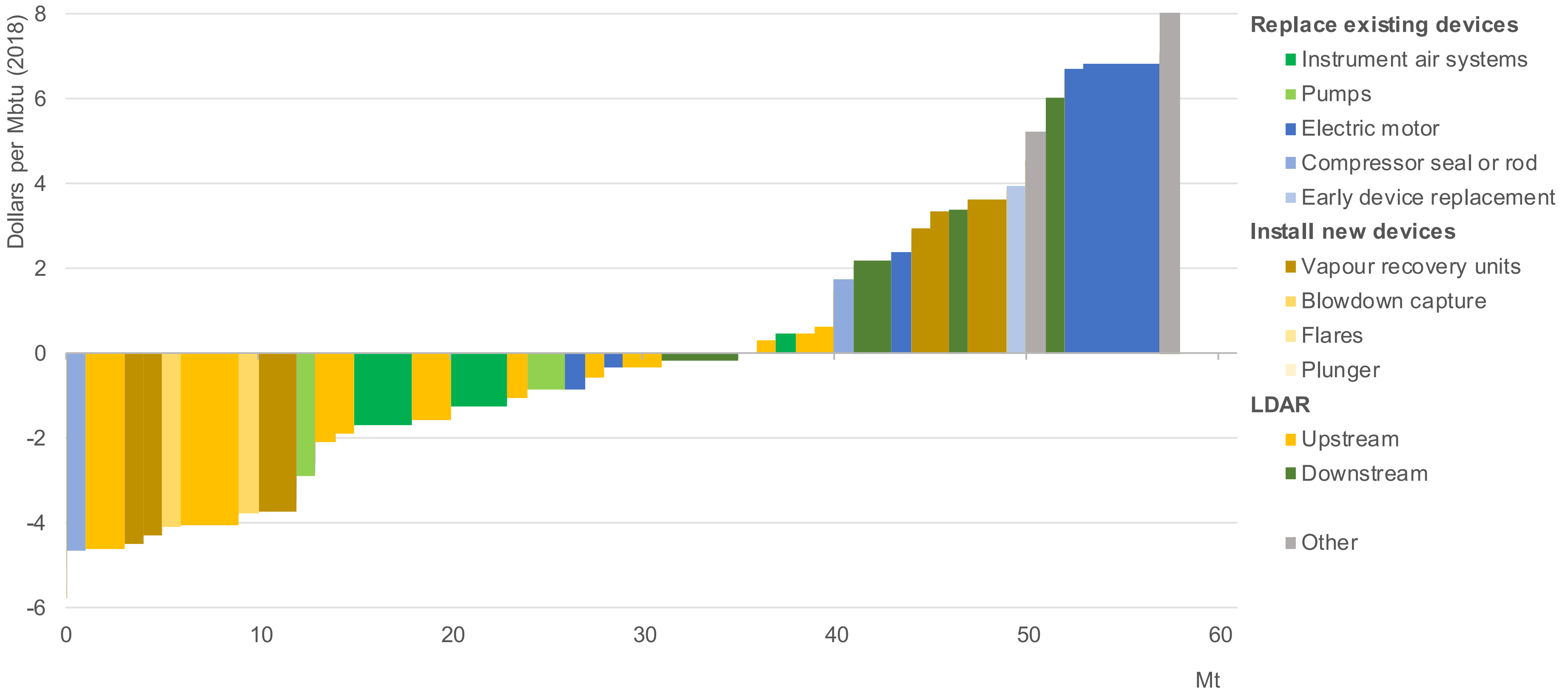
- The reporting companies may be underestimating emissions by relying on average emission or activity factors that are not truly representative of actual levels.
- The emission factors that have been reported may not be representative of what is achieved by the industry as a whole, i.e. because the companies that actively report methane emissions levels are generally those that pay most attention to emissions levels and are the "best performers" in their peer group.
- The top-down studies may be misallocating emissions to the oil and gas sector. It could be that some emissions are assumed to originate from the oil and gas industry but in fact come from other sources such as coal, agriculture or natural sources.

There is evidently a high degree of uncertainty in oil and gas methane emissions levels today. The only real method to reduce this uncertainty is through direct measurements: either ground-based campaigns or by using satellites, a number of which are already in operation or are due to be launched in the coming years.

Nonetheless, enough is known already today to conclude that these emissions cannot be ignored and that they represent a clear risk, both to the climate and to the industry's reputation and licence to operate. The risk is particularly apparent for the role of natural gas in energy transitions.

Many measures to prevent methane leaks could be implemented at no net cost because the value of the gas recovered is greater than the cost of abatement

Marginal abatement cost curve for oil- and gas-related methane emissions, by mitigation measure, 2018



Note: LDAR = leak detection and repair.

Source: Based on IEA (2018), World Energy Outlook 2018, www.iea.org/weo2018. An interactive version of these data is available at https://www.iea.org/reports/methane-tracker/country-and-regional-estimates.

The projected role of natural gas in the SDS relies on rapid and major reductions in methane leaks

A wide variety of technologies and measures are available to reduce methane emissions from oil and gas operations. For example, existing devices such as pneumatic controllers that lead to a large level of vented emissions can be replaced with instrument air systems; vapour recovery units can be installed on crude oil and condensate storage tanks; and introducing frequent LDAR programmes can significantly cut the level of fugitive emissions.

We estimate that if all of these options were to be deployed across the oil and gas value chains, then around 75% of today's 80 Mt of methane emissions from oil and gas operations could be avoided.

In addition, methane is a valuable product and in many cases can be sold once recovered. This means that deploying certain abatement technologies can result in overall savings if the value received for the methane sold is greater than the cost of the technology. Around 45% of current methane emissions could be avoided with measures that would have no net cost (at 2018 natural gas prices).

Increased attention to methane emissions has generated a number of voluntary national and international partnerships to help tackle the problem. However, there remains a large opportunity to reduce these emissions in a cost-effective way. There are many possible reasons why this could be the case. Governments and industry may lack information or awareness about the size or severity of the problem; the infrastructure or investment that is necessary to recover gas and pair it to a productive use may be lacking; or there may be competition for capital within companies with a variety of investment opportunities. In these cases, new or enhanced regulations can be very effective in reducing emissions further.

In the SDS, methane emissions would fall even without any explicit abatement measures or policies, simply because overall oil and gas consumption falls to 2040. However, relying on demand trends to eventually do the job of methane abatement would be a huge missed opportunity, both for efforts to mitigate climate change and also for those that seek to position gas as part of the solution to environmental challenges.

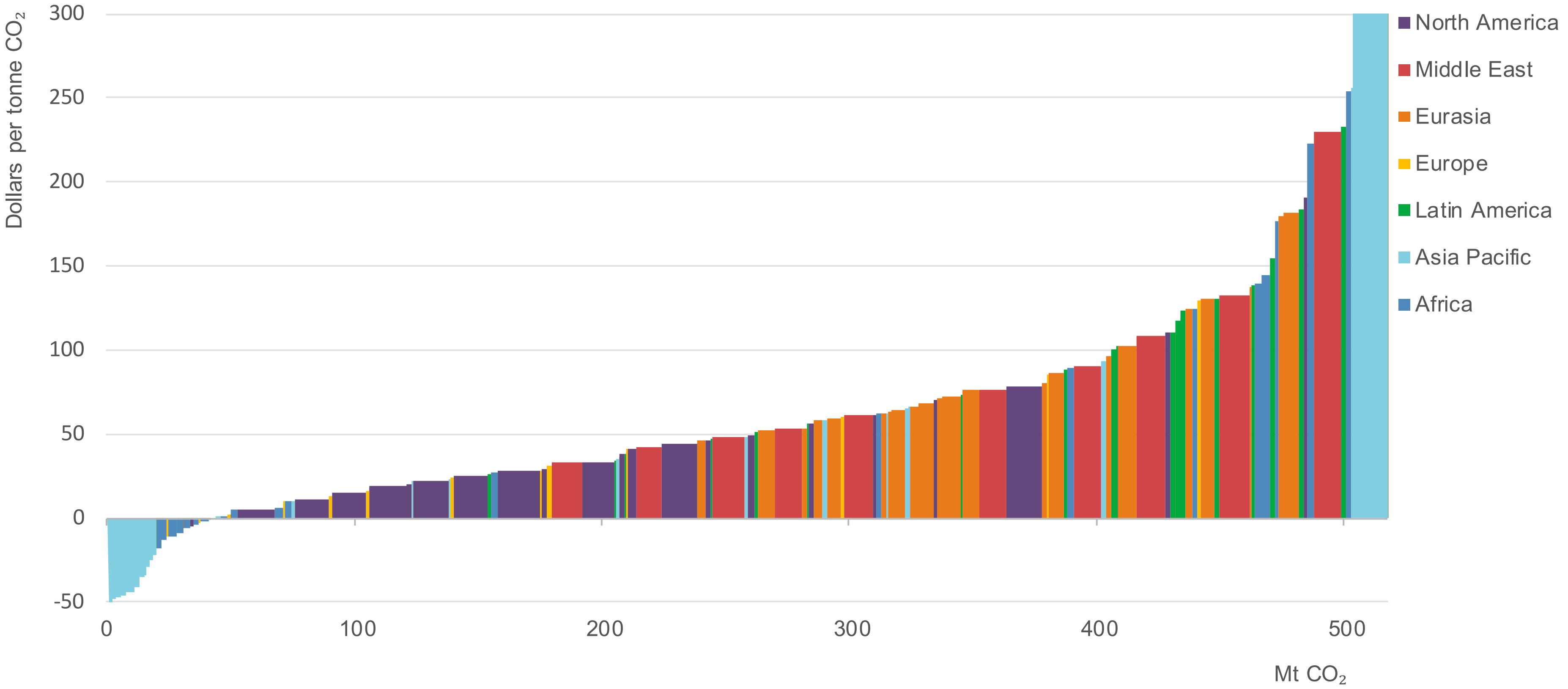
In the SDS, global oil and gas methane emissions in 2040 fall to less than 20 Mt. Without this major and rapid reduction in methane emissions, other emissions would need to fall further and faster in order to be compatible with any given target for stabilising global temperatures.

The measures introduced to reduce methane emissions in the SDS include all the measures that come at no net cost. However, they also include other measures that are technically viable but that would not pay for themselves via the value of the methane that is captured and subsequently sold.

Putting a price on methane emissions, whether within companies or as part of a regulatory approach, would be an important way to incentivise such measures. The level of this price would not need to be very high. For example, if it is assumed that one tonne of methane is equal to 30 tonnes of CO_2 equivalent, then a GHG price of only USD 15/tCO_2 would be sufficient to encourage operators to introduce abatement measures costing up to USD 8/MBtu.

iii) Integrate renewable power and heat into oil and gas operations

CO₂ abatement costs for decentralised renewables to power oil and gas facilities in the SDS, 2040



Note: Assessment considers the energy intensities of different production techniques, the increase in energy intensity per unit of production as a field matures, the cost of deploying decentralised renewables (including future cost reductions), hourly wind and solar PV intensity profiles, whether resources are onshore or offshore, different ratios of solar PV, wind and battery capacities, and the value of gas that is not combusted and that could be sold on the market. The renewable systems are assumed to be installed when the fields are first developed.

Low-carbon electricity and heat can find a productive place in the supply chain, especially if emissions are priced

There are multiple ways in which increasingly cost-competitive renewables can contribute to oil and gas operations; the options below all contribute to reduced emissions but in a rising number of cases they can also reduce costs, particularly if there is a price put on carbon. There are three main avenues:

Electrifying upstream operations using renewable electricity. In some cases, operations can be electrified by purchasing electricity from the grid; this is already the case for certain upstream operations, notably some tight oil developments in the United States and the major new Johan Sverdrup field in Norway. The environmental impact of this approach depends on the emissions intensity of the grid-based electricity: it needs in our estimate to be less than 500 g CO_2/kWh for there to be a real reduction in the overall scope 1 and 2 emissions intensity of operations.

However, many oil and gas operations are in practice in remote locations, far from cities or existing power plants, and are often in countries where the reliability of grid-based supply is not guaranteed. They therefore typically opt to use natural gas to power small-scale (and often relatively inefficient) on-site generators.

An alternative approach is to integrate off-grid renewable energy sources into upstream facilities. Such initiatives are already becoming more widespread, including a 10 MW Sonatrach-Eni project to power an Algerian oil field with solar PV, inaugurated in late 2018, and the 2019 announcement by Equinor of a new 88 MW offshore wind facility to supply electricity to offshore platforms in the southern part of the Norwegian Sea.

We have estimated the potential size of this opportunity based on the costs and emissions savings of installing different sizes of hybrid solar PV, wind and battery storage systems at new oil and gas facilities. Based on this assessment, it is technically possible to reduce upstream emissions by over 500 Mt CO_2 by installing decentralised renewable systems when new resources are first developed. Only a fraction of these would come with no net cost, but at USD 50/t CO_2, around 250 Mt CO_2 could be avoided.

Using low-carbon heat from renewables. Another possibility is to use solar thermal energy to generate heat for thermal EOR operations (known as solar-EOR). This is of particular interest in countries where solar is plentiful but gas is relatively scarce, such as Kuwait, Oman and the United Arab Emirates. In Oman, a 1 GW solar farm is under construction to provide steam for the extraction of around 20 kb/d of heavy oil.

Electrifying liquefaction operations with renewable electricity. There is one electric LNG plant currently in operation (the Snøhvit LNG facility in Norway) and others under construction in North America. There are some barriers to the widespread adoption of this approach, including the need for LNG projects to be located near a reliable source of low-emissions power, but this approach – combined with stringent controls placed on methane emissions – can bring benefits. We estimate that this “cleaner” LNG would provide a 40% reduction in GHG emissions from coal-to-gas switching (for production of heat), compared with a 30% reduction if these mitigation strategies were not in place.

Deploying carbon capture, utilisation and storage technologies

Slides 135 - 141

The oil and gas industry is critical to the outlook for CCUS

The oil and gas industry is already one of the global leaders in developing and deploying carbon capture and utilisation (CCUS) technologies. Of the 35 Mt CO_2 captured today from industrial activities in large-scale CCUS facilities, nearly 80% is captured from oil and gas operations.

CCUS is a critical technology to reach the emissions trajectory of the SDS, with deployment split almost equally between the power and industry sectors (including cement, iron and steel, and refineries). Total CO_2 captured globally rises from 170 Mt CO_2 in 2025 to nearly 2 400 Mt CO_2 in 2040.

In the power sector, CCUS in the SDS is concentrated in a handful of countries, most notably China (for coal) and the United States (for natural gas). The use of CCUS in industrial applications is widespread, as emissions from energy-intensive sectors are typically hard to abate, and CCUS constitutes one of the few currently available technology options to achieve deep levels of decarbonisation.

As shown by the 45Q fiscal incentive in the United States, actions by governments will play an essential role in facilitating the growth in CCUS. This can be via targeted regulatory levers, market-based frameworks, public procurement, low-carbon product incentives, tax credits or grant funding. Governments can also play a role in facilitating the growth of multi-user transport and storage networks that industrial facilities can access, and in helping to manage risks associated with ensuring stored CO_2 does not leak.

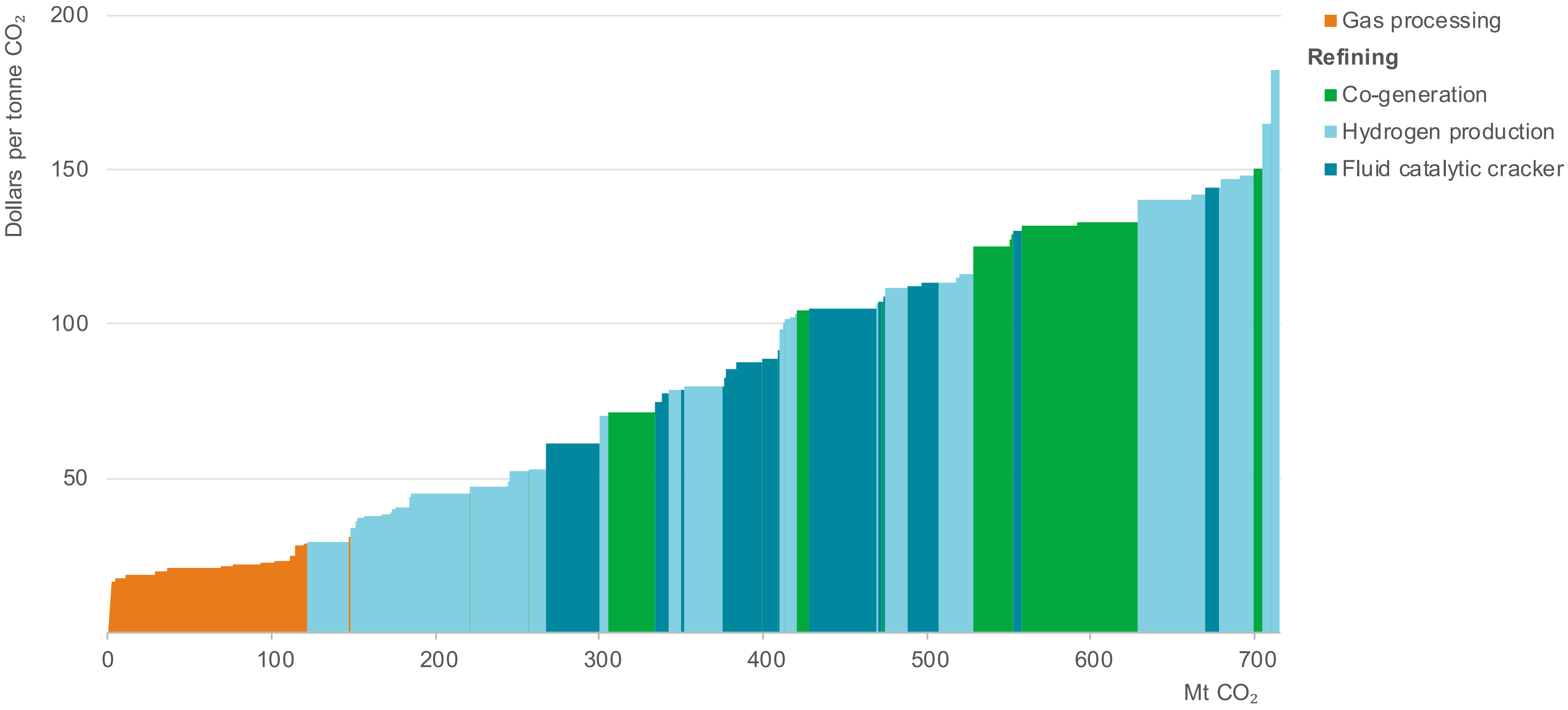
If the incentives are in place to encourage investment in different components of the CCUS value chain, there are several ways to think about the role of the oil and gas industry in relation to CCUS.

- As a source of some concentrated streams of CO_2 that are relatively easy and cost-effective to capture (for example in gas processing or parts of the refining sector). Deployment of CCUS in these areas would contribute to reductions in scope 1 and 2 emissions intensities.
- As a user of CO_2, primarily for injection into reservoirs as a mechanism for EOR. Depending on the source of the CO_2 and the volumes being injected, this could reduce the emissions intensity of the produced oil considerably (and even, theoretically, lead to carbon-negative oil).
- As an industry that undertakes well-funded, high-level research, and that has the large-scale engineering, pipeline and subsurface, and project management capabilities to scale up CCUS. This could have positive spillover implications for many aspects of energy transitions, including for the large-scale production of low-carbon hydrogen and the decarbonisation of heavy industry.

CCUS could also play a key role in helping to achieve "negative emissions" if bioenergy is used in conjunction with carbon capture and storage (BECCS). Negative emissions could help to offset emissions from hard-to-abate sectors, such as aviation or the manufacturing of iron, steel and cement. Further, most scenarios that aim to limit the temperature rise to 1.5°C (such as those assessed in the IPCC special report, *Global Warming of 1.5°C*) rely heavily on BECCS to do so. In the SDS, just under 100 Mt CO_2 is absorbed from the atmosphere using BECCS in 2040.

CCUS could help to reduce the emissions intensity of gas supply as well as refining: A price of USD 50/t CO_2 could reduce annual emissions by around 250 Mt

Opportunities and costs of using CCUS to reduce scope 1 oil and gas CO_2 emissions, 2018



Source: IEA (2018), *World Energy Outlook 2018*, www.iea.org/weo2018.

Gas processing facilities and hydrogen production at refineries are the main opportunities to deploy CCUS along the oil and gas value chains

Globally, we estimate that just over 700 Mt CO_2 of scope 1 emissions from oil and gas operations could be avoided using CCUS. Many of these reductions could be realised at relatively low cost, particularly emissions from natural gas processing and refining processes that yield highly concentrated CO_2 streams. Over 250 Mt CO_2 emissions could be avoided at a cost of less than USD 50/t CO_2.

One of the key opportunities to capture CO_2 emissions from the gas value chain is during natural gas processing. Underground deposits of natural gas can contain significant quantities of naturally occurring CO_2 and this must be removed to meet technical specifications before the gas can be sold or used.

CO_2 removed in gas processing facilities is typically vented, and we estimate that around 150 Mt CO_2 is vented globally in this way. However, there are a number of projects that capture this CO_2, such as the Sleipner projects in Norway. One key advantage of capturing CO_2 from natural gas processing is that the separation process results in a very concentrated stream of CO_2 that can easily be purified prior to transport and storage.

Since the CO_2 content of gas that is transported as LNG has to be extremely low, liquefaction facilities are another stage along the gas value chain where highly concentrated CO_2 emissions could potentially be captured.

There are two major LNG facilities in operation today that are equipped with CCUS units to capture CO_2: the Gorgon project in Australia and the Snøhvit project in Norway. At Gorgon, the natural gas flowing to this facility contains around 15% CO_2, which has to be removed prior to liquefaction; the aim is to capture these CO_2 emissions that would otherwise be vented. Qatar has also announced its intention to step up CCUS deployment in its gas operations.

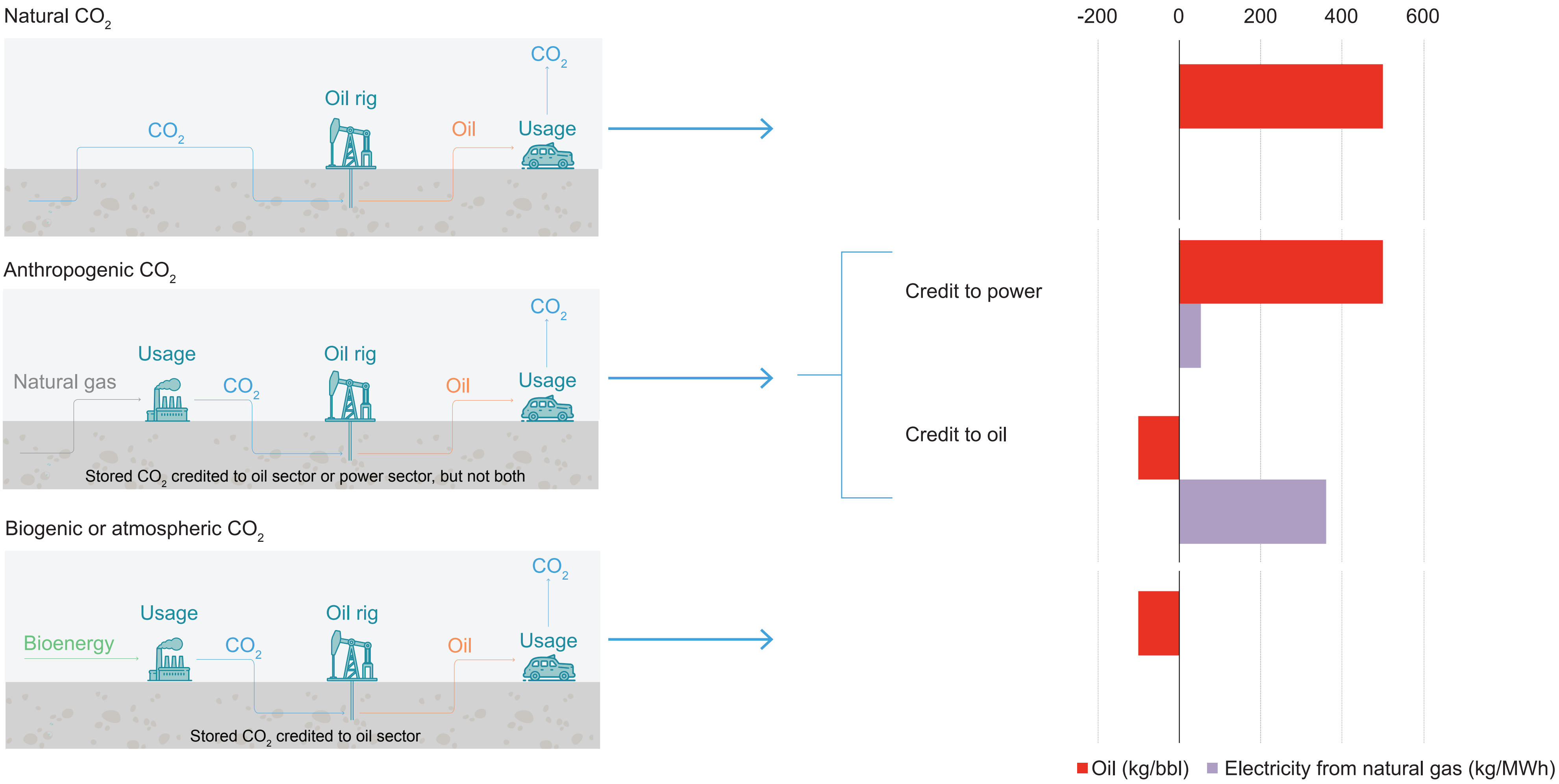
Applying CCUS to refining operations will be a key mechanism to reduce emissions from the oil value chain. Refineries tend to consist of a variety of scattered CO_2 emission sources across different processing units, making it difficult to capture all emissions from a plant. However, there are some units and systems that could be equipped with capture units. This includes hydrogen production units using steam methane reforming (which are the source of around 20% of total CO_2 emissions from a refinery), fluid catalytic cracking units and co-generation systems.

Refineries are one of the largest users of hydrogen today, and demand for hydrogen is set to grow as regulations on the sulphur content of final products tighten. Hydrogen production units in refineries result in highly concentrated CO_2 streams, offering one of the lowest-cost opportunities to apply CCUS. Fluid catalytic cracking units also generate a flue gas containing CO_2 in relatively high concentrations. The adoption of co-generation systems in refineries not only generates energy efficiency benefits but also centralises emissions sources, making CO_2 capture more viable.

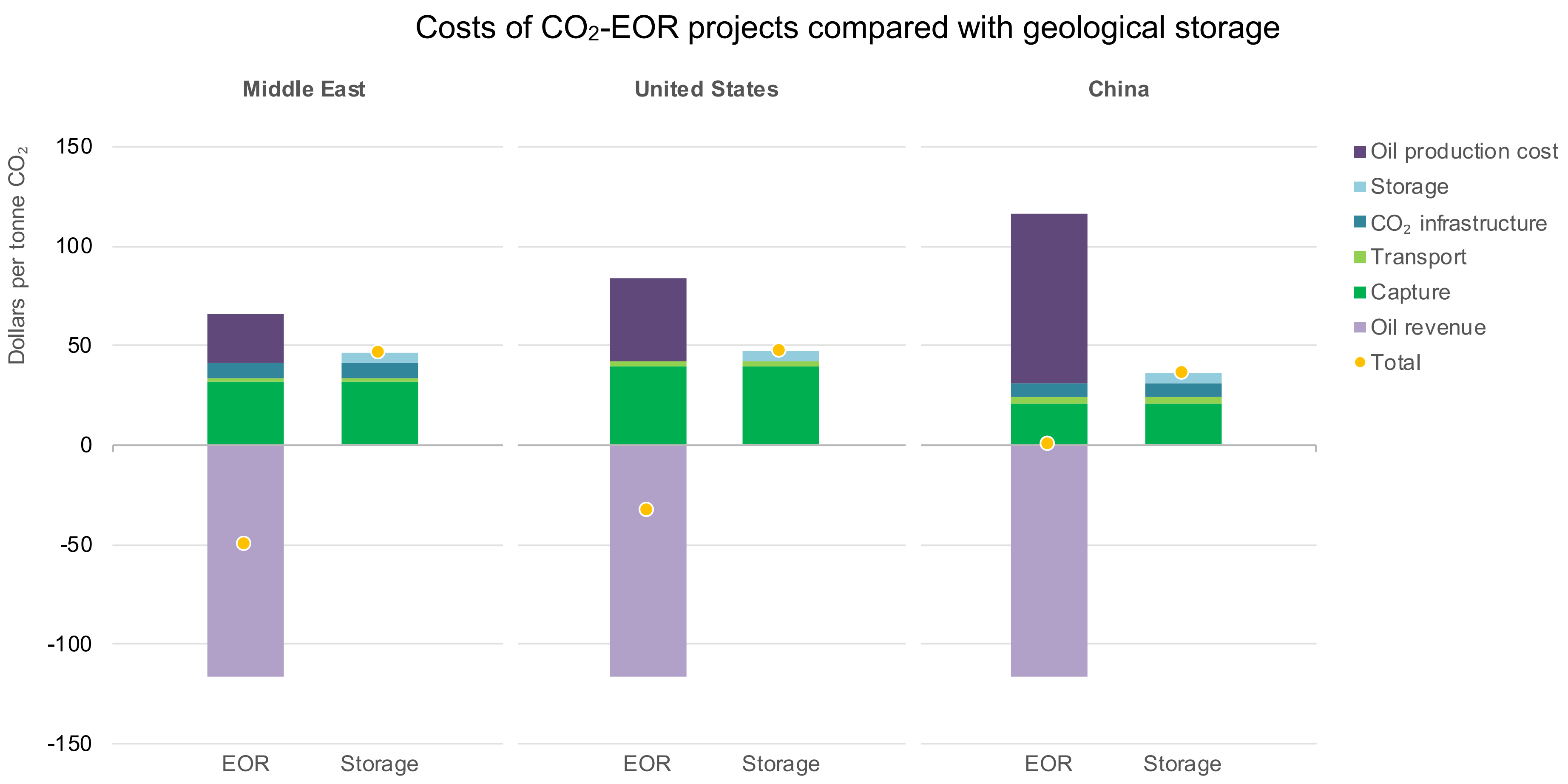
A number of refineries have installed units to capture CO_2 emissions. For example, a large portion of the emissions from the 400 kb/d Pernis refinery in Rotterdam are captured, transported and used in nearby greenhouses, and there are a number of other demonstration CCUS projects in refineries elsewhere.

Injecting CO_2 to enhance oil recovery can provide low-carbon oil, but care is needed to avoid double-counting the emissions reductions

Allocation of CO_2 emissions and credits from CCUS during CO_2-EOR for different sources of CO_2



CO_2 storage for EOR has a lower net cost than geological storage



Note: Assumes a USD 70/bbl oil price.
Source: IEA (2018), *World Energy Outlook 2018*, www.iea.org/weo2018.

CO_2-EOR can be an important stepping stone to large-scale deployment of CCUS

One way to store CO_2 underground is to inject CO_2 into existing oil fields. This is a well-known EOR technique, as the addition of CO_2 increases the overall reservoir pressure to force the oil towards production wells; it can also blend with the oil, improving its mobility and so allowing it to flow more easily towards production wells.

Today the majority of injected CO_2 in CO_2-EOR projects is produced from naturally occurring underground CO_2 deposits. This may appear a somewhat ironic situation, given the wide efforts to reduce CO_2 emissions from the global energy system, but it results from the absence of available CO_2 close to oil fields. In the United States, for example, less than 30% of the near 70 Mt CO_2 injected each year for CO_2-EOR is captured from anthropogenic sources.

Since CO_2 is a costly input to the EOR process, CO_2-EOR operators currently seek to minimise its use. In the United States, between 300 kg and 600 kg of CO_2 is injected in EOR processes per barrel of oil produced. Higher utilisation rates are possible – injection of 900 kg CO_2 per barrel produced could be technically possible in some fields – and this would not only boost production to a higher degree, but also ensure that a greater level of CO_2 is stored per barrel of oil produced.

If enough man-made CO_2 is injected during CO_2-EOR, the amount that ends up stored in the ground could exceed the CO_2 emissions from the production and combustion of the oil itself (the threshold depends on the level of scope 1 and 2 CO_2 emissions but is around 600 kg CO_2/boe). The full life-cycle emissions intensity of the oil therefore would be negative and the oil could be described as net “carbon-negative”.

However, this logic critically depends on from where the CO_2 is sourced. A credit associated with storing CO_2 underground can be counted only once: either it can reduce the emissions from the original source when it was captured or it can reduce the emissions from oil production. It cannot do both.

For CO_2-EOR to produce negative emissions – that is, reduce the stock of CO_2 in the atmosphere – EOR projects would need to inject CO_2 that has either come from the combustion or conversion of biomass or has been captured directly from the air at a rate higher than the scope 1, 2 and 3 emissions arising from the production and consumption of the oil.

In the SDS, CO_2-EOR production rises from 0.5 mb/d today to 1.6 mb/d in 2040, facilitated by higher carbon prices.

Besides the increase in production, a critical indirect benefit of CO_2-EOR is that it offers a low-cost opportunity to deploy CCUS projects. Combining CCUS facilities with CO_2-EOR operations provides a cost-effective way to deploy CCUS. The oil revenues generated reduce project costs and expand the amount of CO_2 stored per unit of investment. Of the 23 CCUS projects currently operating or in construction today, 16 use the captured CO_2 for EOR.

If further CO2-EOR projects using captured CO_2 can be developed, this would be likely to reduce the costs of CCUS more generally through learning-by-doing, and by expanding the market and pipeline network for CO_2.This could then provide a stepping stone towards large-scale deployment of CCUS, including for the production of low-carbon fuels such as hydrogen.

Low-carbon liquids and gases in energy transitions

Slides 142 - 152

The transition towards low-carbon liquids and gases

Reducing the emissions impact of oil and natural gas supply is one element of the transition described in the SDS. But ultimately energy transitions will need truly low-carbon liquids and gases, including some that have some synergies with today's oil and gas industry:

- low-carbon hydrogen
- biomethane
- advanced biofuels.

These fuels all have the potential to be much more widely deployed in a low-emissions energy system, but all face commercial challenges to scale up as they are, for the most part, significantly more expensive to produce than today's oil products and natural gas.

As with many aspects of transitions, there are issues for governments to consider with respect to these low-carbon fuels and technologies, including R&D efforts, their envisaged places in future energy systems, and the regulatory frameworks and targeted support that will be required to scale up their use.

For countries considering the future of gas grids, questions about the relative importance, and respective roles, of electricity and gas networks are central to the design of energy transitions. Long-term strategies need to consider the potential for these networks to deliver different types of gases in a low-emissions future, as well as their role in ensuring energy security.

Oil and gas exporters seeking ways to guarantee long-term markets for their resources may also need to start considering carefully the potential for hydrogen, including options for its transportation to consumers, if it is to offer a long-term alternative to trade in hydrocarbons.

For its part, the oil and gas industry has extensive experience with managing multibillion-dollar projects and in handling liquids and gases. These technologies and fuels could therefore be a good match with their existing skill sets, arguably a better match than electricity or more distributed alternative low-carbon fuels.

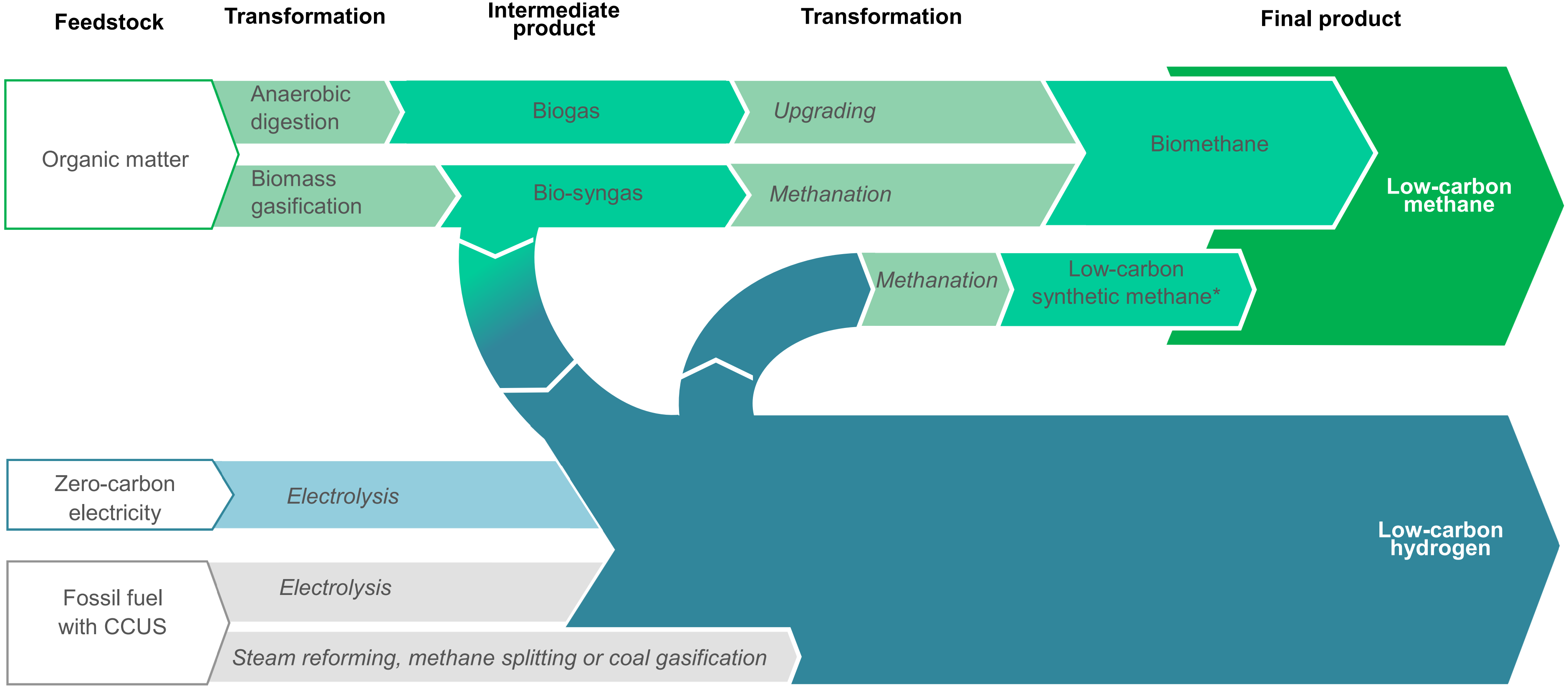
Low-carbon liquids and gases can for the most part take advantage of existing transmission and distribution infrastructure and can be used across the energy sector. They are particularly useful in many hard-to-abate sectors such as aviation, shipping, iron and steel production, chemicals manufacturing, high-temperature industrial heat, and long-distance and long-haul road transport. Without the support of the oil and gas industry, these technologies may never reach the level of maturity where they can supply these sectors cost-competitively.

Moving into these areas does of course come with hazards, not only related to commerciality but also from concerns about the real life-cycle environmental gains from biofuels, especially once disruptions to land use and competition with food supplies are taken into account. That is why the research is focused on commercialising fuel production from waste products and residues, rather than energy crops.

From an oil and gas company perspective, rising interest is underpinned by the affinity of these fuels with existing business models, a hedge against possible future restrictions on high-carbon fuels, and the way that low-carbon liquids and gases allow companies to reduce the carbon intensity of the energy they supply to the market.

Different routes to supply low-carbon methane and hydrogen

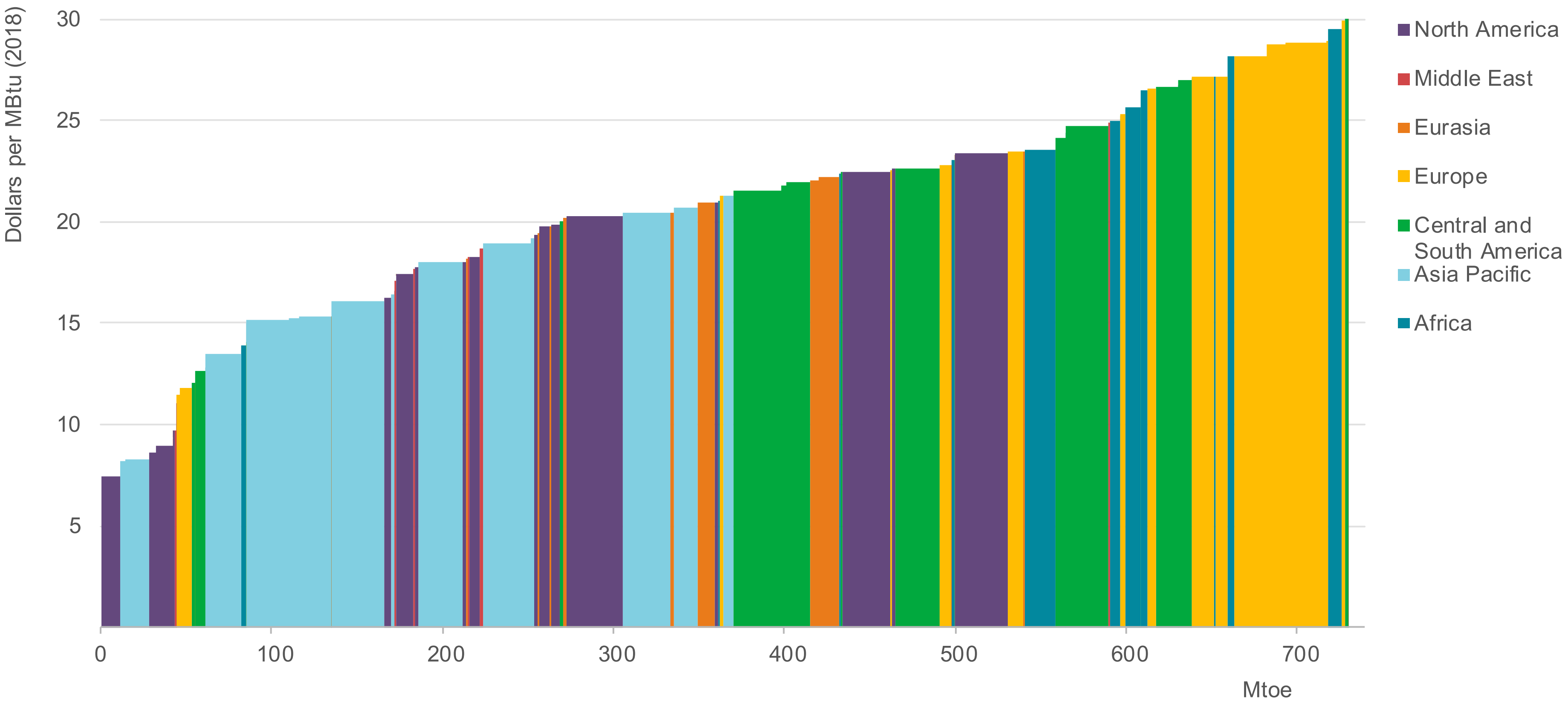
Alternative supply routes to produce low-carbon gases



* Synthetic methane is low-carbon only if the CO_2 originates from biogenic sources or the atmosphere.

Around 20% of today's natural gas demand could be met by sustainable production of biomethane, but at a cost

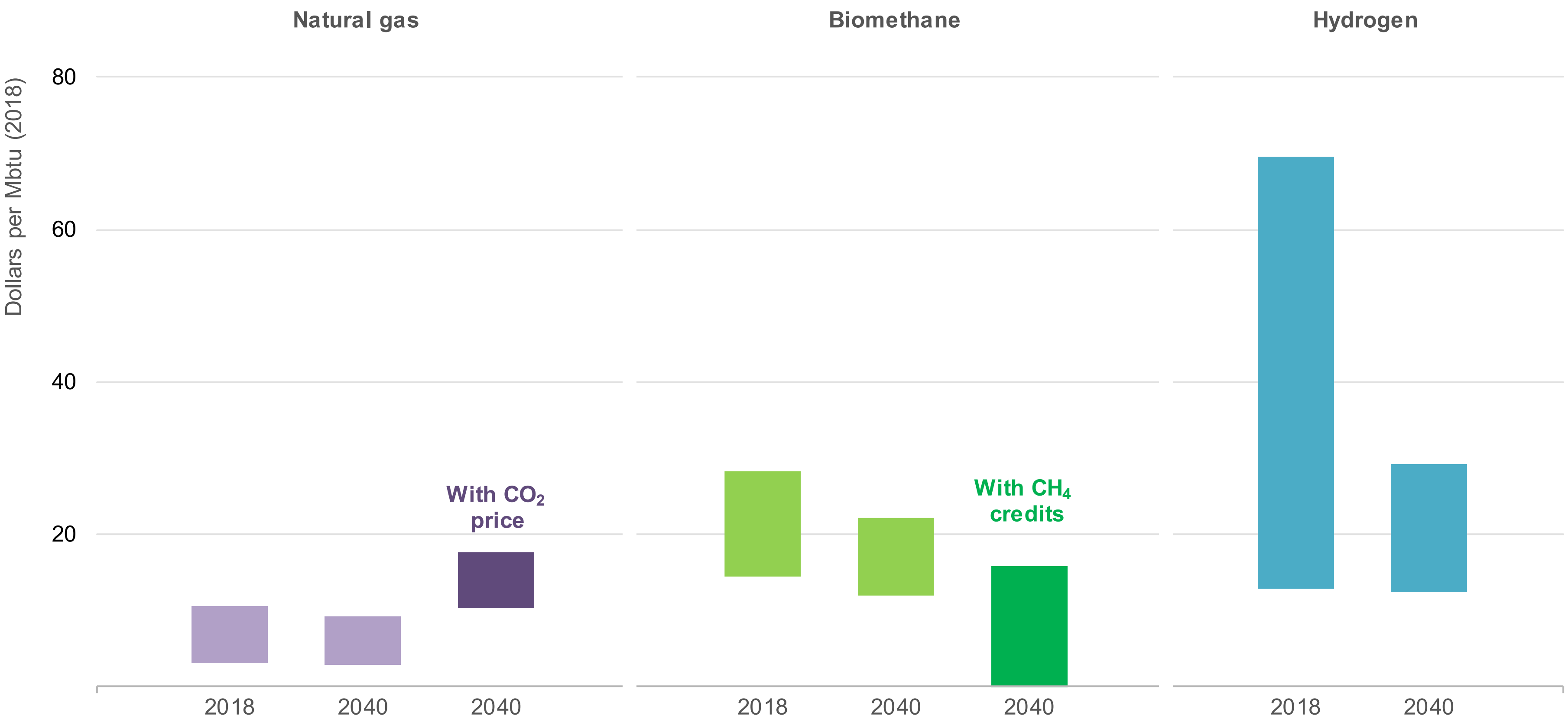
Global sustainable technical potential for biomethane supply, 2018



Source: IEA (2019), *World Energy Outlook 2019*, www.iea.org/weo2019.

By 2040, increased deployment is narrowing the cost gap between low-carbon gases and natural gas in the SDS

Supply costs of natural gas, biomethane and hydrogen in the SDS, 2018 and 2040



Note: "With CH_4 credits" recognises the value of avoiding methane emissions that would otherwise take place from the decomposition of feedstocks; this value utilises CO_2 prices from the SDS and assumes that one tonne of methane is equivalent to 30 tonnes of CO_2.

Source: IEA (2019), *World Energy Outlook 2019*, www.iea.org/weo2019.

Industrial opportunities to scale up the uses of low-carbon hydrogen

Interest in low-carbon hydrogen has increased sharply in recent years, reflecting the improvement in its outlook as a low-carbon energy carrier, especially with the declining costs of renewable electricity. Producing low-carbon hydrogen, however, is costly at the moment, and investment in hydrogen and CCUS infrastructure presents significant risks in the absence of assured supply and demand.

Hydrogen is not new to the energy system; supplying hydrogen to industrial users is a major business globally and integrated oil and gas companies typically have extensive experience producing and handling hydrogen. However, only a fraction of this is low-carbon hydrogen. Beyond its existing uses, low-carbon hydrogen could help deliver deep emissions reductions across a wide range of hard-to-abate sectors.

Producing low-carbon hydrogen from natural gas with CCUS costs USD 12/MBtu to USD 20/MBtu, while producing it from renewable-based electricity costs USD 25/MBtu to USD 70/MBtu. Moreover, the development of hydrogen infrastructure is slow and holding back wider adoption of hydrogen.

With these and other barriers in mind, the IEA has identified four major opportunities to scale up hydrogen use over the next decade (IEA, 2019). In all of these areas, co-operation among governments, and between governments and industry, will be essential:

- Make industrial ports the nerve centres for scaling up the use of clean hydrogen. Today, much of the refining and chemicals production that uses hydrogen based on fossil fuels is already concentrated in coastal industrial zones around the world, such as the North Sea in Europe, the Gulf Coast in North America and southeast China. Encouraging these plants to shift to cleaner hydrogen production would drive down overall costs. These large sources of hydrogen supply can also fuel ships and trucks serving the ports and power other nearby industrial facilities such as steel plants.
- Build on existing infrastructure, such as millions of kilometres of natural gas pipelines. Introducing clean hydrogen to replace just 5% of the volume of countries' natural gas supplies would significantly boost demand for hydrogen and drive down costs.
- Expand hydrogen in transport through fleets, freight and corridors. Powering high-mileage cars, trucks and buses to carry passengers and goods along popular routes can make fuel-cell vehicles more competitive.
- Launch the hydrogen trade's first international shipping routes. Lessons from the successful growth of the global LNG market can be leveraged. International hydrogen trade needs to start soon if it is to make an impact on the global energy system.

Biomethane provides a ready low-carbon alternative to natural gas

A key issue for blending hydrogen into gas grids is the tolerance of existing pipelines and equipment for hydrogen, which has different properties from natural gas. There are no such issues with biomethane, which is a ready alternative. Unlike hydrogen, biomethane, a near-pure source of methane, is largely indistinguishable from natural gas and so can be used without the need for any changes in transmission and distribution infrastructure or end-user equipment.

As of today, over 1 billion tonnes of organic by-products and waste are thrown away or abandoned every year. Their decomposition can lead to emissions of methane, which has a significantly higher global warming potential than CO_2; the waste, if left unmanaged, can cause land and groundwater contamination. If these waste products were collected and processed in an appropriate way, they could provide a valuable source of renewable energy in the form of biogas.

Biogas is already used as a local source of power and heat, especially for rural communities. If biogas is upgraded to pipeline-quality gas (it is then typically known as biomethane), it could help to reduce the emissions intensity of gas supply in gas-consuming economies.

There are over 700 biomethane plants in operation today producing around 2.5 Mtoe of biomethane globally. Although biomethane represents less than 0.1% of natural gas demand today, its production and use are supported by an increasing number of policies, especially in the transport and electricity sectors.

As with hydrogen, biomethane is also expensive today: meeting 10% of today's gas demand with biomethane would cost USD 10/MBtu to USD 22/MBtu. Nonetheless, this report estimates that around 730 Mtoe of biomethane could be produced sustainably today, equivalent to over 20% of global natural gas demand. This potential is widely spread geographically, though some of the lowest-cost options are available in developing economies in Asia.

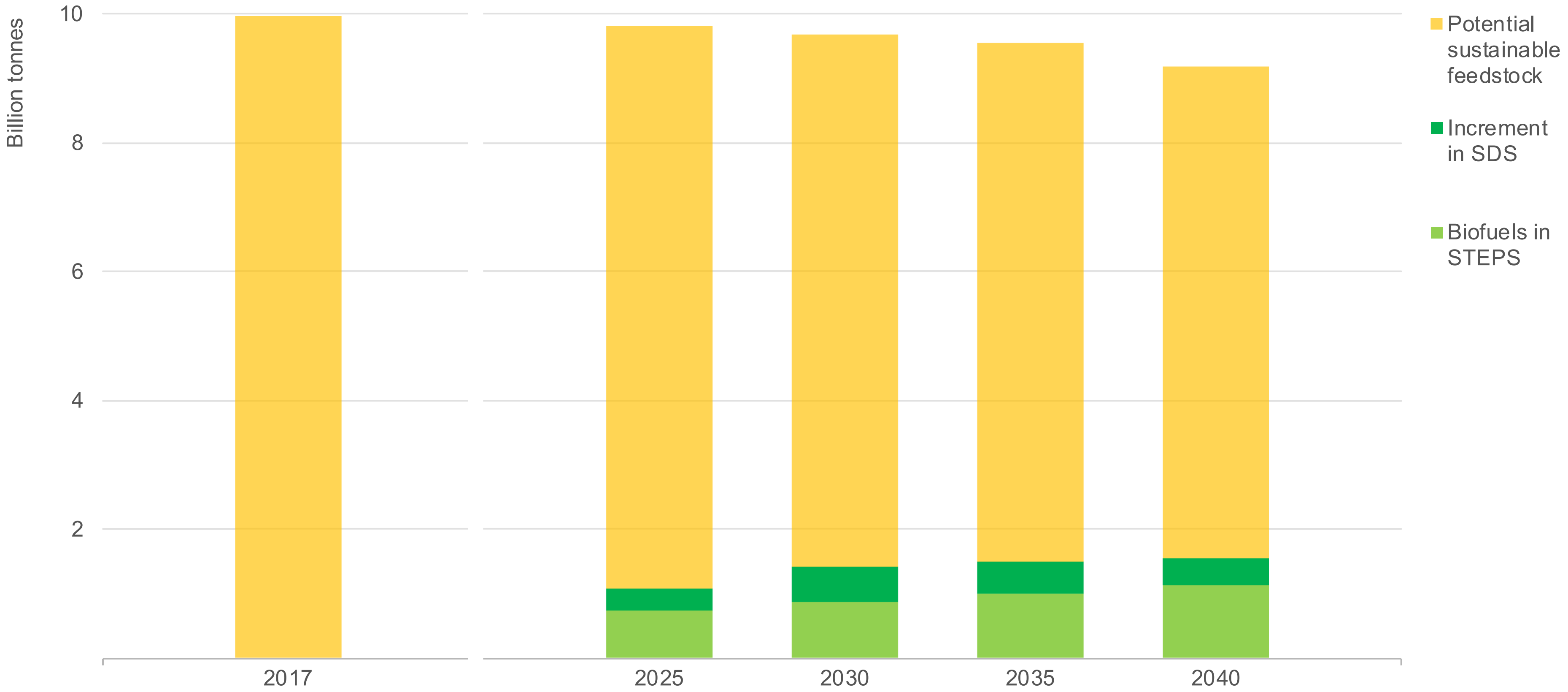
Industry support for biomethane is coming from a number of areas, including some producers of natural gas. But a key constituency that is increasingly supportive of biomethane is made up of gas infrastructure operators who see that gas infrastructure will ultimately need to deliver truly low-carbon energy sources if it is to secure its role in a low-emissions energy system.

In the SDS, biomethane use rises to over 200 Mtoe in 2040, and more than 25 Mtoe of low-carbon hydrogen is injected into gas networks. Low-carbon gases make up 7% of total gas supply globally in 2040 and they are on a steep upward trajectory at the end of the outlook period. Over 15% of total gas supply in China and the European Union is low-carbon gas in 2040.

Globally, low-carbon hydrogen and biomethane blended into the gas grid in the SDS avoid around 500 Mt of annual CO_2 emissions that would have occurred in 2040 if natural gas had been used instead. In addition, over 80 Mtoe of low-carbon hydrogen is also used directly in end-use sectors in 2040.

There is a vast potential to produce biofuels in a sustainable manner using advanced technologies

Sustainable feedstock available and levels needed to cover total biofuel consumption in the SDS



Note: "Sustainable" feedstock has near-zero life-cycle GHG emissions, does not compete with food for agricultural land and does not have other adverse sustainability impacts (such as reducing biodiversity). The sustainable level of wood feedstock estimated here is below annual forest growth rates to ensure that forest levels are preserved.
Source: IEA (2018), *World Energy Outlook 2018*, www.iea.org/weo2018.

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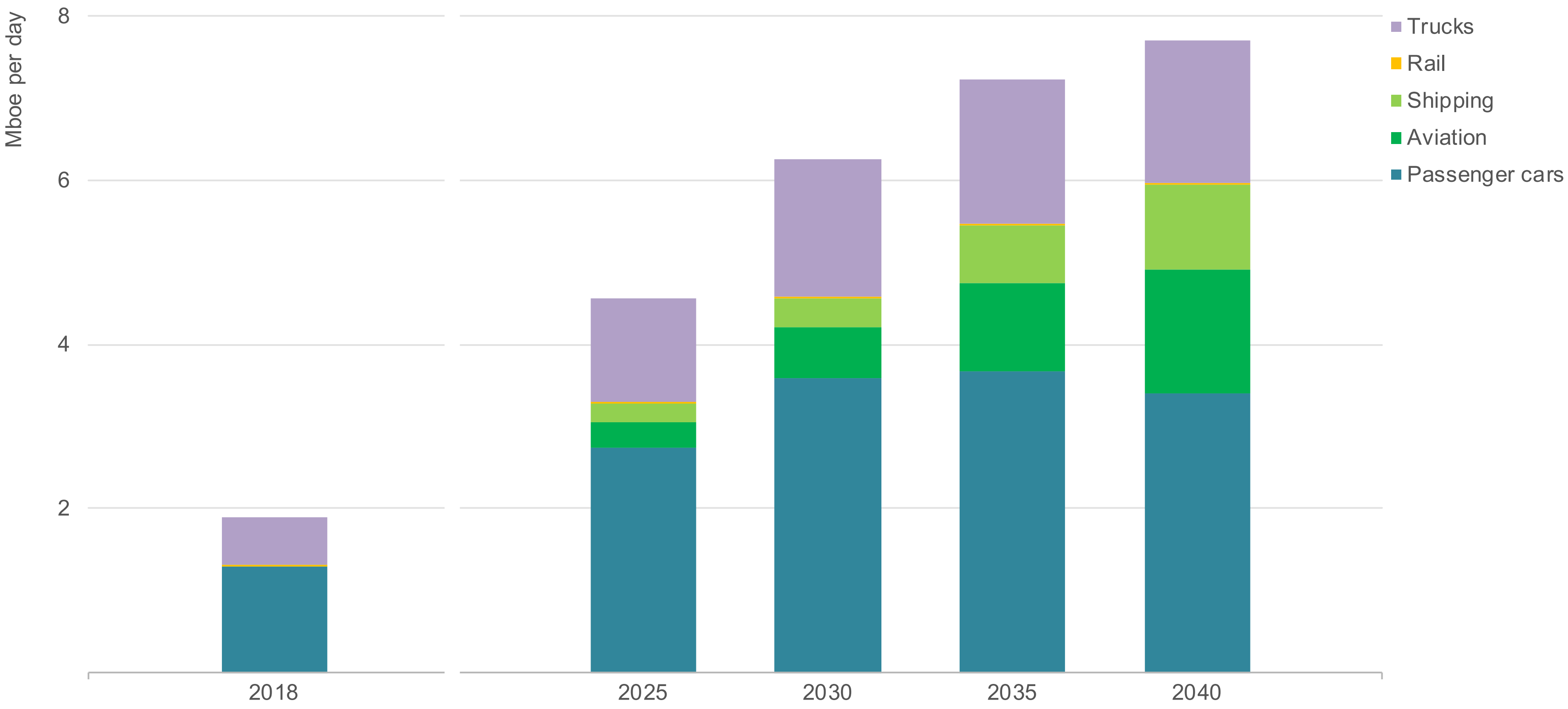
Biofuels are key to emissions reductions in a number of hard-to-abate sectors

Consumption of biofuels by sector in the SDS



Biofuels can make up a growing share of future liquids demand, but most growth will need to come from advanced technologies that are currently very expensive

Biofuels play an increasing important role in the SDS: production quadruples from around 2 mboe/d today to almost 8 mboe/d by 2040. In 2040, biofuels account for around 10% of global liquids demand.

Biofuels are used almost exclusively in the transport sector in this scenario. Consumption in passenger cars grows by around 2 mboe/d from today's level to a peak level of around 3.7 mboe/d in 2035. After 2035, there is a slight dip in the use of biofuels in passenger cars. This is due in part to the increasing electrification of the car fleet, but it is also because biofuels are needed elsewhere in the system as they provide an increasingly important mechanism to reduce emissions from the hard-to-abate aviation and shipping sectors.

Today the use of biofuels in aviation and shipping is limited, but there are few low-carbon alternatives to biofuels in shipping (hydrogen and LNG play some role in the shipping sector in the SDS) and no other viable low-carbon fuels to reduce emissions from aviation.

On the supply side, the majority of the 1.8 mboe/d of biofuels produced globally today use "conventional" methods of production. Concerns have been raised about the sustainability of these methods in some countries, as the feedstocks required can compete with food production for agricultural land and there can be a large increase in CO_2 emissions intensity associated with land clearing and cultivation.

As a result, there is increased interest in advanced biofuels, which can avoid these concerns. Various materials can be used: waste oils, animal fats, lignocellulosic material such as agricultural and forestry residues, and municipal wastes, and all are the subject of current research programmes. If successful, the results of these research programmes could lead to huge potential increases in biofuel production. Many of the oil and gas companies have active R&D programmes in these areas.

We estimate that today there are around 10 billion tonnes of lignocellulosic "sustainable" feedstock that could be used for biofuels production worldwide. The 8 mboe/d of biofuel production in the SDS would only need around 15% of the available feedstock.

While large volumes of advanced biofuels could be produced sustainably, their development and deployment has been slowed by their costs (relative to both conventional biofuels and oil). Conventional biofuel feedstocks can often be harvested close to production centres; they have a higher energy content, and they often have a low level of contaminants so handling and treatment can be relatively inexpensive and simple.

By contrast, advanced biofuel feedstock tends to be spread over a larger geographic area and of variable quality. Producing a barrel of advanced biodiesel costs around USD 140/barrel today. Assuming that this results in no net CO_2 emissions, a carbon tax above USD 150/t CO_2 would be required for such a biodiesel to be cost-competitive with diesel refined from crude oil. The future of advanced biofuels therefore will depend critically on continued technological innovation to reduce production costs as well as stable and long-term policy support.

Creating long-term sustainable markets for hydrocarbons relies on expanding non-combustion uses, or removing and storing the carbon

The response of the world's largest oil and gas resource holders to the prospect of falling demand for carbon-intensive fuels is a critical issue for energy transitions. These countries are always likely to seek out opportunities to monetise these resources. Their development could be made compatible with global aims to reduce emissions either by expanding non-combustion uses of hydrocarbons or by converting the hydrocarbons to zero-carbon fuels to be delivered to consumers.

One option to expand the non-combustion uses of hydrocarbons is to increase the direct production of chemical products relative to transport fuels. Recently, a growing number of companies are making efforts to integrate refining and petrochemical facilities, with an aim to increase chemical product yields beyond the typical levels. There are even more ambitious schemes being pursued to produce chemical products directly from crude oil, with traditional refinery outputs (such as gasoline or diesel) becoming by-products of this process. The first planned "crude-to-chemicals" complex is currently being designed by Saudi Aramco and aims to convert 40-45% of crude oil to chemical products. A second project aims for a higher yield and is being developed based on new thermal cracking technology. These schemes could challenge traditional upstream, refining and petrochemical businesses, especially in the event that demand for transport fuels wanes while petrochemical uses remain strong (as in the SDS).

One option to convert hydrocarbons to zero-carbon fuels is to produce hydrogen from the oil or natural gas and to capture, use or store permanently the separated CO_2 or carbon. Two ways to do this are:

- "**Methane reforming**": this is the most common method, in which methane is converted into pure streams of hydrogen and CO_2 at high temperature and pressure. The pure stream of CO_2 can be captured at relatively low costs, which would then need to be stored underground or incorporated permanently into other materials.
- **"Methane splitting":** whereby methane is converted into hydrogen and solid carbon (also called "carbon black"). The carbon black can be buried or used to produce rubber, tyres, printers or plastics. The splitting could be performed either close to the production site, which would require new hydrogen transmission and distribution infrastructure, or close to the point of end use. The latter production route could make use of existing gas infrastructure to transport and distribute the methane and so may be the more cost-effective option (although it would rely on the consumer handling the carbon black). Methane splitting has received interest from a number of countries and companies, although it is still at a very early stage of development and a number of challenges still need to be resolved.

To illustrate the volumes of CO_2 that could be involved, one can look at the CCUS requirements that would be compatible with large-scale production of oil and gas in selected major producers.

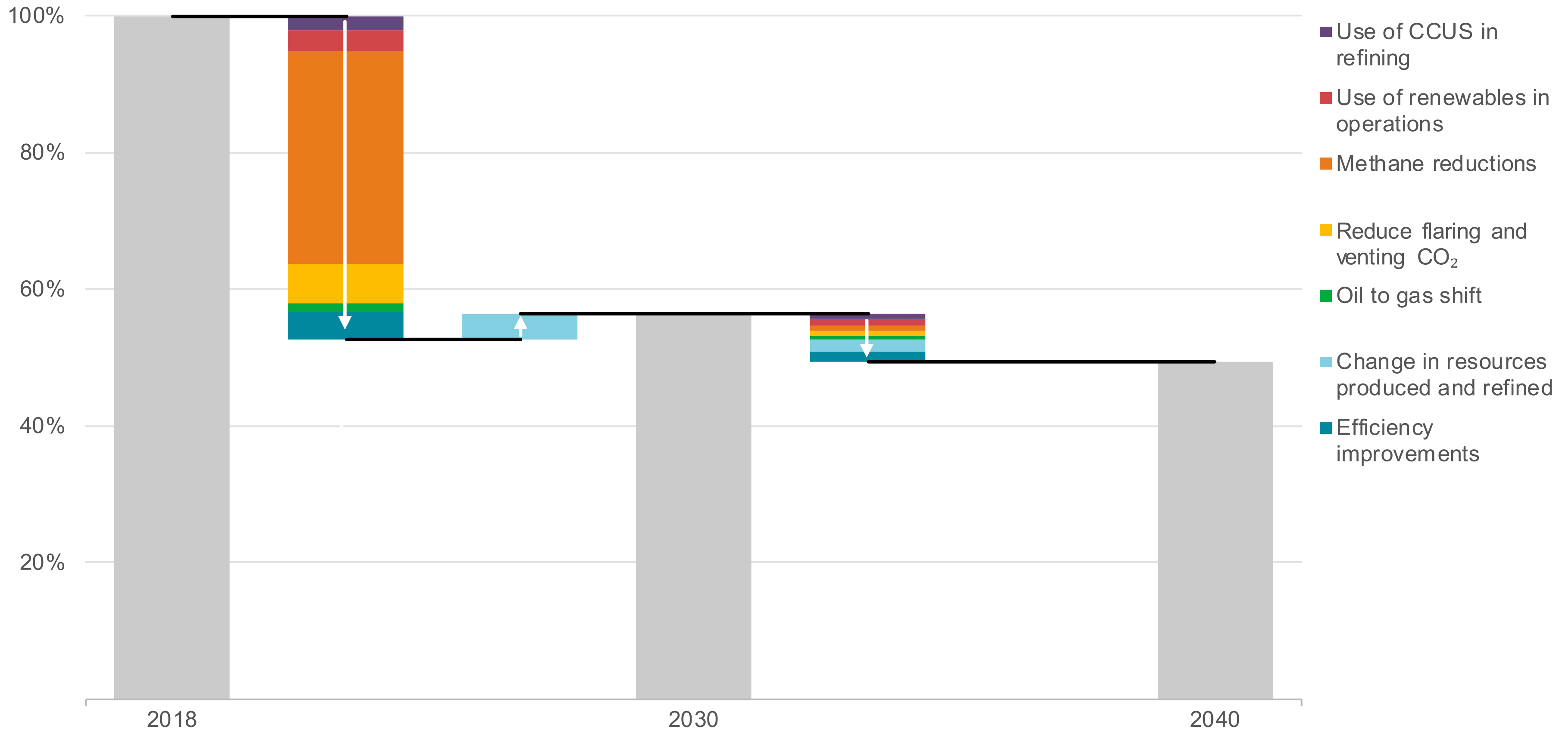
For example, in 2040 the Middle East produces 36 mb/d oil and over 1 tcm of natural gas in the STEPS, compared with 22 mb/d and 650 bcm in the SDS. If these countries were to produce at the higher levels of the STEPS without additional emissions, and assuming that there is large-scale demand for hydrogen, then around 14 mb/d oil and 350 bcm natural gas would need to be converted to hydrogen. This would produce almost 3 000 Mt CO_2 each year. Today, there is around 35 Mt CO_2 captured globally, meaning that CCUS deployment would need to scale up by a factor of 100 within the next 20 years.

The transition from “fuel” to “energy” companies

Slides 153 - 160

The scope 1 and 2 emissions intensity of oil and gas production falls by 50% in the SDS, led by reductions in methane emissions

Changes in the average global scope 1 and 2 emissions intensity of oil and natural gas production in the SDS



Note: Global average scope 1 and 2 emissions for oil and natural gas are around 90 kg CO_2-eq/boe in 2018 and around 45 kg CO_2-eq/boe in 2040.

Immediate and rapid action on reducing emissions from current operations is an essential first step for oil and gas companies in energy transitions

A necessary first step for the oil and gas industry in energy transitions is to reduce the environmental footprint of its operations. This is not important just to reduce GHG emissions, but also because producers that can demonstrate strong action in this area can credibly argue that their oil and gas resources should be preferred over higher-emissions options.

In the SDS, industry efforts are pushed by CO_2 pricing and policy interventions and have a major impact on the level of scope 1 and 2 emissions. The emissions intensity of oil and natural gas production falls by more than 50% between 2018 and 2040, a drop in absolute terms of around 3 200 Mt CO_2.

The biggest impact, by far, on reducing scope 1 and 2 emissions over the next ten years is through tackling methane emissions. Reductions go beyond those technologies that would pay for themselves through the value of the captured methane. All technically available measures to reduce emissions are deployed by 2030, which leads to a 75% reduction in methane emissions from oil and gas operations. As discussed above, only a modest CO_2 price – applied to all sources of GHG emissions – would be needed to incentivise the adoption of these measures, but regulatory interventions could also play a role to encourage their introduction at the pace and scale needed.

Significant emissions reductions also come through strengthened efforts to eliminate flaring, and capturing and reinjecting CO_2 that is extracted with natural gas. There is wider adoption of efficiency improvements in existing facilities and the various "game-changing" measures are incorporated into the design of new facilities. This includes electrifying LNG facilities or equipping them with CCUS units, capturing and storing emissions from refining, and co-locating renewables with new upstream operations.

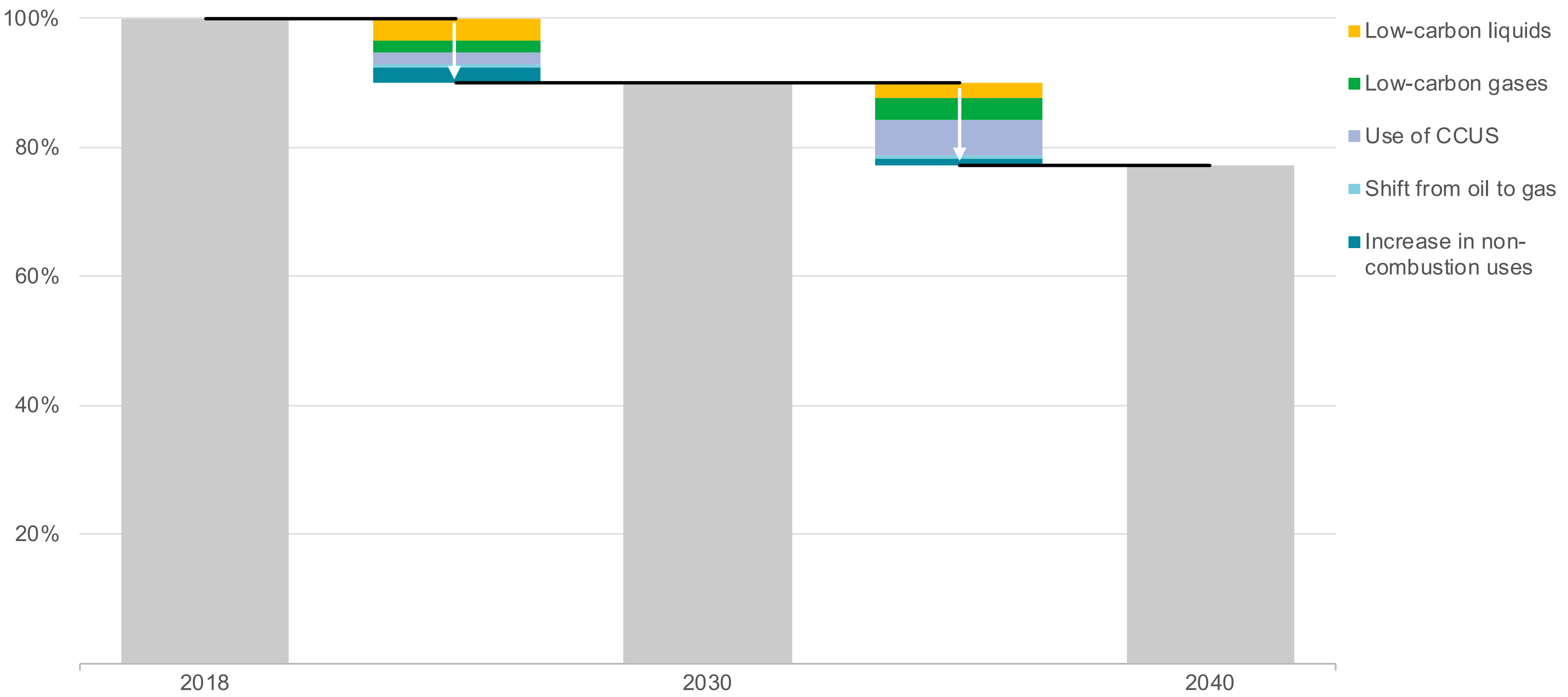
The CO_2 price in the SDS would be sufficient to encourage CO_2-EOR operators to inject anthropogenic rather than natural sources of CO_2. This is a crucial mechanism to storing permanently this CO_2 underground.

The captured CO_2 in this scenario comes from industrial facilities and power plants, which claim the emissions reduction credit. For CO_2-EOR to produce negative emissions – that is reduce the stock of CO_2 in the atmosphere – EOR projects would need to inject CO_2 that has either come from the combustion or conversion of biomass or has been captured directly from the air.

These reductions in scope 1 and 2 emissions are an essential step for oil and natural gas to play the role envisaged in the SDS. If they do not occur, then there would need to be a faster reduction in oil and gas demand to ensure compatibility with international climate targets.

The rise of low-carbon liquids and gases and CCUS help to reduce the scope 3 emissions intensity of liquids and gases by around 25% by 2040

Changes in scope 3 emissions intensity of liquids and gases consumed in the SDS



Consumer choices are key to reductions in scope 3 oil and gas emissions. But, there are still many options to reduce the emissions intensity of liquids and gases

While reducing the emissions intensity of oil and gas production is essential, today a much larger share of emissions comes from combustion of the fuels themselves. Tackling these emissions – along with the emissions from coal – is the critical factor for energy transitions. Many different actors have roles to play in this task, including national policy makers, urban planners, product designers, automobile manufacturers, fuel suppliers and individual consumers. In the SDS, there is a 6 000 Mt CO_2 drop in emissions from the combustion of oil and natural gas between 2018 and 2040 (and an 11 000 Mt CO_2 drop in emissions from coal).

Low-carbon electricity plays a central role in realising these reductions. However, as noted at the start of Section II, more than two-thirds of final energy consumption in the SDS in 2040 still comes from other sources, mainly from liquids and gases. This opens up a major set of questions about the availability of low-carbon fuels and alternative energy carriers such as hydrogen, and the possibilities to deploy CCUS.

In the SDS between 2018 and 2040, there is a 25% reduction in the scope 3 emissions intensity of all liquids and gases that are consumed globally. The largest portion of this reduction stems from the deployment of CCUS. By 2040 there is nearly 400 bcm of natural gas use that is equipped with CCUS (split equally between the power and industry sectors).

Biofuels play an important role in reducing the scope 3 emissions intensity, especially in the near term, while low-carbon gases – both hydrogen and biomethane – play a growing role in the latter part of our projection period as they start to come into the energy system at larger scale. Finally, growth in non-combustion uses of oil, such as the use of oil products as a petrochemical feedstock (assuming that these are not incinerated after use), also helps to reduce scope 3 emissions intensity.

The world is not on track to deliver these kinds of emissions reductions. They will require well-designed policies from governments (including carbon pricing) to promote research, development and large-scale deployment of the relevant technologies and infrastructure.

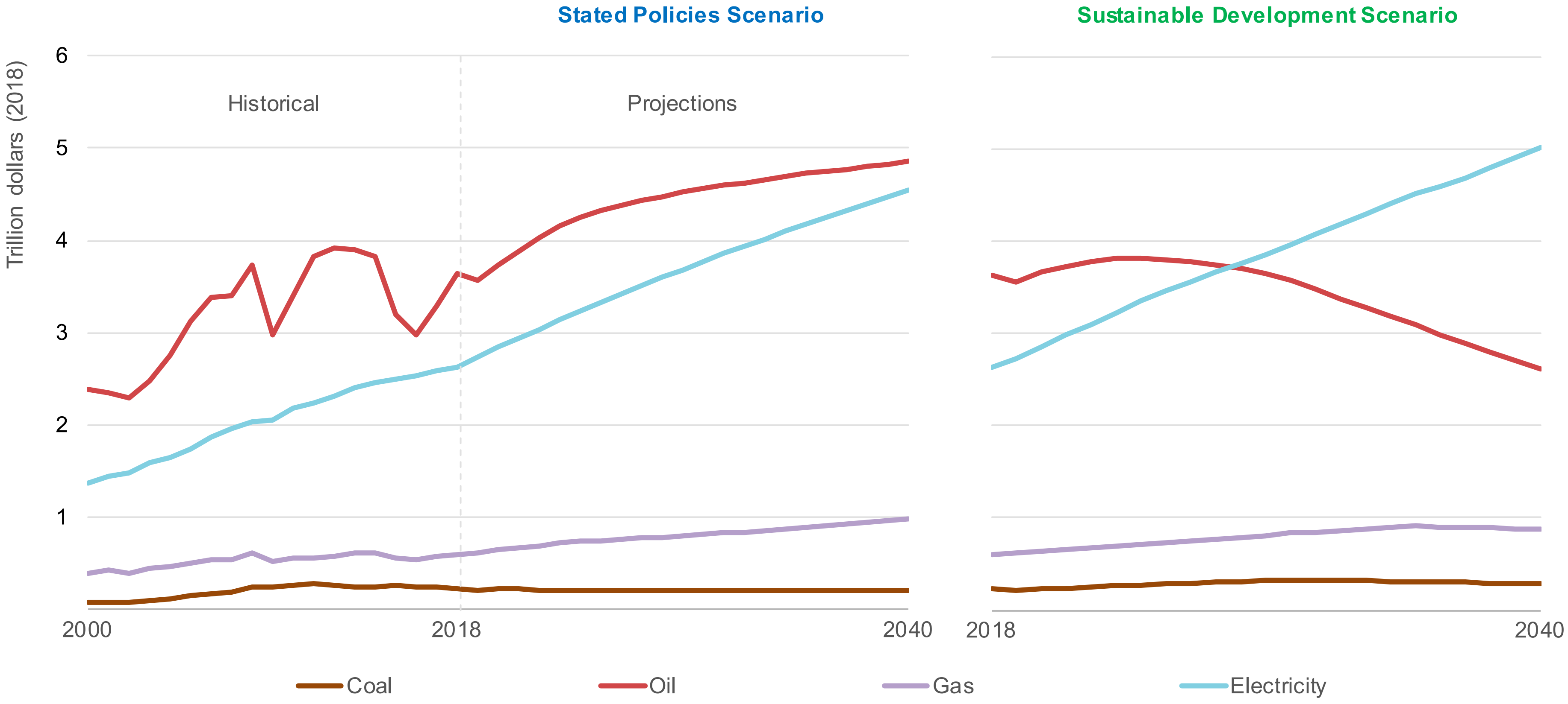
The oil and gas industry has an interest to support and accelerate these processes and, in doing so, create the sort of transition process in which their core skills and expertise find a place.

However, the overall reduction of 25% in scope 3 emissions intensity by 2040 would not, in aggregate, be enough to meet the sorts of targets that have been announced by some oil and gas companies. As technologies mature, or innovative technologies become available, companies could push more strongly on these levers in order to reduce their emissions profile further. But dramatic reductions in the emissions intensity of company portfolios would mean finding additional levers, beyond those available in the traditional business of providing fuels to consumers.

With this in mind, an increasing number of companies are looking into nature-based solutions as a complement to decarbonisation efforts. These efforts fall outside the scope of the energy sector (and of this analysis) but can play an important role. Many are also seeking to expand roles in the electricity sector, part of a journey from “fuel” to “energy” companies.

In the SDS, electricity overtakes oil to become the largest element in consumer energy spending

Global end-user energy spending by fuel and scenario



Note: Includes taxes.
Source: Based on IEA (2018), *World Energy Outlook 2018*, www.iea.org/weo2018.

The dilemmas of company transformations

There are already examples of oil and gas companies that have made a leap into other areas of energy. The oft-quoted example is Ørsted in Denmark: in its previous incarnation as Dansk Olie og Naturgas (Danish Oil and Natural Gas [DONG]) it was charged with the development of Denmark's hydrocarbon resources in the North Sea. It started to diversify into electricity in the early 2000s, at which point it became DONG Energy. Then in 2017 it sold off its declining oil and gas business (to INEOS) and has become a leading light in the expansion of renewable electricity, particularly offshore wind.

The oil and gas assets continue to produce under different ownership (a point sometimes overlooked by the divestment movement), but the company has achieved impressive reductions in its overall emissions intensity. In 2009, Ørsted announced an initial CO_2 reduction target of 50% by 2020, compared with 2006. Now it is targeting GHG reductions of 78% by 2020 and 96% by 2023, with low-carbon energy (electricity and heat, including a significant bioenergy component) instrumental to the company's growth and its financial performance.

In the case of Ørsted, the starting point was a relatively small hydrocarbon resource base and mature fields; it is also operating in an overall policy environment that is targeting aggressive reductions in emissions. Its experience nonetheless offers an example of what might be possible in the broader oil and gas business.

The dilemma for today's fuel companies that are looking at becoming energy companies starts from the fact that oil and gas has been – and remains, for most – a successful business. It has rewarded shareholders with robust dividends, and the transition to "energy" could risk, at least in the near term, these financial returns. As noted in Section III, low-carbon energy businesses can certainly be profitable, but the returns for these segments have generally been lower than for hydrocarbons.

Transformations would also involve moving from business areas where companies have a demonstrable record of achievement into areas where they may currently have much less of a comparative advantage. For smaller or more specialised players in the oil and gas business, this may be a decisive consideration. As discussed in Section III, the strategic choices available to some much larger players, notably NOCs, are also framed by their mandate to act as custodians of national hydrocarbon wealth.

The companies that are embracing the transition from fuel to energy companies are attempting to straddle divergent possible outcomes and risks. Companies are investing to meet oil and gas requirements, sustaining the volume of their oil and gas activity, while building new low-carbon energy businesses. The balancing act is to generate the necessary cash flow to sustain investments in both hydrocarbons and new low-carbon businesses, while remaining financially robust for shareholders.

The companies themselves cannot determine how the relative markets will evolve for oil, gas, electricity or renewable energies. One of the few things, though, that emerges with a degree of certainty in the *WEO* scenarios is that however fast energy demand grows in the future, electricity demand grows more quickly. And the composition of that electricity shifts towards lower-carbon sources. This provides real market opportunities for related businesses seeking to grow or to offset shrinking markets elsewhere.

Low-carbon electricity is an essential part of the world's energy future; it can be part of the oil and gas industry's transformation as well

Investment by oil and gas companies in the electricity sector has to date accounted for a small part of their overall capital spending. Companies have mostly sought to operate effectively in these new businesses through acquisitions rather than organic development. These acquisitions have the benefit of providing an immediate foothold in the market through a viable business, while at the same time acquiring valuable know-how and experience.

Even though today's low-carbon investments may offer lower headline returns than oil and gas, there are ways for companies to structure these investments that increase their attractiveness. Oil and gas companies benefit from low financing costs. In addition, farming down part of the capital in each project to outside investors can help. As a result, with a disciplined approach to investment, IRRs for renewable energy investments can approach levels similar to some oil and gas projects. And even if returns may lag behind those for hydrocarbons, they help companies to immediately meet their carbon intensity commitments.

The viability of opportunities for the oil and gas industry varies widely across the spectrum of low-carbon businesses. Some areas already have viable business models into which the industry can expand. These include solar (PV or thermal, distributed or utility scale), wind (particularly offshore), power trading and aggregation, electricity marketing, biofuels, energy efficiency (including as a service), and natural carbon sinks. For many oil and gas companies, and countries, the development of power generation from natural gas also plays a role in decarbonisation strategies, and the expansion into renewable electricity complements downstream activities in the gas business.

The same is not yet true for other fields, notably hydrogen and CCUS. Here the task is to develop these models through R&D efforts and via partnerships with companies and governments. Oil and gas companies typically seek to lay off risk in high-cost projects by working with others; this approach will also be pivotal if there is to be progress in these less certain and more capital-intensive sectors.

To reduce GHG emissions, the world needs an energy transformation of unprecedented scale and breadth, involving a wide range of clean fuels and low-carbon technologies. The oil and gas industry has global breadth and diversity, as well as huge potential in terms of technical and financial expertise, and management and financial resources. For the future of the oil and gas industry, and its relationship with the societies in which it operates, it is strategically critical to harness this potential to the global fight against climate change.

Annex

Acknowledgements

This report was prepared by the Energy Supply and Investment Outlook (ESIO) Division of the Directorate of Sustainability, Technology and Outlooks (STO). The principal author was Christophe McGlade, with major contributions from Michael Waldron and Tim Gould (Head of Division), who designed and directed the analysis. Other key contributors from across the International Energy Agency (IEA) were Simon Bennett, Alessandro Blasi, Toril Bosoni, Joel Course, Tae-Yoon Kim, Yoko Nobuoka, Paweł Olejarnik, Ryszard Pośpiech, Frances Reuland, Laszlo Varro and Peter Zeniewski. Eleni Tsoukala provided essential support.

Valuable comments and feedback were provided by senior management and numerous other colleagues within the IEA, in particular Mechthild Wörsdörfer, Keisuke Sadamori, Laura Cozzi, Dave Turk and Samantha McCullough.

The analysis relies heavily on the scenario analysis and modelling undertaken by the entire *World Energy Outlook* team.

Thanks also go to Astrid Dumond, Tanya Dyhin, Jad Mouawad, Jethro Mullen and Therese Walsh of the Communications and Digital Office, as well as the Energy Data Centre. Erin Crum was the editor.

The work was undertaken in collaboration with the World Economic Forum, and benefited greatly from discussions at a high-level workshop on the "Oil and Gas Industry in Energy Transitions", organised in Paris on 25 November 2019.

Many experts from outside the IEA provided input, commented on the underlying analytical work, and reviewed a preliminary draft of the report. Their comments and suggestions were of great value.

The individuals and organisations that contributed to this study are not responsible for any opinions or judgements it contains. All errors and omissions are solely the responsibility of the IEA.

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Design in France by IEA – January 2020