The Implications of Oil and Gas Field Decline Rates

International Energy Agency

INTERNATIONAL ENERGY AGENCY

The IEA examines the full spectrum of energy issues including oil, gas and coal supply and demand, renewable energy technologies, electricity markets, energy efficiency, access to energy, demand side management and much more. Through its work, the IEA advocates policies that will enhance the reliability, affordability and sustainability of energy in its 32 Member countries, 13 Association countries and beyond.

IEA Member countries:

Australia
Austria
Belgium
Canada
Czech Republic
Denmark
Estonia
Finland
France
Germany
Greece
Hungary
Ireland
Italy
Japan
Korea
Latvia
Lithuania
Luxembourg
Mexico
Netherlands
New Zealand
Norway
Poland
Portugal
Slovak Republic
Spain
Sweden
Switzerland
Republic of Türkiye
United Kingdom
United States

The European Commission also participates in the work of the IEA

IEA Association countries:

Argentina
Brazil
China
Egypt
India
Indonesia
Kenya
Morocco
Senegal
Singapore
South Africa
Thailand
Ukraine

Source: IEA.
International Energy Agency
Website: www.iea.org

Executive summary

Discussions on the future of oil and gas often overemphasise demand drivers and underappreciate supply drivers

Debate over the future of oil and natural gas tends to focus on the outlook for demand, with much less consideration given to how the supply picture could develop. This asymmetry is misplaced and a thorough understanding of the rate at which production from existing oil and gas fields declines over time is more important than ever. The International Energy Agency (IEA) has long examined this issue. Decline rates – the annual rate at which production declines from an existing oil or gas field – underpin our analysis of market balances and investment needs across all outlook scenarios.

Nearly 90% of annual upstream oil and gas investment since 2019 has been dedicated to offsetting production declines rather than to meet demand growth. Investment in 2025 is set to be around USD 570 billion, and if this persists, modest production growth could continue in the future. But a relatively small drop in upstream investment can mean the difference between oil and gas supply growth and static production. At the same time, less investment is required in a scenario in which demand contracts.

A detailed look at today's global supply picture

The composition of oil and gas production has changed rapidly in recent years with the notable rise of tight oil and shale gas. In 2000, conventional oil fields contributed 97% of total oil output globally, however, by 2024 this share had fallen to 77% as a result of rising output from unconventional fields. In the case of natural gas, around 70% of the 4 300 billion cubic metres (bcm) produced today is from conventional fields, with nearly all of the rest being shale gas produced in the United States. Even with the shale revolution, overall oil and gas output still relies heavily on a small number of supergiant fields, largely in the Middle East, Eurasia and North America, which together accounted for almost half of global oil and gas production in 2024.

Detailed analysis of the production records of around 15 000 oil and gas fields from around the world reveals that the global average annual observed post-peak decline rate is 5.6% for conventional oil and 6.8% for conventional natural gas. This varies widely by field type: supergiant oil fields decline by an average of 2.7% annually, while the average for small fields is more than 11.6%. Onshore oil fields decline more slowly, by an average of 4.2% per year, than those located deep offshore at 10.3%. The Middle East, which holds the world's largest conventional onshore fields, has the lowest oil observed post-peak decline rate at 1.8%, while Europe, which is has a very high share of offshore fields, exhibits the highest decline rate at 9.7%.

In the absence of investment, supply falls quickly

Alongside the *observed rate declines* that are derived from field production histories, it is possible to estimate the *natural rate declines* that would occur if all capital investment were to stop. These declines are even steeper. If all capital investment in existing sources of oil and gas production were to cease immediately, global oil production would fall by 8% per year on average over the next decade, or around 5.5 million barrels per day (mb/d) each year. This is equivalent to losing more than the annual output of Brazil and Norway each year. Natural gas production would fall by an average of 9%, or 270 bcm, each year, equivalent to total natural gas production from the whole of Africa today.

Natural decline rates are becoming steeper. In 2010, natural decline rates would have led to a 3.9 mb/d annual drop in oil production and 180 bcm annual drop in gas production. The sharper natural decline rates observed now compared with 2010 reflects the higher reliance today on unconventional sources, changes in the mix of conventional production (such as more deep offshore fields and NGLs), and a higher supply base.

Most unconventional sources of oil and gas production generally exhibit much faster decline rates than conventional types. If all investment in tight oil and shale gas production were to stop immediately, production would decline by more than 35% within 12 months and by a further 15% in the year thereafter. Shale plays in the United States are also becoming "gassier," raising overall decline rates as oil-rich fields mature.

Under natural decline rates, global oil and gas supply would become much more concentrated among a small number of countries in the Middle East and Russia, with implications for energy security. Most oil production in the United States comes from fast declining unconventional sources, while in the Middle East and Russia most oil is produced from slowly declining conventional supergiant fields. Absent further capital investment, advanced economies would face rapid production declines – a 65% drop over the next decade – while declines would be shallower in the Middle East and Russia (45%).

The oil and gas industry needs to run fast to stand still

If current levels of production are to be maintained, over 45 mb/d of oil and around 2 000 bcm of natural gas would be needed in 2050 from new

conventional fields. Investment in existing conventional oil and gas fields – for example through well workovers, infill drilling, waterflooding – slows production declines from the natural decline rate. There will also be a contribution to the supply balance from oil and gas projects that are still ramping up, from projects that have already been approved for development, and from ongoing investment in unconventional resources. Still, this leaves a large gap that would need to be filled by new conventional oil and gas projects to maintain production at current levels, although the amounts needed could be reduced if oil and gas demand were to come down.

Around 230 billion barrels of oil and 40 trillion cubic metres (tcm) of gas resources have been discovered that have yet to be approved for development. The largest volumes are in the Middle East, Eurasia, and Africa. Developing these resources could add around 28 mb/d and 1 300 bcm to the supply balance by 2050.

Filling the remaining supply gap to maintain today's production through to 2050 would require annual discoveries of 10 billion barrels of oil and around 1 000 bcm of natural gas. These amounts are just above what has been discovered annually in recent years. Developing these resources would add around 18 mb/d and 650 bcm of new oil and gas production by 2050.

In recent years, it has taken almost 20 years on average to bring new conventional upstream projects online. This represents the time from the issuing of a new exploration licence to the moment of first production. This includes five years on average to discover the field, eight years to appraise and approve it for development, and six years to construct the necessary infrastructure and begin production. Around two-thirds of conventional oil and gas projects approved in recent years have been expansions of existing fields, and more than 70% of recent conventional approvals are offshore.

Decline rates are central to IEA modelling and analysis

As oil and gas supply increasingly relies on fields with higher decline rates and complex operating environments, the interplay of investment decisions, economics, and regulation will shape supply resilience and market stability. A detailed understanding how this picture could evolve underpins the IEA's analysis of investment needs in each of our outlook scenarios, including those that achieve ambitious climate objectives, and informs our analysis of the implications of these scenarios for energy security, markets, prices, and emissions.

Introduction

Some elements of the global energy system are evolving rapidly. Nonetheless, oil and natural gas resources will continue to be needed for many decades to come. Most attention today focuses on uncertainties affecting the future evolution of oil and natural gas demand, with much less consideration given to how the supply picture could develop. This asymmetry is misplaced. The supply side matters. Understanding *decline rates* – the annual rate at which production declines from existing oil and gas fields – is a cornerstone to assess the outlook for oil and gas supply and, by extension, for market balances.

Without ongoing investment, oil and gas supply wanes because of declines in production from existing fields. These declines have to be offset. Options include: investing in existing fields to slow decline and/or to boost production; discovering and developing new fields of conventional or unconventional resources; or by reducing demand. Each approach requires large commitments of capital (albeit by different parties). Achieving even a small reduction in decline rates can result in large differences in future supply levels and investment requirements. Decline rates therefore have major implications for market stability and energy security.

Decline rates underpin all of the scenario analyses, ranging from short to long term, undertaken by the IEA. In addition to this report, the IEA has published detailed analyses on decline rates in several editions of the *World Energy Outlook (WEO),* building on the pioneering work on the topic first carried out in the *WEO-2008* and *WEO-2009*, as well as in the medium-term *Oil Market Report* series.

The focus of this analysis is to review current decline rates, how these have changed over time and why, what this means for future oil supply, and to investigate the implications for investment levels and energy security. It is presented in three chapters and an annex:

Chapter 1 reviews recent trends in oil and natural gas production, resource discoveries, project approvals and development, as well as changes in capital and operating costs and upstream investment.

Chapter 2 looks at oil and gas production prospects, starting with an updated analysis of the rate at which output from existing fields is expected to decline. It covers how decline rates vary over time across fields of various sizes, locations and countries, as well as between different types of oil and gas production, most notably conventional versus unconventional oil.

Chapter 3 examines the implications of current decline rates. It translates decline rates into potential drops in future supply, calculates how much investment is required to offset these declines, and considers the implications for energy security. Notably, it concludes some strategic considerations for policy makers and companies.

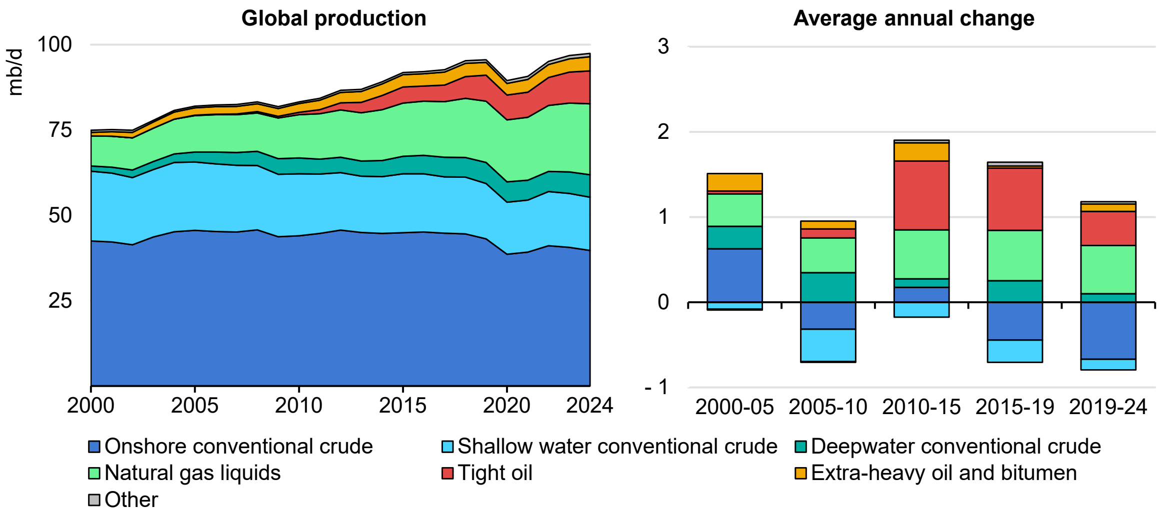
The technical annex presents the methodology used in this analysis, decline rate definitions and details of the regional and country groupings

Chapter 1. Oil and gas production and investment

Trends in oil production

Oil has been the world's largest single energy source since the 1970s. Supply and demand often exhibit large year-on-year fluctuations. Demand increased by close to 1 million barrels per day (mb/d) on average each year between 2000 and 2024, exhibiting a slower pace of growth in recent years. In 2024, global oil supply totalled 100 mb/d, comprising nearly 98 mb/d of oil production and 2 mb/d of processing gains (Figure 1).[1] Natural gas liquids, tight oil and extra-heavy oil and bitumen have been the main drivers of supply growth over the past decade.

Figure 1 Oil production by type and average annual change, 2000-2024



Note: Other includes coal-to-liquids, gas-to-liquids, kerogen oil and additives.

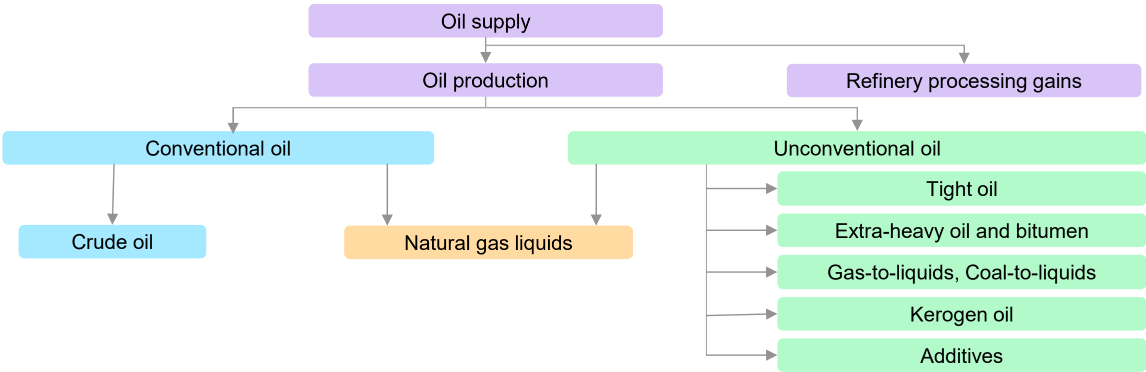
This analysis distinguishes between conventional and unconventional oil as they exhibit very different production dynamics. There is no unique definition to differentiate them. We classify them based on the reservoirs where the oil is found (Figure 2). *Conventional oil* – representing 77% of total oil production today – is

[1] In this report, *oil supply* includes processing gains – the volume increase that occurs during crude oil refining – while *production* excludes these. Production of biofuels and low-emissions liquid hydrogen-based fields are not included within oil supply or production and are not considered further here.

extracted from reservoirs with high permeability and porosity which allow the hydrocarbons to flow freely to the wellbore. *Unconventional oil* – the remaining 23% of total production – is from reservoirs where the oil is more difficult to extract or where it is produced synthetically from other hydrocarbons.

Conventional crude oil accounts for just under 65% of global oil production today, down from a share of 85% in 2000. Just over 40% of total oil production in 2024 was from onshore conventional crude oil fields and around 25% was from offshore fields.[2] Since 2000, around 22 mb/d of conventional crude oil production was from offshore fields. Increases in ultra-deepwater production, led by Brazil, the United States and Guyana, offset declines in shallow water crude oil production with large reductions in the United Kingdom, Norway and Mexico.

Figure 2 Classification of oil supply



Natural gas liquids (NGLs) are liquids produced within a natural gas stream. They are separated from the gas flow either at the wellhead (condensate) or at gas processing plants. Condensate is reported as part of crude oil in some countries, and as part of NGLs in other countries. In this report, condensates are considered to be NGLs for all regions and types of production, except for tight oil areas outside the United States because these data are not available. NGLs were 21% of global oil production in 2024, up from 12% in 2000, of which 14 mb/d were from conventional oil and gas fields, and 7 mb/d were from unconventional fields, mainly shale plays in the United States.

Tight oil is produced from shale or other very low permeability, continuous formations, using hydraulic fracturing and usually horizontal drilling. Tight oil volumes often include both crude oil and condensates, but in the United States

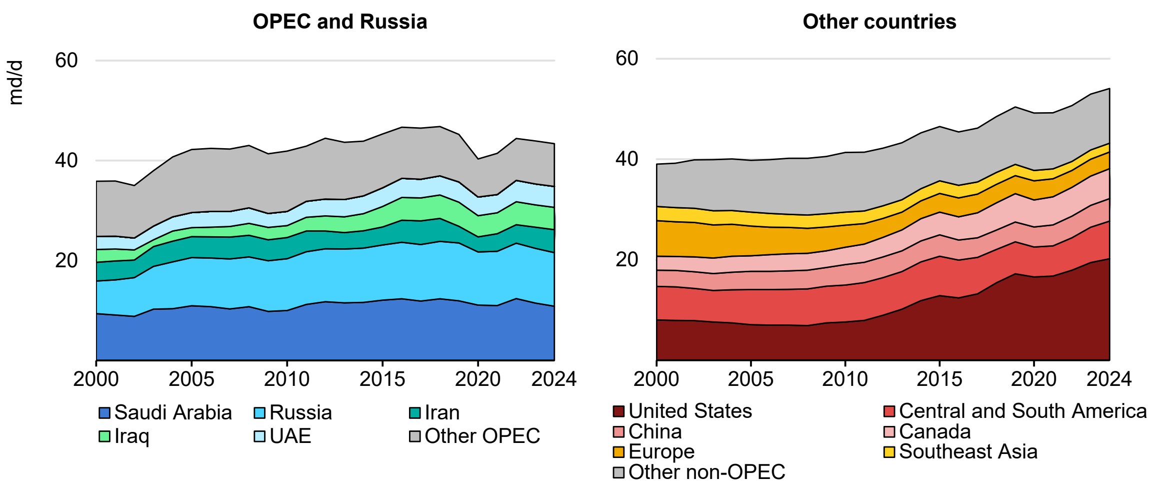
[2] Offshore production is often classified by water depth. In this analysis, shallow water fields are at depths less than 450 metres (m), deepwater from 450 m to 1 500 m, and ultra-deepwater at depths below 1 500 m.

they can be separated. In this report, US tight oil refers only to crude oil, with condensates from tight plays reported as unconventional NGLs. Global tight oil production has doubled from around 5 mb/d in 2015 to 10 mb/d in 2024, of which more than 90% comes from the United States.

Extra-heavy oil and bitumen (EHOB) is unconventional oil characterised by very high viscosity and high density (less than 10° API).[3] Extraction of EHOB requires specialised techniques such as in-situ thermal recovery or mining. It is produced from oil sands in Canada, including 3.5 mb/d of synthetic crude oil and non-upgraded bitumen in 2024, and the Orinoco belt in Venezuela with 0.5 mb/d production in 2024.

The remaining 0.9 mb/d of global oil production include: *additives* (non-hydrocarbon compounds added to or blended with oil products to enhance or modify their properties); *coal-to-liquids* and *gas-to-liquids*, which are liquid fuels produced through the chemical transformation of coal or natural gas; and *kerogen oil* (retorted kerogen-containing shale).

Figure 3 Oil production by region/country, 2000-2024



Note: UAE = United Arab Emirates; OPEC = Organization of the Petroleum Exporting Countries.

The United States, Saudi Arabia, the Russian Federation (herein after Russia) and Canada together currently account for almost half of total global oil production (Figure 3). The United States has almost tripled its production over the last 15 years and produced 20 mb/d in 2024. Saudi Arabia holds the world's largest conventional oil reserves, and it produced almost 11 mb/d in 2024, of which 15%

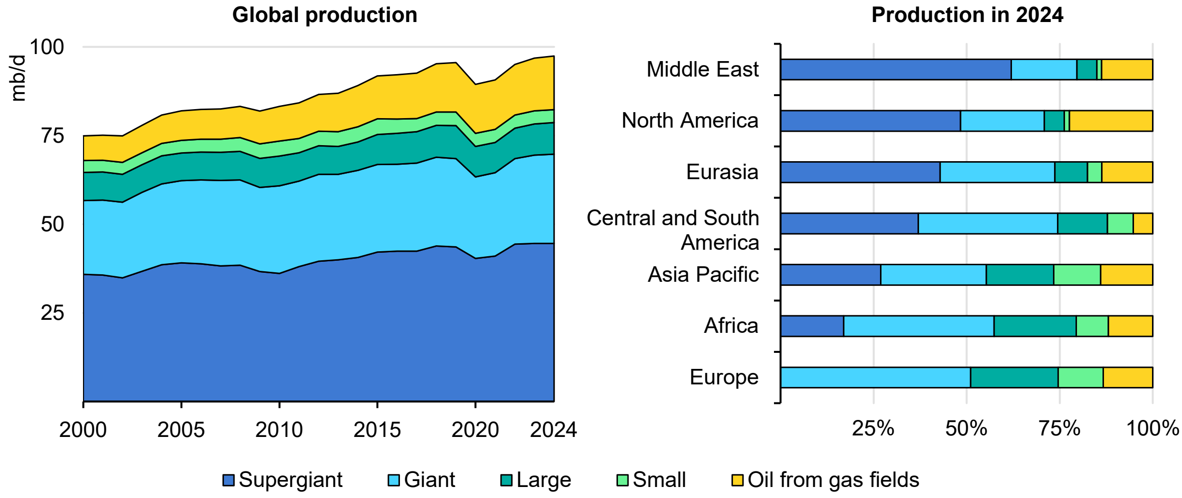
[3] The American Petroleum Institute (API) gravity is an inverse measure of density relative to that of water. A liquid with less than 10 °API is denser than water.

was NGLs. Russia produced around 11 mb/d in 2024, around 10% lower than its peak level in 2019, with a drop in production following its invasion of Ukraine. Canada produced 6 mb/d of oil in 2024, more than half of which was EHOB: unconventional oil production has doubled in the past 15 years, driven by a number of technological advancements that have allowed larger volumes to be produced at lower costs and reduced energy inputs.

The share of global oil production originating from the Organization of the Petroleum Exporting Countries (OPEC) has fallen from about 39% in 2000 to below 34% in 2024. After several years of production restraint, OPEC members have recently begun to unwind voluntary supply cuts, and their spare capacity has dropped from more than 5 mb/d in April 2025 to about 4 mb/d in July 2025.

Supergiant oil fields accounted for just under half of global oil production in 2024.[4] These fields are mostly in the Middle East, Eurasia and North America. They have consistently provided more than 40% of global oil production (Figure 4). Giant oil fields are more numerous and account for about one-quarter of oil produced worldwide. Around two-thirds of the supergiant and giant fields are located onshore, including fields that straddle land and sea, but which are produced from onshore facilities. There are thousands of large and small fields and they account for just under 15% of global production.

Figure 4 Oil production by field size, 2000-2024, and by region, 2024

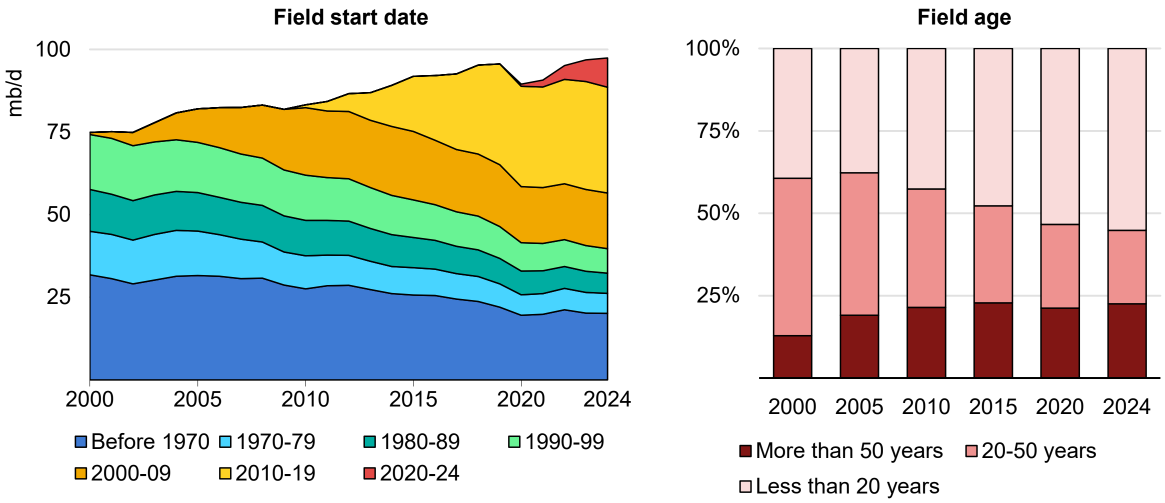


Source: IEA analysis based on data from Rystad Energy (2025).

[4] Field sizes are calculated based on expected cumulative production over the field lifetime. For oil, supergiant = liquid resources more than 5 000 million barrels; giant = liquid resources between 500-5 000 million barrels; large = liquid resources between 100-500 million barrels; and small = liquid resources below 100 million barrels.

In 2024, more than half of oil production was from fields that are less than 20 years old and one-quarter was from fields older than 50 years. Output shares from both of these categories have risen significantly in recent years (Figure 5). For the newer field category, the increase reflects the rise of tight oil and unconventional NGLs. For older fields it highlights the enduring importance of longstanding conventional fields with low marginal costs that have seen recent development programmes to boost production.

Figure 5 Oil production by start date and age, 2000-2024



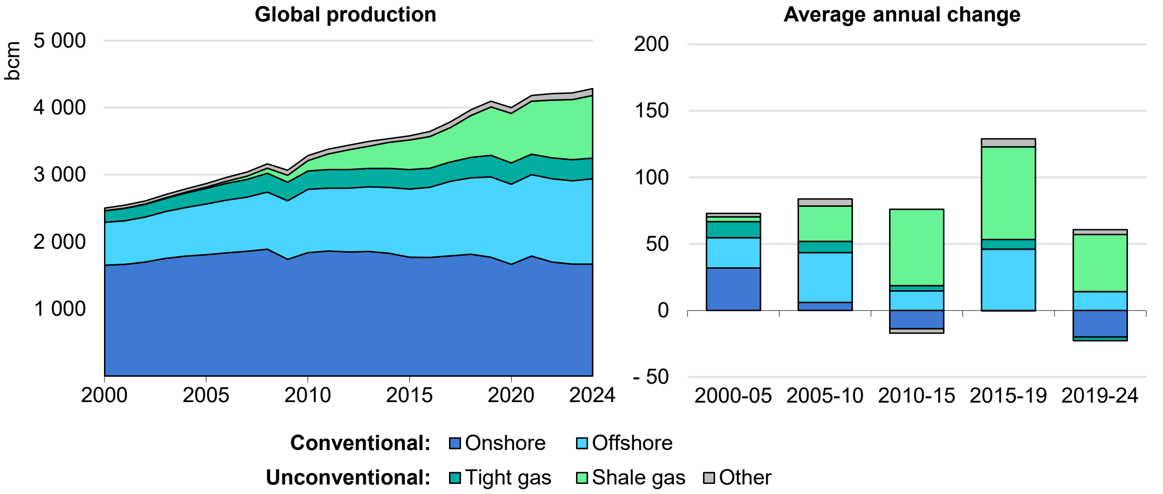
Source: IEA analysis based on data from Rystad Energy (2025).

For fields in the 20-50 year old range, production declines in recent years reflect that the most prolific fields were developed in the 1970s or earlier, and that subsequent exploration and developments were generally smaller finds and often had higher decline rates. For example, many of the fields developed in the 1980s and 1990s were in Europe and US offshore areas which tend to have high decline rates, thus their current contributions are relatively smaller.

Trends in natural gas production

Natural gas has been the fastest growing fossil fuel over the past decade. Demand increased by more than 2% each year on average since 2015 to reach 4 300 billion cubic metres (bcm) in 2024 (Figure 6). There are many types of natural gas resources, each with distinct characteristics and production techniques.

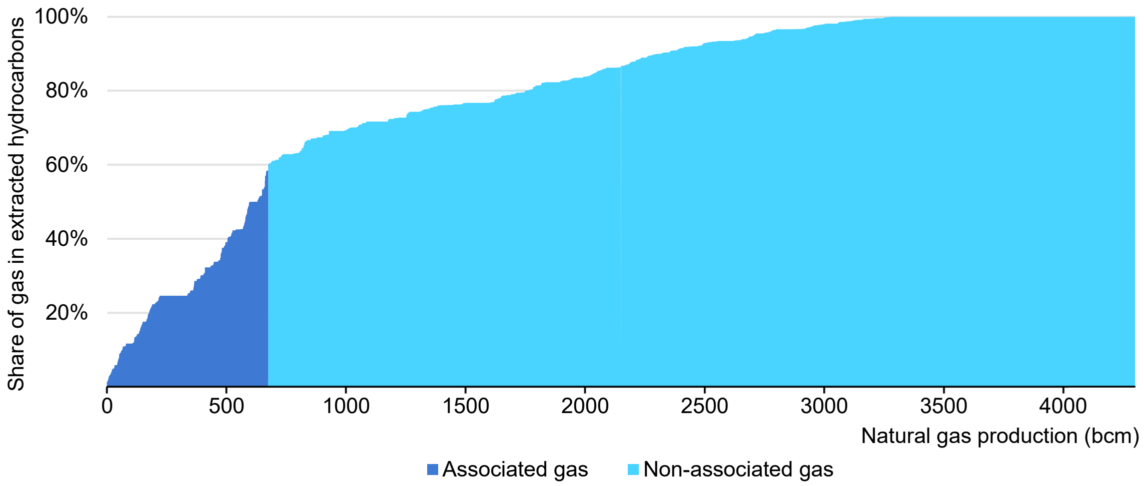
Figure 6 Natural gas production by type and average annual change, 2000-2024



Notes: Other includes coalbed methane and coal-to-gas.

Conventional natural gas is extracted using well-established drilling methods and accounts for around 70% of global gas production today, including both onshore and offshore reserves. Conventional onshore gas production has been stable since 2000 at around 1 800 bcm. In contrast, conventional offshore gas production expanded steadily, increasing by an average of 30 bcm per year since 2015 and to reach almost 1 300 bcm in 2024, largely reflecting developments in the Middle East, including Iran and Saudi Arabia, as well as in Australia.

Figure 7 Share of natural gas in total extracted hydrocarbons by field, 2024

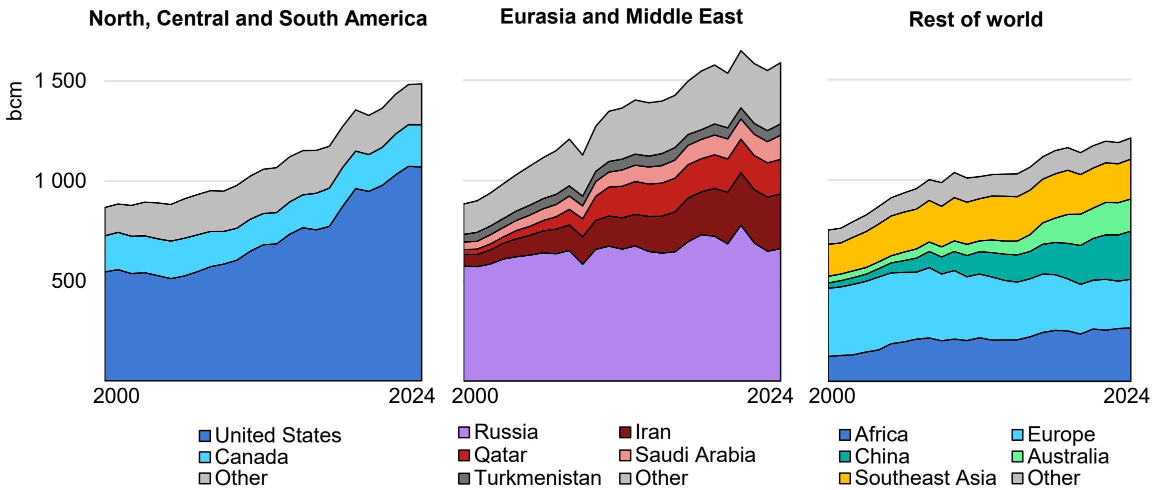


Source: IEA analysis based on data from Rystad Energy (2025).

Unconventional gas is natural gas produced from low permeability rock formations such as tight sandstone and limestone (tight gas), coal seams (coalbed methane), shale plays (shale gas) and coal-to-gas (CTG). More than 300 bcm of tight gas was produced in 2024, about 70% in North America. Coalbed methane (CBM) production in 2024 was around 85 bcm, mainly produced in Australia (50%), United States (20%) and The People's Republic of China (herein after China) (20%). Shale gas production increased rapidly from around 150 bcm in 2010 to 940 bcm in 2024. Nearly 90% of global shale gas produced in 2024 was in the United States, augmented with small but increasing production levels in Canada, Argentina and China. Just under 20 bcm of CTG was produced in 2024, all of which was in China.

Another important distinction is between associated natural gas, which is co-produced from oil fields, and non-associated natural gas, which is produced from gas fields (Figure 7).[5] Around 550 bcm of associated gas was produced and sent to market in 2024. Production costs for associated gas are generally lower than for non-associated gas. This holds particularly in fields in where the oil production infrastructure was in place before gas extraction was planned. However, significant volumes of associated gas are flared each year because the cost of treatment and transport renders it unprofitable to market it.

Figure 8 Natural gas production by region/country, 2000-2024



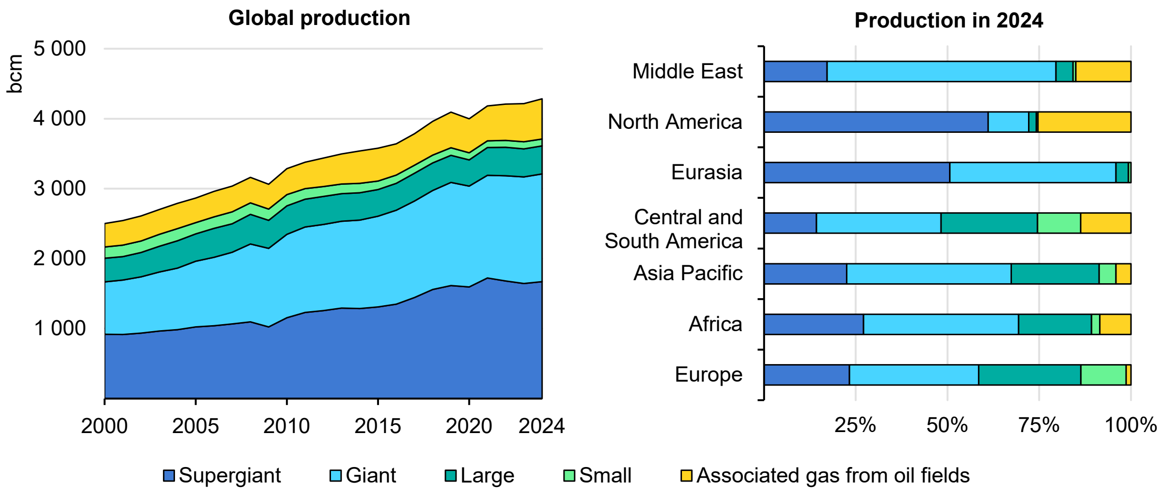
[5] In this report, a field is classified as a natural gas field if natural gas comprises more than 60% of extracted hydrocarbons by energy content and an oil field if natural gas comprises less than 60%. All natural gas produced from oil fields is considered to be associated gas.

Two countries dominate global natural gas production – the United States and Russia (Figure 8). US producers doubled output between 2000 and 2024 and the United States became the world's largest gas-producing country in 2012; US production in 2024 (1 070 bcm) accounted for just under one-quarter of global production. Russia is the second-largest producer, 660 bcm in 2024, primarily from vast onshore conventional natural gas fields. In 2021, production in Russia reached almost 780 bcm, but it faltered following its invasion of Ukraine which led to a sharp reduction in exports to Europe.

Countries in the Middle East account for around 15% of global gas production. Iran produced 275 bcm in 2024, and Qatar produced 170 bcm, placing them as the two largest gas producers in the region. Both produce gas from the non-associated North Field (Qatar) / South Pars (Iran) – the world's largest gas field – which began operations last century.

China more than doubled its natural gas production between 2010 and 2024, from 95 bcm to 240 bcm. This reflects increased production from mature onshore conventional basins and a surge in unconventional production. In 2024, China produced around 70 bcm of shale and tight gas, 20 bcm of CTG, and 15 bcm of CBM. Australia tripled its natural gas production over the past 15 years to 160 bcm in 2024, in part through the development of major conventional offshore natural gas fields, such as the North-West Shelf and Gorgon, as well as by increasing CBM production in Queensland. Around 70% of Australia's gas production in 2024 was exported as liquefied natural gas (LNG).

Figure 9 Natural gas production by field size, 2000-2024, and by region, 2024

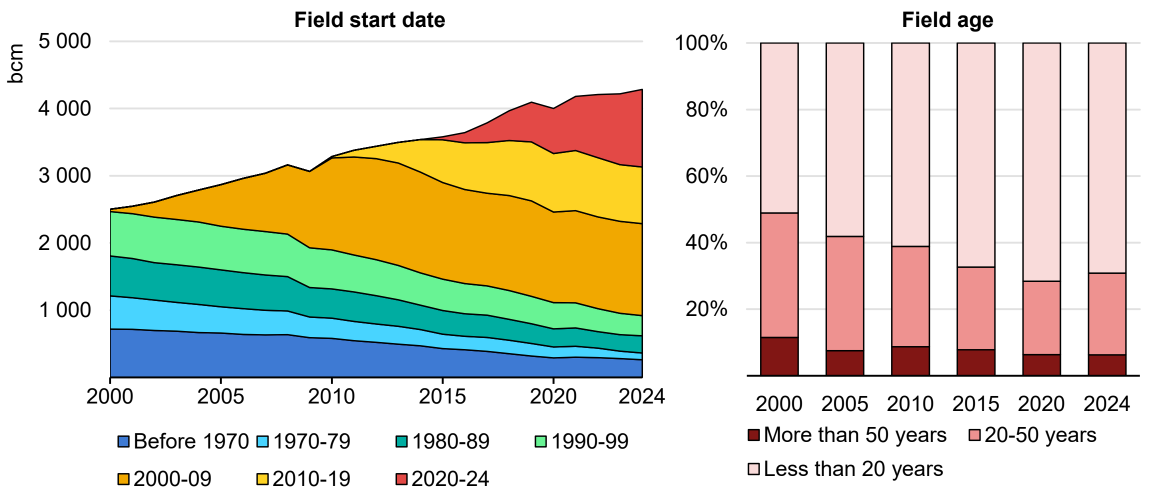


Source: IEA analysis based on data from Rystad Energy (2025).

Around 40 supergiant natural gas fields account for one-third of global natural gas production (Figure 9).[6] They are concentrated in the United States, Russia and Qatar. In each of these countries, supergiant natural gas fields provide more than half of total national gas production. In the United States, this includes the supergiant unconventional gas plays such as Marcellus and Haynesville. Since 2000, total gas production has been about evenly split among supergiant fields (33-41%) giant fields (30-37%), and oil fields (11-14%), while large and small fields account for the remainder.

Natural gas production has become increasingly reliant on new fields to meet growing demand and offset declines at existing fields (Figure 10). In 2024, less than 10% of global natural gas output came from fields that started operations more than 50 years ago, compared with around 25% for oil. Expansion of US shale gas explains a large portion, but there were also a large number of gas field ramp-ups in the 2000s, notably the start of the supergiant Galkynysh gas field in Turkmenistan, as well as smaller operations in the Middle East, Asia and Europe.

Figure 10 Natural gas production by start date and age, 2000-2024



Source: IEA analysis based on data from Rystad Energy (2025).

[6] Field size is calculated on economically recoverable volumes. Supergiant = gas resources more than 800 bcm. Giant = gas resources between 80-800 bcm. Large = gas resources between 10-80 bcm. Small = gas resources below 80 bcm. Oil fields = associated gas.

Oil and gas exploration and resource development stages

The process to undertake new conventional oil and gas resource development tends to occur in three main phases.

- **Exploration and discovery**: Tenders are issued by a host government for exploration licences in an area that could hold oil and natural gas, or a company may directly approach a government or subsurface property owner. Subsurface studies are conducted and companies then decide whether to bid or apply for a licence. If an exploration licence is awarded, the licensee must secure further regulatory approvals before exploration activities can take place and usually commit to drill a certain number of exploration wells over an established period.
- **Resource approval and development**: If hydrocarbon resources are discovered, field testing and analysis is conducted to decide whether they can be produced economically and how best to develop the project. After securing regulatory approval, such as a production licence, a final investment decision (FID) (or "project approval") is taken.
- **Construction and start-up**: Physical development work commences, sometimes in phases, and subsequently the project begins production.

The time required at each stage varies substantially. It depends on factors such as regulatory oversight and management, political stability, subsurface complexity, and whether new facilities and export connections need to be constructed. The development process for unconventional resources differs in that exploration is rarely needed as most of the existing or potential basins are already geologically well known, even if their ability to produce oil and gas economically has yet to be determined.

Tracking conventional oil and gas projects that have started production since 1980, we find little material difference between development times between oil and gas projects. Yet, the overall development timeline for new projects has risen over time.

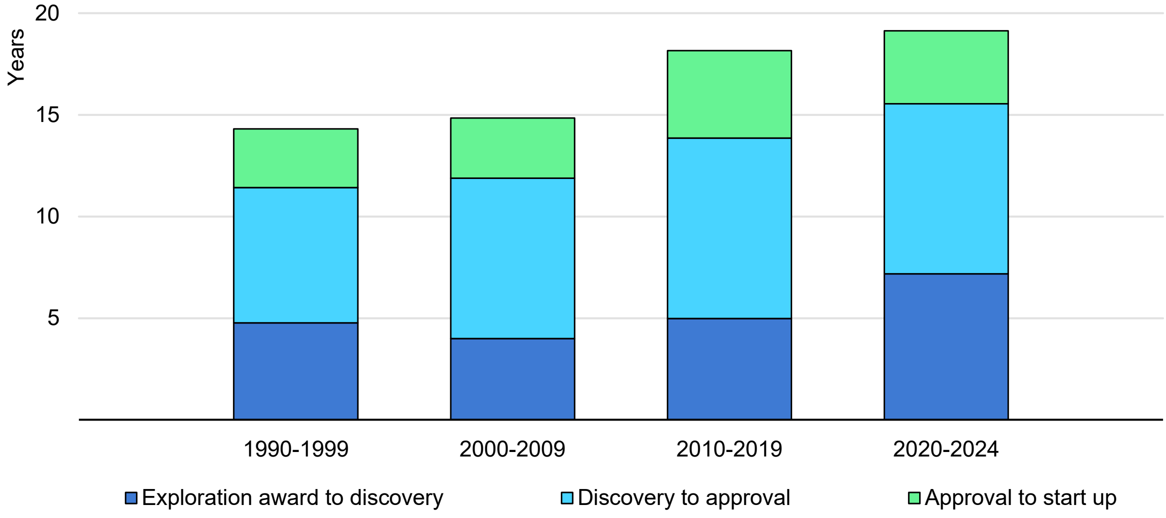
For projects that started between 1990 and 2020, it typically took around four to five years between the award of an exploration licence and the time of discovery. For projects that started production after 2020, it has taken closer to seven years. Longer timelines likely reflect that more exploration has shifted to frontier areas or remote areas that are less known geologically or have political risks. This is against a backdrop of reduced exploration activity overall. As a result, companies now tend to undertake more preparatory work and take longer to appraise the best locations to drill exploration wells.

The time span between discovering a field and taking a FID has also lengthened, averaging around seven years for projects that started before 2010 and nine years for projects that started after 2010. Many of the resources discovered in recent years are more technically complex, e.g. in deepwater and ultra-deepwater areas, so companies spend more time to ensure that a field can be developed safely and commercially. Often this also includes a more gradual, phased development process. In some countries, there have been more stringent environmental and safety regulations which have extended permitting periods.

The period to move from a FID to first production has increased slightly over the decades. While projects have generally become more complex to execute, this has been offset by factors such as more standardisation of production facilities and multi-stage development plans, plus increased focus on shorter cycle projects.

On average, industry wide, projects that started production after 2010 have taken just under 20 years from the award of an exploration licence to commence production (Figure 11). There are notable examples of projects with both much shorter and much longer lead times. For example, the Liza oil and gas field in Guyana took less than five years from discovery to the start of production. In contrast, the Gorgon gas field in Australia, discovered in 1981, took around 35 years to go from discovery to first gas.

Figure 11 **Average time periods for exploration to development stages of new conventional oil and gas projects,1990 to 2024**



IEA. CC BY 4.0.

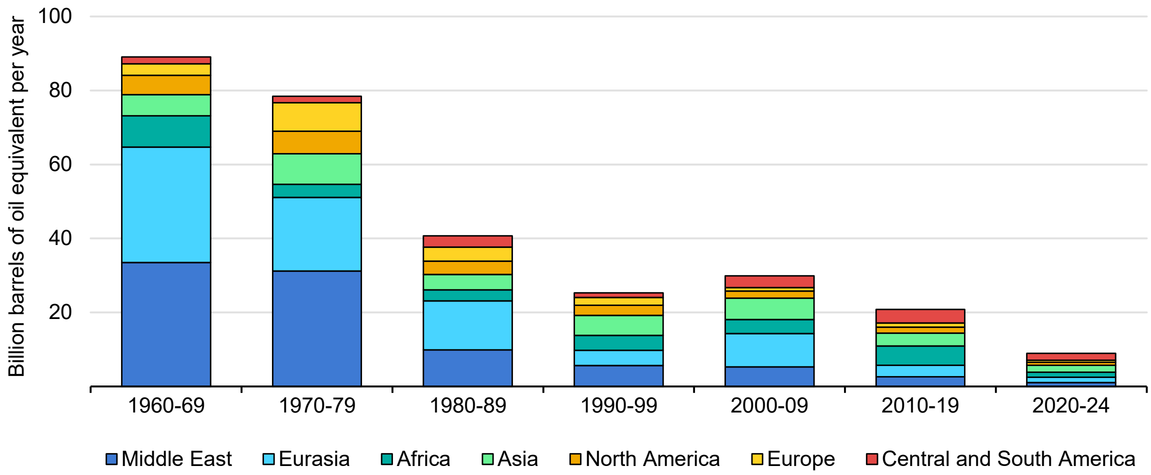
Notes: Values shown are weighted by the resources of the approved project.
Source: IEA analysis based on data from Rystad Energy (2025).

Exploration and discovery stages

Most of the world's conventional oil and gas resources were discovered years ago. The most prolific period of discovery was 1960 to 1980, when just under 60% of total technically recoverable resources were discovered.[7]

Most of the large, easily accessible conventional fields have been thoroughly mapped and developed, leaving primarily smaller, deeper and more technically challenging fields. In the 2020s so far, annual oil and gas discoveries have averaged around 9 billion barrels of oil equivalent (boe), roughly 60% lower than the average in the 2010s and 90% lower than in the 1960s (Figure 12). This reflects lower levels of investment in exploration, driven by capital discipline and a focus on near-term returns.

Figure 12 Average annual conventional oil and gas discoveries, 1960-2024



Source: IEA analysis based on data from Rystad Energy (2025).

The average size of a single discovery has diminished over time from around 150 million barrels of oil equivalent (mboe) of technically recoverable resources in the 1970s to around 40 mboe since 2010. Exceptions to this trend include the discovery of 1.5 billion barrels of oil and gas resources in the Stabroek Block in Guyana in 2015 and around 2 billion boe of natural gas resources in Mozambique in 2010 (both with further discoveries in subsequent years). Oil accounted for around 65% of the volumes discovered in the 1960s and so far in the 2020s oil accounts for around 55% of the volumes discovered.

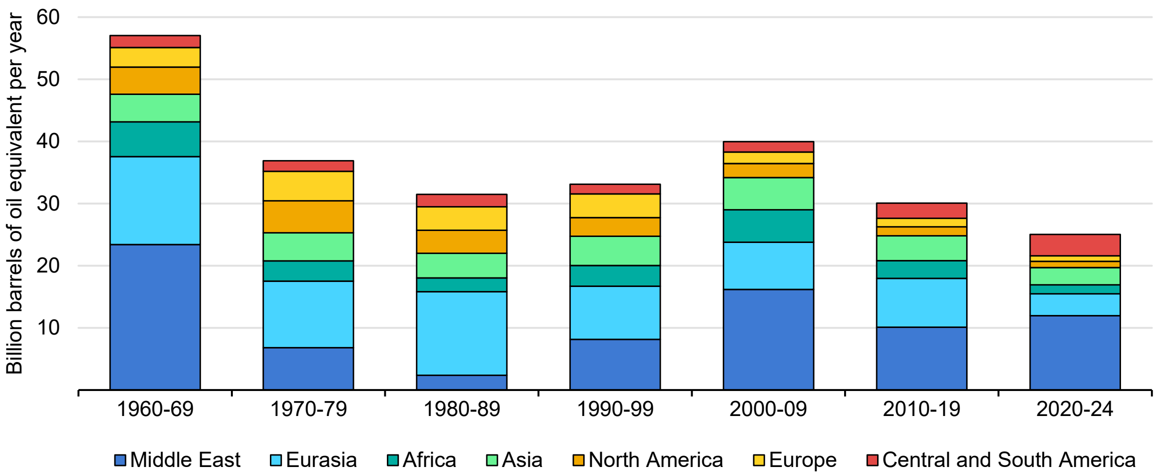
[7] Technically recoverable resources in this report are the sum of reserves, reserves growth, i.e. the projected increase in reserves in known fields, and undiscovered volumes. This does not take into account the commercial viability of developing and producing the resources, and some volumes included may never become economically recoverable.

Approval and development stages

Volumes of oil and gas resources approved for development are lower since the shale revolution began in the late 2000s. Average annual volumes approved in the 2020s is around 40% lower than the levels in the 2000s (Figure 13).

The types of conventional resources being approved underscore significant changes with a notable trend to augment existing projects rather than develop new prospects (Figure 14). In the 1980s, around 65% of resource approvals were for new developments, with the remainder for expansion or redevelopment of existing facilities or fields. So far in the 2020s, just under 40% of resource approvals are for new developments while the largest volumes relate to approvals within existing projects. Over 70% of new conventional oil and gas approvals in the 2020s are offshore resources, much higher than the share in the 1990s to 2010s (40-50%). These trends reflect a long-term structural evolution, as the global oil and gas resource base has been largely mapped and petroleum basins are increasingly mature.

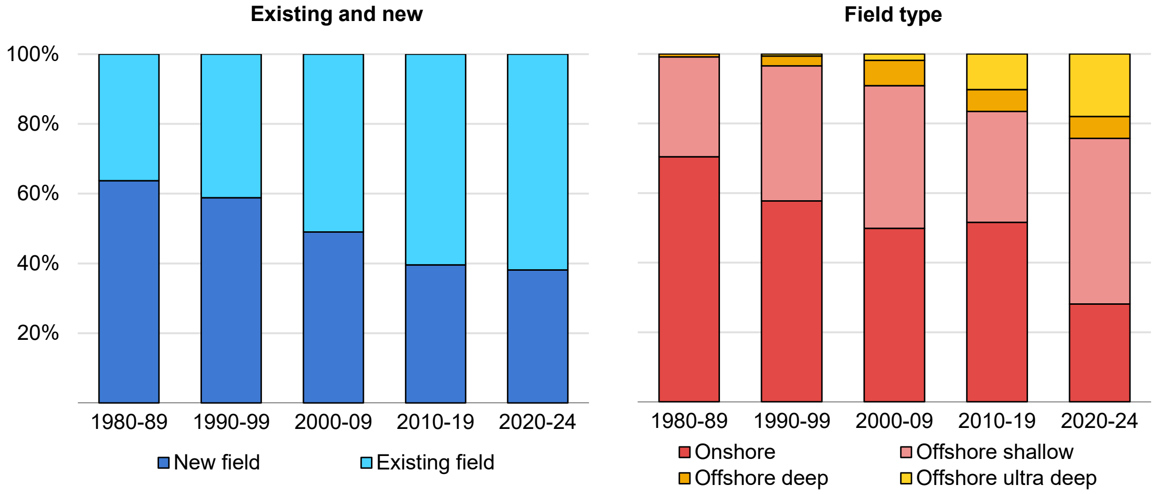
Figure 13 Average annual conventional oil and gas resource volumes approved for development by region, 1960-2024



Source: IEA analysis based on data from Rystad Energy (2025).

Market developments also influence oil and gas activities. For example, related to the shale revolution in the United States, the oil price crashes of 2014-2015 and 2020 as well as uncertainty about long-term oil demand have discouraged investment in the exploration and development of new large, long lead-time conventional hydrocarbon projects. Instead, the industry has imposed stricter capital discipline, particularly after 2020, with a preference for developing lower risk, already-discovered fields, especially if they can be connected to existing production facilities.

Figure 14 Conventional oil and gas project approvals by field type, 1980-2024



Source: IEA analysis based on data from Rystad Energy (2025).

Construction and start-up stages

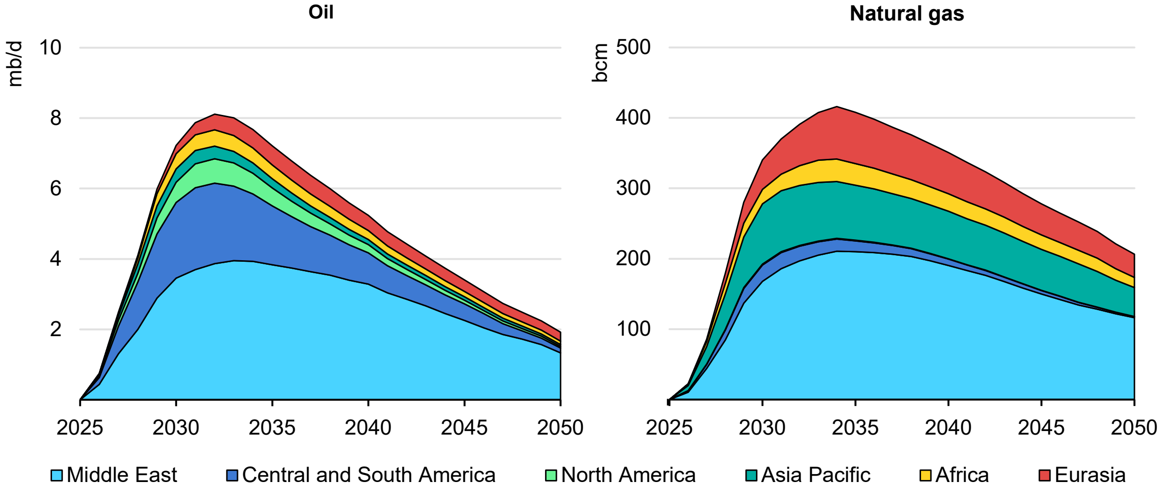
In the construction stage of an oil and gas project, the focus is on physically building the infrastructure needed to extract and process the oil and gas. This includes drilling production wells, installing surface and subsea facilities such as platforms, pipelines, processing units and setting up transportation links.

The scope and complexity of project implementation vary depending on resource size, type and location. For example, straightforward onshore or shallow water projects may achieve production in one or two years after final approval. Whereas deepwater or ultra-deepwater developments are more technically complex and require advanced engineering, often pushing construction timelines to five years or more. Field development may be carried out in phases to effectively manage risks. A phased approach may allow subsequent stages to be completed more quickly and efficiently.

Unconventional resource development also varies with both short and long construction periods. For example, shale gas or tight oil involves rapid, repeated drilling campaigns and modular infrastructure, while oil sands development requires extensive surface processing facilities that take many years before resource production. As oil and gas developments are major capital undertakings, they are susceptible to delays beyond planned timelines.

Approved conventional oil and gas projects that are expected to start producing from the beginning of 2026 are projected to reach a maximum level of production of 8 mb/d of crude oil and NGLs in the early 2030s. Further, these projects are projected to yield around 400 bcm of conventional natural gas at their peak, more than a third of which is explicitly tied to the development of LNG exports (Figure 15).

Figure 15 **Production outlook to 2050 from conventional oil and gas projects that have received FID but were not producing in 2025**



Note: Projects represented have a final investment decision but are not expected to start producing until the start of 2026.
Source: IEA analysis based on data from Rystad Energy (2025).

Upstream capital and operating expenditures

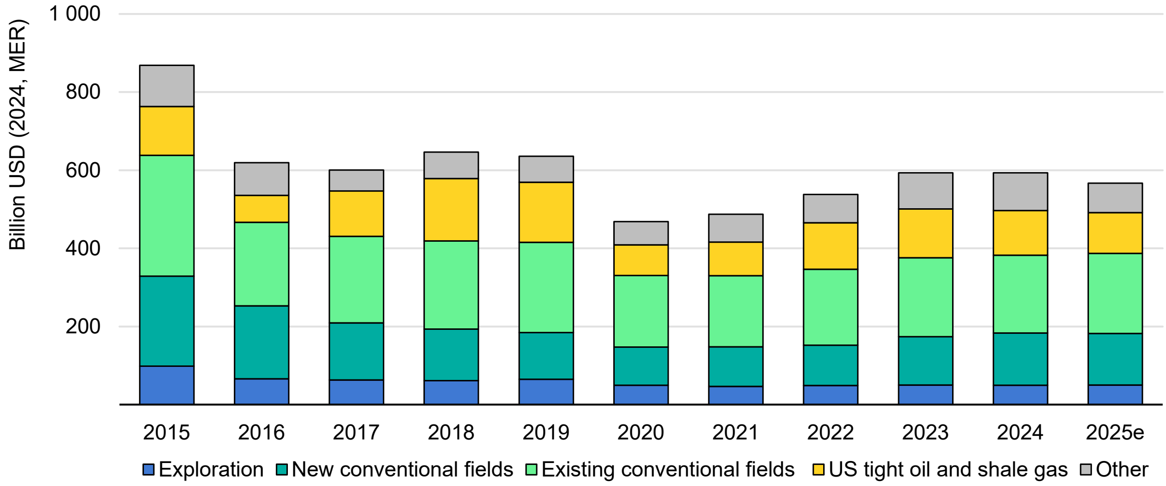
Spending by oil and gas companies on upstream operations is fundamental to the trajectory of global supply.[8] Capital expenditure, simply referred to as investment, involves spending on physical assets such as equipment, production platforms, pipelines and processing facilities, as well as seismic surveys and leased acreage. Qualified expenditure may be capitalised and depreciated over the life of the asset. Upstream oil and gas investment accounts for around 60% of the total capital expenditure on oil and gas supply, with the remainder covering investment in infrastructure and platforms, refineries, pipelines, shipping and liquefaction and regasification assets.

In 2015, around USD 870 billion was spent on exploration, developing new projects and maintaining production in existing projects (Figure 16).[9] Investment fell by 30% in 2016 following a drop in oil price in 2015, and it remained around USD 600 billion annually to 2019. Investment dropped again in 2020 reflecting the impacts of the Covid-19 pandemic, since then it has gradually risen. Based on the

[8] In the oil and gas industry, the upstream category includes exploration, appraisal, development and production; midstream category includes shipping and transporting crude oil or other unrefined energy products; and downstream category includes crude oil refining, NGL fractionation, and the shipping, distribution and marketing of the products.
[9] All investment and costs are presented in real 2024 US dollar terms, at market exchange rates, adjusted for inflation.

most recently announced and revised plans by oil and gas companies, we expect upstream investment to fall by around 5% to just under USD 570 billion in 2025.

Figure 16 Global upstream oil and natural gas capital expenditure, 2015-2025



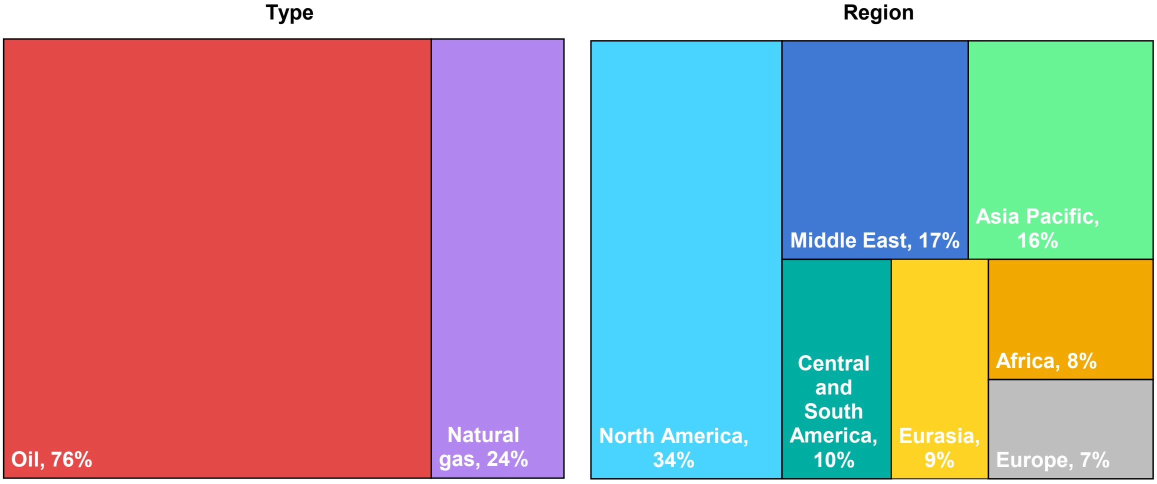
Notes: MER = market exchange rate. Other = extra-heavy oil and bitumen, coal-to-liquids and gas-to-liquids. 2025e = estimated value for 2025.
Source: IEA (2025), World Energy Investment 2025.

While the volume of upstream investment diminished, allocation to the various field types and stages has been broadly consistent over the last decade. Around 10% each year was invested in exploration, 20-30% for new conventional fields, 40% on existing fields, and 20-25% on US shale gas and tight oil developments. Three-quarters of investment in the upstream sector in 2024 was for oil developments and one-quarter for natural gas (Figure 17).

It is expected that investment in the upstream will reach a record level of 20% share of global expenditure in the Middle East in 2025, even though the region is characterised by very low costs per barrel. Further, it is expected that overall upstream investment levels will remain the highest in absolute terms in North America.

Upstream capital investment encompasses a wide variety of elements. It includes the initial spending on exploration activities such as geological and geophysical data acquisition, securing exploration or production rights through lease payments, field development activities like drilling test wells, building surface-level facilities; and components needed to ultimately bring resource production online. It can also include capital spent to preserve the integrity or extend the productive life of existing assets through refurbishments and upgrades.

Figure 17 Upstream investment by type and region, 2024



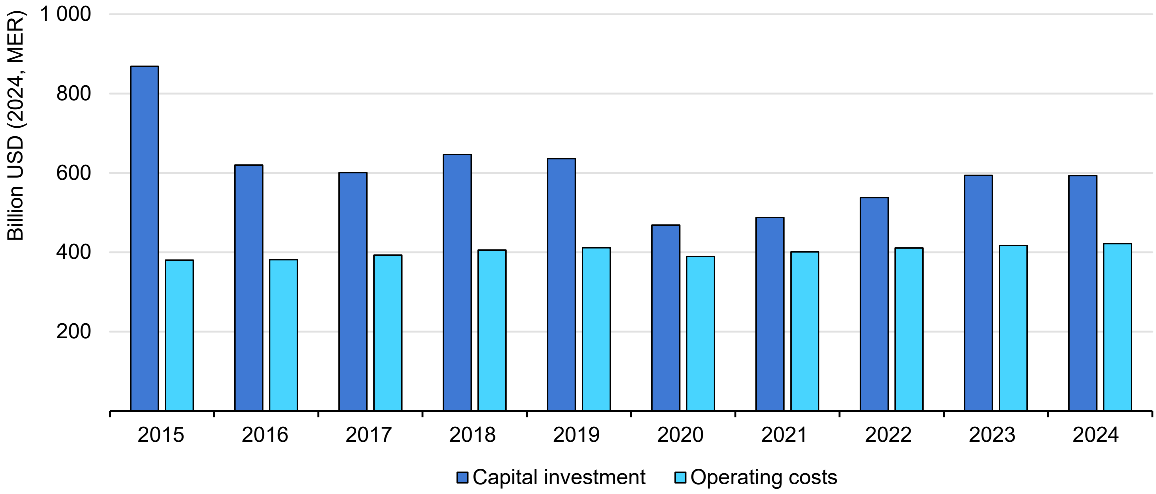
IEA. CC BY 4.0.

Source: IEA (2025), World Energy Investment 2025.

Operational expenditure is the ongoing spending required to operate and maintain oil and gas assets. Operating expenditures are usually expensed immediately on the company income statement. This includes labour, well intervention and maintenance, installing, operating or replacing pumps, utilities, logistics and regulatory compliance costs.

Upstream capital investment has been recovering since the sharp drop during the Covid-19 pandemic, while operating costs have remained relatively constant (Figure 18).

Figure 18 Global upstream capital investment and operating expenditure, 2015-2024



IEA. CC BY 4.0.

Note: MER = market exchange rate.
Source IEA (2025), World Energy Investment 2025.

A key challenge to assess oil and gas investment is the variability of capital and operating expenditure definitions and classifications. These are influenced by accounting standards that are specific to a jurisdiction and complicated by the often-indistinct boundary between the two categories of investment. Capital expenditure in one jurisdiction may be considered as operational expenditure elsewhere, and vice versa. Companies report the conventions used in their accounting principles and while one method generally prevails for consistency for a company, it may vary for its subsidiaries, depending on jurisdiction or local standards.

- For exploration, in the *full cost accounting method*, companies record all exploration and development spending as capital expenditure, regardless of the outcome. In the *successful efforts accounting method*, spending linked to successful exploration is recorded as capital expenditure and unsuccessful efforts are treated as operating expenditure. Capital investment can also change retroactively, with impairment testing undertaken to determine if costs should be retained as capital investment or changed to operating expenditure.
- For existing fields, spending on artificial lift installations, well workovers, subsea tiebacks, gas processing equipment and enhanced oil recovery, may be considered as capital investment or operating expenditure, or a combination of both, depending on the business strategy, technology availability and region.
- For some equipment, such as electric submersible pumps and gas processing equipment, purchases are typically considered to be capital investment, while leasing from service providers is considered as operating expenditure. Typically, a national oil company is more likely to invest in its own equipment for long-term use, while lease models may be more common in smaller operators and in mature fields.

In this analysis, estimates of capital investment for oil and gas are based on the capital expenditure announced and reported by around 90 oil and gas major, independent and national companies. This approach brings together various conventions and accounting practices, though differences are unlikely to have a meaningful impact at the global level. Operating costs are taken to be the day-to-day costs of running oil and gas facilities.

Finding and developing costs

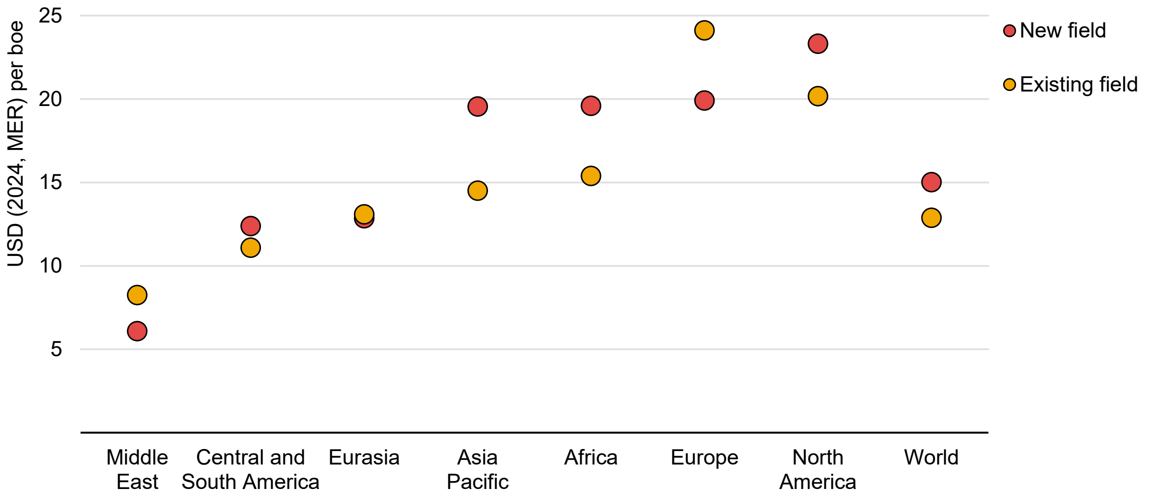
Finding and developing (F&D) costs are those involved with exploring, assessing and beginning production of oil and gas resources. Dividing capital investment by the volumes of oil and gas that are added to reserves is one measure of F&D costs (usually stated in

USD/boe). F&D costs are distinct from the breakeven price, as the latter reflects both capital and operating costs plus fiscal payments.[10]

Development costs of conventional oil and gas fields

Development costs of conventional oil and gas fields vary significantly depending on the type of production and the specifics of the location. Existing fields are often less expensive as they may be able to take advantage of established gathering and transport infrastructure. However, this is not always the case: investment in existing fields is sometimes used for upgrades or maintenance that may be essential for production to continue and may not lead to a large increase in overall reserves; while developing new fields can often deliver efficiency gains when they involve large-scale developments.

Figure 19 **Average development costs for conventional oil projects that started production between 2015 and 2024**



IEA. CC BY 4.0.

Note: Excludes finding costs.
Source: IEA analysis based on data from Rystad Energy (2025).

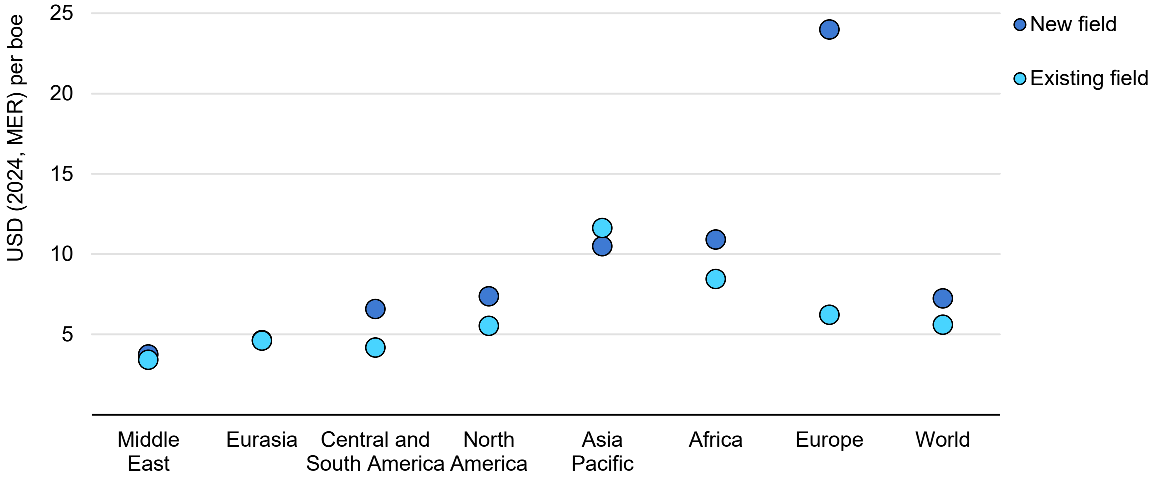
For conventional oil projects that started production between 2015 and 2024, development costs were lowest in the Middle East. During this period, several new giant fields were developed, such as Rabab Harweel in Oman and Faihaa in Iraq, and the region also contains a number of supergiant fields that had previously experienced production declines (for example in Iraq and Kuwait) that could be

[10] The breakeven price is usually defined as the oil or gas price at which the net present value of a project equals zero when future cash flows are discounted using the company's cost of capital.

revived at relatively low cost (Figure 19). Costs were highest in Europe and North America. In Europe, many of the new projects developed over this period benefited from economies of scale (such as Johan Sverdrup in Norway) or used existing near-field infrastructure to help lower costs; in North America, boosting production at existing fields on average cost less than developing new fields.

Development costs for natural gas projects that started between 2015 and 2024 were lowest in the Middle East, Eurasia, and Central and South America (Figure 20). Costs for new gas fields were much higher in Europe, most of which were relatively small and were developed in areas without pre-existing infrastructure. They are lower for existing fields, mainly because of the large cost efficiencies that were realised during the development of the giant Troll West gas project that included tiebacks to the Troll A platform (excluding this field from the calculation for Europe would increase development costs for existing fields to around USD 20/boe).

Figure 20 **Average development costs for conventional natural gas projects that started production between 2015 and 2024**



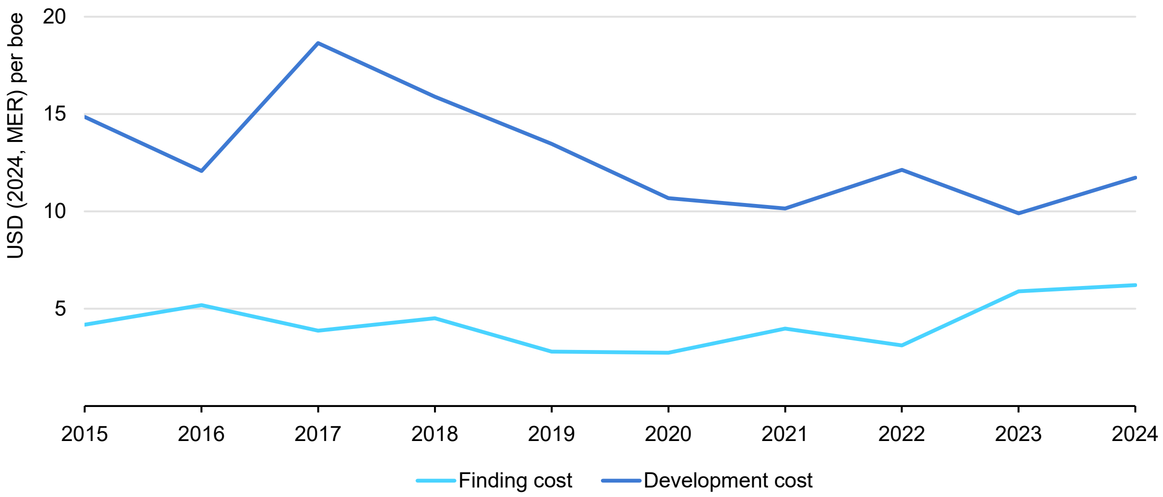
Note: Excludes finding costs.
Source: IEA analysis based on data from Rystad Energy (2025).

How have oil and gas F&D costs evolved over the last decade?

The per barrel cost of finding conventional oil and gas increased by around 50% in real terms in the 2015-2024 period, as exploration efforts yielded lower returns: over this period exploration expenditure declined by around 50% while discovered resources fell by around 65%.

Development costs for conventional oil and gas have fallen by more than one-third since their peak in 2017 (Figure 21). The largest reductions have occurred in oil fields, for which costs have almost halved since 2017 and now average around USD 14/boe. All regions except the Middle East saw cost reductions between 30-50%, with countries in Africa seeing some of the steepest reductions. These gains occurred mainly as a result of reductions in the cost of developing offshore projects.

Figure 21 Global weighted-average F&D costs per barrel for conventional oil and gas, 2015-2024



Note: For development costs, shows costs of projects starting production in each year. For finding costs, shows exploration investment divided by estimated reserves found in each year.
Source: IEA analysis based on data from Rystad Energy (2025).

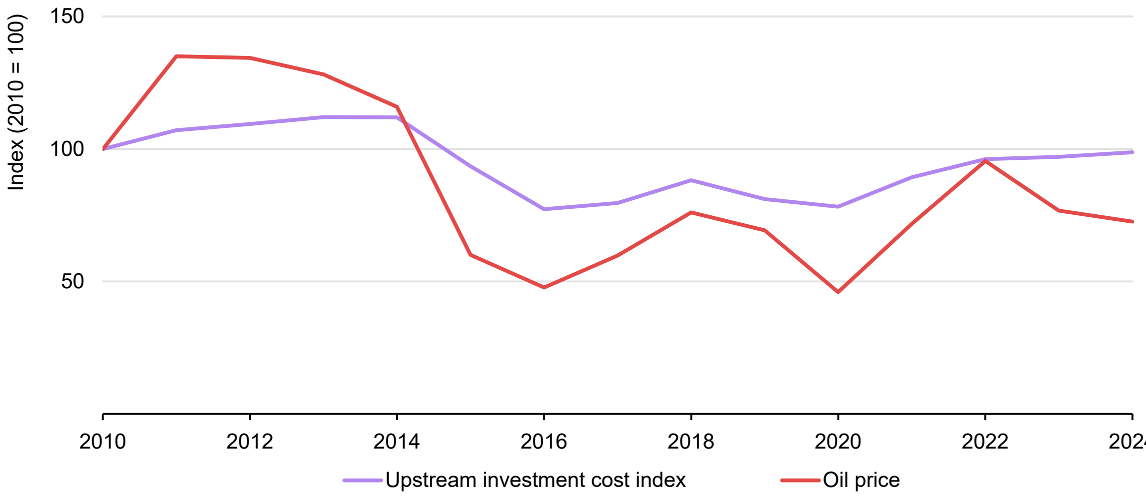
Three key factors led to the reduction in development costs over the last decade: changes in the types of projects executed; changes in the design of projects; and cyclical factors that change the cost of implementing a given project design.

The clearest example of changes in the types of conventional projects executed is the preference for projects that have shorter intervals between approval and first production, and shorter payback periods. Reservoir and fluid quality also come into play; light fluids in high quality reservoirs reduce the time to first oil and support higher subsequent production rates. For example, in the Stabroek Block in Guyana, the favourable fluid quality and reservoir volume made projects commercially viable despite the economic challenges of developing a new deepwater area. High grading of assets leads to an overall reduction in the average capital cost of the projects that proceed.

Project designs also changed significantly over the last decade. Many companies have increased focus to deliver higher rates of return, rather than high production volumes. The adoption of digital technologies, standardisation and modularisation added efficiencies. For example, 3D and 4D seismic data acquisition and processing, logging while drilling, advanced rotary steerable systems for directional drilling, intelligent completions, and normally unmanned installations have contributed to optimise well designs and field development. Standardisation significantly reduces front-end engineering and construction time by repeating proven designs instead of developing something entirely new. The oil and gas industry is also seeking ways to deploy artificial intelligence options to help with reservoir characterisation, to monitor and adjust drilling and production, to predict maintenance needs, and to improve environmental and safety performance.

Cyclical factors also can have a major influence on F&D costs. Higher oil prices typically boost upstream activity, which often increases the cost of oilfield services and equipment such as drilling rigs, specialised labour, and raw materials. This cycle tends to reverse as supply catches up with demand or as oil prices decline. The broader macroeconomic context also affects the cost of key upstream inputs, including steel, cement, and broad inflationary and labour market pressures.

Figure 22 IEA Upstream Investment Cost Index and oil price index, 2010-2024



Note: Oil price is a weighted average of import prices among IEA member countries.

The Upstream Investment Cost Index (UICI) is an indicator developed by the IEA to monitor cyclical cost trends in the conventional upstream oil and gas sector (Figure 22). It captures the annual evolution of capital expenditures and operating expenses as input costs related to drilling services and the construction of production facilities, as well as the costs of labour, materials and equipment that are incorporated into charges for drilling, related services and facilities. As such, the index serves as an upstream industry-specific deflator. Materials and rig rates together account for more than 60% of the index.

The UICI has moved broadly in tandem with oil market cycles, although the magnitude of the year-on-year changes tends to be smaller. There were large dips in the UICI in 2016 and 2020, although it has risen in the past few years and the level in 2024 was around the same as in 2015. Recent increases in the costs of basic materials and elevated offshore drilling day rates supported by high utilisation rates look set to increase unit costs for the oil and gas industry marginally in 2025, although impacts will vary between companies and countries. Still, in the longer term, we anticipate that unit costs will revert to the traditional pattern of following the oil price.

Bringing these elements together, we estimate that the vast majority of the reduction in the development cost of conventional oil and gas projects over the past ten years is likely due to real structural reductions rather than cyclical changes. Still, cost reductions secured by cutting back infrastructure from project plans that could have supported future developments could lead to an overall structural increase in costs in the long term.

There have also been large reductions in development costs for unconventional oil sources. The cost of producing EHOB through in-situ methods have fallen by around 45% since 2015, and tight oil operators have also managed to achieve major cost reductions (Box 1).

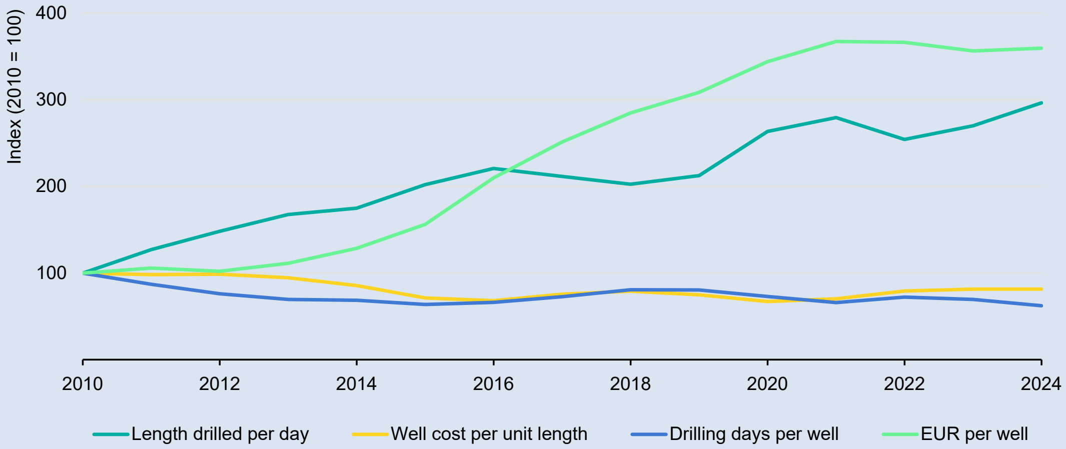
Box 1 Structural cost reductions in US tight oil over the last decade

The oil price crash in 2014 had a huge impact on tight oil operators. Prior to this, the cost of drilling a well, hydraulic fracturing, connecting to distribution infrastructure, and paying taxes and royalties meant that operators required a West Texas Intermediate (WTI) oil price over USD 90/barrel to generate a reasonable rate of return. By 2016, this dropped to less than USD 60/barrel. Even as some of the best acreage has been depleted, operators have continued to achieve efficiency improvements through a variety of mechanisms, including:

- Focussing activity on the most productive areas. The wave of mergers and acquisition activity in 2024, for example, allowed companies to secure better inventory, including contiguous acreage that allowed for longer laterals.
- Increasing the volumes of oil and gas produced from a given well. The horizontal length drilled in one day is three-times more than in 2010 (Figure 23), and wells can now be drilled in 40% less time, sharply cutting rig rental costs.
- Reducing the unit costs by drilling multiple wells from a single location and drilling multiple wells to produce oil from different shale layers. New fracturing technologies have also been deployed, which improve operational efficiency and reduce costs.

Some cost reductions have been more cyclical; for example, the costs of drilling and completion services fell by more than one-third between 2014 and 2016 but have since risen, with further cost pressure expected in 2025. While there remains a wide range in costs between operators and shale plays, the aggregate effect is that the WTI breakeven price of tight oil in 2024 is around USD 50/barrel, more than 40% lower than in 2014.

Figure 23 Measures of efficiency for US tight oil production since 2010



Notes: EUR = estimated ultimate recovery. Includes Permian, Eagle Ford, Bakken plays weighted by production in each year.

Source: IEA analysis based on data from Rystad Energy (2025).

Chapter 2. Observed and natural decline rates in oil and gas fields

Why does conventional oil and gas production decline?

The lifetime of oil and gas fields is usually categorised by patterns of activity. Typically, an operator drills wells sequentially during the early part of the life of the field, leading to a gradual increase in production as more wells come on-stream, called the ramp-up phase. The operator then produces with a fixed number of wells for a period as production reaches a plateau phase, and a gradual decline as the rate of production at each well decreases.

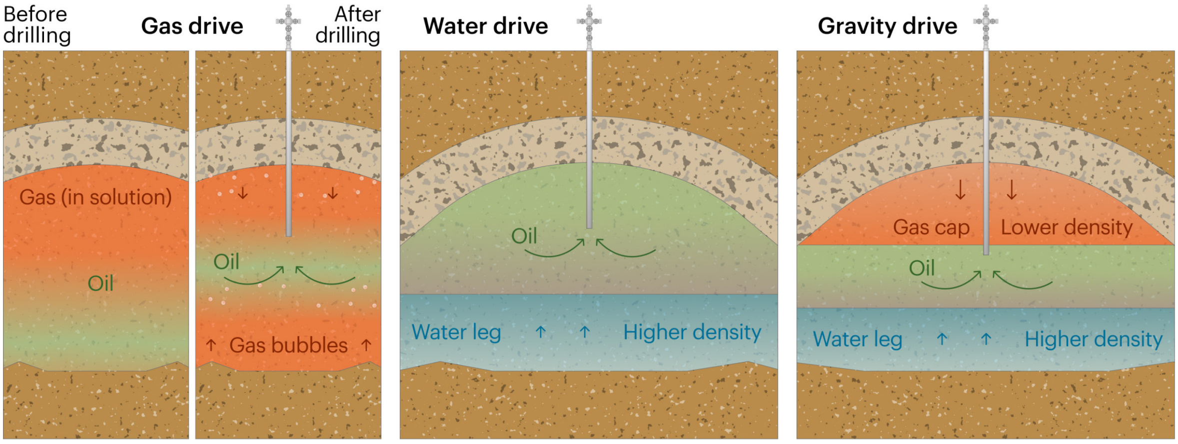
Declines at the well level are influenced by many complex features of the hydrocarbon accumulation as well as the natural reservoir drive mechanisms, which are the natural forces that push oil and gas toward the wellbore (Figure 24). Those main forces are:

- **Gas drive:** Expanding gases present within a reservoir drive oil toward the wellbore. In "solution gas" drive, gas dissolved in oil forms bubbles as the oil is extracted from the reservoir, which pushes additional oil towards the wellbore. In "gas cap" drive, a layer of free gas above the oil expands steadily keeping pressure high to assist oil flow.
- **Water drive**: As oil is produced, pressure in the reservoir drops and water from a connected aquifer moves into the reservoir. This maintains pressure and physically pushes the oil towards the wellbore helping sustain production rates.
- **Gravity drive**: Is the combined action of gas and water drives. Gas from the gas cap expands downward while water moves upward and gravity causes oil to drain towards the wellbore.

Over time, these natural driving forces become less effective as pressure falls and as the proportion of water extracted alongside the oil and gas increases, referred to as the water cut. For gas reservoirs that contain condensates, as the reservoir pressure falls, liquids can also drop out of solution, and this slows the volumes of natural gas produced.

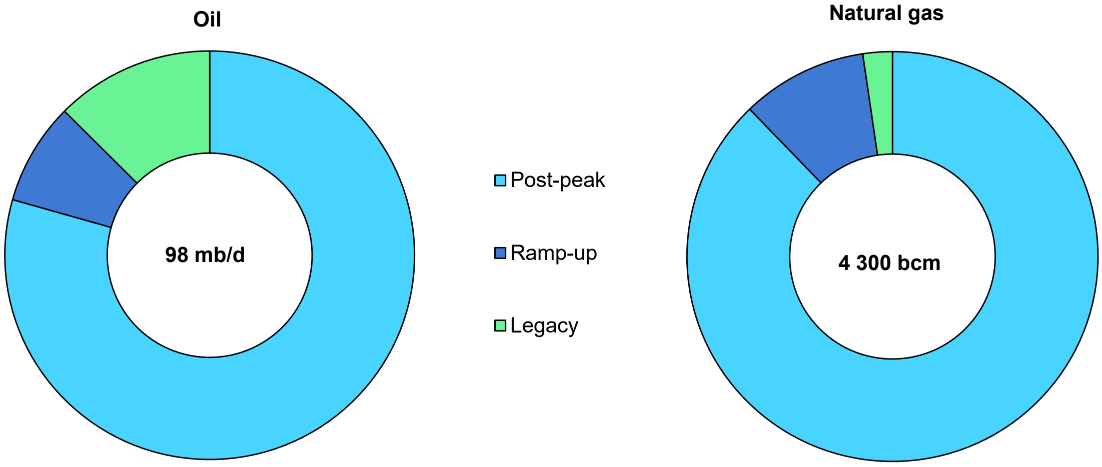
Above-ground factors also influence decline rates. Surface equipment limitations, such as undersized valves or poorly maintained wellheads, can restrict flow and artificially increase the observed decline rate. Processing capacity constraints can emerge, for example as the water cut or the ratio of natural gas to oil increases, which may force operators to reduce production.

Figure 24 Natural reservoir pressure depletion mechanisms in oil extraction



Similarly, pipeline and export bottlenecks can limit volumes, compelling production restraints. Operational practices such as maintenance shutdowns or well interventions create temporary interruptions that may distort decline trends. Economic factors, such as a drop in prices, OPEC production management, policy decisions, regulatory compliance requirements, such as related to emissions reductions, and geopolitical events can all lead to intentional production cuts or well shut-ins.

Figure 25 Global oil and gas production by field status, 2024



In 2024, around 80% of global oil production and 90% of natural gas production came from fields that had passed their peak in production (including unconventional production) (Figure 25). A further 10% of production was from ramp-up fields, i.e. fields that have been brought online in the past decade and that have yet to reach a definitive peak in production. The remainder was from legacy fields, which are conventional crude oil and natural gas fields that were brought online before 2015 and have yet to reach peak production. These have generally been subject to above-ground constraints, such as OPEC quota requirements, and so are hard to include in post-peak field analysis. This includes a number of the supergiant fields in the Middle East and Russia.

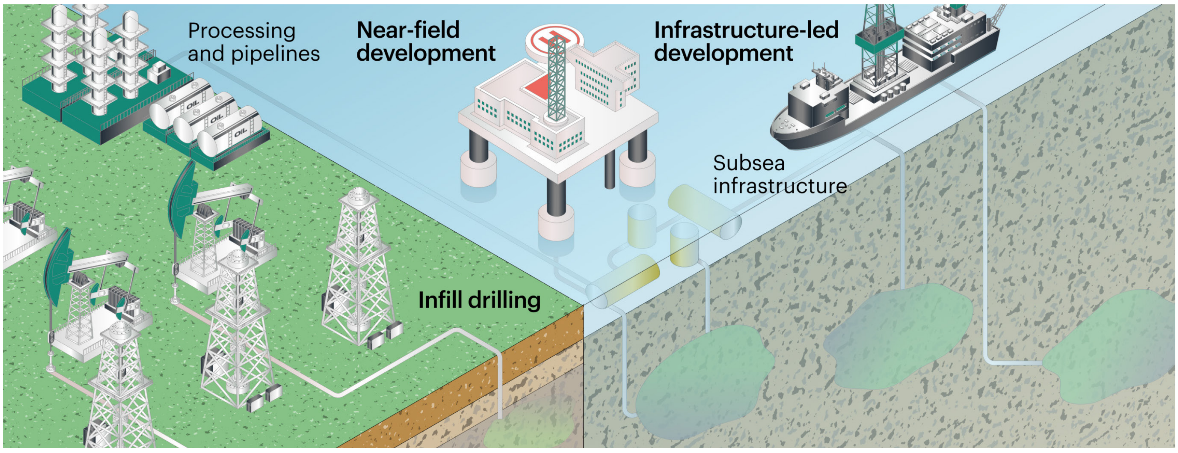
Field decline management

After a primary recovery period, during which oil and gas is produced via natural reservoir drive mechanisms, operators can deploy a variety of measures to boost production or to slow decline. This includes infill drilling of both vertical and horizontal wells, pumping and lifting, large-scale injections such as water flooding, and enhanced recovery techniques. In practice, these activities can occur in sequence or in combination according to suitability, availability and economics of the technology, and in accordance with a company's reservoir management practices.

Infill drilling involves drilling additional wells in an existing field to access previously bypassed or unswept areas of the reservoir. This can increase production for a period of time and will tend to offset natural production decline. In reservoirs with uneven depletion or compartmentalisation, increasing well density will tend to increase production, although the additional recovery needs to be carefully balanced against the cost of drilling new wells. As horizontal and multilateral well designs evolved, these were also used to increase production beyond what vertical wells could deliver. Once well density is maximised and infill drilling slows, production decline may accelerate above the rates observed before the new drilling was undertaken.

Infill drilling differs from new near-field developments (Figure 26). Infill wells are drilled within the existing boundaries of a producing field, usually placed between existing wells. In the North Sea, mature oil fields like Ekofisk and Clair have used infill drilling in combination with additional recovery techniques such as water flooding to increase total production.

Figure 26 Field decline management strategies



IEA. CC BY 4.0.

Near-field development uses existing infrastructure to tap into previously unconnected reservoirs. After an initial anchor project is developed, other pockets of oil and gas may be tapped that would not otherwise be economically viable to recover without the existing infrastructure (Box 2). This strategy also extends to exploration, whereby operators may focus efforts near existing infrastructure because development costs for any new discoveries are likely to be lower, known as infrastructure-led exploration. In recent years, several new developments have been planned and designed from the outset to accommodate potential additional near-field developments, especially in challenging areas such as offshore deepwater plays. For example, the Whiptail project in Guyana will produce via a dedicated new floating production storage and offloading vessel and use a tie-back to infrastructure, such as the subsea systems and logistics hubs, that have already been developed in the Stabroek block. A number of projects that have recently received final investment decisions (FID) in the North Sea and US federal offshore also feature expansions that tie-back to existing infrastructure.

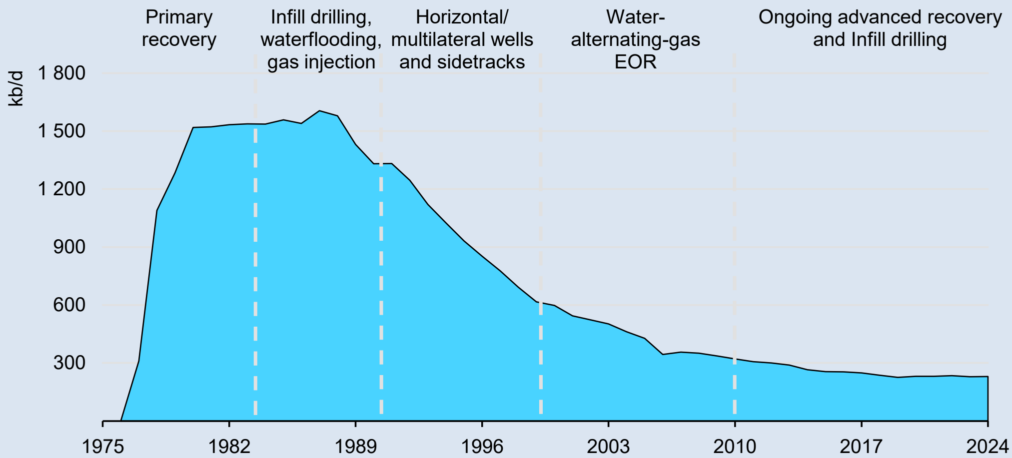
Box 2 Secondary recovery efforts and infrastructure-led development at the Prudhoe Bay oil field

In Alaska, the onshore coastal Prudhoe Bay supergiant oil field began production in 1977, nine years after the first discovery well was drilled (Figure 27). The field is estimated to hold around 20 billion barrels of technically recoverable oil, making it a key supergiant field in North America. The remoteness and Arctic climate posed significant challenges to development. Commercial production began only after the completion of huge infrastructure projects including the 1 300 kilometre (km) Trans Alaska Pipeline System.

Prudhoe Bay sustained production of over 1.5 million barrels per day during the 1980s. In the mid-1980s, secondary recovery measures were initiated, including infill drilling and waterflooding. Miscible gas injections, an enhanced oil recovery technique, that alternated with water injections were also first deployed from the mid-1980s as the field was starting to decline and these injections continue today. From its peak level, production declined by around 7% on average per year to the mid-2000s. Advanced drilling techniques such as multilateral wells were employed in the late 1990s which helped to slow average annual observed declines rates to about 5% from the peak through to 2024.

Existing infrastructure at Prudhoe Bay improved the economics for nearby projects by supporting infrastructure-led development. The Kuparuk River Unit, for example, began production in 1981 and reached peak output of around 300 thousand barrels per day (kb/d), and the Colville River Unit which began production in 2000. Additional production is anticipated with the Willow project (Bear Tooth Unit), slated to start flowing in 2029.

Figure 27 Oil production in Prudhoe Bay, 1975-2024



Source: IEA analysis based on data from Rystad Energy (2025).

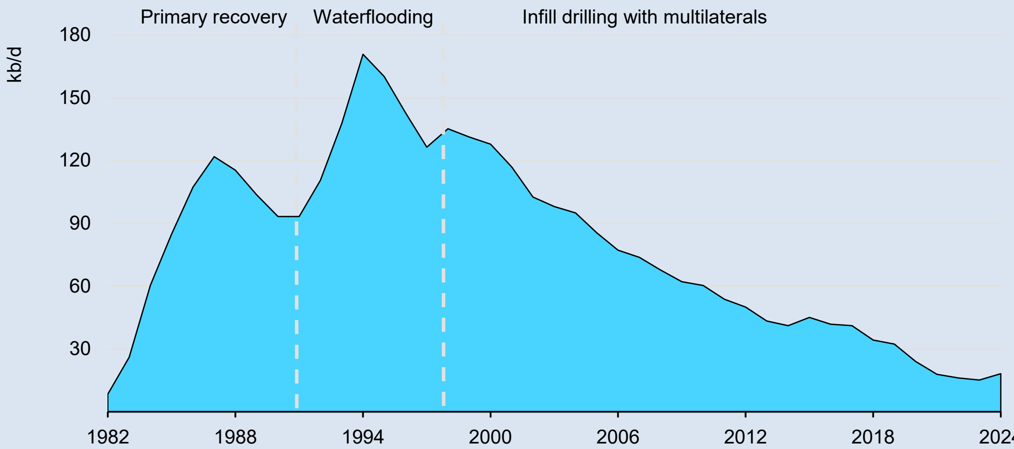
Where natural reservoir pressure becomes insufficient to maintain economic flow rates, a suite of technologies termed “artificial lift” can be deployed to enhance fluid production. Artificial lift consists of two main techniques: pumping and injection. Pumping involves the use of either surface-mounted or downhole equipment such as rod pumps, progressive cavity pumps, or electrical submersible pumps to mechanically raise hydrocarbons to the surface. Injection involves introducing gas to reduce the density of the fluid column and facilitate fluid flow to the wellbore.

Box 3 Waterflooding and infill drilling at the Takula Field

Takula, a shallow water field in Angola, was discovered in 1971 and was the first major offshore oil development in the country. It started production in late 1982 (Figure 28). Technically recoverable resources are estimated to be around 1 billion barrels, the majority of which has already been produced. The Takula Field has seven reservoirs which required nine offshore production platforms plus additional platforms for gathering and injection operations.

Production reached an initial peak in 1987 at 120 kb/d, five years after first production, as the well platforms were sequentially installed and brought into operation. As production started to decline, waterflooding operations began in the early 1990s and oil output reached a new peak of 170 kb/d soon after. As production started to decline again, new wells were drilled from 1998 using multilateral well designs and applied waterflooding: the compound average annual observed post-peak decline rate after this peak is about 7%.

Figure 28 Oil production in Takula Field, 1982-2024



Source: IEA analysis based on data from Rystad Energy (2025).

Water injection or waterflooding is also widely used to help displace oil and push it toward production wells. Considered *secondary recovery*, these techniques are designed to increase and maintain pressure that has been lost after primary recovery. Waterflood operations require source water (surface water, seawater, aquifers and produced water), water production and treatment facilities, and injection wells. Gas may also be used. Injecting natural gas or nitrogen increases reservoir pressure and can reestablish the gas cap to help drive oil toward production wells. Injected gas is usually sourced from produced gas separated at the surface or purchased from external suppliers or generated on-site. Alternating water and gas injections can be used to enhance the efficiency of both water and gas movement in the reservoir.

Use of primary and secondary recovery techniques may leave around two-thirds of the oil originally in place in the reservoir. Over time, the water production rate also increases: this presents operational and economic challenges as high water handling costs may accelerate the limits of field viability, leading to faster rates of field abandonment.

In addition to primary and secondary recovery, enhanced oil recovery (EOR) techniques can be used by operators to attempt to boost production rates and the overall recovery factor.[11] EOR works by altering the physical or chemical properties of the oil itself, making it easier to extract, or by modifying the geologic formation properties to improve oil flow and recovery rates. Around 3% of global oil produced today is through EOR. The main EOR techniques are:

- **CO_2 EOR** where carbon dioxide (CO_2) is injected to boost recovery either through a miscible or immiscible process. In a miscible CO_2 process, the CO_2 mixes with or dissolves into the oil, thereby increasing its mobility and susceptibility to being pushed by water. In an immiscible process, the gas does not dissolve into the oil but instead pushes the remaining oil; this is often combined with water injection. Nitrogen and natural gas can also be used in place of CO_2.
- **Chemical EOR** involves the injection of polymers and/or surfactants. These chemicals can change the ability of oil to flow through the geologic formation and allow more oil to move out of pores and flow to the production well. Surfactants reduce the surface tension of the oil, thus improving its ability to be displaced by water.
- **Thermal EOR** in which facilities at the surface generate steam that is injected into a well. This heats the oil in the formation, temporarily reducing its viscosity and increasing its mobility to facilitate recovery.

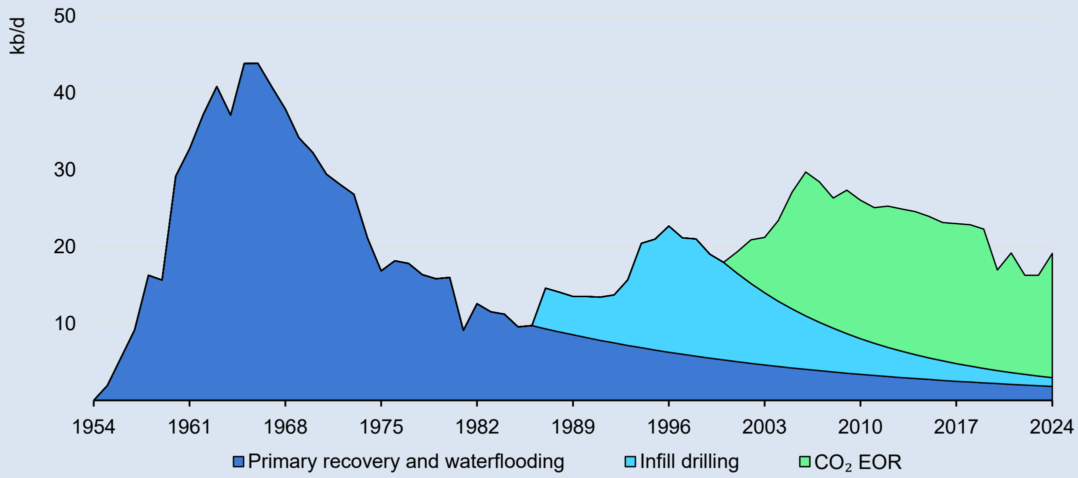
Box 4 CO_2 EOR at the Weyburn-Midale Field Complex

The Weyburn-Midale Field Complex in Saskatchewan, Canada started production from vertical wells in the mid-1950s. Waterflooding operations beginning in the early 1960s. Production peaked in 1966 at 44 kb/d and subsequently declined by around 6% each year on average to the mid-1980s (Figure 29). In the same period, vertical

[11] Recovery factor is the amount of oil and gas recovered relative to the oil and gas originally in place.

and horizontal infill wells were drilled and production rose to a secondary peak of 23 kb/d in 1996.

Figure 29 Oil production in Weyburn field, 1954-2024



Source: IEA analysis based on data from Rystad Energy (2025).

As production started to decline again, a large-scale CO_2 EOR project was developed with injection starting in 2001. The CO_2 is captured from a synthetic fuel plant in the United States, transported by pipeline and injected into the reservoir to maintain pressure and mobilise previously inaccessible oil. Between 2000 and 2006, overall production rates increased from 18 to 30 kb/d. In recent years, production has declined by around 2% on average each year. In total, around 40 million tonnes (Mt) of CO_2 has been injected into the reservoir since 2001. This equates to around 0.3 tonnes of carbon dioxide (t CO_2) injected for each additional barrel of oil produced. (About 0.4 t CO_2 is emitted when a barrel of oil is combusted).

Decline rates in conventional oil and gas production

An essential starting point for any assessment of the outlook for oil and gas markets is an understanding of how decline rates vary over time and across different field types. Because definitions of decline vary in industry practice, it is essential to be clear about the terms used and how these are derived (Box 5).

This report is based on a field-by-field analysis of historical production data from around 15 000 individual oil and gas fields that have reliable production records. Those data are used to generate estimates of observed post-peak decline rates. This relied on historical production data provided by Rystad Energy and includes fields from a wide range of geological types, locations, sizes and ages. The 4 000 largest fields within this sample, which together account for around 20% of global post-peak oil and gas production, were reviewed manually to determine the timing and magnitude of peak production and subsequent decline phases. For the remaining fields, decline rates were derived using an algorithm implemented in R (a programming language).

The general approach and definitions employed build on the foundational work of several editions of the *World Energy Outlook (WEO)*, specifically the *WEO-2008* and *WEO-2013* for oil, and the *WEO-2009* for natural gas. A notable modification in this analysis is that the reported observed post-peak decline rates take into account the production histories of all fields that have passed their peaks, even those that have since stopped producing, to provide a more encompassing view of how decline rates vary between regions and types of production.[12]

Box 5 Decline rate definitions

Simple year-on-year decline: The annual change in real historical production from a field or group of fields that have passed peak production, measured relative to production from the same field in the previous year. Production levels included in this measure include the impact of investment undertaken by operators to slow declines or to increase production.

Observed post-peak decline: The compound average annual decline in production since the year of peak production. This also includes the impacts of ongoing investment by operators to slow declines or to increase production. Observed decline can be classified in three phases:

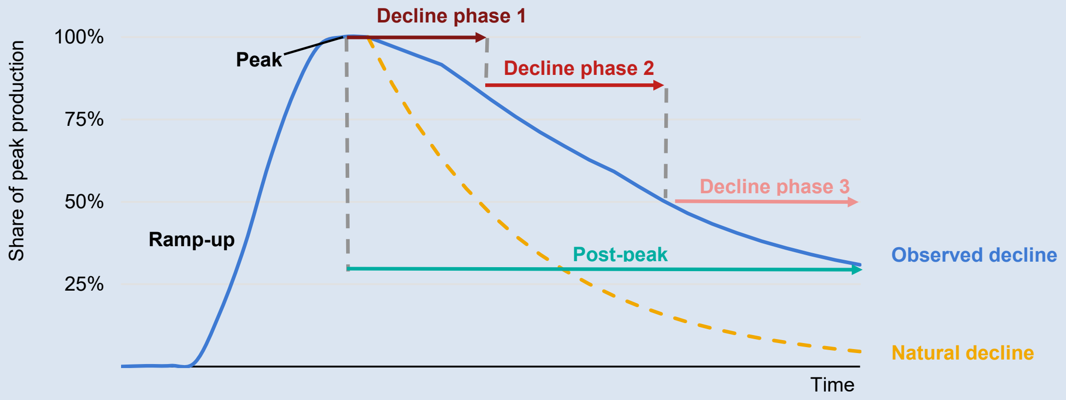
- Phase 1: From peak to when production falls below 85% of the peak level.
- Phase 2: From the end of Phase 1 to when production drops to 50% of the peak level.
- Phase 3: From the end of Phase 2 to the last year with a material level of production which is generally the final recorded year, or when production drops below 5% of the peak level (Figure 30).

Natural decline: The decline in production that would be seen with continued operational expenditure but no further capital investment. In practice, very few fields

[12] For example, in this report, the phase 1 decline rate of a field that has since stopped producing is included in the global phase 1 observed post-peak decline. In the *WEO-2013*, the global phase 1 observed post-peak decline was based only on fields that were in phase 1 at the time of the assessment, i.e. in 2013. See Technical annex for further information.

have undergone natural decline since maintenance capital investment is typically used to try to slow a drop in production. Therefore, estimates are derived from observed declines, adjusted for assumptions on investment in existing fields and capital efficiency.

Figure 30 Decline rate phases used in this analysis

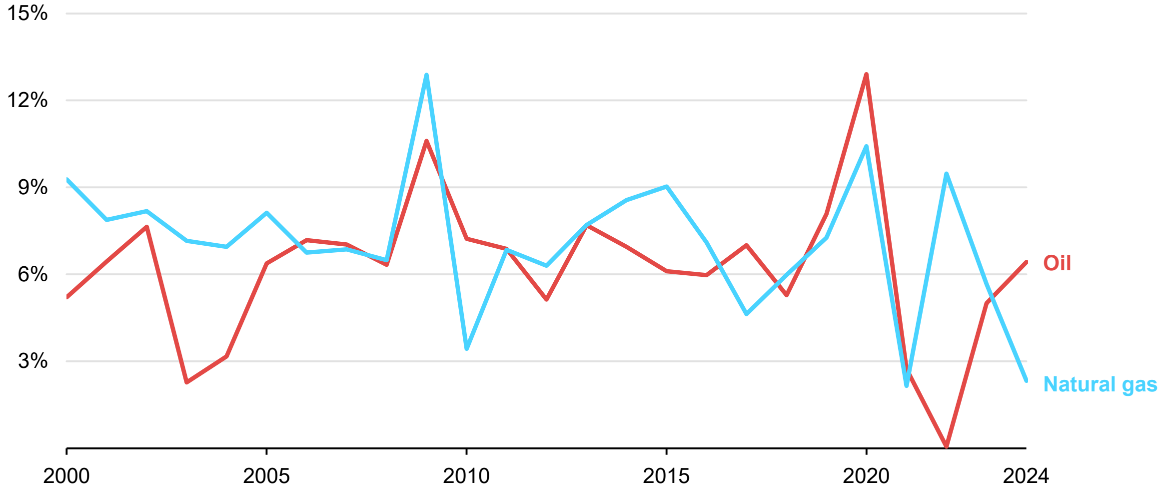


In practice, few oil and gas fields exhibit a smooth production trajectory. Implementing additional or enhanced recovery techniques can increase production above the 85% or 50% production threshold. In addition, external factors can cause production to drop to very low levels for an extended period, though potentially they may bump up. In this analysis, each decline phase is based on the final year in which each production threshold was passed, unless there is clear evidence of the adoption of EOR methods, which is considered a new field development. Decline rates are weighted by each field's cumulative production volume to arrive at global or regional averages. Further details of the methodology employed is in the technical annex.

Simple year-on-year decline rates

Decline rates for individual fields differ markedly over time. Short-term fluctuations can reflect changes in well productivity, pressure drops, the impact of the production policies implemented by companies or OPEC members, cyclical changes in investment in field redevelopment, as well as policy, geopolitical factors and fluctuations in oil prices and fiscal terms. For example, a drop in the oil price may render some fields unprofitable so they are shut in, though this is relatively rare except for fields that are already producing at very low levels, or make large ongoing investment less economic, which would mean production falls faster and leads to a higher simple decline rate.

Figure 31 Simple year-on-year decline rates for post-peak conventional crude oil and natural gas fields, 2000-2024



Notes: The simple year-on-year decline rate takes the sum of production output from all post-peak fields in a given year and compares it with production from the same set of fields in the previous year. The sample of fields included in the assessment of each year will change as new fields pass their peak in production and as fields are shut in.

The year-on-year or simple decline rate for all post-peak oil and gas fields therefore exhibits a wide year-on-year variation (Figure 31). For example, in 2009 demand was subdued because of the global financial crisis, oil and gas demand fell by 2% that year, and production in a number of fields was deliberately reduced to reflect weaker demand. Thus the sharp drop in the simple decline rate in 2010 reflects the reopening of these fields. Similarly, in 2020-2021 the simple decline rate exhibited significant variations. These were driven by a sharp production drop in 2020 amid the Covid-19 pandemic. A strong rebound followed in 2021. In 2022, OPEC+ boosted production to curb rising oil prices after Russia invaded Ukraine, resulting in a further reduction in the simple decline rate for oil.

These large year-on-year fluctuations are a key reason why we focus here on observed post-peak decline rates: these take the compound average annual decline rate (CADR) since the year in which production peaked. This approach is much less sensitive to year-to-year variations than the simple year-on-year observed decline rates.

Observed post-peak decline rates

Conventional crude oil

Based on the production histories of all conventional crude oil fields that have past their peak, we estimate that the global average observed post-peak CADR is 5.6% weighted by the cumulative production of each field. Breaking down these rates further shows that declines vary markedly between distinct types of conventional crude oil fields and over the field lifetime (Table 1).

Table 1 Observed post-peak CADR of conventional oil fields (%)

	Decline phase 1	Decline phase 2	Decline phase 3	Average post-peak
Onshore	3.6	7.9	7.3	4.2
Shallow offshore	8.0	12.6	10.4	8.5
Deep and ultradeep offshore	10.2	16.2	12.5	10.3
Supergiant	1.4	4.6	6.8	2.7
Giant	5.4	10.0	7.9	6.3
Large	10.1	15.4	10.1	9.4
Small	14.0	18.6	12.8	11.6
Africa	10.6	12.1	9.6	8.1
Asia Pacific	5.2	10.2	8.3	5.9
Central and South America	6.4	9.6	10.9	7.7
Eurasia	4.5	10.8	7.2	6.5
Europe	8.1	14.7	10.5	9.7
Middle East	1.7	3.3	5.7	1.8
North America	7.6	13.6	9.1	8.3
OPEC	3.0	4.8	7.9	2.9
Non-OPEC	6.6	12.4	8.8	7.6
All fields	**5.0**	**9.8**	**8.5**	**5.6**

Notes: CADR = compound average annual decline rate. Definitions of water depths and field sizes are in Chapter 1.

Production from larger fields tends to decline more slowly than from smaller fields. Larger fields tend to have higher natural pressure, and economies of scale mean they are more likely to justify investment in improved reservoir management, and secondary and tertiary recovery techniques. They also tend to have multiple production reservoirs or zones meaning they are developed in successive tranches, with operators phasing infill drilling to extend peak production periods to maximise the sustained use of associated processing and transport infrastructure.

Offshore fields tend to decline more quickly than onshore fields. This is because offshore fields – especially those at deep water depths – are typically optimised for quicker payback due to their financial and technical risks and so are developed using fewer wells with higher initial flow rates to recover costs quickly. Another contributing factor is the high cost of well interventions, which often require a rig, making repairs or deploying additional or enhanced recovery techniques economically unviable in many cases. This leads to earlier and steeper declines once reservoir pressure begins to fall.

Because of the differences in decline rates between field types, the decline rates calculated for the Middle East and Russia, where fields tend to be very large and onshore, are much lower than those elsewhere. Observed post-peak decline rates are highest for the fields that have been developed in Europe, where production is predominantly offshore.

Decline rate phases 2 and 3 are significantly higher than those in phase 1 for nearly all types of fields and locations. Water or gas breakthrough tends to be dominant during decline phases 2 and 3, and so water comprises an increasing volume of the extracted liquids. In addition, as fields age, an increasing number of extraction wells can be shut in if continued production does not justify ongoing operating costs. In general, declines when a field is in phase 3 are slightly lower than in phase 2, as this is the period when operators are most likely to introduce secondary recovery techniques.

Natural gas

Trends in observed post-peak declines in natural gas fields, across different types and locations, exhibit many of the same characteristics as those in oil fields. (Table 2). Declines are less for supergiant fields and onshore fields. This means that at a regional level average post-peak declines are smallest in the Middle East and Russia. However, phase 3 declines in Middle East fields are very steep.

In general, associated gas production declines faster than non-associated gas fields. The non-associated gas decline rate is slightly slower than the decline in oil fields, since many oil fields tend to become gassier over time.

Table 2 Observed post-peak CADR of conventional natural gas fields (%)

	Decline Phase 1	Decline Phase 2	Decline Phase 3	Post-peak
Onshore	2.9	8.5	7.2	5.3
Shallow offshore	7.0	16.6	14.6	9.0
Deep and ultradeep offshore	7.6	14.9	20.8	9.5
Supergiant	1.8	7.1	6.5	4.4
Giant	3.9	12.3	13.3	6.5
Large	9.6	17.9	13.7	11.1
Small	15.3	23.7	17.7	15.9

	Decline Phase 1	Decline Phase 2	Decline Phase 3	Post-peak
Africa	11.7	19.9	15.2	12.9
Asia Pacific	4.6	13.3	11.3	6.1
Central and South America	8.4	17.0	14.2	10.6
Eurasia	1.7	7.6	5.3	4.4
Europe	4.7	11.3	14.0	7.5
Middle East	3.4	14.3	25.8	5.2
North America	11.2	19.1	14.1	12.0
Associated	8.1	15.6	9.6	8.3
Non-associated	4.2	11.1	9.7	6.7
All fields	**4.5**	**11.5**	**9.7**	**6.8**

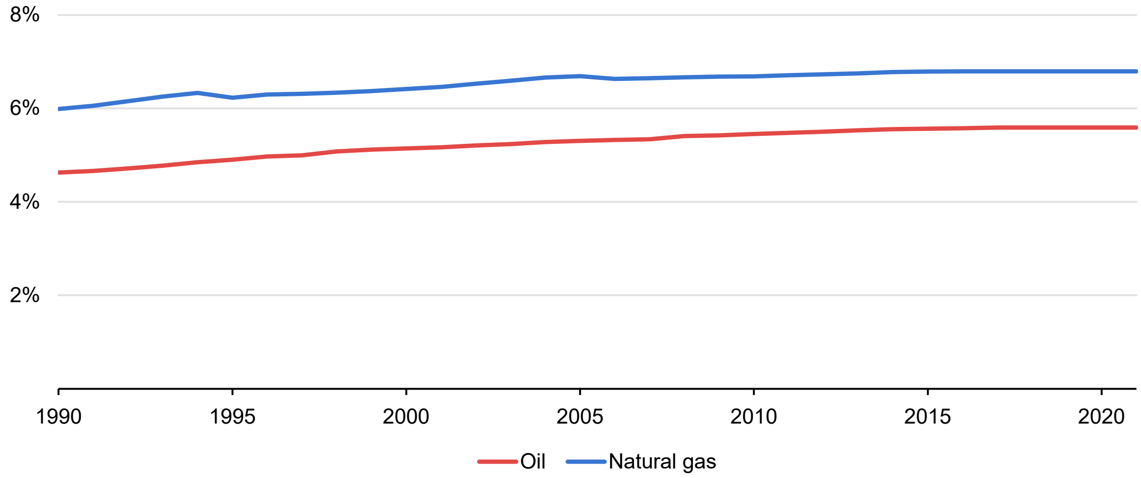
Note: CADR = compound average annual decline rate. Definitions of water depths and field sizes are in Chapter 1.

The global average observed post-peak decline rate for natural gas is around 1.5 percentage points higher than for oil. There are a number of reasons for this. Gas is more compressible and flows more easily than oil, leading to higher initial production rates and faster declines after peak. Oil recovery factors are generally lower than those for natural gas, but additional and enhanced recovery methods are more commonly applied to oil, which helps sustain production over a longer period. In addition, a larger share of conventional natural gas production comes from offshore fields, about 45% for gas versus 25% for oil, and offshore project designs tend to have higher decline rates.

Changes in observed post-peak decline rates over time

The observed post-peak decline rate shows fewer annual fluctuations than the simple year-on-year decline rate, but there are still visible trends over time. For example, for conventional crude oil, the global average observed post-peak CADR has risen from around 4.5% in the early 1990s to 5% in the early 2000s and to 5.6% since 2015 (Figure 32).

Figure 32 **Global average observed post-peak CADR for conventional crude oil and natural gas fields since 1990**



Note: Shows the observed post-peak CADR of all post-peak fields in each year weighted by cumulative production.

A similar trend holds for conventional gas fields, where the global average observed post-peak CADR has increased from 6% in the early 1990s to 6.5% in the early 2000s to just under 7% in the period since 2010.

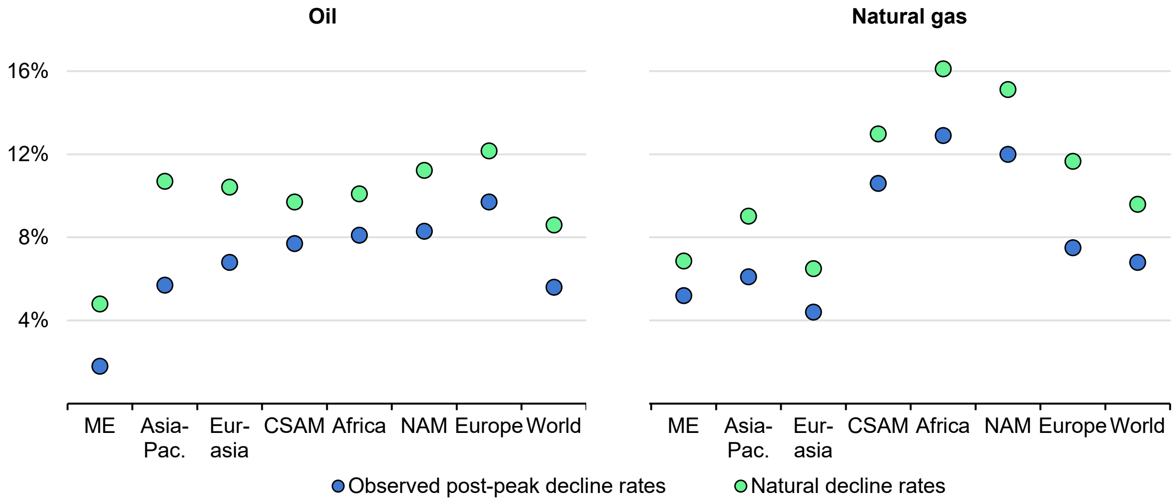
This can be explained by the types of fields that have peaked over time. In the 1990s, a larger share of post-peak production came from large onshore fields, while a larger share of post-peak production today comes from small offshore fields. Another factor is that advances in production technology have allowed operators to introduce secondary recovery techniques earlier in the working life of a field. Companies are now more likely to optimise production and reservoir management techniques to maximise near-term production and the net present value of future cash flows, which in some cases may mean a field is overdeveloped and experiences a steeper decline.

Natural decline rates

Natural declines – the drop in production that would occur in the absence of any upstream capital investment – are rarely, if ever, observed in the real world. Companies typically maintain investment in underperforming fields, even amid steep production declines, through maintenance capital expenditure, e.g. equipment replacement, since these costs are generally outweighed by ongoing revenue generation. Still, an understanding of natural decline rates is a critical parameter in oil and gas supply modelling as it determines the level of future investment requirements.[13]

Natural declines are calculated based on the amount of capital expenditure spent in existing fields and assumptions about the capital efficiency of this investment, i.e. development costs as shown in Figure 19 and Figure 20. This yields an estimate of additional resources mobilised in each year, which is then translated into production levels over time. Subtracting this from the observed post-peak CADR gives an estimate of production that would have occurred in the absence of the additional expenditure. Given the heterogeneity of oil and gas fields, it is impractical to estimate capital efficiency on a field-by-field basis, and so this analysis is conducted at the regional level using data on investment in existing fields and their representative development cost benchmarks.

Figure 33 Observed post-peak and natural decline rates for oil and gas by region



Note: ME = Middle East; Asia-Pac. = Asia Pacific; CSAM = Central and South America; NAM = North America.

On this basis, we estimate that the difference between the global average observed post-peak and natural decline rates is around 3 percentage points for both oil and

[13] Natural decline rates can be conceptualised in various ways. For example, some define them as the drop in production that would be observed in the absence of both capital and operating expenditure. In this analysis, we look at production declines only in the absence of capital expenditure. This allows us to distinguish between day-to-day operational expenditure required to keep fields producing and the specific investment undertaken by operators that are undertaken to slow declines, such as drilling new wells.

natural gas (Figure 33). Adding this to the global average observed post-peak declines implies a natural decline of around 8.5% for the post-peak oil fields in our assessment and 9.5% for post-peak gas fields.

Decline rates in unconventional oil and gas production

Tight oil and shale gas

The resource characteristics and decline mechanisms of tight oil and shale gas are very different from those of conventional resources. Tight oil and shale gas formations have very low permeability and individual wells drain only a very small volume of the overall reservoir. Once a well is drilled and hydraulically fractured, production initially surges as oil and gas flow from the newly created fractures, but this drains rapidly and output declines steeply in a hyperbolic pattern. These wells typically produce around 80% of their total output within the first two years, compared with less than 10% for conventional wells. After this sharp drop, production tails off at a much lower rate, declining more like an exponential curve as reservoir pressure continues to fall. For this reason, tight oil and shale gas wells are generally modelled with hyperbolic decline followed by an exponential decline, whereas conventional resources are commonly represented by exponential decline over their entire lifespan.[14] In addition, development timescales for tight oil and shale gas wells in the United States are generally far shorter than is the case for conventional resources: it can take as little as three months for a tight oil operator to move from securing development approval to the start of production.

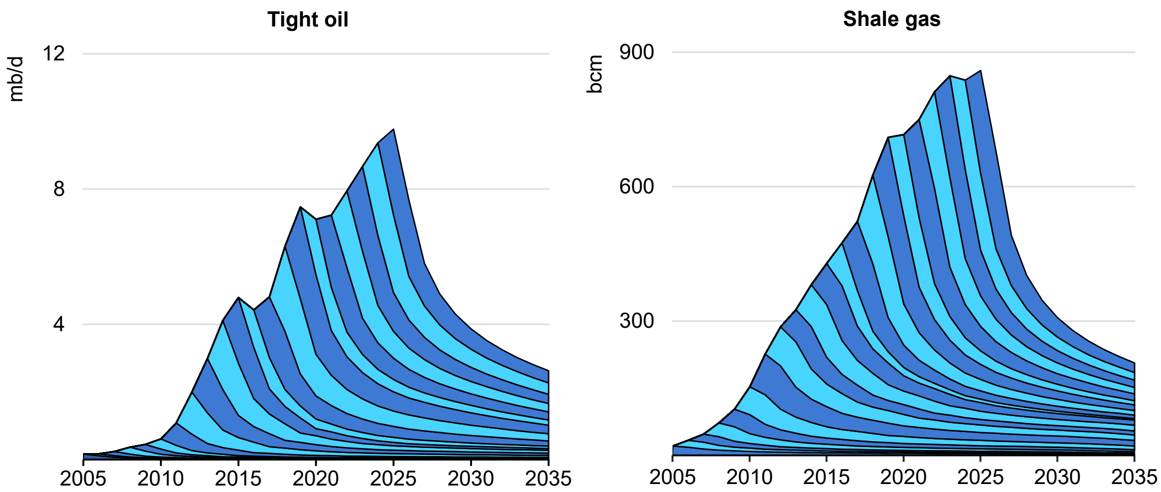
The natural decline rate for tight oil and shale gas, i.e. the drop in production if all capital investment and drilling were to stop, is very steep. More than three-quarters of the 10 000 tight oil wells that began production in 2025 in the United States are needed simply to compensate for declines at existing wells. Based on a detailed play-by-play assessment, we estimate that if no new wells were to be completed after the end of 2025, then US tight crude oil and condensate production would fall by around 3.5 mb/d by the end of 2026 (a 35% decline), and by an additional 1.2 mb/d in the year thereafter (a further 18% decline).

The long tail of production from wells provides a baseload of production in the longer term, and the aggregate natural decline rate therefore slows over time. By 2035, there would still be around 2.5 mb/d of tight oil production, even though all

[14] In exponential decline, production drops at a constant percentage rate over time; in hyperbolic decline, the production rate falls quickly at first but then slows down.

of the individual wells would be past their production peaks (Figure 34). These curves are hyperbolic but the compound average annual natural decline rate over the period to 2035 for US tight oil would be 12%.

Figure 34 Tight oil and shale gas in the United States by well start-up year and projected production based on natural declines



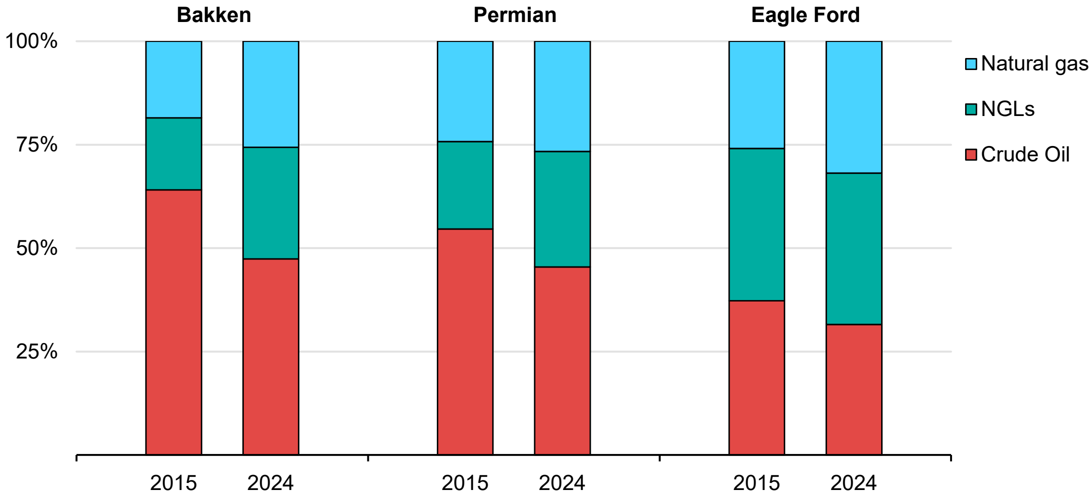
Notes: mb/d = million barrels per day; bcm = billion cubic metres. Data shown assume that all investment ends on 1 January 2026. Bands show production from all wells drilled in each 12-month period starting in 2005.

US shale gas follows a similar trend, although the decline rates are generally slightly greater. If no new shale gas wells were to be drilled from the end of 2025, production would fall by nearly 350 bcm within 12 months, and the compound average annual natural decline rate to 2035 for would average around 13%.

Defining observed decline rates for tight oil and shale gas basins is complex. On one hand, because each well only drains a small part of the reservoir, it could be considered as independent of all previously drilled wells and so could count as a new development. This would mean that the observed decline rate for a shale play would be equivalent to the natural decline rate. On the other hand, because wells are usually drilled very close to each other, often with common infrastructure, each well could also be considered as a small extension of an existing development. In this case, new wells could be considered as continued investment in an existing asset, lifting production from a natural rate of decline to an observed rate of decline.[15] In this report, when discussing supply balances with ongoing investment, tight oil and shale gas are therefore considered separately from conventional oil and gas.

Over the past decade, US shale plays have gradually become gassier, producing a higher proportion of natural gas and natural gas liquids (NGLs) relative to crude oil. As many of the oil-rich zones – particularly in some of the most prolific plays like the Bakken, Permian Basin and Eagle Ford – have matured, new wells have encountered higher gas-to-oil ratios, as the reservoir pressure in more mature areas of production is more amenable to higher rates of gas recovery (Figure 35). This has important implications for decline rates, as lower pressure in newer wells tends to translate into higher rates of decline.

Figure 35 Evolution of liquids and gas production in selected unconventional plays in the United States, 2015 and 2024



Note: NGLs = natural gas liquids.
Source: IEA analysis based on data from Rystad Energy (2025).

Extra-heavy oil and bitumen

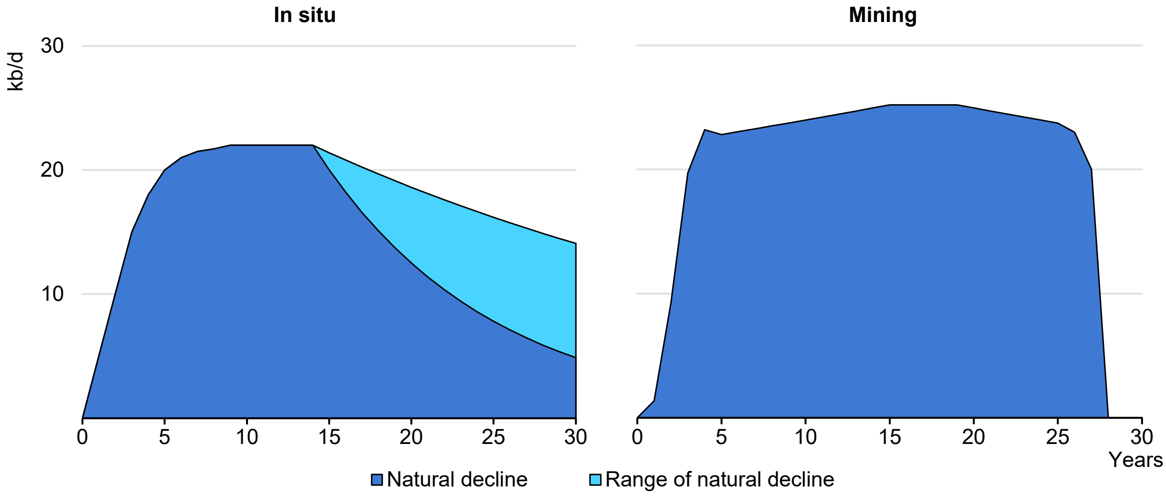
Extra-heavy oil and bitumen (EHOB) is produced mainly in Canada and Venezuela. It has very high viscosity and its recovery relies on mining, if the resource is sufficiently shallow, or in-situ thermal stimulation methods such as steam-assisted gravity drainage (SAGD).

[15] Some wells drilled in close proximity interact with existing wells, inducing changes in pressure, fracture geometry and ultimately well performance. This "parent-child" relationship has been extensively documented in US shale plays and has led to increased sophistication of co-development and optimisation models.

Natural decline rates in general are low for mining given the mechanical nature of the process (Figure 36). Output is generally stable as long as bitumen deposits remain accessible, and trucking and shovelling operations are maintained, which is usually expensed as operating costs. Declines occur due to resource depletion, planned reductions in output, and maintenance.

SAGD involves a combination of two closely spaced horizontal wells: steam is injected into the well closer to the surface and oil then drains under gravity towards the lower production well. Upfront investment is usually relatively large, covering both well drilling and processing facilities, e.g. for steam generation, water processing and diluent blending. Once the steam plant is operational and the well pads are producing, fields can produce at relatively consistent levels for some time without further capital investment, i.e. under natural declines. However, there is a wide range of variability between reservoir types, and continued investment and ongoing drilling of new injector-producer pairs and expansions are needed for in-situ projects to sustain production over their lifetimes.

Figure 36 Natural decline rate examples for in-situ and mining EHOB projects



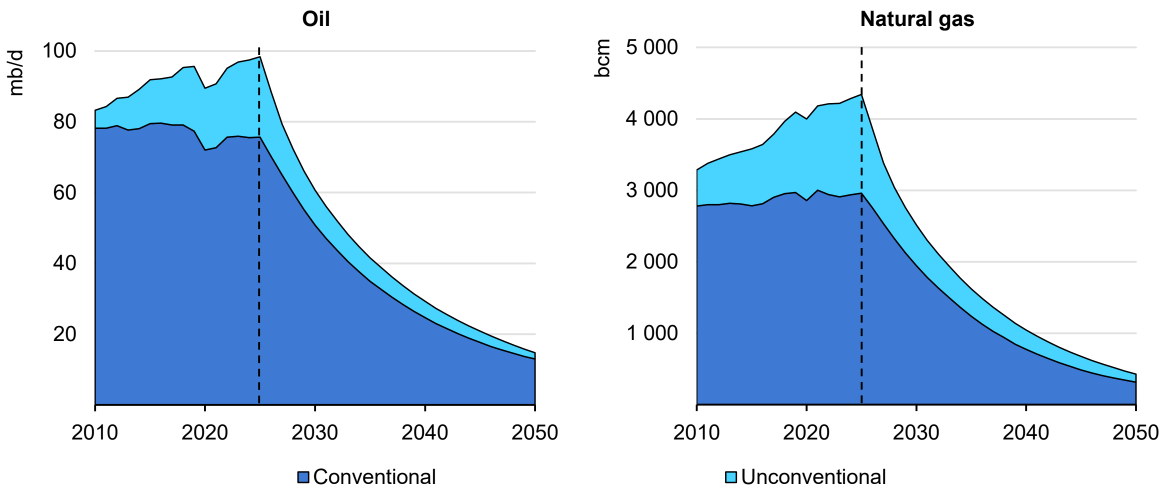
Notes: Range of natural decline indicates differences in natural decline rates from different reservoir properties that impact the effectiveness of in situ heating.

Chapter 3. Implications of decline rates for production, investment and security

Oil and gas production under natural declines

Long-term projections of future oil and gas supply need to take into account how decline rates vary for different field types and how these will evolve over time, as fields move from one decline phase to the next. Based on the analysis in Chapter 2, we estimate that absent any investment in new or existing projects from the end of 2025 – i.e. if production from all existing conventional and unconventional oil and gas fields falls under natural declines – global oil production would decline by around 8% each year on average to 2035 and natural gas production would fall by more than 9% every year (Figure 37).

Figure 37 Global oil and gas production with natural declines rates from 2025

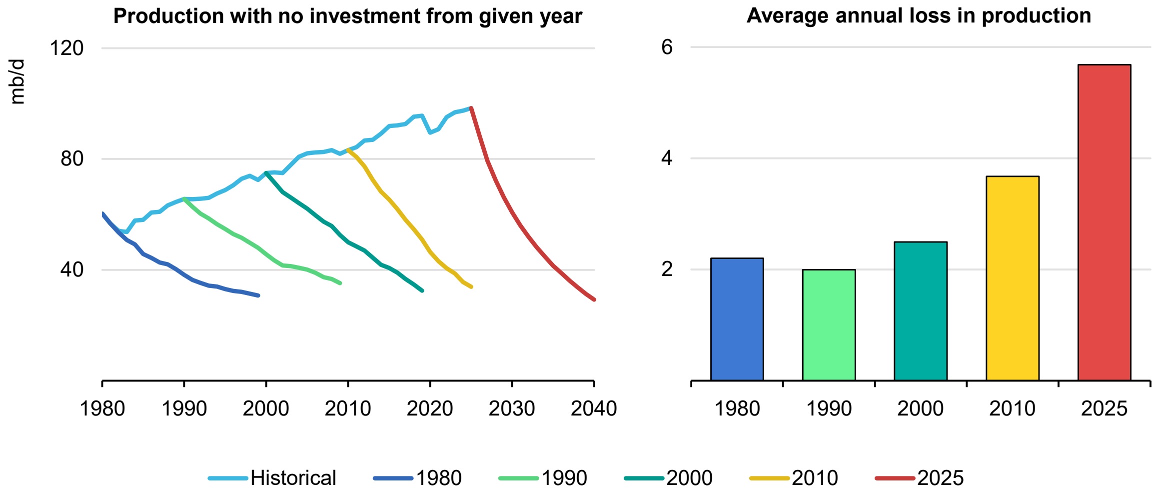


Note: Natural decline rates begin from the end of 2025.

For oil, this drop would be more than 5.5 million barrels per day (mb/d) every year on average to 2035, equivalent to losing more than the entire current oil production in Brazil and Norway from the global balance every year. For natural gas, it would be a loss of 270 billion cubic metres (bcm) every year, equivalent to losing annually all of the gas produced today by countries in Africa.

At these natural decline rates, overall oil production from both conventional and unconventional projects in 2035 would fall to 42 mb/d and natural gas to around 1 600 bcm. The annual production loss for unconventional oil and gas would be particularly steep, especially in the years immediately following a cessation of investment. By 2035, more than 70% of today's unconventional production would be lost; conventional production would fall by around 55%. By 2050, oil would fall to 15 mb/d and gas would fall below 500 bcm.

Figure 38 Oil production under natural decline rates worldwide



Note: Loss in production is the average annual drop over the subsequent 10 years.

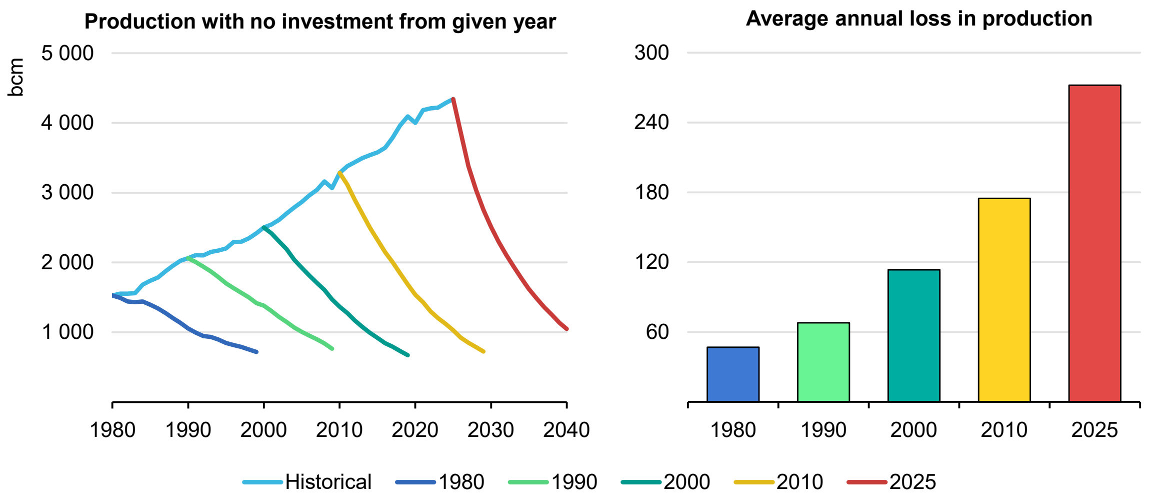
Production losses under natural decline rates from the end of 2025 are much steeper than in the past. For example, if all investment in existing fields had ended in 2010, production would have fallen by about 4 mb/d per year for oil (Figure 38) and 180 bcm per year for natural gas (Figure 39). Today, the corresponding annual losses of supply under natural decline rates are 1.5 mb/d higher for oil and 90 bcm higher for gas. This increase is caused by three main factors:

- **Higher shares of unconventional oil and gas**: Tight oil and shale gas have much steeper natural decline rates than conventional sources and their share of global production in 2025 (16%) is much higher than in 2010 (2%). This accounts for around 650 kb/d of the 1.5 mb/d increase in the annual loss of supply for oil in 2025 compared with 2010, and around 35 bcm of the 90 bcm additional loss for natural gas.
- **Changes in the composition of conventional oil and gas production:** Today's conventional oil supply balance has a higher share of NGLs (18%, up from less than 15% in 2010), and a larger share of production coming from deepwater offshore fields (10%, up from 7% in 2010). NGLs and offshore fields tend to have higher natural decline rates than onshore conventional crude oil fields. Offshore

gas fields also make up a higher share of global conventional gas production today than in 2010. Taken together, these factors explain around 200 kb/d of additional supply loss for oil and 10 bcm for natural gas in 2024 compared with 2010.

- **Higher overall production**: Oil production in 2025 is around 20% higher than in 2010 and natural gas production around 30% higher. Even if the global average natural decline rates for oil and gas in 2024 were to be the same as in 2010, an increase in the base level of production leads to higher annual average loss. This effect explains around 650 kb/d of the additional supply loss for oil and 45 bcm for natural gas in 2024 compared with 2010.

Figure 39 Natural gas production under natural decline rates worldwide



Note: Loss in production is the average annual drop over the subsequent 10 years.

Impacts of decline rates on the oil and gas supply balance

Understanding how supply evolves under natural decline rates generates important insights into future investment needs. But it does not give a true picture of the requirements for new oil and gas projects because there are several other sources of production that contribute to the energy balance.

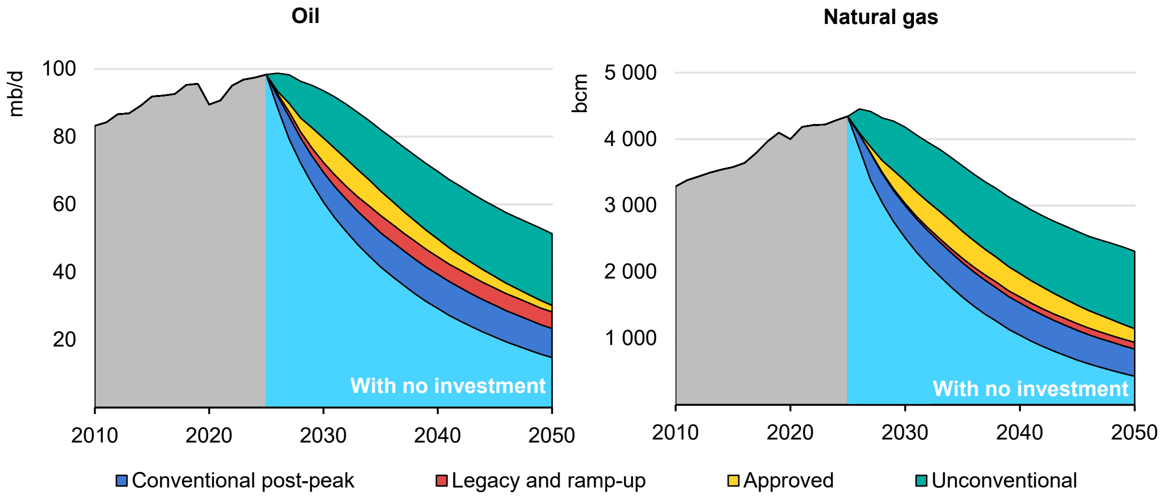
As discussed, under natural decline rates oil production would fall to 42 mb/d and natural gas to around 1 600 bcm in 2035. To determine how much additional supply is needed from new conventional oil and gas projects to keep production at today's levels, requires consideration of supply from continued investment in post-peak fields and unconventional oil and gas projects, as well as production from fields that have yet to reach their peak, including ramp-up, legacy and already approved fields. This needs to consider:

- **Investment in conventional post-peak projects**. Such investment can boost supply in existing post-peak fields from the natural decline rate to the slower observed post-peak decline rate. The use of new primary and secondary recovery techniques staves off declines and brings global production up by around 10 mb/d for oil and 500 bcm of natural gas in 2035 compared with natural decline rates.
- **Existing legacy projects and those in the ramp-up phase**. Around 10% of oil and gas production today comes from projects that have not yet reached peak production. If these fields follow historical patterns of ramping up to peak or plateau production and then observed post-peak declines, this would add around 5 mb/d of oil and 70 bcm of natural gas supply to the supply mix in 2035 compared with natural decline rates.
- **New approved conventional projects**. These are conventional fields which are under construction or have received final investment decision but have not yet commenced production. They are expected to add another 7 mb/d of oil and 410 bcm of natural gas supply in 2035 (see Figure 15).
- **Investment in unconventional projects:** For tight oil and shale gas, continuing investment would lead to much greater production than under natural declines. Output from newly drilled and completed wells would evolve over time, shaped by ongoing efficiency gains and tempered by the gradual depletion of the most productive areas. Continued investment at historical levels in EHOB also adds to the supply mix. In total, this adds a further 18 mb/d of oil and 1 000 bcm of natural gas in 2035 compared with natural decline rates.

Taken together, adding these sources to production under natural decline rates would mean 82 mb/d of oil production and 3 600 bcm of natural gas production globally in 2035 (Figure 40). By 2050, production would have dropped to 51 mb/d of oil and 2 300 bcm of natural gas, equivalent to an annual average decline rate between 2025 and 2050 of around 3% for both oil and natural gas.

To keep supply at current levels through to 2050, would therefore require an additional 47 mb/d of oil and 2 000 bcm of natural gas from new projects that have not yet been approved, potentially accompanied by decisions to bring online some of today's spare oil production capacity.

Figure 40 Oil and natural gas production with no investment and additions from investment in existing and approved projects



Source: IEA analysis based on data from Rystad Energy (2025).

Based on our assessment of discovered but not-yet approved resources (see Chapter 1), there are around 230 billion barrels of conventional oil and 40 trillion cubic metres (tcm) of conventional gas that have been discovered but not yet approved for development. Most of the world's undeveloped oil and gas resource finds are in Africa, the Middle East and Eurasia and include recent discoveries that require new infrastructure, as well as several mature supergiant oil and gas fields that are awaiting the next tranche of investment as part of multi-phase development programmes. For example, the North Field gas field in Qatar has been developed in six phases to date, but the majority of the discovered resource is as-yet undeveloped. On average, development timelines for new projects today are longer than they were in the past, but there are numerous projects, notably in Brazil and Africa, that are nearing final investment decisions, after which they could begin production within a three to five year period. We estimate that these resources could contribute up to 13 mb/d and 600 bcm of production in 2035, and around 28 mb/d and 1 300 bcm in 2050.

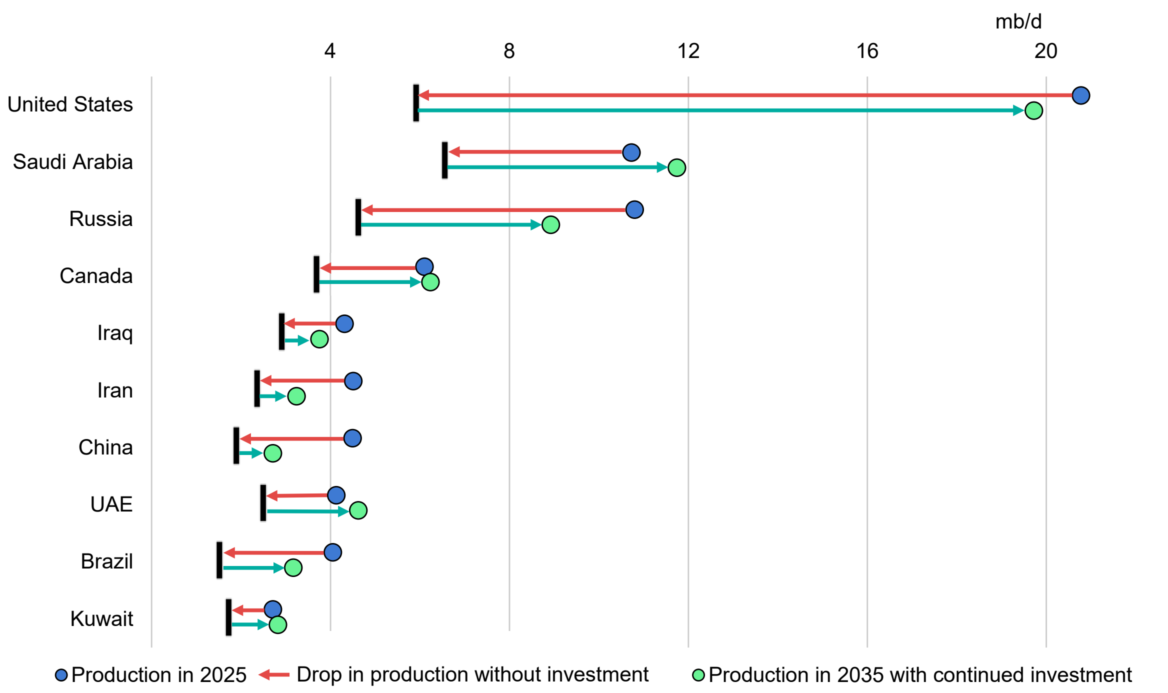
New exploration licences issued today would likely not bring new production online until the 2040s, but to maintain oil and gas production at today's levels through to 2050, an additional 19 mb/d of oil and 660 bcm of natural gas would need to be produced in 2050 from fields not yet discovered. This would mean that, on average, around 10 billion barrels of oil and 1 tcm of gas would need to be discovered each year. This is slightly above the amounts that have been discovered over the last five years (see section 1).

Regional results

In the absence of any upstream investment, oil and gas production would fall most sharply in the United States. Its production is dominated by unconventional sources such as tight oil and shale gas, and total output would decline by around 15 mb/d and 800 bcm between 2025 and 2035 (a drop of 75% over this period) (Figure 41). Meanwhile, regions with a stronger base of conventional oil and gas production, including Russia and the Middle East, would see a more gradual decline, losing around 45% of current production for oil and natural gas by 2035.

The extent to which continued investment in existing and approved oil projects can offset natural decline rates differs significantly across regions. In the United States, investment in tight oil and shale gas, approved projects, and projects that are in the ramp-up phase, would compensate for around 90% of the drop in oil production between 2025 and 2035. Filling the remaining supply gap to match current production levels – a further 1 mb/d – would require new developments (including possible further increases from tight oil). In Canada, the combined effect of natural declines in its conventional production, in situ and mining EHOB projects, and tight oil production is a drop of about 2.5 mb/d from natural rate declines in 2035, although these would be fully compensated by incremental production from continued investment in existing and approved projects.

Figure 41 **Oil production under natural decline rates and with investment in existing and approved projects in selected countries, 2025-2035**

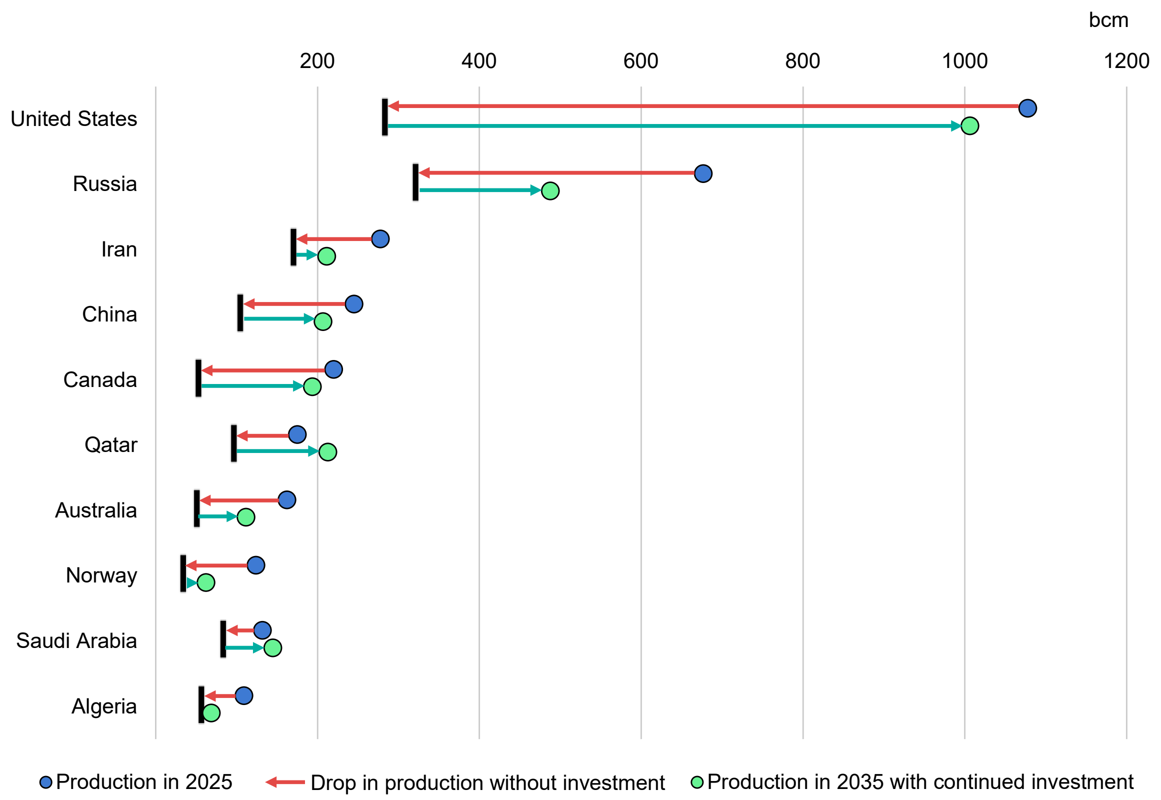


Notes: Green arrows show the increase in production from continued investment in post-peak fields, ramp-up, legacy and already approved conventional projects as well as unconventional oil and gas projects. UAE = United Arab Emirates.

In Saudi Arabia and the United Arab Emirates, anticipated production growth from approved projects, along with existing spare capacity and continued investment in existing projects, can offset, if not overcompensate, the loss of production from natural declines, especially as decline rates are relatively shallow in both countries.

The picture is similar for natural gas (Figure 42). The United States sees the largest overall drop in production from natural decline rates between 2025-2035: the total loss in its production under natural decline rates is larger than the equivalent loss for the next four largest gas-producing countries combined, although the massive expansion in LNG export capacity means the majority of this fall is compensated by upstream supply growth. Similarly in Qatar, large-scale expansion of LNG export capacity is driving significant growth in its upstream assets, meaning natural rate declines would be more than offset by continued investment in existing assets and its resource development plans.

Figure 42 **Natural gas production under natural decline rates and with investment in existing and approved fields in selected countries, 2025-2035**



Note: Green arrows show the increase in production from continued investment in post-peak fields, ramp-up, legacy and already approved conventional projects as well as unconventional oil and gas projects.

Investment

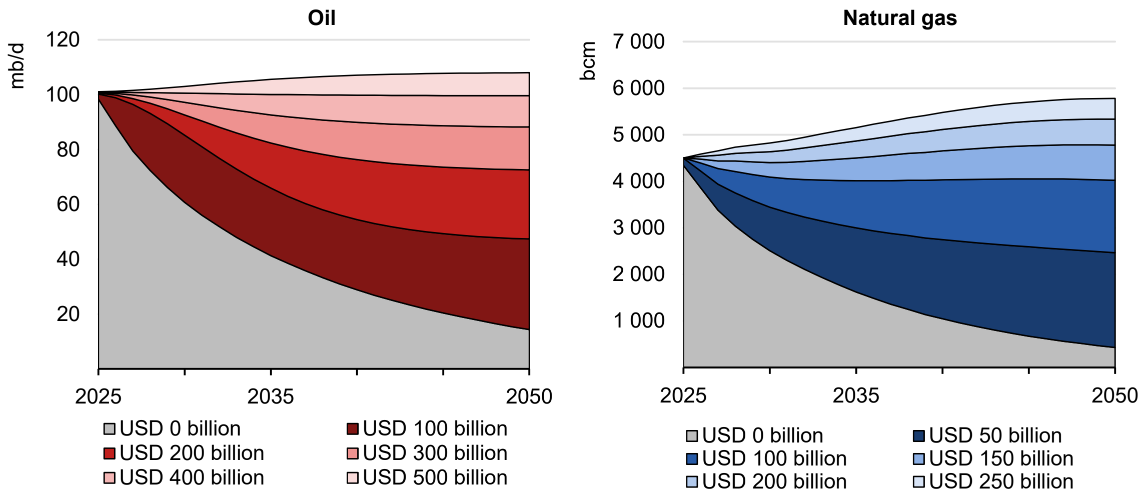
Since 2019, annual capital investment in the oil and gas sector worldwide has averaged around USD 550 billion. We estimate that around 90% of this spending, i.e. around USD 500 billion, has gone towards replacing declining production from existing fields with only about 10% directed to projects that expand supply to meet rising demand.

Decline rates have become steeper over time and so a higher level of investment is now required to offset them. For example, if decline rates were to have remained at the levels they were in the 1980s, the required average annual investment to compensate for the annual loss in supply would drop from USD 500 billion to USD 360 billion.

Looking forward, given decline rates today and how they will evolve in the future, an important question is how much future production could be mobilised at different levels of upstream investment. Prices are a key variable in this consideration as they determine activity levels undertaken by companies as well as the overall costs of production (discussed in Chapter 2). Future technology improvements and the level of resource depletion are also important factors to take into account.

If oil and gas prices were to drop to very low levels and annual average upstream oil and gas upstream investment were to total around USD 150 billion from 2025 onwards, the largest share of investment would be directed to existing assets to extend their productive life through refurbishments, upgrades, tiebacks or infill drilling campaigns (Figure 43). The costs involved in these efforts are on average less than around USD 7 per barrel of oil equivalent.

Figure 43 Global oil and natural gas production at varied average annual upstream investment levels to 2050



At higher prices, overall investment levels would increase but in general each additional barrel of oil added to the supply mix would tend to cost slightly more to develop and extract.This is because investment would increasingly be directed to exploring and developing new fields in frontier basins and building supporting infrastructure from scratch. Capital expenditure to develop such new fields on average cost around 50-150% more than the cost to maintain or develop existing assets, and given the need for higher prices to stimulate investment, this also increases costs.

If annual upstream investment averages USD 540 billion through to 2050, this would lead oil and gas production to remain around current levels.[16] This takes into account the likely evolution of upstream development costs and assumes that the geographical distribution and the different types of resources are kept broadly constant, and that the ratio of production to capacity in OPEC members remains at the same level as today. Upstream oil and gas investment in 2025 is likely to be around USD 570 billion, implying a small increase in production if this persists.

What is clear is that a relatively small drop in upstream investment can mean the difference between oil and gas supply growth and static production. Much less investment is also required in a scenario in which demand contracts (Box 6).

Box 6 Oil and natural gas in the Net Zero Emissions by 2050 Scenario

The IEA Net Zero Emissions by 2050 (NZE) Scenario is a normative scenario that maps out a path to limit the rise in global average temperatures to 1.5 degrees Celsius. In this scenario, a huge acceleration in the pace of energy transitions relative to current trends means that oil demand drops to around 55 mb/d in 2035 and natural gas demand falls to 2 250 bcm (Figure 44).

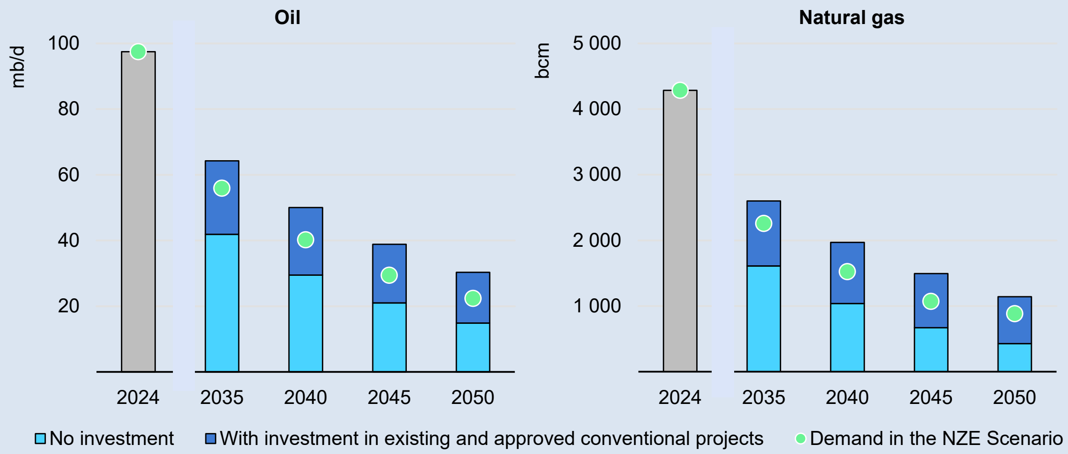
This is more than the level of production in 2035 under natural decline rates (42 mb/d of oil and 1 600 bcm of natural gas). But it is less than production with investment in existing conventional oil and gas assets (including in post-peak fields, legacy assets, and ramp-up projects) and from projects that have already been approved for development; total production in this case would be 64 mb/d of oil and 2 600 bcm of natural gas in 2035.

The pace of demand reduction in the NZE Scenario is therefore sufficiently rapid that, in aggregate, no new long lead-time conventional upstream projects would need to

[16] This is the annual average value through to 2050. A slightly smaller amount would be needed over the next decade and slightly more in the following 15 years since resource depletion at current levels of production are assumed to increasingly outweigh the impact of technology improvements.

be approved for development. In addition, to ensure a smooth balance between supply and demand, declines in demand in the NZE Scenario would lead to the early closure of several higher cost projects before they reach the end of their technical lifetimes. In 2050, for example, around 8 mb/d of oil production and 250 bcm of gas production would be retired earlier than would be implied by observed declines rates.

Figure 44 Global oil and natural gas demand in the NZE Scenario, and production with investment in existing and approved conventional projects, 2024-2050

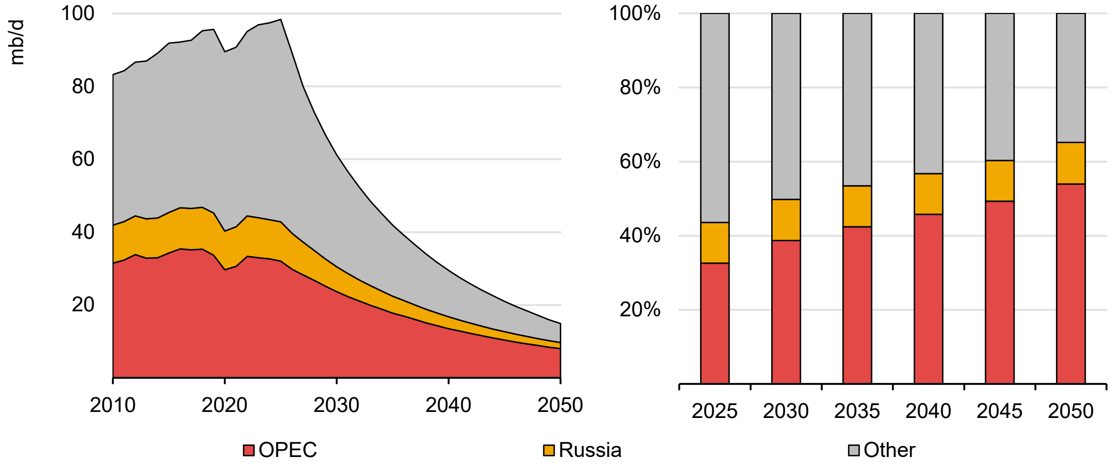


Security

This analysis highlights that decline rates are slowest for conventional onshore supergiant fields, the majority of which are located in the Middle East and Russia, while decline rates are fastest in smaller offshore fields. Therefore, absent further investment in upstream supply, oil production from existing fields would become more concentrated among the OPEC member countries and Russia (Figure 45). Under natural decline rates, their share of global oil production would rise from 43% today to 53% in 2035 and more than 65% in 2050, a level not seen in the history of oil markets. This would also have major implications for global gas trade: assuming countries would look to meet domestic demand first, natural declines would mean that around 80% of today's LNG supply would no longer be available in 2035.

Resources in non-OPEC countries that can respond quickly to changes in prices, such as tight oil and shale gas, require more investment and drilling activity to maintain current rates of production. Tracking their contribution to the supply balance with no further investment illustrates how quickly markets could tighten.

Figure 45 Natural decline rate for oil production in selected regions to 2050



Another potential risk for markets is tied to the level of spare capacity in oil markets that are tied to supergiant fields. While these fields decline slowly in phase 1, our analysis highlights that percentage losses that are up to five-times faster in phases 2 and 3. While the supergiant fields held by OPEC members have been carefully managed to adapt to changes in global markets, there is a large degree of uncertainty around when they might enter decline phases 2 or 3; the rapid drop in output could compromise their ability to provide spare capacity buffers. A similar situation holds in the case of natural gas, with the added complication that many supergiant fields have extensive associated pipeline infrastructure that may struggle to adapt to changes in pressure and flow rates from lower output.

Strategic considerations

The debate concerning the future of oil and gas tends to focus on the outlook for demand, with attention to the structural and policy factors that shape its trajectory. IEA analysis has consistently emphasised the importance of supply-side considerations. This report focuses on a crucial supply-side issue that does not always receive the attention it deserves.

Our analysis shows that accelerating decline rates, increased reliance on unconventional resources, and shifts in project development patterns are reshaping the oil and gas supply landscape. These trends indicate that efforts to sustain global production at current levels will require ongoing, targeted investment mainly to maintain existing assets, but also to develop new projects to meet demand, as well as adaptive approaches to asset management, technology development and deployment. As global supply increasingly depends on fields with higher decline rates and more complex operating environments, the interplay between investment decisions, project economics and regulatory frameworks will be central in shaping the resilience of supply and the stability of energy markets in the coming years.

A thorough understanding of decline rates is therefore essential. For companies, it guides decisions on where, how and why to commit capital, whether to develop, sustain or abandon fields, and which technologies and collaborations to support. There are also key considerations for policy makers, which need to understand the implications and trade-offs with security and investment so that they can tailor fiscal regimes, new exploration awards, import strategies, and support for clean energy technologies to ensure national energy supplies while minimising environmental impacts and emissions levels. For the IEA, detailed study of decline rates underpins our guidance on investment requirements in all our outlook scenarios, including scenarios reaching ambitious climate objectives. It also informs our analysis of the implications of the scenarios for energy security, markets, prices, and emissions.

Building on the analytical findings of this report, policy makers and companies may wish to consider approaches to:

- **Integrate an understanding of oil and gas field decline rates into long-term planning of energy systems.** This includes implications for domestic production and energy security, the location of import and export markets, and the appropriate sizing and future-proofing of new and existing oil and gas infrastructure.
- **Catalogue and support technology development that aligns resource extraction with global and national emissions reduction objectives.** This includes the need for the oil and gas industry to reduce its scope 1 and 2 emissions. A key example is CO_2-based enhanced oil recovery (EOR), which can increase production while sequestering more carbon dioxide than is released from the production and combustion of the extracted oil.
- **Improve transparency, standardisation and accessibility of data on decline rates and reservoirs.** More granular and consistent reporting on field activity, alongside standardised curation and storage of reservoir data, would allow policy makers and market participants to better anticipate supply-demand balances, avoid price volatility, and enable independent assessments to guide effective policy and fiscal treatment.
- **Promote planning and transparent funding mechanisms for field abandonment and decommissioning.** This includes establishing abandonment funds and promoting co-ordination among owners, lessees and government agencies to manage environmental liabilities.
- **Develop sustainable water management practices**. This includes produced water rights and handling, utilisation, recycling, and disposal of water associated with oil and gas operations.
- **Support research and innovation incentives across the asset lifecycle.** These should target ways to manage environmental impacts at different stages of the field development cycle.

Technical annex

Methodology

Observed decline rates

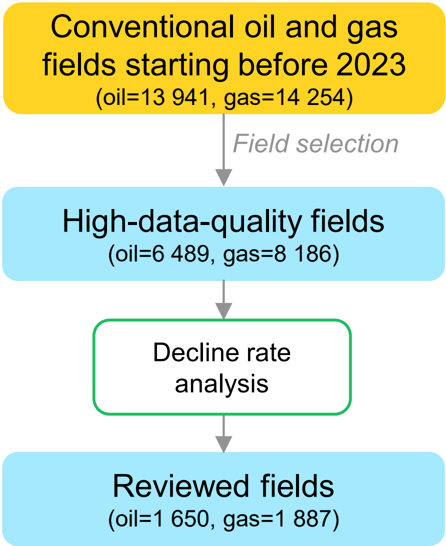
The field-by-field historical production records used in this analysis are based on data from the UCube database produced by Rystad Energy, an independent energy consulting services and business intelligence data firm. Rystad's UCube contains production and investment data for around 30 000 individual oil and gas assets worldwide. (Downloaded 12 March 2025 for this analysis.)

Rystad compiles information from various sources, including government data, annual reports and investor presentations. The data are assigned confidence levels of high, medium, low, speculative, or not available. In our analysis, we include individual oil and natural gas assets in which production has peaked only if more than 50% of the historical data points are of high confidence level or if more than 66% are medium-confidence level. Assets must also have less than 4% speculative data and have no missing values. Assets based on aggregated company-level data rather than representing individual production assets were excluded, mainly in onshore areas of the United States, as were fields that have experienced prolonged disruptions due to multi-year conflicts.

This led to a selection of around 6 500 individual post-peak oil fields and around 8 200 post-peak natural gas fields, across all regions, field types and asset sizes as a base for this analysis. We manually reviewed the results generated by an algorithm analysing the 1 650 largest oil fields and 1 900 largest gas fields and made adjustments to more accurately capture the decline rate profile of these fields, although this was only necessary in around 10% of cases (Figure A.1).

Methodology consistent with previous IEA analyses was applied to detect the three phases of post-peak decline. We developed an algorithm in the programming language R to identify for each field: the date and level of peak production; the date at which production levels last equate to 85% of peak production (decline phase 1); the date at which production levels last equate to 50% of peak production (decline phase 2); and the level and final date of production (decline phase 3). If production passes one of these thresholds between years, the recorded date is based on extrapolating between the two years. These dates and production levels are used to calculate the three decline phases. The average observed post-peak decline rate is based on the level and date of peak production and the final level and date of production.

Figure A.1 Workflow for processing Rystad's field-by-field dataset



Some fields remain very close to their peak production level for multiple years, but there is a single year with slightly higher production than those before or after. In these cases, we record the earliest preceding date when production was within 5% of the peak production level.

For the date and level of final production, we include the most recent year, usually 2023, or the last year when production drops below 95% of its peak. Without this, if a field has a very low but non-zero level of production in its final year, then the post-peak and phase 3 decline would be very high.

For fields where production drops below the 85% or 50% threshold but then returns above this, perhaps due to the application of secondary recovery techniques, we record the date once production falls below the threshold for the last time.

Tables A.1 and A.2 indicate the number of reviewed fields by field type, region and asset size. Apart from supergiant oil and gas fields, and gas fields in Eurasia and the Middle East, all categories include at least 25 fields across the three decline phases.

The three decline phases and the compound average annual decline rate (CADR) for each field are combined into the averages shown based on their cumulative production. Another option would be to weight by production in each year. Doing so would increase the importance of fields that are currently producing in the averages and exclude entirely the data for fields that are no longer producing. Weighting by cumulative production therefore gives a more representative overview of how all fields within each category have performed in the past.

Table A.1 Oil projects included in the observed post-peak CADR analysis by field type and region by decline phase (number of projects)

	Decline phase 1	Decline phase 2	Decline phase 3
Onshore	792	726	628
Shallow offshore	700	687	626
Deep and ultradeep offshore	158	141	100
Supergiant	15	13	9
Giant	141	117	106
Large	575	548	475
Small	919	876	764
Africa	315	303	263
Asia Pacific	314	280	245
Central and South America	244	229	204
Eurasia	129	108	77
Europe	233	232	210
Middle East	44	38	25
North America	371	364	330
OPEC	257	248	219
Non-OPEC	1 393	1 306	1 135
All fields	**1 650**	**1 554**	**1 354**

Two key differences with the analysis in this report compared with the *World Energy Outlook in 2013* (*WEO-2013*) relate to the screening of the Rystad data and the selection of fields included in the assessment of decline phases. In this analysis, we use Rystad's meta information to select only those fields with high data quality; this information was not available at the time of the *WEO-2013*, which therefore included all assets in the analysis of observed post-peak decline rates.

The decline phases reported in the *WEO-2013* used data only from fields that were currently in that phase (as of 2012). For example, for an onshore field that was in phase 2 in 2012, its phase 2 CADR would have been included in the phase 2 CADR reported for all onshore fields. However, the phase 1 CADR of that field was not included in the phase 1 CADR reported for all onshore fields. In this report, we include all historical information to assess decline rate phases. For example, in this report, the phase 1 CADR of that onshore field is included in the phase 1 CADR for all onshore fields.

The number of fields included in this analysis and the scope of data incorporated into the assessment thus differs across the distribution of assets by region, field type, asset size and lifecycle.

Table A.2 : Natural gas projects included in the observed post-peak CADR analysis by field type and region by decline phase (number of projects)

	Decline phase 1	Decline phase 2	Decline phase 3
Onshore	467	426	345
Shallow offshore	1 334	1 308	1 129
Deep and ultradeep offshore	86	78	52
Supergiant	17	12	8
Giant	172	145	75
Large	827	789	629
Small	839	829	647
Africa	49	43	26
Asia Pacific	300	266	178
Central and South America	107	99	65
Eurasia	30	21	9
Europe	483	473	381
Middle East	29	20	9
North America	857	853	691
All fields	**1 855**	**1 775**	**1 359**

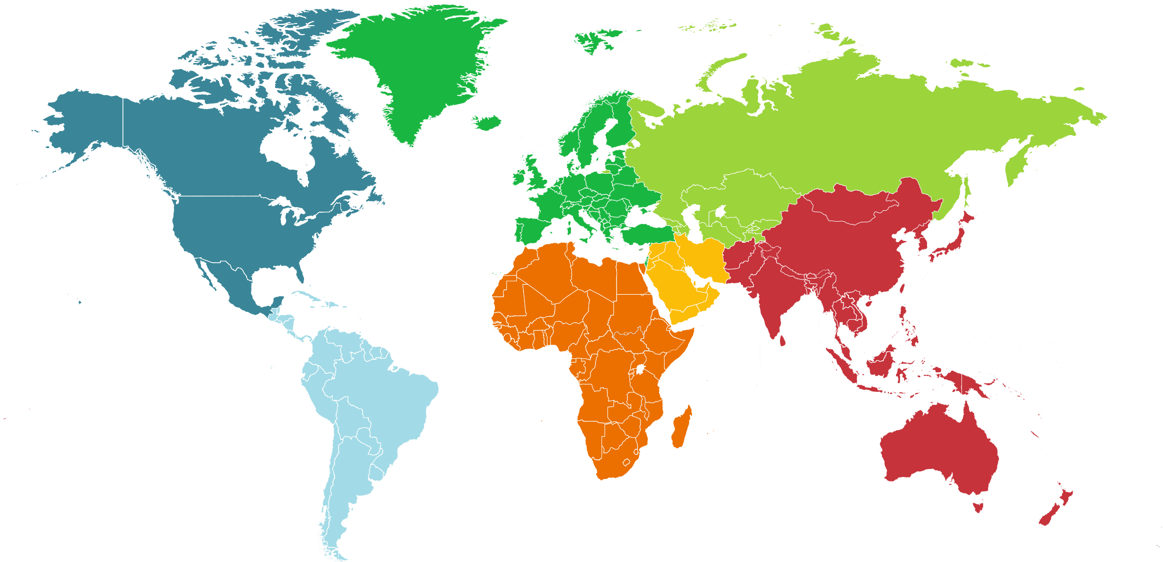
Natural decline rates

In this analysis, natural decline rates are derived by linking annual capital expenditure in existing fields to assumptions about capital efficiency, i.e. representative development costs. This approach allows us to estimate the volume of additional resources mobilised each year, which is subsequently converted into projected production levels.

The heterogeneity of oil and gas fields makes it impractical to conduct such analysis at the field level. In contrast to observed decline rates that are estimated from field-level data, we therefore derive natural decline rates for seven regions: Africa, Asia, Eurasia, Europe, Middle East, North America and Central and South America. We estimate development costs for each region and for different production start-up years to compute the capital efficiency of oil and gas fields in each region for different production vintages. We divide upstream capital expenditure by capital efficiency per vintage to estimate the level of production that would be associated with the capital expenditure and then subtract this from actual production to derive the natural decline in production.

Regional and country groupings

Figure A.2 Main country groupings



IEA. CC BY 4.0.

Note: This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Africa: Algeria, Angola, Benin, Botswana, Burkina Faso, Burundi, Cabo Verde, Cameroon, Central African Republic, Chad, Comoros, Côte d'Ivoire, Democratic Republic of the Congo, Djibouti, Egypt, Equatorial Guinea, Eritrea, Ethiopia, Gabon, Gambia, Ghana, Guinea, Guinea-Bissau, Kenya, Kingdom of Eswatini, Lesotho, Liberia, Libya, Madagascar, Malawi, Mali, Mauritania, Mauritius, Morocco, Mozambique, Namibia, Niger, Nigeria, Republic of the Congo (Congo), Rwanda, Sao Tome and Principe, Senegal, Seychelles, Sierra Leone, Somalia, South Africa, South Sudan, Sudan, United Republic of Tanzania (Tanzania), Togo, Tunisia, Uganda, Zambia, and Zimbabwe.

Asia Pacific: Australia, Afghanistan, Bangladesh, Brunei Darussalam, Bhutan, Cambodia, Cook Islands, Democratic People's Republic of Korea (North Korea), Fiji, French Polynesia, India, Indonesia, Japan, Kiribati, Korea, Lao People's Democratic Republic (Lao PDR), Macau (China), Malaysia, Maldives, Mongolia, Myanmar, Nepal, New Caledonia, New Zealand, Pakistan, Palau, Papua New Guinea, Philippines, The People's Republic of China (China), Samoa, Singapore, Solomon Islands, Sri Lanka, Chinese Taipei, Timor-Leste, Thailand, Tonga, Vanuatu, and Viet Nam.

Caspian: Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyzstan, Tajikistan, Turkmenistan and Uzbekistan.

Central and South America: Anguilla, Antigua and Barbuda, Argentina, Aruba, Bahamas, Barbados, Belize, Bermuda, Plurinational State of Bolivia (Bolivia), Bolivarian Republic of Venezuela (Venezuela), Bonaire, Sint Eustatius and Saba, Brazil, British Virgin Islands, Cayman Islands, Chile, Colombia, Costa Rica, Cuba, Curaçao, Dominica, Dominican Republic, Ecuador, El Salvador, Falkland Islands (Malvinas), Grenada, Guatemala, Guyana, Haiti, Honduras, Jamaica, Montserrat, Nicaragua, Panama, Paraguay, Peru, Saint Kitts and Nevis, Saint Lucia, Saint Maarten (Dutch part), Saint Pierre and Miquelon, Saint Vincent and Grenadines, Suriname, Trinidad and Tobago, Turks and Caicos Islands, and Uruguay.

China: Includes (The People's Republic of) China and Hong Kong, China.

Eurasia: Caspian regional grouping and the Russian Federation (Russia).

Europe: Austria, Belgium, Bulgaria, Croatia, Cyprus,[17,18] Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovak Republic, Slovenia, Spain and Sweden, Albania, Belarus, Bosnia and Herzegovina, Gibraltar, Iceland, Israel,[19] Kosovo, Montenegro, North Macedonia, Norway, Republic of Moldova, Serbia, Switzerland, Türkiye, Ukraine and United Kingdom.

Middle East: Bahrain, Islamic Republic of Iran (Iran), Iraq, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syrian Arab Republic (Syria), United Arab Emirates and Yemen.

North America: Canada, Mexico and United States.

OPEC (Organization of the Petroleum Exporting Countries): Algeria, Bolivarian Republic of Venezuela (Venezuela), Equatorial Guinea, Gabon, Iraq, Islamic Republic of Iran (Iran), Kuwait, Libya, Nigeria, Republic of the Congo (Congo), Saudi Arabia and United Arab Emirates.

[17] Note by Republic of Türkiye: The information in this document with reference to “Cyprus” relates to the southern part of the island. There is no single authority representing both Turkish and Greek Cypriot people on the island. Türkiye recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of the United Nations, Türkiye shall preserve its position concerning the “Cyprus issue”.

[18] Note by all the European Union Member States of the OECD and the European Union: The Republic of Cyprus is recognised by all members of the United Nations with the exception of Türkiye. The information in this document relates to the area under the effective control of the Government of the Republic of Cyprus.

[19] The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD and/or the IEA is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

OPEC+: OPEC grouping plus Azerbaijan, Bahrain, Brunei Darussalam, Kazakhstan, Malaysia, Mexico, Oman, Russian Federation (Russia), South Sudan and Sudan.

Acknowledgements

This study was prepared by the World Energy Outlook (WEO) team in the Directorate of Sustainability, Technology and Outlooks in co-operation with other directorates and offices of the International Energy Agency (IEA).

Christophe McGlade, Head of the Energy Supply Unit, co-ordinated the work and was the lead author; he designed and directed the report together with **Tim Gould**, Chief Energy Economist.

The other main authors were: **Charlène Bisch, Jeanne-Marie Hays, Jérôme Hilaire, Gyubin Hwang, Gabriele Romeo, Courtney Turich,** and **Peter Zeniewski**.

Other key contributors were: **Pierre Demey, Chiara Hampton, Jacob Messing, Ryszard Pospiech, Natalie StClair, Jemima Storey,** and **Rebecca Schulz**.

Eleni Tsoukala and **Davina Till** provided essential support.

Debra Justus carried editorial responsibility.

Valuable comments and feedback were provided by other senior management and numerous other colleagues within the International Energy Agency. In particular, Alessandro Blasi, Toril Bosoni, Laura Cozzi, and Keisuke Sadamori.

Thanks go to the IEA Communications and Digital Office for their help to produce the report and website materials, particularly to Poeli Bojorquez, Curtis Brainard, Astrid Dumond, Jethro Mullen, Liv Gaunt and Andrea Pronzati.

The IEA Office of the Legal Counsel, Office of Management and Administration and Energy Data Centre provided assistance throughout the preparation of the report.

Many senior government officials and international experts provided input and reviewed preliminary drafts of the report. Their comments and suggestions were of great value. They include:

Achraf Benhassine	Ministry of Energy of Algeria
Adnan Shihab Eldin	Oxford Institute for Energy Studies
Alex Wood	US Department of Energy
Andrew Walker	Cheniere
Anthony Yuen	Citi

Ben Wilby	Westwood Global Energy Group
Bob McNally	Rapidan Energy
Camilla Aamodt	Equinor
Christopher Birdsall	ExxonMobil
Christopher Moghtader	NewsBase Research
Darcy Blais	Natural Resources Canada
Dilhan Ilk	DeGolyer and MacNaughton
Geoffroy Hureau	Cedigaz
Humayun Soomro	Natural Resources Canada
Ian Thom	Wood Mackenzie
Ilaria De Santo	SLB
Jan Hein Jesse	Jesco bv
Jason Goh	ExxonMobil
Julien Perez	OGCI
Kamel Ben Naceur	Nomad Consultants
Michael Cohen	BP
Nadine Mader-Kayser	Norwegian Offshore Directorate
Nayoung Kim	UBS
Paolo Ghinzani	Saipem
Per Magnus Nysveen	Rystad Energy
Philippe Dewimille	TotalEnergies
Richard Baker	Shell
Robert G. Schwiers Jr.	Chevron
Robert Kleinberg	Columbia CGEP
Sunaina Ocalan	Hess
Tatiana Mitrova	Columbia CGEP
Torbjorn Kjus	Aker BP
Wim Thomas	ES3 Energy Scenarios to Strategy
Yousef Alshammari	London College Energy Economics
Yulia Grigsby	Goldman Sachs

IEA Publications
International Energy Agency
Website: www.iea.org
Contact information: www.iea.org/contact

Typeset in France by IEA - September 2025
Cover design: IEA
Photo credits: © Shutterstock