



bp Annual Report and Form 20-F 2025



Strong performance – building for the future

Our investor proposition

A simpler, stronger and more valuable bp, see [page 19](#).

Our strategy

We are growing the upstream, focusing the downstream and investing with discipline in transition, see [page 8](#).

Our primary targets

Adjusted free cash flow★ growth

>20%^a

adjusted free cash flow compound annual growth rate (CAGR)★ from 2024-27

Net debt★

\$14-18bn

by end 2027

Structural cost reduction★

\$5.5-6.5bn^b

by end 2027

Return on average capital employed (ROACE)★

>16%^a

in 2027

→ [Progress on our primary targets, page 8](#)

Growing the upstream



Image: Argos platform, US

Focusing the downstream



Image: bp retail site, London, UK

Disciplined investment in transition



Image: bp bioenergy, Brazil

^a This is on a price adjusted basis that assumes a hypothetical price environment of \$70/bbl Brent, \$4/mmBtu Henry Hub, and \$10.3/bbl refining indicator margin (all 2024 real) and assumptions about the impact of these marker prices on underlying replacement cost profit before tax.

^b Following the outcome of the strategic review of Castrol, which resulted in the decision to divest a 65% shareholding, the \$4-5 billion structural cost reduction target by end 2027, introduced at the February 2025 Capital Markets Update, has increased.

Navigating this report

→ [Read more on another page of this report](#)

[Read more online](#)

Task Force on Climate-related Financial Disclosures (TCFD)

Information that supports TCFD Recommendations and Recommended Disclosures in relation to Metrics and Targets is indicated with [TCFD](#).

Glossary

Words and terms marked with ★ are defined in the glossary on [page 375](#)

More information

Online quick read

A concise summary of the *bp Annual Report and Form 20-F 2025*, highlighting strategy and performance information.

[bp.com/annualreport](https://www.bp.com/annualreport)

Online reporting centre

All our bp corporate reports, including the bp Sustainability Report and the bp Energy Outlook.

[bp.com/reportingcentre](https://www.bp.com/reportingcentre)

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About bp

We operate at the heart of the global energy system, helping countries across the world with their energy needs and serving millions of customers every day.

Our purpose

Delivering energy to the world, today and tomorrow.

Who we are

Our culture frame 'Who we are' defines what we stand for at bp, building on our best qualities and those things that are most important to us. It comprises three simple beliefs that can inspire each of us at bp to be our best every day: live our purpose, play to win, care for others.

bp.com/ourbeliefs

Safety and sustainability

27

tier 1 and 2 process safety events★
(2024 38)

→ [Read more on pages 55 and 37](#)

34.3MtCO₂e

GHG emissions – operational control
(2024 33.6MtCO₂e)

Performance

\$0.1bn

profit for the year attributable to bp shareholders
(2024 \$0.4bn)

\$7.5bn

underlying replacement cost (RC) profit★
(2024 \$8.9bn)

2.3m

barrels of oil equivalent – oil and gas production^a
(2024 2.4m)

90%

proved reserves replacement ratio★^a
(2024 50%)

\$6.28/boe

upstream unit production costs★
(2024 \$6.17/boe)

96.1%

bp-operated upstream plant reliability★
(2024 95.2%)

96.3%

bp-operated refining availability★
(2024 94.3%)

a On a combined basis of subsidiaries and equity-accounted entities.

Segment performance

At 31 December 2025, the group's reportable segments were gas & low carbon energy, oil production & operations and customers & products. Each is managed separately, with decisions taken for the segment as a whole, and represents a single operating segment that does not result from aggregating two or more segments (see Financial statements – Note 5).

Gas & low carbon energy^a

Comprises our gas & low carbon energy businesses. Our gas business includes regions with upstream activities that predominantly produce natural gas, gas trading and our Archaea Energy business. Our low carbon business includes solar, offshore wind, hydrogen and carbon capture and storage (CCS), and power trading, and until its divestment in December 2025 also included onshore wind. Power trading includes trading of both renewable and non-renewable power.

\$1.3bn

replacement cost (RC) profit before interest and tax^b
(2024 \$3.1bn^c)

→ [Segment performance, page 28](#)

\$5.4bn

underlying RC profit before interest and tax[★]
(2024 \$6.8bn)

Oil production & operations^a

Comprises regions with upstream activities that predominantly produce crude oil, including bpx energy.

\$8.6bn

RC profit before interest and tax^b
(2024 \$10.8bn)

→ [Segment performance, page 31](#)

\$9.4bn

underlying RC profit before interest and tax
(2024 \$11.9bn)

Customers & products

Comprises customer-focused businesses, which include convenience and retail fuels, EV charging, as well as *Castrol*, aviation, B2B, midstream and bp bioenergy. It also comprises our products businesses which include refining and oil trading.

\$4.1bn

RC profit before interest and tax^b
(2024 loss \$(1.0)bn^c)

→ [Segment performance, page 34](#)

\$5.3bn

underlying RC profit before interest and tax
(2024 \$2.5bn)

Other businesses & corporate

Comprises technology; bp ventures; shipping; our corporate activities and functions; and any residual costs of the Gulf of America oil spill.

\$(40)m

RC loss before interest and tax^b
(2024 loss \$(1.0)bn)

→ [Segment performance, page 36](#)

\$(0.6)bn

underlying RC loss before interest and tax
(2024 loss \$(0.6)bn)



Image: Colleagues at our Houston headquarters, US

a The Azerbaijan-Georgia-Türkiye and Middle East and North Africa (MENA) regions have been further subdivided by asset.

b IFRS requires that the measure of profit or loss disclosed for each operating segment is the measure that is provided regularly to the chief operating decision maker. For bp, this measure of profit or loss is replacement cost profit before interest and tax, which reflects the replacement cost of inventories sold in the period and is arrived at by excluding inventory holding gains and losses[★] from profit before interest and tax. Replacement cost profit for the group is not a recognized measure under IFRS. For further information see Financial statements – Note 5.

c Restated for material items to reflect the move of our Archaea Energy business from the customers & products segment to the gas & low carbon energy segment.

Chair's letter



Dear shareholders,

bp is one of the world's great energy companies, with a strong team, high quality assets and distinctive strengths in key business areas. I was honoured to be appointed as chair in 2025, joining a company that is making progress on a reset strategy, albeit with challenges to overcome. With the environment in which we operate continuing to be shaped by geopolitical uncertainty and complex market dynamics, we need to accelerate delivery, reduce complexity and increase our financial resilience in order to realise the full value of the business for shareholders.

Appointment of Meg O'Neill

One of my first tasks, working with fellow board members, was to identify an outstanding leader to take the company forward. Murray Auchincloss stepped down in December 2025 after more than three decades of service to bp, the last five as a member of our board, first as chief financial officer and then as chief executive. I would like to thank him for his contribution and commitment to bp.

In December 2025 we appointed Meg O'Neill as chief executive who will join bp on 1 April 2026. Meg's track record of driving transformation and growth with disciplined capital allocation makes her the right leader for bp as we pursue significant strategic and financial opportunities. And her relentless focus on business improvement and financial discipline gives us high confidence in her ability to shape the company for its next phase of growth.

Safety and performance in 2025

The board plays a critical role in monitoring the organization's culture and setting the tone from the top. This is particularly important on safety. Employees and contractors at bp face a complex range of risks across the business. Sadly in 2025, four colleagues working in bp's US retail operations lost their lives. On behalf of the board, I would like to extend our sincere condolences to their families, friends and colleagues.

Safety will always be the board's highest priority. That's why we continue to work with the leadership team to ensure every incident is thoroughly investigated and the lessons learned are applied.

On process safety, I commend the teams that contributed to a decrease in serious process safety events of about one third, compared with 2024.

Ongoing improvement in safety is the foundation for strong operational performance. In 2025 the teams set new records for plant reliability on the upstream side of the business and availability in refining.

Strategic progress was also strong with seven major projects★ delivered in the year and significant exploration success, including the world's largest offshore discovery. Carol provides more detail on safety and performance in her letter overleaf.

Governance

In early 2025 the board's focus moved from the resetting of strategy to overseeing disciplined performance and the delivery of our four primary financial targets. Together with Meg O'Neill's appointment, the board's composition and capability have been further strengthened during 2025 deepening its expertise in key strategic areas: oil and gas, disciplined capital allocation and the oversight of performance and risk.

Our governance framework remains a foundation for delivering sustainable long-term value for shareholders. That framework has also evolved, recognizing the changing needs of the business and external developments, including the implementation of provision 29 of the UK Corporate Governance Code, relating to risk management and internal control. And it will continue to evolve, informed by a further review, to ensure the framework and the board that oversees it are best placed for the bp we want to be, rather than the bp we have been over recent years.

Engagement with stakeholders remained a priority in 2025. On joining the board, I initiated an extensive dialogue with our largest shareholders, complemented by a continued focus by the board on workforce engagement.

More to do

Over the course of 2026, you will see bp taking concerted action to strengthen the company and position it to grow and deliver sustainable value for the long term. One such step was the board's decision earlier this year to suspend the share buyback and fully allocate excess cash to our balance sheet. And you will see bp continue to take action to simplify and high-grade the portfolio, reduce the cost base and make disciplined investments in the best and highest-returning opportunities. Most importantly, you will see the board supporting a management team focused on growing cash flow and returns.

A better bp

I offer my thanks to the bp teams, whose dedication, skill and determination continue to shine through, no matter the challenge. And thank you to you, bp's owners, for your guidance and your trust. The board and I will continue to actively engage with you and communicate with increasing clarity and transparency. With your support we can and will become a stronger bp. One that is more sustainable in every way, especially in the creation of value for shareholders.

Albert Manifold

Chair
6 March 2026

Interim chief executive officer's letter



Dear fellow shareholders,

As interim CEO, I want to thank our teams for their outstanding commitment through a period of transition for bp. Operational performance in 2025 was consistently strong and we made significant progress following the resetting of our strategy.

Our new chair, Albert Manifold, has set us a challenge to fulfil bp's true potential – and I know the team will rise to this. We're focused, we're in action, we're determined to make bp the strongest it can be, and we look forward to welcoming Meg O'Neill as CEO in April 2026.

Safety comes first

Tragically, in 2025, four people died while working in our US retail business. Three were employees in our TravelCenters of America business. Two of them were killed in separate incidents where they were struck by passing vehicles as they carried out emergency roadside assistance, highlighting the complex range of risks faced across our business. In response, this service on active highways has been permanently withdrawn to protect our employees. The fourth was a contractor, in our *Thorntons* business. Our thoughts are with their families, friends and colleagues.

In the high-hazard industry we work in, nothing is more important than safety. We seek to learn from every incident, no matter how big or small – and we expect everyone in bp to work safely. On process safety, we made strong progress, with 29% fewer combined tier 1 and 2 process safety events★ in 2025, but we have much more to do.

It is important to say that safety is more than robust controls and systems. It is also about having a culture where every decision reflects care in our work – and care for others. Day in, day out, we must continue to work towards our goal: eliminating fatalities, life-changing injuries and the most serious process safety incidents.

Financial and operating performance

In 2025 we delivered a strong underlying financial performance with an underlying RC profit★ of \$7.5 billion^a, despite a weaker price environment, and operating cash flow★ of \$24.5 billion.

We also had a strong operational performance across bp.

In 2025 we:

- Delivered record upstream plant reliability★ and refining availability★, with both above 96%.
- Produced 2.3 million barrels of oil and gas a day, beating our guidance at the start of 2025.
- Started up seven major projects★ safely, five ahead of schedule.
- Made 12 discoveries – including bp's biggest offshore discovery in 25 years, Bumerangue in Brazil.
- Increased our proved reserves replacement ratio★ to 90% – up from an average of around 50% in the previous two years.

Strategic progress

We took decisive action to high-grade our portfolio and strengthen our company in 2025, including our \$20 billion disposal programme and the subsequent decision to suspend the share buyback and fully allocate excess cash★ to our balance sheet. These are choices designed to position us for long-term growth.

We also made progress on our four primary targets, increasing adjusted free cash flow★ by around 55%^{bcd} in 2025 and returns (ROACE★) to around 14%^{bde}, both on an adjusted price basis. We reduced net debt★ to \$22.2 billion^f and made progress strengthening our balance sheet, achieving \$2.8 billion^g of our \$4-5 billion structural cost reduction★ target, which we have now increased to \$5.5-6.5 billion^h.

In addition, we have announced or completed over \$11 billion of divestments in the first year.

Looking forward and thanks

bp is a great company with huge potential. We have outstanding technology and engineering skills, excellent resources and exceptional global partnerships. And, most of all, we have brilliant people whose performance across the year was key to producing strong results.

It is an honour to represent bp as interim CEO, and the leadership team and I look forward to the year ahead. My deepest thanks go to our teams, our partners and our owners. We are grateful for your support and your challenge, and together, under Meg's leadership, we will make bp go from strength to strength.

Carol Howle
Interim chief executive officer
6 March 2026

Nearest IFRS-equivalent measures

\$0.1bn

profit for 2025 attributable to bp shareholders^a

(10)%

Operating cash flow less total capital expenditure★ in 2025 vs 2024^{cd}

0.1%

profit for 2025 attributable to bp shareholders divided by total equity at 31 December 2025^{de}

\$58.0bn

finance debt at the end of 2025^f

a Underlying RC profit for the group is a non-IFRS measure and its nearest IFRS equivalent measure is profit for the year attributable to bp shareholders.

b This is on a price adjusted basis and is assuming a hypothetical price environment of \$70/bbl Brent, \$4/mmBtu Henry Hub, and \$10.3/bbl refining indicator margin (all 2024 real) and assumptions about the impact of these marker prices on underlying replacement cost profit before tax.

c Adjusted free cash flow on a price adjusted basis is a non-IFRS measure. The nearest IFRS equivalent measures to calculate adjusted free cash flow on a price adjusted basis CAGR are net cash provided by operating activities of \$24.5 billion for 2025 and \$27.3 billion for 2024 and total cash capital expenditure of \$14.5 billion for 2025 and \$16.2 billion for 2024. A reconciliation is provided on page 387.

d This does not form part of bp's Annual Report and Form 20-F as filed with the SEC.

e ROACE on a price adjusted basis is a non-IFRS measure. The nearest IFRS measures of the numerator and denominator are profit for 2025 attributable to bp shareholders of \$0.1 billion and total equity at the end of 2025 of \$74.0 billion respectively. A reconciliation is provided on page 385.

f Net debt is a non-IFRS measure and its nearest IFRS equivalent measure is finance debt at the end of 2025. See Note 27 for more information.

g Cumulative structural cost reduction since 2023, of which \$2 billion in 2025 and \$750 million in 2024. Structural cost reduction is decreases in underlying operating expenditure★. A reconciliation is provided on page 386.

h Following the outcome of the strategic review of *Castrol*, which resulted in the decision to divest a 65% shareholding, the \$4-5 billion structural cost reduction target by end 2027, introduced at the February 2025 Capital Markets Update, has increased.

Energy markets

The operating environment

bp operates across volatile energy markets. Here we discuss broader economic trends we have observed that influence our sector as a whole.

The world economy grew by around 3.3%^a in 2025, stronger than had been expected in April 2025^b. Growth rates varied across economies, with US GDP estimated to have grown by 2.1%, while the eurozone economy expanded by only 1.4%^a. China's growth in 2025 is estimated to have been 5%^a, achieving the government 'around 5%' target.

Inflation continued to ease globally, moving closer to central banks' target levels in most major economies. This disinflationary trend allowed several central banks, including the US Federal Reserve and the European Central Bank, to cut interest rates. In the case of the Federal Reserve, further rate cuts are expected in 2026, based on financial market pricing.

Oil

Oil prices trended lower during 2025, amid strong supply and relatively weak demand growth.

Non-OPEC+ supply grew by 1.8mmb/d^c in 2025, led by offshore projects, oil sands, tight oil and NGLs, mostly from the Americas. OPEC+ supply grew by 1.3mmb/d^c in 2025, largely due to unwinding of production cuts from OPEC+8, especially Saudi Arabia. That steadily increasing supply meant that global oil supply is estimated to have been 3mmb/d^c higher over the year as a whole than in 2024. That contrasted with demand growth of only 0.8mmb/d, taking demand to 104mmb/d, and leading to a supply/demand imbalance of around 2.2mmb/d over the year as a whole^c.

The imbalance weighed on prices, with Dated Brent averaging \$69/bbl in 2025, down from \$81/bbl in 2024^d. OECD commercial inventories grew by 3% over the course of the year, compared to a 1% fall last year^e. Significant government stockpiling in China of around 550kb/d in 2Q25 and 3Q25 absorbed some of the supply/demand imbalance, and there was also an increase in the amount of oil being held in tankers at sea, which reached 2,006mmb, 232mmb higher than the five-year average, as sanctioned Russian and Iranian barrels were held off the market^c.

Natural gas

In the US, Henry Hub (HH) gas prices rebounded to their highest level since 2022^f due to a 26%^g year-on-year increase in LNG export demand and colder-than-normal start to the year. Higher gas prices supported a recovery in drilling activity in non-associated (dry) shale plays which, combined with well productivity gains, increasing gas-to-oil ratios in the Permian, and increased pipeline connectivity, meant that gas production grew by 4%^g, reaching record high levels.

Outside of North America, global gas demand grew by less than 1% in 2025^h. TTF and JKM increased 9%ⁱ and 3%^j respectively. A further reduction in Russian supply to the EU at the onset of 2025 contributed to the higher gas prices, reducing gas demand growth in Asia in particular. LNG supply from new liquefaction projects ramped up through the year and drove a near 7%^h increase in global LNG production.

Refining indicator margin

We have updated the metric used to track the refining margin environment to the refining indicator margin (RIM)^k. After a weak 1Q25, RIM increased over the rest of the year, supported by lower crude prices, relatively resilient product demand, tight product inventories and unplanned capacity outages and disruptions. RIM averaged \$12.8/bbl over 2025 as a whole, up \$2.1/bbl (19%) from its average level in 2024^k.

Power and renewables

Electricity demand growth continued to outpace total energy demand growth, driven by increasing electrification in China and by growing prosperity and industrialization in emerging economies. Growing demand from data centres looks set to increase electricity demand materially in the coming years, particularly in the US.

Total solar and wind capacity additions in 2025 are estimated to have exceeded 600GW, breaking the previous record set in 2024^l. Bioenergy growth also maintained momentum, supported by resilient demand for liquid biofuels in road transport, rising biomethane output, and a growing pipeline of announced sustainable aviation fuel (SAF) capacity.

Hydrogen and carbon capture and storage

Persistent high costs and the slow pace of enabling policy continued to challenge the decarbonization of many harder-to-abate processes, including through technologies such as low carbon hydrogen and carbon capture.

The project pipeline for production of low carbon hydrogen has contracted recently and only around 4Mtpa^m is either currently operational or under construction. Growth of the global carbon capture and storage project pipeline slowed significantly in 2025. Operational and under-construction projects have now reached just over 100Mtpaⁿ in total capacity.

Market activity

	2025	2024
Global oil consumption ^c	104.0mmb/d	103.2mmb/d
Global oil production ^c	106.2mmb/d	103.1mmb/d
Natural gas consumption ^h	4,286bcm	4,251bcm
Natural gas production ^h	4,264bcm	4,224bcm
Dated Brent average ^d	\$69.10/bbl	\$80.76/bbl
West Texas Intermediate (WTI)★ average ^o	\$64.87/bbl	\$75.87/bbl
Henry Hub average ^f	\$3.52/mmBtu	\$2.19/mmBtu
Dutch Title Transfer Facility (TTF)★ average ⁱ	36.2 Euros per MWh (\$11.9/mmBtu)	34.4 Euros per MWh (\$10.9/mmBtu)
Japan-Korea (Asian) LNG average ^j	\$12.2/mmBtu	\$11.9/mmBtu
Refining indicator margin★	\$12.8/bbl	\$10.7/bbl

a IMF World Economic Outlook update, January 2026, measured on a Purchasing Power Parity basis.

b IMF World Economic Outlook, April 2025, measured on a Purchasing Power Parity basis.

c IEA Oil Market Report, January 2026.

d LSEG Data Management Solution (Dated Brent spot price).

e IEA Monthly Oil Data Service, January 2026.

f S&P Global Energy Platts Henry Hub spot price.

g EIA Short-term Energy Outlook, January 2026.

h IEA Gas Market Report, Q1-2026.

i S&P Global Energy Platts Dutch TTF day ahead price.

j S&P Global Energy Platts JKM spot price.

k bp has retired the refining marker margin (RMM) and replaced it with the bp refining indicator margin (RIM). The bp RIM reflects a broader set of crudes and products, and is more representative of bp's refining portfolio and realized refining margin per barrel. Actual margins realized by bp may vary due to a variety of factors, including the actual mix of crude and product for a given quarter.

l IEA Renewable Energy Progress Tracker. PV capacity additions are converted from DC to AC basis.

m IEA Global Hydrogen Review, September 2025.

n GCCSI Global Status of CCS 2025, October 2025.

o LSEG Data Management Solution (West Texas Intermediate).

Energy outlook

The *bp Energy Outlook 2025 (2025 Outlook)* explores the trends and uncertainties surrounding the energy transition out to 2050.

The *2025 Outlook* helps inform bp's views of the risks and opportunities posed by the energy transition. The scenarios within it explore the possible implications of different judgements and assumptions concerning the nature of the energy transition. The uncertainty associated with the transition is substantial, and these scenarios are not predictions of what is likely to happen or what bp would like to see happen. We use the output from these scenarios to help inform our strategic thinking.

We published the *2025 Outlook* in September 2025, designed around two scenarios informed by recent trends and developments in the global energy system. The *2025 Outlook* provides key insights about how the energy system may evolve over the next 25 years.

The two scenarios – Current Trajectory and Below 2°C (see 'Two scenarios to explore the energy transition', below) – explore the speed and shape of the energy transition out to 2050 and help to inform a resilient strategy for bp.

A new section in the *2025 Outlook* uses sensitivity analysis to discuss several key issues affecting the energy transition, including the possible implications of increased geopolitical fragmentation and sustained weakness in energy efficiency. Each sensitivity analysis examined possible impacts on the global energy system.

Scenarios for strategic decision making

We use scenarios to inform strategy, manage risk, and improve decision making.

Some of these scenarios are based on climate and other policies currently in force, and on current global aims and pledges around the energy transition. Other scenarios are based on achieving a certain pace or degree of transition, and consider how the energy system might change to achieve that.

In thinking about appropriate scenarios to inform our strategy, we use both approaches.

How scenarios inform our strategy

The use of scenarios described in the *2025 Outlook*, and those from other organizations, aids our understanding of the energy transition and helps us to think about how different outcomes might impact our strategy.

The use of a broad range of scenarios to inform our strategy supports our efforts to make it robust and resilient to the range of uncertainty we face.

By considering various time horizons we can identify key milestones or signposts which might emerge over the next five, 10 or 25 years and inform our view of the key sources of uncertainty affecting the global energy system.

We actively monitor changes in the external environment and refresh or review the scenarios as needed in response to these signals.

For the purposes of testing the resilience of our strategy to the range of uncertainty in the energy transition, we have used scenarios drawn from other credible sources such as the International Energy Agency (IEA), the Network for Greening the Financial System (NGFS) and the UN Principles for Responsible Investment (UN PRI) to compile a catalogue of scenarios (our Transition Scenario Catalogue★). These include some scenarios considered by these data providers to be consistent with 1.5°C and well-below 2°C.

Read more on the Transition Scenario Catalogue, our resilience analysis and the outcome of that work on [page 49](#).

How we create scenarios

We quantify the scenarios in the *2025 Outlook* using our global energy modelling system. This comprises a suite of models to help us understand the supply and demand dynamics of the global energy system.

The modelling framework uses historical data based on the Energy Institute's Statistical Review of World Energy, the IEA's World Energy Balances data and a range of other data sets.

Each scenario is determined by a set of key assumptions, including population and economic growth, pace of technological change, resource constraints and government policies. These are informed by expert analysis from external organizations including the United Nations, Oxford Economics and Rystad Energy. We benchmark our scenarios against external organizations including the IEA, the IPCC, and S&P Global.

The modelling techniques used vary by sector and include a combination of econometric modelling, adoption curves and consumer choice modelling.

 [bp Energy Outlook 2025
bp.com/energyoutlook](https://www.bp.com/energyoutlook)

Two scenarios to explore the energy transition

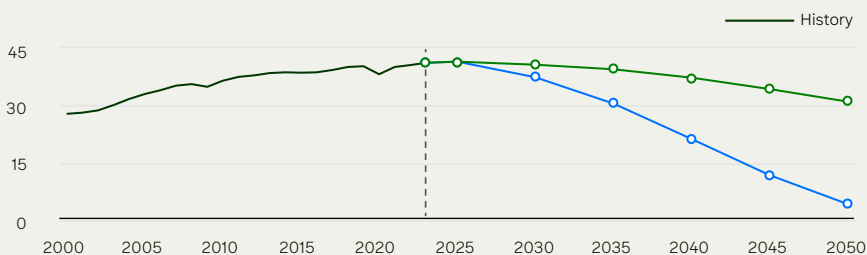
Carbon emissions Gt CO₂e^a

Current Trajectory

is designed to capture the broad pathway along which the global energy system is currently travelling. It places weight on climate policies already in force and on global aims and pledges for future decarbonization. At the same time, it recognizes the myriad challenges associated with meeting these aims. CO₂ equivalent (CO₂e) emissions in Current Trajectory peak in the mid-2020s and by 2050 are around 25% below 2023 levels.

Below 2°

explores how different elements of the energy system might change to achieve a substantial reduction in carbon emissions (a net 90% fall in CO₂e emissions by 2050). It assumes a significant tightening of climate policies alongside shifts in societal behaviour and preferences, which together support more rapid adoption of low carbon energy alongside faster gains in energy efficiency.



^a Carbon emissions include CO₂ emissions from energy use, industrial processes, natural gas flaring and methane emissions from energy production.

Our strategy

Our strategy helps bp compete and grow value as energy demand evolves and continues to grow, all in service of growing shareholder value and returns.

**Growing
upstream**

**Focusing
downstream**

Disciplined investment in transition

Growing the upstream: our oil and gas business

We are growing upstream production and cash flow through disciplined investment. We have a deep upstream resource base, and combined with disciplined investment criteria, we are well positioned to deliver medium and long-term organic growth.

Focusing the downstream: our customers and products business

We continue to reshape the portfolio to focus on markets and businesses where we have advantaged and integrated positions. We are taking clear actions to drive improved performance, including addressing costs in our customers business, and improving operations in refining.

Investing with discipline in transition

We are investing with discipline: with selective investment in biogas, biofuels and EV charging, where we see strong demand growth; adopting innovative capital-light partnerships in renewables; and focusing investment on hydrogen and carbon capture projects to support us in decarbonizing our operations, and position us for growth through the next decade.

All while continuing to drive value through our distinctive strengths in trading, technology and partnerships.

Progress on our primary targets

We use four primary targets to measure our progress and how we are improving performance. These targets, alongside the guidance and financial frame (see [page 18](#)), support our strategy. Taken together, we believe our primary targets will underpin growth in the value of bp. Our progress in 2025 is set out below:

Primary targets	2025	2025 on a price adjusted basis	Targets
Adjusted free cash flow growth ★	25%^{ab} (from 2024-25)	~+55%^{ab} (from 2024-25)	>20%^c compound annual growth rate from 2024-27
Net debt ★	\$22.2bn^d	n/a	\$14-18bn by end 2027
Structural cost reduction ★	\$2.8bn^e (cumulative since 2023)	n/a	\$5.5-6.5bn^f by end 2027
Return on average capital employed (ROACE) ★	13.9%^g	~14%^{ag}	>16%^c in 2027

Nearest IFRS-equivalent measures

2025
-10%^{ab} operating cash flow★ less total capital expenditure★ from 2024-25
\$58.0bn^d finance debt
n/a
0.1%^g profit for 2025 attributable to bp shareholders divided by total equity at 31 December 2025

a This does not form part of bp's Annual Report and Form 20-F as filed with the SEC.

b Adjusted free cash flow and adjusted free cash flow on a price adjusted basis are non-IFRS measures. The nearest IFRS equivalent measures to calculate adjusted free cash flow and adjusted free cash flow on a price adjusted basis CAGR are net cash provided by operating activities of \$24.5 billion for 2025 and \$27.3 billion for 2024 and total cash capital expenditure of \$14.5 billion for 2025 and \$16.2 billion for 2024. A reconciliation is provided on page 387.

c This is on a price adjusted basis that assumes a hypothetical price environment of \$70/bbl Brent, \$4/mmBtu Henry Hub, and \$10.3/bbl refining indicator margin (all 2024 real) and assumptions about the impact of these marker prices on underlying replacement cost profit before tax.

d Net debt is a non-IFRS measure. The nearest IFRS equivalent measure is finance debt at the end of 2025. See Note 27 for more information.

e Cumulative structural cost reduction since 2023, of which \$2 billion in 2025 and \$750 million in 2024. Structural cost reduction is decreases in underlying operating expenditure★. A reconciliation is provided on page 386.

f Following the outcome of the strategic review of *Castrol*, which resulted in the decision to divest a 65% shareholding, the \$4-5 billion structural cost reduction target by end 2027, introduced at the February 2025 Capital Markets Update, has increased.

g Return on average capital employed (ROACE) and ROACE on a price adjusted are non-IFRS measures. The nearest IFRS measures of the numerator and denominator are profit for 2025 attributable to bp shareholders of \$0.1 billion and total equity at the end of 2025 of \$74.0 billion respectively. A reconciliation is provided on page 385.

Our strategy in action

Growing upstream

In 2025 we advanced our upstream strategy and delivered seven major project start-ups, five of which were ahead of schedule. Start-ups included GTA, in Mauritania and Senegal, Cypre in Trinidad and Murlach in the UK North Sea. We also announced 12 discoveries, including Bumerangue in Brazil, our largest exploration discovery in 25 years, plus further finds in Brazil, Egypt, the Gulf of America, Libya and Trinidad, as well as discoveries in Namibia and Angola through Azule Energy, our 50-50 joint venture with Eni.

In upstream oil and gas production, we achieved our best wells reliability in years at 98% and a record full-year plant reliability★ at >96%. Our proved reserves replacement ratio★ was 90% – up from an average of around 50% in the prior two years.

In April we announced a Miocene oil discovery at the Far South prospect in Green Canyon Block 584, 120 miles off the coast of Louisiana. Drilled to 23,830 feet in 4,092 feet of water, the discovery signals potentially commercial volumes and helps to strengthen our upstream portfolio.

In August we announced the start-up of the Argos Southwest Extension project, seven months ahead of schedule. From appraisal to first oil, the project was developed in about 25 months – a record for bp. Argos has a gross production capacity of up to 140,000 barrels of oil per day (boe/d).

In December the development programme for the Karabagh field in the Caspian Sea, offshore Azerbaijan, was approved by the management committee (joint venture) and subsequently by State Oil Company of the Azerbaijan Republic (SOCAR) as the State representative. Seismic acquisition commenced thereafter.

We also completed the divestment of the Culzean gas field in the UK North Sea to NEO Next in December.

Image: Argos Southwest Extension project, US

→ [Read more on page 28-33](#)



Delivering operational value

From predictive analytics to seismic imaging, we are applying technological solutions to deliver operational value. In our upstream, technology has helped to lift plant reliability to 96.1%. Advances in seismic imaging are helping us explore more accurately, contributing to one of our best recorded years for exploration with 12 new discoveries, including through our joint ventures. And digital tools such as our asset and wells trajectory optimizer (AWTO) help plan safe routes from the surface to the reservoir in days instead of weeks or months.

Focusing downstream

2025 was also a strong year for the downstream, delivering a significant step up in performance. We achieved around \$1.6 billion in cumulative structural cost reductions★ (2024-25) and sustained refinery availability★ above 96%, strengthening commercial performance across refining, trading, midstream and fuels. Customers reported its highest underlying RC profit before interest and tax★ since 2019, with growth across all businesses.

As we continue streamlining our portfolio, in 2025 we reached an agreement to sell a 65%

stake in *Castrol*, completed the sale of the Netherlands mobility, convenience and *bp pulse* businesses, and announced plans to sell the Gelsenkirchen refinery and the Austria retail business.

As part of our broader retail network high-grading programme, in 2025 we exited around 5% of our company owned retail sites★, supporting our plan to exit around 10% by 2027.

In EV charging, we are focusing investment on four core markets and utilising our retail network to maximise returns.

Image: Rotterdam refinery, Netherlands

→ [Read more on page 34](#)



Digital-led marketing transformation

As part of our global marketing transformation programme, we consolidated 19 digital platforms into six and activated a global marketing and communications hub in Mumbai in 2025. The programme also includes deploying AI-driven technology to develop investment insights in more than 40 markets and tools to support segmentation and personalization. These changes have helped to streamline operations, accelerate delivery, and strengthen customer engagement.

Disciplined investment in transition

We focused our low carbon energy portfolio in 2025, prioritizing investment choices that deliver value for shareholders.

We formed JERA Nex bp, a 50:50 offshore wind joint venture between JERA and bp. The new joint venture brings together each parties' complementary expertise for a balanced mix of operating assets and development projects.

We sold our US onshore wind business to LS Power. And we continued to manage the pace of investment in biogas and refine and high-grade our hydrogen and carbon, capture and storage (CCS) portfolio. This included decisions not to progress H2Teesside and to end participation in projects in Oman, Australia and the US Gulf Coast. In 2025 we focused on delivering four sanctioned projects in 2024: Lingen green hydrogen project, Castellón green hydrogen project, the Northern Endurance Partnership (NEP), and Net Zero Teesside Power (NZT) – and the UCC project in Indonesia.

→ [Read more on page 28](#)

Consistency with the Paris goals

Pursuing a strategy that is consistent with the Paris goals

What we mean by Paris-consistent

The 2019 CA100+ resolution★ requires us to disclose the strategy that the board considers in good faith to be consistent with the Paris goals.

When we refer to ‘consistency with Paris’ we consider this to mean consistency with the world meeting the temperature goal set out in Articles 2.1(a) and 4.1 of the Paris Agreement on Climate Change★.

The Paris goals, which we support, were restated in the Global Mutirão at COP30 in Belém in November 2025.

We believe the world is on an unsustainable path, and the carbon budget to meet the Paris goals is running out.

bp’s strategy is informed by these considerations. It is designed to create long-term value for shareholders, while enabling delivery of our net zero ambition. It is tested for resilience to the uncertainty of the energy transition across many different potential pathways, including various Paris-consistent pathways.

In the *bp Annual Report and Form 20-F 2021* we set out, based on **three key principles**, why the board considers our strategy to be consistent with the Paris goals. Here we set out, on the same three grounds, why the board continues to consider this to be the case.

Informed by Paris-consistent energy transition scenarios

The speed and nature of the energy transition are uncertain, and so we consider a range of scenarios from multiple sources including the *bp Energy Outlook 2025* (see **page 7**) to develop and test our strategic thinking. This helps to reinforce our confidence in the robustness and resilience of our strategy to the range of uncertainty we face.

We are confident that our approach is science based. We see the Intergovernmental Panel on Climate Change (IPCC) as the most authoritative source of information on the science of climate change, and we use it and other sources such as the IEA World Energy Outlook to inform our strategy. The IPCC highlights that there are a range of global pathways by which the world can meet the Paris goals, with differing implications for regions, industry sectors and sources of energy.

Strategic resilience

We believe our strategy positions bp for success and resilience in a Paris-consistent world – a world that is progressing on one of the many global trajectories considered to be Paris-consistent, and ultimately meets the Paris goals.

The strategy diversifies bp’s portfolio and business interests, reducing the risk that challenges facing a single business area might adversely affect bp’s strategic resilience.

In addition, within the inevitable constraints associated with factors such as long-term capital investments, contractual commitments and organizational capabilities at any given time, bp’s ability to maintain its strategic resilience rests, in part, on the governance used to keep the strategy and associated targets and aims under review in light of new information and changes in circumstances.

In our climate-related financial disclosures on **page 49**, we describe how we have conducted an analysis to test our view of the resilience of our strategy, based on the Capital Markets Update presented on 26 February 2025 (and the financial frame presented with bp’s fourth-quarter and full-year 2025 results on 10 February 2026), to different climate-related scenarios.

For the purposes of testing the resilience of our strategy to the range of uncertainty in the energy transition, we have used scenarios drawn from other credible sources such as the International Energy Agency (IEA), the Network for Greening the Financial System (NGFS) and the UN Principles for Responsible Investment (UN PRI) to compile a catalogue of scenarios (our Transition Scenario Catalogue★). These include scenarios considered by these data providers to be consistent with well-below 2°C and 1.5°C outcomes^a.

As further explained on **page 50**, while the results of any such analysis must be treated with caution overall, this resilience test again reinforced our confidence in the continued resilience of our strategy to a wide range of ways in which the energy system could evolve throughout this decade, including in scenarios consistent with limiting temperature rise to 1.5°C.

The analysis also again highlighted that, while within the Transition Scenario Catalogue lowest oil prices are associated with 1.5°C scenarios, there is considerable uncertainty – demonstrated by the range within, and overlap between, the prices indicated for each scenario family.

In the Transition Scenario Catalogue used for the analysis, while the lowest oil price is associated with a 1.5°C scenario, a number of the 1.5°C and well-below 2°C scenarios have oil prices in 2030 that are substantially higher than this – and when compared to bp’s own central case oil price planning assumption for 2030, the oil price in a number of the well-below 2°C and 1.5°C scenarios is also higher.

Taking this into account, the analysis supported our belief that our strategy is financially resilient against the lowest prices associated with a Paris-consistent world in the Transition Scenario Catalogue. This in turn supports our view that our strategy is resilient to such a Paris-consistent world.

^a Our 2025 analysis used data from our Transition Scenario Catalogue★ which is based on the WBCSD Climate Scenario Catalogue version 3.0, published on 16-05-2024 and downloaded on 13-11-2024, with updates made for scenario updates subsequently published by relevant underlying data providers – such as IEA, UN PRI and NGFS. For more details on this see page 54.

Contributes to net zero

We believe that our strategy enables bp to make a positive contribution to the world achieving net zero greenhouse gas (GHG) emissions and meeting the Paris goals – outcomes which we believe to be in the best interests of bp as well as beneficial to society generally.

We continue to see opportunity in the energy transition – and there are many ways bp can contribute to the world getting to net zero outside of our aims to be net zero across our operations and sales by 2050 or sooner.

In addition to our transition businesses★ such as Archaea Energy and bp bioenergy, we aim to make a meaningful contribution to the world getting to net zero through investing with discipline in low carbon energy in ways that are capital light for bp. These investments are not readily quantifiable by metrics associated with bp's net zero aims. Examples of investments:

- Lightsource bp operates with a develop, engineer, construct and farm-down business model that creates value through selling majority interests in assets it has developed to strategic partners. Our net zero aims only recognize the impact of power when we sell it, rather than the power produced by assets we have farmed down.
- In 2025 JERA and bp completed the formation of JERA Nex bp, a 50:50-owned joint venture (JV), see [page 9](#). The development of renewable power generation often helps to displace more carbon intensive alternatives and thus supports decarbonization of the power grid.
- In 2025 in the UK, bp and partners continued to develop the Net Zero Teesside Power (NZE Power) and Northern Endurance Partnership (NEP) projects. The NZE and NEP projects have started construction on-site, with commercial operations expected in 2028. Once fully operational NZE will have the ability to capture up to 2 million tonnes of CO₂ per annum for storage via the NEP storage infrastructure which is sized for an initial 4 million tonnes of CO₂ per annum within the East Coast Cluster, with the ability to expand in the future. Where CO₂ is transported offshore for permanent storage on behalf of other entities (such as local heavy industries), this will not show up in bp's GHG metrics.

We also support collective action through participation in external initiatives, low carbon collaboration and support for others in their own decarbonization efforts. We seek to use the company's influence with trade associations that conduct climate-related advocacy.

As part of our broader advocacy efforts in connection with bp's strategy, we continue to advocate for well-designed policies that enable an energy transition consistent with the goals of the Paris Agreement.

Helping policymakers to design and put in place scalable low carbon policies that support the transition to net zero can help deliver our strategy and capitalize on the opportunities associated with the world achieving the Paris goals, but the benefit of such actions, if successful, extends well beyond any implications for bp's own GHG metrics. That is because well-designed low carbon policies can advance the decarbonization of a whole economy – something of potentially greater impact than a single company can achieve through its own portfolio.

Responding to shareholder interest in Paris consistency

In 2019 the board recommended that shareholders support a special resolution requisitioned by Climate Action 100+ (CA100+) on climate change disclosures. The CA100+ resolution passed with more than 99% of votes cast. This is the seventh year we have included responses throughout the Annual Report and we have adopted a similar approach to previous years.

The CA100+ resolution, which includes safeguards such as protections for commercially confidential and competitively sensitive information, is on [page 376](#). Key terms related to this resolution response are indicated with ★ and defined in the glossary on [page 376](#). These should be reviewed with the following information:

Element of the CA100+ resolution	Related content	Where
Strategy that the board considers in good faith to be consistent with the Paris goals.	Our strategy and business model	8 & 12
	Pursuing a strategy that is consistent with the Paris goals	10
How bp evaluates each new material capex investment★ for consistency with the Paris goals and other outcomes relevant to bp strategy.	Our investment process	20
Disclosure of bp's principal metrics and relevant targets or goals over the short, medium and long term, consistent with the Paris goals.	Key performance indicators	14
	Sustainability: net zero aims and targets	37
	See 'TCFD Metrics & Targets' for an overview	54
Anticipated levels of investment in:	Our strategy	8
(i) Oil and gas resources and reserves.	Financial frame: disciplined investment allocation	18
(ii) Other energy sources and technologies.	Transition business★ investment	21
bp's targets to promote operational GHG reductions.	Sustainability: net zero★ aims	37
Estimated carbon intensity of bp's energy products and progress over time.	Sustainability: net zero sales aim★	38
Any linkage between above targets and executive pay remuneration.	Directors' remuneration report	91
	2025 annual bonus outcome	99
	2026 remuneration policy	106

Our business model

An integrated energy company

We believe we have a world-class portfolio – a top-tier oil and gas business in attractive basins, and leading integrated positions and brands across the value chain. All underpinned by distinctive capabilities in trading, technology and partnerships.

→ [Read more about our strategy, page 8](#)

People and resources^a



61

countries of operation

93,700

employees

~11,300

engineers

\$14.5bn

capital expenditure★

\$274m

invested in research and development

2,958

granted and pending patent applications held by bp and its subsidiaries

6,191mmboe

proved hydrocarbon reserves for the group^b

>110 years

energy sector experience

^a Data as at 31 December 2025.
^b On a combined basis of subsidiaries and equity-accounted entities. See page 248 for more information on bp's oil and gas reserves.

Our organization

We have three main businesses – gas & low carbon energy, production & operations, and customers & products – enabled by supply, trading & shipping and technology.

And three teams serve as enablers of business delivery: finance; legal; and people, culture & communications.



Enabled by

Supply, trading & shipping

Connects energy producers, suppliers, markets and customers to keep energy flowing and help build out tomorrow's energy system.

Image: Traders at our Canary Wharf office, London, UK





Delivering value for stakeholders

Gas & low carbon energy

Combining and integrating our existing natural gas capabilities with power trading and growth in low carbon businesses and markets (see [page 28](#)).

Production & operations

The operational heart of bp, producing the hydrocarbon energy and products the world wants and needs – safely and efficiently (see [page 31](#)).

Customers & products

Innovating with new business models and service platforms to deliver the future of mobility, energy and services for our customers (see [page 34](#)).



Investors and shareholders

\$5.1bn

total dividends distributed to bp shareholders (2024 \$5.0bn)

Employees

66%

employee engagement score^c (2024 70%)

Customers

1,113mb/d

retail fuel volumes[★] (2024 1,125mb/d^d)

Society

\$64m

supporting additional initiatives to benefit communities (2024 \$76m)

Governments and regulators

\$8.3bn

corporate income and production tax paid (2024 \$10.6bn)

Partners and suppliers

\$142.5bn

in payments to suppliers for goods and services (2024 \$146.6bn)

^c As a result of changes to the question set and the inclusion of employees from our retail business in the 2025 Pulse survey, the engagement score for 2025 is not comparable with prior years.

^d 2024 baseline adjusted for portfolio changes to show underlying trend.

Technology

Drives digital and innovations with our science, engineering and digital capabilities.

Image: Colleagues at our Rotterdam refinery, Netherlands



Key performance indicators

We assess the performance of the group across a wide range of measures and indicators that are consistent with our strategy.

In addition to our four financial primary targets, as described on [page 8](#), our key performance indicators (KPIs) set out the metrics that help the board and leadership team assess bp's performance. Our leadership team uses all these measures to evaluate operating performance and inform its financial, strategic and operating decisions.

Financial

Total shareholder return (%) ●



■ ADS basis ■ Ordinary share basis

Total shareholder return (TSR) represents the change in value of a bp shareholding over a calendar year (American Depositary Share (ADS) in USD, ordinary share in GBP). It assumes that dividends are reinvested to purchase additional shares at the closing price on the ex-dividend date.

2025 performance

Improved TSR reflects year-on-year growth in dividend per share and an increase in the share price.

Operational

Oil and gas production (mboe/d)



Oil and gas production tracks how our projects are helping grow our business. We report production of crude oil, condensate, natural gas liquids (NGLs), natural bitumen and natural gas on a volume per day basis for our subsidiaries and equity-accounted entities. Natural gas is converted to barrels of oil equivalent at 5,800 standard cubic feet of natural gas = 1 boe.

2025 performance

2025 reported production was down compared with 2024 mainly due to the divestments in Egypt and Trinidad in the fourth quarter of 2024 and base decline, partly offset by major projects★ start-ups and growth in bpx energy.

Upstream unit production costs (\$/boe)



The upstream unit production cost is calculated as production cost divided by units of production. Production cost does not include ad valorem and severance taxes. Units of production are barrels for liquids★ and thousands of cubic feet for gas. Amounts disclosed are for bp subsidiaries only and do not include bp's share of equity-accounted entities.

2025 performance

Unit production costs was slightly higher, mainly due to portfolio mix.

Key

● Used for remuneration policy

TCFD TCFD Recommendations and Recommended Disclosures

Remuneration

To help align the focus of the bp leadership team and executive directors with the interests of our shareholders, certain measures are used for executive remuneration.

→ [Directors' remuneration report, page 91](#)

Upstream ★ plant reliability (%)

2025	96.1
2024	95.2
2023	95.0
2022	96.0
2021	94.0

bp-operated upstream plant reliability is calculated taking 100% less the ratio of total unplanned plant deferrals divided by installed production capacity, excluding non-operated assets and bpx energy. Unplanned plant deferrals are associated with the topside plant and, where applicable, the subsea equipment (excluding wells and reservoirs). Unplanned plant deferrals include breakdowns, which does not include Gulf of America weather-related downtime.

2025 performance

Delivered our record upstream plant reliability in 2025.

Refining availability (%)

2025	96.3
2024	94.3
2023	96.1
2022	94.5
2021	94.8

bp-operated refining availability represents Solomon Associates' operational availability for bp-operated refineries. The measure shows the percentage of the year that a unit is available for processing after subtracting the annualized time lost due to turnaround activity and all mechanical, process and regulatory downtime.

Refining availability is an important indicator of the operational performance of our downstream businesses.

2025 performance

2025 refining availability was the best availability on record at 96.3%, driven by strengthened maintenance programmes, enhanced digital monitoring and improved outage recovery. Compared with 2024, it reflected improved reliability and notably the absence of the Whiting refinery power outage.

Refining throughputs (mb/d)

2025	1,440
2024	1,394
2023	1,411
2022	1,504
2021	1,594

Refinery throughputs are based on the quantity of crude and condensate processed per day. It represents the actual volume fed into the refinery's distillation units.

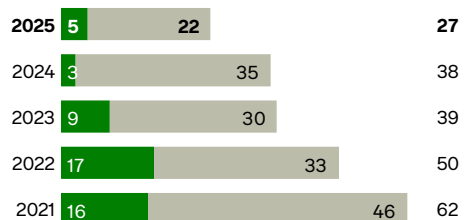
2025 performance

Refining throughputs in 2025 increased compared with 2024, reflecting the absence of the Whiting refinery power outage in 2024.

Key performance indicators continued

Safety and non-financial

Tier 1 and 2 process safety events^{★ab} ●



■ Tier 1 process safety events ■ Tier 2 process safety events

We track tier 1 and tier 2 events and report the aggregated outcome. Tier 1 events are losses of primary containment from a process of greatest consequence – causing harm to a member of the workforce, damage to equipment from a fire or explosion, a community impact or exceeding defined quantities (per API RP 754 tier 1 definitions). Tier 2 events are those of lesser consequence (per API RP 754 tier 2 definitions).

2025 performance

Our combined tier 1 and tier 2 process safety events (PSEs) have decreased for the last 12 years, apart from in 2019. In 2025 there were 27 PSEs, down from 38 in 2024. Tier 1 events increased to five (2024 three) and tier 2 events decreased to 22 (2024 35), see [page 55](#).

Reported recordable injury frequency^{★a}



Reported recordable injury frequency (RIF) measures the number of reported work-related employee and contractor incidents that result in a fatality or injury per 200,000 hours worked.

2025 performance

In 2025 our RIF decreased by 21%. This reduction is encouraging, but we know we must continue improving our safety performance, including through applying the IOGP Life-Saving Rules and our Safety Leadership Principles. For more on safety, see [page 55](#).

Women in group leadership^{cd} (%)



Our people are crucial to delivering our purpose and strategy. We aim to recruit talented people with diverse perspectives, backgrounds, skills and experiences, invest in their development and promote an inclusive culture.

Each year we report the percentage of women in group leadership.

2025 performance

The percentage of women in group leadership increased to 37% in 2025, continuing an upward trend over the previous five years.

Employee engagement^{ce} (%)



We conduct a Pulse annual employee survey to understand and monitor levels of employee engagement and identify areas for improvement.

2025 performance

The 2025 Pulse annual survey, which ran in September, saw our engagement score decrease. The results reflect the significant organizational changes happening across bp. We continue to build engagement plans based on survey feedback and on real-time updates from our monthly snapshot, Pulse live, see [page 57](#).

Key

- Used for remuneration policy
- TCFD TCFD Recommendations and Recommended Disclosures

a Exclusions to safety metrics – tier 1 and 2 process safety events and recordable injuries may occur in entities that have been recently acquired or where bp has recently taken full ownership have been granted a deviation from specific reporting requirements in bp's Operating Management System (OMS)★ for an initial transitional period. As such, data from Archaea Energy, TravelCenters of America, Lightsource bp, bp bioenergy, X Convenience and new Eagle Ford assets in bpx energy are not included in 2025 reported data.

b The metric includes reported PSEs occurring within bp's operational HSSE reporting boundary. That boundary includes bp's own operated facilities and joint ventures where bp is the operator. In some cases, we may also provide information about some joint venture activities where bp is not the operator.

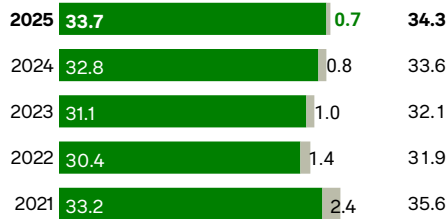
c Relates to bp employees.

d Group leaders are our most senior leaders. Their roles include operational, functional and regional leadership.

e As a result of changes to the question set and the inclusion of employees from our retail business in the 2025 Pulse survey, the engagement score for 2025 is not comparable with prior years.

GHG emissions^{abcde} –

operational control (MtCO₂e) ^{TCFD}



■ Scope 1 (direct) emissions ■ Scope 2 (indirect) emissions

We report Scope 1 and Scope 2 greenhouse gas (GHG) emissions material to our business on a carbon dioxide-equivalent basis. This KPI comprises Scope 1 (from running the assets within our operational control boundary) and Scope 2 (associated with importing electricity, heating and cooling that is bought in to run those operations) data covered by our net zero operations★ aim (to be net zero★ across our operations by 2050 or sooner). It comprises 100% of Scope 1 and 2 emissions or activities within bp’s operational control boundary.

2025 performance

In 2025 our combined Scope 1 and 2 emissions increased due to growth in our portfolio and project start-ups. Scope 1 (direct) emissions were 33.7MtCO₂e^{de} – an overall increase from 32.8MtCO₂e in 2024.

Of these Scope 1 emissions, 32.8MtCO₂e were carbon dioxide and 0.9MtCO₂e were from methane. In 2025 our Scope 2f (indirect) emissions decreased by 0.1MtCO₂e, to 0.7MtCO₂e, compared with 2024, see [page 37](#).

Basis of calculation^b

bp’s reported GHG emissions include methane (CH₄) and carbon dioxide (CO₂). Other GHGs are not included as they are not material to our operations. CH₄ emissions are converted to CO₂ equivalent using the 100-year global warming potential recommended by the Fifth Assessment Report (AR5) of the Intergovernmental Panel on Climate Change (IPCC).

Data are required to be submitted into the bp group reporting tool in accordance with bp’s Operating Management System★ (OMS) requirements, broadly following the GHG Protocol Corporate Standard and the Ipieca Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions 2nd Edition, May 2011. The responsibility for quantifying and submitting GHG emissions for reporting is assigned to individual bp facilities and business departments, which are termed reporting units (RUs).

Methane intensity^{ag} (%) ^{TCFD}



We define methane intensity★ as the amount of methane emissions from our upstream oil and gas operations as a percentage of the gas that goes to market from those operations. This applies to methane emissions within our operational control boundary, where we have the highest degree of control. Methane emissions from non-producing activities, such as exploration drilling, are excluded. In 2024 we started reporting methane intensity based on our new measurement approach across our major operated oil and gas assets.

2025 performance

Our methane intensity was 0.04% in 2025, and the methane emissions from our upstream operations used to calculate this intensity were 25kt (2024 46kt), see [page 38](#).

Basis of calculation^b

All operated upstream assets report methane (CH₄) emissions on a 100% basis, including emissions from operated upstream oil and gas and also includes terminals and LNG facilities. Marketed gas production: all upstream gas reaching a market from bp-operated upstream assets, whether or not this is bp-owned product, and includes gas production from natural gas wells and associated gas from oil production wells. Throughput from bp-operated oil and gas terminals is excluded to avoid double counting despite their associated CH₄ emissions being included in the metric. CH₄ data are required to be submitted into the bp group reporting tool, in accordance with OMS requirements, broadly following the GHG Protocol Corporate Standard and the Ipieca Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions 2nd Edition, May 2011. The responsibility for quantifying and submitting CH₄ emissions for reporting is assigned to individual bp facilities and business departments (RUs).

a These are our KPIs for the purposes of our disclosures pursuant to the UK CFD Regulations 2022 and Section 414CB (2A) (h) of the Companies Act 2006.
 b Included as part of disclosures pursuant to the UK CFD Regulations.
 c Total (100%) Scope 1 (direct) GHG emissions from source activities operated by bp or otherwise within bp’s operational control boundary. bp’s reported GHG emissions include CH₄ and CO₂.
 d Due to rounding some totals may not agree exactly to the sum of their component parts.
 e In 2025 bp made an adjustment to the operational control boundary for Scope 1 and 2 GHG emissions. This means certain operations, assets or sources which were previously included such as power generation on contractor-operated drilling rigs are now excluded. This change has a less than 1% impact on reported operational emissions. For more information on the scope of bp’s operational control boundary see [bp.com/basisofreporting](#).
 f Scope 2 emissions on a market basis, covered by bp’s net zero operations aim.
 g Prior to 2024 these emissions were calculated using a different methodology and therefore the methane intensity reported in those years and calculated using that data does not directly correlate to progress towards delivering the 2025 target. Prior year data is provided for information purposes, and we do not seek to directly compare prior years.

Our financial frame

Strengthening the balance sheet to manage and grow the business

Our financial frame sets out how we allocate the cash we generate to deliver dividends to shareholders, strengthen our balance sheet and invest with discipline to grow the value of bp.

Dividend

The resilient dividend is our first capital allocation priority. For the second quarter 2025, our dividend per ordinary share increased by 4% from 8.000 to 8.320 cents.

Based on our current forecasts and subject to the board's discretion each quarter, the dividend is expected to increase by at least 4% per ordinary share a year.

Strengthening the balance sheet

We are committed to strengthening the balance sheet and continue to target improving credit metrics within an 'A' grade credit range. We reiterate our primary target for net debt★ of \$14-18 billion by the end of 2027.

During 2025, finance debt decreased from \$59.5 billion to \$58.0 billion and net debt decreased from \$23.0 billion to \$22.2 billion.

When considering our capital structure, we also look at other instruments including hybrid bonds and securities or obligations such as leases and Gulf of America settlement liabilities. At year-end 2025 the total of net debt, hybrid bonds and securities, leases and Gulf of America settlement liabilities was \$57.8 billion.

Following a decision by the board at the fourth quarter 2025 results announcement to suspend share buybacks, excess cash★ will now be fully allocated to the balance sheet, in service of optimizing financing costs and to accelerate strengthening of the balance sheet.

Disciplined investment

We will continue to invest with discipline, driven by value, and focused on delivering returns.

Investment is allocated across our businesses based on a set of criteria that balances strategic alignment, hurdle rates, volatility, integration value, sustainability and risk (see [page 22](#)).

In 2025 capital expenditure★ was \$14.5 billion. We expect capital expenditure to be \$13.0-13.5 billion in 2026. This includes expenditure on inorganic opportunities. We believe this level of capital expenditure supports progressively growing earnings per ordinary share in the long term.

Share buybacks

We announced share buybacks of \$2.25 billion for 2025 and shareholder distributions, comprising dividends and buybacks, were around 30%^b of our 2025 operating cash flow★.

At the fourth quarter 2025 results in February 2026, the board decided to suspend share buybacks and fully allocate excess cash to accelerate strengthening of the balance sheet, optimizing financing costs and improving cash flow.

Our financial frame

Shareholder distributions

Resilient dividend

Expect annual increase of the dividend per ordinary share of at least 4%^a

Balance sheet

\$14-18bn

Net debt target by end 2027

'A' range credit metrics through cycle

Capital expenditure

\$13.0-13.5bn

in 2026

Disciplined investment allocation, assessed against a set of balanced criteria

^a Shareholder distribution decisions, including dividends and share buybacks, are subject to board discretion, taking into account factors including, but not limited to, current forecasts and credit metrics.

^b Includes all share buybacks and dividends announced for 2025. The dividend announced for the fourth quarter 2025 amount is estimated.

Our investor proposition: a simpler, stronger and more valuable bp

As we reflect on our progress in 2025 and look forward to the future, we are aligned around our conviction in bp's potential to grow significant long-term shareholder value and we are in action to simplify and strengthen the company.

Strong operational performance

Strengthening the balance sheet

Improving capital discipline

Driving to top quartile on costs

Growing cash flow and returns

A simpler bp

Continuing to focus on high grading the portfolio.

Record asset uptime; exploration success; focusing downstream; seven project start-ups; driving deeper and faster on cost and capital efficiency.

Performance interventions delivered in 2025, giving us strong momentum into 2026.

A stronger bp

Fully allocate excess cash★ to the balance sheet.

Target to reduce net debt★ to \$14-18 billion by end 2027.

Target \$5.5-6.5 billion^a of structural cost reductions★ by end 2027.

A more valuable bp

Target of >20%^b CAGR adjusted free cash flow growth★ from 2024-2027 and expected progressive dividend growth of at least 4%^c per annum.

Group ROACE★ target of >16%^b by end 2027.

Deep upstream resource base combined with disciplined investment criteria – well positioned to deliver medium and long-term organic growth.

All underpinned by our commitment to safety in everything we do.

→ [Our strategy and primary targets, page 8](#)

2026 guidance

	2026 guidance	2025 actual
Upstream reported production (guidance is both reported and underlying production★)	Reported production to be slightly lower/underlying production to be broadly flat compared with 2025	2.3m mboe/d
Total capital expenditure★	\$13-13.5bn, weighted to the first half	\$14.5bn
Depreciation, depletion and amortization	Broadly flat compared with 2025	\$17.8bn
Divestments and other proceeds ^d	\$9-10bn, including approximately \$6bn from the announced <i>Castrol</i> transaction, all significantly weighted to the second half	\$5.3bn
Gulf of America oil spill payments ^e (pre-tax)	Around \$1.6bn pre-tax, of which \$0.4bn in the first quarter and \$1.1bn in the second quarter	\$1.2bn
Other businesses & corporate underlying annual charge	Around \$1bn	\$0.6bn
Underlying effective tax rate★	Around 40% ^f	42% ^g

a Following the outcome of the strategic review of *Castrol*, which resulted in the decision to divest a 65% shareholding, the \$4-5 billion structural cost reduction target by end 2027, introduced at the February 2025 Capital Markets Update, has increased.

b This is on a price adjusted basis that assumes a hypothetical price environment of \$70/bbl Brent, \$4/mmBtu Henry Hub, and \$10.3/bbl refining indicator margin (all 2024 real) and assumptions about the impact of these market prices on underlying replacement cost profit before tax.

c Shareholder distribution decisions, including dividends and share buybacks, are subject to board discretion, taking into account factors including, but not limited to, current forecasts and credit metrics.

d Divestment proceeds are disposal proceeds as per the group cash flow statement. See page 26 for more information on divestment and other proceeds.

e See Financial statements – Note 22 for more information on payables related to the Gulf of America oil spill.

f Underlying effective tax rate is sensitive to the impact that volatility in the current price environment may have on the geographical mix of the group's profits and losses.

g Non-IFRS measure and its nearest IFRS equivalent measure for 2025 is effective tax rate of 83%.

The guidance above contains forward-looking statements and should be read in conjunction with the cautionary statement on [page 362](#).

Our investment process

How we use price assumptions

Our price assumptions are used for our investment appraisal processes. They are also used to inform decisions about internal planning and for value-in-use impairment testing of assets for financial reporting.

The role of price assumptions

Our decisions on individual investments are informed by our view of the price environment and consider the balanced investment criteria discussed below.

Our price assumptions continue to reflect a range of possibilities, including that the transition to a lower carbon economy and energy system could accelerate. Our investment appraisal assumptions, which take a long-term perspective, focus on the fundamental trends affecting the energy sector and our businesses.

From February 2025 until January 2026, we held our key investment appraisal price assumptions constant at the levels set out in the *bp Annual Report and Form 20-F 2024*. For relevant investment cases assessed from February 2026, we have applied and plan to apply the prices shown in the key investment appraisal assumptions table (right) for our central price case. Brent oil and Henry Hub gas assumptions average around \$67/bbl and \$4.4/mmBtu respectively (2024 \$ real) from 2026 to 2050.

We consider these prices to be broadly consistent with a range of transition paths compatible with meeting the Paris goals, but they do not correspond to any specific Paris-consistent scenario. We also consider a range of other price assumptions in investment appraisals, including product and market-specific prices relevant to individual investment cases.

We apply carbon prices rising from \$67/tCO₂e in 2026 to \$135/tCO₂e in 2030 and \$200/tCO₂e by 2050 (2024 \$ real) in certain cases (see box, right).

Impairment testing

Our best estimate of future prices for use in value-in-use impairment testing continues to be based on our investment appraisal price assumptions, with quarterly review of near-term prices to confirm that the assumptions appropriately reflect any changes to expectations due to short-term market trends.

Impairment price assumptions were held constant in 2025 at the levels disclosed in the *bp Annual Report and Form 20-F 2024* until the fourth quarter, when the updated investment appraisal price assumptions shown below were used for value-in-use impairment testing.

Key investment appraisal assumptions^a TCFD

2024 \$ real	2030	2040	2050
Brent oil (\$/bbl)	70	67	60
Henry Hub gas (\$/mmBtu)	4.1	4.5	4.5
Refining indicator margin (RIM) ^b ★ (\$/bbl)	12.0	8.5	5.0

In addition to the prices shown we also test whether investments meet our return expectations (see page 22) using \$60/bbl Brent oil price series.

Carbon price TCFD

2024 \$ real	2030	2040	2050
Carbon (\$/tCO ₂ e)	135	175	200

a The values in the table represent the central case.

b The disclosed RIM assumptions in the table exclude carbon pricing impacts and assume a normalized cost of renewable identification numbers (RINs).

For investment appraisal, potential future operational emissions costs that may be borne by bp as a result of an investment are included as bp costs, as described in the box below (generally without assuming incremental revenue associated with those emissions), in order to incentivize engineering solutions that reduce operational carbon emissions from projects. For the treatment of emission cost assumptions in value-in-use impairment testing, see Financial statements – **Note 1**.

Investment process price assumptions

All investments are evaluated against relevant price assumptions for oil, natural gas, refining margins or other commodities across a range of alternative price or margin series (typically a central, upper and lower series). In addition, all investment cases with anticipated annual operational GHG emissions (Scope 1 and 2) above 20,000 tonnes of CO₂ equivalent (bp net), must estimate those anticipated GHG emissions and include an associated carbon cost in the investment economics, using the carbon prices above.

Our investment price assumptions place some weight on scenarios in which the transition to a low carbon energy system is sufficiently rapid to meet the goals of the Paris Agreement, as well as scenarios in which the transition may not be sufficiently rapid. They also place some weight on a range of other factors that can drive prices, and which are not directly related to the Paris goals.

These price assumptions do not link to specific scenarios or outcomes, but instead try to capture the range of different possibilities surrounding the future path of the global energy system. The nature of the uncertainty means that the price ranges inevitably reflect considerable judgement. The ranges are reviewed and updated as necessary, as our understanding of and judgements about the energy transition evolve.

In addition to consideration of a range of price assumptions, investment cases also assess the impact of alternative assumptions covering other selected variables relevant to the economics of the investment. These variables may include cost, schedule, resources, policy changes, or other areas of uncertainty, to assess the robustness of investment cases to a range of other factors.

Investment governance and evaluating consistency with the Paris goals

Governance framework

bp's framework for investment governance seeks to ensure that investments align with our strategy, can be accommodated within our prevailing financial frame, and add shareholder value. It enables investments to be assessed in a consistent way against a range of criteria relevant to our strategy, including sustainability criteria.

Investments follow an integrated stage-gate process designed to enable our businesses to choose and develop the most attractive investment cases. A balanced set of investment criteria are considered (see [page 22](#)). This allows for the comparison and prioritization of investments across a diverse range of business models.

The governance framework specifies that proposed investments are evaluated using relevant assumptions, including carbon prices for projected operational emissions where applicable. It also sets out requirements for assurance by functions independent of the business before a final investment decision (FID) is taken.

Our investment framework also includes processes to review investment outcomes. During construction, and for two years after start-up, major project investments are included in an annual effectiveness of investment review, which tracks investments' delivery against the assumptions used in their investment cases. Key findings are shared with the board. Around two years after completion, investments above defined financial thresholds also prepare a post project evaluation to share lessons learned across bp businesses - including reviews of strategic, commercial, and technical assumptions, decisions, and delivery.

The role of the board

The board assesses capital allocation across the bp portfolio, including the level and mix of capital expenditures★ and divestments, strategic acquisitions, distribution choices and deleveraging, as well as reviewing certain investment cases for approval.

Resource commitment meeting

For acquisitions and organic capital investments above defined financial thresholds, investment approval is conducted through the executive-level resource commitment meeting (RCM), which is chaired by the chief executive officer. The RCM reviews the merits of each investment case against a balanced set of criteria (see [page 22](#)) and considers any key issues raised in the assurance process.

The CA100+ resolution★ requires bp to disclose how we evaluate the consistency of new material capex investments★ with (i) the Paris goals and (ii) a range of other outcomes relevant to bp's strategy.

bp's evaluation of the consistency of such investments with the Paris goals was undertaken by the RCM for new material capex investments sanctioned in 2025 (see [page 23](#)).

bp's evaluation of an investment's consistency with 'a range of other relevant outcomes' is achieved by considering its merits against bp's balanced investment criteria, described on [page 22](#).

bp board

Reviews and approves investment cases of more than \$3 billion for resilient hydrocarbons, more than \$1 billion for all transition or low carbon investments★ and any significant inorganic acquisition that is exceptional or unique in nature.



Resource commitment meeting

Forum for executive management's review and approval of investments related to existing and new lines of business above \$250 million, or \$25 million for acquisitions, or which exceed the relevant EVP's financial authority, and any project considered strategically important such as a new market entry.



Investment allocation committees

EVP-level forums to review and approve investment cases within a business group as per individual EVP financial authority (up to \$250 million, or typically \$25 million for acquisitions).



Business group investment governance meetings

SVP-level forums that review and approve investment cases within a business group or function, up to the individual SVP's financial authority.



Cross-group meetings

Forums that facilitate discussions across businesses and functions, to support project development, sensitivity analysis, integration opportunities and risk assessment ahead of investment committee meetings.

Transition business investment

bp set out anticipated investment in transition businesses★ through to 2027 as part of our reset strategy in February 2025. This investment was \$2.3 billion in 2025 including \$0.8 billion of inorganic spend.

EV charging: In EV charging, we are focusing investment in four core markets - Germany, UK, China and the US, with joint ventures in the Iberian region and India. We are utilizing our retail network to maximise returns. And we opened new ultra-fast★ charging hubs at major airports in the US.

Bioenergy: We completed the commercial integration of bp bioenergy, including the final deferred capital payment. We continued to scale biofuels but allocated capital only where projects are economically robust and aligned with demand progression. Consistent with this approach, we took the decision to stop further work on the development of a standalone biofuels production (HEFA) facility at our Rotterdam refinery in the Netherlands. In January 2026, we also announced the launch of Etlas, a new 50:50 joint venture with Corteva to produce oil from crops for use in the production of biofuels such as sustainable aviation fuel (SAF) and renewable diesel (RD), see [page 35](#).

Our biogas business, Archaea Energy, continued its growth, starting up eight new renewable natural gas (RNG)★ landfill plants in 2025.

Low carbon energy: We focused our low carbon energy portfolio, prioritizing investment choices that deliver value for shareholders. In December we completed the sale of our US onshore wind business, bp Wind Energy, to LS Power. And we formed JERA Nex bp, a 50:50 joint venture between JERA and bp, focused on offshore wind development, ownership and operations, see [page 9](#).

Hydrogen and carbon capture and storage (CCS): We continued to refine our portfolio, including the decisions not to progress H2Teesside and to end our participation in projects in Oman, Australia and the US Gulf Coast. In 2025 we focused on delivering four projects sanctioned in 2024: Lingen green hydrogen★ project, Castellón green hydrogen project, the Northern Endurance Partnership (NEP), and Net Zero Teesside Power (NZT).

Our investment process continued

Balanced investment criteria

All investment cases must set out their investment merits and are considered against a set of six balanced investment criteria – although investment decisions may also take other factors into account as appropriate. This standardized approach is intended to create a level playing field for decision making and allows portfolio-wide comparisons of investment cases. The decision to endorse an investment based on the information provided represents our evaluation that it is consistent with what the 2019 CA100+ resolution★ refers to as “a range of other outcomes relevant to bp’s strategy”.

The **six** balanced investment criteria are:

Strategic alignment: For all investment cases, we consider whether the investment supports delivery of our strategy, including our net zero aims. We also assess if the investment case involves distinctive capability that bp has, or intends to develop, and whether it adds to an existing ‘scale’ business within the portfolio or could help us create one.

Safety and risks: For all investment cases, we provide an assessment of the key risks to the investment that have a significantly higher probability than usual or have a significantly greater impact (relative to the size of the project) were they to occur. Safety risk management at bp is underpinned by our Operating Management System★ (OMS), which is designed to help us sustainably deliver safe, reliable and compliant bp operations.

Sustainability: For all investment cases, we consider how any proposed business opportunity is connected to the energy transition, societal needs and the environment. This approach is underpinned by our purpose and sustainability frame. All RCM cases must consider significant impacts of an investment on bp’s sustainability aims, informed by our sustainability assessment template for investment cases (for our use of carbon prices, see box on [page 20](#)).

Investment economics: For all investment cases, we consider investment economics against a range of relevant measures. Depending on the nature of the investment case, these may include return expectations (e.g. internal rate of return or IRR), net present value, discounted payback and profitability index, reflecting assumptions about relevant commodity prices, margins and carbon prices (see [page 20](#)). The forward economics of an investment case are considered against relevant economic indicators at the time of the investment decision. We may also refer to these expectations as hurdle rates, although as noted, each case is assessed according to its combined merit against our full set of balanced criteria.

1. For our upstream business (including biogas), we seek an IRR of 15%.
2. For our downstream business (including EV charging and biofuels), we seek portfolio-level returns in excess of 15%.

For investments in hydrogen and CCS, we expect levered returns in the mid-teens, including farm-down and integration value.

For any investment, the relevant return expectations above are assessed using our central price assumptions. For additional capital discipline for investments in oil and gas production, we also compare the central price hurdle above (15%) to a case in which the Brent oil price starts at \$60/bbl and later declines to the level of our key appraisal assumptions by 2050 (see [page 20](#)). In addition, for investments in our oil and gas and refined products businesses, as well as any other investments that do not fall within one of the specific businesses set out above, we compare the IRR in our lower-price case to a cost of capital hurdle rate.

Volatility and rateability: Our investment economics metrics also consider the degree of uncertainty of the cash flows when considering investment cases. For example, some cases have more certainty of future costs and revenue projections. Variation in net present values for the key variables in an investment case are quantified by sensitivity analysis to give a range of potential outcomes against our key investment hurdles.

Optionality and integration: Our assessment considers the degree of optionality offered by a project – the ability to adapt our business to changing circumstances. This could be an option to sell a product with a floor price, or the right to purchase additional equity in a joint venture at specific terms. Other types of options include the right to develop (or not develop) extensions to existing projects, or to change the course of a project’s development depending on market circumstances. We likewise seek out integration along value chains across multiple products, services, geographies and customers. For example, our gas production can supply liquefaction plants whose LNG is monetized by our trading business. Likewise, carbon sequestration projects may allow us to add value to our gas production by reducing carbon intensity.

Paris consistency evaluation process

Our new material capex investments★ are intended to support the delivery of bp’s strategy.

For evaluations conducted in 2025, investments in scope for evaluation were defined as:

- **New:** investment in a new project, or extension of an existing project/asset, or share of an entity that is new to bp, or a substantial increase in bp’s share.
- **Material:** more than \$250 million capex investment.

Quantitative evaluations

For our investment economics and sustainability investment criteria we considered quantitative guide levels, as set out below, to inform the evaluation of each investment’s consistency with the goals of the Paris Agreement. For evaluations in 2025 we used the central price IRR and other economic hurdles, as set out in the *bp Annual Report and Form 20-F 2024* (page 22). As in previous years, we used our operational carbon intensity★ as a guide level, reflecting our portfolio average. As our approach matures with experience, we may continue to adjust or supplement our methodology. There may be instances when new material capex investments are evaluated as consistent with the Paris goals despite either the economic or sustainability guide levels not being met. The RCM may also take account, in its Paris consistency evaluation, of the six balanced investment criteria using qualitative assessments.

Investment economics: We calculated economic indicators using our central price, and where applicable, our lower price cases, and applying our carbon price assumptions to relevant operational GHG emissions. (For our current key central case oil and natural gas price assumptions, see [page 20](#), where we also set out our view on their consistency with achieving the Paris goals). We then compared the economic indicators to the relevant economic guide level (see below), based on the corresponding hurdles. We typically target a threshold of >1.0x the relevant IRR guide level, as set out in the *bp Annual Report and Form 20-F 2024* (page 22).

Sustainability: Where appropriate, we compared the operational carbon intensity of the investment (on the basis of equity share) to the portfolio average equity share GHG emissions intensity shown in the *bp ESG Datasheet 2024* for the relevant business activity (Exploration, production and LNG). We normally target a ratio of less than 100%, meaning that the investment is expected to reduce the average operational carbon intensity of the relevant portfolio. The potential impact of new material capex investments on bp’s net zero aims is a further consideration.

Evaluation outcome

In 2025 eight new material capex investments were approved. All were evaluated as being consistent with the Paris goals, taking into account both quantitative and qualitative evaluations and the balanced criteria above.

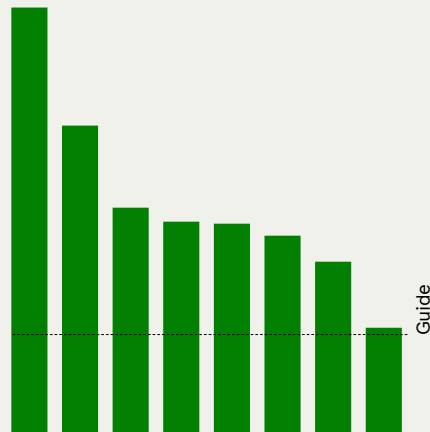
Evaluation of investment performance against quantitative guide levels

All eight investments exceeded the IRR guide level as shown in the chart.

Six of the eight investments had emissions intensities below the relevant intensity guide level. Of the remaining two investments, one produces gas that is processed at an existing LNG facility, with overall emissions intensity (including midstream onshore processing) higher than our overall portfolio average, but upstream-only emissions that are below portfolio average. This investment was supported taking into account our qualitative assessment, including the role LNG plays in the energy transition – especially in the Asia Pacific region – and the strength of the investment economics. We do not show a carbon intensity for the eighth investment because bp does not have any ownership interest in the asset or any right to the production.

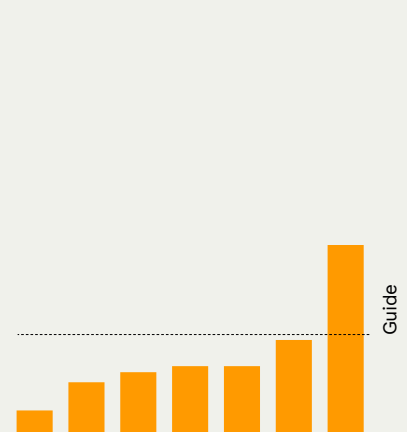
Investment economics

Against central price IRR hurdle



Sustainability

Against operational carbon intensity



Decisions taken in 2025

In 2025 there were eight new material capex investment decisions evaluated for Paris consistency, described here approximately in the order the investment decisions were made:

Ginger: We sanctioned the Ginger gas development in Trinidad and Tobago. Ginger will be our fourth subsea project in the country and will be tied back to our existing Mahogany B platform. First gas from the project is expected in 2027, making Ginger one of bp’s 10 major projects expected to start up between 2025 and 2027. At peak, the development is expected to have the capacity to produce average gas production of 62,000 barrels of oil equivalent per day.

KGD6 Infill Wells: We approved investment in drilling four offshore infill gas wells in the KGD6 block in India to be brought online in 2028. The infill wells target incremental production, benefiting from the use of existing infrastructure.

Shah Deniz Compression: In June bp and its partners agreed the final investment decision for the \$2.9 billion Shah Deniz Compression project. The project is designed to access and produce low pressure gas resources from the field, increasing resource recovery and extending production life. The project is expected to allow production of around an additional gross 50 billion cubic metres of gas and 25 million barrels of condensate. The project is expected to receive first gas in 2029.

Atlantis Major Facility Expansion: The Atlantis Major Facility Expansion project aims to enhance production at the Atlantis field by injecting water into targeted reservoirs to help access harder-to-reach barrels. We plan to start up the facility in 2027.

Kirkuk redevelopment: In 2025 bp agreed with the government of Iraq to help redevelop several fields in Kirkuk, in the north of Iraq. We will work initially with Iraq’s North Oil Company and North Gas Company to stabilize and grow production. Work will include a drilling programme, rehabilitation of existing wells and facilities, and construction of new infrastructure, including gas expansion projects.

Tiber and Guadalupe: In September we took a final investment decision on bp’s Tiber and Guadalupe developments in the Gulf of America, approving its second new production platform in less than two years in the critical US offshore region. Production from the new floating production platform, which is expected to have the capacity to produce 80,000 barrels of crude oil per day, is expected to start in 2030.

Greater Western Flank 4: We approved infill investment in the Greater Western Flank 4 development in Australia’s North West Shelf. This is a five-well subsea programme tied back to existing infrastructure to help sustain reliable gas supply to regional markets.

Juniper Wells: We approved investment in decommissioning of three existing wells, along with drilling and completion of three single zone sidetracks in Trinidad and Tobago. The infill programme is expected to deliver around 19mmboe, with the first gas expected in 2027.

Building for the future



\$0.1bn

profit attributable to bp
shareholders
(2024 profit \$0.4bn)

\$7.5bn

underlying replacement
cost (RC) profit★
(2024 profit \$8.9bn)

\$24.5bn

operating cash flow★
(2024 \$27.3bn)

Financial and operating performance

	\$ million except per share amounts		
	2025	2024	2023
Sales and other operating revenues	189,335	189,185	210,130
Profit before interest and tax	12,642	11,297	27,348
Finance costs and net finance income/expense relating to pensions and other post-employment benefits	(4,896)	(4,515)	(3,599)
Taxation	(6,451)	(5,553)	(7,869)
Profit (loss) for the year	1,295	1,229	15,880
Non-controlling interest	(1,240)	(848)	(641)
Profit (loss) for the year attributable to bp shareholders	55	381	15,239
Inventory holding (gains) losses★, before tax	1,351	488	1,236
Taxation charge (credit) on inventory holding gains and losses	(334)	(119)	(292)
Replacement cost (RC) profit (loss)★	1,072	750	16,183
Net (favourable) adverse impact of adjusting items★ ^a , before tax	5,885	9,344	(1,143)
Total taxation charge (credit) on adjusting items	528	(1,179)	(1,204)
Underlying RC profit	7,485	8,915	13,836
Adjusted EBITDA★	37,615	38,012	43,710
Dividend paid per ordinary share (cents)	32.640	30.540	27.760
Dividend paid per ordinary share (pence)	24.509	23.720	22.328
Profit per ordinary share (cents)	0.35	2.38	87.78
Profit per ADS (dollars)	0.02	0.14	5.27
Underlying RC profit per ordinary share★ (cents)	48.02	54.40	79.69
Underlying RC profit per ADS★ (dollars)	2.88	3.26	4.78
Adjusting items^a			
Gains on sale of businesses and fixed assets	987	670	361
Net impairment and losses on sale of businesses and fixed assets	(6,035)	(6,930)	(5,838)
Environmental and related provisions	(656)	(181)	(647)
Restructuring, integration and rationalization costs	(520)	(222)	37
Fair value accounting effects (FVAEs) ^b	2,220	(1,852)	9,403
Gulf of America oil spill	(31)	(51)	(57)
Other	(1,422)	(273)	(1,711)
Total before interest and taxation	(5,457)	(8,839)	1,548
Finance costs	(428)	(505)	(405)
	(5,885)	(9,344)	1,143
Adjusting items total taxation	(528)	1,179	1,204
	(6,413)	(8,165)	2,347

a See page 336 for more information.

b See page 337 for information on the cumulative impact of FVAEs.

At 31 December 2025 the group's reportable segments are gas & low carbon energy, oil production & operations and customers & products. Each is managed separately, with decisions taken for the segment as a whole, and represent a single operating segment that does not result from aggregating two or more segments. See Financial statements – **Note 5** Segmental analysis.

Results

The profit for the year ended 31 December 2025 attributable to bp shareholders was \$0.1 billion, compared with \$0.4 billion in 2024.

After adjusting profit attributable to bp shareholders for inventory holding losses and a net adverse impact of adjusting items, underlying RC profit for the year ended 31 December 2025 was \$7.5 billion. The result reflected lower liquids realizations, lower gas marketing and trading result, partly offset by stronger performance in customers & products. The oil trading contribution was broadly flat.

For 2024, after adjusting profit attributable to bp shareholders for inventory holding losses and a net adverse impact of adjusting items underlying RC profit was \$8.9 billion. The result reflected lower refining margins, lower realizations, a lower gas marketing and trading result and a lower oil trading contribution, partly offset by lower taxation.

For a discussion of bp's financial and operating performance for the years ending 31 December 2023 and 31 December 2024, see *bp Annual Report and Form 20-F 2024*, pages 24-37.

Adjusting items

In 2025 the net adverse pre-tax impact of items, which bp has classified as adjusting (adjusting items) was \$5.9 billion including:

- Favourable fair value accounting effects (FVAEs) relative to management's measure of performance of \$2.2 billion primarily related to a favourable impact of FVAEs relating to the hybrid bonds and to the relative decline in LNG forward prices over the period in addition to the realization of gains as cargoes were delivered. The impacts of FVAEs relative to management's internal measure of performance are provided on [page 337](#).

- Net impairment and losses on sale of businesses and fixed assets includes net impairment charges of \$5.4 billion which primarily relate to Lightsource bp and Archaea Energy.
- In addition, \$1.4 billion net impairment charges, of which \$1.1 billion primarily relates to the Archaea Energy and offshore wind businesses, were reported through equity-accounted earnings (reported within the 'other' category).

In 2024 the net adverse pre-tax impact of adjusting items was \$9.3 billion including:

- Adverse FVAEs relative to management's measure of performance of \$1.9 billion primarily due to an increase in the forward price of LNG during 2024, compared to a decline in 2023, and the adverse impact of the FVAEs relating to the hybrid bonds in 2024.
- Net impairment and losses on sale of businesses and fixed assets includes a loss of \$1.1 billion relating to the sale of the ground fuels business in Türkiye (see Financial statements – **Note 2**) and net impairment charges of \$5.1 billion (see Financial statements – **Note 4**).
- In addition, \$0.5 billion net impairment charges were reported through equity-accounted earnings (reported within the 'other' category).
- The 'other' category also includes a \$0.5 billion gain relating to the remeasurement of bp's pre-existing 49.97% interest in Lightsource bp and a \$0.5 billion gain relating to the remeasurement of certain US assets excluded from the Lightsource bp acquisition (see Financial statements – **Note 3** for further information); and recognition of onerous contract provisions related to the Gelsenkirchen refinery. The unwind of these provisions will be reported as an adjusting item as the contractual obligations are settled.

See Financial statements – **Note 4** for more information on impairments, and [pages 336 and 337](#) for more information on adjusting items and FVAEs.

Taxation

The charge for corporate income taxes was \$6,451 million in 2025 compared with \$5,553 million in 2024. The effective tax rate (ETR) on the profit before taxation for the year in 2025 was 83%, compared with 82% in 2024. The ETR on the profit before taxation for the year in 2025 and 2024 was impacted by fair value accounting effects and other adjusting items, including limited tax relief on impairment charges. Excluding inventory holding gains or losses and adjusting items, the underlying ETR★ in 2025 was 42% compared with 41% in 2024.

Underlying ETR is a non-IFRS measure. A reconciliation to IFRS information is provided on [page 384](#).

Outlook for 2026

2026 guidance

- bp expects reported upstream★ production to be slightly lower and underlying upstream production★ to be broadly flat compared with 2025. Within this, bp expects underlying production from oil production & operations to be broadly flat and production from gas & low carbon energy to be lower.
- In its customers business, bp expects to make continued progress growing cash flows, supported by lower underlying operating expenditure★ driven by structural cost reductions★. These benefits will be partly offset by the earnings impact of completed and announced divestments. Reported earnings will benefit from lower depreciation as a result of the assets held for sale accounting treatment of *Castrol* following the planned divestment. Fuel margins are expected to remain sensitive to movements in the cost of supply.
- In products, bp expects significantly lower level of turnaround activity.
- bp expects other businesses & corporate underlying annual charge to be around \$1.0 billion for 2026. The charge may vary from quarter to quarter.
- The underlying ETR for 2026 is expected to be around 40% but it is sensitive to a range of factors, including the volatility of the price environment and its impact on the geographical mix of the group's profits and losses.

Group performance continued

Cash flow and debt information

	\$ million		
	2025	2024	2023
Cash flow			
Operating cash flow★	24,493	27,297	32,039
Net cash used in investing activities	(11,504)	(13,250)	(14,872)
Net cash provided by (used in) financing activities	(15,880)	(7,297)	(13,359)
Cash and cash equivalents at end of year ^a	36,624	39,269	33,030
Capital expenditure★^b	(14,533)	(16,237)	(16,253)
Divestment and other proceeds^c	5,314	4,224	1,843
Debt			
Finance debt	57,958	59,547	51,954
Net debt★	22,182	22,997	20,912
Net debt including leases★	35,686	34,909	31,902
Finance debt ratio★(%)	43.9%	43.2%	37.8%
Gearing★(%)	23.1%	22.7%	19.7%
Gearing including leases★(%)	32.5%	30.8%	27.2%

a 2025 and 2024 include \$68 million and \$65 million respectively of cash and cash equivalents classified as assets held for sale in the group balance sheet.

b An analysis of capital expenditure by segment and region is provided on page 335.

c Divestment proceeds are disposal proceeds as per the group cash flow statement. See below for more information on divestment and other proceeds.

Operating cash flow

Operating cash flow for the year ended 31 December 2025 was \$24.5 billion, \$2.8 billion lower than 2024. Compared with 2024, operating cash flows in 2025 primarily reflected working capital movements partly offset by higher profits from operations and lower tax payments.

Movements in working capital★ adversely impacted cash flow in the year by \$4.8 billion, including an adverse impact from the Gulf of America oil spill of \$1.1 billion. Other working capital effects were principally an increase in derivative assets. bp actively manages its working capital balances to optimize and reduce volatility in cash flow.

Operating cash flow for the year ended 31 December 2024 was \$27.3 billion, \$4.7 billion lower than 2023. Compared with 2023, operating cash flows in 2024 primarily reflected lower profits from operations partly offset by working capital movements.

Movements in working capital favourably impacted cash flow in 2024 by \$4.0 billion, including an adverse impact from the Gulf of America oil spill of \$1.1 billion. Other working capital effects were principally a decrease in other current assets.

Net cash used in investing activities

Net cash used in investing activities for the year ended 31 December 2025 decreased by \$1.7 billion compared with 2024.

The decrease mainly reflected a decrease in expenditure on fixed assets reflecting the phasing of spend within the lower capital frame for 2025 partly offset by deferred acquisition payments.

Total capital expenditure for 2025 was \$14.5 billion (2024 \$16.2 billion), of which organic capital expenditure★ was \$13.6 billion (2024 \$16.1 billion). Inorganic capital expenditure for 2025 includes the final payment for the bp Bunge Bioenergia 2024 acquisition. Inorganic capital expenditure for 2024 includes the cash acquired net of acquisition payments on completion of the bp Bunge Bioenergia and Lightsources bp acquisitions. Sources of funding are fungible, but the majority of the group's funding requirements for new investment comes from cash generated by existing operations. bp expects capital expenditure of around \$13-13.5 billion in 2026.

Total divestment and other proceeds for 2025 amounted to \$5.3 billion, including amounts received from the sale of the US onshore wind, Netherlands mobility & convenience and bp pulse businesses. Other proceeds for 2025 consist of \$1.5 billion from the sale of non-controlling interests in the Permian and Eagle Ford midstream assets and \$1.0 billion from the sale of a non-controlling interest in the subsidiary that holds our 12% share in the Trans-Anatolian natural gas pipeline (TANAP).

Total divestment and other proceeds for 2024 amounted to \$4.2 billion, including \$0.9 billion from the sale of receivables and \$0.7 billion cash received, both relating to prior divestments, and \$0.6 billion relating to the formation of Arcius Energy. Other proceeds for 2024 consist of \$0.8 billion of proceeds from the sale of a non-controlling interest in the subsidiary that holds our 20% share in Trans Adriatic Pipeline AG (TAP) and \$0.5 billion of proceeds from the sale of a 49% interest in a controlled affiliate holding certain midstream assets offshore US.

bp expects divestment and other proceeds to be \$9-10 billion in 2026, including approximately \$6 billion from the announced *Castrol* transaction.

Net cash provided by (used in) financing activities

Net cash used in financing activities for the year ended 31 December 2025 was \$15.9 billion, compared with \$7.3 billion in 2024. Compared with 2024, financing cash flows in 2025 primarily reflected net repayments compared to net proceeds from the issuance and repayment of finance debt, and lower receipts from the issue of perpetual hybrid bonds, partly offset by a decrease in share buybacks, and an increase in receipts relating to transactions involving non-controlling interests.

In 2025, 836 million ordinary shares (2024 1,238 million) were repurchased for a total cost of \$4.5 billion (2024 \$7.1 billion), including transaction costs of \$24 million (2024 \$38 million). Of these, 176 million shares repurchased were cancelled and 659 million shares were held as treasury shares.

Total dividends paid to shareholders in 2025 were 32.640 cents per share, 2.10 cents higher than 2024. This amounted to total dividends paid to shareholders of \$5.1 billion in 2025 (2024 \$5.0 billion). The board decided not to offer a scrip dividend alternative in respect of the 2025 and 2024 dividends.

Debt

Finance debt at the end of 2025 decreased by \$1.6 billion from the end of 2024 primarily reflecting net repayments of long-term finance debt, partly offset by changes in fair value where hedge accounting is applied. The finance debt ratio at the end of 2025 increased to 43.9% from 43.2% at the end of 2024.

Net debt at the end of 2025 decreased by \$0.8 billion from the 2024 year-end position. Gearing at the end of 2025 increased to 23.1% from 22.7% at the end of 2024. Net debt and gearing are non-IFRS measures. See Financial statements – **Notes 26** and **27** for further information on finance debt and net debt.

For information on financing the group's activities see Financial statements – **Note 29** and Liquidity and capital resources on **page 338**.

Group reserves and production^a

	2025	2024	2023
Estimated net proved reserves (net of royalties)			
Liquids (mmb)	3,447	3,699	3,747
Natural gas (bcf)	15,916	14,786	17,471
Total hydrocarbons ^b (mmb/e)	6,191	6,248	6,759
<i>Of which:</i>			
Equity-accounted entities ^b	1,330	1,377	1,437
Production (net of royalties)			
Liquids (mb/d)	1,199	1,166	1,115
Natural gas (mmcf/d)	6,450	6,914	6,944
Total hydrocarbons (mboe/d)	2,312	2,358	2,313
<i>Of which:</i>			
Subsidiaries	1,931	2,008	1,967
Equity-accounted entities	380	350	345

a Because of rounding, some totals may not agree exactly with the sum of their component parts.

b See Supplementary information on oil and natural gas on page 241 for further information.

Total hydrocarbon proved reserves at 31 December 2025, on an oil equivalent basis including equity-accounted entities, decreased by 1% compared with 31 December 2024 (0.2% decrease for subsidiaries and 3% decrease for equity-accounted entities). Natural gas increased by 8% (10% increase for subsidiaries and 3% decrease for equity-accounted entities).

There was a net increase from acquisitions and disposals of 27mmb/e within our US and North Sea subsidiaries.

Total hydrocarbon production for the group was 2% lower compared with 2024. The decrease comprised a 3.8% decrease (3.5% increase for liquids and 9.7% decrease for gas) for subsidiaries and an 8.6% increase (0.8% increase for liquids and 37.0% increase for gas) for equity-accounted entities.

Gas & low carbon energy

Gas & low carbon energy segment comprises our gas & low carbon businesses. Our gas business includes regions^a with upstream activities that predominantly produce natural gas, gas trading and our Archaea Energy business. Our low carbon business includes solar, offshore wind, hydrogen and CCS, and power trading, and until its divestment in December 2025 also included onshore wind. Power trading and marketing includes trading of both renewable and non-renewable power.

Financial and operating performance

	\$ million		
	2025	2024	2023
Sales and other operating revenues^b	40,333	32,628	50,297
Profit before interest and tax ^c	1,330	3,052	14,081
Inventory holding (gains) losses [★]	–	–	(1)
RC profit before interest and tax^c	1,330	3,052	14,080
Net (favourable) adverse impact of adjusting items ^{★cd}	4,037	3,751	(5,358)
Underlying RC profit before interest and tax[★]	5,367	6,803	8,722
Taxation on an underlying RC basis	(1,972)	(2,137)	(2,730)
Underlying RC profit before interest	3,395	4,666	5,992
Depreciation, depletion and amortization	4,969	4,835	5,680
Exploration write-offs	30	222	362
Adjusted EBITDA^{★e}	10,366	11,860	14,764
Capital expenditure[★]			
Gas ^f	2,946	4,246	3,517
Low carbon energy	464	1,596	1,256
	3,410	5,842	4,773

a The Azerbaijan-Georgia-Türkiye and Middle East and North Africa (MENA) regions have been further subdivided by asset to allow reporting in either gas & low carbon or oil production & operations as appropriate.

b Includes sales to other segments.

c 2024 has been restated for material items to reflect the move of our Archaea Energy business from the customers & products segment to the gas & low carbon energy segment.

d See page 337 for information on the cumulative impact of FVAEs.

e A reconciliation to RC profit before interest and tax is provided on page 388.

f 2024 and 2023 have been restated to reflect the move of our Archaea Energy business from the customers & products segment to the gas & low carbon energy segment.

Financial results

Sales and other operating revenues for 2025 are higher than 2024 mainly due to higher gas marketing and trading revenues partly offset by lower volumes.

RC profit before interest and tax for 2025 was \$1,330 million compared with \$3,052 million for 2024.

In 2025 items which bp has classified as adjusting had a net adverse impact of \$4,037 million including favourable fair value accounting effects (FVAEs)[★] of \$1,270 million, relative to management's view of performance, and net impairment charges of \$4,038 million, primarily relating to Lightsource bp and Archaea Energy. In addition, \$1,082 million impairment charge was recognized through equity-accounted earnings, primarily relating to Archaea Energy and offshore wind businesses.

After adjusting RC profit for the net impact of items which bp has classified as adjusting, underlying RC profit before interest and tax for

2025 was \$5,367 million, compared with \$6,803 million for 2024. The decrease reflects the divestments in Egypt and Trinidad in the fourth quarter of 2024, a lower gas marketing and trading result, and a higher depreciation, depletion and amortization charge, partly offset by lower exploration write-offs and the absence of the foreign exchange loss in Egypt in the first quarter of 2024.

In 2024 items which bp has classified as adjusting had a net adverse impact of \$3,751 million including adverse FVAEs of \$1,550 million, relative to management's view of performance, partly offset by a gain of \$1,006 million as a result of remeasurement of our previously existing interest and related assets on the step-acquisition of Lightsource bp (LSbp).

See Financial statements – **Note 4** and **Note 16** for further information on net impairment charges.

Operational update

Reported production for 2025 was 785mboe/d, 11.6% lower than the same period in 2024. Underlying production[★] for the full year was 2.1% lower, mainly due to base decline partly offset by major projects[★] start-ups.

Strategic progress

Gas

In April we safely loaded the first cargo of liquefied natural gas (LNG) for export from its GTA Phase 1 project offshore Mauritania and Senegal – see the case study on **page 29** for more information.

In May we made the final investment decision (FID) to invest in an infill wells programme at the offshore KG D6 gas block located offshore India.

In June together with our partners, we announced the FID for the new Shah Deniz Compression project, the next stage of development of the giant Shah Deniz gas field in the Azerbaijan sector of the Caspian Sea (bp operator 29.99%).

In Trinidad and Tobago we have made progress on our growth projects – see the case study, on **page 29** for more information.

In Egypt we have made progress on growing our portfolio:

- In February we began production from the second development phase of the Raven field.
- In March we announced the successful completion of drilling operations at the El Fayoum-5 gas discovery well in the North Alexandria Offshore Concession. This was the final well in our four-slot drilling campaign in the West Nile Delta (WND) and our second consecutive gas discovery following El King-2 well in the North King Mariout Offshore Concession.
- In September we signed a memorandum of understanding (MoU) to evaluate opportunities for a five-well programme in the Mediterranean Sea.
- In January 2026 we were awarded two offshore exploration concession: North-East El Alamein Offshore and West El Hammad Offshore, advancing our exploration portfolio and long-term growth ambitions.

In November the Greater Western Flank 4 project in the North West Shelf, offshore Australia (bp 16.67%, operator Woodside) reached FID. The project involves five subsea tieback wells with start-up targeted for 2028.

Biogas

In December Archaea Energy and Osaka Gas Trading and Export entered into an agreement for the procurement of approximately 26,000Nm³ of biomethane derived from landfill gas, produced at Archaea Energy's facilities operating in the US.

During the fourth quarter Archaea Energy started up two renewable natural gas (RNG)★ landfill plants (Middle Point and NW Tennessee) bringing the total to eight landfill plants started-up in 2025, with a total capacity of more than 6 million mmmBtu. Since 2023 Archaea Energy has added a total of 19 landfill plants and total capacity of 18 million mmmBtu per year.

LNG portfolio

On the supply side, bp has had strong growth in 2025 with the start-up commissioning and subsequent strong performance at the Greater Tortue Ahmeyim Phase 1 LNG export project in Mauritania and Senegal, in which bp is the operator. 19 cargoes were lifted by bp's ST&S organization – which has 100% offtake rights from the project.

Venture Global announced Commercial Operations Date for bp's long-term contract from Calcasieu Pass as 15 April, since which bp has lifted all the long-term cargoes made available to it under this agreement.

Portfolio growth also occurred in the sales portfolio with the start-up of the second power plant within the GNA JV's integrated regas terminal and power plant at Porto do Acu in Brazil's Rio de Janeiro state, owned by bp, Prumo and Siemens. The project is owned by bp, Prumo, Siemens and SPIC and bp has 100% supply rights to this facility.

A number of globally diverse long term sales to third parties were also signed in 2025, for example a long-term sale with A2A into Italy – increasing diversification to our portfolio; a long-term sale agreed with Torrent Power into India – expanding customer portfolio; a long term sale with Zhejiang Energy in China – building on our regional experience; and a three-year sale to Türkiye's Botas – deepening customer relationships in key demand centres.

See Oil and gas disclosures for the group on **page 340** for more information on oil and gas operations in the regions.

Low carbon energy

In 2025 we took action to focus our portfolio and further high-grade our projects – both through partnerships, to create capital light joint ventures – and through divestments, making strong progress on the programmes that are driving focus and reducing costs.

Hydrogen and carbon capture and storage

In 2025 we focused on delivering four projects sanctioned in 2024: Lingen green hydrogen★ project, Castellón green hydrogen project, the Northern Endurance Partnership (NEP), and Net Zero Teesside Power (NZT).

We continued to refine our hydrogen and carbon, capture and storage (CCS) portfolio. This included decisions not to progress H2Teesside and to end participation in projects in Oman, Australia and the US Gulf Coast.

Renewables and power

Offshore wind

In August 2025 we formed JERA Nex bp, a 50:50 offshore wind joint venture between JERA and bp. The new JV brings together each parties' complementary expertise for a balanced mix of operating assets and development projects.

Onshore renewables

In February 2025 we announced our intention to bring a strategic partner into our solar business, LSbp.

LSbp continues to be a leading global onshore renewable developer in markets with attractive sector returns.

In June Shafag (Jabrayil) Solar Ltd, bp's joint venture with SOCAR Green and the Azerbaijan Business Development Fund, announced FID on the 240MW AC Shafag solar plant in the Jabrayil district of Azerbaijan. In parallel, investors in the Sangachal terminal sanctioned the linked Sangachal terminal electrification project.

In December we completed the sale of our US onshore wind business, bp Wind Energy, to LS Power. The transaction included 10 operating assets across seven US states.



LNG milestone

We safely loaded the first cargo of LNG for export from our Greater Tortue Ahmeyim (GTA) Phase 1 project offshore Mauritania and Senegal. By the end of 2025 we delivered 19 cargoes for export. Phase 1 includes one of Africa's deepest subsea structures, with wells located in water depths of up to 2,850 metres (9,350 feet).

Image: Aerial image of GTA in the Atlantic Ocean



Progress in Trinidad and Tobago

We marked four major milestones in Trinidad and Tobago in 2025. In March we sanctioned the Ginger gas development and confirmed exploration success at Frangipani. The Cypre project delivered first gas in April. And Mento, a joint venture with EOG Resources, delivered first gas in May.

Image: Mento platform, Trinidad and Tobago

Gas & low carbon energy continued

Estimated net proved reserves and production^a (net of royalties)

	2025	2024	2023
Estimated net proved reserves (net of royalties)			
Crude oil ^b (mmb)	100	113	128
Natural gas liquids (mmb)	–	1	1
Total liquids ^{★c}	101	115	129
Natural gas ^e (bcf)	6,366	6,965	8,635
Total hydrocarbons ^{★c} (mmboe)	1,198	1,316	1,618
<i>Of which equity-accounted entities^d:</i>			
Liquids (mmb)	1	1	–
Natural gas (bcf)	162	196	–
Total hydrocarbons (mmboe)	29	35	–
Production (net of royalties)			
Crude oil ^b (mb/d)	75	88	96
Natural gas liquids (mb/d)	10	8	9
Total liquids (mb/d)	85	96	105
Natural gas (mmcf/d)	4,059	4,596	4,778
Total hydrocarbons (mboe/d)	785	888	929
<i>Of which equity-accounted entities^e:</i>			
Liquids (mb/d)	5	2	2
Natural gas (mmcf/d)	165	9	–
Total hydrocarbons (mboe/d)	34	4	2
Average realizations^{★f}			
Liquids (\$/bbl)	65.50	75.37	77.03
Natural gas (\$/mcf)	6.60	5.90	6.13
Total hydrocarbons (\$/boe)	41.34	38.57	40.21

a Because of rounding, some totals may not agree exactly with the sum of their component parts.

b Includes condensate and bitumen.

c Includes 1.7 million barrels of total liquids (1.7 million barrels at 31 December 2024 and 2.2 million barrels at 31 December 2023) and 231 billion cubic feet of natural gas (219 billion cubic feet at 31 December 2024 and 430 billion cubic feet at 31 December 2023) in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

d bp's share of reserves of equity-accounted entities in the gas & low carbon energy segment.

e bp's share of production of equity-accounted entities in the gas & low carbon energy segment.

f Realizations are based on sales by consolidated subsidiaries only – this excludes equity-accounted entities.



Operations in Oman

Block 61 in Oman (bp operated with a 40% equity stake) delivered strong operational performance in 2025. Technical enhancements enabled the site to reach its highest-ever gas flow rate. We operate two drilling rigs, underpinning our development programme and acquiring key data to inform the reservoir's potential. A major turnaround was delivered eight days earlier than the scheduled time, supported by new robotic tools that reduced confined-space work and improved reliability and efficiency. Block 61 has the capacity to supply a third of Oman's domestic natural gas demand.

Image: Block 61, Oman

Oil production & operations

Oil production & operations segment comprises regions^a with upstream activities that predominantly produce crude oil, including bpx energy.

Financial and operating performance

	\$ million		
	2025	2024	2023
Sales and other operating revenues^b	24,527	25,637	24,904
Profit before interest and tax	8,560	10,780	11,191
Inventory holding (gains) losses★	(2)	9	–
RC profit before interest and tax	8,558	10,789	11,191
Net (favourable) adverse impact of adjusting items★	856	1,148	1,590
Underlying RC profit before interest and tax★	9,414	11,937	12,781
Taxation on an underlying RC basis	(4,409)	(5,165)	(5,998)
Underlying RC profit before interest	5,005	6,772	6,783
Depreciation, depletion and amortization	7,719	6,797	5,692
Exploration write-offs	313	544	384
Adjusted EBITDA★^c	17,446	19,278	18,857
Capital expenditure★	6,760	6,198	6,278

a The Azerbaijan-Georgia-Türkiye and Middle East and North Africa (MENA) regions have been further subdivided by asset to allow reporting in either gas & low carbon or oil production & operations as appropriate.

b Includes sales to other segments.

c A reconciliation to RC profit before interest and tax is provided on page 388.

Financial results

Sales and other operating revenues for 2025 were lower than 2024 mainly due to lower realizations partially offset by higher volumes.

RC profit before interest and tax for 2025 was \$8,558 million compared with \$10,789 million for 2024.

Adjusting items for 2025 had a net adverse impact of \$856 million principally relating to net impairment charges. See Financial statements – **Note 4** and **Note 16** for further information on net impairment charges.

After adjusting RC profit for the net adverse impact of adjusting items, underlying RC profit before interest and tax for 2025 was \$9,414 million, compared with \$11,937 million for 2024. The lower profit reflects lower liquids realizations, lower share of net income of equity-accounted entities, a higher depreciation, depletion and amortization charge, partly offset by higher volumes and lower exploration write-offs.

Adjusting items for 2024 had a net adverse impact of \$1,148 million mainly relating to net impairment charges. See Financial statements – **Note 4** and **Note 16** for further information on net impairment charges.

Operational update

Reported production for 2025 was 1,527mboe/d, 3.8% higher than the same period of 2024. Underlying production★ for the year was 2.6% higher compared with the same period of 2024 reflecting bpx energy performance.

Strategic progress

- In April bp announced a Miocene oil discovery at the Far South prospect in the US Gulf of America. bp drilled the exploration well in Green Canyon Block 584 approximately 120 miles off the coast of Louisiana in 4,092 feet of water. The well was drilled to a total depth of 23,830 feet. The Far South co-owners are bp (operator, 57.5%) and Chevron U.S.A. Inc. (42.5%).
- In June bp announced it had signed fully termed agreements with the State Oil Company of the Azerbaijan Republic (SOCAR) to acquire 35% participating interests and become the operator of two exploration and development blocks in the Caspian Sea – the Karabagh oil field and the Ashrafi-Dan Ulduzu-Aypara (ADUA) area. In December the development programme for the Karabagh field in the Caspian Sea, offshore Azerbaijan, was approved by the management committee (joint venture) and subsequently by State Oil Company of the Azerbaijan Republic (SOCAR) as the State representative. Seismic acquisition commenced thereafter.



Bumerangue discovery

In August 2025 bp reported a significant hydrocarbon discovery at the Bumerangue well in Brazil's Santos Basin. Bumerangue is one of 12 exploration discoveries we made in 2025, across several basins, including the Gulf of America and Namibia, through Azule Energy, our 50:50 independent joint venture with Eni.

Image: Valaris renaissance drill ship

Kirkuk contract goes live

In October 2025 bp's contract with Iraq's North Oil Company and North Gas Company became effective, after agreeing an initial baseline production rate of 328,000 barrels per day. Under the contract we will invest in the redevelopment of several giant oil fields in Kirkuk, in the north of Iraq.

Oil production & operations continued

- Azule Energy, bp's 50% joint venture, made the following progress during the year:
 - In April Rhino Resources (42.5%) along with co-venturers Azule Energy (42.5%), Namcor (10%), and Korres Investments (5%) announced the successful drilling of the Capricornus 1-X exploration well in block PEL-85 in the Orange Basin.
 - In July Azule Energy, operator of Block 15/06 in Angola, together with its partners, announced the successful start-up of the Agogo Integrated West Hub Project, which aims to fully develop the Agogo and Ndungu fields in Block 15/06.
 - In July Azule Energy, operator of Block 1/14, and its partners announced a gas discovery at the Gajajeira-01 exploration well, located offshore in the Lower Congo Basin, Angola.
 - In October Rhino Resources, operator of the Petroleum Exploration Licence 85 in the Orange Basin offshore Namibia, partnering with Azule Energy, announced a discovery at the Volans 1-X well.
- In August bp announced the start-up of the Argos Southwest Extension project in the Gulf of America. The project consists of three wells and a new drill centre tied back to the Argos platform and is expected to add 20,000 barrels of oil equivalent per day of gross peak annualized average production. bp is operator of Argos with 60.5% working interest, with co-owners Woodside Energy (23.9%) and Union Oil Company of California, an affiliate of Chevron U.S.A. Inc. (15.6%).
- In September bp announced it has reached a final investment decision (FID) on the Tiber-Guadalupe project in the Gulf of America. The 100% bp-owned Tiber-Guadalupe will be bp's seventh operated oil and gas production hub in the Gulf of America, featuring a new floating production platform with the capacity to produce 80,000 barrels of crude oil per day. The project includes six wells in the Tiber field and a two-well tieback from the Guadalupe field. Production is expected to start in 2030.
- In October bp agreed to sell its 32% non-operated working interest in the Culzean development in the central North Sea to Serica Energy. NEO Next exercised its option to acquire bp's stake on the same terms as those agreed by Serica. In December bp completed the divestment of the Culzean gas field in the UK North Sea to NEO Next.
- In December bp successfully delivered first oil from the Atlantis Drill Center 1 expansion project in the US Gulf of America, its seventh global upstream major project★ start-up of the year. The two-well subsea tieback to the existing Atlantis platform is expected to add 15,000boe/d gross peak annualized average production.

See Oil and gas disclosures for the group on **page 340** for more information on oil and gas operations in the regions.



Permian basin progress

Our US onshore oil and gas business, bpx energy, completed Crossroads, its fourth central delivery facility in the Permian Basin. We also completed the sale of our non-controlling interests in Permian and Eagle Ford midstream assets to Sixth Street for \$1.5 billion, while bpx energy remains the operator. The transaction supports our divestment programme targeting \$20 billion by 2027.

Image: bpx energy midstream facility, US

Estimated net proved reserves and production^a (net of royalties)

	2025	2024	2023
Estimated net proved reserves (net of royalties)			
Crude oil ^b (mmb)	2,908	3,112	3,193
Natural gas liquids (mmb)	439	472	426
Total liquids	3,346	3,584	3,618
Natural gas (bcf)	9,550	7,821	8,836
Total hydrocarbons★ (mmboe)	4,993	4,932	5,142
<i>Of which equity-accounted entities^c:</i>			
Liquids (mmb)	885	917	1,001
Natural gas (bcf)	2,410	2,467	2,527
Total hydrocarbons (mmboe)	1,301	1,342	1,437
Production (net of royalties)			
Crude oil ^b (mb/d)	993	953	910
Natural gas liquids (mb/d)	121	117	100
Total liquids (mb/d)	1,114	1,070	1,010
Natural gas (mmcf/d)	2,391	2,318	2,165
Total hydrocarbons (mboe/d)	1,527	1,470	1,383
<i>Of which equity-accounted entities^d:</i>			
Liquids (mb/d)	272	272	269
Natural gas (mmcf/d)	438	431	432
Total hydrocarbons (mboe/d)	347	346	343
Average realizations★^e			
Liquids (\$/bbl)	60.64	69.85	72.09
Natural gas (\$/mcf)	3.69	2.55	4.17
Total hydrocarbons (\$/boe)	49.45	53.96	58.34

a Because of rounding, some totals may not agree exactly with the sum of their component parts.

b Includes condensate and bitumen.

c bp's share of reserves of equity-accounted entities in the oil production & operations segment. During 2025 gas operations in Angola, Argentina, Bolivia, Mexico and Norway were conducted through equity-accounted entities.

d bp's share of production of equity-accounted entities in the oil production & operations segment.

e Realizations are based on sales by consolidated subsidiaries only – this excludes equity-accounted entities.



North Sea start-up

We safely started up production from the Murlach field in the UK North Sea in 2025. The two-well subsea tieback is expected to deliver peak net production of approximately 15,000 barrels of oil equivalent per day to the Eastern Trough Area Project (ETAP) hub, which has been operating for 27 years. Murlach was our sixth of seven major project start-ups in 2025.

Image: Murlach in the North Sea

Customers & products

Customers & products segment comprises our customer-focused businesses, which include convenience and retail fuels, EV charging, as well as *Castrol*, aviation, B2B, midstream and bp bioenergy. It also comprises our products businesses which include refining and oil trading.

Financial and operating performance

	\$ million		
	2025	2024	2023
Sales and other operating revenues^a	148,783	155,401	160,215
Profit (loss) before interest and tax ^b	2,747	(1,522)	2,993
Inventory holding (gains) losses [★]	1,353	479	1,237
Replacement cost (RC) profit (loss) before interest and tax^b	4,100	(1,043)	4,230
Net (favourable) adverse impact of adjusting items ^{★bc}	1,172	3,560	2,183
Underlying RC profit before interest and tax[★]	5,272	2,517	6,413
Of which:			
customers – convenience & mobility	3,764	2,584	2,644
<i>Castrol</i> – included in customers	971	831	730
products – refining & trading	1,508	(67)	3,769
Taxation on an underlying RC basis	(1,066)	(452)	(1,454)
Underlying RC profit before interest	4,206	2,065	4,959
Depreciation, depletion and amortization	4,145	3,957	3,548
Of which:			
customers – convenience & mobility	2,443	2,135	1,736
<i>Castrol</i> – included in customers	179	176	167
products – refining & trading	1,702	1,822	1,812
Adjusted EBITDA^{★d}	9,417	6,474	9,961
Of which:			
customers – convenience & mobility	6,207	4,719	4,380
<i>Castrol</i> – included in customers	1,150	1,007	897
products – refining & trading	3,210	1,755	5,581
Capital expenditure[★]	4,071	3,789	4,761
Of which:			
customers – convenience & mobility	2,480	2,059	3,135
<i>Castrol</i> – included in customers	161	227	262
products – refining & trading ^e	1,591	1,730	1,626

a Includes sales to other segments.

b 2024 has been restated for material items to reflect the move of our Archaea Energy business from the customers & products segment to the gas & low carbon energy segment.

c See page 337 for information on the cumulative impact of FVAEs.

d A reconciliation to RC profit before interest and tax by business is provided on page 350.

e 2024 and 2023 have been restated to reflect the move of our Archaea Energy business from the customers & products segment to the gas & low carbon energy segment.



X Convenience in Australia

bp acquired X Convenience, an Australian fuel and convenience retailer. The move significantly increases our presence as a national network in Australia, with almost 50 additional sites strategically located in the south and west of the country. X Convenience gives fleets and consumers access to our bp fuel, convenience, and loyalty programmes, while retaining the strong X Convenience brand.

Image: X Convenience site, Australia

Engaging customers with *earnify*

earnify – bp's unified digital loyalty and rewards platform in the US – grew rapidly in 2025, surpassing 8 million members as active membership doubled since launch. By simplifying rewards, enhancing digital engagement, and improving margin delivery, *earnify* is becoming a scalable ecosystem strengthening customer loyalty and fueling future retail growth.

Financial results

Sales and other operating revenues in 2025 were lower than in 2024, mainly due to lower product prices.

RC profit before interest and tax for 2025 was \$4,100 million, compared with a loss of \$1,043 million for 2024.

In 2025 items which bp has classified as adjusting had a net adverse impact of \$1,172 million (including adverse fair value accounting effects of \$207 million – relative to management's view of performance), of which \$913 million related to impairments of assets, primarily in the products business, offset by \$317 million of gains on disposal of assets and businesses. See Financial statements – **Note 4** for further information on disposals and impairments.

After adjusting RC profit for the net adverse impact of items, which bp classified as adjusting, underlying RC profit before interest and tax (underlying result) was \$5,272 million, compared with \$2,517 million for 2024. The result was significantly higher, reflecting stronger performance both in customers and products.

In 2024 items which bp has classified as adjusting had a net adverse impact of \$3,560 million (including adverse fair value accounting effects of \$81 million – relative to management's view of performance), of which \$1,143 million related to impairments of assets, which included an impairment of the Gelsenkirchen refinery and \$1,267 million related to loss on disposal, mainly related to the Türkiye ground fuels business disposal.

Customers – the convenience and mobility underlying result for 2025 was higher than 2024. The 2025 underlying result benefited from stronger integrated performance across fuels and midstream and lower underlying operating expenditure★ supported by structural cost reductions★, as well as a more than 15% increase in *Castrol's* earnings with year-on-year growth for 10 consecutive quarters.

Products – the underlying result for 2025 was significantly higher than 2024, primarily driven by higher realized margins, the absence of the first quarter 2024 plant-wide power outage at the Whiting refinery and higher commercial optimization. The results also benefited from lower underlying operating expenditure driven by structural cost reductions. The oil trading contribution was broadly flat compared with 2024.

Operational update

bp-operated refining availability for 2025 was 96.3%, higher compared with 94.3% in 2024, mainly due to the absence of the Whiting refinery power outage.

Strategic progress

In 2025 clear strategic focus and improved execution strengthened returns and materially increased our competitiveness. Early in 2025 we committed to growing our customers & products adjusted operating cash flows★ having delivered around 60%^a of our 2027 adjusted operating cash flow growth target in 2025.

Reshaping our integrated portfolio

Alongside the divestments we completed or announced, including *Castrol*, Netherlands mobility, convenience and *bp pulse* businesses, Austria retail, and Gelsenkirchen refinery, we continued to focus on markets where our integrated businesses provide the greatest advantage. This included further high grading of our retail network, exiting around 5% of our company owned sites as we progress towards our target of around 10% by 2027.

Focusing EV charging in priority markets

bp pulse continued to make progress with EV charging investment now focusing primarily in four core markets Germany, UK, China and the US, with joint ventures in the Iberian region and India. *Aral pulse* was named Germany's best charge point operator for the third consecutive year and in the UK *bp pulse* advanced its network reset programme and extended its long-standing partnership with Transport for London through 2029.

Progressing strategic choices in biofuels

Alongside the commercial integration of bp bioenergy, in 2025 we continued to scale biofuels but allocated capital only where projects are economically robust and aligned with demand progression.

We took the decision to stop further work on development of a standalone biofuels production (HEFA) facility at our Rotterdam refinery in the Netherlands.

In action to improve performance

Customers delivered its highest underlying RC profit before interest and tax since 2019 with all businesses growing year-on-year.

Customers' strong 2025 performance was underpinned by a reduction in structural costs. These reductions reflect sustained execution across procurement, supply chain efficiencies, organizational simplification and operating model changes.

In 2025 air bp delivered sustainable aviation fuel (SAF) in over 60 locations in 22 countries driven by the requirement of both European SAF mandates and customer voluntary SAF demand.

Realizing value from recent customers acquisitions

We continued to integrate and optimize our recent acquisitions:

- We have completed the commercial integration of bp bioenergy, a leading sugarcane bioethanol producer – creating a strong platform to deliver synergies and improve value realization with trading.
- In our TravelCenters of America business, we are progressing a targeted business improvement plan, focused on strengthening safety and operational performance, sharpening commercial discipline, and improving customer delivery.

Strengthening refining availability and competitiveness

In 2025 refining delivered the best availability on record at 96.3%, driven by strengthened maintenance programmes, enhanced digital monitoring and improved outage recovery. Higher availability has supported stronger and more consistent margin capture across the portfolio.

In refining structural cost reductions were delivered through optimizing maintenance activities and driving efficiencies across the supply chain.

Taken together, these improvements resulted in delivery of around 80% of our 2027 \$3/bbl cash breakeven reduction ambition^b.

Partnering in biofuels

bp and Corteva, one of the world's leading agriscience companies, launched Etlas – a new biofuels 50:50 joint venture. Etlas works with farmers to grow canola, mustard and sunflower crops for use in sustainable aviation fuel and renewable diesel. Etlas aims to grow a million tonnes of feedstock per year by the mid-2030s, enough for around 800,000 tonnes of biofuel.

a Taking growth against 2024 normalized for 2025 environmental conditions (refining margins and foreign exchange).

b 2027 \$3/bbl cash breakeven reduction ambition is defined as refining margin per barrel required to attain pre-tax breakeven operating cash flow excluding working capital movements, normalized for turnaround activity levels, foreign exchange and energy prices; like-for-like portfolio.

Other businesses & corporate

Other businesses & corporate comprises technology, bp ventures, shipping, our corporate activities & functions and any residual costs of the Gulf of America oil spill.

Financial and operating performance

	\$ million		
	2025	2024	2023
Sales and other operating revenues^a	2,232	2,290	2,657
Profit (loss) before interest and tax	(40)	(988)	(903)
Inventory holding (gains) losses [★]	–	–	–
Replacement cost (RC) profit (loss) before interest and tax	(40)	(988)	(903)
Net (favourable) adverse impact of adjusting items ^{★p}	(608)	380	37
Underlying RC profit (loss) before interest and tax[★]	(648)	(608)	(866)
Taxation on an underlying RC basis	399	292	322
Underlying RC profit (loss) before interest	(249)	(316)	(544)
Depreciation, depletion and amortization	989	1,033	1,008
Capital expenditure[★]	292	408	441

a Includes sales to other segments.

b See page 337 for information on the cumulative impact of FVAEs.

Financial results

RC loss before interest and tax for 2025 was \$40 million, compared with \$988 million for 2024.

Adjusting items for 2025 had a net favourable impact of \$608 million. Adjusting items include impacts of fair value accounting effects, which had a favourable impact of \$1,157 million.

Adjusting items for 2024 had a net adverse impact of \$380 million. Adjusting items include impacts of fair value accounting effects, which had an adverse impact of \$221 million.

After adjusting RC loss for the adjusting items, underlying RC loss before interest and tax for 2025 was \$648 million, compared with a loss of \$608 million for 2024.

Sustainability

Sustainability at bp

Our sustainability frame focuses on three areas – getting to net zero, improving people’s lives and caring for our planet.

Reporting on sustainability

In this section, we cover selected sustainability issues along with information in the following areas:

- Performance on our net zero aims, see [page 37](#).
- Climate-related financial disclosures, see [pages 41-54](#).
- Our approach – safety, ethics and compliance, our people, biodiversity, water, and ‘Who we are’ (our beliefs), see [pages 55-59](#).

We provide an update on our actions on our aims, and our wider progress in relation to embedding sustainability, in our latest Sustainability Report bp.com/sustainabilityreport.

Our sustainability aims

We have five sustainability aims, focused on the areas we believe are most relevant to the long-term success of our business.

Net zero operations

Our aim is to reach net zero★ by 2050 or sooner for Scope 1 and 2 emissions within bp’s operational control^a, including by maintaining ‘near-zero’ methane intensity★ across our operated producing assets, enabled by supportive government policies. [See page 38](#).

Net zero sales

Our aim is to reduce to net zero the average lifecycle carbon intensity of the energy products★ we sell by 2050 or sooner, enabled by supportive government policies and the decarbonization of energy demand. [See page 38](#).

People

Our aim is to support our employees and local communities through the energy transition. [See page 59](#).

Biodiversity

Our aim is to support biodiversity where we operate^b. [See page 59](#).

Water

Our aim is to reduce our net freshwater use in stressed catchments where we operate. [See page 59](#).

Net zero

Our ambition remains to be a net zero company by 2050 or sooner, and to help the world get to net zero.

Both our net zero aims make explicit what is needed to enable their delivery – and delivery of the associated interim targets or aims.

Our future business and investment decisions, which will affect the outcomes for these aims, will be intended to facilitate delivery of our strategy and investor proposition, applying our balanced investment criteria, one of which relates to sustainability.

We believe our net zero ambition and aims, taken together, are consistent with the goals of the Paris Agreement.

By setting a path that enables us to make a positive contribution, working to build out and participate in many of the new energy value chains the world will need, and through our efforts to reduce our overall operational emissions, our ambition and aims support the world’s progress towards the goals of the Paris Agreement.

Net zero aims 2025 performance

Aims	Measure/coverage	2019	2025 performance	2025 targets	2030 aims	Aims for 2050 or sooner
Net zero operations★	Scope 1+2	Baseline 54.5MtCO ₂ e	37% ^{cd}	20% ^c	45-50% ^c	Net zero★
	Methane intensity★	0.14%	0.04% ^e	0.20%		Near zero
Net zero sales★	Average lifecycle carbon intensity of sold energy products★	Baseline 84gCO ₂ e/MJ	7% ^f	5% ^f	8-10% ^f	Net zero

a On a CO₂e basis.

b At our new in-scope bp-operated projects and major operating sites.

c Reduction in absolute emissions against 2019 baseline.

d In 2025 bp made an adjustment to the operational control boundary for Scope 1 and 2 GHG emissions. This means certain operations, assets or sources which were previously included, such as power generation on contractor-operated drilling rigs, are now excluded. This change has a less than 1% impact on reported operational emissions. For more information on the scope of bp’s operational control boundary see bp.com/basisofreporting.

e Since 2024 reported absolute methane emissions from major operated oil and gas processing sites are based on our new measurement approach. Prior to 2024 these emissions were calculated using a different methodology and therefore the methane intensity reported in those years and calculated using that data does not directly correlate to progress towards delivering the 2025 target.

f Reduction in the average lifecycle carbon intensity of sold energy products against the 2019 baseline. The percentage change is calculated from the source data instead of the rounded carbon intensity number.

Sustainability continued

Net zero operations ^{TCFD}

Our aim is to reach net zero by 2050 or sooner for Scope 1 and Scope 2 emissions within bp's operational control including by maintaining 'near-zero' methane intensity★ across our operated producing assets, enabled by supportive government policies.

We achieved a reduction of 37% against a targeted 20% reduction in our operational emissions by end-2025 and are aiming for a 45-50% reduction by the end of 2030, both against our 2019 baseline.

New projects coming online add to the challenge of reducing our operational emissions. Continued investment in abatement and further portfolio optimization will be needed to meet our 2030 aim.

We also achieved our 2025 target for methane intensity of 0.20%. Our methane intensity for 2025 was 0.04%, compared with 0.07% in 2024.

Scope 1 and 2 emissions

Our combined Scope 1 and 2 emissions were 34.3MtCO₂e^{ab} in 2025 – an increase from 33.6MtCO₂e in 2024 due to growth in our portfolio and seven major project start-ups. The total decrease in emissions to 2025 includes 18MtCO₂e attributable to divestments and 5.7MtCO₂e in emissions reductions activity.

In 2025 our Scope 1 (direct) emissions were 33.7MtCO₂e – an overall increase from 32.8MtCO₂e in 2024. Of these Scope 1 emissions, 32.8MtCO₂e were from carbon dioxide and 0.9MtCO₂e from methane^c.

In 2025 our Scope 2 (indirect) emissions^d decreased by 0.1MtCO₂e, to 0.7MtCO₂e, compared with 2024. The enhanced use of lower carbon power agreements contributed to this decrease.

We report our Scope 1 and 2 emissions on an operational control and equity share basis in the *bp ESG Datasheet 2025*.

bp.com/ESGdata

Scope 3 emissions ^{TCFD}

In 2025 our Scope 3 category 11 emissions were 471MtCO₂e^e. These are the end-use emissions associated with sales of energy products, as determined in bp's calculation of the average carbon intensity of our sold energy products★.

Methane

Since 2024 absolute methane emissions have been reported based on our new methane measurement approach across our major operated oil and gas processing sites. Using this approach, our methane intensity was 0.04% in 2025 (2024 0.07%). Methane emissions from our upstream★ operations used to calculate this methane intensity were 25kt in 2025 (46kt in 2024^e).

Marketed gas volumes were broadly flat at 3,637bcf in 2025.

The lower emissions and intensity in 2025 were primarily from improved management of abnormal plant conditions in our Tangguh operations, Indonesia, reported in 2024.

We remain on track to reach zero routine flaring by 2030 in line with our aim under the World Bank's Zero Routine Flaring Initiative.

Net zero sales ^{TCFD}

Our aim is to reduce to net zero the average lifecycle carbon intensity of the energy products★ we sell by 2050 or sooner, enabled by supportive government policies and the decarbonization of energy demand.

We have achieved our target to reduce the intensity of our sold energy products by 5% from the 2019 baseline by the end of 2025. We are aiming for an 8-10% reduction by the end of 2030 compared to our 2019 baseline.

Average carbon intensity of sold energy products (gCO₂e/MJ)^f

	2025	2024	2023	2022	2021	2019
Average carbon intensity of sold energy products	79	79	80	81	81	84
Oil/refined products	91	91	91	92	92	95
Gas/NGLs	67	67	67	67	67	68
Bioproducts ^g	38	41	44	43	44	47
Power/heat ^h	51	50	56	29	27	28

In 2025 the average carbon intensity of our sold energy products was 79gCO₂e/MJ. This represents a 7% reduction from our 2019 baseline.

The incremental improvement in performance from 2024 was primarily driven by a growth in retail power sales across our utility businesses – bp Energy Retail and GETEC, our trading business, and our renewable businesses – Lightsource bp and JERA Nex bp. It was supported by the high grading of our retail portfolio and improved identification of end-user sales volumes within the refined product category.

Details of our net zero sales methodology are in the *bp Basis of Reporting 2025*.

bp.com/basisofreporting

As announced in February 2025, we plan to invest selectively and with discipline in transition businesses★, see [page 21](#).

Our disciplined approach to capital investment means that individual investments will be made when we consider there to be a clear and compelling business case, in line with our balanced set of investment criteria, see [page 22](#).

Advocacy related to net zero

We regularly advocate for or comment on the development of policy that is relevant to bp and our sustainability aims. In 2025 our advocacy activities focused on various aspects including bioenergy, hydrogen and carbon pricing. We publish examples of our activity online at bp.com/advocacyactivities.

a In 2025 bp made an adjustment to the operational control boundary for Scope 1 and 2 GHG emissions. This means certain operations, assets or sources which were previously included, such as power generation on contractor-operated drilling rigs, are now excluded. This change has a less than 1% impact on reported operational emissions. For more information on the scope of bp's operational control boundary see bp.com/basisofreporting.

b Due to rounding some totals may not agree exactly to the sum of their component parts.

c Since 2024 reported absolute methane emissions from upstream major operated oil and gas processing sites are based on our new measurement approach. Prior to 2024 these emissions were calculated using a different methodology and therefore the methane intensity reported in those years and calculated using that data does not directly correlate to progress towards delivering the 2025 target. Prior year data is provided for information purposes, and we do not seek to directly compare prior years.

d Scope 2 emissions on a market basis.

e This Scope 3 category 11 metric follows a different methodology and boundary to the Scope 3 category 11 emissions from the carbon in bp's upstream oil and gas production (known previously as bp's aim 2 (net zero production), which was retired in February 2025), so is not directly comparable to prior years of data for that retired aim and does not correlate to progress towards any retired targets associated with it. Although these emissions are a subset of the lifecycle emissions under bp's net zero sales aim, there is no target or aim associated with them. See bp.com/basisofreporting for more detail on methodology.

f The aggregate lifecycle emissions and energy values used in the calculation of the average lifecycle carbon intensity of sold energy products★ are provided in the *bp ESG Datasheet 2025*.

g Includes biofuels and biogas.

h Covers all power, including renewable and non-renewable.

TCFD Information that supports TCFD Recommendations and Recommended Disclosures in relation to governance (see [pages 41-44](#))

Streamlined energy and carbon reporting (SECR) information

Further information on our greenhouse gas (GHG) emissions, energy consumption and energy efficiency is set out here and on the following page. It includes disclosures in respect of the SECR requirements. Further breakdown of our GHG and energy data is available in the *bp ESG Datasheet 2025* at bp.com/ESG.

Operational control ^{ab}	Unit	2025	2024	2023
Scope 1 (direct) emissions^c	MtCO ₂ e	33.7	32.8	31.1
UK and offshore	MtCO ₂ e	1.0	1.0	1.0
Global (excluding UK and offshore)	MtCO ₂ e	32.6	31.8	30.1
Scope 2 (indirect) emissions – location-based^c	MtCO ₂ e	1.7	2.4	2.0
UK and offshore	MtCO ₂ e	0.02	0.02	0.02
Global (excluding UK and offshore)	MtCO ₂ e	1.7	2.4	1.9
Scope 2 (indirect) emissions – market-based^c	MtCO ₂ e	0.7	0.8	1.0
UK and offshore ^d	MtCO ₂ e	0.03	0.02	0.0
Global (excluding UK and offshore)	MtCO ₂ e	0.7	0.8	1.0
Energy consumption^e	GWh	134,448	129,872	124,770
UK and offshore	GWh	4,718	4,526	4,688
Global (excluding UK and offshore)	GWh	129,730	125,347	120,082
Ratio of Scope 1 (direct) and Scope 2 (indirect) emissions to gross production^f	teCO ₂ e/te	0.16	0.16	0.16
UK and offshore	teCO ₂ e/te	0.12	0.13	0.13
Global (excluding UK and offshore)	teCO ₂ e/te	0.16	0.16	0.16

a Operational control data comprises 100% of emissions from activities operated by bp / where bp or its subsidiaries has full authority to introduce and implement its OMS★. Read more at bp.com/basisofreporting.

b Due to rounding, some totals may not agree exactly to the sum of their component parts.

c In 2025 bp made an adjustment to the operational control boundary for Scope 1 and 2 GHG emissions. This means certain operations, assets or sources which were previously included such as power generation on contractor-operated drilling rigs are now excluded. This change has a less than 1% impact on reported operational emissions. For more information on the scope of bp's operational control boundary see bp.com/basisofreporting.

d REGOs and other instruments reflected in our data had not been retired at the time of publication but are expected to be retired subject to business decisions at the end of the compliance period.

e Energy content of flared or vented gas is excluded from energy consumption reported as although it reflects loss of energy resources, it does not reflect energy use required for production or manufacturing of products.

f Gross production comprises upstream production, refining throughput and petrochemicals produced.

Streamlined energy and carbon reporting (SECR) information

Energy efficiency measures

Operational efficiency

We take a portfolio view of our project improvement activities at individual sites. This allows us to prioritize the most effective projects, supporting energy efficiency, reduced carbon emissions, and lower costs.

During 2025 we completed energy efficiency reviews across four production regions: the North Sea, Oman, Egypt and Asia Pacific. Our refining business also completed the energy efficiency programme launch in 2024. Additional reviews were carried out at the Cherry Point (US), Castellón (Spain) and Gelsenkirchen (Germany) refineries. The opportunities identified through these reviews will be progressed through our established business processes and plans that support our net zero ambition.

In 2025 a total of 14 new emissions reduction projects and actions contributed to reductions of 0.27MtCO₂e, including low carbon energy consumption projects. This is in addition to the 27 emissions reduction projects delivered in 2024, which achieved a reduction of 0.42MtCO₂e. These projects are tracked based on GHG reductions and include energy efficiency improvements.

Archaea Energy purchased renewable energy certificates (RECs) equivalent to 125ktCO₂e in emissions savings on a market basis.

A further 144ktCO₂e of emissions reductions were achieved through energy efficiency improvements in production processes and flaring optimization projects during 2025. These included:

- Three projects at our Tangguh facility delivering 45ktCO₂e in reductions, including flare purge rate rationalization and boil-off gas flaring minimalization.
- A power synchronization project between two platforms in Trinidad and Tobago which reduced spinning reserve through an electrical tie-over enabling load sharing, delivering 14ktCO₂e reductions.
- Ongoing programmes at bpx energy including replacement of natural-gas driven pneumatic controllers, installation of solar air compressors, electrification measures and reductions in fugitive emissions, delivering 80ktCO₂e.

In addition, our Castellón, Rotterdam (Netherlands), and Whiting (US) refineries have implemented further actions to drive energy efficiency and reduce carbon emissions, including steam trap repair and replacement programmes. At Cherry Point the restoration of cooling water infrastructure improved reliability in meeting refinery needs and enhanced the efficiency of compressor operations.

As part of managing energy efficiency, we take a portfolio-wide approach to assessing and prioritizing spinning reserve reduction opportunities. Spinning reserve involves running additional power generation machines to provide an excess of energy supply. This can help to protect production from plant vulnerabilities, including power generation reliability. Reducing spinning reserve can increase exposure to power fluctuations for production. We take a risk-based approach when considering reducing the number of running machines. This allows bp to realise emissions and maintenance cost reductions from fewer running machines, while managing the associated production risk.

bp is involved in several external groups working on energy efficiency, including the Oil & Gas Climate Initiative (OGCI), the International Association of Oil & Gas Producers (IOGP) and Energy Star. We continue to run an annual training course for new chemical engineers, which includes energy efficiency upskilling, and we offer GHG emissions and energy efficiency training for more experienced engineers and practitioners.

Reporting methodology

Our approach to reporting GHG emissions broadly follows the GHG Protocol Corporate Standard and the Ipeca Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions 2nd Edition, May 2011. We calculate GHG emissions based on fuel consumption and fuel properties for major sources, such as flares.

We report CO₂ and methane. We do not include nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulphur hexafluoride as they are not material to our operations.

Energy consumption is monitored and reported centrally from all operated sites by fuel type. This includes all energy, both imported and self-produced, used to run our operations and aligned with our GHG reporting boundary, but excludes energy content of flared or vented gas. Although flaring and venting reflects loss of energy resources, it does not reflect energy use required for production or manufacturing of products.

Ratio of Scope 1 and Scope 2 emissions to gross production

bp reports a ratio of Scope 1 and Scope 2 emissions to gross production, see the SECR table on [page 39](#). This covers all our Scope 1 and Scope 2 emissions on an operational control boundary basis and uses gross operated sales from our operated oil and gas facilities, refinery throughput and petrochemicals produced. The denominator uses output from production businesses, refineries and petrochemical facilities, which account for 96% of total operated emissions. The intensity ratio has remained the same as 2024.

The ratio provided in the SECR table uses production and throughput from our operated upstream, refining and chemicals businesses as a measure of output which can be consistently reported against. We report data on a consolidated basis in the Annual Report and Form 20-F and this differs to the production and throughput used for the ratio in the SECR table, which aligns with the operational control boundary basis.

Climate-related financial disclosures^a

We want to continue to work constructively with the IFRS Foundation's International Sustainability Standards Board (ISSB) and others as they develop good practices and standards for transparent climate-related reporting.

In 2025 we continued to engage with the World Business Council for Sustainable Development (WBCSD) in relation to its ongoing 'Climate Scenario Analysis Reference Approach for Companies in the Energy System'. Read about how we have used the WBCSD Scenario Catalogue^b as the start point for consolidating our Transition Scenario Catalogue★, which was used to inform our own scenario analysis, on [page 52](#).

TCFD statement

We report in line with the FCA Listing Rule UKLR 6.6.6R(8), which requires us to report on a 'comply or explain' basis against the TCFD Recommendations and Recommended Disclosures in respect of the financial year ended 31 December 2025^c.

We consider our climate-related financial disclosures to be consistent with all of the TCFD Recommendations and Recommended Disclosures and that they are therefore compliant with UKLR 6.6.6R(8). We have set out our disclosures against each TCFD Recommended Disclosure and in doing so have covered both the Recommended Disclosure and the related Recommendation^d. We have made disclosures that take into consideration references made to the materiality of information in the Recommendations related to Strategy and Metrics and Targets. In determining materiality for these purposes, we considered whether particular information may have the potential to influence the economic decisions of our shareholders. We have also, where appropriate, considered the TCFD guidance and other supporting materials referred to in the UK Listing Rules^e. In the Strategy (b) section on [page 46](#), we describe elements of our plans for the transition to a lower carbon economy as we execute our strategy.

As explained on [page 10](#), we explain why we consider our strategy to be consistent with the goals of the Paris Agreement.

The strategy has been developed taking into consideration, among other things, the bp Energy Outlook scenarios, which take account of climate commitments and pledges made by countries in which we operate alongside a range of other factors.

In preparing our disclosures we have made several judgements, and while we are satisfied that they are consistent with the TCFD Recommendations, Recommended Disclosures and reporting requirements under the UK CFD Regulations, we will continue to monitor guidance as it evolves and consider opportunities to enhance our disclosures.

Governance

TCFD Recommendation:

Disclose the organization's governance around climate-related issues and opportunities.

Recommended Disclosure:

- Describe the board's oversight of climate-related risks and opportunities.
- Describe management's role in assessing and managing climate-related risks and opportunities.

The board's role

One of the core roles of the board is to promote the success of the company for the benefit of its shareholders as a whole while having regard to various factors, including the interests of our other stakeholders and the impact of our operations on the environment and the communities where we operate.

In performing this role, the board sets and monitors bp's strategy. It is responsible for monitoring bp's management and operations and obtaining assurance about the delivery of its strategy.

Any changes to the company's purpose, strategy and values (which we call 'Who we are') are reserved for the board for approval in accordance with the board-approved corporate governance framework.

The board's responsibilities extend to oversight of bp's internal control and risk management framework, including climate-related risks and opportunities, as set out in the terms of reference of the board, available online at [bp.com/governance](https://www.bp.com/governance).

The board considers that our strategy allows bp to be flexible to adapt to the evolution of the external environment, including market changes, to remain consistent with the Paris goals.

The board and its committees have oversight of climate-related issues^f, which include climate-related risks and opportunities. Related board and committee activities are set out within the board activities section and committee reports respectively, which can be found on the pages detailed in the table on [page 42](#).

Climate-related risks and opportunities were discussed at each relevant board meeting covering strategy in 2025, and the committees considered climate-related issues where appropriate to do so in fulfilling their responsibilities. Verbal reports from each of the committee chairs are given at board meetings to keep the board apprised of the relevant matters discussed including, where applicable, climate-related risks and opportunities.

Our company secretary's office manages the process by which board and committee agendas are set and works closely with teams in bp to develop materials that assist the board to discharge its responsibilities, including in respect of climate-related issues.

The board also reviewed documents containing climate-related disclosures – including these TCFD disclosures.

^a This section provides disclosures pursuant to the FCA Listing Rule UKLR 6.6.6R(8) and in line with the Companies (Strategic Report) (Climate-related Financial Disclosure) Regulations 2022 (The UK CFD Regulations). In the main, we consider our TCFD disclosures achieve UK CFD compliance. Where additional information has been provided beyond our TCFD disclosures to achieve compliance with the CFD Regulations, this has been specifically called out.

^b Our 2025 analysis used a suite of external scenarios from various providers – this took as its start point the latest WBCSD (World Business Council for Sustainable Development) Scenario Catalogue (V3, published in 2024), which we then updated for relevant metrics where underlying source data providers (IEA, NGFS, UN PRI) have published more recent (or withdrawn older) transition scenarios. We have referred to this as our Transition Scenario Catalogue★ – for more detail see page 52.

^c In considering the consistency of our disclosures with the TCFD Recommendations and Recommended Disclosures we have had regard to, among other things, the documents referred to in UKLR 6.6.8G and 6.6.9G, as applicable to the financial year 2025.

^d In preparing the disclosures we have referred to the TCFD implementation guidance 'Annex: Implementing the Recommendations of the Task Force on Climate-related Financial Disclosures (October 2021)', available from fsb-tcfd.org/publications.

^e UKLR 6.6.8G and UKLR 6.6.9G.

^f We interpret the term 'climate-related issues' to relate primarily to those climate-related risks and opportunities for bp that are relevant to the delivery of long-term shareholder value in the context of the energy transition.

Climate-related financial disclosures continued

Learning and development

The board continues to develop its knowledge and expertise on climate-related and sustainability matters. For example, in 2025, the board took part in the following:

Renewables and power update	Included recent progress on, and plans for, offshore wind. Update provided to assist the board in remaining abreast of key energy transition risks and opportunities.
Hydrogen and carbon capture and storage transition growth ★ engine update	Update provided on bp-led projects including the Northern Endurance Partnership and Net Zero Teesside Power. Assisted the board in remaining abreast of key energy transition risks and opportunities.
Energy and economic update	The briefing was given by our chief economist on developments shaping the key political and societal trends currently affecting the energy transition, in advance of publication of the <i>bp Energy Outlook 2025</i> in September 2025. Briefing assisted the board in remaining abreast of key developments.

The board is due to receive further updates on bp's strategic process and sustainability frame in 2026.

Climate and sustainability expertise

The board believes its members possess the necessary expertise related to climate change and sustainability to support the group's strategy. In particular, eight of our non-executive directors have specific climate change and sustainability expertise, as set out below.

This determination is based on an assessment of their background and experience, with a focus on their background in the energy sector, experience in executive roles and depth of experience in sustainability and climate change, including climate-related risks and opportunities.

For more general director skills information, see [page 73](#).

- **Dame Amanda Blanc** is the Group CEO of Aviva plc, and has held several executive roles across the industry. She was Co-Chair of the UK Transition Plan Taskforce.
- **Dave Hager** has over 40 years' experience in the oil and gas industry. During his time as CEO of Devon Energy Corporation, he was instrumental in developing its approach to climate and sustainability. He also served on the American Petroleum Institute Executive Committee as the organization set out its positions on climate and sustainability. He has served on the bp safety and sustainability committee since December 2025.
- **Simon Henry** has significant climate and sustainability experience from senior roles across the energy and financial sectors. As CFO of Shell, he oversaw group strategy through the period of the 2015 Paris Agreement. He contributed to Lloyds Bank's first climate strategy, supported the development of PetroChina's Sustainability Report, and, while a Non-Executive director at Rio Tinto, helped shape its emissions reduction plans. He has served on the sustainability committees at Rio Tinto and Harbour Energy, and was a contributing member of Chapter Zero and the Energy Transition Commission.
- **Albert Manifold** has a strong track record of strategic leadership and operational delivery. As CEO of CRH plc, the global building materials company, he embedded decarbonization, circularity and water efficiency into the company's strategy and, under his leadership, CRH made recognized progress in climate performance.
- **Melody Meyer** has deep-rooted operational experience in the energy sector which equips her to advise on climate-related risks and opportunities. She has chaired bp's safety and sustainability committee since November 2019, which oversees the implementation of bp's sustainability frame and net zero ambition.
- **Hina Nagarajan** has over 30 years' experience in senior roles within the customer-focused FMCG sector. Through her executive roles at Diageo, she is responsible for assessing and mitigating risks related to climate and sustainability, as well as delivery of ESG targets for her region and Diageo plc. During her time as CEO of United Spirits Limited (Diageo plc's listed Indian subsidiary), she oversaw the implementation of Diageo India's 10-year ESG action plan, and its Society 2030 mission, in addition to a number of other sustainability initiatives.
- **Satish Pai** has extensive experience in the resource and energy industries. He is managing director of metals company Hindalco Industries Limited, and leads the company's Sustainability Board in overseeing sustainability initiatives – such as sustainable mining practices, energy conservation and recycling. He has served on the bp safety and sustainability committee since March 2023.
- **Johannes Teysen** brings CEO experience from his time at E.ON, where under his leadership, it split its hydrocarbons and non-hydrocarbons businesses – giving him significant experience of considering climate-related risks and opportunities. He has sat on bp's safety and sustainability committee since 2021. He is a director of Alpiq Holding AG, a Swiss energy services provider and electricity producer in Europe.

Board and committees' consideration of climate-related issues

For examples from the year ended 31 December 2025, see the text indicated with **TCFD** on the pages set out below.

→ **The board: pages 73-75**

Safety and sustainability committee: pages 82-83

Audit committee: pages 84-88

Remuneration committee: pages 91-117

The role of management

The board, subject to certain conditions and limitations, delegates day-to-day management of the business of the company to the CEO. The CEO is responsible for proposing bp's strategy and annual plan to the board for approval and leading the bp leadership team in delivering bp's strategy and annual plan.

Under this delegation, the CEO is responsible for overseeing the implementation of a comprehensive system of internal controls that are designed to, among other things (a) identify and manage risks that are material to bp, (b) protect bp's assets, and (c) monitor the application of bp's resources in a manner that meets external regulatory standards. Risks, for these purposes, include the climate-related risks and opportunities for bp associated with the issue of climate change and the transition to a lower carbon economy. This is set out in the CEO role profile at bp.com/board.

The assessment and management of climate-related risks and opportunities are embedded across bp at various levels and delegated authority flows down from the board through the CEO. See [page 60](#) for more information on risk governance and oversight.

2025 activity

Where considered appropriate, climate-related risks and opportunities were discussed at bp leadership team meetings in 2025 as part of regular business performance updates prepared for these meetings.

The bp leadership team provides oversight of risk, including climate-related risk, through the various committees described on [page 60](#). They are informed about and monitor emerging risks over the short, medium and longer term via emerging risk papers produced by our SVP treasury. Members of the leadership team receive information on the longer-term risks and opportunities associated with the energy transition via updates produced by our chief economist. These papers are shared with the board.

SVP level and beyond

The bp leadership team is supported by bp's senior-level leadership and their respective teams, with dedicated business and functional expertise focused on climate-related risks and opportunities or on matters which may be affected by such risks and opportunities. This includes: health, safety, environment and carbon; risk; and strategy and sustainability (which includes our carbon ambition, policy and economics teams). Alignment between group, business and functional leaders is fostered through other meetings, such as the TCFD working group which leads the preparation of bp's climate-related financial disclosures.

Management consideration of climate-related risks and opportunities is organized as follows:

Resource commitment meeting	Forum for approval of investments related to existing and new lines of business above \$250 million or \$25 million for acquisitions, or which exceed the relevant EVP financial authority, and any project considered strategically important such as a new market entry, see page 21 .
Group operational risk committee	Provides oversight of safety and operational risk management performance for the group, where appropriate. Climate-related factors may affect certain sources of safety and operational risk, such as severe weather events.
Group operational risk committee (sustainability)	<p>In October 2025 our executive-level group sustainability committee (GSC), was replaced by the group operational risk committee (sustainability) (GORC(S)). This executive-level committee, chaired by the chief financial officer, provides oversight, challenge and support in the implementation of our sustainability frame and aims, and oversight of the management of potentially significant sustainability risks and opportunities, including those related to climate change.</p> <p>Between the GSC and GORC(S) there were four scheduled meetings in 2025 with ad hoc discussions held as needed. In both committees, members considered bp's sustainability aims, progress against targets and bp's position on certain strategic sustainability issues.</p> <p>The outputs from the committee are shared with the board and its committees, including the safety and sustainability committee, as appropriate.</p>
Group financial risk committee	Monitors the effectiveness of bp's financial reporting, systems of internal control and financial risk management, namely material group financial risks. Where appropriate, it considers the planned approach to assurance and verification of non-financial reporting ahead of updating the audit committee.

Acquired businesses

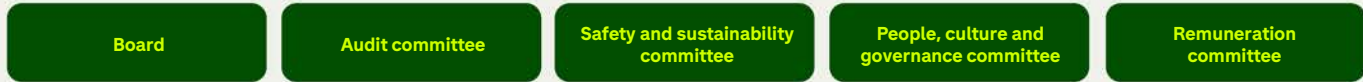
Integration plans are developed to transition acquired businesses into bp's system of internal control, over an appropriate timeframe.

Climate-related financial disclosures continued

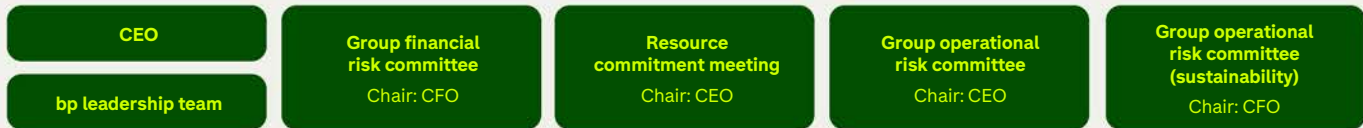
Climate governance: management of climate-related matters

As at 1 January 2026

bp board level



EVP level



SVP level



Cross-bp forums and meetings



Risk Management

TCFD Recommendation:

Disclose how the organization identifies, assesses and manages climate-related risks.

Recommended Disclosure:

a. Describe the organization's processes for identifying and assessing climate-related risks.

bp's risk management system and policy, described on [page 60](#), are designed to address all types of risks including our principal risks and uncertainties, described on [page 62](#).

As part of this system, our businesses and functions are responsible for identifying, assessing, managing and monitoring risks associated with their business or functional area.

The process for identifying risks is outlined on [page 61](#) and guidance to support consistency has been made available to our businesses to provide them with a climate-related taxonomy, which they are able to use as they see fit in their identification and assessment of risk.

Where risks – including climate-related risks – are identified, businesses and functions are required to assess them, in line with our risk management policy. This includes an impact and likelihood assessment which supports the consideration of relative significance and prioritization of risk management activities.

The impact criteria outlined on [page 63](#) include health and safety, environmental, financial and non-financial (such as regulatory impact) criteria and are used for assessing risks, including climate-related risks. This provides a consistent basis for assessment across bp.

For the purposes of our TCFD disclosures, we use the TCFD's distinction between 'physical' and 'transition' climate-related risks.

Identification, assessment and management of climate-related opportunities^a

As set out in our TCFD Strategy a and b disclosures on [page 46](#), we have identified potentially material climate-related opportunities and our strategy has been informed by these. We identify climate-related opportunities by considering a range of information sources, including the bp Energy Outlook, which helps to inform our thinking about how the energy system might evolve. Business opportunities continue to be originated across bp, and taken forward through bp's investment governance framework. For example, our gas & low carbon energy and customers & products businesses support the delivery of low carbon and transition opportunities through organic and inorganic growth.

Our investment governance framework (see [page 21](#)) provides the mechanism by which alignment of these opportunities with our strategy is assessed and decisions on which to progress are made.

a Information added to satisfy the UK CFD Regulations.

Recommended Disclosure:

b. Describe the organization's processes for managing climate-related risks.

c. Describe how processes for identifying, assessing and managing climate-related risks are integrated into the organization's overall Risk Management.

Risk Management process

Risks which may be identified include potential effects on operations at asset level, performance at business level and developments at regional level from extreme weather or the transition to a lower carbon economy.

As part of our annual process the bp leadership team and board review the group's principal risks and uncertainties. Climate change and the transition to a lower carbon economy continues to be identified as a principal risk, see [page 64](#). It covers various aspects of how risks associated with the energy transition could manifest. Physical risks such as extreme weather, which may be affected or intensified by climate change, are covered in our principal risks related to safety and operations.

Physical risk

Physical risks are typically identified at the asset or project level and managed depending on the level of risk assessed.

In the North Sea and Gulf of America, regions more prone to severe weather conditions, our offshore facilities monitor meteorological and oceanographic conditions through the collection of measurements. This data is collated and periodically compared against the 'Basis of Design' for the facility. If significant differences are observed, then this may trigger an update to the 'Basis of Design', prompting action to reassess risks such as structural integrity and station-keeping and if necessary, implement additional risk mitigations, for example updating procedures for shutting down and removing personnel from facilities ahead of severe weather events. Updates may also be made as a result of other new knowledge, analysis methods and data, including climate projections where appropriate.

Our major projects★ are required to assess the potential impact of severe weather and projected climate-related physical impacts. Where relevant, potential changes in environmental conditions, such as sea level rise and ambient temperatures, over the expected lifetime of a project are to be considered as part of the design process.

Building on a modelling exercise conducted in 2022, a screening approach to support identification of potential severe weather and physical climate-related hazards at operational sites across bp has been rolled out since 2024 as part of our operational management system. Since 2024 screening has been conducted for a number of sites each year.

Where potential hazards are identified, and as appropriate, this enables further work to be carried out to assess potential risks and implement appropriate management measures.

For other assets, such as our retail sites★, that are typically not exposed to a comparable level of severe weather risk, climate-related risks such as flooding or wind damage may be managed where appropriate through the emergency response plans and business continuity plans which are mandated through bp-wide policies.

Additionally, at a group level we recognize risk associated with the potential for increased water stress due to climate change and other factors and the impact this could have on our operations and in the catchments where we operate. In order to understand the water-related challenges that we face, we review our water impacts, risks and opportunities at our major operating sites. These reviews consider the quantity and quality of water used as well as any regulatory requirements. We anticipate adopting site-level activities as part of our aim to reduce our net freshwater use in stressed catchments where we operate. We anticipate adopting a focused freshwater management approach, addressing water-related business risk where it is greatest, and we anticipate that our freshwater withdrawal in stressed catchments will be covered by freshwater management plans by 2028. For more about water, see [page 59](#).

Transition risk

The board appraises bp's strategy and monitors bp's management and operations to obtain assurance over the delivery of its strategy. This approach enables the effective management of climate-related transition risks and opportunities facing bp associated with the energy transition. For the purposes of our TCFD disclosures, we group transition risks identified by our businesses and functions into the three broad material climate-related transition risks to bp, see [page 52](#). However, we continue to assess and manage the component parts of those broad transition risks, including:

Policy and legal risks

Our strategy and sustainability team leads the definition of policy positions in line with bp's strategy and bp's sustainability aims. They work with our regional organizations as well as corporate entities to discuss regional and global policy trends and support external positioning and interactions relating to policy and advocacy topics.

Our group operational risk committee (sustainability) provides oversight of sustainability matters and our issues and advocacy meeting covers emerging advocacy issues.

Our legal team manages bp's litigation, including climate-related litigation, and advises on the management of associated risks. This includes the use of internal lawyers and, where appropriate, external counsel.

Market risks

In developing our business strategies, we consider market risks, controls and mitigations, including future demand in the different geographies in which we might operate, the competitive landscape and the potential value proposition. We manage these risks through our investment decisions, our hedging and optimization activity, and through key business processes, including the group investment assurance and approval process.

Reputational risks

Our investor relations, communications and external affairs teams work to mitigate reputation-related risks, which include the risk of shareholder action. Our investor relations team co-ordinates engagement with key investors on both a bilateral basis and through investor initiatives to support understanding of bp's strategy and gain insights to inform feedback they provide to the group.

Our communications and external affairs teams help to manage corporate reputation through identification and monitoring of key issues and both proactive and reactive engagement with relevant stakeholder groups. The teams also advocate for policies that support our strategy and sustainability aims, see [page 38](#).

Technology risks

Our technology team works to both mitigate risks and identify opportunities associated with evolving and emerging technologies that play a role in the changing global energy system. The team generates technology reports for review by bp senior leaders and the recommendations are overseen by the relevant leadership teams, through the Innovation Advisory Council. In appropriate cases this helps to underpin and appraise the business case for new investments, new partnerships and new technology tools/methods where these are being driven by technology innovation.

Climate-related financial disclosures continued

Strategy

TCFD Recommendation:

Disclose the actual and potential impacts of climate-related risks and opportunities on the organization's business, strategy and financial planning where such information is material.

Recommended Disclosure:

a. Describe the climate-related risk and opportunities that the organization has identified over the short, medium, and long term.

In setting and monitoring delivery of bp's strategy, the board and leadership team consider climate-related risks and opportunities across the:

- **Short term** (to 2026): aligning with our near-term business and financial planning timeframe.
- **Medium term** (to 2030): aligning with our group business outlook timeframe, and enabling us to think beyond our short-term targets and adjust course if appropriate.
- **Long term** (to 2050): using scenarios to help explore the wide range of uncertainties surrounding the energy transition over the next 25 years. For more detail on our approach, see [page 7](#).

TCFD categorizes climate-related transition risk and opportunity as follows: policy and legal, market, reputation and technology. It also refers to climate-related acute and chronic physical risks and opportunities. Risks in each of these categories have been identified using a risk management process that our businesses and functions are required to follow. For more about how the relative significance of identified risks is evaluated, see Risk Management on [page 44](#).

The risks and opportunities identified have been considered in relation to bp's reset strategy, as announced in February 2025.

Climate-related transition risks and opportunities

At a group level, we have identified three broad, material climate-related transition risks, outlined on [page 52](#), underpinned by underlying risks that are assessed and managed through the risk process outlined.

These transition risks may cut across our short-, medium- and long-term time horizons; however, we indicate below wherever there is a particular time horizon in which the risk has been considered. The transition risks are also global in nature, so we do not discuss specific geographies here, but the underlying risks refer to specific geographies where appropriate^a. We also see significant potential for upside – or opportunity – associated with some of these risks. These are discussed under each risk on [page 52](#) and in relation to Recommended Disclosure (b) we also describe the potential impacts of both the risks and opportunities to bp.

Climate-related physical risks

The physical risks identified primarily relate to severe weather and often represent potential for increased drivers for safety and operational risks to our operations, particularly process safety, personal safety, and environmental risks, see Risk factors [page 62](#). In addition, we have identified the potential for changes in the availability of freshwater, including as a result of climate change, as a risk to some of our operations. Higher instances of extreme weather also have the potential to impact supply chains and critical infrastructure, such as air and sea ports, as well as our customers.

We recognize that we could also face other forms of physical climate-related risk over the longer term, for example associated with changes in sea level, extreme temperatures and flooding, which could impact our operations. As these risks are primarily operational, and location-specific, they are not grouped in the same way as transition risks.

Like other businesses around the world, in the longer term we could face adverse market or value chain conditions associated with large-scale cumulative impacts of physical climate change if global mitigation and adaptation efforts are insufficient or unsuccessful.

Offshore facilities

In the case of our offshore facilities, climate change could create greater uncertainty around frequency and/or intensity of severe weather events, such as extreme waves, loop currents, and storms, particularly in the medium to long term. These factors could affect the future risk profile of an asset over its lifetime, and could also impact production or costs.

Water resources

Water resources are increasingly under pressure from various factors, including climate change, and this poses a potential risk to some of our operations that depend on the availability of freshwater. Based on analysis using the World Resources Institute (WRI) Aqueduct Global Water Risk Atlas, and in certain cases review of site-specific local data sources, six of our 16 major operating sites in 2025 were located in regions with high to extremely high water stress. Using WRI data, we have identified the potential for this risk to increase in the medium term. For more on water consumption, see [page 59](#).

We do not currently foresee any material opportunities arising from changes in the physical environment as a result of climate change. However, the actions we are taking to make our operations more resilient, for example through improving efficiency of our freshwater use, may also bring about benefits such as reduced costs.

Recommended Disclosure:

b. Describe the impact of climate-related risks and opportunities on the organization's businesses, strategy, and financial planning.

bp's plans for the energy transition

In this section we talk about some of our plans for the transition across bp's business areas and where we do so we have identified these with [TP](#)^b. We describe below how we believe our strategy and net zero ambition are both good for business and support society's drive towards the Paris goals.

Throughout the strategic report we set out bp's strategy and plans for the energy transition. This includes our progress against 2025 performance, see [page 21](#).

Our progress against our net zero aims are described on [pages 37-38](#).

TP

Our strategy, business and financial plans are informed by a range of inputs including the climate-related risks and opportunities associated with the energy transition outlined above. We describe how we use scenarios to inform our strategy on [page 7](#).

a Underlying risks are specific, for example, local or business-specific risks identified by specific bp entities through the risk processes described above under Risk Management.
b This is not intended to be an exhaustive list of our plans for the transition, but rather illustrative of some of the core elements of our plans.

Climate-related transition risks and opportunities

1

The value of our hydrocarbon business could be impacted by climate change and the energy transition.

Changes in policy, legislation, consumer preferences or markets as a result of growing concerns about climate change and the energy transition could reduce demand for fossil fuels or lower their price relative to our financial planning assumptions, particularly in the medium to long term, negatively impacting returns from or the value of our hydrocarbon businesses. Changes in regulations, including carbon pricing and fossil fuel policies, could also impact compliance and operating costs in our oil and natural gas production and refining businesses.

Alternatively, prices (such as Brent oil and Henry Hub natural gas) during the next decade could be higher than our financial planning assumptions under certain transition pathways, including those aligned with the Paris Agreement. This could strengthen returns from our hydrocarbon businesses (including securing higher proceeds from assets we choose to divest) which may enable us to deliver enhanced shareholder value, further strengthen our balance sheet and grow investment in the transition, in line with our financial frame.

2

Our ability to grow or deliver expected returns from our transition businesses* could be impacted by the energy transition.

Several factors could restrict the growth of our transition businesses* or returns from them. These factors include: lack of, or insufficient development and application of, policies, regulations and frameworks that support low carbon businesses; insufficient consumer demand for our low carbon offering; strong competition in the market; or the insufficiently rapid development of supporting technologies and infrastructure or constraints on supply chains for low carbon energies. This could particularly impact bp in the short to medium term as new markets and technologies develop but could also represent a longer-term risk.

Alternatively, demand, policy support or enabling technology and supply chain growth for renewables could support a more rapid portfolio shift with expansion of our low carbon businesses and higher returns from them.

Some low carbon businesses, including renewable power, bioenergy and emerging technologies such as hydrogen and carbon capture and storage (CCS), rely on policy support to promote growth. We support well-designed, robust public policy that enables this.

Changes in customer preferences, pace of technology and infrastructure development and deployment and costs could impact the markets for low carbon products and services. For example, the pace of adoption of electric vehicles (EV) could impact utilization rates, and consequently returns, from our EV charging networks.

We recognize that the pace of our transition relative to our core low carbon target sectors and regions is important. If we move more slowly than those markets, we may miss investment opportunities and customers may prefer different suppliers with potential negative consequences to demand for our products and to our reputation. If we move faster than these markets, we risk investing in technologies or low carbon products that are unsuccessful because there is insufficient demand for them. However, our investment may also help to stimulate demand and provide us with a leading position in growth markets.

3

Our ability to implement our strategy could be impacted by changing stakeholder attitudes towards the energy sector, climate change and the energy transition.

Negative perceptions of the energy sector, or bp, could have a number of consequences, for example: adverse litigation; reputational impacts, including our ability to attract and retain talent; and shareholder action. These consequences could affect us in the short, medium or long term.

Alternatively, increased support from our stakeholders could enable access to additional capital and new investors, strengthening our ability to deliver our strategy and enabling faster growth of our low carbon businesses.

The world is in an 'energy addition' phase of the energy transition in which it is consuming increasing amounts of both low carbon energy and fossil fuels. The *bp Energy Outlook 2025* highlights that, although the structure of energy demand will likely change over the long term, with the importance of fossil fuels declining, replaced by a growing share of low carbon energy, led by wind and solar power, oil and natural gas continue to play a significant role in the global energy system for at least the next 10-15 years. This requires continuing investment in upstream oil and natural gas.

The insights from the *bp Energy Outlook 2025* support our view that investment into oil and gas will be needed for decades to come and also that, while the pace and shape of the transition in the long run is uncertain, we continue to see the energy transition as a significant opportunity to grow value.

Perceived inconsistencies between the pace of bp's transition and societal expectations could have reputational and commercial impacts that might impair our ability to deliver our strategy. However, we also see potential to positively differentiate bp, by delivering against our strategy, net zero ambition and sustainability aims.

Climate-related financial disclosures continued

Oil and gas

In February 2025 we announced an increase in upstream investment versus our prior guidance. This additional investment allows us to strengthen the portfolio, for example we are building our US portfolio to around 1 million boe/d by 2030, increasing production in our US onshore business and developing our Gulf of America Paleogene resource. In the Middle East we are now partnered in the redevelopment of several giant oilfields in Kirkuk, [page 31](#), alongside our existing position in Rumaila, Iraq. These examples, alongside other investment in our existing portfolio, additional access and exploration underpin expected growth in underlying production to 2.3-2.5mboe/d in 2030, excluding future potential divestments.

We recognize that the transition presents uncertainty for our upstream business, including the possibility of lower oil and gas prices. In recent years we have maintained top quartile unit production cost at around \$6 per barrel, made strong progress on operational reliability and commerciality across our portfolio, and we retain optionality to divest lower margin barrels. We intend to maintain the disciplined application of our balanced investment criteria, which include the consideration of applicable economic hurdle rates and operational emissions intensity levels, from a portfolio across oil and gas. Read more about our investment process on [page 20](#).

As an outcome of our strategy and informed by our current outlook, and its underlying assumptions, which may change over time, we are aiming for the Scope 1 and 2 emissions from our operations – the majority of which are associated with the operating assets in our hydrocarbons portfolio (refining and upstream oil and gas combined) – to be 45-50% lower at the end of 2030 than in 2019 and we plan to maintain ‘near zero’ methane intensity★ across our operated producing assets, see [pages 37-38](#).

TP Customers and products

As announced in February 2025, we are focusing the downstream – our customers & products business – reshaping the portfolio to focus on markets and businesses where we have advantaged and integrated positions.

We recognize the risk of a decline in demand for conventional vehicle fuels and products due to the energy transition and are working to increase the efficiency and resilience of our existing fuels and lubricants businesses through operating cost reductions and margin optimization. In December 2025, we announced an agreement to divest a 65% shareholding in *Castrol*, strengthening our balance sheet while retaining exposure to future growth and optionality. We are also increasing the resilience of our existing fuels

network and high-grading our regional footprint. Since 2020 we have exited our Switzerland, Turkey and Netherlands mobility and convenience businesses, and in the past year have announced our exit from our mobility businesses in Austria. We are reallocating capital into our most advantaged positions such as major transit routes in key markets where we see sustained demand for fuels and EV growth, e.g. EV charging investments on our sites near the German Autobahn road network.

Our integrated mobility model across fuels (hydrocarbons and biofuels), convenience and EV charging provides resilience to the pace of transition by allowing us to flex our offer to meet customer demand.

In aviation, we will make selected high-return investments to build our footprint; and see strong growth potential in sustainable aviation fuel through the transition.

Our biofuels business is already playing a key role in building resilience to the energy transition – helping to decarbonize the mobility value chain using existing infrastructure. In Q4 2024 we took full ownership of bp bioenergy in Brazil, accessing around 50kb/d of production and see potential for future growth with support from policy and market conditions. Our feedstock positions also provide opportunity to additional resilience to anticipated supply shortages in the transition. In Q1 2026 we launched Etlas, a joint venture with Corteva, continuing our momentum in feedstocks with the aim to produce one million metric tonnes of feedstock per year by the mid-2030s (see [page 35](#)).

At our refineries, the energy transition could impact demand for certain products in the future and raise costs. We expect the impacts to be region- and asset-specific and are difficult to fully anticipate. Consequently, we are continuing to drive greater competitiveness and value from our refineries, aiming for 96% or above Solomon refining availability. We are also repositioning our refining portfolio and building resilience through value chain integration, co-production of biofuels alongside traditional products and selective decarbonization initiatives.

TP Low carbon energy

Ongoing volatility and uncertainty continues to impact low carbon energy businesses globally, underlining the need to be aligned with and flexible to market and policy development. As announced in February 2025, we are changing our model for low carbon – delivering with partners and with external financing that will be capital-light for bp and help improve our equity returns.

In offshore wind, we established the JERA Nex bp joint venture in Q3 2025. Recognizing the exposure to transition volatility seen in recent

years, JERA Nex bp plans to focus on highly disciplined, capital efficient growth, with bp retaining an option to our equity share of power offtake.

In solar, Lightsource bp continues to be a leading global onshore renewable developer in markets with attractive sector returns.

In our hydrogen and CCS businesses, we are prioritizing fewer, higher value projects in the near term while building capability and future optionality to scale and grow as the market develops. By focusing on projects in jurisdictions where we have an adequate regulatory framework, access to the value chain including our own or customer demand and leveraging access to advantaged carbon capture and renewable power, we aim, over time, to decarbonize our operations and help our customers decarbonize. We sanctioned four projects, for example, Lingen, Germany in 2024 which is in line with our focus on decarbonizing bp operations.

Through Archaea Energy, we believe we are uniquely positioned in the US to meet growing demand for renewable natural gas★ as the transition progresses. We are building resilience by improving capital efficiency and reducing operating costs and continue to assess and develop new routes to market and customer solutions to create future optionality.

TP Supply, trading & shipping (ST&S)

Our ST&S business provides risk management, flow and optimization services for our bp equity and assets and third-party customers, with a proven track record of resilience to commodity cycles and the ability to capture upside when market conditions present opportunities.

The diversification of our traditional oil business helps mitigate the risk of falling demand in the US and Europe by providing access to growing demand centres such as Latin America and Sub-Saharan Africa and in growth markets such as petrochemicals, biofuels and adjacent agricultural commodities.

Our gas and power business spans regional and global markets. Our LNG portfolio offers exposure to a lower carbon growth market combined with flexibility through our advantaged key global positions. Additionally, with the acquisition of BP Energy Retail in the US and GETEC in Europe, ST&S is building resilience by participating further down the value chain towards end consumers. Our power trading business allows us to optimize across the value chain from generation to wholesale markets to customers. This helps position us for further electrification of the energy system as well as further decarbonization of electricity.

Impact on technology

We are investing in digital and technology solutions that can help to generate value for bp, manage risk and help accelerate the transition through focused scale-up and innovation. This investment includes targeted focus on research and development where bp is and can be differentiated and growing partnerships to increase leverage. We expect our research and development spend to be increasingly focused on technologies with the potential to help identify and access new oil and gas opportunities at lower cost, reduce GHG emissions and enable our transition businesses★. See [page 9](#) for examples of technology investments in 2025.

We recognize the potential for disruptive technologies to impact our strategy. Alongside our research and development investments, our bp ventures portfolio also includes investments in emerging technologies and business models that can help support our businesses and deliver our strategy.

Physical risk

The potential impacts of the types of physical risks we have identified could include reduced production, throughput or sales – for example as a result of damage to facilities or supply chain disruption – or in a most extreme case loss of life or an asset. Due to uncertainties associated with the impact of climate change on severe weather events in the future, it is difficult to quantify the potential impacts associated with any increase in these risks as a result of climate change.

Having considered both geographic factors and the ability of climate models to adequately represent future trends in physical climate parameters, we seek to take the uncertainties concerning climate-related physical risk into account in our approach to design and operating criteria for existing assets and new major projects★. Where appropriate, we have updated our metocean design criteria to include consideration of both forward-looking and historical models, including climate and synthetic models, in an attempt to mitigate both models and extrapolation uncertainty. The particular models chosen will depend in part on geographic location. See Risk Management, [page 44](#), for how we manage these uncertainties.

As a step in seeking to improve the resilience of our operations to the physical changes that might result from climate change that we have described above, we have continued to undertake screening of present-day and future potential physical risk exposure for selected key assets and identified those sites with potential for heightened exposure to physical risks in order to prioritize these for further site-based assessment.

Recognizing the potential impact of climate change and other factors on water resources, as part of our water aim, we are taking steps to be more efficient in operational freshwater use (read more about water use on [page 59](#)).

Impacts on our financial planning

Capital allocation: We plan to invest sufficient capital to execute our strategy, enabling us to mitigate the risks and capture the opportunities we have identified. As part of our annual planning processes, we assess the distribution of capital across our business areas, including consideration of market evolution. In February 2026 we announced that we expect capital expenditure★ to be \$13.0-13.5 billion in 2026. To help maintain resilience to the pace of transition and access opportunities, we will continue to flex capital as policies, technologies and markets evolve.

Access to capital: While there is potential for concerns about the energy transition to impact banks' or debt investors' appetite to finance hydrocarbon activity, we do not anticipate any material change to funding in the short to medium term. We are committed to strengthening the balance sheet and continue to target improving credit metrics within an 'A' grade credit range. We reiterate our primary target for net debt of \$14-18 billion by the end of 2027. Net debt decreased from \$23.0 billion to \$22.2 billion during 2025.

Since the end of 2019 we have repurchased around \$26 billion of short-dated existing bonds and issued over \$12 billion of new bonds with a duration of 20 years or longer, doubling the duration of our debt book.

We provide further information on financial frame elements related to capital expenditure, balance sheet management and buybacks on [page 18](#).

We provide more detail on financial risk factors, including liquidity risk in Financial statements – [Note 29](#).

Investment criteria: Investments are evaluated against a balanced set of six investment criteria, including sustainability (see [page 22](#)). The assessment of economics includes a set of price assumptions that reflect our view of market evolution (for our key investment appraisal price assumptions, see [page 20](#)). In addition, the investment economics for all investment cases where bp's share of annual greenhouse gas (GHG) emissions from operations are anticipated to exceed specific thresholds include a carbon price for those emissions, which rises from \$67/tCO₂e in 2026 to \$135/tCO₂e (2024 \$ real) in 2030.

Impacts on financial performance and position

Assessing the impact of climate change and the energy transition requires the use of a number of judgements and estimates.

We have set out the significant accounting policies, judgements and estimates used in assessing the impact of climate change in Financial statements – [Note 1](#).

This includes information on pricing, useful economic lives, timing of implementation of policies or decommissioning provisions, and assumptions related to how each might change over time and how such assumptions may impact our currently reported assets and liabilities.

Our price assumptions, including those set out on [page 20](#), reflect a range of future possible scenarios and take account of the potential impact of climate-related risks and opportunities as well as current economic and geopolitical factors. Consequently, impairment losses and impairment reversals consider inputs that arise from climate change and the energy transition. It is not possible to quantify separately the impact of these different inputs on our impairments. However, in conducting our impairment sensitivity tests, that in part reflect transition downside risk, we consider reductions in revenue that, if driven by price alone, would be consistent with prices within the range covered by the 1.5°C scenario family within the Transition Scenario Catalogue★ data sets used for TCFD resilience testing below.

Financial statements – [Note 1](#) provides information on impairment assumptions and sensitivities. [Note 4](#) provides information on gains and losses on disposal or closure of business and operations, and impairments and impairment reversals, and [Note 8](#) provides information on impairment losses relating to exploration for and evaluation of oil and natural gas resources. See Financial statements – [Note 1](#), [Note 4](#) and [Note 8](#) for more information.

Recommended Disclosure:

c. Describe the resilience of the organization's strategy, taking into consideration different climate-related scenarios, including a 2°C or lower scenario.

We believe our strategy positions bp for success and resilience in a Paris-consistent world – a world that is progressing on one of the many global trajectories considered to be Paris-consistent, and ultimately meets the Paris goals, see [pages 10-11](#).

As in 2024, to help test our view of this, we have assessed the resilience of our strategy to different climate-related scenarios, including 1.5°C consistent scenarios.

Climate-related financial disclosures continued

We did this in three steps:

1. First, we evaluated all business areas in our portfolio by i) quantitatively assessing their financial significance, in the context of bp's total financial outlook, to understand the potential scale of financial/strategic impact that could be put at risk if exposed to transition uncertainty, including 1.5°C; and ii) considering whether there is a key variable – such as price or demand – which would represent a transition driver of such risk.
2. Second, we quantitatively assessed the impact, to each business area, of potential transition exposure scenarios in 2030 – the point in our planning horizon at which there is widest transition uncertainty.
 - For each of those business areas with both sufficient scale and for which a specific transition risk driver was identified – which collectively represent over 70% of our 2030 adjusted EBITDA★ outlook – we performed a scenario analysis focused on that transition risk driver, across a range of transition pathways^a, including 1.5°C, as set out below and in our methodology summary on [page 52](#).
 - For each of the remaining business areas we performed a simplified quantitative scenario analysis, by testing the financial impact of a scenario in which each business area's expected 2030 adjusted EBITDA is assumed to be reduced to zero – an outcome at least as detrimental to that business area's adjusted EBITDA as could reasonably be expected to result from business-as-usual (BAU), well-below-2°C and 1.5°C transition pathways.
 - In this way, all business areas were quantitatively tested to downside impacts at, or beyond, a range of transition scenarios.
3. Finally, on the basis of the results of steps 1 and 2, we identified those business areas for which the possible consequences of the downside scenario(s) were sufficiently significant to potentially jeopardize group strategic resilience – as in prior years, the only business areas for which this was found to be the case were oil and gas production with respect to their exposure to oil price. For these business areas we assessed the potential implications for bp's strategic resilience (as defined below) over the period from 2027 to 2030.

To undertake steps 2 and 3, we identified financial criteria which can be modelled as proxies for strategic resilience – choosing to

do this through three lenses consistent with our financial frame (as set out on [page 18](#)), being our ability to deliver:

- i. a resilient dividend;
- ii. a stronger balance sheet that continues to target improving our credit metrics within the 'A' grade range; and
- iii. disciplined investment allocation.

This is not intended to represent a 'definition' of resilience beyond the purposes of this exercise, and a core assumption of this analysis is necessarily that, aside from any implications of the scenarios being tested, including potential mitigations (such as capital or cost management) that we might naturally expect to take in response, bp will deliver the assumed underlying strategic and financial priorities out to 2030.

To undertake the modelling in steps 2 and 3, we used a suite of external scenarios from various providers (for example, IEA's World Energy Outlook (WEO 2024) Net Zero Emissions by 2050 (NZE) scenario.

This suite of scenarios took as its start point the latest WBCSD (World Business Council for Sustainable Development) Scenario Catalogue (V3, published in May 2024), which we then updated for relevant metrics where underlying source data providers (IEA, NGFS, UN PRI IPR) have published more recent (or withdrawn older) transition scenarios. We refer to this as our Transition Scenario Catalogue★, with more detail on its preparation provided on [page 53](#).

When considering the long term (post-2030 to 2050), attention is drawn to the sensitivity analysis conducted as part of our value-in-use impairment testing for oil and gas assets, outlined in Financial statements – [Note 1](#). While not intended to extend the strategic resilience test as outlined above to the long term, it provides an indication of how we monitor potential longer-term financial impact to revenue downside which, if resultant from reductions in price in isolation, may be associated with prices towards the bottom of the range of trajectories in the Transition Scenario Catalogue.

Our approach, described in more detail on [page 52](#), is directly applicable to transition risks #1 and #2 – as well as their associated opportunities – as these lend themselves to a financially quantified scenario-based analysis. The approach does not directly address transition risk #3 – however, we believe that some of the potential drivers for transition risk #3, namely policy and societal trends, may be implicit in these scenarios, and we believe that the successful execution of our strategy will,

over time, help to mitigate this risk to bp as well as positioning us to take advantage of the potential associated opportunities. This scenario analysis exercise also does not directly address climate-related physical risk, our strategic resilience to which is further discussed below.

Key insights from our scenario analysis and resilience test

While the results of any such analysis must be treated with caution (being necessarily dependent on numerous assumptions and methodological choices, and having its own limitations) overall this analysis and resilience test reinforced our confidence in the continued resilience of our strategy to a wide range of transition scenarios, including those consistent with limiting temperature rise to 1.5°C.

In summary, the modelling indicated once again that oil prices consistent with a 1.5°C transition scenario remain our greatest transition exposure to 2030, but that nonetheless bp remains resilient to the lowest oil price scenarios tested.

In undertaking this analysis we observed:

- There is considerable uncertainty across, and often within, each Transition Scenario Catalogue family in the pace and nature of the transition to 2030 – and therefore considerable range of potential financial impact across some of the variables selected for the analysis, reflecting the complexity and interdependencies of the energy transition (see table on [page 53](#)). Generally, we observed that the faster the pace of transition, the greater the uncertainty in the exact shape of the resulting energy system in 2030.
- Oil price^b is likely to remain the main source of climate-related transition uncertainty for our strategy through to 2030, reflecting both the wide range of potential pathways and the expected contribution to our total adjusted EBITDA★ over this period, that oil-price-linked businesses represent^c.
- In the 1.5°C family, the potential downside in 2030 suggested by the lowest oil prices in the Catalogue (the IEA WEO 2024 Net Zero Emissions by 2050 (NZE) scenario) is around 23% of group adjusted EBITDA in 2030. Scenarios from other scenario families and providers (e.g. NGFS) indicated higher prices in this time period.

a Although such scenarios do not and cannot represent all possible futures, we value them as a simplified and schematic way to consider the potential implications of, and uncertainty inherent within, a range of possible energy transition pathways to a future bp portfolio mix.

b Our multi-year (2027-30) oil price resilience test considered 2030 low oil prices consistent with the most extreme scenario in the Transition Scenario Catalogue – the IEA WEO 2024 Net Zero Emissions by 2050 (NZE) scenario at \$42/bbl (2023 \$ real – inflated in line with bp's other planning assumptions). Intervening years are interpolated from 2025 average actual Brent oil price.

c Note that for the purposes of our scenario analysis and resilience test, we have assessed the impact of oil price across both our oil production businesses and those natural gas businesses for which commercial outcomes are linked to oil price.

- Even with the most extreme 1.5°C-consistent low oil price environment in any of the scenarios, over the period from 2027-30, taking into account our ability to optimize within the frames set out in our strategy, and the mitigations that we would naturally be expected to make in a lower oil-price world, in our analysis we are able to deliver across the three lenses we use to consider strategic resilience for TCFD purposes, described above.
- Furthermore, in several of the source scenarios within the Transition Scenario Catalogue tested, including those consistent with 1.5°C, well-below 2°C and BAU families, oil price could potentially offer a financial upside relative to our reference 2030 group business outlook.
- The maximum potential scale of downside impact on our 2030 group adjusted EBITDA (across the 1.5°C, well-below 2°C and BAU scenarios) from our other natural gas and our refining businesses was modelled to be around 5%, while from each of our fuels and low carbon energy business areas was <3%.
- It is reasonable to consider each potential outcome in isolation since the outcomes for different business areas vary across scenarios (see table on [page 53](#)). Our diversified portfolio helps mitigate the implications for our strategic resilience of the exposure of any individual business area to the identified risk.
- In a BAU scenario, we believe our strategy mitigates the risk of what we and others have referred to as a 'delayed and disorderly' transition, which might follow in the medium to long term. Should the earnings of any one of our in-scope transition business areas be challenged in the modelled timeframe, our analysis suggests that the impact of this on group adjusted EBITDA in 2030 would not be sufficient to impact the resilience of our strategy, as described above.
- When considering the long term, the outcome of impairment sensitivity analysis is detailed in the Financial statements – **Note 1**, which indicates the magnitude of the reduction in the carrying amount of bp's currently held upstream oil and gas properties.

It is important to note that insights from this analysis are necessarily limited by the scenarios, methodologies and business assumptions used. The analysis should not be taken as a prediction of the future.

Maintaining strategic resilience to the transition

Taking into consideration potential constraints associated with factors such as long-term capital investment, contractual commitments and organizational capabilities at any given time, bp's ability to maintain strategic resilience rests, in part, on the governance used to keep the strategy under review in light of new information and changing circumstances.

To enable us to understand and respond to the changing pace of the energy transition, we monitor and assess key indicators and metrics, such as policy development, renewables installed capacity, EV sales and low carbon technology costs.

Our strategy and capital allocation, the associated risks, opportunities and (by association) their implications for our resilience are all reviewed by the bp leadership team and the board and updated as they consider appropriate.

Resilience to physical risk

As described on [page 49](#), we have identified a number of physical risks which may affect our business and assets, the frequency or severity of which could be affected by climate change. Exposure to physical climate-related risk is highly dependent on geographical location and on factors such as asset design, and we seek to manage these risks accordingly. We consider that our approach to managing these risks, described in Risk Management Recommended Disclosure b) on [page 46](#), supports our strategic resilience to them.

For the purposes of this Recommended Disclosure, we have considered the potential for physical risks to bp-operated assets to increase as a result of climate change (namely, increases in the potential frequency or intensity of extreme weather events) to such an extent as to have the potential to impact the resilience of our strategy. We have undertaken analysis of potential changes in certain physical conditions, such as air temperature, precipitation, sea level rise and wave heights, for our onshore and offshore major operating sites, based on Shared Socioeconomic Pathway^a (SSP) emission scenarios 1-2.6, 2-4.5 and 5-8.5.

Even in the highest emissions pathway (SSP5-8.5) the results of our analysis suggest that, on the basis of the 50th percentile values and compared to the baseline used (1991-2020), changes in the physical parameters considered are generally unlikely to be significant over the medium term.

There is, however, uncertainty across different scenarios and wider variances were observed when looking at the 5th and 95th percentile values. Where the data does suggest greater potential for climate-related changes in physical conditions, we intend to consider whether further work is necessary to understand the potential for those changes to adversely impact our operations. For example, modelled changes in extreme precipitation by 2030 (50th percentile values) are less than 10% across all onshore major operating sites apart from Oman – where we have already undertaken hydrological studies and flood risk assessments that have supported the development of our operations there.

Our transition risk scenario analysis identified impacts on the earnings of our oil-priced businesses as having the most potential to impact the resilience of our strategy in 2030. Therefore, and viewing resilience through the same lenses that we describe above, we have considered the extent to which our oil and gas production business would need to be impacted by evolving physical risk over the same timeframe for the scale of financial impact to be sufficient to jeopardize the resilience of our strategy out to 2030.

We concluded that a significant proportion of our oil and gas assets would need to be permanently or temporarily shut in for resilience to be jeopardized in this way.

Historically, severe weather risks to our operated assets have not occurred at a scale which could reduce earnings so significantly as to jeopardize the resilience of our strategy. As reflected in the latest science from the IPCC, it is in the nature of climate-induced severe weather events that their occurrence, intensity and severity are unpredictable and uncertain. Our own analysis on major operating sites, described above, is consistent with this IPCC view.

Despite this uncertainty, we have found no definitive basis in either the IPCC report or the limited number of detailed studies we have undertaken (see [page 49](#)), to conclude that climate-change-induced increases in the frequency or severity of severe weather events would be likely to result, at any point in time out to 2030, in disruption and shutdowns across our oil and gas portfolio on a scale that would reduce earnings so significantly as to jeopardize the resilience of our strategy.

For the purposes of this Recommended Disclosure, the resilience of our strategy was considered separately for the relevant transition and physical risks; accordingly, we did not seek to take account of any interdependencies or cumulative effects between the two types of climate-related risk, and the associated potential financial impact.

^a SSPs have been developed by the climate change research community to describe plausible major global developments that together would lead in the future to different challenges for mitigation and adaptation to climate change. The SSPs are based on five narratives describing alternative socioeconomic developments, including sustainable development, regional rivalry, inequality, fossil-fuelled development and middle-of-the-road development.

Climate-related financial disclosures continued

Our approach to testing resilience to transition risk

Most of our analysis focused on our medium-term time horizon (2030) – far enough ahead to provide a divergent range of scenarios, while not so far ahead that it is unrealistic to attempt to generate credible financial metrics for bp, or an individual business area within bp. For the variable(s) considered most significant, we also assessed resilience over the period 2027-30. Beyond 2030 we highlight the impairment sensitivities in the Financial statements – **Note 1**.

Our analysis sought to quantify the potential impact of a range of scenarios, including those consistent with 1.5°C, on bp's currently held (at the time the analysis was completed) internal reference group business outlook to 2030. This outlook is used for internal corporate planning and holds a deterministic view of our portfolio, activity set, cost and capital frame – this aligned with the strategic direction shared at the February 2025 Capital Markets Update.

We have additionally validated the conclusions of step 3, below, using our most recent internally-held financial outlook (as at 10 February 2026).

Resilience is assessed against the financial priorities set out in the 4Q/full year 2025 results update (10 February 2026).

A high-level summary of the steps taken as part of our scenario analysis is as follows:

- 1. Whole company assessment:** We defined, through quantitative analysis, which business areas could have both the financial scale and clear transition exposures to potentially impact bp's strategic resilience.
 - a. We assessed the business areas in our portfolio by i) quantitatively evaluating each business area's 'potential significance' by its expected contribution to bp group adjusted EBITDA★ in 2030 and therefore the quantum of financial impact that might be put at risk by transition uncertainty (including pathways consistent with 1.5°C); and ii) by identifying, for each, whether there were primary potential value driver(s) that different transition pathways might impact ('transition risk driver(s)').
 - b. Three broad business areas (see table below), representing over 70% of 2030 adjusted EBITDA, were identified as both providing a potentially significant financial contribution and facing clear primary transition risk drivers, and so were subjected to the driver-based analysis set out in steps 2a-2b below.
 - c. The remaining business areas followed a simplified approach – step 2c.

2. Scenario analysis: We tested the financial impact of transition on all of bp's business areas in 2030 through either specific 'driver-based' scenario modelling (a-b), or 'simplified' scenario analysis (c).

- a. For the driver-based scenario analysis, we selected the primary transition risk driver(s) for each business area – the variable(s) from the Transition Scenario Catalogue★ (see below) representing what we consider to be the primary driver(s) of that business area's primary exposure to the energy transition. For each transition risk driver, we extracted the full range of 2030 outcomes within each scenario 'family'. Given the global nature of the transition risks and opportunities we have identified, we used the 'world' values in the Catalogue except for gas price (see table on **page 53**).
- b. By calibrating the Catalogue's 2030 scenarios to relevant business metrics underpinning our strategic planning (for example, oil price or primary energy demand for oil), we modelled the impact of each variable, across the full range of scenarios and each scenario family, including the most extreme downside scenarios, on the 2030 expected earnings (adjusted EBITDA) for the associated business area. For example, we applied an underlying RC profit★ rule of thumb to the deviation of oil prices in the Catalogue versus our reference case price. This analysis was 'unmitigated' (see 'Other key considerations', below).
- c. For the simplified scenario analysis, used for the remaining business areas identified in step 1c, we took a simpler conservative approach, by evaluating whether a scenario in which each business area's expected 2030 adjusted EBITDA is assumed to be reduced to zero (an outcome considered to be at least as detrimental as could be expected to result from ranges associated with 1.5°C, 2°C or BAU scenario families) could have the potential to impact strategic resilience (as defined below).
- d. This analysis enabled us to assess the potential for each business area to impact group adjusted EBITDA (and by implication associated cash flows) in 2030, when compared to the reference group business outlook, to identify which (if any) businesses, variables and scenarios may have the potential to most materially impact strategic resilience (as defined below), and as such, which business areas should be carried forward into a multi-year resilience assessment.

3. Multi-year resilience test: This step tested bp's resilience to the exposure of any sufficiently material business areas to downside scenarios that may have the potential to jeopardize the ability to generate excess cash flow★ and a strong cash cover ratio – financial metrics that were treated for the purposes of this analysis as representing financial evidence of delivery of bp's strategic financial priorities (see below).

From step 2, in 2025, only the exposure to oil price was assessed as sufficiently material in this sense. Our multi-year (2027-30) oil price resilience test considered sustained low oil prices interpolated from 2025 actual Brent price to the most extreme 2030 Transition Scenario Catalogue case (IEA WEO 2024 NZE by 2050 Scenario) – falling to a 2030 minimum price of \$42/bbl (2023 \$ real).

Other scenarios, from providers such as UN PRI IPR and NGFS, formed part of the Catalogue, but indicated higher prices than the IEA WEO NZE case used.

For information about the approach to impairment sensitivity testing see Financial statements – **Note 1**.

Transition Scenario Catalogue data

- The latest WBCSD^a Energy Climate Scenario Catalogue which was Version 3.0 published May 2024, has been used as a starting point for compiling a suite of transition scenarios. While there has been no more recent update to the WBCSD Catalogue (at the time of preparation), certain underlying source providers (IEA^b, NGFS^c, UN PRI IPR^d) have since published updated scenarios for key transition variables or have 'retired' older scenarios.
- To reflect this more recent information, the Transition Scenario Catalogue we used is therefore based on variables and scenario families from WBCSD V3, updated for amended IEA, NGFS and UN PRI IPR data where available (see footnotes on the next page for details).
- For updated variables, oil and gas price and primary energy demand for oil (used for oil, gas and refining) were directly available in the published data. 'Final energy demand for liquid oil in road transport'; used for bp's road transport-related business areas, was not directly available from updated publications and so required some simple derivation by bp: 'Total final consumption in road transport' (IEA) and 'Final energy demand in road transport' (NGFS) were

disaggregated to estimate the proportion associated with liquid oil based on the published breakdown of 'Road transport final energy demand by energy source' published in WBCSD V3. We believe that this disaggregation of source data was similarly required in previous years to be conducted by WBCSD and its partners in preparing their Scenario catalogues.

Other key considerations

- For the purposes of steps 2 and 3, we considered the resilience of our strategy to climate-related transition risk through the three lenses described on [page 52](#). We defined the following as proxy indicators for these lenses:
 - Positive group excess cash flow (in 2024 termed 'surplus cash flow'), to demonstrate whether after funding, among other things, capital spend within our disclosed capital frame to 2027 (February 2025 Capital Markets Update) and a resilient dividend per ordinary share, sufficient excess cash flow remains to maintain or reduce net debt over the period.
 - Healthy cash cover ratio as an indicator of the ability to maintain a strong investment grade credit rating.
- For steps 2 and 3, we made the simplifying assumption that, aside from the driver being modelled, our strategy, operating model, volumes, margins, sales proceeds and tax rates would remain unchanged out to 2030.
- There are a range of mitigations or actions that we might naturally be expected to experience (e.g. through deflation) or to take in response to external market, price and demand trends, including cost reductions, portfolio adjustments, shareholder distribution and balance sheet choices, capital reallocation or capital reductions within the frames set out in our strategy.
- For step 3, given we would seek to make use of opportunities to maintain our strategic flexibility in the face of the many uncertainties of the energy transition, our methodology retains the optionality in downside scenario modelling to apply some or all of these mitigations.
- As outlined above, we utilized our latest internal reference group business outlooks as the basis against which resilience has been tested, as this forms a deterministic view against which to model the transition sensitivities to 2030 and aligns to the strategic updates provided to investors in February 2025 (and February 2026). Alongside disclosed elements such as the capital frame range to 2027, this includes shaping assumptions such as future distributions and net debt management.
- Rules of thumb applied to convert variance in hydrocarbon price to variance in adjusted EBITDA, these are considered appropriate to the period in question – i.e. they reflect the portfolio's changing price leverage over the period to 2030. Due to the evolution of bp's portfolio, these rules of thumb may diverge from any short-term rule of thumb that we publish.
- Through conducting this analysis, we do not intend to imply or commit to a specific forward trajectory of usage of cash, beyond any disclosed in the investor update in February 2025 (and 4Q/full year 2025 results on 10 February 2026) or other published strategy updates. While we cannot disclose, for confidentiality reasons, the detail of the deterministic case, the test assesses whether the resilience indicators in our reference group business outlook are impacted by the transition uncertainties tested. Further, by the nature of the timeframes considered, a variety of uncertainties exist around this deterministic case (including transition risk itself).
- The design of a strategic resilience analysis involves numerous methodological choices and assumptions any one of which could reasonably have been different, leading to different outcomes. We have found value in conducting this analysis; however, we are mindful of the limitations to any such exercise and the highly qualified nature of any conclusions which may be drawn from it. The disclosures provided here should be read in conjunction with the rest of our strategic report, where we discuss how we have developed, and continue to evolve, our approach to strategy.

Transition Scenario Catalogue★ family ranges for 2030 key transition variables

Scenario families (as categorised by WBCSD/source providers):		BAU		Below 2°C		1.5°C	
Business area	Transition variable	Min	Max	Min	Max	Min	Max
Oil and natural gas production	Oil price ^e (\$2023/bbl)	65.2	81.2	65.4	81.2	42.0	72.3
	Natural gas price ^f (\$2023/mmbtu)	3.81	4.38	2.59	4.38	2.10	4.62
Refining – refined oil demand	Primary energy demand for oil (% change vs 2020)	-2.4	14.4	-4.2	8.7	-21.3	-5.9
Conventional fuels retail and midstream	Final energy demand for liquid oil in road transport (EJ/yr)	74.3	88.7	71.9	88.7	63.5	72.1

For the other business areas not shown above^g, we applied the generic scenario analysis methodology described in point 2d, above, thereby ensuring coverage of all of bp's business areas.

a World Business Council for Sustainable Development; for the WBCSD Energy Climate Scenario Catalogue 3.0 (2024) see https://climate-scenario-catalogue.shinyapps.io/final_2024/.
b IEA World Energy Outlook (WEO) 2023, in WBCSD V3, updated with relevant data from IEA WEO 2024 (published October 2024); see <https://www.iea.org/reports/world-energy-outlook-2024>.
c NGFS v4.2, in WBCSD V3, updated with relevant data from NGFS v5.0 (released November 2024); see <https://www.ngfs.net/ngfs-scenarios-portal/data-resources>.
d UN PRI Inevitable Policy Response Forecast Policy Scenario (2023), in WBCSD V3, updated with relevant data from UN PRI IPR Transition Forecast Scenario (2025); UN PRI IPR Required Policy Scenario (2021), in WBCSD V3, removed (now regarded as outdated); see <https://ipr.transitionmonitor.com>.
e Oil price sensitivities have been applied to the oil and gas production portfolio that is linked to oil marker prices – as such it not only reflects oil production exposure, but also a proportion of bp's natural gas production that is contracted off oil marker prices.
f Gas prices shown reflect Henry Hub price ranges. Where available, Asian and UK gas price sensitivities have also been selected and compared to the Henry Hub sensitivity percentages with the maximum deviation selected and applied to the respective Asian and NBP rules of thumb for these parts of the gas portfolio, in order to provide the most conservative uncertainty range.
g In 2025 this included, for example, biogas and biojet production, aviation fuel sales, EV charging, renewables and hydrogen production, as well as convenience and trading and shipping.

Climate-related financial disclosures continued

Metrics and targets

TCFD Recommendation:

Disclose the metrics and targets used to assess and manage relevant climate-related risks and opportunities where such information is material.

We present the principal group-wide metrics and targets used to assess and manage climate-related risks and opportunities in line with our strategy and risk management process below, with metrics and targets mapped to the most relevant of TCFD's

cross-industry, climate-related metric categories (such as 'transition risks').

The metrics and targets themselves are disclosed at the most appropriate locations in this strategic report.

TCFD recommended disclosures – metrics and associated targets/goals

a) Disclose the metrics used by the organization to assess material climate-related risks and opportunities in line with its strategy and risk management process.

Transition risks

- Note 5 to Financial statements: Segmental analysis. Segment revenue (in table), [pages 185–189](#)
- Estimated net proved reserves and production (net of royalties), [page 27](#)
- Note 4 to Financial statements: Disposals and impairments, [page 182](#)
- Note 8 to Financial statements: Impairment losses (in table), [page 190](#)
- Oil and natural gas prices used for value-in-use impairment testing and recoverability of asset carrying values, [pages 168 and 274](#)

Physical risks

- Number of major operating sites in regions with high to extremely high water stress, [page 59](#)
- Freshwater withdrawals and consumption at major operating sites in regions with high or extremely high water stress, [page 59](#)

Climate-related opportunities

- Note 5 to Financial statements: Segmental analysis. Segment revenue (in table), [pages 185–189](#)
- Gas & low carbon energy, [page 28](#)

Capital deployment

- Financial frame, [page 18](#)
- Price assumptions, key investment appraisal assumptions, [page 20](#) (in table, indicated with [TCFD](#))
- Amount invested in transition businesses★, [page 21](#)
- Additional information – capital expenditure by segment, [page 335](#)
- Note 7 to Financial statements: expenditure on research and development (in table), [page 189](#)
- Note 8 to Financial statements: exploration and evaluation costs (in table), [page 190](#)

Internal carbon prices

- Internal carbon price, [page 20](#)

Remuneration

- Directors' remuneration report metrics: operated carbon emissions, [page 99](#)

b) Disclose Scope 1, Scope 2, and, if appropriate, Scope 3 greenhouse gas (GHG) emissions, and the related risks

GHG emissions

- Key performance indicators (relevant KPIs shown with TCFD), [page 17^a](#)
- Scope 1 and 2, in SECR table [page 39](#)
- Ratio of Scope 1 and 2 emissions: gross production, in SECR table [page 39](#)
- Scope 3 (related to category 11) emissions [page 38^b](#)
- TCFD: risks as described in Strategy a, [page 46](#)
- Risk factors, [page 67](#)
- A further breakdown of our GHG and energy data by business group is available in the *bp ESG Datasheet 2025* at [bp.com/ESG](#)

c) Describe the targets used by the organization to manage climate-related risks and opportunities and performance against targets.

Transition risks

- Net zero operations★ (including methane), [page 38](#)
- Net zero sales★, [page 38](#)

Physical risks

- Water, [page 59](#)

Climate-related opportunities

- Net zero operations (including methane), [page 38](#)
- Net zero sales, [page 38](#)

Capital deployment

- Transition business investment, [page 21](#)

Remuneration

- Incentivizing employees, [page 58](#)

GHG emissions

- Net zero operations (including methane), [page 38](#)
- Net zero sales, [page 38](#)

a These are our KPIs for the purposes of our disclosures pursuant to the UK CFDR Regulations and Section 414CB (2A) (h) of the Companies Act 2006.

b In determining the Scope 3 emissions that are 'appropriate' to be disclosed for the purposes of this Recommended Disclosure, we have considered this term in the context of the recommendation to disclose the metrics and targets used to assess and manage relevant climate-related risks and opportunities.

Sustainability continued

Our approach to sustainability

Our approach to sustainability is built on strong foundations. They guide the way we work, underpin our focus on safety and support our net zero, people and planet aims.

Safety comes first

At bp, safety comes first. We want to improve our safety performance and work towards our goal to eliminate fatalities, life-changing injuries and tier 1 process safety events.

We deeply regret the four fatalities and three life-changing injuries that occurred in 2025.

Three employees in our TravelCenters of America business^a died at work – two while carrying out emergency roadside assistance in separate incidents and one while servicing a truck. In response, we have permanently stopped roadside assistance next to active traffic lanes. A contractor in our *Thorntons* retail business died after falling from a ladder.

One employee and two contractors suffered life-changing injuries. Two were hand injuries – one in our TravelCenters of America business^a, the other in our Mauritania and Senegal business. The third was a head injury which occurred during a crane lifting activity in the North Sea (UK).

We have offered our support to the bereaved families and the injured workers. We know we have more work to do to improve our safety culture and performance.

Keeping people safe

We remain focused on risks that have the potential to cause fatalities or significant injuries and we monitor and report on key workforce personal safety metrics in line with industry standards. We include both employees and contractors in our data. Life-changing injuries decreased from six in 2024 to three in 2025^{ab}. Our recordable injury frequency (RIF) also decreased by 21% compared to 2024, see [page 16](#). These reductions are encouraging, but we know we must maintain our efforts to continue improving our safety performance, by applying the International Association of Oil & Gas Producers' (IOGP) Life-Saving Rules and our own Safety Leadership Principles.

In 2025 we gained new insights about the effectiveness of the IOGP's Life-Saving Rules in bp, due to the introduction of conformance checklists tailored to the needs of specific businesses.

Driving safety

Driving continues to be one of the biggest personal safety risks we face at bp. In 2025 five severe vehicle accidents occurred (2024 5). The number of kilometres driven fell by 19% during the same period.

	2025	2024	2023
Severe vehicle accident rate per million km driven	0.03	0.02	0.02

Our Operating Management System^c

Our Operating Management System (OMS)[★] provides a single framework for delivering safe, reliable and compliant operations. Our OMS sets out the way in which our businesses within our operational control around the world are expected to understand and manage their environmental and social impacts, including requirements on engaging with stakeholders who may be affected by our activities.

We review and amend these requirements from time to time to reflect our priorities. Any variations in the application of our OMS, in order to reflect the specific circumstances of a bp entity or meet local regulations or circumstances, are subject to a governance process.

Our OMS requires each of bp's operating businesses to create and maintain its own OMS handbook, describing how it will carry out its local operating activities.

We use a 'three lines of defence' model to facilitate the effective management of all types of risk, including safety. The nature and extent of first, second and third lines of defence activities are based on the type and level of risk.

Preventing incidents

We plan our operations carefully to identify potential hazards and manage risks at every stage through rigorous operating and maintenance practices applied by capable people. We design our new facilities in line with process safety, good design and engineering principles. We track our process safety performance using industry-aligned metrics such as those found in the American Petroleum Institute recommended practice 754 and the IOGP recommended practice 456.

Our combined reported tier 1 and tier 2 process safety events[★] (PSEs) have decreased for the past 12 years, apart from in 2019. There were 27 PSEs in 2025 (2024 38), of which five were tier 1 (2024 3) and 22 were tier 2 (2024 35).

In 2025 the number of oil spills^d increased to 110, compared with 96 in 2024.

Our operating sites share examples of good practice, while our central health, safety, and environment incident investigations team reviews serious or complex incidents, which may include near misses. Supported by the use of leading indicators, such as inspections and equipment tests, these activities help us monitor and strengthen controls and identify and address systemic gaps to prevent incidents.

	2025	2024	2023
Tier 1 and tier 2 process safety events [★]	27	38	39
Oil spills – number	110	96	100
Oil spills – contained	57	49	52

Emergency preparedness

We have disaster recovery, crisis and business continuity management plans and work to build day-to-day response capabilities to support local management of incidents. We test our plans and preparedness through exercises that simulate real-life scenarios. In 2025 we conducted 37 exercises in countries including India and the US.

Security

We protect our people, assets and operations, and manage security through a threat-driven, risk-based approach. We continuously monitor threats from activism, civil unrest or political instability, terrorism, armed conflict, and criminal and cyber activity. Our 24-hour intelligence and response information centre in the UK monitors global security risk in real time. It helps us to assess the safety of our people and provide them with practical advice if there is an emergency.

Cyber security

The severity, sophistication and scale of cyber attacks continue to evolve. Increasing digitization, the emergence of new technology such as generative artificial intelligence, and reliance on IT systems and cloud platforms

a At the time of publication (March 2026), as part of the transition period for recently acquired businesses, the safety reporting processes were still being integrated into bp's safety reporting processes. As such, data from Archaea Energy, TravelCenters of America, Lightsource bp, bp bioenergy, X Convenience and new Eagle Ford assets in bpx energy are not included in 2025 reported data.

b In addition to the four life-changing injuries reported in the *bp Annual Report 2024*, two additional injuries that occurred in late 2024 were later classified as life-changing after the publication of the 2024 report, in accordance with the 180-day classification window for life-changing injuries, bringing the total to six life-changing injuries in 2024.

c For recently acquired businesses, there is typically a transition period while bp's operating standards, as set out in OMS, are integrated or aligned.

d The number of accidental or unplanned losses of hydrocarbon from primary containment from a bp or contractor operation, irrespective of any secondary containment or recovery. Oil spills > 1bbbl are defined as any liquid hydrocarbon release of more than, or equal to, one barrel (159 litres, equivalent to 42 US gallons).

Sustainability continued

makes managing cyber risk a priority for many industries, including our own. Direct or collateral impact can come from a variety of cyber threat actors, including nation states, criminals, terrorists, hackers and insiders. As in previous years, we have experienced threats to the security of our digital systems and our barriers have worked well to mitigate and contain them to minimize any impact on our business.

We have a range of measures to manage this risk, including the use of cyber security policies and procedures, security protection tools, threat monitoring and event detection capabilities, and incident response plans. We conduct exercises to test our response to, and recovery from, cyber attacks. We collaborate closely with governments, law enforcement and industry peers to understand and respond to threats.

To encourage vigilance among our employees, our extensive cyber security training courses and awareness programmes provide regular education on a wide range of topics such as phishing and the correct classification and handling of our information. We also use a cyber barometer tool to empower individual risk mitigation.

→ [How we manage risk, page 60](#)
[Additional disclosures – cyber security, page 360](#)

Working with contractors

Through documents that help bridge our health, safety and environmental policies and those of our contractors, we define the way our OMS co-exists with systems used by our contractors to manage risk on a site. We conduct risk-based quality, technical, health, safety and security audits before awarding contracts. Once contractors start work, we continue to monitor their safety performance. Our OMS includes requirements and practices for working with contractors. Our standard model contracts include health, safety and security requirements. We expect and encourage our contractors and their employees to act in a way that is consistent with our code of conduct and take appropriate action if those expectations, or their contractual obligations, are not met.

Our partners in joint arrangements

We monitor performance and how risk is managed in our joint arrangements★, whether we are the operator or not. In joint arrangements where we are the operator, our OMS, code of conduct and other policies apply.

We aim to report on aspects of our business where we are the operator – as we directly manage the performance of these operations.

Where we are not the operator, our OMS is available as a reference point for bp businesses when engaging with other operators and co-venturers. We have a group framework to assess and manage bp's exposure risks from our participation in these types of arrangements.

Where appropriate, we may seek to influence how risk is managed in arrangements where we are not the operator.

The people, culture and governance committee reviews workforce policies and practices and their alignment with bp's strategy, purpose, beliefs and culture, and conducts workforce engagement measures.

→ [People, culture and governance committee report, page 89](#)

Our people

Workforce by gender

	Male		Female		Female %	
	2025	2024	2025	2024	2025	2024
As at 31 December 2025						
Board directors	7	5	6	6	46	55
Leadership team	4	5	4	5	50	50
Group leaders	169	186	99	100	37	35
Subsidiary★ directors	473	519	294	253	38	33
All employees ^a	58,400	62,000	35,100	38,300	37	38

Number of employees

	2025	2024	2023
As at 31 December 2025			
Gas & low carbon energy	5,600	6,500	4,800
Oil production & operations	9,300	9,200	8,800
Customers & products	66,900	73,100	63,400
Other businesses & corporate	11,800	11,700	10,800
Total	93,700	100,500	87,800

a Some employees have not disclosed gender, therefore are not included in this total.

Our culture

We want to build a culture that supports all of our employees and promotes inclusion, wellbeing and development.

Our culture frame, 'Who we are', defines what we stand for and is integrated into our code of conduct and our approach to inclusion. We maintain oversight of our culture by measuring employee sentiment and encouraging employees to use our speak-up channels. Read more about the board's role in overseeing bp's culture on [page 90](#).

Developing our people

Our people are crucial to delivering our strategy and aims. We invest to ensure we have the right people with the right skills from diverse backgrounds, and we provide training, development and competitive rewards for them.

In 2025 bp employees collectively completed around 2.1 million hours of formal learning (2024 1.2 million hours). bp's learning and development framework is applicable to all employees and covers safety, technical and operational skills, leadership, and future skills. Our mandatory training curriculum covers conformance with our internal standards and applicable laws and regulations.

Building an inclusive culture

Part of our people aim is to foster an inclusive culture with an employee workforce that reflects the communities where we work. To deliver our strategy we believe we need to capitalize on the diversity of perspectives, backgrounds, skills and experiences within our workforce.

Improving representation

We make all employment decisions based on merit without regard to gender, race, age, disability, or any other protected status.

In 2025 global female representation in bp was 37% (2024 38%), four of the eight positions in our leadership team were held by women, and 37% of group leader roles were filled by women (2024 35%).

In 2025 our ethnic minority representation in the UK remained steady at 22% of our overall workforce (2024 22%).

 [bp Gender and Ethnicity Pay Gap Report, bp.com/ukgenderpaygap](#)

In line with UK reporting requirements, we disclose information against external targets on the representation of women and ethnic minorities on our board and executive management. Read more on diversity reporting in line with the Listing Rules on [page 126](#).

→ [Composition of the board, page 73](#)

Promoting inclusion

To promote an inclusive culture, we support employee-run business resource groups (BRGs) in areas such as age diversity, social mobility, gender, ethnicity, and disability.

As well as bringing employees together, these groups contribute to our inclusive culture, provide a representative voice for employees and highlight and celebrate the achievements of different groups. Each group is sponsored by a senior leader and open to all employees.

Improving accessibility

We continue to take steps to progress inclusion for our neurodivergent employees and those with disabilities. We offer access to support including assistive technology, such as immersive readers and peripheral accessories.

To help meet the requirements of our employees we work closely with our employee-led disability BRGs.

If existing employees become disabled, our policy is to engage and use reasonable accommodations or adjustments to enable continued employment.

We have partnerships to help us implement best practice methods to support neurodivergent employees and those with disabilities. Our partners include the Business Disability Forum in the UK.

Employee engagement

Our managers hold team and one-to-one meetings with their team members, complemented by formal processes through works councils in parts of Europe.

We regularly communicate with employees on factors that affect bp's performance, and seek to maintain constructive relationships with labour unions formally representing our employees.

In 2025 we reset our approach to performance management to reflect our organizational focus on delivering bp's strategy^a by introducing clearer, more transparent processes – aligned goals, business scorecards, a new annual review cycle and a simple individual rating system. These changes will help embed a stronger performance culture that supports our strategy.

We monitor employee sentiment through several channels including our Pulse annual employee survey, which is sent to all eligible employees, and through our Pulse live survey, which is sent to a representative sample of employees weekly. In 2025 our overall engagement metric, employee engagement, decreased to 66%^b (2024 70%).

We will continue to develop engagement plans based on feedback from the annual and weekly surveys to help us deliver on safety, and meet our strategic objectives. The 2025 Pulse survey results highlight three priority areas for engagement in 2026: two of these – emphasizing psychological safety, and strategy and performance – were also priorities in 2025. The third – career and development – is new.

→ [Our employee engagement key performance indicator, page 16](#)
[How the board engaged with the workforce, page 80](#)

Workforce health and wellbeing

We include an employee wellbeing index in our Pulse annual employee survey and weekly Pulse live surveys. Results from 2025 showed that employee wellbeing decreased to 69%^b (2024 73%) generally because of organizational transformation.

During bp's transformation programme, we have offered comprehensive mental health support to employees which has been developed through listening forums and employee feedback.

Our approach to workforce health and wellbeing combines globally available services that can be tailored to meet local needs. All employees have access to our global digital health and wellbeing hub, Thrive@bp.

a This reset approach to performance management is subject to local law, including consultation where required.

b As a result of changes to the question set and the inclusion of employees from our retail business in the 2025 Pulse survey, the engagement and wellbeing scores for 2025 are not comparable with prior years.

Sustainability continued

Linking remuneration to sustainability ^{TCFD}

The bonus scorecard for 2025 against which eligible employees^a are measured incentivized them through three themes: safety and sustainability (30%); operational performance (15%); and financial performance (55%). For 2025 our sustainability measure was linked to our operated carbon emissions. This measure covers Scope 1 and 2 emissions based on our net zero operations★ aim. Our 2023-25 long-term incentive plan scorecard was linked to emissions reductions against our 2019 baseline (15%).

For 2026, progress towards our aim to achieve net zero operations by 2050 or sooner will continue to be rewarded through our long-term performance share plans rather than the annual bonus. For 2026-28 the scorecard measure will focus on reducing Scope 1 and 2 operational emissions (20%).

→ [Directors' remuneration report, page 91](#)

Share ownership

We encourage employee share ownership and have a number of employee share plans in place. For example, we operate a ShareMatch plan, matching bp shares purchased by our employees. We also make annual share awards as part of our total reward package for all senior and mid-level employees globally, and a portion of our more junior professional grade employees.

Ethics and compliance

Our code of conduct

Our code sets out the principles and expectations that guide our daily activities. It provides a framework to support safe and ethical decision making, sets the standards for how we do the right thing and empowers us to speak up without fear of retaliation. Our code is the foundation of 'Who we are', our culture frame, and it puts safety first. Together with our Safety Leadership Principles and OMS★, it helps us act responsibly, comply with applicable laws, and implement our sustainability frame.

Our code applies to all bp employees, officers and board members^b. Regular mandatory training and communications help employees understand how to apply it and how to raise questions or concerns.

All bp employees are required to confirm annually that they have read and understand our code and act in accordance with its principles. We expect and encourage all our

contractors and their employees to act in ways that are consistent with it.

Any concerns or enquiries can be raised through multiple speak-up channels. These include line managers, senior leaders, and contacts in our people & culture, ethics & compliance, safety & operational risk assurance or legal teams. We also have a confidential global helpline, OpenTalk. It is available for bp employees, the wider workforce, communities, business partners and other stakeholders and can be accessed all day, every day by telephone or internet and in 75 languages. Anyone has the right to contact OpenTalk anonymously, except where prohibited by law.

We take potential misconduct seriously and thoroughly review allegations and respond, conducting investigations where appropriate.

We may take action in response to reported concerns to help proactively mitigate issues around misconduct. We follow a defined disciplinary process and will take action or issue sanctions where appropriate. These may include coaching or training, formal reprimands or dismissal.

Nearly 5,000 concerns or enquiries were reported in 2025 (2024 ~2,800). In 2025 around 1,300 separations resulted from non-conformance with our code, including unethical behaviour. Almost 90% of these separations were from our retail business.

The most frequently raised concerns in 2025 related to alleged bullying, harassment and discrimination, with these accounting for around half of all concerns. The second most common concerns related to allegations concerning assets and financial integrity.

The 2025 mandatory code of conduct training assigned to all bp employees included a specific section on non-harassment. Additionally, employees were assigned a separate training module aimed at preventing fraud.

 bp.com/codeofconduct

Anti-financial crime

We operate in parts of the world where bribery and corruption present a high risk, so it is important that we engage with our employees, contractors, suppliers and others to emphasize that our commitment to ethical and compliant operations is unwavering.

Our code of conduct explicitly prohibits engaging in any form of bribery, corruption or money laundering and promotes lawful and ethical business practices. It includes an

expectation that we work to make sure our business partners comply with our requirements.

Our group-wide policies covering anti-bribery and corruption, anti-money laundering, anti-fraud and anti-tax evasion all include measures and guidance to assess risks, understand relevant laws and report concerns. They apply to all bp-operated businesses.

We provide appropriate training including for those employees in locations or roles assessed to be at a higher risk of bribery and corruption, money laundering and fraud that could benefit bp.

In 2025 around 8,100 employees completed anti-bribery and corruption training as part of our ethics and compliance risk-based learning. This is higher than the 5,900 employees trained in 2024, due to the rolling cadence we use to assign training.

We also conduct anti-bribery compliance audits on selected suppliers to assess their conformance with our anti-bribery and corruption contractual requirements. We take corrective action with suppliers and business partners who fail to meet our expectations, which may include terminating contracts. In 2025 we issued 19 ABC supplier audit reports (2024 32).

Political donations and activity

We prohibit the use of bp funds or resources to support any political candidate or party. We recognize the rights of our employees to participate in the political process and these rights are governed by the applicable laws in the countries where we operate. Our stance on political activity is set out in our code of conduct.

In the US we provide administrative support for the bp employee political action committee (PAC) – a non-partisan, employee-led committee that encourages voluntary employee participation in the political process. The bp employee PAC is governed by a board of directors and administrative by-laws. All contributions made by the bp employee PAC are weighed against its criteria for candidate support and reviewed for legal compliance before funds are sent to the recipients requested by our employees, and are publicly reported in accordance with US election laws. Contributions made by the PAC are from employee contributions and not bp funds.

a The number of employees eligible for a cash bonus in 2025 was around 43,500.

b For recently acquired businesses, there is a transition period while bp's ethics and compliance standards, as required in our code, are integrated or aligned.

Tax transparency

We take a responsible and transparent approach to tax, guided by our responsible tax principles which align with our code of conduct and our beliefs.

We comply with the tax legislation of the countries in which we operate and we do not tolerate the facilitation of tax evasion by people who act for or on behalf of bp.

We are committed to transparency around our tax principles and the taxes we pay. We paid \$8.3 billion in corporate income and production taxes to governments in 2025 (2024 \$10.6 billion).

[bp Tax Report, bp.com/tax](#)

Trade associations

Trade associations and industry initiatives play a key role in fostering collaboration, sharing knowledge and bringing stakeholders together.

We made changes to the way we review our trade association memberships in 2025. We reviewed those with membership fees of \$100,000 or more to identify any significant misalignments or lack of influence on relevant policy between the association reviewed and bp.

[bp.com/tradeassociations](#)

People and planet

Improving people's lives

We want to support employees, our wider workforce and local communities.

People

Our aim is to support our employees and local communities through the energy transition by:

- Equipping employees with skills that can improve their access to opportunities in the energy transition.
- Developing targeted just transition plans^a for select assets or regions, that help manage potential impacts on and opportunities for people as we transition.
- Fostering an inclusive culture with an employee workforce that reflects the communities where we work (read more on [page 57](#)).

We recognize the importance of a just energy transition – one that delivers decent work, quality jobs and supports the livelihoods of local communities. We report on our work to equip employees with the skills they need now and for the energy transition, and on how we are supporting local communities in the *bp Sustainability Report 2025*.

Human rights

We believe everyone deserves to be treated with fairness, respect and dignity. We respect the rights of our workforce and those living in communities where we operate, who are potentially affected by our activities.

We set out our commitments in our human rights policy and code of conduct. Our policy aligns with the UN Guiding Principles on Business and Human Rights.

It is underpinned by the International Bill of Human Rights and the International Labour Organization's Declaration on Fundamental Principles and Rights at Work, including its core conventions.

To support our teams, we provide human rights training and other awareness-raising activities.

[bp.com/humanrights](#)

Caring for the planet

We want to make a positive difference to the environment in which we operate.

Biodiversity

We understand international concern regarding the global decline in biodiversity and recognize that our businesses can have impacts and dependencies on nature.

We aim to support biodiversity where we operate^b, by:

- Aiming to achieve a net positive impact (NPI) on all new in-scope^c projects.
- Implementing biodiversity enhancement plans at our major operating sites.
- Collaborating with others to support selected biodiversity restoration projects.

Building on the work we did in 2022 to finalize our NPI methodology for use on new, in-scope projects, we have made consistent progress over the past few years in our work to apply it. By the end of 2025 six of our projects were either implementing or developing NPI plans. In addition, all our major operating sites in

biodiversity-sensitive areas had developed or started to implement biodiversity enhancement plans.

[bp.com/biodiversity](#)

Water

We aim to reduce our net freshwater use in stressed catchments where we operate^d, by:

- Being more efficient with freshwater use in our operations.
- Collaborating with others to replenish freshwater in stressed^d catchments. We anticipate that by 2028, our freshwater withdrawal in stressed catchments will be covered by freshwater management plans.

To understand our water-related challenges, we review water impacts, risks and opportunities at our operating sites. These reviews consider the quantity and quality of water used as well as any applicable regulatory requirements.

Our water consumption in 2025

Since 2020 we have reduced freshwater withdrawals (excluding once through cooling water) by 15% and freshwater consumption by 15% against the baseline^e. Reductions in 2025 were the result of operational efficiencies at our Lingen refinery in Germany, and at Whiting refinery and bpx energy Eagle Ford facilities in the US.

At our major operating sites, 13% (2024 11%) of our total freshwater withdrawals and 22% (2024 20%) of freshwater consumption were from regions with high or extremely high water stress in 2025.

Air emissions

We monitor our air emissions – sulphur oxides, nitrogen oxides and non-methane hydrocarbons – and, where possible, put measures in place to reduce the potential impact of our operational activities on local communities and the environment. In 2025 our total air emissions were flat compared to 2024.

[bp.com/ESGdata](#)

^a We will work to develop just transition plans with input from potentially affected stakeholders to help manage social risks and opportunities.

^b At our new in-scope bp-operated projects and major operating sites.

^c New bp-operated in-scope projects where planned activities have the potential for significant direct impacts on biodiversity are required to develop NPI action plans for those activities.

^d The threshold bp uses for stress is based on a water stress level of 'high' or above, as defined by the WRI Aqueduct Water Risk Atlas. bp determines areas of water stress using either the WRI Aqueduct Water Risk Atlas or using site-specific local data sources.

^e Following an update in 2024 to the basis for calculating freshwater withdrawal to align with the basis for calculating freshwater consumption and improve clarity and consistency, metrics based on freshwater withdrawal data have been restated for the years 2020-23 to reflect the exclusion of once through cooling water, including the 2020 baseline.

^f The 2020 baseline for freshwater withdrawal is 96.4 million m³ per year and for freshwater consumption is 55.9 million m³ per year.

Risk management and internal control

Risk management and internal control

bp identifies, manages, monitors and reports on the principal risks and uncertainties that can impact our ability to deliver our strategy. These are described in Risk factors on [page 67](#).

bp's system of internal control and risk management

bp's system of internal control is a holistic set of internal controls that includes policies, processes, management systems, organizational structures, culture and standards of conduct employed to manage bp's business and associated risks. Risk management forms an integral part of this system and operates as one of the key mechanisms through which internal controls are designed, implemented and monitored.

An effective approach to risk management is central to how bp operates, supporting safe, compliant, and reliable operations as well as greater efficiency and sustainable financial results that contribute to long-term business resilience. Within the system of internal control, bp's risk management system and risk management policy are tailored to our business model and governance structure and align with the expectations of the regulatory and governance regimes applicable to bp.

Where appropriate, they draw on recognized international standards, including ISO 31000 and the COSO Enterprise Risk Management framework, and are designed to provide a consistent and clear framework for identifying, assessing, managing (including responding to), monitoring and reviewing, and reporting risks from the group's business activities and operations to management and the board.

The system seeks to avoid incidents and enhance business outcomes by allowing us to:

- Understand the risk environment, identify the specific risks and assess the potential exposure for bp.
- Determine how best to deal with these risks to manage overall potential exposure.
- Manage the identified risks in appropriate ways.
- Monitor and seek assurance over the effectiveness of the management of these risks and intervene for improvement where necessary.
- Report clearly and consistently to management, the leadership team and the board on how principal risks are being managed, monitored and assured, with any identified enhancements that are being made.

Risk oversight and governance

Our key risk oversight and governance committees include:

Board and committees

- bp board.
- Audit committee.
- Safety and sustainability committee.
- Remuneration committee.
- People, culture and governance committee.

Leadership team and committees

- Leadership team meeting – for oversight and for strategic and commercial risks.
- Group operational risk committee – for health, safety, security, environment and operations integrity risks. Group operational risk committee (sustainability) – for sustainability-related risks.
- Group financial risk committee – for finance, treasury, trading and cyber risks.
- Group disclosure committee – for financial and non-financial reporting risks.
- People and culture committee – for employee risks.
- Group ethics and compliance committee – for legal and regulatory compliance and ethics risks.
- Resource commitment meeting – for investment decision risks.
- bp quarterly internal audit meeting – for assurance on the oversight of bp's principal risks.

Acquired businesses

Integration plans are developed to transition acquired businesses into bp's system of internal control, over an appropriate timeframe.

Our risk management activities



→ [bp governance framework, page 77](#), [board activities, page 78](#), [committee reports, pages 82-91](#) and [risk management and internal control, page 127](#).

Divested businesses

Separation and transition plans are used to divest businesses in a controlled manner, with clear allocation of responsibilities, appropriate oversight of transitional service arrangements, and continued management of any retained liabilities or obligations.

Day-to-day risk management

Management and employees at our facilities, assets, and within our businesses (including supply, trading & shipping) and functions seek to identify and manage risk, promoting safe, compliant and reliable operations. bp requirements, which take into account applicable laws and regulations, underpin the practical plans developed to help reduce risk and deliver safe, compliant and reliable operations as well as greater efficiency and sustainable financial results.

Business and strategic risk management

Our businesses and functions integrate risk management into key business processes such as strategy, planning, performance management, resource and capital allocation and project appraisal. They apply this by using a standard framework for collating risk data, assessing risk management activities, driving further improvements, and informing decisions on new or changing activities.

Board oversight of risk and internal control

The board is responsible for establishing and maintaining an effective risk management and internal control framework, and for determining the nature and extent of the principal risks it is willing to take in order to achieve its long-term strategic objectives.

Throughout 2025, management, the leadership team, the board and relevant committees provided oversight of how principal risks to bp were identified, assessed, and managed. They supported appropriate governance of risk management, including having relevant policies in place to help manage risks.

Such oversight may include internal audit reports, group risk reports and reviews of the outcomes of business processes including strategy, planning and resource and capital allocation. bp's group risk team analyses the group's risk profile and maintains the group's risk management system.

Risk management processes

bp's risk management processes help underpin the long-term resilience of our business model by promoting transparent, risk-informed decision making and the identification and management of risks and potential opportunities aligned with bp's strategic priorities. These include existing processes and sources of insight to consider emerging risks or opportunities, such as emerging risk communications to the board, bp's risk management system, the *bp Energy Outlook*, bp's technology-related news and insights, ongoing emerging technology scanning and strategy reviews. They also include ongoing enhancements to our system of internal control and risk management, which are informed by lessons learned and evolving governance expectations.

We aim for a consistent basis of measuring risk to:

- Establish a common understanding of risks on a like-for-like basis, taking into account potential impact and likelihood.
- Report risks and their management to the appropriate levels of the group.
- Inform prioritization of specific risk management activities and resource allocation.

bp's risk management policy sets out requirements for the group to follow. These requirements support the consideration of three risk types:

- Strategic and commercial.
- Safety and operational.
- Compliance and control.

Risk identification – our businesses and functions identify risks across these risk types on an ongoing basis, using a range of approaches including risk workshops, subject-matter expertise, hazard identification processes and engineering requirements.

Risk assessment – identified risks are assessed for potential impact and likelihood on a worst credible and net (residual) basis across a number of criteria, including health and safety, environmental, financial and non-financial (including reputation and regulatory impact levels). This provides a consistent basis for evaluating and comparing risks.

Risk response, monitoring, and reviewing – risk management activities are prioritized where improvements are needed based on a number of factors, including the risk assessment, strength of existing risk management measures, strategy and plans and legal and regulatory requirements. Risk management measures, including mitigations, are identified for each risk and monitored to the extent considered appropriate. To support leadership oversight of decisions relating to risk management, the appropriate organizational levels (EVP, SVP, VP) are notified of risks and asked to endorse risk management plans, depending on the assessed potential impact and likelihood. As part of bp's annual planning process, the leadership team and the board review the group's principal risks and uncertainties. These may be updated during the year in response to changes in internal and external circumstances. Emerging risks are also considered when determining whether updates to the group's principal risks are required.

Risk reporting – risk information is reported through a structured cadence that supports timely escalation and oversight. Businesses and functions provide updates on changes in risk exposure, progress of planned risk management actions, and the strength of risk management measures, including mitigations. This enables consistent aggregation across the group and supports management, the leadership team and the board in monitoring and reviewing bp's principal and emerging risks and overall risk profile.

Assurance and internal audit

bp's internal audit team provides independent and objective assurance to the chief executive and the board on the adequacy and operating effectiveness of bp's system of internal control, including risk management arrangements. Internal audit reports, thematic findings, and improvement recommendations are considered by the board and committees as part of their oversight.

The group risk team maintains the risk management and internal control framework, analyses the group's risk profile, and provides further oversight and reporting.

Assurance activities across management, specialist risk and control functions and internal audit are aligned with bp's principal risks and underpin the effectiveness of bp's risk management and internal control framework.

Principal risks and uncertainties (Risk factors)

Principal risks and uncertainties

The risks discussed below, individually or in combination, could have a material adverse effect on the implementation of our strategy and business model, financial performance and financial condition, cash flows and liquidity, operational delivery, reputation, and long-term shareholder value. These are the risks the board considers to be bp's principal risks and uncertainties (or Risk factors).

Our risk profile

The nature of our business is long term, meaning many of our risks are enduring in nature. However, risks can develop and evolve over time, and their potential impact or likelihood may vary in response to internal and external events.

During 2025, the board conducted a review of the group's principal risks, informed by bp's updated strategy, changes in our operating environment, stakeholder expectations, and the board's commitment to maintaining clear and effective oversight. Following this review, the board approved a streamlined set of 16 principal risks (previously 20).

The reduction does not reflect a change in bp's underlying risk exposure; rather, the principal risks have been reorganized to align with how risks are governed and managed across the group. Certain items previously presented as standalone risks, such as insurance, and crisis and business continuity management, are now reflected within broader control and response capabilities that support multiple principal risks. In addition, some risks have been combined, where appropriate, to remove duplication and present a single view of related drivers, accountability, and impacts.

Strategic and commercial risks

Commodity prices and market environment

Our financial performance is impacted by fluctuations in the prices of oil, natural gas, refined products, and emerging energy commodities due to factors such as volatile energy markets, exchange rates, or structural shifts in demand and supply, policy, or trade (such as carbon pricing or LNG flows).

These prices are affected by factors such as global supply and demand dynamics, the actions of key market participants (including OPEC+), and a range of external factors such as geopolitical instability, public health situations (including the outbreak of an epidemic or pandemic), sanctions, trade tariffs, and policy interventions that impact energy flows.

Prolonged periods of low commodity prices may reduce revenue, margins, and cash flow, potentially requiring asset impairments, or a reprioritization of strategic activity and may also impact our ability to work within our financial frame including potential reductions in capital investment. Conversely, higher prices do not always translate into improved returns due to fiscal regimes, cost inflation, or constrained market access.

In refining, profitability can be volatile and is affected by regional supply and demand imbalances (including regional oversupply or tightness, demand shifts, shifts in product mix, feedstock availability, and crack spread volatility).

Currency movements – particularly where revenues and capital costs are denominated in different currencies – also impact project economics and reported earnings.

Broader structural shifts, such as the pace of the energy transition, evolving climate policy, carbon pricing mechanisms, consumer preferences, and the realignment of global energy trade (e.g. LNG flows, carbon border adjustments) may lead to enduring changes in market conditions. These shifts could affect the long-term competitiveness or economic viability of existing assets and investment plans.

Accessing and producing hydrocarbon resources

Failure to adequately access, develop or sustain production of hydrocarbon resources may result in delivery delays, missed strategic targets and adversely impact our financial performance and undermine our reputation.

Our ability to generate value depends on successfully identifying, accessing, developing, and sustaining reliable production of hydrocarbon resources at pace and scale. This requires securing access; navigating geopolitical and regulatory complexity; effective and timely development and deployment of technologies; delivering projects on time; and executing with operational and commercial discipline.

Delivery risks may arise from joint venture misalignment, production reliability issues, or extended unplanned outages across the hydrocarbon value chain. Our activities are sometimes conducted in challenging environments such as those prone to natural disasters and extreme weather events, which heightens the risks of technical integrity failure. The physical characteristics of an oil or natural gas field, and cost of drilling, completing or operating wells are inherently uncertain. We may be required to curtail, delay or cancel drilling operations or stop production because of a variety of factors, including unexpected drilling conditions, pressure or irregularities in geological formations, equipment failures or accidents, adverse weather conditions and compliance with governmental requirements. Such outages can materially impact value, erode investor confidence, and delay strategic delivery.

This risk is increased in politically sensitive jurisdictions, under volatile fiscal regimes, or where accountability for portfolio progression is unclear following divestments – near to medium-term value remains heavily dependent on competitive, reliable hydrocarbon delivery. Sustained underperformance, partner misalignment, or high-profile project delays could limit reserve replacement and constrain growth.

Major project delivery

Failure to invest in the best opportunities or deliver major projects successfully could adversely affect our financial performance and long-term competitiveness.

Our ability to select, define, execute, and deliver large-scale, capital intensive, physical projects (such as field developments, refineries and infrastructure expansions) is critical to our financial performance and resilience. These projects are often complex and executed in technically demanding, geopolitically sensitive or geographically challenging environments. Additional factors such as extreme weather events or regulatory constraints can affect schedule and cost performance.

Major projects are often delivered through joint ventures, strategic partnerships, or third-party-led models, which can constrain our control and influence over delivery, governance, and standards.

The selection and design of our major projects need to be resilient to the impact of severe weather events (e.g. metocean criteria) and other environmental factors (e.g. water scarcity).

Potential risks include ineffective investment prioritization, subsurface uncertainty, capability constraints, supply chain disruption, inflationary pressure or delays in permitting, regulatory approval, commercial agreements, or execution.

A failure to deliver key projects to schedule, scope, budget, quality, or HSE standards may lead to cost overruns, delays in production or revenue, reputational harm, impairment, or loss of licence to operate.

Geopolitical exposure

The diverse locations of our business activities and operations around the world expose us to a wide range of geopolitical developments (including sanctions, trade route restrictions, civil unrest, conflict, or government intervention).

Geopolitical risks arise from operating in jurisdictions undergoing political, regulatory, or economic transition – and from broader societal, ideological, and technological shifts – including changes to taxation or regulatory regimes, international sanctions, trade restrictions, expropriation or nationalization of property, civil strife, strikes, insurrections, acts of terrorism, acts of war, and public health situations (including the outbreak of an epidemic or pandemic).

These events have, and can, disrupt business activities and operations, restrict access to key markets, and adversely affect financial performance, long-term growth opportunities, or reputation.

Rising bloc politics, energy nationalism, and alliance-driven policy divergence could further fragment global trade and investment patterns, influencing where bp may operate, partner, pursue business opportunities and compete. Competition over critical minerals and low carbon technologies is increasingly geopolitical, shaping access to resources and markets.

Geopolitical rivalry extends into technology and cyber domains, exposing potential operational and reputational vulnerabilities linked to supply-chain sovereignty, data integrity, and industrial security. Political instability, shifts in alliances, or increased government intervention may lead to barriers to market access, disruptions in supply chains, or challenges in executing existing or planned operations. Divergent or extraterritorial regulations (including sanctions, data, and carbon border mechanisms) may create conflicting legal obligations and compliance complexity across jurisdictions.

Such events may also affect investor sentiment, financing conditions, and access to capital. Growing fragmentation of global trade and regulation, coupled with rising energy nationalism and polarized international alliances, may exacerbate volatility in energy supply, demand, and prices. Our exposure to particular jurisdictions, vendors, and technologies exposes us to the potential for geopolitical tensions to intersect with performance delivery, investor sentiment, and stakeholder trust.

Liquidity, capital access and financial resilience

External market conditions can impact our ability to maintain liquidity, credit strength, or access to capital markets which could impair our ability to operate, meet financial commitments, or deliver our strategy.

Market volatility, operational incidents, legal proceedings, regulatory actions, or geopolitical crises could reduce access to funding or trigger unexpected calls on cash, even where insurance or other risk transfer mechanisms exist. A significant liquidity event or credit rating downgrade could lead to higher financing costs, constrained access to capital, and reduced financial flexibility, forcing us to reprioritize investment, reduce expenditure, or accelerate planned or unplanned divestments or dilutions, potentially at less than the full market value.

We are also exposed to credit risk through financial counterparties, joint ventures, trading partners, receivables, customers, delays in settlements, receipt of divestment proceeds, or divestments not completing when planned. All can impact cash flow and our ability to work within our financial frame and in more severe cases, we may need to review and reallocate financial commitments or long-term obligations such as pension funding arrangements.

Maintaining confidence with investors, lenders, and credit rating agencies is essential to preserving financial resilience and access to affordable funding, especially during periods of capital scarcity or policy uncertainty.

→ [Energy markets, page 6](#)

[Liquidity and capital resources, page 338](#)

[Liquidity, financial capacity and financial, including credit, exposure, page 68](#)

Principal risks and uncertainties (Risk factors) continued

Partner and third-party risk

The performance, standards, or compliance of non-operated joint ventures, strategic partners, contractors, sub-contractors, or other third parties could expose bp to legal, operational, financial, or reputational harm.

Many of our business activities are conducted through partners and third parties – including non-operated joint ventures, strategic partners, contractors, sub-contractors, and suppliers – where we may have limited influence and control over performance or compliance.

Our partners and contractors are responsible for the adequacy of their resources and capabilities, and there may be financial, reputational, operational or safety exposures and consequences for bp if their performance, risk management or governance standards are inadequate, including their safety practices, cyber-attacks, quality or delivery of work, financial management, legal compliance, advocacy positions, and environmental, social and governance (ESG) standards.

In some cases, third parties may not be able or may not be willing to compensate us against all of the costs we may incur on their behalf, or pay their share of losses and liabilities which may arise in connection with the activities in which they have participated. Irrespective of whether or not bp controls or has direct oversight of third parties, we may still be pursued by regulators or claimants, and may still be the focus for interest groups or media attention in the event of an incident.

Digital, cyber security and data risk

Increasing reliance on digital infrastructure, growing AI adoption, and evolving cyber threats exposes bp and our third-party suppliers and contractors to data loss, infrastructure failures, or system compromise which could result in operational disruption, regulatory breaches, significant fines and reputational harm.

bp's digital infrastructure, data platforms, applications and connected technologies are core enablers to our businesses, operations, trading activities, customer engagement, and corporate functions. These systems face fast-evolving cyber threats – including ransomware, nation-state interference, and insider attacks – amplified by complex third-party ecosystems and AI-enabled technologies.

A breach or failure of our third-party supplier's or contractor's digital systems, including operational technology and cloud environments, could result in the loss, misuse, or compromise of sensitive data – including personal, operational, or commercial information.

The loss or misuse of data or sensitive information, including employees' and customers' personal data, injury to people, disruption to our business, harm to the environment or our assets, legal or regulatory breaches, may result in legal liability and significant costs including fines, cost of remediation or reputational consequences.

At the same time, the rapid advancement and scaling of generative and agentic AI – including predictive technologies – presents both significant opportunities and emerging systemic risk. Without clear organization-wide governance, bp may underperform, miss strategic upside, or fall behind on safe and compliant AI deployment.

Critical national infrastructure, data protection and privacy regulations – particularly in sensitive geographies – continue to grow, increasing expectations on security, data sovereignty, ethical use of AI, and accountability for data handling. This reflects the strategic importance of establishing and maintaining resilience, trust, and performance in a fast-digitizing environment. For more on cyber security see [page 360](#).

Climate change and the transition to a lower carbon economy

Developments in policy, law, regulation, technology and markets, including societal and investor sentiment, related to the issue of climate change and the transition to a lower carbon economy could increase costs, reduce revenues, constrain our operations and affect our business plans and financial performance.

Laws, regulations, policies, obligations, government actions, social attitudes and customer preferences relating to climate change and the transition to a lower carbon economy, including the pace of change to any of these factors, and also the pace of the transition itself, could have adverse impacts on our business including on our access to and realization of competitive opportunities, a decline in demand for, or constraints on our ability to sell certain products, constraints on production and supply, adverse litigation and regulatory or litigation outcomes, increased costs from compliance and increased provisions for environmental and legal liabilities.

Investor preferences and sentiment are influenced by ESG considerations including climate change and the transition to a lower carbon economy. Changes in those preferences and sentiment could affect our access to capital markets and our attractiveness to potential investors, potentially resulting in reduced access to financing, increased financing costs and impacts upon our business plans and financial performance.

Technological improvements or innovations that support the transition to a lower carbon economy, and customer preferences or regulatory incentives that alter fuel or power choices, could impact demand for our products (including low carbon energy).

Depending on the nature and speed of any such changes and our response, these changes could increase costs, reduce our profitability, reduce demand for certain products, limit our access to new opportunities, require us to write down certain assets or curtail or cease certain operations, and affect investor sentiment, our access to capital markets, our competitiveness and financial performance.

Policy, legal, regulatory, technological and market developments related to climate change could also affect future price assumptions used in the assessment of recoverability of asset-carrying values. This may affect whether there is continued intent to develop exploration and appraisal of intangible assets; the timing of decommissioning of assets; and the useful economic lives of assets used for the calculation of depreciation and amortization.

Competitiveness

Failure to maintain a competitive strategy, underpinned by a strong portfolio of assets, cost performance, innovative technology, projects and long-term growth opportunities, could negatively impact our investors' confidence in our ability to grow long-term shareholder value and returns.

We operate in an increasingly complex, fast-paced, ever-changing, competitive global energy market with evolving competitor strategies. As an integrated energy company, our ability to remain competitive with a compelling, differentiated proposition for stakeholders depends on the quality and agility of our strategic, commercial, and operational decisions and the execution of those decisions including those related to costs, capital allocation, innovation, technology adoption, portfolio development, customer propositions, and talent deployment.

We could be adversely affected if we fail to anticipate or respond effectively to rapid shifts in policy, consumer preferences, investor expectations, and disruptive competitor activity or fail to protect our intellectual property, increasing the risk of constrained operations and diminished returns, and shareholder expectations.

Ineffective communication of our strategic direction and a compelling value proposition could undermine stakeholder confidence and investor expectations of bp's long-term value.

Talent, leadership and organizational capability

Failure to retain, develop, and attract the talent, leadership, capabilities and behaviours required to deliver our strategy could weaken performance, culture, and long-term value creation.

To manage our costs competitively and build our resilience, we look to simplify and digitalize our processes while evolving our skills and capabilities, in line with our strategy and global market trends. Failure to manage change and transfer knowledge appropriately could decrease efficiency, weaken performance and increase costs.

We face growing competition for high-calibre talent across a diverse set of business and function portfolios, and a broad set of geographies.

Expectations around organizational culture, ways of working, leadership behaviours, and career development opportunities must be balanced with disciplined performance and shared values and behaviours. Failure to attract, develop and retain the right talent, could result in delivery shortfalls, diminished competitiveness, and erosion of stakeholder trust. For more on our people see [page 56](#).

Safety and operational risks

Process safety, personal safety and environmental risks

bp's operations and business activities are exposed to a wide range of safety, operational integrity, and environmental risks – particularly under growing complexity and delivery intensity – which could result in major incidents that harm people or the environment, disrupted operations, damage to bp's reputation, legal liability, undermine our financial standing or threaten our licence to operate.

bp operates in complex and high-risk environments where process safety, personal safety, occupational health, technical integrity, transportation, marine operations, and environmental risks could result in major incidents with significant human, environmental, financial, and reputational consequences. As a result, we could face regulatory action and legal liability, including penalties and remediation obligations, increased costs and, potentially, denial of our licence to operate.

Despite safety controls, barriers, and management systems, failures may still occur due to technical breakdowns, equipment failure, human error, extreme (acute or chronic) weather and climate-related factors, or third-party actions.

Risk exposure is heightened during drilling, production, marine transport and logistics, pipeline operations, project construction or maintenance activities – especially in environmentally sensitive (e.g. areas of water scarcity, biodiversity), remote or geologically complex locations, or where infrastructure reliability and emergency response capabilities are constrained. These risks extend to both the public and our workforce and contractors, including physical safety, life-saving rule violations, and occupational health exposures such as chemical, biological, psychosocial, or infectious risks.

Past incidents across the industry have resulted in fatalities, significant spills, long-term environmental damage, large-scale remediation costs, and lasting reputational harm. bp's ability to maintain the technical integrity of its assets, retain its licence to operate and meet stakeholder expectations, depends on consistently high performance in safety and environmental execution across the portfolio.

As bp continues to scale delivery across a more diversified portfolio it remains essential that safety systems, controls, and organizational safety culture are maintained and strengthened at every level of the business to prevent serious failures, provide operational continuity, and uphold trust with stakeholders.

→ [Safety, page 55](#)

Security

Hostile acts such as terrorism, civil unrest, armed conflict, sabotage, activism, piracy, insider threats, workplace violence, cyber-enabled physical attacks, or threats to personnel security such as kidnapping or detention could harm our people, disrupt operations, compromise critical assets, or damage our reputation.

Security threats may emerge or intensify in response to geopolitical instability, conflict, or state-linked activity that could target critical infrastructure or supply chains. They may also be politically, ideologically, or financially motivated and influenced by regional instability, activism, social unrest, or bp's presence in higher-risk geographies. Increasing interdependence between cyber, information, and physical domains may create additional vulnerabilities across operational technology, logistics, and data-driven systems.

Assets such as pipelines, terminals, transportation routes, offshore platforms, and operational-technology systems could be particularly exposed. The risk of insider activity – including unauthorized data access, sabotage, or information leakage – is also a continuing concern, particularly in complex joint ventures or politically sensitive environments.

The consequences of a major security incident could include operational shutdown, financial loss, workforce harm, legal costs and liabilities or reputational damage. More broadly, a significant incident could disrupt supply chains, invite regulatory scrutiny, or adversely affect confidence in bp's ability to operate safely and reliably in challenging environments.

Product quality

Failure to supply products to customers, meet technical specifications or regulatory standards could lead to harm, operational disruption, reputational damage, or legal and financial consequences.

bp provides products – including fuels, lubricants, petrochemicals, biofuels, and consumables – that meet technical specifications, regulatory requirements, and customer expectations. We operate a complex global value chain spanning production, refining, blending, transportation, and delivery. Failures may arise at any point in this chain due to contamination, formulation errors, process deviation, mislabelling, equipment failure, or inadequate quality assurance.

Product quality risks may originate upstream (e.g. formation variability, production chemistry), midstream (e.g. blending inconsistencies, custody transfer), or downstream (e.g. additives, packaging, distribution). Failures can result in safety incidents, environmental harm, damage to customer equipment, product recalls, legal liability, and loss of brand trust.

As customer expectations and regulatory regimes evolve – particularly regarding decarbonized and high-integrity products – maintaining end-to-end product integrity is critical to safeguarding our reputation, maintaining brand trust, securing market access, and protecting long-term commercial relationships. Widespread or high-profile failures could result in product recalls, legal exposure, or reputational harm – especially in regulated or safety-critical sectors.

Principal risks and uncertainties (Risk factors) continued

Compliance and control risks

Legal, regulatory and ethical compliance

Ethical misconduct, non-compliance with law and regulation or changes in law and regulation could increase costs, constrain our operations and affect our strategy, business plans and financial performance. Incidents of ethical misconduct or non-compliance could also damage our reputation and result in litigation, regulatory action, penalties and potentially affect our licence to operate.

Incidents of ethical misconduct or non-compliance with applicable laws and regulations, including anti-bribery and corruption, competition and antitrust, data privacy, and anti-fraud laws, trade restrictions or other sanctions, could damage our reputation, and result in litigation, regulatory action, penalties and potentially affect our licence to operate. In relation to trade restrictions or other sanctions, current geopolitical factors have increased these risks.

Our businesses and operations are subject to the laws and regulations applicable in each country, state or other regional or local area in which they occur. These laws and regulations result in an often complex, uncertain and changing legal and regulatory environment for our global businesses and operations. Changes in laws or regulations, including how they are interpreted and enforced, can and do impact all aspects of our business.

Royalties and taxes, particularly those applied to our hydrocarbon activities, tend to be high compared with those imposed on similar commercial activities. In certain jurisdictions there is also a degree of uncertainty relating to tax law interpretation and changes.

Governments may change their fiscal and regulatory frameworks in response to public pressure on finances or for other policy reasons, resulting in increased amounts payable to them or their agencies.

Changes in law or regulation could increase the compliance and litigation risk and costs, reduce our profitability, reduce demand for or constrain our ability to sell certain products, limit our access to new opportunities, require us to divest or write down certain assets or curtail or cease certain operations, or affect the adequacy of our provisions for pensions, tax, decommissioning, environmental and legal liabilities.

Changes in laws or regulations could result in the nationalization, expropriation, cancellation, non-renewal or renegotiation of our interests, assets and related rights. Potential changes to pension or financial market regulation could also impact funding requirements of the group. Following the Gulf of America oil spill, we may be subjected to a higher level of fines or penalties imposed in relation to any alleged breaches of laws or regulations, which could result in increased costs.

Financial and physical commodity trading activities

We undertake physical and financial trading across global commodity and financial markets. Risk associated with our trading activities could arise from a failure to maintain robust oversight, controls, and disciplined execution in our trading activities which could result in business disruption, financial loss, regulatory action, or reputational damage.

We conduct physical and financial trading across global commodity and financial markets, both on exchange and 'over the counter', some of which are financially regulated activities. Our trading activities expose us to multiple risks, including market, credit, operational, conduct, liquidity and regulatory risks. Failure to maintain effective oversight and controls, and disciplined execution in our trading activities, could result in business disruption, financial loss, reputational harm, regulatory intervention, and/or impair our ability to operate.

There is a risk that a single trader or a group of traders could act outside of our delegations and controls, leading to regulatory intervention and resulting in financial loss, fines and potentially damaging our reputation, and could affect our permissions to trade.

Integrity of financial and non-financial reporting

Failure to maintain integrity in financial and non-financial reporting may result in material misstatement or regulatory breach, which could lead to regulatory action, legal liability and reputational damage.

The accuracy and reliability of our external reporting depends on the strength of our internal control environment, the robustness of our systems and data governance, and our people.

Failure to accurately report our data – including financial results, sustainability and environmental, social and governance disclosures, reserves estimates, and operational performance – could lead to regulatory action, legal liability, investor action and reputational damage.

How we manage principal risks and uncertainties

How we manage principal risks and uncertainties

bp manages its principal risks and uncertainties through our system of internal control (described earlier in this section). The following pages set out the key risk management activities for each principal risk.

There can be no certainty that our risk management activities will mitigate or prevent these, or other risks, from occurring. Further details of the principal risks and uncertainties faced are set out on [page 62](#).

Strategic and commercial risks

Commodity prices and market environment: We seek to manage this risk through market analysis and strategic scenario planning, which inform our portfolio, business development, and capital allocation decisions. This analysis draws on internal and external data sources provided by our global energy and trading insights teams (supply, trading & shipping (ST&S) and economics & energy insights). Outputs are integrated into our planning and investment governance processes and reviewed regularly by management.

We assess the implications of price, margin, and exchange rate volatility across a range of scenarios and test the robustness of investment cases against changing macroeconomic and regulatory assumptions. The *bp Energy Outlook* is updated annually to reflect shifts in policy, demand, and trade patterns.

Our strategy is designed to remain resilient across a wide range of market conditions. This is supported by a diversified portfolio, a disciplined financial frame, and an ongoing focus on capital efficiency and investment flexibility.

Accessing and producing hydrocarbon resources: We seek to manage this risk through our subsurface teams in production & operations (P&O) and gas & low carbon energy, who have responsibility for accessing and progressing hydrocarbons resources. The teams are accountable for delivering high-value resources to support our strategic and financial goals. They work closely with technology and other enabling functions to assess resource potential, prioritize opportunities, and advance viable projects. P&O executes capital and operational activities and is accountable for safe, competitive, and efficient delivery.

Risk management is embedded through our Operating Management System (OMS) and a suite of supporting frameworks embed quality, control, and investment discipline. These include the Exploration Common Process, Discovered Resource Management, Area Development Planning, and the Group Investment Assurance and Approvals Process (GIAAP). Together, they guide how we identify, evaluate, approve and deliver access and development opportunities. Data often enables our ability to pivot and adjust plans after a materialized risk.

This risk is monitored through established governance and management processes, including regular review of performance indicators, assurance outcomes, and incident learnings, with escalation through appropriate executive and board-level forums where required.

→ [Our strategy, page 8](#)

Major project delivery: We seek to manage this risk through a structured, disciplined approach to investment appraisal, project execution, and performance governance. Our projects organization exists to assess, develop, and execute projects across bp, providing deep technical expertise in capital delivery, design, execution, and integration. It operates under a globally aligned Project Delivery Common Process, adapted to project size, complexity, and risk.

Major projects are subject to rigorous assurance throughout the lifecycle – from early framing and appraisal through to commissioning and performance evaluation. Defined stage gates, verification reviews, and central investment governance provide disciplined decision making and alignment to strategic objectives.

A structured management of change process enables any technical, commercial, or scope variations can be assessed, approved and documented through appropriate governance channels, helping to protect cost, schedule and safety integrity.

Within the design phase of our projects, we consider metocean criteria against historic and projected models and environmental impact factors.

Investments are evaluated against a balanced set of investment criteria – for example, assessment of economics includes a set of price assumptions that reflects our view of market evolution and the economics of all investment cases where bp's share of annual greenhouse gas (GHG) emissions from operations are anticipated to exceed certain thresholds include a carbon price for those emissions.

Oversight is maintained through performance reviews, supplemented by discipline checks, post-project evaluations, and capital forecasting cycles. Cross-functional forums provide alignment between project, commercial, and procurement functions. This governance framework enables consistent assurance, early identification of delivery challenges, and investment decisions aligned with strategic and performance expectations.

Note: Large-scale digital or transformation programmes that interface with capital delivery are assessed through equivalent governance and assurance to protect schedule, cost, and performance integrity.

How we manage principal risks and uncertainties continued

Geopolitical exposure: We seek to manage this risk through intelligence and international advisory, which integrates geopolitical horizon scanning, strategic and baseline threat assessments, deal-specific risk support, and the New Country Entry process. Together, these mechanisms support real-time decision making, portfolio resilience, and longer-term strategic investments.

Our geopolitical advisory council provides an independent perspective on macro-level geopolitical trends.

At an operational level, we have defined government-relations and stakeholder-engagement processes that seek to maintain trusted relationships in host countries. Where appropriate, risk mitigation and contingency plans are developed, and ongoing monitoring is overseen through intelligence, security and crisis management.

Liquidity, capital access and financial resilience: We seek to manage this risk through a combination of governance, planning, and treasury controls, including:

Financial frame governance provides a disciplined approach to capital allocation, balance sheet strength, and investment priorities. This helps bp maintain a resilient dividend, a strong investment-grade credit rating, and a clear hierarchy of capital uses, supported by regular board and group financial risk committee review.

Our disciplined Liquidity Management Framework (LMF), which is embedded within the treasury function and reviewed regularly by senior management, defines clear thresholds for undrawn committed credit facilities, minimum cash buffers, liquidity stress testing parameters, and monitoring routines. The LMF also integrates our Commercial Paper (CP) programme, governs the investment of treasury cash with defined exposure limits, and connects with the capital markets team to issue securities that sustain cash levels.

Together, these frameworks help create a strong, flexible balance sheet, preserve access to capital markets, and enable us to respond effectively to external shocks or market disruptions.

→ [Liquidity and capital resources, page 338](#)
[Financial statements – Note 29](#)

Partner and third-party risk: We seek to manage partner and third-party risk, including exposure from non-operated joint ventures, contractors, and sub-contractors, through a combination of governance, self-verification & oversight, assurance, and commercial controls designed to provide proportionate oversight and influence where bp does not have operational control.

For joint ventures, accountability for day-to-day oversight rests with the business unit or function holding bp's equity interest, supported by non-operated joint venture solutions, which provides guidance on risk exposure management, strategic governance, self-verification & oversight, and assurance. Exposure in non-operated joint ventures is monitored through a risk barometer, periodic risk reviews, and targeted assurance activities, with escalation to executive or board-level committees where appropriate.

For contractors, suppliers, and other third parties, we apply a structured procurement framework. This includes pre-engagement and ongoing due diligence covering financial stability, legal compliance, anti-bribery and corruption (ABC), labour practices, cyber security, and sustainability performance. Supplier relationships are tiered (transactional, core, strategic) to provide proportionate oversight, and key contracts embed our expectations and standards on safety, ethics, and operational integrity.

We review and, where appropriate, enhance governance arrangements for strategic partnerships, capital-light ventures, and high-exposure third parties as part of our established oversight cycle to confirm that assurance and engagement are commensurate with bp's level of influence and potential exposure.

Together, these measures support informed oversight of our third-party relationships and help protect bp's delivery, integrity, and reputation where operational control is limited.

Digital, cyber security and data risk: We seek to manage this risk through an approach aligned with global standards, including the National Institute of Standards and Technology Cybersecurity Framework, as well as our internal requirements for cyber security, digital infrastructure, data privacy, and responsible AI. Our controls span cyber defence tools, resilience testing, third-party oversight, and ethical data governance.

We continuously monitor the evolving threat landscape and emerging technologies – including AI, quantum computing, and cloud infrastructure – to identify potential vulnerabilities and disruptors. Cyber threat detection, security testing, and ethical hacking are supported by incident response protocols and a delegated authority model to isolate or disconnect operations when needed. We actively manage our resilience capability and maturity, with the ability to activate protocols to restore systems and data to protect prioritized critical business outcomes while minimizing disruption.

We collaborate with government bodies, law enforcement, and industry peers to track and respond to fast-evolving threats. We reinforce a culture of digital responsibility through employee training, exercises (including prolonged IT outage scenarios) to test response and recovery procedures, and executive-level briefings. Regular maturity assessments and operational reviews help track organizational resilience across infrastructure, data, and third-party digital dependencies.

→ [Cyber security disclosures, page 360](#)

Climate change and the transition to a lower carbon economy: Developments in policy, law, regulation, technology and markets, including societal and investor sentiment, related to the issue of climate change and the transition to a lower carbon economy could increase costs, reduce revenues, constrain our operations and affect our business plans and financial performance.

Risks associated with climate change and the transition to a lower carbon economy impact many elements of our strategy and, as such, these risks are managed through key business processes including setting the bp strategy and annual plan, capital allocation and investment decisions. The outputs of these key business processes are reviewed in line with the cadence of these activities. See [page 47](#) for more information on how transition risks and opportunities are managed.

→ [Climate-related financial disclosures, page 41](#) and [Financial statements – Note 1 and Note 33](#)

Competitiveness: We seek to manage this risk jointly through our investor relations and competitor insights (IR&CI) and strategy teams.

The IR&CI and strategy teams work closely with communications and external affairs teams, business teams and functions to support the shaping of our future strategy by gathering and synthesizing market and sector intelligence and investor sentiment and analysing our performance through competitor benchmarking.

Our strategy team evaluates longer-term trends and monitors macro themes as we seek to maintain a distinct competitive advantage that underpins our value proposition.

Through market updates, analyst calls, investor meetings, media outreach and our corporate reporting, IR&CI communicates and engages with investors and stakeholders to gather feedback, address concerns, and monitor shifts in investor sentiment. This informs any necessary adjustments to our portfolio, capital allocation, technology and performance required to keep pace with current and future market demands.

The articulation of our unique value proposition and strategic priorities to investors, analysts, and other stakeholders builds understanding and confidence in how we are seeking to grow value and returns, and navigate risks, by adapting and capitalizing on opportunities in a fast-changing environment.

Talent, leadership and organizational capability: We seek to manage this risk through global, scalable talent strategies, which can effectively adapt and support the resourcing needs of bp's strategy. Our people, culture & communications team works in partnership with business leaders to attract, develop and retain the capabilities needed to deliver our strategy.

Strategic workforce planning is supported by market intelligence, people analytics, and scenario modelling to assess talent supply, demand, and future skills needs. Robust talent acquisition frameworks and early careers programmes help to build a pipeline of diverse and critical skills, while targeted learning platforms and leadership offers support continuous development.

We embed clear succession planning and performance development processes to identify and support high-potential individuals, with emphasis on building leadership depth and capability across the organization. Employee listening mechanisms such as the annual Pulse survey, culture assessments, and behavioural insight tools help assess engagement, cultural alignment, and employees' resilience to change.

Knowledge transfer and changes in accountability are managed through a robust management of change process. bp's culture is embedded with bp's code of conduct and our culture frame 'Who we are'.

→ [People, page 55](#)

Safety and operational risks

Process safety, personal safety, and environmental risks: We seek to manage process safety, personal safety, and environmental risks through our Operating Management System★ (OMS), which defines the standards and systematic practices for safe, reliable, and compliant operations. Key activities include inspection, maintenance, testing, incident investigation, and workforce competency development. It provides a risk-based framework for identifying, assessing, and mitigating hazards throughout the lifecycle of our operations.

Our dedicated wells organization applies consistent processes for well design, construction, and management. Production & operations plays a central role in managing safety and environmental risks across hydrocarbon operations. It is accountable for maintaining safe, compliant, and reliable performance and promotes a strong safety culture across sites and partners.

These activities are supported by regular monitoring, assurance and review through bp's established management and governance processes, with escalation where exposure changes or issues arise.

→ [Safety, page 55](#)

Security: We seek to manage this risk through bp's global Security Risk Management Framework, which provides structured processes for identifying, assessing, and mitigating security threats (including those linked to geopolitical instability or hybrid conflict) at both strategic and operational levels. The framework integrates oversight from intelligence, security and crisis management (ISC) and is supported by our network of business security representatives.

Key components include the Unified Risk Picture threat assessment methodology, which provides consistent visibility of priority risks and vulnerabilities across the group; insider risk management processes addressing unauthorized access, sabotage, and data exfiltration; executive protection protocols for high-profile personnel; security governance and policy standards aligned with industry best practice; technology assessments that keep site security infrastructure fit-for-purpose, and rigorous compliance with the Voluntary Principles on Security and Human Rights.

The framework operates under a defined governance structure with regular reviews by the ISC, annual risk assessments, and periodic assurance reviews. It also supports bp's crisis management and business continuity planning, which provides co-ordinated preparedness and response to potential security incidents across regions and assets. Where appropriate, emerging activism, misinformation, or social unrest trends are monitored to anticipate and manage potential threats to bp's people and operations.

Product quality: We seek to manage product quality risk across our global value chain by our operating businesses, working in close partnership with the applied sciences quality assurance team. We use a structured Product Quality Framework aligned with our Operating Management System, which includes quality standards, risk assessments, incident management, and assurance processes. Where necessary, we apply industry-specific or enhanced internal standards, particularly in sectors such as aviation.

This risk is monitored through established governance and management processes, including regular review of performance indicators, assurance outcomes, and incident learnings, with escalation through appropriate executive and board-level forums where required.

How we manage principal risks and uncertainties continued

Compliance and control risks

Legal, regulatory and ethical compliance: With support of our businesses and functions, we seek to identify, assess and manage legal and regulatory risks relevant to bp's operations, strategy, business plans and financial performance. To support this work, we seek to develop co-operative relationships with governmental authorities in line with our code of conduct, to allow appropriate focus on areas of potential risk or uncertainty, while also protecting bp's interests within the law.

Our code of conduct, the foundation of our culture frame 'Who we are', is applicable to all employees and central to managing this risk. Additionally, we have group requirements and training covering areas such as anti-bribery and corruption, anti-money laundering, competition/anti-trust law, data privacy and international trade regulations. We offer an independent confidential helpline, 'OpenTalk', for employees, contractors and other third parties, with the option to raise concerns anonymously.

Financial and physical commodity trading

activities: We seek to manage risks associated with financial and physical commodity trading through dedicated risk control frameworks with defined delegated authorities, monitoring, and oversight structures.

Trading is conducted by authorized personnel operating within approved mandates and limit structures. Activities and associated risks are actively managed and monitored, in line with the group-wide three lines of defence model which includes independent risk and compliance functions. As part of this risk model, robust control frameworks, risk-based monitoring, exception reporting and escalation protocols are in place.

→ **Financial statements – Note 29**

Integrity of financial and non-financial reporting

reporting: We seek to manage this risk through group-wide financial and non-financial reporting, control and assurance frameworks designed by our finance organization. The control operation and assurance activities within these frameworks are executed at multiple levels within our businesses and functions, following a 'line-of-defence' model.

For financial reporting, we apply bp's Sarbanes Oxley (SOx) Management Assessment Framework, which includes annual control testing; deficiency evaluations and reporting; an annual acknowledgement process confirming performance of control owner accountabilities; quarterly representations from our businesses and functions; and enterprise-level control assessments.

For non-financial reporting, we follow our ESG and non-financial reporting (ESG-NFR) control and assurance framework, which includes help to determine the appropriate level of control and assurance activity to be applied, annual due diligence with control owners and pre-publication reviews.

We also maintain a Fraud Risk Management Governance Framework to identify, assess and mitigate the risk of fraudulent activity.

As reporting expectations and requirements evolve under various frameworks and regulations in the UK and in other jurisdictions, we continue to review and enhance, as needed, our reporting controls, approach to assurance and approach to disclosure.

Compliance information

bp non-financial and sustainability information statement

Produced in compliance with Sections 414CA and 414CB of the Companies Act. Information incorporated by cross reference.

Requirement	Relevant policies and standards	Information related to policies and any due diligence processes
a Environmental matters	<ul style="list-style-type: none"> Net zero aims TCFD Sustainability frame Biodiversity position (online) 	<ul style="list-style-type: none"> Climate-related financial disclosures - pages 41-54 People and planet - page 59 Our Operating Management System★ (OMS) - page 55 Decision making by the board - page 81
b Employees	<ul style="list-style-type: none"> bp values and code of conduct (online) 	<ul style="list-style-type: none"> Our people - page 56 Safety - page 55 Our values ('Who we are') and code of conduct - pages 57-58 Employee engagement (Pulse annual and Pulse live employee surveys) - page 57 How the board engaged with stakeholders (workforce) - page 80
c Social matters	<ul style="list-style-type: none"> Sustainability frame 	<ul style="list-style-type: none"> Our Operating Management System★ (OMS) - page 55 Improving people's lives - page 59 Decision making by the board - page 81
d Respect for human rights	<ul style="list-style-type: none"> Business and human rights policy (online) Modern slavery statement (online) Labour rights and modern slavery principles (online) Code of conduct (online) 	<ul style="list-style-type: none"> Improving people's lives - page 59 Human rights - page 59 Our values ('Who we are') and code of conduct - pages 57-58
e Anti-corruption and anti-bribery	<ul style="list-style-type: none"> Anti-bribery and corruption policy Code of conduct (online) 	<ul style="list-style-type: none"> Ethics and compliance - page 58 Our partners in joint arrangements - page 56
Description of principal risks relating to matters (a-e above)		<ul style="list-style-type: none"> How we manage risk - pages 67-70 Risk factors - page 62 TCFD (climate-related risk management) - pages 44-45
Relevant information		
Business model description	<ul style="list-style-type: none"> Business model - page 12 	
Description of non-financial KPIs	<ul style="list-style-type: none"> Measuring our progress - pages 16-17 	

TCFD index table^a

Our TCFD disclosures can be found on the following pages.

TCFD Recommendation	TCFD Recommended Disclosure	Where reported
Governance Disclose the organization's governance around climate-related issues and opportunities.	a Describe the board's oversight of climate-related risks and opportunities.	<ul style="list-style-type: none"> Page 44
	b Describe management's role in assessing and managing climate-related risks and opportunities.	<ul style="list-style-type: none"> Page 45
Strategy Disclose the actual and potential impacts of climate-related risks and opportunities on the organization's business, strategy and financial planning where such information is material.	a Describe the climate-related risks and opportunities the organization has identified over the short, medium, and long term.	<ul style="list-style-type: none"> TCFD Strategy a, page 46 Pursuing a strategy that is consistent with the Paris goals, page 10 Strategy, page 8 Risk factors, page 67
	b Describe the impact of climate-related risks and opportunities on the organization's businesses, strategy, and financial planning.	<ul style="list-style-type: none"> TCFD Strategy b, page 46 Risk factors, page 67 - description of principal risks Strategy, page 8
	c Describe the resilience of the organization's strategy, taking into consideration different climate-related scenarios, including a 2°C or lower scenario.	<ul style="list-style-type: none"> TCFD Strategy c, page 49 Strategy, page 8 Pursuing a strategy that is consistent with the Paris goals, page 10
Risk management Disclose how the organization identifies, assesses and manages climate-related risks.	a Describe the organization's processes for identifying and assessing climate-related risks.	<ul style="list-style-type: none"> Risk Management, page 44 How we manage risk, page 60 Risk factors, page 67
	b Describe the organization's processes for managing climate-related risks.	<ul style="list-style-type: none"> Risk Management, page 44 How we manage risk, page 60
	c Describe how processes for identifying, assessing, and managing climate-related risks are integrated into the organization's overall risk management.	<ul style="list-style-type: none"> Risk Management, page 44 How we manage risk, page 60 Risk factors, page 67
Metrics and targets Disclose the metrics and targets used to assess and manage relevant climate-related risks and opportunities where such information is material.	a Disclose the metrics used by the organization to assess climate-related risks and opportunities in line with its strategy and risk management process.	<ul style="list-style-type: none"> TCFD metrics and targets, page 54
	b Disclose Scope 1, Scope 2, and, if appropriate, Scope 3 GHG emissions, and the related risks.	<ul style="list-style-type: none"> GHG emissions data, page 38
	c Describe the targets used by the organization to manage climate-related risks and opportunities and performance against targets.	<ul style="list-style-type: none"> Our net zero aims and targets, pages 37-38

a We consider the information in our TCFD disclosures, taken together with our climate-related non-financial KPIs on pages 16-17 of this report, to be compliant with the disclosure requirements of Section 414CB of the Companies Act, as amended by the UK CFD Regulations.

Section 172 statement

In accordance with the requirements of Section 172 of the Companies Act 2006 (the Act), the directors consider that, during the financial year ended 31 December 2025, they have acted in a way that they consider, in good faith, would most likely promote the success of the company for the benefit of its members as a whole, having regard to the likely consequences of any decision in the long term and the broader interests of other stakeholders, as required by the Act.

→ For more information in support of this statement, see [board activities, page 78](#), [our stakeholders, page 80](#) and [key decisions, page 81](#)

The strategic report was approved by the board and signed on its behalf by Ben J.S. Mathews, company secretary, on 6 March 2026.

Corporate governance

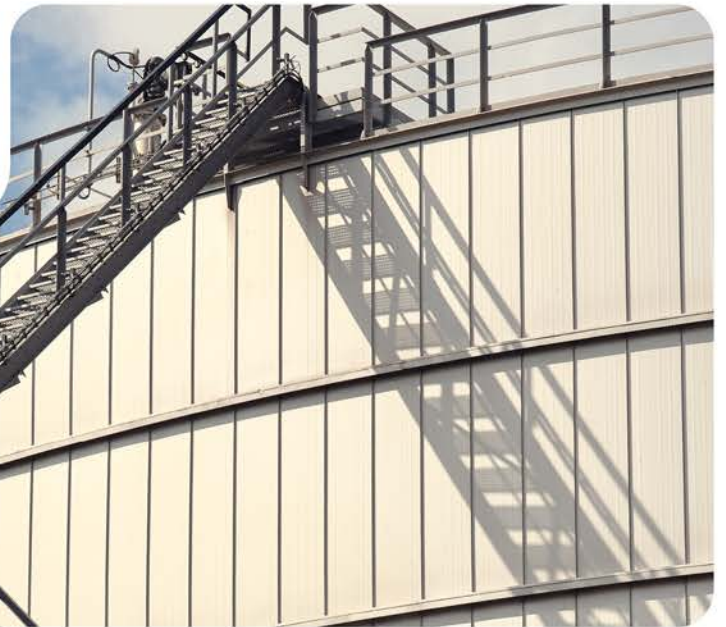
“In early 2025 the board’s focus moved from the resetting of strategy to overseeing disciplined performance and the delivery of our four primary financial targets.”

Albert Manifold
Chair

→ [Read Albert’s letter on page 4](#)

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Image: Rotterdam refinery, Netherlands



Board composition

Board gender diversity

	March 2026	March 2025
Female	6	6
Male	7	5

46%

of directors are female

Board ethnic diversity

	March 2026	March 2025
White	10	8
Asian	3	3

3

directors who identify as from a minority ethnic background

Non-executive directors’ tenure

	March 2026	March 2025
1-3 years	4	3
4-6 years	6	5
7-9 years	1	1

→ [Board biographies, page 73](#)

Board of directors

As at 6 March 2026



Albert Manifold
Chair

Appointed Board: 1 September 2025;
chair: 1 October 2025

Nationality Irish

External appointments

- Non-executive director at LyondellBasell Industries.
- Non-executive director at Mercury Engineering.
- Adviser to Clayton Dubilier & Rice.

Significant past appointments

- A number of senior positions at CRH plc over a 28-year career, including chief executive officer from January 2014 to December 2024.
- Chief operating officer of Allen McGuire & Partners.

Key skills and experience

- Extensive experience of driving a business through exceptional growth and strategic transformations, leading to profitability and cash generation, and consistently improving returns to shareholders.
- Certified public accountant and a chartered accountant. Holds a master of business administration and a master's in business studies, both from Dublin City University.



Carol Howle
Interim chief executive officer

Appointed 18 December 2025

Nationality British

External appointments

- Non-executive board member of the Royal Navy.

Significant past appointments

- Various senior leadership roles at bp, including executive vice president, supply, trading & shipping and chief operating officer for integrated supply and trading, oil.

Key skills and experience

- With 25 years at bp, Carol has a deep knowledge of the company and extensive experience in the energy industry. Carol is also a non-executive board member of the Royal Navy and chair of the Navy Audit and Risk Assurance Committee.



Kate Thomson
Chief financial officer

Appointed 2 February 2024

Nationality British

External appointments

- Board member of Aker BP since 2016.
- Main committee member of The 100 Group.

Significant past appointments

- Joined bp in 2004.
- Group head of tax, BP p.l.c.
- Group treasurer, BP p.l.c.
- SVP finance for production & operations, BP p.l.c.

Key skills and experience

- Has a detailed understanding and experience of the energy sector and provides deep technical insight from her broad experience of leading teams across the bp group in tax, treasury and commercial finance.



Dame Amanda Blanc
Independent non-executive director

Appointed 1 September 2022

Nationality British

External appointments

- Group CEO of Aviva plc.
- Member of the Association of British Insurers Board.
- Member of the UK Government's British Infrastructure Taskforce.

Significant past appointments

- CEO of Europe, Middle East, Africa & Global Banking at Zurich Insurance Group.
- Group CEO at AXA UK, PPP & Ireland.
- Several senior executive roles across the insurance industry.
- Member of the Prime Minister's Business Council.
- Member of HMT National Wealth Fund Taskforce.

Key skills and experience

- Brings wide-ranging board experience with strong industry and regulatory connections having previously been Chair of the Association of British Insurers.
- Combines the experience of leading insurance businesses in the UK and Europe with being a member of HM Treasury's Business Infrastructure Taskforce.



Tushar Morzaria
Independent non-executive director

Appointed 1 September 2020

Nationality British

External appointments

- Non-executive director of BT Group plc.
- Non-executive director of Legal & General Group plc.

Significant past appointments

- Various senior roles at JP Morgan, including CFO of its Corporate & Investment Bank.
- Group finance director and member of the board of Barclays PLC, 2013 to 2022.
- Non-executive chairman of EMEA Investment Banking, Barclays until 2024.

Key skills and experience

- Over 25 years of strategic financial management, investment banking, operational and regulatory experience.
- Breadth of knowledge and insight into financial, tax, treasury, investor relations and strategic matters and strong experience in delivering corporate change programmes while maintaining a focus on performance.

Key

- Executive director
- Non-executive director
- Leadership team member

Committee members key

- Committee chair
- Safety and sustainability committee
- Audit committee
- People, culture and governance committee
- Remuneration committee

For further detail on the directors' climate change and sustainability experience, see the TCFD section on [page 41](#), and further biographical information for each director is available online at:

bp.com/whoware

Board of directors continued

Ian Tyler
Independent
non-executive director



Appointed 1 April 2025

Nationality British

External appointments

- Chair of Grafton Group plc.
- Senior Independent Director of Anglo American plc.
- Chair of BMT Group Ltd.
- Member of KPMG Public Interest Committee

Significant past appointments

- Served as chair of Affinity Water Limited, AWE Management Limited, Al Noor plc, Amey UK plc, Vistry Group plc (formerly Bovis Homes Group) and of Cairn Energy plc.
- Non-executive director of BAE Systems plc, VT Group plc, Mediclinic plc, Cable & Wireless Communications plc, and Synthomer plc.
- CEO and finance director positions at Balfour Beatty plc.

Key skills and experience

- Extensive executive and non-executive experience across multiple industries.
- Recent experience leading the remuneration committees of some of the UK's largest quoted companies.

Melody Meyer
Independent
non-executive director



Appointed 17 May 2017

Nationality American

External appointments

- Non-executive director of AbbVie Inc.
- Non-executive director of Airswift Parent LLC.
- President of Melody Meyer Energy LLC and Women with Energy LLC.
- Director of the National Bureau of Asian Research.
- Advisory board member of McKinsey Advancing With Excellence.
- Trustee of Trinity University.

Significant past appointments

- President of Chevron Asia Pacific E&P until 2016 after 37 years of service in key leadership roles in global exploration and production.

Key skills and experience

- Deep understanding of the factors influencing safe, efficient and commercially high-performing projects in a global organization.
- Expertise in the execution of major capital projects, technology, R&D, creation of businesses in new countries, strategic business planning, merger integration, leading change, and safe and reliable operations.

Satish Pai
Independent
non-executive director



Appointed 1 March 2023

Nationality Indian

External appointments

- Managing Director of Hindalco Industries Limited.
- Director of Novelis Inc.
- Non-executive director, Aditya Birla Management Corporation Ltd.
- Director, Indian Institute of Metals.

Significant past appointments

- Executive vice president, worldwide operations and other engineering and management roles at Schlumberger across 28 years of service.

Key skills and experience

- Accomplished and transformative executive with operations and technology experience in the resources and energy industries.
- Strong digital capability and experience.

Dr Johannes Teysen
Independent
non-executive director



Appointed 1 January 2021

Nationality German

External appointments

- Senior advisor to Kohlberg Kravis Roberts.
- President of Alpiq Holding Ltd.
- Senior advisor to Viridor Limited.

Significant past appointments

- Several leadership positions at VEBA AG (merged with VIAG AG in 2000 and renamed to E.ON AG and later to E.ON SE).
- Member of the board of management of the E.ON Group's central management company in Munich in 2001 and E.ON SE in 2004.
- Vice-chair of E.ON SE, 2008 and CEO, 2010 to 2021.
- President of Eurelectric, 2013 to 2015.
- Vice-chair of the World Energy Council, responsible for Europe, 2006 to 2012.
- Member of the supervisory board of Salzgitter AG, 2006 to 2016, and Deutsche Bank AG, 2008 to 2018.

Key skills and experience

- Extensive experience and deep knowledge of the energy sector and its continuing transformation.
- Considerable knowledge and experience of climate-related risk oversight.

Hina Nagarajan
Independent
non-executive director



Appointed 1 March 2023

Nationality Indian

External appointments

- President of Diageo Africa.
- Executive Director and Vice Chairperson of East African Breweries PLC and Member of Board Nomination and Remuneration Committee.
- Member of the Global Executive Committee of Diageo plc.

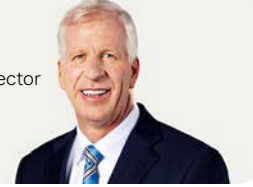
Significant past appointments

- Leadership positions at United Spirits Limited (Diageo India), Reckitt, Mary Kay India and Nestlé India with over 30 years' experience in the fast-moving consumer goods (FMCG) industry.
- Non-executive director at two companies which were publicly quoted at the time: Guinness Ghana Breweries Plc and Seychelles Breweries Limited.
- Board member of The Advertising Standards Council of India.
- Director and Co-Chair of International Spirits and Wines Association of India.

Key skills and experience

- Deep and wide-ranging experience in customer-focused FMCG businesses in complex emerging markets.
- Extensive experience in assessing climate-related risks and opportunities.

Dave Hager
Independent
non-executive director



Appointed 2 June 2025

Nationality American

External appointments

- none.

Significant past appointments

- Leadership positions at the Oryx Energy Company.
- Executive vice president and later chief operating officer of Kerr-McGee.
- Board memberships with EnLink Midstream and Pride International Inc.
- Various senior leadership roles at the Devon Energy Corporation, including executive chairman, 2021 to 2013.
- Director of MRC Global Inc.

Key skills and experience

- Over 40 years' experience in the oil and gas industry.
- Deep-rooted knowledge of the US upstream oil and gas industry.



Karen Richardson
Independent non-executive director

Appointed 1 January 2021

Nationality American

External appointments

- Partner at Artius Capital Partners.
- Non-executive director of Artius II Acquisition Inc.
- Non-executive director (lead independent director) of Exponent Inc.

Significant past appointments

- Senior operating roles in the public and private technology sectors.
- Vice president of sales at Netscape Communications Corporation, 1995 to 1998.
- Senior executive roles at E.piphany from 1998, including CEO, 2003 to 2006.
- Non-executive director of BT plc, 2011 to 2018.
- Director of Worldpay Inc. (Worldpay Group plc), 2016 to 2019.
- Chair of Origin Materials Inc., 2021 to 2024.

Key skills and experience

- Extensive digital, technology, cyber and IT security knowledge.
- 30 years' technology industry experience including working with innovative Silicon Valley companies.



Simon Henry
Independent non-executive director

Appointed 1 September 2025

Nationality British

External appointments

- Advisor to the Board of Oxford Flow Ltd.
- Member of the Board of the Audit Committee Chairs' Independent Forum.

Significant past appointments

- Non-executive director of Rio Tinto plc between 2017 and 2025.
- Directorships with Harbour Energy plc, Lloyds Banking Group plc and PetroChina Ltd.
- Various senior executive and leadership roles at Shell, including chief financial officer from 2009 to 2017.

Key skills and experience

- Extensive career in energy industry internationally with broad experience of the global upstream and downstream energy industry.
- Wide-ranging expertise and experience with financial and commercial understanding of global markets.



Ben J S Mathews
Company secretary

Appointed 7 May 2019

Role and career summary

Ben joined bp as company secretary in May 2019. He is co-chair of the Corporate Governance Council of the Conference Board and is a Fellow of the Chartered Governance Institute. Ben serves on the executive committee of the Association of General Counsel and Company Secretaries of the FTSE 100 (GC100), having previously served as its chair for four years.

Ben's global company secretary team is responsible for providing independent advice and support to the plc board and the boards of all other legal entities in the bp group. The team's vision is to enhance stakeholder value through dynamic corporate governance.

Former appointments include group company secretary of HSBC Holdings plc and Rio Tinto plc.

	Board meeting attendance		Committee membership				Skills and experience							
	Scheduled	Ad hoc	Audit	Remuneration	People, culture and governance	Safety and sustainability	Society, politics and geopolitics	Technology, digital and innovation	People leadership and organizational transformation	Operational excellence and risk management	Global business leadership and governance	Finance, risk and trading	Energy markets	Climate change and sustainability
Non-executive directors														
Albert Manifold (Chair) ^{a,b}	3/3	2/2			●		●		●		●	●		●
Helge Lund (Chair) ^a	6/6	2/2			●		●		●		●		●	●
Dame Amanda Blanc	8/8	5/5		●	●		●		●		●	●		●
Pamela Daley ^{a,c}	2/4	1/2	●	●							●	●	●	
Dave Hager ^{a,b}	4/4	2/2				●		●	●		●	●	●	●
Simon Henry ^a	3/3	2/2					●	●	●		●	●	●	●
Tushar Morzaría ^{b,c}	8/8	4/5	●	●				●	●		●	●		
Melody Meyer ^c	8/8	4/5		●		●			●		●		●	●
Hina Nagarajan ^c	6/8	5/5	●		●		●		●		●		●	●
Satish Pai ^c	8/8	4/5				●		●	●		●		●	●
Karen Richardson ^c	8/8	4/5	●					●	●		●	●		
Dr Johannes Teysen	8/8	5/5			●	●		●	●		●	●	●	●
Ian Tyler ^{a,b}	6/6	3/3	●	●				●	●		●	●		
Executive directors														
Carol Howle (CEO) ^a	0/0	0/0												
Murray Auchincloss (CEO) ^a	8/8	5/5												
Kate Thomson (CFO)	8/8	5/5												

● Chair of the committee ● Member of the committee

a Board changes: The appointments to the board were Ian Tyler (1 April 2025), Dave Hager (2 June 2025), Simon Henry (1 September 2025), Albert Manifold (1 September 2025; chair of the board from 1 October 2025) and Carol Howle (18 December 2025). Pamela Daley (7 July 2025), Helge Lund (30 September 2025), and Murray Auchincloss (18 December 2025) stepped down. Each director attended all board meetings following their appointment or prior to their retirement from the board, as applicable.

b Committee changes: Tushar Morzaría chaired the remuneration committee until 16 April 2025; Ian Tyler became remuneration committee chair from 17 April 2025 and joined the audit committee from 2 June 2025; Helge Lund chaired the people, culture and governance committee (PCGC) until 30 September 2025; Albert Manifold was appointed chair of the PCGC from 1 October 2025; and Dave Hager joined the safety and sustainability committee from 10 December 2025.

c Attendance exceptions: Pamela Daley was unable to attend the scheduled meetings in April and May, and the ad hoc meeting in February due to personal reasons; Tushar Morzaría was unable to attend the ad hoc meeting in February due to a pre-existing external commitment; Melody Meyer was unable to attend the ad hoc meeting in October due to a pre-existing external commitment; Hina Nagarajan was unable to attend the scheduled meetings in March and September due to pre-existing external commitments; Satish Pai was unable to attend the ad hoc meeting in February due to a pre-existing external commitment; and Karen Richardson was unable to attend the ad hoc meeting in December due to a pre-existing external commitment.

Leadership team

Gordon Birrell
EVP production
& operations



Leadership team tenure Appointed on 1 July 2020

Nationality British

Board memberships

Gordon is a non-executive director of Azule Energy Holdings Ltd.

Career summary

Before being appointed to his new role, Gordon was chief operating officer for production, transformation and carbon. In his bp career, Gordon has spent time in various leadership, technical, safety and operational risk roles, including four years as bp president Azerbaijan, Georgia and Türkiye. Gordon is a fellow of the Royal Academy of Engineering.

Emma Delaney
EVP customers
& products



Leadership team tenure Appointed on 1 July 2020

Nationality Irish

Board memberships

Director of RBML limited

Career summary

Emma has spent 30 years working in bp, both in the upstream and the downstream. Prior to joining bp's executive team on 1 April 2020, she was regional president for West Africa. She has held a variety of senior roles including upstream chief financial officer for Asia Pacific and head of business development for gas value chains. In downstream she held roles in retail and commercial fuels and planning.

Kerry Dryburgh
EVP people, culture
& communications



Leadership team tenure Appointed on 1 July 2020

Nationality British

Board memberships

None

Career summary

Kerry leads people, culture & communications, which also includes brand, global transformation, health and wellbeing and workplace. Prior to her current role, she headed HR for bp's upstream business and served as group chief talent officer, alongside senior HR roles in supply, trading and corporate functions. Kerry began her career with an apprenticeship and worked across several sectors in Europe and Asia before joining bp in 2010.

Emeka Emembolu
EVP technology



Leadership team tenure Appointed on 18 April 2024

Nationality British

Board memberships

None

Career summary

Emeka is EVP of Technology at bp, leading digital, safety, security and science to advance innovation and safeguard the business. He has spent over 25 years with bp, previously serving as chief of staff to the CEO and leading the North Sea business as regional SVP. His earlier roles span senior technical roles across the Gulf of America, Canada, North Africa and Alaska.

William Lin
EVP gas & low
carbon energy



Leadership team tenure Appointed on 1 July 2020

Nationality American

Board memberships

William serves on the supervisory board of Corbion, a publicly listed biotechnology company where he chairs the sustainability & safety committee and sits on the audit committee. He also chairs the board of JERA Nex bp, a global offshore wind developer and is vice-chair at Pan American Energy Group, Argentina's largest independent energy company.

Career summary

William has worked at bp for 30 years and now leads the group's global natural gas and low carbon businesses and markets. Prior to this role, he held other senior management positions including the chief operating officer for upstream regions, regional president for Asia Pacific, and vice president for gas developments and operations for Egypt.

Mike Sosso
EVP legal



Leadership team tenure Appointed on 1 January 2024

Nationality American

Board memberships

None

Career summary

Mike took on the role of EVP legal in January 2024. In his role, Mike is accountable for leading the legal function and executing the legal strategy for the group. Mike joined bp in 2011 and has held a number of leadership positions across legal. He also previously held the role of VP ethics and compliance. Prior to joining bp, Mike practised law in the Washington, DC office of Skadden, Arps, Slate, Meagher & Flom.

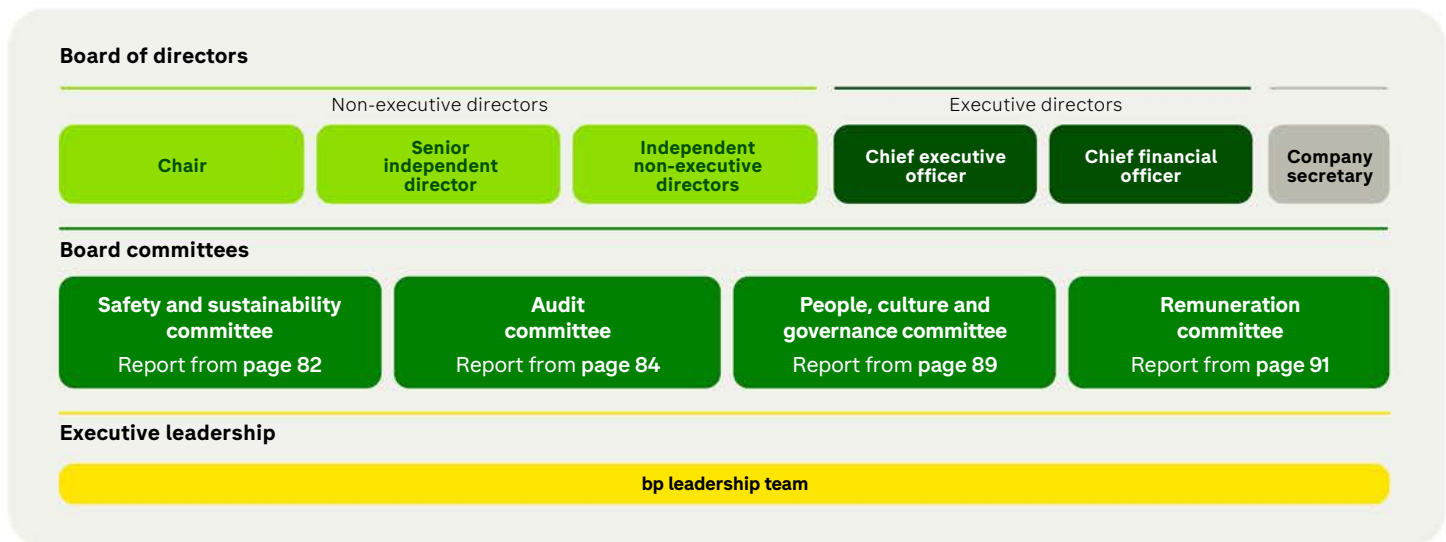
Carol Howle
EVP supply, trading
& shipping



Carol Howle is also part of the bp leadership team in her role as EVP supply, trading & shipping.

You can read her bio on [page 73](#).

Governance framework



bp's governance framework helps to drive informed and efficient decision making through a clear division of responsibilities. This enables bp to operate effectively and in alignment with the strategy as set by the board.

Responsibilities of the board

The board is appointed by shareholders. Its responsibility, through the directors, is to promote the success of the company, to drive value for shareholders, having regard to the company's stakeholders and the consequences of the decisions it takes in the long term. Fulfilling this role, the board is responsible for setting and overseeing the implementation of the company's strategy, purpose and values. The board's oversight role includes monitoring culture and reviewing the effectiveness of the company's system of internal control.

More detailed information about the board's activities is available from [page 78](#).

Delegation of authority

There are four main committees of the board, each operating under delegated responsibilities which are outlined in their respective terms of reference available at bp.com/governance.

Day-to-day management of the business is delegated by the board to the chief executive officer (CEO), who in turn is advised and supported by a leadership team (bpLT) comprising seven individuals who are accountable to her for their respective business or functional areas, with defined financial authority levels. Decisions are taken by the CEO in the execution of the operational responsibilities delegated to her by the board.

For example, the CEO's authority includes a limit on the nature and type of investments, capital expenditure★ and financial commitments she may take in isolation. Any matters that exceed this limit, or that go beyond the annual plan or approved strategy, constitute a matter reserved for the board as a whole.

Further delegations of authority are maintained throughout the business in a consistent way.

Board committees

The four board committees operate under terms of reference which are reviewed periodically.

The chair of each committee routinely reports to the full board on their activities and, where applicable, makes recommendations for the board's approval.

Board roles

Non-executive directors (NEDs)

Provide independent oversight, mentoring and constructive challenge to the executive directors and bpLT. NEDs bring valuable external perspective and support effective governance in matters such as performance management and succession planning.

Chair

- As chair, Albert Manifold leads the board and is accountable to shareholders for its overall effectiveness.
- This includes shaping and managing the culture of the boardroom, facilitating the board's ability to hear the views of stakeholders, and overseeing the composition and development of the board.

Senior independent director (SID)

- Amanda Blanc acts as a sounding board for the chair and, if necessary, as an intermediary for other directors and investors.

Executive directors

Executive directors are tasked with the implementation of bp's strategy and are responsible for all executive management matters affecting the company.

Chief executive officer (CEO)

- In her capacity as interim CEO, Carol Howle is responsible for the design and implementation of bp's strategy and annual plan, which are ultimately approved by the board.
- In accordance with the authorities delegated to her, the CEO implements the system of internal control and is responsible for setting policies, standards and procedures that foster bp's culture and values. In this regard, she is accountable to the board which oversees the effectiveness of the internal control framework.

Chief financial officer (CFO)

- Our CFO Kate Thomson provides financial leadership for the business and supports the CEO in the development and implementation of the strategy.

Company secretary

Ben Mathews advises the board on corporate governance matters, changes to and compliance with board procedures, and monitors regulatory requirements. He also supports the chair in providing timely, accurate and clear information to the board.

Further information on specific board roles is available at bp.com/governance.

Board activities: promoting long-term sustainable success

In 2025, the board and its committees held regular meetings as needed, to address business requirements. Agendas were set in advance by the chair, CEO, and company secretary, focusing on four pillars of strategy, performance, people, and governance. The board's activities, supported by its committees, spanned each of these pillars. In 2025 this included visits to bp Washington DC, US and the Whiting refinery in Chicago, US, facilitating direct engagement with a range of stakeholders. Highlights are provided below.

Strategy and performance

Strategic direction ^{TCFD}

- Worked closely with the CEO and the leadership team to approve a new purpose and reset strategy for bp, as announced in February 2025.
- Established a routine of discussing progress against the primary targets included in the reset strategy with management, including insights into specific areas of the business with the greatest impact on delivery.

Macroeconomics ^{TCFD}

- Received regular updates on macroeconomic and geopolitical factors affecting our strategy, plan and performance.

Annual plan

- Reviewed full-year delivery against the 2024 plan and monitored progress against 2025 objectives, enhanced by regular performance insight sessions with leadership from key business areas.
- Reviewed and approved the 2025 annual plan that focused on capital allocation, cost reduction and initiatives to improve the balance sheet and reduce net debt.

Financial frame and distributions

- Reviewed and approved a refreshed financial frame to support the reset strategy, covering capital allocation, a targeted reduction of net debt, and the delivery of resilient shareholder distributions.
- Regularly reviewed performance against the financial frame.
- Regularly reviewed shareholder distribution options in alignment with the financial frame.

Capital expenditure

- Received an update from the CEO at every board meeting covering projects across all bp's businesses and, where appropriate, climate-related considerations.^{TCFD} These updates included any inorganic acquisition or divestment opportunities of more than \$1 billion.

Mergers and acquisitions pipeline

- Regularly reviewed divestment opportunities in support of the net debt target set out as part of the reset strategy.
- Reached a final investment decision for the Tiber and Guadalupe projects in the Gulf of America, approving bp's second new production platform in less than two years.
- Approved the divestment of bp's majority interest in Castrol.

Acquisition reviews

- Evaluated progress on the integration of transition businesses, Archaea Energy and TravelCenters of America. ^{TCFD}

Offsites

- Board members visited three US sites: Whiting refinery, bpx energy operations in Denver and bp Washington DC.

Technology

- Received an update on progress and delivery of the technology functional reorganization, digital transformation programme, the continued development and impact of strategic partnerships and priorities for 2026.
- Participated in deep-dive sessions on the use of breakthrough imaging and robotic automation, and the deployment of generative artificial intelligence solutions across bp businesses.

Safety and sustainability ^{TCFD}

- Routine reviews of safety performance undertaken, including measurement against targets and ad hoc reporting, as required.
- Focused the sustainability aims on those most relevant to the long-term success of our businesses and to our net zero ambition.

Principal risks

- Analysed trends and themes arising from risk management processes.
- Performed mid-year and full-year reviews of bp's principal and emerging risks, including those related to climate (see [page 127](#)). ^{TCFD}

Internal controls

- Evaluated the group's internal control and risk management systems as part of the review and approval of the *bp Annual Report and Form 20-F*.
- Routinely received reports from group risk and internal audit – no specific concerns were identified and the board concluded that the systems remain resilient, fit for purpose, and aligned with external expectations (see how we manage risk on [page 60](#) and bp's system of internal control on [page 127](#)).

Board activity highlights

January and February:

- Board meeting, virtual
- Board and committee meetings (audit; people, culture and governance; remuneration; and safety and sustainability) including Q4 results, London, UK.

March and April:

- Board and committee meetings (audit and remuneration) including Q1 results, virtual.
- 2025 Annual General Meeting, Sunbury, UK.
- Workforce engagement session with employees from the US and UK.

May and June:

- Board and committee meetings (audit; people, culture and governance; remuneration; and safety and sustainability), Washington DC, US.
- Visit to Whiting refinery, US.
- Workforce engagement sessions with employees from Brazil; Canada; Gulf of America; US; and UK.

People

Engagement

- Undertook the board's workforce engagement programme (WFEP), using it to bring employee feedback into the boardroom to allow for board decisions to be better informed of stakeholder views (see [page 80](#)).
- Through the board's site visits, directors met with high-potential employees to improve visibility and profile of the executive succession pipeline and to increase director interaction with the workforce in those locations (further information on in-person site visits on [page 80](#)).

Culture

- Received feedback from Pulse employee surveys, agreeing actions and initiatives in response.
- Reviewed the annual ethics and compliance report, and the function's priorities and objectives.

Succession planning

- Supported by the people, culture and governance committee, the board received updates on succession plans for the board (see [page 90](#) for further information on board succession).
- Undertook a review of leadership development initiatives, including succession plans for the bp leadership team.



Image: Members of the board at our Canary Wharf office, London, UK

Governance

Board composition and director changes

- Following a comprehensive selection process, appointed:
 - Albert Manifold as non-executive director with effect from 1 September 2025 and as chair of the board and chair of the people, culture and governance committee with effect from 1 October 2025.
 - Ian Tyler as a non-executive director and member of the remuneration committee with effect from 1 April 2025, and as chair of the remuneration committee with effect from 17 April 2025.
 - Dave Hager as a non-executive director with effect from 2 June 2025, and as a member of the safety and sustainability committee with effect from 10 December 2025.
 - Simon Henry as a non-executive director with effect from 1 September 2025.
 - Carol Howle as interim CEO with effect from 18 December 2025 and Meg O'Neill as CEO with effect from 1 April 2026.

Corporate governance framework

- Considered the corporate governance framework, including the terms of reference for the board and each committee.

Director training and knowledge sessions

- Completed online training on topics including the code of conduct and cyber security.

Board performance review

- Conducted an internally facilitated board and committee performance review led by the chair and company secretary (see [page 90](#)).

Investor engagement

- The chair, executive directors, senior independent director, remuneration committee chair, company secretary and members of senior management engaged with investors through meetings, roadshows, quarterly results calls, presentations and the Annual General Meeting. Reports on such engagement was shared with the full board.

Key: TCFD Recommendations and Recommended Disclosures

Board activity highlights

July and August:

- Board and committee meetings (audit; people, culture and governance; remuneration; and safety and sustainability), including Q2 results, London, UK.
- Visit to bpx energy, Denver, US.
- Workforce engagement session with employees from Greece; Hungary; Spain; UK; and US.

September and October:

- Board and committee meetings (audit; remuneration; and safety and sustainability) London, UK.
- Visit to bp supply, trading and shipping floor, London, UK by the audit committee.
- Workforce engagement sessions with employees from India; Malaysia; and UK.

November and December:

- Board and audit committee meetings, including Q3 results, virtual.
- Board and Committee meetings (people, culture and governance; remuneration; audit and safety and sustainability) London, UK.
- Workforce engagement sessions with employees from Hungary; India; UAE; and UK.

Our stakeholders

Directors regularly engage with a wide range of stakeholders to gain different insights, giving the board a more rounded perspective in support of the decisions it takes. This engagement helps the directors fulfil their statutory duties and build greater trust inside and outside of bp. It also helps improve the board's understanding of stakeholder views on bp's strategy, performance, operations and governance – all in support of the long-term success of the company.



Image: Members of the board during their tour of Whiting refinery, US

Stakeholders key

- Investors and shareholders
- Customers
- Workforce
- Governments and regulators
- Partners and suppliers
- Society

Our Section 172(f) statement describes how the directors have had regard to the matters set out in Section 172(1)(a) to (f) of the Companies Act 2006; see [page 71](#).

Further information on the board's activities and key decisions, including how stakeholder interests have been considered, can be found on [pages 78–80](#) and [page 81](#).

Fostering mutual understanding

The board's approach to stakeholder engagement allows for a better understanding of matters that are important and relevant to the decisions it takes and to support the delivery of bp's strategy.

For the non-executive directors (NEDs), one of the key mechanisms for engagement with colleagues is the workforce engagement programme (WFEP). NEDs participate in roundtable sessions with selected individuals on a specific topic. In 2025 these sessions included safety, culture, remuneration and technology.

To engage bp colleagues, directors were involved in bp's webcasts during the year. Additionally, on becoming chair of bp, Albert Manifold gave a video message to introduce himself to bp employees and set out his priorities.

bp's financial and operational performance was an important topic for both investors and the workforce in 2025, with directors seeking to enhance each group's understanding of the factors affecting the company's overall performance through their engagements.

Promoting balanced perspectives

In 2025 board engagements included eight WFEP sessions, and meetings with local businesses, partners, governments and regulators from key jurisdictions.

The audit committee participated in a floor walk of the supply, trading & shipping function at bp's Canary Wharf site in the UK.

Several director engagements were held with leadership teams from Archaea Energy, bpx energy and the Gulf of America, in addition to a dedicated session with the US leadership team as part of the board programme in May.

In addition to the AGM, results calls, roadshows, one-to-one and group meetings with investors in 2025, bp held a retail shareholder engagement event, hosted by the company secretary. Feedback from this event was used by the board to inform future investor engagements. As with all shareholder engagement activity, including votes received from shareholders at the AGM, the feedback received is taken into account in helping to inform board discussion and debate and areas of particular focus for management.

Delivery of strategy guided by stakeholder perspectives

The bp strategy reset announced in February 2025 was developed following a comprehensive stakeholder engagement programme undertaken throughout 2024. In 2025 the board's focus was on overseeing management's performance in its delivery of the strategy.

→ [See more on key decisions, page 81](#)

Building trust in bp

Two themes for the board in helping to maintain and enhance organizational trust continue to be safety performance and culture.

On safety, directors gained valuable insights from employees, suppliers and partners as part of board meetings, company-wide engagements and site visits. Examples in 2025 included presentations by refining, bpx energy and Gulf of America on safety plans and performance. Notably, the safety and sustainability committee's visit to the Whiting refinery in the US provided direct insights on the site's approach to safety, operational reliability and its ongoing commitment to continuous performance improvement.

Related to culture, feedback was shared on progress against bp's organizational transformation. The Pulse employee engagement survey reports and OpenTalk reports (bp's whistleblowing service) continue to be a feature of board discussions. Looking to the future of bp, the board reviewed the talent pipeline and leadership development. Board member participation in the bpChallenge, bp's flagship early-careers event, offered valuable perspectives into the company's talent development programme. For more on culture see [page 90](#).

Opportunities for collaboration

By attending meetings and events with external stakeholders, and bp's partners and suppliers, the board gained insight into market trends and development opportunities.

Engagements with governments and regulators, together with consideration of wider society's interests, focused on long-term, sustainable value. For example, capital investment (Argos expansion in US Gulf of America), and portfolio growth opportunities (Egypt, Trinidad and Tobago, Mauritania and Senegal).

bp's success in collaboration with partners has led to several joint venture discoveries, including in Namibia's Orange Basin and Gajajeira-01 in Angola. A key highlight in 2025 was the Bumerangue (Brazil) discovery – the biggest for bp in 25 years.

Benchmarking progress

Stakeholder engagement enhances the board's ability to benchmark our progress against peers and to innovate, ultimately benefiting our shareholders, workforce, customers, suppliers and business partners, and the communities where bp operates.

Key decisions

Section 172 of the Companies Act 2006 requires directors to act in a way they believe will promote the success of the company for the benefit of its shareholders. The directors are required to consider the long-term impact of their decisions, the interests of employees, relationships with stakeholders, the community and environment and maintain high standards of business conduct. Set out below are four of the key decisions taken by the board during 2025 reflecting the directors' consideration of these requirements.

Strategy and performance ^{TCFD}

In support of the strategy reset, announced in February 2025, the board approved a refreshed financial frame with four primary financial targets: growing free cash flow, increasing the cost reduction target, reducing net debt and generating higher returns on investment. Five focused sustainability aims were also approved: net zero operations, net zero sales, people, biodiversity, and water.

Having taken these decisions, the board wanted to closely monitor and oversee the implementation of the reset strategy and the delivery of the primary targets. During 2025, the board engaged in an extensive dialogue with the bpLT, with more granular reporting reviewed at every board meeting. This approach was supplemented by a programme of insight sessions where the leaders of the businesses with the greatest potential impact on delivery of the targets provided deeper insight on their plans and targets and tools that could be used to mitigate any risk to delivery into those business areas.

The board, through the remuneration committee, sought to achieve alignment of performance measures for the group's long and short-term incentive arrangements with the reset strategy, ensuring that the four primary financial targets form part of the basis for internal performance management and remuneration outcomes through to 2027.

Stakeholders considered



Leadership transition

After more than three decades with bp, Murray Auchincloss informed the chair of his openness to step down as CEO were an appropriate leader identified who could accelerate delivery of bp's strategy. A committee of the board was established and undertook a comprehensive search process which led to the appointment of Meg O'Neill as CEO with effect from 1 April 2026, with Carol Howle serving as interim CEO from 18 December 2025 until Meg's appointment takes effect.

When reviewing the recommendations from the committee to appoint Meg, the board considered how the leadership transition could accelerate bp's strategic vision to become a simpler, leaner, and more profitable company, and created an opportunity to make the necessary transformative changes to maximize value for shareholders.

The board considered Meg to be the most appropriate candidate given her proven track record of driving transformation, growth, and disciplined capital allocation. Her relentless focus on business improvement and financial discipline positions her well in leading bp through its next phase of growth.

Stakeholders considered



Expanding production capacity

In September 2025 the board took a final investment decision (FID) for a seventh operated oil and gas production hub, Tiber-Guadalupe, in the US Gulf of America. The new hub, which features a floating production platform and includes six wells in the Tiber field and a two-well tieback from the Guadalupe field, is expected to have a production capacity of 80,000 barrels of oil per day. Production is expected to start in 2030.

In reviewing the FID proposal, the board considered how existing platform and subsea equipment designs could be utilized to drive cost efficiencies across the production hub's construction, commissioning and operations. The board concluded that the hub's strategically advantaged location, ability to deploy enhanced high-pressure drilling technology and synergies identified from using more than 85% of the design from bp's Kaskida project (another board-approved oil and gas production hub in the Gulf of America, announced in July 2024) combined to make a strong economic case for sanctioning this project.

Stakeholders considered



Castrol divestment approval

In December 2025 the board approved the sale of a 65% shareholding in *Castrol* to Stonepeak, at an enterprise value of \$10.1 billion. This represents an implied EV / LTM EBITDA of around 8.6x reflecting the strength of the business and future growth potential.

The decision followed a comprehensive strategic review of *Castrol*, through which the board considered how the transaction would accelerate delivery of bp's reset strategy, including focusing the downstream, and strengthening the balance sheet. With the transaction expected to generate approximately \$6.0 billion in net proceeds for bp upon completion, the board decided to fully utilize the proceeds to reduce net debt. Completion is anticipated by the end of 2026, subject to regulatory approvals. The board decided to retain a 35% interest in the new joint venture, providing continued exposure to *Castrol's* growth while maintaining the option to divest its remaining stake after a two-year lock-up period.

Stakeholders considered



Safety and sustainability committee



“The committee provided disciplined oversight of safety, security and sustainability across the business.”

Melody Meyer
Safety and sustainability committee chair

Meetings and attendance

The committee met five times during 2025. Regular attendees included EVP production and operations; SVP safety and operational risk assurance; SVP intelligence, security and crisis management; SVP digital security; SVP HSE and carbon; and SVP global ethics and compliance.

	Five scheduled meetings
Non-executive directors	
Melody Meyer: member (from May 2017), chair of the committee (from November 2019)	5/5
Dave Hager: member (from December 2025)	0/0
Satish Pai: member	5/5
Johannes Teyssen: member ^a	4/5

^a Johannes Teyssen was unable to attend the scheduled meeting in September 2025 due to an existing external commitment.

Chair’s introduction

Dear fellow shareholders,

I am pleased to present the safety and sustainability committee report for the year ended 31 December 2025.

During 2025, the committee provided disciplined oversight of safety, security, and sustainability across the business, with a strong emphasis on risk management and operational excellence. This included overseeing progress in the implementation of Process Safety Improvement Plans (PSIPs) in certain businesses, conducting deeper dives on both process and personal safety, reviewing personal and cyber security, and considering operational integrity. The committee also reviewed the principal safety risks and associated mitigations, and received updates on the integration of bp’s safety standards into newly acquired businesses.

Tragically, four colleagues lost their lives during 2025. We extend our sincere condolences to the families, friends and colleagues of all of those impacted.

One fatality occurred in our *Thorntons* retail business and three occurred in separate incidents in our TravelCenters of America (TA) business during roadside assistance activities. During the incident investigation, and permanently thereafter, all highway roadside assistance activities were suspended in our TA business. As with all major incidents, the committee received reports on the incident investigation findings and the actions taken in response.

Following the company’s strategy reset in February 2025, the committee provided oversight on the implementation of the five refreshed sustainability aims: net zero operations; net zero sales; people; biodiversity; and water. For more information see [page 37](#).

During 2025, members of the committee participated in a site visit to Whiting refinery in the US. This site visit provided the opportunity to have open and constructive dialogue with employees and observe bp’s safety and sustainability culture and performance in action.

As I reach the end of my nine-year term on the board and as chair of the committee, I want to express my sincere appreciation for the high level of engagement, transparency and commitment demonstrated across bp in advancing safety performance, sustainability and operational excellence.

Looking forward to 2026, the committee will focus its oversight on maintaining the good progress and continuous improvement in safety performance and the implementation of bp’s Operating Management System★ within recently acquired businesses.

Role of the committee

The committee oversees the management of safety and sustainability matters, including physical and cyber security and relevant systems and processes, focusing on those which it considers to be most potentially material from time to time.

Key responsibilities

The committee’s full terms of reference can be viewed at bp.com/governance.

Melody Meyer
Committee chair
6 March 2026

Activities during the year

Overseeing improved safety performance

The committee continued to oversee safety performance, supporting management's progress in reducing combined tier 1 and 2 process safety events★. During 2025, combined tier 1 and tier 2 safety performance improved, with combined process safety events being 29% lower than in 2024.

The committee received regular reports from the EVP production and operations on safety and operational performance, incident reviews, and on the mitigation of principal and emerging safety risks around the business. It also received updates from management on the implementation of PSIPs in certain businesses and updates on personal security improvements, including the integrity of crisis management and business continuity processes.

Deep-dive updates regarding significant or material events and specific risk areas within the business were also received. The committee challenged management on the root cause and learnings from these incidents and how learnings are embedded into existing safety processes.

Providing challenge on risk management

The committee provides independent challenge to management on the effectiveness of the processes and procedures implemented to manage safety and sustainability risk. This is achieved through regular review and monitoring of the principal risks allocated to it by the board and through deep-dives on key risk areas including wells, process safety, marine risk, product quality, pipeline risk, transportation risk, maintenance integrity, cyber security, ethics and compliance, and regulatory compliance.

Further deep-dives were undertaken into specific areas of risk within the business covering risk management and safety performance in newly acquired businesses, such as TravelCenters of America, Archaea Energy and bp bioenergy. This provided the committee with enhanced oversight of the integration of bp's Operating Management System★ into newly acquired businesses.

The committee routinely received:

- Updates on the activities of internal audit, focused on operational safety audits, together with an annual report on bp's system of internal control. This provides an independent view on management's safety and sustainability performance, as well as an independent assessment of key challenges and risk areas.

Briefings from the SVP global ethics and compliance on emerging areas of risk and associated mitigations, including increased reports of external threats affecting retail operations.

Reports on cyber security risks and the effectiveness of mitigation processes, including identification of emerging cyber risks from AI and geopolitical events.

The committee also continued its joint engagement with the audit committee through combined updates on non-operated joint venture safety and sustainability.

Oversight of sustainability matters

Refreshing bp's sustainability frame ^{TCFD}

The committee reviewed and endorsed a refreshed sustainability frame with five aims: net zero operations; net zero sales; people; biodiversity; and water. Progress against these aims was monitored through regular updates from management. In 2025 focused deep-dives were undertaken into each pillar of the sustainability frame, with focus on management's plans to address areas of more challenged delivery.

Human rights and global reporting landscape

The committee reviewed progress on mitigations in human rights and modern slavery. It also kept abreast of the current global sustainability reporting environment, including bp's plans for compliance through reporting from management.

Sustainability and safety linked remuneration targets

The committee made recommendations to the remuneration committee regarding safety and sustainability targets and outcomes that are tied to remuneration. This included critically analyzing current methodologies for the setting of targets to ensure they remain appropriately stretching, and incorporated changes to the sustainability frame announced in February 2025.



Whiting refinery visit

During the visit to the Whiting refinery, the S&SC members were briefed on infrastructure upgrades, with particular emphasis on enhancements to electrical systems and the refinery's continued focus on safety, reliability and continuous improvement.

The S&SC members also took a driving tour of the refinery to gain a deeper understanding of its operational footprint and integration with the local community. The visit provided an opportunity for the Whiting team to demonstrate their critical role in bp's integrated value chain and commitment to operational excellence.

Image: Whiting refinery, US

Audit committee



“The committee had particular focus on advancing digital transformation initiatives.”

Tushar Morzaria
Audit committee chair

Meetings and attendance

The committee met eight times during 2025. Regular attendees included the chief financial officer (CFO), group controller, SVP internal audit, EVP legal and the external auditor.

Non-executive directors	Eight scheduled meetings
Tushar Morzaria: member (from September 2020), chair of the committee (from May 2021)	8/8
Pamela Daley ^a : member (until 7 July 2025)	2/4
Karen Richardson: member	8/8
Hina Nagarajan ^b : member	7/8
Ian Tyler: member (from 2 June 2025)	4/4

^a Pamela was unable to attend the meetings in April and May due to personal reasons.

^b Hina was unable to attend the meeting in September due to pre-existing external commitments.

Chair’s introduction

Dear fellow shareholders,

I am pleased to present the audit committee report for the year ended 31 December 2025.

Financial reporting remains central to the committee’s responsibilities – monitoring its integrity, overseeing management’s control procedures and evaluating their effectiveness and working with internal and external auditors to ensure that what you – our shareholders – rely on in our reporting has been appropriately challenged and reviewed. This involves acting on behalf of the board and co-ordinating input from other committees as needed, including reporting and making recommendations to the board.

In 2025 the committee maintained its oversight of bp’s reporting processes, with particular emphasis on advancing digital transformation initiatives and monitoring their implementation progress.

Among its many activities during the year, the committee has monitored progress against bp’s 2027 \$4-5 billion structural cost reduction target. In addition, the committee is overseeing the mandatory external audit tender, with the tender process expected to conclude during 2026.

As the regulatory environment evolves, the committee remains engaged with management to oversee bp’s approach to new reporting requirements, with particular focus on the new UK Corporate Governance Code 2024, provision 29 readiness. The committee also monitored management’s plans for the implementation of financial and non-financial reporting developments.

In September 2025 the committee visited bp’s supply, trading and shipping business in Canary Wharf, London. The visit included a tour of the trading floors and business briefings, with a particular focus on the energy and commodities trading operations. Read more on [page 85](#). The committee continues to engage with other stakeholders where appropriate, including through regulatory inspections when they occur.

On behalf of my colleagues on the committee, I would like to extend my thanks for the continued professional support and focus of effort by management and our various advisers during a year where bp delivered strong performance in some areas but had some challenges in others. We look forward to continuing this journey through 2026.

Role of the committee

The committee monitors the effectiveness of the group’s financial reporting, including ESG and climate-related financial disclosures, as well as systems of internal control and risk management as allocated by the board. It also monitors the integrity of the external and internal audit processes.

This report describes how bp has approached compliance with the provisions of the FRC’s Audit Committees and the External Audit: Minimum Standard.

Key responsibilities

A summary of the committee’s terms of reference is on [page 359](#) and the full terms of reference can be viewed at bp.com/governance.

Tushar Morzaria
Committee chair
6 March 2026

Financial expertise

The board is satisfied that

- Tushar Morzaria, the chair of the committee, has recent and relevant financial experience as required by the UK Corporate Governance Code and that he is competent in accounting and auditing in accordance with the FCA’s Disclosure Guidance and Transparency Rules.
- The committee has an appropriate and experienced blend of commercial, financial and audit expertise to assess the issues it is required to address, as well as competence in the relevant sector in which bp operates. During 2025, Ian Tyler was appointed as a member of the committee, further strengthening the committee’s financial expertise.
- As a US foreign private issuer, the committee meets the independence criteria provisions of Rule 10A-3 of the US Securities Exchange Act of 1934, and Tushar Morzaria can be regarded as an audit committee financial expert as defined in Item 16A of Form 20-F.

Activities during the year

Monitoring the integrity of financial reporting and assurance

- Through monitoring and reviewing that bp's financial statements and formal announcements relating to bp's financial performance are clear and appropriate, the committee oversees the integrity of our financial reporting.
- Management's application of key accounting policies and recommendations on financial reporting judgements was carefully considered, with the committee concluding that these matters were appropriately addressed in the financial statements.
- The committee monitored progress and reporting on cost savings.

Going concern, viability and fair, balanced and understandable considerations

The committee reviewed the company's going concern assumption and longer-term viability statement. In determining and recommending to the board that it was appropriate to adopt the going concern basis of accounting and the longer-term viability of the company, the committee carefully considered and, where appropriate, constructively challenged relevant underlying assumptions and supporting analysis.

The committee received an update from management on the verification process for the bp *Annual Report and Form 20-F* in support of its recommendation to the board that the report was fair, balanced and understandable. These documents were comprehensively reviewed with input from subject matter experts and the external auditors. The committee's review included consideration of bp's non-financial disclosures such as the Task Force on Climate-related Financial Disclosures (TCFD) that are made in compliance with the UK Listing Rules. ^{TCFD}

Maintaining resilience through systems of internal control and risk management

- The committee oversaw risk management and internal control processes, routinely reviewing and monitoring principal risks allocated to it by the board through a combination of business or function reviews and focused engagement with key stakeholders.
- Through a deep-dive update, the committee reviewed supply, trading and shipping business performance.

The session focused on the refined products trading and shipping interface, LNG and power benches as well as key and emerging market, operational and geopolitical risks.

- The committee reviewed the affordability of proposed distributions, taking into account factors such as whether sufficient distributable reserves are available.
- In addition, the committee received:
 - updates on the systems in place to assess fraud risk and the controls in place to manage and mitigate identified risks, reflecting developments such as to the UK's Economic Crime and Corporate Transparency Act.
 - an update on compliance with new business regulations, together with additional briefings during the year on technical accounting updates and developing ESG disclosures. ^{TCFD}
- The committee remained focused on regulatory developments, including receiving updates on the consideration of enhancements to bp's risk management and internal control framework as a result of the UK Corporate Governance Code 2024, and received updates on implementation progress.

Effectiveness of risk management and systems of internal control

The committee reviewed and challenged management on the effectiveness of the system of internal control and agreed that it did not require further action nor were there any significant failings or weaknesses to report. As part of this assessment the committee considered internal audit's annual review of internal control and risk management, together with an assessment of it from management. Further details can be found on **pages 127-128**. The committee also discussed internal controls and financial reporting processes during the year, challenging control gaps identified, root cause analysis and remediation actions, and reviewing progress towards addressing deficiencies that had previously been identified in relation to manual journal controls. Tier II control gap reporting was introduced at each scheduled meeting. Further details on internal controls in place for financial reporting can be found on **page 360**.

In addition, the committee received updates on the evolution and enhancement of non-financial reporting controls and assurance, such as first and second line of defence activities. ^{TCFD}



Canary Wharf site visit

During the audit committee's tour in September of the supply, trading and shipping (ST&S) floors in Canary Wharf, London, the directors met internal stakeholders based there, hearing from colleagues in gas & power and refining & products trading.

Image: Audit committee members at our Canary Wharf office, London, UK

Audit committee continued

Overseeing the relationship with external and internal audit

- During the year, the FRC's Audit Quality Review (AQR) team selected Deloitte's audit of the Company's Annual Report and Accounts for the year ended 31 December 2024 as part of its annual inspection of audit firms. The review was assessed as 'limited improvements required' with only one other finding identified. The chair of the committee received a full copy of the FRC's report, and discussed it with Deloitte. The committee confirmed that there were no significant areas for improvement identified, no key findings within the report and was satisfied that there is nothing within the report which might have a bearing on the audit appointment.
- On the recommendation of the committee, the board will propose the reappointment of Deloitte as the company's external auditor to shareholders at the 2026 annual general meeting. The external auditor's independence and objectivity were reviewed and monitored by the committee using a combination of factors, including assurances provided to it by the external auditor, the level of non-audit fees, and the timeline for lead audit partner rotation and re-tender of audit services. The committee concluded that it was satisfied with the audit team's effectiveness, service quality and commitment, including that the external auditor provides constructive challenge to management. In support of this, the committee received reports from the external auditor that covered insights from their audit work, actions taken to address the FRC's annual report on the external auditor, and the inspection results of the external auditor's quality control procedures. During 2025, following the 2024 audit, the external auditor undertook an auditor effectiveness review. The process comprised a series of interviews with senior stakeholders within bp who engage with the audit team on a regular basis. Stakeholder feedback reflected a positive view of the quality and effectiveness of the audit. In addition,

the committee received reports from management, which included a survey seeking internal stakeholder feedback on the external auditor's performance and bp's commitment to the audit. The main measurement criteria covered planning and scope, robustness of audit, independence and objectivity, quality of delivery, quality of people and service, and value-added advice.

- The committee met privately with the external auditor during the year and, in addition, reviewed, approved and monitored progress against the external audit plan, considering materiality levels, audit risks, scoping changes, and resourcing. The committee is satisfied that the external auditor has full access to staff and records. The committee continued to monitor and review the effectiveness and capabilities of the internal audit function. This included, for example, reviewing and approving the internal audit plan in the context of bp's principal risks. The committee concluded that the function had independent, unrestricted scope, access to information, and sufficient resources to fulfil its mandate. They met privately with the SVP internal audit, discussed regular updates on internal audit activities and where appropriate challenged management's response and progress made on the closure of findings.

A summary of the external audit approach, including audit risks, is set out in the independent auditor's report on [pages 130-148](#).

Lead audit partner rotation and re-tender of audit services

The external auditor must rotate the lead audit partner every five years and other senior staff every five to seven years.

The company complies with the Statutory Audit Services for Large Companies Market Investigation (Mandatory Use of Competitive Tender Processes and Audit Committee Responsibilities) Order 2014, which requires bp to tender the audit at least every 10 years.

External audit services were last tendered in 2016, and the external auditor has been in that role since 2018 (seven years). During the year the committee agreed an approach, timeline and selection criteria for a re-tendering of audit services that is anticipated will be completed by the end of 2026, for the 2028 audit.

Oversight of audit fees and non-audit services

The committee reviewed and approved the audit services fee and terms of engagement for the external auditor while retaining oversight of bp's policy on non-audit services and the review and approval of non-audit services.

The total amount of audit and non-audit fees paid to Deloitte for 2025 is set out in Financial statements – **Note 36**. The committee is satisfied that the audit fee is appropriate in respect of the audit services provided. The majority of non-audit fees relate to work of an assurance nature.

The non-audit services policy safeguards audit objectivity and independence through the prohibition of non-audit tax services being provided by the external auditor, the limitation of audit-related work which falls within defined categories, and by stating that the auditor may not perform non-audit services that are prohibited by the SEC, Public Company Accounting Oversight Board (PCAOB), International Auditing and Assurance Standards Board (IAASB) or the FRC.

The external auditor is considered for permitted non-audit services only when its expertise and experience of bp are important. Approvals for individual engagements of pre-approved permitted services below certain thresholds are delegated to the group controller or the CFO. More information is outlined in the principal accountant's fees and services on [page 361](#).

Examples of how key accounting judgements and estimates were considered and addressed, and how relevant accounting policies have been applied

Key accounting judgements and estimates	Audit committee activity	Conclusions/outcomes
Impact of climate change and the energy transition ^{TCFD}		
Climate change and the transition to a lower carbon economy may have significant impacts on the currently reported amounts of the group's assets and liabilities and on similar assets and liabilities that may be recognized in the future.	<ul style="list-style-type: none"> Reviewed management's best estimate of oil and natural gas price assumptions for value-in-use impairment testing and investment appraisal. Reviewed management's determination that its best estimate of oil and natural gas prices is in line with a range of transition paths consistent with the goals of the Paris climate change agreement. 	<ul style="list-style-type: none"> Management's revised best estimates of oil and natural gas prices are in line with a range of transition paths consistent with the goals of the Paris climate change agreement. See Financial statements – Note 1 for more details on how bp applies carbon pricing in its impairment testing, sensitivity analyses estimating effects of changes in net revenue and changes in the expected timing of decommissioning.
Provisions		
The group holds provisions primarily for decommissioning, environmental remediation and litigation. The most significant provision is for the future decommissioning of oil and natural gas production facilities and pipelines. Estimation uncertainty exists as most of these events are many years in the future. Assumptions are made by bp in relation to cost estimation, settlement dates, technology, legal requirements and discount rates. There is also a risk that decommissioning obligations from previously divested assets revert to bp.	<ul style="list-style-type: none"> Received briefings on decommissioning (including the process for managing the risk of decommissioning reversion), environmental, asbestos and litigation provisions. These included the requirements, governance and controls for the development and approval of cost estimates and provisions in the financial statements. Reviewed and challenged the group's discount rates for calculating provisions. 	<ul style="list-style-type: none"> Decommissioning provisions of \$12.3 billion were recognized on the balance sheet at 31 December 2025. The discount rate used by bp to determine the balance sheet obligation at the end of 2025 was a nominal rate of 4.5% based on long-dated US government bonds. The discount rate remains unchanged from the prior year.
Recoverability of asset carrying values		
Determination as to whether and how much an asset (including exploration intangibles), cash generating unit (CGU) or group of CGUs containing goodwill is impaired involves management judgement and estimates on uncertain matters such as future commodity prices, discount rates, production profiles, reserves and the impact of inflation on operating expenses. Judgement is required to determine whether it is appropriate to continue to carry intangible assets related to exploration costs on the balance sheet.	<ul style="list-style-type: none"> Reviewed policy and guidelines for compliance with oil and gas reserves disclosure regulation, including the group's reserves governance framework and controls. Reviewed and challenged the group's oil and gas price assumptions. Reviewed and challenged the group's discount rates for impairment testing purposes. Impairment charges, reversals and 'watch-list' items were reviewed in the quarterly due diligence process. 	<ul style="list-style-type: none"> The group's price assumption for Brent oil and for Henry Hub gas were updated as set out on page 20 and Financial statements – Note 1. Sensitivity analyses estimating the effect of changes in net revenue and discount rate assumptions have been disclosed in Financial statements – Note 1. Net impairment charges of \$5.2 billion as disclosed in Financial statements – Note 4. Exploration intangibles totalled \$4.0 billion at 31 December 2025.
Taxation		
Computation of the group's income tax expense and liability, the provisioning for potential tax liabilities and the level of deferred tax asset recognition are underpinned by management judgement and estimation of the amounts which could be payable. Judgement is also required when determining whether a particular tax is an income tax or another tax type.	<ul style="list-style-type: none"> Received regular updates on the group's tax risk exposures and deferred tax asset recognition. Reviewed the judgements exercised over tax risk provisioning as part of its annual review of key provisions. 	<ul style="list-style-type: none"> Deferred tax assets of \$4.3 billion were recognized on the balance sheet at 31 December 2025. The calculation of tax risk provisions is consistent with IAS 37 and IFRIC 23.
Pensions		
Accounting for pensions and other post-employment benefits involves making estimates when measuring the group's pension plan surpluses and deficits. These estimates require assumptions to be made about uncertain events, including discount rates, inflation and life expectancy.	<ul style="list-style-type: none"> Reviewed and challenged the group's assumptions used to determine the projected benefit obligation at the year end, including the discount rate, rate of inflation, salary growth and mortality levels. 	<ul style="list-style-type: none"> At 31 December 2025, surpluses of \$7.8 billion and deficits of \$4.8 billion were recognized on the balance sheet in relation to pensions and other post-employment benefits. The method for determining the group's assumptions remained largely unchanged from 2024. The values of these assumptions and a sensitivity analysis of the impact of possible changes on the benefit expense and obligation are provided in Financial Statements – Note 24.

Audit committee continued

Examples of how key accounting judgements and estimates were considered and addressed, and how relevant accounting policies have been applied continued

Key accounting judgements and estimates	Audit committee activity	Conclusions/outcomes
Supplier finance arrangements		
<p>The group's trade payables include certain supplier finance arrangements that utilize letter of credit facilities and promissory notes. Judgement is required to assess trade payables subject to supplier financing arrangements to determine whether they should continue to be classified as trade payables and give rise to operating cash flows or finance debt and financing cash flows.</p>	<ul style="list-style-type: none"> Received a briefing on the group's supplier finance arrangements. Reviewed the group's proposed enhanced disclosures in relation to Amendments to IAS 7 'Statement of Cash Flows' and IFRS 7 'Financial Instruments: disclosures' relating to supplier finance arrangements. 	<ul style="list-style-type: none"> bp had liabilities of \$5.6 billion, \$1.4 billion and \$1.0 billion, respectively, in respect of letters of credit, promissory notes and reverse factoring arrangements that are presented within trade and other payables at 31 December 2025. The disclosures required by the Amendments to IAS 7 'Statement of Cash Flows' and IFRS 7 'Financial Instruments: disclosures' relating to supplier finance arrangements are included in Financial Statements – Note 29.
Derivatives		
<p>For its level 3 derivative financial instruments, bp estimates their fair values using internal models due to the absence of quoted market pricing or other observable, market-corroborated data.</p> <p>Judgement may be required to determine whether contracts to buy or sell commodities meet the definition of a derivative, in particular LNG contracts.</p>	<ul style="list-style-type: none"> Received a briefing on the group's trading risks and reviewed the system of risk management and controls in place. Reviewed the control process and risks relating to the trading business. Received updates on accounting judgements on LNG contracts. 	<ul style="list-style-type: none"> bp has assets and liabilities of \$20.1 billion and \$18.2 billion, respectively, recognized on the balance sheet for level 3 derivative financial instruments at 31 December 2025, mainly relating to the activities of the supply, trading & shipping function. bp's use of internal models to value certain of these contracts has been disclosed in Financial Statements – Note 1. bp considers that contracts to buy or sell LNG do not meet the definition of a derivative under IFRS.

People, culture and governance committee



“2025 has been a busy year for the committee, with a strong focus on board succession.”

Albert Manifold
People, culture and governance committee chair

Meetings and attendance

The committee met five times during 2025. The CEO and EVP people, culture & communications regularly attend these meetings.

Non-executive directors	Five scheduled meetings
Albert Manifold: member (from September 2025); chair of the committee (from October 2025)	1/1
Helge Lund: member (until September 2025); chair of the committee (until September 2025)	4/4
Dame Amanda Blanc: member	5/5
Dr Johannes Teyssen: member	5/5
Hina Nagarajan: member	5/5

Chair’s introduction

Dear shareholders,

I am pleased to present the people, culture and governance committee report for the year ended 31 December 2025, my first since being appointed as board chair and as chair of the committee on 1 October 2025.

2025 has been a particularly busy year for the committee, with a strong focus on board succession.

In support of the strategy reset in February 2025 and to fill current and anticipated vacancies on the board, the committee undertook a search process to identify new board members who would bring the additional skills and experience required as bp embarked on its next chapter. The search process resulted in three new non-executive directors being appointed:

- Ian Tyler was appointed on 1 April 2025, succeeding Tushar Morzaria as chair of the remuneration committee with effect from 17 April 2025 and becoming a member of the audit committee from 2 June 2025.
- Dave Hager joined the board on 2 June 2025 and became a member of the safety and sustainability committee with effect from 10 December 2025.
- Simon Henry joined the board on 1 September 2025.

In April 2025, Helge Lund informed the board of his intention to step down as chair. Pamela Daley informed the board in July 2025 that she would also be standing down from the board. During the year, Murray Auchincloss also informed the board of his openness to step down as CEO.

Comprehensive search processes were undertaken by separate committees of the board in connection with these decisions.

In turn, this led to my own appointment as a non-executive director from 1 September 2025, succeeding Helge as chair of the board and of this committee on 1 October 2025. It also resulted in the appointment of Meg O’Neill as CEO with effect from 1 April 2026, with Carol Howle being appointed as interim CEO with effect from 18 December 2025 until Meg joins the board.

Further information on these search processes is provided on [page 90](#).

In addition to board succession matters, during 2025, the committee continued its focus on culture, reviewing feedback from the workforce engagement sessions that took place during the year and the results of the annual and live employee pulse surveys to gauge employee sentiment.

Role of the committee

The committee seeks to ensure that the composition and structure of the board and leadership team remain effective. It also monitors the balance of skills, knowledge, experience and diversity of the board. The committee oversees the development of a diverse pipeline for executive succession to the board and leadership team through continuous succession planning and monitoring development plans for bp leaders and beyond.

The committee tracks bp’s culture and its alignment with our ‘Who we are’ culture frame, and monitors sentiment of the workforce.

The process for the nomination, induction and orderly succession of candidates for the board, the leadership team and the company secretary role are led by the committee, as is the annual board and committee performance review.

Key responsibilities

The committee’s full terms of reference can be viewed at bp.com/governance.

Albert Manifold
Committee chair
6 March 2026

Diversity statistics and outcomes

As at 31 December 2025, 46% of the board were women, three senior board positions were held by women and three directors identified as being from a minority ethnic background. For further details on board and leadership team diversity, in line with the UK Listing Rules, see [page 126](#).

As at 31 December 2025, senior management, defined as the leadership team (being the first layer of management below board level) and the company secretary^a, and their direct reports, comprised 44% women (2024 50%) and 22% Black, Asian and other ethnic minority individuals (2024 29%).

^a As defined in the UK Corporate Governance Code 2024.

People, culture and governance committee continued

Activities during the year

Succession planning

Chair and CEO succession

The board established two committees to lead the selection processes for the company's next chair and CEO. The committee that led the search process for the new chair was chaired by Dame Amanda Blanc, joined by Melody Meyer, Hina Nagarajan and Johannes Teysen as members. The committee that led the search process for the CEO was chaired by Albert Manifold, joined by Dame Amanda Blanc, Dave Hager, Karen Richardson, and Ian Tyler as members.

Executive search consultants, Egon Zehnder^a, were appointed to support both processes by identifying suitable candidates to replace Helge Lund and Murray Auchincloss against role specifications agreed by the respective committees and the board. Each role specification set out the skills, experience, diversity and knowledge required for each role, including leadership capability, industry, sector, safety and operational expertise.

Shortlisted candidates were invited to interviews with members of each committee. The preferred candidates for each role were then invited to meet the full board.

The board appointed Albert Manifold as a non-executive director and chair designate with effect from 1 September 2025 and as chair of the board and this committee with effect from 1 October 2025.

The board appointed Meg O'Neill as CEO with effect from 1 April 2026. Carol Howle was appointed as interim CEO with effect from 18 December 2025 until Meg joins the board. See [page 81](#) for further information on the decision-making process and stakeholder considerations.

The board and committees

As part of the ongoing process to refresh the board and to ensure it has the right balance of skills, experience, and diversity needed to meet the company's current and future priorities, the committee agreed the criteria for three new non-executive roles. The criteria focused on candidates primarily from the UK and US with industry, sector, safety and operational experience, including, in the case of the remuneration committee leadership, remuneration committee expertise and the ability to lead complex remuneration considerations for a complex global company such as bp.

Suitable candidates for each role were identified against the agreed role profiles with support from Egon Zehnder^a and shortlisted candidates were invited to interview with members of the committee.

This process resulted in the board approving the committee's recommendations to appoint

Ian Tyler, Dave Hager, and Simon Henry as new non-executive directors.

During the year, the membership of the board committees was also reviewed. As a result, Ian Tyler was appointed as chair of the remuneration committee with effect from 17 April 2025 and as a member of the audit committee from 17 April 2025. Dave Hager was appointed as a member of the safety and sustainability committee with effect from 10 December 2025.

bp's leadership team

The committee oversees development plans for bp's senior leaders and emerging talent and their alignment with executive succession planning over various timescales. Development plans identify the desired breadth and depth of experience and roles required to bolster the skills of individuals with executive potential.

Diversity

Better decision making and outcomes are achieved when people with differences of opinion and with different backgrounds come together with a common ambition. The committee periodically reviews the board's diversity, equity and inclusion (DE&I) policy.

The board's DE&I policy applies to the board and its committees, and complements bp's wider diversity policies, the group's values, code of conduct and sustainability frame. It includes gender and ethnicity representation targets for the board that are aligned with the UK Listing Rules. Read more at bp.com/governance.

Oversight of culture and the voice of the workforce

The committee oversees employee engagement, leading and lagging indicators of culture, and how culture is being embedded. This includes monitoring feedback from the workforce engagement programme (WFEP) and private sessions with bp's SVP, ethics and compliance (E&C), who has accountability to, and direct channels of communication with, the committee. The committee is responsible for approving the appointment and termination of the SVP, E&C and reviews and recommends their remuneration to the remuneration committee.

The WFEP continued during 2025 with directors engaging with employees across multiple regions and from different disciplines on topics including leadership and culture, safety (including retail safety), transformation, and remuneration. Insights from these sessions are collated and shared with the board, strengthening its consideration of workforce views in board discussions and the decisions it ultimately takes. The committee continues to consider that the WFEP is the most appropriate mechanism for workforce engagement, given the activities and structure of bp. Read more on [page 80](#).

Board performance

The externally facilitated board performance review in 2024 highlighted the continuing importance of succession planning to drive the delivery of the reset strategy. Building on the outputs from the 2024 review, the board appointed three new non-executive directors and introduced enhanced performance reporting by management during the year. This reporting was supplemented by a programme of insight sessions, providing the board with in-depth briefings from leaders of the businesses with the greatest impact on the delivery of strategy.

The CEO's performance review is conducted by the chair, with input from the senior independent director. Given the short tenure of Albert Manifold, a performance review of the chair was not undertaken in 2025. This process is usually led by the senior independent director.

Helge Lund's decision to step down from the board in April 2025 and the appointment in September 2025 of his successor offered an opportunity, alongside the board's established performance-evaluation processes, for the continuing directors to reflect on the roles and performance of the board and its committees. This in turn influenced the skills, experience and leadership credentials that were sought from the new board chair and, then also, the new CEO.

Ultimately, having appointed Albert Manifold as chair from 1 October 2025 and Meg O'Neill as new CEO from 1 April 2026, the board concluded that the process of the 2025 performance review for the board and its committees had been comprehensively undertaken. In view of this, a standalone supplementary performance review was therefore not warranted. Additionally, and since his appointment to the role, the chair held a series of one-to-one meetings with each non-executive director to discuss their reflections on the board's performance and that of its committees and individual board members.

Overall, the insights gathered from the 2025 performance review will inform the future needs and roles of the board and its respective committees, how they operate and the optimal composition of the board over the longer term.

Among the changes already in motion as a result of this review process, members of the leadership team routinely join board meetings to discuss safety, operational and financial performance, major projects and delivery of the four primary targets set out in the reset strategy. The introduction of a reporting dashboard during the year strengthened this enhanced board oversight of performance at a more granular level, by business group and against key metrics. This is being supplemented with additional scheduled board time for in-depth discussions on performance and portfolio composition.

^a The committee engaged Egon Zehnder in support of search activity for new board candidates. Egon Zehnder does not have any connection with the company or individual directors, save that Egon Zehnder provides advice and support on bp's executive development programme.

Directors' remuneration report



"2025 was a year of strong underlying financial and operational performance and we have made meaningful progress towards the strategic priorities announced in February 2025."

Ian Tyler

Remuneration committee chair

Meetings and attendance

The chair and the chief executive officer (CEO) are standing attendees, except for matters relating to their own remuneration. The CEO is consulted on the remuneration of the chief financial officer (CFO) and other members of the leadership team, and receives input from the committee on remuneration across the wider workforce. Both the CEO and CFO are consulted on matters relating to the group's performance and the metrics adopted for each performance cycle.

bp's EVP people, culture & communications, SVP reward, external advisors and other executives may attend where necessary. The committee consults other board committees on the group's performance and on issues relating to the exercise of judgement or discretion as necessary.

The committee met nine times during 2025. Meeting attendance can be found below.

Non-executive directors	Seven scheduled meetings	Two ad hoc meetings
Ian Tyler: chair of the committee ^a	4/4	2/2
Tushar Morzaria: member ^a	7/7	2/2
Dame Amanda Blanc: member	7/7	2/2
Pamela Daley: member ^b	2/4	0/0
Melody Meyer: member	7/7	2/2

a Ian Tyler was appointed as remuneration committee chair from the conclusion of the 2025 AGM. Tushar Morzaria stepped down as interim remuneration committee chair from this date.

b Pamela Daley stepped down as a non-executive director and member of the remuneration committee on 7 July 2025.

Role of the committee

The role of the committee is to determine and recommend to the board the remuneration policy and to set chair, executive director and leadership team remuneration. In determining the policy, the committee takes into account various factors, including wider workforce remuneration, structures and alignment of reward with performance, thus promoting the long-term success of the company. The committee also reviews workforce remuneration and monitors related policies, satisfying itself that incentives and rewards are aligned with bp's goals and culture.

Key responsibilities

A summary of the committee's terms of reference is on [page 359](#) and the full terms can be reviewed at bp.com/governance.

Key areas of focus in 2025

- **Workforce engagement** – engaged with the wider workforce on performance, reward and wellbeing. This included holding a workforce engagement programme session in July 2025, where selected employees were invited to discuss bp's approach to reward and employee engagement.
- **Remuneration outcomes** – agreed the outcomes of incentive awards for executive directors, including reviewing performance 'in the round' and determining whether discretion should be exercised. Monitored in-flight progress of equity and bonus awards.
- **Performance measures** – discussed and agreed the performance measures for the 2025 annual and long-term performance scorecards to ensure alignment with bp's strategy. This included reflecting on our sustainability measures and seeking input from the safety and sustainability committee. [TCFD](#)
- **Framework on fatalities** – reflected on the impact of fatalities on annual bonus outcomes and the framework that was introduced in 2024 to help guide decisions going forward.
- **Change in leadership** – set the remuneration terms for the interim CEO and incoming CEO. Agreed the exit arrangements for the outgoing CEO.
- **Merit-based reviews** – reviewed pay for performance arrangements for the leadership population in line with bp's reward principles.

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Directors' remuneration report continued

Chair's introduction

Dear shareholders,

I am pleased to present the directors' remuneration report for the year ended 31 December 2025.

This is my first report as chair of the remuneration committee, having taken on the role from Tushar Morzaria on 17 April 2025. Having agreed to step into the role on an interim basis, I would like to thank Tushar for his leadership of the committee during this period.

The committee remains focused on ensuring our remuneration policy supports the delivery of bp's strategic priorities, aligning executive reward outcomes with sustainable long-term value creation for our shareholders. Constructive dialogue with our shareholders has been an important part of this process, and we are grateful for the insights shared during 2025.

We are asking shareholders to vote on two remuneration resolutions at bp's 2026 AGM:

- Our remuneration report, which presents remuneration outcomes for 2025 and how we intend to apply the policy in 2026.
- Our remuneration policy (the policy), which outlines the framework that will apply to our executive directors, non-executive directors and chair of the board.

Business performance

While performance over the three-year performance period for the EDIP was mixed, 2025 was a year of strong underlying financial and operational performance. bp delivered operating cash flow★ of \$24.5 billion, underpinned by disciplined capital allocation and efficiency with a 10% reduction in capital expenditure★ compared with 2024. Operationally, plant reliability★ and refining availability★ both exceeded 96%, reaching their highest levels on record.

We also made meaningful progress towards the strategic priorities set out in our reset strategy announced in February 2025. We established four primary targets through to the end of 2027: growing cash flow, improving returns, reducing costs and strengthening the balance sheet. We remain on track to deliver against these objectives.

During the year, we agreed the sale of a 65% shareholding in *Castrol*, which we expect to generate net proceeds of approximately \$6 billion, and completed the sale of our US onshore wind business. We also delivered \$2.0 billion of structural cost reductions★, strengthening our financial position and supporting continued delivery into 2026.

Incentive outcomes

2025 annual bonus

The scorecard for this cycle consisted of five measures; tier 1 and tier 2 process safety events★ (15% of award), operated carbon emissions (15%), reliability and availability (15%), modified free cash flow★ (30%) and structural cost reductions (25%).

Safety and sustainability

Within the annual bonus scorecard, safety performance is measured against the number of tier 1 and tier 2 process safety events each year (7.5% weighting each).

For 2025, we achieved a combined outcome of 87.5% of maximum for this measure. We reported five tier 1 process safety events during the year resulting in an outcome between target and maximum. Tier 2 performance was strong with a significant reduction in the number of events compared to prior year (22 events in 2025 compared to 35 events in 2024), resulting in a maximum outcome for this measure. This reflects our continued focus on process and personal safety.

However, we are deeply saddened by the four workforce fatalities during the year – three at *TravelCenters of America* and one at *Thorntons*. Further details of these fatalities are set out on [page 55](#).

In assessing the impact of the fatalities during the year, the committee was mindful of the total number of fatalities across the group and, with input from the safety and sustainability committee, reflected on the circumstances of each fatality. However, in line with our framework, the three fatalities at *TravelCenters of America* have been dealt with predominately at a local level – see [page 101](#) for further details. In respect of the group score, it was agreed that that a downward adjustment was justified when reflecting on the fatality at *Thorntons* and broader safety performance, and the entire bonus score was reduced by 4 points for all participants.

Sustainability performance was assessed against operated carbon emissions, which covers Scope 1 and 2 emissions based on bp's net zero operations aim. Our performance was strong and we delivered 1.6MteCO₂e ahead of our scorecard target, which resulted in an outcome of 73% of maximum.

Financial and operational

Under our financial and operational categories, bp delivered strong performance across all measures.

From an operational perspective, our performance was assessed against both plant reliability and refining availability. We achieved an outcome of 96.2% which resulted in an above target outcome.

Our financial performance was assessed against modified free cash flow and structural cost reduction. Modified free cash flow was \$12.4 billion, which resulted in the maximum outcome, reflecting our continued focus on strong capital discipline during 2025.

In line with our remuneration policy, the targets for modified free cash flow are adjusted for the actual commodity price environment to reflect underlying performance.

This was the first year that structural cost reductions were included in our scorecard. We delivered \$2.0 billion of cost reductions which resulted in performance between target and maximum.

Overall result

The formulaic annual bonus outcome, reflecting safety, operational and financial performance was therefore 1.63 out of a maximum of 2 (81.5% of maximum).

As described previously, the committee exercised its discretion to account for the fatalities during 2025 and reduced the formulaic outcome by 4 points to 1.59 out of 2 (79.5% of maximum).

2023-25 performance shares

The 2023-25 performance share scorecard was measured against relative TSR (20% weighting), return on average capital employed (ROACE)★ (20%), adjusted EBIDA per share compound annual growth rate (CAGR)★ (20%), sustainable emissions reductions (15%) and strategic progress (25%).

rTSR

bp placed fifth in the comparator group, resulting in nil vesting for this measure.

Financials

Financial performance was assessed against our returns and earnings measures and performed below the targets set at the start of the performance period, achieving nil vesting. The 2023-25 average ROACE was 15.4% and adjusted EBIDA per share CAGR was 9.8%.

Sustainability performance

We delivered Scope 1 and 2 greenhouse gas emissions reductions of 12.9% against our 2019 baseline. This resulted in an outcome between threshold and target, with vesting of 22% of maximum.

Strategic progress

Strategic progress was assessed using a combination of quantitative assessment (via financial KPIs) and qualitative judgement against the three strategic pillars set in 2023.

As set out in the 2024 directors' remuneration report, the committee also considered the strategic changes announced in 2023 and the Capital Markets Update in February 2025 when scoring performance against the original criteria.

We provide a detailed view of the committee's review of strategic progress on [pages 103-105](#).

Having considered the above, the committee determined that bp made strong progress over the three-year period and an outcome of 80% of maximum was felt appropriate for this measure.

Overall results

Overall, performance share vesting for the 2023-25 cycle was 23.3% of maximum. The committee believes that, given a large component of the strategic progress measures comprise financial KPIs, this outcome properly reflects achievement over the period and therefore has not applied any further discretion.

Board changes

In December 2025, Murray Auchincloss stepped down as CEO, and from the board, by mutual agreement. Remuneration decisions relating to Murray have been made in accordance with our shareholder-approved policy and contractual obligations, with full details provided on [page 113](#).

Carol Howle assumed the role of interim CEO on 18 December 2025, having previously served as EVP supply, trading & shipping. She will be succeeded by Meg O'Neill whose appointment as CEO takes effect from 1 April 2026.

Incoming CEO: Meg O'Neill

The committee has determined the remuneration package for the incoming CEO in line with our shareholder-approved remuneration policy, considering Meg's experience, external market benchmarks, shareholder expectations and broader operating environment.

Meg will receive a base salary of £1.6 million on appointment. This has been set at 2.5% above the salary level of her predecessor when taking into account the workforce salary increase that he would have been eligible for in April 2026. In reaching this decision, the committee considered Meg's proven track record as a high performing CEO within the sector and the experience and leadership credentials she will bring to lead bp through the next phase of its transformation journey.

Meg will receive standard benefits for an executive director, as provided for in the remuneration policy. These include a pension allowance of 20% of base salary aligned with the wider UK workforce. She will also participate in bp's annual incentive plans. There will be no change to the operation of our minimum shareholding requirement.

In line with our policy, Meg will receive relocation support to facilitate her move from Australia to the UK. She will also receive compensation for incentive awards forfeited on leaving her previous employer. Further details of Meg's joining arrangements are set out on [page 108](#).

Interim CEO: Carol Howle

Upon assuming the role of interim CEO on 18 December 2025, Carol's salary was set at £1.508 million aligned with the level of her predecessor. She will not be entitled to a salary increase in respect of 2026 and she will receive our standard executive benefits and pension provisions.

For 2026, Carol will be eligible to receive awards in line with our policy. She is also subject to bp's in- and post-employment minimum shareholding requirement from the date of appointment.

Looking ahead to 2026

Policy review

Our current remuneration policy was last approved in 2023 with 94% shareholder support. In line with the normal three-year cycle, we will be seeking approval for a revised policy at the 2026 AGM.

Over the past year, the committee has undertaken a detailed review of each element of the existing policy, assessing its effectiveness in incentivizing and rewarding the delivery of bp's strategy. We concluded that the current framework continues to allow us to set stretching, relevant and motivating short- and long-term performance measures, that are clearly aligned to the strategic priorities we expect leadership to deliver.

Accordingly, beyond a small number of updates to ensure continued alignment with evolving market practice, we are not proposing any significant changes at this time. We consulted with our top 30 shareholders, representing over 40% of our register, who were generally supportive of this approach for the 2026 AGM.

However, the committee is mindful that bp is progressing through the next stage of its transformation and therefore it is possible that further changes to our remuneration approach may be needed. Within this context, it may be that we will ask shareholders for approval of an updated policy ahead of the next required triennial vote. The remuneration committee will engage with bp's major shareholders on any such proposals in advance.

Annual pay review

Kate Thomson's base pay will increase by 3.5%, in line with the average increase in the UK. Adjustments in other jurisdictions will vary by local conditions.

Review of performance measures

As part of the broader policy review, the committee reflected on the performance measures used in our incentive scorecards and considered whether they remain aligned to the reset strategy announced in February 2025.

2026 annual bonus

To support the stretching goals within bp's reset strategy, the committee believes focus should be on sustained financial performance over the next year, with a particular lens on cash generation and cost reduction.

The scorecard categories and weightings have therefore been simplified, placing financial performance at the forefront (65% of award), supported by strong and sustained operational delivery (20%) and a continued focus on safety (15%). The underlying measures within the categories remain broadly unchanged from prior years and our framework on fatalities will continue to apply.

Progress towards bp's net zero operations aim will continue to be rewarded through our performance share plans rather than the annual bonus.

2026-28 performance shares

In line with the simplified structure of the annual bonus, the performance share plan has also been streamlined to ensure focus on the measures most critical to delivering our reset strategy.

For 2026-28, the scorecard will focus on the following key measures: shareholder returns (30% of award), cash generation (25%), ROACE (25%) and a continued focus on reducing Scope 1 and 2 operational emissions in line with bp's aim to reach net zero operations by 2050, or sooner (20%).

For the shareholder returns measure, the peer group has been reviewed for alignment with the reset strategy. The 2026-28 group will be simplified to five companies, focusing on the oil super majors who are considered our closest peers.

We have also broadened the underpin for our performance share awards. Going forward, the committee will take into consideration overall safety performance as well as ongoing progress towards a strong and resilient balance sheet when assessing final outcomes, providing further alignment with bp's long-term priorities.

Conclusion

2025 was a year of strong progress. Taking all circumstances into account, the committee believes that the overall remuneration outcomes are appropriate.

The committee remains committed to maintaining an open and transparent dialogue on remuneration matters with our shareholders. I would like to thank you for another year of constructive engagement and your continued support ahead of the 2026 AGM.

Ian Tyler

Chair of the remuneration committee
6 March 2026

Directors' remuneration report continued

Key performance highlights in 2025

\$24.5bn

operating cash flow ★
improved cash conversion

\$14.5bn

capital expenditure ★
10% YoY reduction

2.3mmboed

upstream ★ **production**
exceeded plan

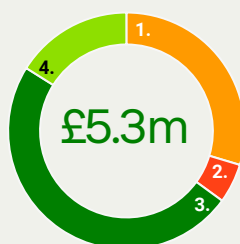
- Refining availability of 96.3% and plant reliability of 96.1% were highest on record.
- 7 major projects started up, 5 ahead of schedule.
- \$11bn completed or signed divestments, including \$6bn *Castrol* transaction.
- On track against primary targets set out in Capital Markets Update (February 2025).

Total remuneration in 2025

- 1. Salary and benefits
- 2. Cash allowance in lieu of pension
- 3. Annual bonus
- 4. Performance shares

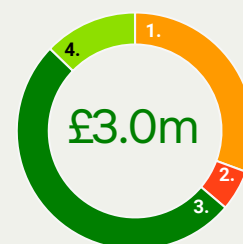
Single figure
Chief executive officer (outgoing)

35% Fixed
65% Variable pay



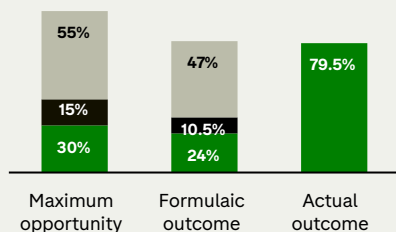
Single figure
Chief financial officer

36% Fixed
64% Variable pay



Pay outcomes in 2025

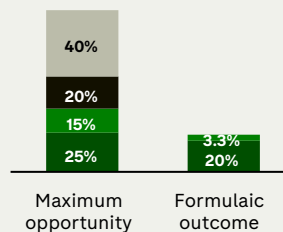
Annual bonus
(2025 ACB)



81.5% of maximum
formulaic outcome

79.5% of maximum
formulaic outcome
actual outcome after exercise of discretion

Performance shares
(2023-25 EDIP)



23.3% of maximum
formulaic outcome

- Safety and sustainability
- Operations ■ Financials

- Strategic progress ■ Sustainability
- rTSR ■ Financials

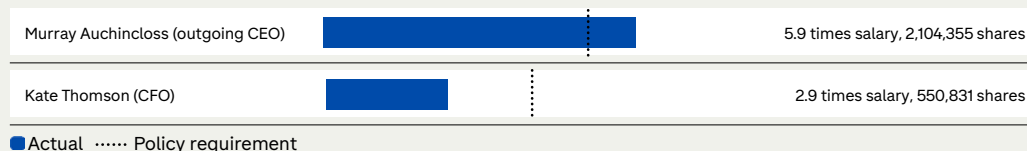
Application of discretion

The committee may exercise discretion in determining the outcomes of the annual bonus and performance shares, reflecting the broader stakeholder experience during the performance period. For 2025, downward discretion was applied and the 2025 ACB has been reduced by 4 points. Further details of the application of discretion have been set out on [page 101](#).

Alignment with shareholders

Share ownership

Share ownership aligns the interests of executive directors with those of shareholders.



Application of remuneration policy for 2026

Set out below is an illustration of how the remuneration policy will be implemented for 2026.

	2026	2027	2028	2029	2030	2031	2032	
Fixed pay (salary, pension and benefits)								<ul style="list-style-type: none"> Upon appointment, the incoming CEO's salary will be £1.6 million. For 2026, the CFO's salary will increase by 3.5%, from £864k to £894k, in line with the wider workforce average.
Annual bonus^a								<ul style="list-style-type: none"> CEO max opportunity: 225% of salary. CFO max opportunity: 225% of salary. For 2026, the scorecard has been simplified to focus on safety, operational and financial performance (see below).
Performance shares								<ul style="list-style-type: none"> CEO max opportunity: 500% of salary. CFO max opportunity: 450% of salary. Similarly to the annual bonus, the 2026-28 scorecard has been simplified with an increased focus on emissions reductions, financial and shareholder return measures (see below).
Shareholding requirement								<ul style="list-style-type: none"> In-employment and post-employment guidelines will continue to apply.

^a Half the bonus is paid in cash, and half is deferred into bp shares for three years until 'minimum shareholding requirement' is met. At this point, 67% is paid in cash and 33% is deferred into bp shares.

Alignment of 2026 variable remuneration with strategy

Each year, the committee sets a remuneration framework for executive directors that supports and incentivizes the execution of our strategy. For 2026, the scorecards have been simplified to reflect our business priorities, supported by strong safety and operational performance, with financial measures at the forefront. Further details on the rationale for their inclusion can be found on **pages 109-110**.

	Strategy (upstream, downstream, transition)	Primary targets	KPIs
Annual bonus			
Safety (15%)			
Tier 1 and tier 2 process safety events ★	●		●
Financials and operations (85%)			
bp-operated reliability ★ and availability ★	●		●
Structural cost reductions ★ (\$bn)	●	●	●
Modified free cash flow ★ (\$bn)			●
Performance shares			
Cumulative reduction % in operated carbon emissions (20%)			●
Adjusted free cash flow CAGR ★ (25%)		●	●
ROACE ★ (25%)		●	●
Relative TSR (30%)			●

→ [Strategy and primary targets page 8](#), [KPIs page 14](#)

Engaging with our workforce

We believe that our people are the key to bp's success and our approach to performance and reward should be fair and consistent across the organization. As a committee, we spend considerable time on matters relating to performance and remuneration arrangements across the wider workforce.

Element of remuneration	All employees	Executive directors
Salary	Salary is the basis for a competitive total reward package for all employees. We conduct an annual salary review for all non-unionized employees. In setting pay budgets, we assess how employee pay is currently positioned relative to market rates, wage inflation, forecasts and business context.	The salaries of our executive directors are reviewed annually. The review will take into account the same factors considered for the wider workforce. Salary increases for executive directors will typically be at or below the workforce rate, other than in specific circumstances.
Pensions and benefits	We operate different pension plans by location and for those parts of our business where market practice is markedly different, e.g. our retail business. For our population of non-retail employees in the UK, we provide a flexible cash benefits allowance of 20% of salary. The benefits available are aligned with competitive market practice in our different jurisdictions.	Executive directors receive a cash allowance in lieu of pension aligned with the wider workforce (currently 20% of salary). Other than the provisions of car, security and tax preparation related benefits, benefit packages are broadly aligned with those of other employees in the UK.
Annual bonus	More than half of the eligible workforce participate in an annual cash bonus plan that multiplies a grade-based target bonus amount by a bp performance factor derived from the bonus scorecards. From 2025, business scorecards have been introduced for certain parts of bp. Individual performance is assessed through a performance rating which may result in an uplift or decrease to bonus outcomes. We operate different bonus plans for those parts of our business where market practice is markedly different.	The annual bonus for the executive directors is linked to the same bp performance factor as for the wider workforce. Executive directors are not entitled to a bonus uplift linked to individual performance. For executive directors, a portion of any award is deferred into shares for three years. The deferral rate depends on whether the executive director has met their minimum shareholding requirement.
Performance shares	We operate share plans with three-year vesting for all our senior leaders. Opportunity varies across two broad tiers: group leaders (approximately 300) and senior-level leaders (approximately 4,000).	Executive directors are eligible for performance share awards, which are subject to stretching performance targets over a three-year period. An additional three-year post-vesting holding period applies for executive directors.

Other elements of pay

Recognition

energize!, our global recognition platform, is open to all employees for peer-to-peer recognition. The scheme aims to celebrate employees' contributions, highlight behaviours vital to our success and drive performance. In 2025, a total of 39,900 employees received energize! awards.

We also operate a spot bonus programme, where individuals or teams can be nominated to receive a one-off cash award to recognize their achievements or particular initiatives. Senior leaders actively participate in the programmes, often by recognizing the contributions of their team members. In 2025, 6,600 employees were awarded spot bonuses in recognition of their contributions.

Focus@bp

focus@bp is our internal platform that helps support performance development. The platform enables employees to set dynamic goals, have regular check-ins, give and receive meaningful feedback and grow skills to enable our teams to develop and deliver.

We believe that performance matters, both individually and collectively, and development is key in helping to improve our performance as a business. focus@bp forms the basis of discussions relating to development or progression and the achievement of goals is factored in when making decisions in relation to an individual's remuneration.

All-employee share plan

bp operates an award-winning global ShareMatch programme which is available to over 18,000 employees in 46 countries. This plan offers our employees the opportunity to invest and share in bp's success, fostering a culture of shared ownership. At the end of 2025, the participation rate in the scheme was 64% of eligible employees.

Workforce highlights in 2025

Driving our performance culture

Following the strategy reset announced in February 2025, bp is undertaking a broad transformation to become a more competitive, focused and value-driven organization.

As part of this, we reviewed and updated our approach to performance management to make it clearer, more consistent and better aligned with bp's strategic goals. This evolution represents a culture shift and an operational change, influencing how our employees support bp in delivering its ambitions.

To date, four changes have been introduced:

- **Aligned goals:** Common goals are now set at an entity or sub-entity level, giving employees a clearer line of sight to organizational priorities and how their work contributes to bp's strategy.
- **Business scorecards:** Business-level scorecards have been introduced alongside the group scorecard, strengthening the link between business performance and reward outcomes.
- **Annual review cycle:** The performance cycle now incorporates quarterly check-ins, alongside our existing mid-year and year-end conversations, to support more regular, meaningful conversations.
- **Individual ratings:** A simple rating system has been introduced to assess individual performance over the year, with outcomes directly impacting reward decisions.

Together, these changes will help embed a stronger performance culture that supports our strategy.

Supporting employees during organizational transformation

Our approach to workforce health and wellbeing is centred around the needs of our people, combining globally available services that can be tailored to meet specific local needs. All employees have access to our global digital health and wellbeing hub, Thrive@bp.

During bp's transformation programme, we have offered comprehensive mental health support to employees which has been developed through listening forums and employee feedback. Recognizing the pivotal role of our leaders, we have also offered tailored resources to help them support their teams and look after their own mental health.

Support has included on-site counselling, check-ins with counsellors and advice from psychologists, coaching and access to other specialists through webinars. We offered bespoke mental health training on 'thriving' through change, which has been completed more than 4,000 times and included a leader-specific module.

Healthy minds

Our bespoke mental health education programme, Healthy Minds, provides elearning modules for all bp employees.

Since its launch in 2024, more than 14,000 modules have been completed and more than 75% of our senior leaders have engaged in the programme.



Workforce engagement

Receiving feedback from our employees remains an important way in which the board stays connected to the broader employee experience.

On remuneration specifically, as part of the board-led workforce engagement programme (WEFP), a dedicated session was held in July 2025 to hear employee views on changes to performance management, including the introduction of business scorecards and performance ratings.

The discussion provided valuable insight into how these changes are being received across the organization.

Image: Retail colleague at our Oak Tree service station in Surrey, UK



Shareholder views

The committee is committed to maintaining an open dialogue with our shareholders. During the year, we engaged with our top 30 shareholders (representing over 40% of our shareholder register).

The insights shared during this engagement play an important role in shaping our decisions. We value the feedback received, helping us to understand evolving expectations on reward matters.

Image: Trading and shipping colleagues at our Canary Wharf office in London, UK

Directors' remuneration report continued

Executive directors' pay for 2025

Single figure table – executive directors (audited)^a

	Carol Howle ^b thousand 2025	Murray Auchincloss ^c thousand 2025	Kate Thomson thousand 2025	Murray Auchincloss thousand 2024	Kate Thomson thousand 2024
Salary	£57	£1,434	£845	£1,450	£731
Benefits	£2	£138	£82	£132	£67
Cash allowance in lieu of pension	£11	£287	£169	£290	£146
Annual bonus ^{de}	£83	£2,594	£1,545	£734	£370
Performance shares ^{fg}	£733	£854	£387	£2,573	£697
Total remuneration	£886	£5,307	£3,029	£5,179	£2,011
Total fixed remuneration	£70	£1,859	£1,096	£1,872	£944
Total variable remuneration	£816	£3,448	£1,932	£3,307	£1,067

a Due to rounding, the totals may not agree exactly with the sum of the component parts.

b Carol Howle was appointed interim CEO on 18 December 2025, having previously been EVP supply, trading & shipping. The amounts disclosed reflect her service in the year as an executive director.

c Murray Auchincloss stepped down as CEO on 18 December 2025, having been appointed as permanent CEO on 17 January 2024. The amounts disclosed reflect his service in year as an executive director.

d In line with the 2023 policy, annual bonus is subject to deferral into shares for three years at a rate of 33% or 50%, depending on whether an individual has met their minimum shareholding requirement. See page 100 for further detail on the approach taken for the 2025 annual bonus.

e For Carol Howle, a portion of the annual bonus relates to performance within her capacity as EVP supply, trading & shipping. The pro-rated value of this award amounts to £36k of the figure disclosed, of which half is to be delivered in cash and half is to be deferred into bp shares for three years. The remuneration committee has determined that the measures and targets linked to this portion of the award are commercially sensitive and therefore have not been disclosed. The remaining portion of the annual bonus relates to group performance, as set out on page 99, and in line with the terms of that award will not be subject to deferral requirements in respect of 2025.

f For Murray Auchincloss, the value of the performance share award has been calculated using the average share price in the last three months of 2025 of £4.40 and includes notional dividends accrued up to 13 February 2026. For 2024, the performance shares have been restated to reflect the share price on the date of vesting of £3.60 and actual dividends received.

g For Carol Howle and Kate Thomson, the value of the performance share award relates to their roles prior to their appointment to the board. For 2023-25, the awards have been calculated using the average share price in the last three months of 2025 of £4.40 and includes notional dividends up to 13 February 2026. For 2023-25, performance share awards below board had a different scorecard to executive directors, which resulted in an outcome of 52.8% of maximum. For 2024, the performance shares have been restated to reflect the share price on the date of vesting of £4.63 and actual dividends received.

Overview of single figure outcomes

Salary

In respect of 2025, Murray Auchincloss received a salary increase in line with the wider workforce and his base pay was set at £1.508 million. Kate Thomson received a salary increase of 8%, reflecting her development in role and leadership of the finance function, which increased her base pay to £864,000. These changes were effective from the 2025 AGM on 17 April 2025.

Carol Howle was appointed as interim CEO on 18 December 2025. From the date of appointment, her base pay was set in line with that of her predecessor at £1.508 million.

Benefits

Executive directors received car-related benefits, coverage of tax return preparation, security assistance, insurance and medical cover.

Cash allowance in lieu of pension

In line with the 2023 directors' remuneration policy, executive directors receive a cash allowance in lieu of pension of 20% of salary. This is in line with the wider workforce in the UK.

Annual bonus

For 2025, the committee assessed performance against a bonus scorecard of measures across three categories: safety and sustainability, operations and financials. These measures were aligned with our strategy and investor proposition as set out at the beginning of the year.

2025 annual bonus scorecard and outcome

Annual bonus scorecard

Categories	Measures	Threshold (0)	Target (1)	Maximum (2)	Weighting Outcomes	
Safety and sustainability (30%)	Tier 1 process safety events★	9	6	4	7.5%	0.11
		Actual: 5				
	Tier 2 process safety events★	39	30	27	7.5%	0.15
		Actual: 22				
	Operated carbon emissions (MtCO ₂ e)	38.9	35.5	32.1	15%	0.22
		Actual: 33.9 ^a				
Operations (15%)	bp-operated reliability★ and availability★	95.1%	95.9%	96.7%	15%	0.21
		Actual: 96.2%				
Financials (55%)	Modified free cash flow★ (\$bn)	6.5	8.5	10.5	30%	0.60
		Actual: 12.4				
	Structural cost reductions★ (\$bn)	0.6	1.4	3	25%	0.34
		Actual: 2				

Formulaic outcome 1.63 out of 2.00

Formulaic scorecard outcome **1.63 out of 2.00**
 + Application of framework on fatalities **4 point reduction** (see page 101)
 + Overriding committee judgement **No adjustment**
 = **1.59 out of 2.00**

^a The actual operated carbon emissions outcomes used for bonus calculation purposes (33.9MtCO₂e) is based on the agreed portfolio scope at beginning of the plan year and differs from the figure reported elsewhere in the bp Annual Report and Form 20-F 2025 (34.3MtCO₂e) due to portfolio changes.

Directors' remuneration report continued

Summary of performance

Safety performance, as measured by tier 1 and 2 process safety events★, was strong with the mechanical outcome achieving between target and maximum performance. The total number of events is less than prior year, with 27 tier 1 and tier 2 events in 2025 (38 in 2024). This year-on-year improvement underpins the importance of our process safety improvement plans and the delivery of the actions they outline.

Operated carbon emissions performance is measured against the anticipated emissions based on the business plan and activity set identified at the beginning of the year. For 2025, operated carbon emissions of 33.9MtCO₂e (footnote a) resulted in an outcome between target and maximum. This holds underlying operated emissions broadly flat compared to the 2024 result, after accounting for previously identified portfolio growth and full year impact of project start-ups.

The most significant contributions to emissions performance of 1.6MtCO₂e below 2025 plan came from improved management of abnormal plant conditions in the Asia Pacific region; continuation of previously implemented efficiencies across refining sites; and flaring reductions and operational stability in the Azerbaijan, Georgia and Türkiye region.

Emission reduction projects totalling 0.27MtCO₂e implemented by our business in 2025 included: Archaea Energy renewable natural gas switching to low carbon power; bpx energy's central distribution project, which enabled decommissioning of legacy natural gas-driven equipment; focus on flare system and practices improvements at Tangguh, and synchronization of power and power management strategy implementation in Trinidad and Tobago.

Reliability and availability is a combined measure of bp-operated refining availability★ and bp-operated plant reliability★ with a performance outcome of 96.2% – between target and maximum. Refining availability and plant reliability both strengthened year-on-year, with refining availability of 96.3% (94.3% in 2024) and plant reliability of 96.1% (95.2% in 2024).

Financial performance, as measured by **modified free cash flow★** and **structural cost reduction★**, was strong. bp generated modified free cash flow of \$12.4 billion, which resulted in the maximum outcome. Similarly, steady progress was made against our structural cost reduction measure, delivering \$2.0 billion of reductions which was between target and maximum.

Overall outcome

The formulaic score for the 2025 annual bonus was 1.63 out of 2 (81.5% of maximum).

The committee considered bp's framework on fatalities when reflecting on the formulaic outcome. Sadly, there were four workforce fatalities during the year. Full details on the application of the framework have been provided on [page 101](#).

Having considered the above, alongside a holistic review of performance, the committee determined that the formulaic score should be reduced by 4 points to 1.59 out of 2 (79.5% of maximum).

Approach to deferral

In relation to the policy on deferral requirements, the committee reviewed the executive directors' shareholdings during the year to assess if the minimum shareholding requirement had been met.

As at 18 December 2025, the date Murray Auchincloss stepped down from the board, his shareholding represented 5.87x salary. This is above the minimum shareholding requirement for the CEO of 5x salary and his pro-rated 2025 award will therefore be subject to a deferral rate of 33%. While Kate Thomson has made strong progress towards her minimum shareholding requirement since her appointment in 2024, her shareholding represented 2.94x salary (as at 13 February 2026). This is below the minimum shareholding requirement for the CFO of 4.5x salary and her 2025 award will therefore be subject to a deferral rate of 50%.

As Carol Howle was only appointed interim CEO on 18 December 2025, the committee agreed that her 2025 award would be calculated based on her salary and award opportunity level prior to appointment. Her bonus award in respect of group performance will therefore not be subject to any deferral requirements.

a The actual operated carbon emissions outcomes used for bonus calculation purposes (33.9MtCO₂e) is based on the agreed portfolio scope at beginning of the plan year and differs from the figure reported elsewhere in the *bp Annual Report and Form 20-F 2025* (34.3MtCO₂e) due to portfolio changes.

bp's framework on fatalities

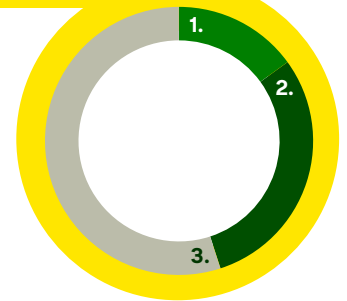
We are working towards our goal of eliminating workplace fatalities. In 2024 we implemented a new framework on fatalities. This framework, developed in consultation with shareholders and the safety and sustainability committee (S&SC), links safety performance directly to the bonus scorecard.

Full details of our framework on fatalities can be found in the 2023 directors' remuneration report.

bp.com/investors

Framework on fatalities

- 1. Operations (15%)
- 2. Safety and sustainability (30%)
- 3. Financial (55%)



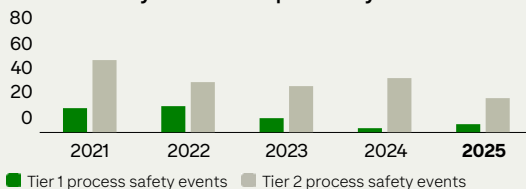
What happened during the year?

At bp, safety remains our top priority and we are deeply committed to ensuring that our operations are carried out safely every single day.

Safety performance in 2025

During 2025, we recorded five tier 1 events, a slight increase compared with the prior year. Tier 1 events represent our more serious incidents and it remains essential that we stay focused on reducing these incidents. Encouragingly, the number of tier 2 events fell significantly, with 22 events compared to 35 in 2024.

Process safety events over past five years



However, there were sadly four workforce fatalities during the year – three at our recently acquired TravelCenters of America facilities and one at *Thorntons*.

How was the framework applied?

The committee made reference to the framework in determining the impact of fatalities on the 2025 bonus outcome.

Fatality at *Thorntons*

In April 2025, a contractor had a fatal incident while repairing one of our facilities. Since then, a thorough investigation has been undertaken to understand the underlying causes and to ensure that appropriate measures are put in place to prevent similar occurrences in the future.

The committee has reflected on this event, receiving input from the S&SC, and the reward impact is summarized below.

Fatalities at TravelCenters of America

When bp acquires a new asset, it determines whether an initial transition period (typically 1 to 3 years) is required to allow for full embedding of bp OMS systems. During this period, assets are not consolidated into bp group safety systems and are managed using local performance tracking and scorecards. This is consistent with the approach taken under the fatality framework for the ACB.

For TravelCenters of America, it was agreed that this acquisition should be treated as an excluded new asset for three performance years (i.e. to the end of 2025) – reflecting the scale and complexity of the business, with ~20,000 employees and an inherently different risk profile to bp's core operations.

The fatalities have, however, been considered at a local level and detail of the reward impact is set out below.

Further details of these fatalities are set out on [page 55](#).

What was the outcome?

In line with the framework, the committee reflected on the fatality at *Thorntons*. While the S&SC confirmed that the incident was unforeseeable and not indicative of a systemic issue, we believe that any loss of life is unacceptable and have decided to reduce the outcome by 4 points for all participants. Regarding the fatalities in TravelCenters of America, a more material reduction has been made to the local bonus plan. The S&SC has also advised that corrective action has been undertaken to prevent similar occurrences in the future.

The committee is mindful of the need to ensure that the fatality framework continues to support our determination to eliminate workforce fatalities. During 2026, the committee will reflect on this and make any necessary changes to the framework.

4 point reduction

resulting in a final bonus score of **1.59 out of 2** for all participants of the group ACB.

Directors' remuneration report continued

2023-25 performance share plan scorecard and outcome

2023-25 performance shares were granted under the executive directors' incentive plan (EDIP). The scorecard for this cycle consists of sustainable emissions reductions (15% weighting), relative total shareholder return (rTSR) (20% weighting), return on average capital employed (ROACE)★ (20% weighting), adjusted EBIDA per share CAGR★ (20% weighting) and strategic progress (25% weighting).

2023-25 performance share plan scorecard (audited)

Share plan scorecard

Categories	Measures	Threshold	Maximum	Weighting	Outcomes
Net zero (15%)	Net zero across entire bp operations by 2050 (Scope 1 + 2)	12%	16%	15%	3.3%
		Actual: 12.9%			
rTSR (20%)	rTSR	Fourth	First	20%	0%
		Actual: Fifth			
Financials (40%)	ROACE (average 2023-25)	20.2%	22.2%	20%	0%
		Actual: 15.4%			
Financials (40%)	Adjusted EBIDA per share CAGR	12.5%	14.5%	20%	0%
		Actual: 9.8%			
Strategic progress (25%)	Deliver value through resilient hydrocarbon business	Qualitative and quantitative assessment by the committee, see pages 103-105 .		25%	20%
	Demonstrate track record, scale and value in low carbon energy				
	Accelerate growth in convenience and mobility				
Assessed outcome				23.3% out of 100%	

Assessed outcome
23.3% out of 100%

+

Underpin: Committee review of absolute shareholder returns, long-term safety and environmental performance, low carbon and climate change considerations.

No adjustment

=

Final vesting after committee judgement
23.3% out of 100%

Sustainability performance

To the end of 2025, actions or interventions that have led to ongoing reductions in Scope 1 and 2 emissions have totalled 12.9% relative to the baseline year of 2019. The main contributions during the performance period have come from centralization and electrification of bpx energy processing infrastructure, refineries switching to low carbon power, and a focus on flare system and practices improvements across production sites.

Relative TSR

During the performance period, bp's rTSR performance placed it fifth out of eight in the comparator group which resulted in nil vesting.

Financials

Performance of ROACE and adjusted EBIDA per share CAGR, at 15.4% and 9.8% respectively, were below the targets set at the start of the performance period and achieved nil vesting.

As part of the review of outcomes, the committee considers the impact of the external environment with respect to ROACE outcomes, and in respect of adjusted EBIDA per share CAGR the committee reviews share buyback activity outside of plan during the performance period. It determined that, in line with past practice, no further adjustments should be made to either of these elements for the 2023-25 cycle.

Strategic progress

Overview of strategic progress (2023-25)

Assessing performance against this measure has been challenging as it spans a three-year period that has been marked by significant strategic change.

The criteria, including financial KPIs, set at the start of the performance period (2023) were intended to measure delivery against the three strategic pillars at that time: resilient hydrocarbons, low carbon energy and convenience and mobility. However, as our strategy has continued to evolve, these original objectives no longer fully reflect the strategic performance achieved over the period.

The committee has therefore assessed performance against the original criteria, including the financial KPIs, whilst also considering the broader strategic milestones delivered during the period. In particular, progress against the reset strategy outlined as part of the Capital Markets Update in February 2025 has been taken into account. In summary:

Pillar 1: Resilient hydrocarbons

Delivered strong operational and financial performance over the period with 2025 refining availability★ and plant reliability★ both exceeding 96%, delivering unit production costs in line with target and production above our plan. We brought 17 major projects★ across oil, gas and refining online and had significant exploration success, including Bumerangue in Brazil.

Pillar 2: Low carbon energy

Since setting targets in 2023, bp's low carbon energy business has undergone significant transformation, leading to the retirement of the original objectives. The business has delivered a robust set of results within the context of the reset strategy and shifting priorities focused on value.

Pillar 3: Convenience and mobility

Strong operational growth, with 21% convenience gross margin CAGR 2023-25 (inclusive) including the acquisition of TravelCenters of America in 2023. With some of the measures being retired under the reset strategy, financial performance has remained strong with modified free cash flow for 2025 above the plan we set in 2023, underpinned by significant year-on-year growth in operating cash flow★.

Overall performance:

Considering delivery against both the original pillars and progress against our reset strategy to date, an outcome of **80% of maximum** was deemed appropriate for 2023-25.

Directors' remuneration report continued

Key ● On track ● Strong progress ● Improvement required

1. Deliver value through a resilient hydrocarbon business KPIs (KPIs as set in 2023)

Unit production cost ●

Average unit production cost over the period was \$6.08/boe with 2025 delivered at \$6.28/boe, in line with our 2025 target, representing strong progress on this target while making value-based portfolio choices.

Plant reliability ●

2025 plant reliability of 96.1% was a record high, reflecting our focus on operational delivery and supporting our production exceeding plans.

Refining availability ●

Refining availability was high in 2025 with all four quarters above 96% and a full year average of 96.3%, reflecting strong progress on this KPI, with 2024 impacted by the plant-wide power outage at Whiting.

2023	2024	2025	2025 target	2023	2024	2025	2025 target	2023	2024	2025	2025 target
\$5.8/boe	\$6.2/boe	\$6.3/boe	\$6.0/boe	95.0%	95.2%	96.1%	96.0%	96.1%	94.3%	96.3%	96.0%

Overview

- Continued to high-grade our portfolio and drive higher margins.
- Delivered 17 major projects (15 in oil and gas, two in refining) including seven in 2025 of which five were ahead of schedule.
- Continued to high-grade our portfolio, including growing bpx energy production by 43% and being selected to help governments develop their resources.
- Exceptional exploration year with 12 discoveries in 2025, including in the Gulf of America, Namibia and Brazil.
- The hydrocarbon business performed well against financial measures.

2. Demonstrate track record, scale and value in low carbon energy KPIs (KPIs as set in 2023)

Developed renewables to FID★ ●

Growth has been driven by Lightsource bp. Tracking below target as the solar sector has been significantly impacted by higher interest rates, inflation and supply chain constraints. As a result, the portfolio has been high-graded based on value, managed pace of development and decapitalization.

No outcome for 2025 following bp's reset strategy and subsequent retirement of our strategic pillars and associated targets.

Renewables pipeline★ ●

Growth has been driven by Lightsource bp as well as successful offshore wind bids, which now sit within the JERA Nex bp joint venture. The hydrogen and CCS portfolio has been prioritized based on deliverability, value and returns – with four sanctioned projects in development.

Similar to developed renewables to FID, no outcome is shown for 2025 following bp's reset strategy and subsequent retirement of measures.

2023	2024	2025	2025 target	2023	2024	2025	2025 target
6.2GW	8.2GW	n/a	20GW	58.3GW	60.6GW	n/a	n/a

Overview

- The low carbon energy business underwent a significant portfolio reset and rationalization – driving down costs and improving capital efficiency to support the group's modified free cash flow delivery.
- JERA and bp completed the formation of JERA Nex bp in August 2025, establishing a top-tier global offshore wind joint venture. The sale of bp's onshore wind business to LS Power completed in December 2025.
- Adjusted EBITDA over the period was lower than expected, reflecting a challenging US solar market and increased ramp up and origination spend in hydrogen, CCS and offshore wind to progress previous growth targets. 2025 reflects effective delivery of portfolio high-grading and the decapitalization strategy.

3. Accelerate growth in convenience and mobility KPIs (KPIs as set in 2023)

Convenience margin growth★ ●

The acquisition of TravelCenters of America completed in 2023 underpinning 21% convenience gross margin CAGR over the period.

Strategic convenience sites★ ●

As the target was retired at the start of 2025, in line with our reset strategy, the measure was not tracked during 2025. However, performance was close to target at end of 2024.

Castrol performance (revenue) ●

Castrol had a strong 2025, and now has 10 quarters of consecutive year-on-year earnings growth. Castrol continued strategic growth initiatives, including expansion of its thermal management portfolio beyond cooling fluids into integrated full-service solutions.

2023	2024	2025	2025 target	2023	2024	2025	2025 target	2023	2024	2025	2025 target ^a
60%	17%	(5)%	10%	2,850	2,950	n/a	3,000	\$7.0bn	\$6.9bn	\$7.1bn	n/a

Overview

- Despite the 2025 strategy reset focussing on downstream, the convenience and mobility business made strong progress against the objectives set back in 2023 – providing the platform to grow the business.
- Convenience and mobility delivered adjusted EBITDA below plan, reflecting the more challenging market backdrop and refocused capital frame. However, modified free cash flow was ahead of target.

a The Castrol performance KPI was retired during the performance period and performance has therefore been considered 'in the round' including reference to earnings and volume growth.

Overall assessment

As set out in the 2024 directors' remuneration report, the committee has assessed performance against the original three strategic pillars within the context of bp's reset strategy:

In February 2025, bp introduced a fundamentally reset strategy as part of its Capital Markets Update (CMU). The strategy focuses on strengthening performance by growing free cash flow, returns and building long-term shareholder value, supported by four primary targets to be delivered by the end of 2027.

For all the primary targets, performance is currently on track or ahead of plan with strong underlying financial performance during 2025.

Growing free cash flow ●

CMU target: >20% CAGR (2024-27)

Adjusted free cash flow★ was increased by c.55% in 2025, based on CMU price assumptions, which is ahead of plan.

Reducing net debt ●

CMU target: \$14-\$18bn (end of 2027)

Net debt★ at the end of 2025 was \$22.2 billion, which is \$800 million lower than at the end of 2024.

During 2025, \$1.2 billion of perpetual hybrid bonds were redeemed and bp made \$1.2 billion of pre-tax payments against our Gulf of America settlement liability.

Structural cost reductions★ ●

CMU target: \$4-\$5bn (end of 2027)

Since the start of the programme, bp has delivered \$2.8 billion of the cost reduction target. Having reflected on the outcome of the strategic review to divest *Castrol*, the CMU target was increased (to \$5.5-\$6.5 billion).

Generating higher returns ●

CMU target: >16% ROACE★ (end of 2027)

ROACE was around 14%, based on CMU price assumptions, an increase from around 12% in 2024.

Conclusion

Taking into account delivery against the targets set under the original pillars, alongside bp's evolving strategic context and the progress made on our reset strategy to date, the committee concluded that performance on this measure supports vesting of the strategic progress measure at 80% of maximum. Strategic progress remains a key measure for outstanding awards and the committee will continue to apply judgement in the context of broader strategic delivery.

Other vesting considerations

Along with the results from the scorecard measures, the committee considers an 'underpin' to the formulaic outcome in order to determine the final vesting percentage. The underpin broadens our performance assessment, allowing us to consider vesting outcomes with overall alignment to absolute shareholder returns, environmental and safety factors and progress in matters relating to low carbon and climate change. Where relevant, we take input from the safety and sustainability committee and the audit committee to deepen and enhance our perspective.

Having considered the above, the committee concluded that the vesting outcome was suitably reflective of the company's underlying performance and the experience of shareholders overall through the performance period. The committee agreed it was not necessary to apply discretion to the formulaic outcome and therefore approved vesting of 23.3% for the 2023-25 EDIP award. This decision yields the outcome shown in the table below for the former CEO. The scorecard detail is shown on [page 102](#).

The committee was satisfied that the remuneration policy had operated as intended and therefore no further changes were required. No malus and clawback provisions were applied in respect of the annual bonus or EDIP awards in the previous financial year.

2023-25 performance share plan outcome (audited)

	Shares awarded	Unvested shares following application of performance factor	Value of unvested shares following application of performance factor ^a	Impact of share price change ^a
Carol Howle ^b	137,610	166,594	£733,014	(£56,642)
Murray Auchincloss	717,958	194,018	£853,679	(£93,129)
Kate Thomson ^b	72,650	87,951	£386,984	(£29,903)

a These values reflect the impact of the change in share price since grant related to the number of shares which are no longer subject to performance conditions, including dividend equivalents accrued at 13 February 2026. The face values of these awards were calculated using a market price of ordinary shares at close on the dates of award, as follows: £4.88 on 2 May 2023 and £4.74 on 7 June 2023 respectively. The average share price during Q4 2025 was £4.40. The amount reported as 2025 income in the single figure is therefore £0.854 million for Murray, £0.733 million for Carol and £0.387 million for Kate.

b Carol Howle's and Kate Thomson's awards were made under the below board performance share plan where grants are made at 50% of maximum, rather than at 100% of maximum as for the EDIP. For 2023-25, performance share awards below board had a different scorecard to executive directors, which resulted in an outcome of 52.8% of maximum.

Directors' remuneration report continued

Policy implementation for 2026

The table below shows how the remuneration policy, being submitted to shareholders for approval at the 2026 annual general meeting on 23 April 2026, will be implemented. As outlined in the chair's statement, the 2023 policy has been broadly rolled forward for 2026. Full details of the policy being submitted for shareholder approval can be found on [pages 118-125](#).

Policy feature	2026 implementation
Salary	
<p>To provide fixed remuneration to reflect the scale and complexity of both the business and the role, and to be competitive with the external market.</p> <p>When setting salaries, the committee considers practice in other energy majors, as well as European and US companies of a similar size, geographic spread and business dynamic to bp. Percentage increases for executive directors will not exceed that for the wider workforce, other than in specific circumstances identified by the committee (e.g. in response to a substantial change in responsibilities).</p> <p>Salaries are normally set in the home currency of the executive director and are reviewed annually. They may be reviewed at other times where appropriate.</p>	<ul style="list-style-type: none">• The budgeted increase to our UK salaried staff effective from 1 April 2026, our annual salary review date, will be 3.5%.• For 2026, the executive director's salaries will be: Meg O'Neill: £1,600,000 (from appointment) Carol Howle: £1,508,000 (from appointment) Kate Thomson: £894,000 (3.5% increase, effective 2026 AGM)
Pensions and benefits	
<p>Executive directors normally participate in the company retirement plans that operate in their home country.</p> <p>New appointees from within the bp group retain previously accrued benefits related to service prior to appointment as executive director. For their service as a director, cash allowance in lieu of pension will be up to 20% of base salary.</p> <p>For future appointments, the committee will carefully review any retirement benefits to be granted to a new director, taking account of retirement policies across the wider group and any arrangements currently in place.</p>	<ul style="list-style-type: none">• Executive directors' cash allowance in lieu of pension is 20% of base pay (in line with the wider workforce).• Prior to their appointment as executive directors, Carol and Kate received a UK deferred pension. No further pension is accrued under either plan.• Benefits will remain unchanged for 2026 and include car-related provisions, security assistance, assistance with tax preparation, insurance and medical cover.
Annual bonus	
<p>Bonus is measured against an annual scorecard. The committee holds discretion to choose the specific measures and the relative weightings adopted in the annual scorecard, to reflect the annual plan as agreed with the board.</p> <p>Numeric scales are set for each measure, to score outcomes relative to targets. A scorecard outcome of 1.0 reflects the target outcome and 2.0 is the maximum outcome.</p> <p>Target bonus is 112.5% of salary, and maximum bonus is 225% of salary.</p> <p>Half the bonus is paid in cash, and half is deferred into bp shares for three years up until the 'minimum shareholding requirement' is met. At this point, 67% is paid in cash and 33% is paid in bp shares. Dividends (or equivalents, including the value of any reinvestment) may accrue in respect of any deferred shares.</p> <p>Awards are subject to operationally robust and effective malus and clawback provisions as described below.</p>	<ul style="list-style-type: none">• For 2026, our scorecard will be assessed against the following categories: safety (15%), operations (20%) and financials (65%).• See page 109 for further details on measures for the 2026 annual bonus.• The framework on fatalities, which helps guide decisions on adjustments to the bonus outcome in relation to fatalities, will continue to be applied. Further detail has been provided on page 101.

Policy feature	2026 implementation
Performance shares	
<p>Performance shares are granted with a three-year performance period, measured against a scorecard.</p> <p>The committee holds discretion to choose the specific measures and the relative weightings adopted in the scorecard, to ensure they are focused on the near-term priorities for delivering the bp strategy in the interests of shareholders.</p> <p>Annual grants are 500% of salary for the CEO, and 450% of salary for any other executive director. Awards will vest in proportion to the outcomes measured through the performance scorecard, subject to any adjustment by the committee, and will be subject to a three-year post-vesting holding period.</p> <p>Awards are subject to operationally robust and effective malus and clawback provisions as described below.</p>	<ul style="list-style-type: none"> • For our 2026-28 cycle, the scorecard categories will be rTSR (30%), financials (50%) and environmental, social and governance (20%). • See page 109 for further details on measures for the 2026-28 EDIP. • The award will be subject to an underpin that takes into consideration overall safety performance and ongoing progress towards a strong and resilient balance sheet over the performance period. • The 2026-28 awards will be granted based on the average closing share price of each calendar day in the 90-day period ending on the date of bp's 2026 AGM.
Shareholding requirement	
<p>CEO to build a shareholding of at least five times salary, and other executive directors four and a half times salary, within five years of appointment.</p> <p>Executive directors are required to maintain that level for at least two years after they cease to be a director.</p>	
Malus and clawback	
<p>Operationally robust and effective malus and clawback provisions apply to our incentive awards.</p> <p>The following events can trigger either malus or clawback: a material safety or environmental failure; material reputational damage; an incorrect award outcome due to miscalculation or incorrect information; a restatement due to financial reporting failure or misstatement of audited results; material misconduct; or fraud.</p> <p>In addition, malus may be triggered by the following events: material downturn in performance of the group or any part of it and conduct leading to significant losses; or other exceptional circumstances that the committee considers similar in nature.</p> <p>The period during which malus and/or clawback may be applied is generally three years from vesting or, if longer, until the expiry of any retention or holding period applicable to an award, which is considered a sufficient period for any issues that might give rise to malus or clawback to be identified.</p>	
Committee flexibility	
<p>The committee has discretion to adjust performance measures and weightings, and to revise the peer group for the rTSR measure.</p> <p>This discretion allows appropriate realignment, throughout the policy term, for changes in the annual plan and for the anticipated evolution of the low carbon business environment.</p> <p>The committee also holds discretion in determining the outcomes for annual bonus and performance shares, allowing it to take broad views on alignment with shareholder experience, environmental, societal and other relevant considerations e.g. portfolio changes.</p>	

Directors' remuneration report continued

Incoming CEO's arrangements

As announced on 17 December 2025, Meg O'Neill will join bp as CEO on 1 April 2026. Her salary has been set at £1,600,000 and she will not be eligible to receive a salary increase until the conclusion of the wider annual pay review process in April 2027. She is eligible for a cash allowance in lieu of pension which will be 20% of salary in line with the wider workforce and her other benefits will be in line with policy.

Regarding her incentive awards, Meg's opportunity levels will align with the maximums outlined in the table above. For 2026, both her annual bonus and performance share award will be pro-rated to reflect the portion of the year she serves as an executive director. The awards will be subject to the deferral requirements, holding periods and malus and clawback provisions outlined under our policy.

Relocation support

Meg will be relocating from Australia where her previous employer was headquartered and she will receive relocation assistance to support her move. This includes – among other elements – immigration support, temporary accommodation for up to six months and shipping. The cost of the relocation assistance is subject to clawback if Meg was to resign within two years of appointment to the role. Limited repatriation support will be provided at the end of Meg's tenure.

Buy-out awards

On appointment, Meg will be granted cash and share-based awards to replace remuneration foregone when leaving her previous employer. In line with the policy, the committee took into account the nature, timing and value of the awards being forfeited when determining the structure and size of the buy-out awards offered. The committee is satisfied that the buy-out awards are consistent with the policy and reflect like-for-like replacement, noting the complexities in Meg's foregone awards such as a mix of standard performance awards, non-performance awards, and pre-grant performance awards, each with overlapping five-year vesting periods. The buy-out awards will take three forms:

- Cash awards: To replace the 2025 annual bonus, 2026 annual bonus (pro-rated to 31 March 2026), and share awards where the full vesting period would have elapsed or would substantially have elapsed prior to Meg joining. The value of the annual bonus and performance shares will be based on her previous employer's actual performance where possible. For foregone performance and restricted shares due to vest in the first half of 2026, the value will be based on the 30-day average share price of her previous employer up to the vesting date. Full details of the value of this cash award will be disclosed in the 2026 directors' remuneration report.
- Restricted share awards: To replace the forfeited restricted share awards (outstanding and to be granted in respect of 2025 pre-grant performance). This buy-out award will also cover performance share awards due to vest in 2027 and 2028 where in-flight performance has been valued at 50% of maximum. The awards will be aligned with the vesting schedules of Meg's foregone awards and have an expected value of £8.3 million.
- Performance share awards: To replace the forfeited performance share awards due to vest in 2029, 2030 and 2031 following their respective five-year periods. These awards will be subject to bp's relative TSR performance, with the start of the performance period being 1 April 2026. The awards will be aligned with the vesting schedules of her foregone awards and have an expected value of £1.8 million.

Buy-out awards	Estimated value ^a	Vesting date
Cash awards		
Replacement cash award	£1.7m ^b	Paid upon joining ^c
Restricted share awards		
Tranche 1	£0.5m	April 2027
Tranche 2	£1.0m	May 2027
Tranche 3	£0.4m	March 2028
Tranche 4	£1.5m	April 2028
Tranche 5	£0.9m	March 2029
Tranche 6	£0.8m	April 2029
Tranche 7	£1.8m	March 2030
Tranche 8	£1.4m	March 2031
Performance share awards (expected value, subject to TSR performance)		
Tranche 1	£0.4m	April 2029
Tranche 2	£0.7m	March 2030
Tranche 3	£0.7m	March 2031

^a Estimated value is based on an illustrative share price of £12.50 for Woodside Energy and exchange rate of 1:0.5 (AUD:GBP). Performance share awards have been shown at target (i.e. 50% of max).

^b Estimated value of the 2026 annual bonus (pro-rated to 31 March 2026) not included as value is currently unknown.

^c Or, if later, following the date the award from the previous employer would have been paid.

Where awards are being replaced with shares, this will be calculated using the 90-day average of bp's and Woodside Energy's share prices, and foreign exchange rate, prior to 1 April 2026.

A significant proportion of the buy-outs will be delivered in shares (over 85%), aligning Meg with shareholders from appointment and representing a value equivalent to 6.3x of salary over a 5-year period. In line with the policy, Meg will be expected to retain shares vesting from share awards (including buy-outs) until her shareholding requirement of 5x salary has been met.

Measures for the 2026 annual bonus

For 2026, the scorecard has been simplified and performance will now be assessed against four measures across three categories: safety (15%), operations (20%) and financials (65%). This change reflects our continued focus on delivering sustained financial performance, supported by strong safety and operational outcomes.

As part of this simplification, the emissions measure has been removed from the short-term scorecard. To maintain appropriate balance, the weighting of emissions within the long-term incentive award has been increased from 15% to 20% (see below). Our ambition to reach net zero by 2050 remains unchanged, but we believe that progress towards this long-term objective is more appropriately evaluated through our performance share award rather than the annual bonus.

Across the remaining categories, the underlying measures remain unchanged from prior year. For safety, however, we will revert to assessing performance on a combined tier 1 and tier 2 basis. In recent years, the number of tier 1 process safety events has continued to decline, which is a positive trajectory to report. However, the number of events has made it increasingly difficult to set robust and meaningful standalone targets for tier 1 performance and it is no longer practicable to assess performance independently.

Importantly, the framework on fatalities will continue to apply to the 2026 annual bonus and will be considered at year-end if a fatality occurs during the year. The targets are commercially sensitive and will be disclosed in the 2026 directors' remuneration report.

Safety 15%		Operations 20%		Financials 65%	
Measures include	Weighting	Measures include	Weighting	Measures include	Weighting
Tier 1 and tier 2 process safety events★	15 %	bp-operated reliability and availability★	20 %	Modified free cash flow ^a ★	35 %
				Structural cost reduction★	30 %

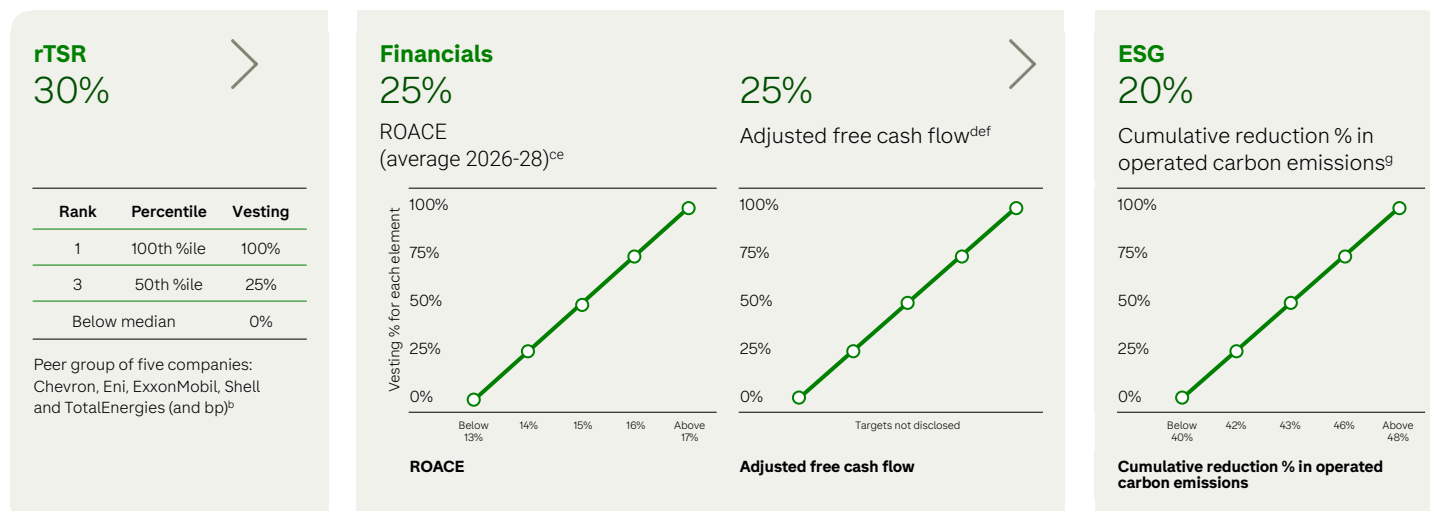
Measures for the 2026-28 performance shares (EDIP)

Provided below is a summary of the measures we have chosen for the 2026-28 performance share plan. The number of measures has been reduced, with the scorecard now focused on shareholder returns, financial delivery and progress against our external emissions targets.

For relative TSR, the peer group has been reviewed to ensure alignment with the reset strategy. The committee has agreed to reduce the number of comparator companies, concentrating on the oil super majors who represent our closest and most strategically aligned peers. In light of the reduced peer group, the committee reviewed the approach to assessing relative TSR performance and agreed to adopt a percentile-based methodology for the 2026-28 cycle. This approach provides a more proportionate assessment of performance across the peer group and greater alignment with the shareholder experience.

Within the financials category, the underlying measures remain unchanged. For the 2025-27 cycle, targets were set in line with our external ambitions to the end of 2027, as outlined at the Capital Markets Day in February 2025. Looking ahead, ROACE★ will revert to being assessed on an average basis – consistent with past practice – while adjusted free cash flow★ will be assessed based on performance through to the end of 2028.

Lastly, the underpin has been broadened to include progress towards a strong and resilient balance sheet, reflecting our long-term priorities.



- Underpin will take into account overall safety performance as well as ongoing progress towards a strong and resilient balance sheet.
- Remuneration committee discretion will reflect shareholder experience, environment, societal and other inputs.
- Subject to usual malus and clawback provisions.

a Target set includes receipt of Castrol proceeds prior to finalization of year-end results.

b Straight-line vesting between median and maximum.

c Based on the average ROACE over 2026, 2027 and 2028.

d Based on adjusted free cash flow at the end of the three-year period.

e Adjustments may be required in certain circumstances. The external environment to be a considered judgement in final outcomes.

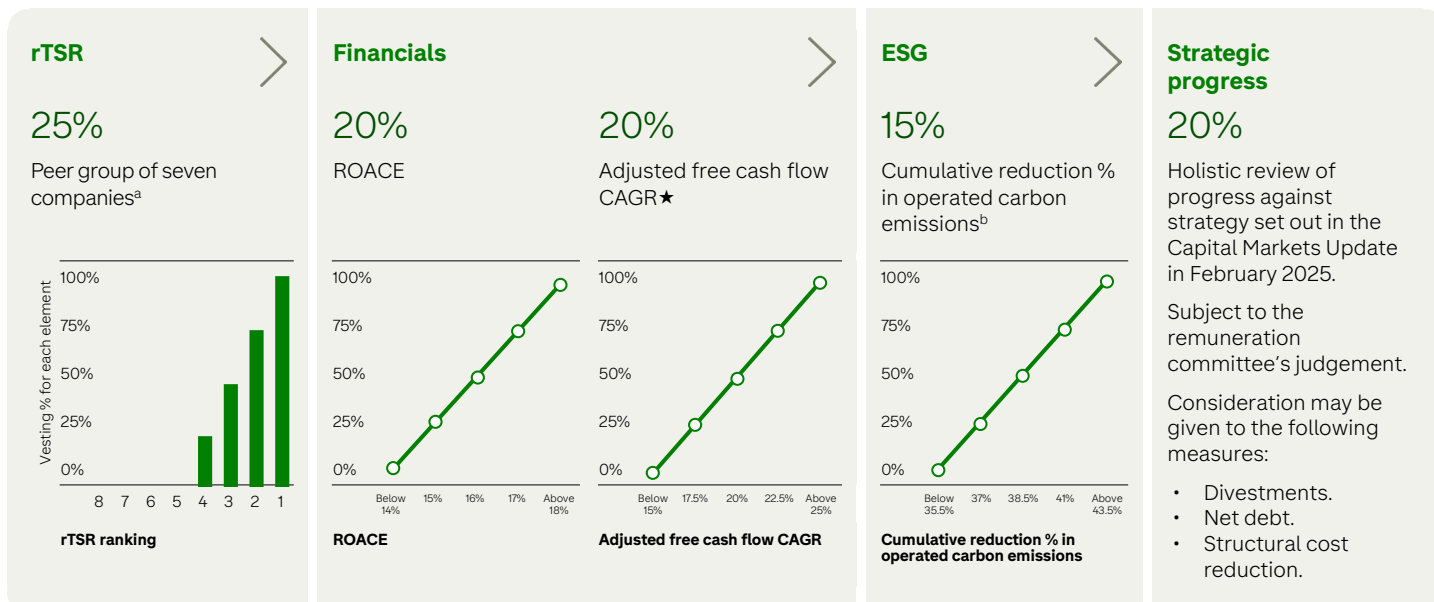
f Targets are considered to be commercially sensitive and will be disclosed in full at the end of the performance period.

g Scope 1 and 2 GHG emissions reductions vs. 2019 baseline from operated carbon emissions including portfolio change. Corporate activity unknown at the time that targets are set to be a considered judgement in final outcomes.

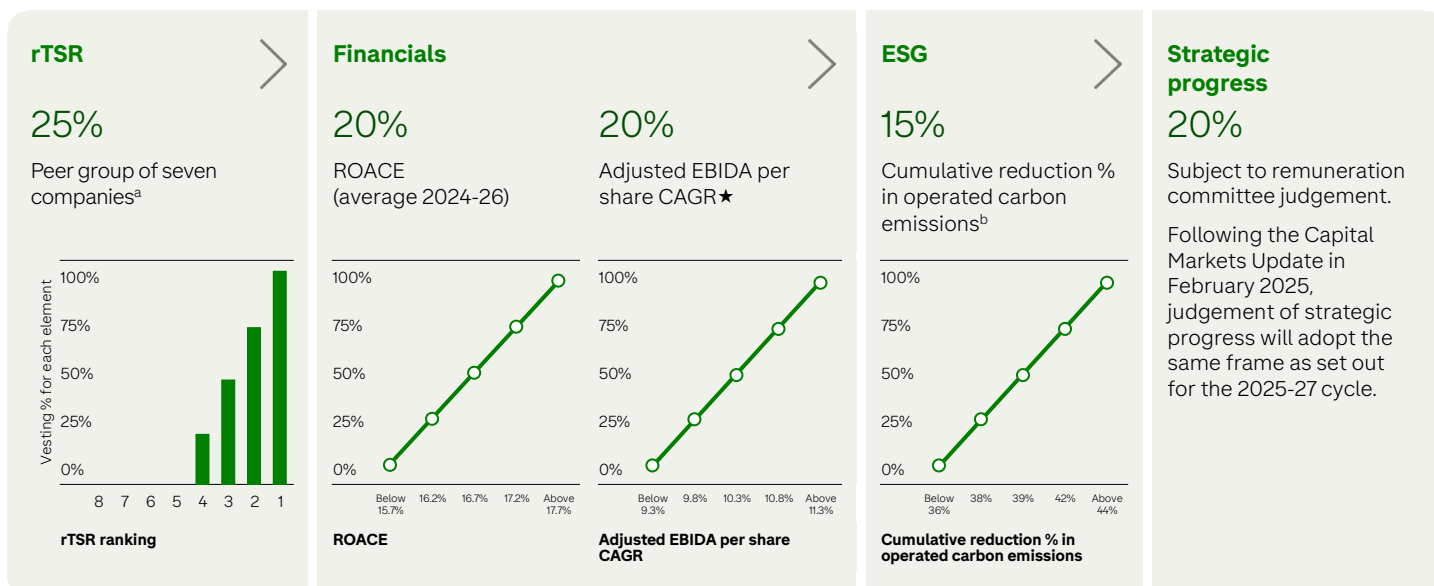
Directors' remuneration report continued

Provided below is an overview of the performance measures and weightings of each of our in-flight awards.

Measures for 2025-27 performance shares



Measures for 2024-26 performance shares



^a Peer group includes Chevron, Eni, Equinor, ExxonMobil, Repsol, Shell and TotalEnergies (and bp).

^b The committee determined that the operated carbon emissions targets under the above EDIP awards should be adjusted in order to align with the strategy reset at the start of 2025 (2024-26 only) and subsequent recalibration of internal goals and principles around emissions (2024-26 and 2025-27). The effect of this change, which was made in conjunction with the safety and sustainability committee, is to widen the target range by reducing the threshold and increasing the maximum under both awards.

Stewardship and executive director interests

We believe that our executive directors should build and maintain a meaningful interest in the company. Our policy therefore requires the CEO and CFO to build a personal shareholding of five times and four and a half times, respectively, their salary within five years of their appointment. They are expected to maintain this level of personal shareholdings for two years post-employment.

Directors' shareholdings and aggregated interests (audited)

	Directors' ordinary shares or equivalents at 13 February 2026	Aggregated interests at 13 February 2026, all plans				Current shareholding for MSR ^{b,d}	Value of current shareholding ^{c,d} £	Multiple of salary achieved ^d
		Unvested awards not subject to performance conditions		Unvested awards subject to performance conditions				
		Shares ^a	Options	Shares	Options			
Carol Howle	491,903	1,040,861	750,000	381,825	–	1,047,640	4,829,622	3.20
Murray Auchincloss ^d	1,816,006	1,094,742	152,301	3,273,590	–	2,104,355	8,847,761	5.87
Kate Thomson	432,482	219,236	500,000	1,659,711	–	550,831	2,539,331	2.94

a Includes deferred and restricted shares, and performance shares prior to application of the performance factor.

b Includes ordinary shares or equivalents and unvested awards not subject to performance conditions on a net-of-tax basis, excluding dividends.

c Based on ordinary share price at 13 February 2026 of £4.61 (close price).

d Murray Auchincloss stepped down on 18 December 2025. The shareholding disclosed reflects his individual holding and includes interests of a person closely associated with him as at that date. The shareholding for MSR purposes, the value of his shareholding and multiple of salary achieved are each presented as at 18 December 2025. In accordance with the plan rules, his unvested performance share awards will be pro-rated to 17 December 2026.

Executive directors have additional interests in performance and deferred bonus shares. These interests are shown in aggregate in the table above, and interests awarded during 2025 in the tables below. For performance shares, the figures reflect maximum possible vesting levels (excluding the addition of reinvested dividends) even though the actual number of shares that vest will depend on the extent to which performance conditions are satisfied.

Performance and deferred shares (audited)

	Award	Number of shares granted	Grant date	Face value of the award ^a , £	Vesting date
Carol Howle ^b		–	–	–	–
Murray Auchincloss ^b	2025-27 EDIP Performance ^c	1,790,973	30 April 2025	6,268,406	April 2028
Kate Thomson		923,515	30 April 2025	3,232,303	April 2028
Carol Howle ^b		–	–	–	–
Murray Auchincloss ^b	2025 EDIP Deferred ^d	59,840	30 April 2025	209,440	April 2028
Kate Thomson		51,947	30 April 2025	181,815	April 2028

a The face value of awards granted during 2025 have been calculated using a market price of ordinary shares at close on the date of award, as follows: £3.50 on 30 April 2025. In calculating the number of ordinary shares over which these awards were made, the committee applied the average price of ordinary shares over the 90 calendar days up to and including the annual general meeting held on 17 April 2025 (£4.21).

b Murray Auchincloss stepped down as CEO effective 18 December 2025 and Carol Howle was appointed as interim CEO on the same date. As Carol was a below board employee when her 2025-27 GSVP award was granted, detail of this award has not been disclosed as it is considered to be commercially sensitive.

c Performance conditions are measured 15% on cumulative reduction % in operated carbon emissions, 25% on TSR relative to Chevron, ExxonMobil, Shell, TotalEnergies, Eni, Equinor and Repsol over three years, 20% ROACE measured to the end of 2027, 20% adjusted free cash flow CAGR vs. 2024 baseline and 20% strategic progress assessed over the performance period. Minimum vesting under this award (below threshold performance) is 0%. At threshold performance, vesting would be 6.25% of maximum.

Since 2010, vesting of the performance shares under EDIP has been subject to a safety underpin. If the committee assesses that there has been a material deterioration in safety performance, or there have been major incidents, either of which reveal underlying weaknesses in safety management, then it may conclude that shares should vest only in part, or not at all. In reaching its conclusion, the committee obtains advice from the S&SC.

The performance period is 1 January 2025 to 31 December 2027.

The 2026 performance share awards under EDIP are expected to be made following the conclusion of the 2026 annual general meeting.

d There is no identified minimum vesting threshold level. The 2025 bonus year deferred share awards under EDIP are expected to be made following the conclusion of the 2026 annual general meeting.

Directors and leadership team

No directors or other leadership team members own more than 1% of the shares in issue. At 13 February 2026, our directors and leadership team members collectively held interests of 5,127,004 ordinary shares or their calculated equivalents, 3,840,510 restricted share units (with or without conditions) or their calculated equivalents, 4,964,919 performance shares or their calculated equivalents and 4,027,241 options over ordinary shares or their calculated equivalents, under bp group share option schemes.

Directors' remuneration report continued

Chair and non-executive director interests

Fee structure

The table below shows the fee structure for the chair and non-executive directors (NEDs). The chair is not eligible for committee chairship and membership fees. The senior independent director (SID) is eligible for committee chairship and membership fees, and their fee includes the board member fee. Committee chairs do not receive a membership fee for the committee they chair.

Under the 2023 policy, fee levels are reviewed annually alongside wider workforce salaries with any changes taking effect from 1 April. For the 2026-27 year, no changes are being made to the base fee for NEDs and for the SID. In accordance with the policy, the remuneration committee is responsible for determining the chair's fee. Following the appointment of Albert Manifold as chair on 1 September 2025, the committee approved his fees and benefits at that time. No further changes to the chair's fee are being made for 2026-27.

£ thousand per annum	2026/27 fees	2025/26 fees
Chair	1,000	888
Senior independent director	181.5	181.5
Board member	130.5	130.5
Audit, remuneration and safety and sustainability committees chairship	35	35
Committee membership	20	20

2025 remuneration (audited)

The table below shows the fees paid and applicable benefits. Benefits include travel and other expenses relating to the attendance at board and other meetings. Under the terms of his engagement with the company, Albert Manifold has the use of a fully maintained office for company business, a car and driver, and security advice in London. Benefits values have been grossed up using a tax rate of 45%, where relevant, as an estimation of tax due.

£ thousand	Fees		Benefits		Total	
	2025	2024	2025	2024	2025	2024
Dame Amanda Blanc	220	198	–	1	220	198
Pamela Daley ^a	87	164	5	17	93	181
Dave Hager ^b	78	–	37	–	114	–
Simon Henry ^c	44	–	1	–	44	–
Helge Lund ^d	658	845	28	38	686	882
Albert Manifold (chair) ^d	333	–	50	–	384	–
Melody Meyer	184	182	56	9	240	191
Tushar Morzaria	189	189	32	1	221	190
Hina Nagarajan	169	157	39	17	208	174
Satish Pai	149	144	5	5	154	149
Karen Richardson ^e	194	169	15	16	209	185
Dr Johannes Teysen	169	160	6	5	175	165
Ian Tyler ^f	135	–	34	–	169	–

a Pamela Daley stepped down as a non-executive director on 7 July 2025.

b Dave Hager was appointed as a non-executive director on 2 June 2025.

c Simon Henry was appointed as a non-executive director on 1 September 2025.

d Albert Manifold was appointed as a non-executive director and chair-elect on 1 September 2025, and assumed the role of chair on 1 October 2025, succeeding Helge Lund, who stepped down as chair on 30 September 2025.

e Fee includes £25,000 p.a. for chairing the bp digital advisory council and £20,000 p.a. for chairing innovation advisory council.

f Ian Tyler was appointed as a non-executive director on 1 April 2025.

Chair and non-executive directors' interests (audited)

The figures below include all the interests of the chair and each NED of the company in shares of bp (or calculated equivalents) that have been disclosed to bp. Our 2023 policy encourages NEDs to establish a holding in bp shares of the equivalent value of one year's base fee during their tenure.

	Ordinary shares or equivalents ^a				Value of current shareholding ^b	% of guideline achieved
	At 1 January 2025	At 31 December 2025	Changes to 13 February 2026	At 13 February 2026		
Dame Amanda Blanc	23,500	47,100	–	47,100	£217,131	166%
Pamela Daley ^c	40,332	n/a	n/a	n/a	n/a	n/a
Dave Hager ^d	n/a	45,000	–	45,000	\$282,450	164%
Simon Henry ^e	n/a	–	–	–	–	–%
Helge Lund ^f	600,000	n/a	n/a	n/a	n/a	n/a
Albert Manifold (chair) ^f	n/a	–	–	–	–	–%
Melody Meyer	38,646	38,646	–	38,646	\$242,568	141%
Tushar Morzaria	71,972	71,972	–	71,972	£331,791	254%
Hina Nagarajan	25,944	30,944	–	30,944	£142,652	109%
Satish Pai	33,000	33,000	–	33,000	\$207,130	120%
Karen Richardson	35,316	35,316	–	35,316	\$221,667	129%
Dr Johannes Teysen	35,000	35,000	–	35,000	£161,350	124%
Ian Tyler ^g	n/a	–	–	–	–	–%

a Includes interests of persons closely associated.

b Based on ordinary share and ADS prices at 13 February 2026 of £4.61 and \$37.66. Where a US\$ value is provided these shares are held as ADSs.

c Pamela Daley stepped down as a non-executive director on 7 July 2025.

d Dave Hager was appointed as a non-executive director on 2 June 2025.

e Simon Henry was appointed as a non-executive director on 1 September 2025.

f Albert Manifold was appointed as a non-executive director and chair-elect on 1 September 2025, and assumed the role of chair on 1 October 2025, succeeding Helge Lund, who stepped down as chair on 30 September 2025.

g Ian Tyler was appointed as a non-executive director on 1 April 2025.

Payments to past directors and for loss of office**Departure terms for Murray Auchincloss (audited)**

As set out elsewhere in the report, Murray Auchincloss stepped down from the board by mutual agreement on 18 December 2025. Details of his departure terms have been set out below and are consistent with the company's shareholder-approved policy.

In line with his 12-month notice period, Murray will remain an employee on his existing terms until 17 December 2026. During this period, he will continue to receive his contractual salary and benefits.

In respect of his incentive awards, Murray will remain eligible to receive a pro-rata annual bonus in respect of his services during 2025, of which 33% will be deferred into bp shares in line with the policy. He will not be entitled to a bonus in respect of 2026. Outstanding deferred bonus awards will vest in line with normal timescales.

Murray's unvested performance share awards under the EDIP will be pro-rated up to 17 December 2026 but will continue to vest on their normal dates subject to the achievement of the relevant performance conditions. The resulting shares are subject to a 12-month holding period following vesting. Vested shares already in a holding period will be released 12 months following his cessation of employment, i.e. 17 December 2027, or on their original release date, if earlier. He will not be eligible for a 2026 EDIP grant.

He is entitled to receive ongoing tax filing support in respect of any trailing income from the company and a contribution towards his legal fees incurred in connection with stepping down to the total of £10,000 (plus VAT). He will continue to be covered by D&O insurance and will benefit from an indemnity in respect of third-party liabilities.

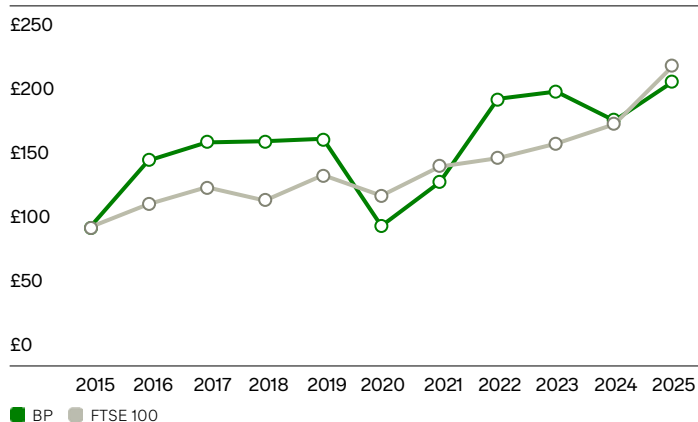
Post-employment benefits (audited)

We made no payments within the scope of the disclosure requirements to any past director of bp during 2025.

Directors' remuneration report continued

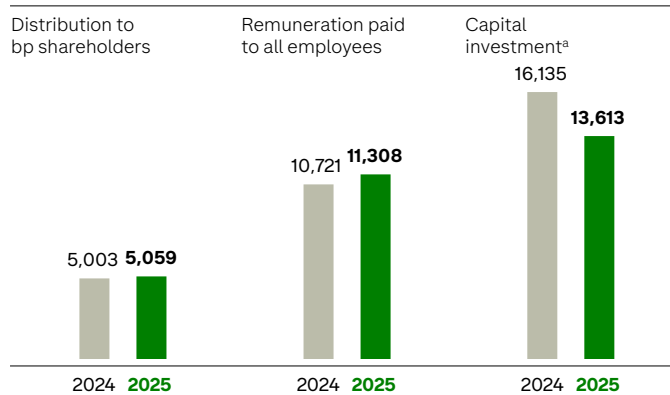
Other disclosures

Historical TSR performance



The graph above shows the growth in value of hypothetical £100 investments in BP p.l.c. ordinary shares, and in the FTSE 100 index (of which bp is a constituent), over 10 years from 31 December 2015 to 31 December 2025.

Relative importance of spend on pay (\$ million)



a. Organic capital expenditure ★.

History of chief executive officer remuneration

Year	Chief executive officer	Total remuneration, thousand	Annual bonus % of maximum	Performance shares % of maximum
2016	Bob Dudley	\$ 11,904	61	40
2017	Bob Dudley	\$ 15,108	71.5	70
2018	Bob Dudley	\$ 15,253	40.5	80
2019	Bob Dudley	\$ 13,234	67.5	71.2
2020 ^a	Bob Dudley	\$ 188	0	32.5
	Bernard Looney	£ 1,735	0	32.5
2021	Bernard Looney	£ 4,457	80.5	30
2022	Bernard Looney	£ 10,331	75.5	54
2023 ^{ab}	Bernard Looney	£ 1,175	n/a	n/a
	Murray Auchincloss	£ 5,391	79.5	75
2024	Murray Auchincloss	£ 5,179	22.5	66.5
2025^{acd}	Murray Auchincloss	£ 5,307	79.5	23.3
	Carol Howle	£ 886	79.5	52.8

a 2020, 2023 and 2025 figures show remuneration for the periods of qualifying service as CEO during the respective years.

b In respect of 2023, Bernard Looney did not receive any variable pay awards and his single figure shown in the table above excludes the impact of malus and clawback.

c Murray Auchincloss stepped down from his position as CEO on 18 December 2025 and was succeeded by Carol Howle as interim CEO on 18 December 2025. For 2025, Carol's performance share award was granted when she was below board level and is therefore based on a different scorecard to executive directors.

d Share price has been based on the average share price over Q4 of the 2025 FY of £4.40.

Chief executive officer to employee pay ratio

Year	Method	25th percentile: pay ratio, total pay and benefits, (salary)	50th percentile: pay ratio, total pay and benefits, (salary)	75th percentile: pay ratio, total pay and benefits, (salary)
2019 ^a	Option A	543:1	188:1	82:1
2020 ^a	Option A	99:1	40:1	19:1
2021	Option A	208:1	87:1	35:1
2022	Option A	421:1	172:1	69:1
2023 ^b	Option A	268:1	103:1	45:1
2024	Option A	196:1	74:1	37:1
2025 ^{bc}	Option A	219:1	79:1	39:1
		£28,331	£78,644	£160,265
		(£26,237)	(£55,675)	(£97,425)

a Bob Dudley's pay has been converted from US dollars as per the ratios reported in the *bp Annual Report and Form 20-F 2020*.

b For 2023 and 2025, the total single figure used to derive the CEO pay ratio is a combination of the two individuals in position of CEO during the year. For 2023, in respect of the former CEO, the calculation has been based on the total single figure excluding the impact of malus and clawback in order to provide a comparison with prior years. Appropriate pro-rating of fixed and variable pay has been applied.

c Share price for the CEO share plan vesting has been based on the average share price over Q4 of the 2025 FY of £4.40.

This is our seventh year reporting the CEO pay ratio following the requirements introduced in 2018. As per the past six years, we have selected Option A as our reporting basis, being the most accurate approach available, and we confirm that no broadly applicable components of pay have been omitted. Where necessary, full-time equivalent pay has been calculated by simple engrossment of part-year values. Employee values relate to pay and benefits for the year ended 31 December 2025.

Changes in the pay ratio over time reflect the fact that CEO remuneration is more heavily weighted to variable pay, resulting in larger year-on-year swings than wider workforce pay. This is evidenced by the variability of the CEO pay ratio over the past seven years. This volatility in the pay ratio reporting from year to year is expected, and illustrates one of the challenges in commenting on whether the pay differentials are appropriate. In 2025, the pay ratios have remained broadly consistent year-on-year, with the 50th percentile pay ratio increasing from 74:1 to 79:1. While the annual bonus was higher in 2025 (79.5% compared to 22.5% in 2024), this was partly offset by a significantly lower EDIP outcome for the former CEO (23.3% compared to 66.5% for the 2022-24 cycle).

The committee believes in performance-based remuneration. For all employees eligible to participate in the annual cash bonus plan, there is an individual uplift available each year which allows managers to nominate exceptional individuals based on their personal contributions during the year. For senior leaders, a significant portion of the remuneration package continues to be linked to performance-based reward. It is therefore the view of the committee that the remuneration frameworks we have in place for executive directors and the wider workforce are fit for purpose and deliver pay outcomes appropriate to the circumstances of the year, with differentials that reflect the relative contributions made at different levels of the organization.

The committee is satisfied that the median pay ratio reported this year is consistent with bp's pay policies for employees and does not constitute a reason to modify our pay programmes.

Directors' remuneration report continued

Percentage change comparisons: directors' remuneration versus employees

In the table below, values in column 'a' represent the percentage change in salary and fees; values in column 'b' represent the percentage change in taxable benefits; and values in column 'c' represent the percentage change in bonus outcomes for performance periods in respect of each financial year. For the purposes of comparison, the employee percentages shown below represent the relative change between the median full-time equivalent pay for every employee employed at BP p.l.c. at any point during the relevant financial year, and the equivalent median value for the preceding financial year. Where increases are infinite relative to the preceding year, we have shown them as 100% for illustration; where a director was appointed or retired part-way through the year, we have annualized pay except for one-time items; and where comparison to the prior year is not possible, we have used dashes.

Percentage change for:	2025 vs. 2024			2024 vs. 2023			2023 vs. 2022			2022 vs. 2021			2021 vs. 2020		
	a	b	c	a	b	c	a	b	c	a	b	c	a	b	c
Employees	6%	-%	124%	4%	-%	-65%	6%	1%	4%	2%	1%	45%	7%	-9%	100%
Carol Howle	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Murray Auchincloss	-1%	5%	253%	43%	-61%	-60%	30%	283%	31%	7%	530%	3%	5%	5%	100%
Kate Thomson ^a	16%	23%	318%	-%	-	-	-	-	-	-	-	-	-	-	-
Dame Amanda Blanc	11%	(89)%	n/a	24%	-72%	n/a	38%	100%	n/a	-	-	n/a	-	-	n/a
Pamela Daley	3%	(68)%	n/a	3%	-75%	n/a	2%	2%	n/a	7%	43%	n/a	4%	1385%	n/a
Dave Hager	-	-	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Simon Henry	-	-	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Helge Lund	4%	(25)%	n/a	4%	-43%	n/a	3%	78%	n/a	-%	97%	n/a	-%	-24%	n/a
Albert Manifold (Chair)	-	-	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Melody Meyer	1%	512%	n/a	-1%	-68%	n/a	2%	-14%	n/a	13%	139%	n/a	-4%	283%	n/a
Tushar Morzaria	-	3,559%	n/a	9%	-73%	n/a	2%	-46%	n/a	25%	100%	n/a	5%	-%	n/a
Hina Nagarajan	8%	129%	n/a	13%	-46%	n/a	-	-	n/a	-	-	n/a	-	-	n/a
Satish Pai	4%	11%	n/a	3%	-88%	n/a	-	-	n/a	-	-	n/a	-	-	n/a
Paula Rosput Reynolds	(100)%	(100)%	n/a	3%	-70%	n/a	2%	-14%	n/a	16%	145%	n/a	-	228%	n/a
Karen Richardson	15%	(6)%	n/a	-5%	-12%	n/a	11%	-20%	n/a	30%	96%	n/a	-	-	n/a
Sir John Sawers	(100)%	(100)%	n/a	3%	63%	n/a	2%	105%	n/a	17%	1%	n/a	-	1588%	n/a
Johannes Teysen	6%	14%	n/a	7%	-68%	n/a	3%	12%	n/a	21%	65%	n/a	-	-	n/a
Ian Tyler	-%	-%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

a Kate Thomson's increase in salary reflects the adjustment from her previous role to the salary level for an Executive Director following her appointment on 2 February 2024.

Independence and advice

The board considers all committee members to be independent with no personal financial interest, other than as shareholders, in the committee's decisions. Further detail on the activities of the committee in 2025 is set out in the remuneration committee report on [page 91](#).

During 2025, Ben Mathews, who was employed by the company and reported to the chair of the board, acted as secretary to the remuneration committee.

The committee also received advice on various matters relating to the remuneration of executive directors and senior management from Kerry Dryburgh, EVP people, culture & communications, and Ashok Pillai and Clare Peake, SVP reward.

Following a competitive tender process, Willis Towers Watson (WTW) replaced PwC as independent advisors to the committee in 2025. PwC and WTW advice included, for example, support with remuneration benchmarking and updates on market practice. Both are members of the Remuneration Consulting Group and, as such, operate under the code of conduct in relation to executive remuneration in the UK. The committee is satisfied that the advice received is objective and independent. The committee is comfortable that both the PwC and WTW engagement partners and team who provide remuneration advice to the committee do not have connections with the company or its directors that may impair their independence.

Total fees or other charges (based on an hourly rate) for the provision of remuneration advice to the committee in 2025 (save in respect of legal advice) were £67,683 and £64,800 to PwC and WTW respectively. Freshfields LLP (Freshfields) provided legal advice on specific compliance matters to the committee. PwC, WTW and Freshfields provided other advice in their respective areas to the group.

Shareholder engagement

Throughout 2025 the committee engaged regularly on remuneration policy and approach with bp's largest shareholders, as well as their representative bodies. This dialogue will continue throughout 2026. The table below shows the recent votes on the directors' remuneration report and policy.

Year	% vote 'for'	% vote 'against'	Votes withheld
2025 – Directors' remuneration report	95.54%	4.46%	36,686,921
2023 – Directors' remuneration policy	94.23%	5.77%	36,921,641

Service contracts and letters of appointment

The service contracts of executive directors do not have a fixed term. Service contracts for each executive director are available for shareholders to view upon request at the company's registered office. Each executive director's service contract contains a 12-month notice period. Consistent with the best interests of the group, the committee will seek to minimize termination payments.

	Date of contract	Effective date
Carol Howle ^a	17 December 2025	18 December 2025
Murray Auchincloss ^a	17 January 2024	17 January 2024
Kate Thomson	2 February 2024	2 February 2024

^a Murray Auchincloss stepped down as CEO effective 18 December 2025. Carol Howle was appointed interim CEO on the same date.

The non-executive directors (NEDs) have letters of appointment, which are available for shareholders to view upon request at the company's registered office. All continuing directors are subject to annual re-election by shareholders at the annual general meeting. Normally, NEDs will be encouraged to serve for up to six years from their appointment, and for a further three years by invitation, in line with the provisions of the 2024 Code, subject to annual re-election.

External appointments

The board supports executive directors taking up appointments outside the company to broaden their knowledge and experience. Each executive director is permitted to retain any fee from their external appointments. Such external appointments are subject to agreement by the chair and reported to the board. Any external appointment must not conflict with a director's duties and commitments to bp. Details of appointments as NEDs of publicly listed companies during 2025 are shown below.

	Appointee company	Additional position held at appointee company	Total fees, £
Kate Thomson	Aker BP ASA ^a	Director	0

^a Held as a result of the company's shareholding in Aker BP ASA.

This directors' remuneration report, including the 2026 remuneration policy set out on the **pages 118 to 125**, has been approved by the board and signed on its behalf by Ben J.S. Mathews, company secretary, on 6 March 2026.

Directors' remuneration report continued

Directors' remuneration report – the 2026 remuneration policy

This section of the report sets out the remuneration policy for executive directors and non-executive directors, which shareholders will be asked to approve at the AGM on 23 April 2026 and, if approved, will take effect for any payments made or awarded after that date. The company will continue to honour any arrangements granted under previous remuneration policies which were consistent with the policy in force at the time of grant.

As outlined in the chair's statement, the committee undertook an initial review of the policy during 2025 and agreed to defer a more detailed review of the policy until after the 2026 AGM. The policy set out on the following pages has therefore largely been rolled forward from the previous policy, which was approved at the 2023 AGM and received strong support from shareholders with a vote of 94% in favour.

While no material changes are being proposed to the 2026 remuneration policy, minor changes have been made to the wording in certain areas to increase clarity and effective operation.

Policy table – executive directors

Salary and benefits

Purpose	To provide fixed remuneration to reflect the scale and complexity of both the business and the role, and to be competitive with the external market.	
Operation and opportunity	Salary <p>Salary levels will relate to the nature of the role, performance of the business and the individual, market positioning and pay conditions in the wider bp group. There is no maximum salary under the policy.</p> <p>When setting salaries, the committee considers practice in other energy majors as well as European and US companies of a similar size, geographic spread and business dynamic to bp. The committee will also consider salary increases for the most senior management and the wider workforce. In particular, percentage increases for executive directors will not exceed increases for the broader employee population, other than in specific circumstances identified by the committee (e.g. in response to a substantial change in responsibilities).</p> <p>Salaries are normally set in the home currency of the executive director and are reviewed annually. They may be reviewed at other times where appropriate, for example following a major role change.</p>	Benefits <p>Executive directors are entitled to receive those benefits available to a majority of the wider workforce in their home country. These include participation in all-employee share plans, sickness pay, relocation assistance and parental leave. Benefits are not pensionable.</p> <p>Executive directors may receive other benefits that are judged to be cost-effective and appropriate in terms of the individual's role, time and/or security. These may include car-related benefits and/or cash in lieu, security, assistance with tax return preparation, insurance and medical benefits. The company may meet any tax charges arising on benefits provided to directors.</p> <p>The taxable value of benefits provided may fluctuate during the period of this policy, depending on the cost of provision and a director's personal circumstances.</p>

Retirement benefits

Purpose	To recognize competitive practice in the directors' home country while being aligned with the majority of the workforce.	
Operation and opportunity	<p>Executive directors normally participate in the company retirement plans that operate in their home country.</p> <p>New appointees from within bp group retain previously accrued benefits. For future appointments, the committee will carefully review any retirement benefits to be granted to a new director, taking account of retirement policies across the wider workforce and any arrangements currently in place.</p>	<p>Retirement benefits for executive directors will be limited to the allowance offered to the majority of the workforce in the executive's home country (the maximum allowance in the UK is currently 20% of salary).</p>

Annual bonus

Purpose	To provide variable remuneration dependent on the execution of the business strategy on an annual basis. Bonus is subject to a mandatory deferral into bp shares which are held for three years to reinforce the long-term nature of the business and alignment with shareholders.	
Operation and opportunity	<p>The bonus is based on performance against annual measures and targets set at the start of the year, evaluated over the financial year and assessed following the year-end.</p> <p>The target annual bonus is half of the maximum available, and typically relates to delivery of performance in line with targets in the annual plan.</p> <p>Executive directors may earn a maximum annual bonus of 225% of salary. This maximum level would relate to performance at or above the highest end of the performance scale for every measure. The committee intends to set demanding requirements for maximum payment.</p> <p>Achievement of threshold performance would normally result in a payout of 0% of the maximum opportunity.</p> <p>Bonus calculation is typically based on salary as at 31 December in each performance year.</p>	<p>The final bonus outcome, following the formulaic assessment of performance relative to targets, is specifically reserved as a matter for the committee's judgement. Accordingly, the committee may exercise its discretion to adjust the formulaic outcome either upwards or downwards.</p> <p>Half the bonus is paid in cash, and half is deferred into bp shares for three years up until 'minimum shareholding requirement' (MSR) is met, as determined by the committee under the shareholding guidelines. Once met, 67% is paid in cash and 33% is deferred into bp shares. Dividends (or equivalents, including the value of any reinvestment) may accrue in respect of any deferred shares.</p> <p>Awards are subject to malus provisions before they are delivered and to clawback thereafter for a period of three years. Further detail is set out on page 121.</p>
Performance framework	The committee determines a scorecard of specific measures, weightings and targets each year to reflect the priorities in the annual plan, as agreed with the board, and thus deliver the group's strategy.	The scorecard will typically include a balance of financial and non-financial measures. Details of the measures and weighting will typically be reported in advance each year in the annual report on remuneration, while targets, where commercially sensitive, will be disclosed retrospectively.

Performance shares

Purpose	To link the largest part of remuneration opportunity with the long-term performance of the business.	
Operation and opportunity	<p>The maximum annual award level for the chief executive officer will be 500% of salary and 450% of salary for other executive directors.</p> <p>Annual awards of shares will vest based on performance relative to measures and targets that reflect the delivery of bp's strategy over a performance period of typically three years.</p> <p>For each measure, the threshold level at which vesting is first triggered is not expected to yield vesting above 25% of the maximum.</p>	<p>The final performance shares outcome, following the formulaic assessment of performance relative to targets, is specifically reserved as a matter for the committee's judgement. Accordingly, the committee may exercise its discretion to adjust the formulaic outcome either upwards or downwards.</p> <p>The shares that vest are subject to a three-year post-vesting holding period.</p> <p>Dividends (or equivalents, including the value of reinvestment) may accrue in respect of share awards to the extent that they vest.</p> <p>Awards are subject to malus provisions before vesting and to clawback provisions thereafter for a period of three years. Further detail is set out on page 121.</p>
Performance framework	At the outset of each performance cycle, the committee determines a scorecard of specific measures, weightings and targets to reflect the group's long-term strategic priorities and shareholder interests.	The scorecard will typically include a balance of financial and non-financial measures (including sustainability). The committee will assess overall safety performance as well as progress towards the reduction of net debt as an underpin in determining the final vesting percentage.

Shareholding requirement

Purpose	To provide alignment between the interests of executive directors and our other shareholders.	
Operation and opportunity	The chief executive officer is required to build and maintain a minimum shareholding of five times base salary within five years of appointment, and to maintain that minimum shareholding for at least two years after they cease to be a director.	Other executive directors are required to build and maintain a minimum shareholding of four and a half times base salary within five years of appointment, and to maintain that minimum shareholding for at least two years after they cease to be a director.

Directors' remuneration report continued

Notes to the policy table

1. How is variable pay linked to performance?

Annual bonus	Bonus aligned with company performance >	<100% MSR ^a : 50% paid in cash; 50% in bp shares deferred for three years >100% MSR ^a : 67% paid in cash; 33% in bp shares deferred for three years
Performance shares	Share award for meeting three-year targets >	Six-years; three-year performance period + three-year holding period
Share ownership	Long-term shareholding >	Built up over five years and maintained for a further two years post-employment

a MSR: group chief executive to build a shareholding of at least five times salary, and other executive directors four and a half times salary, within five years of appointment.

The three elements described above provide a balance between a focus on short-term, medium-term and long-term performance, while encouraging behaviours which are in the long-term interests of shareholders. The operation of variable pay is supported by a focus on stewardship. There is a requirement that the chief executive officer will build up a holding of five times salary, and other executive directors a holding of four and a half times salary, over a period of five years following appointment and maintain that level during employment and for a further two years post-employment.

2. How are performance measures linked to strategy?

Variable pay is linked to performance measures designed to deliver the bp strategy. At the start of each year, the remuneration committee reviews the measures, targets and weightings to ensure they remain consistent with the priorities in the annual plan and the group strategy. For the annual bonus and performance shares, the approach to performance measurement is intended to provide a balance of measures to assess performance reflecting the global scale of the business, the unique characteristics of the energy sector, and progress in transitioning to an integrated energy company.

3. Our use of flexibility, judgement and discretion

The committee reviews bp's performance against specific measures and targets, and in doing so may make both quantitative and qualitative assessments of performance in reaching its decisions. This involves the application of judgement and discretion, in which the committee also seeks relevant input from the board's audit and safety and sustainability committees. Accordingly, the committee may decide to adjust the formulaic outcome derived from the relevant scorecards, either upwards or downwards, to reflect broader considerations. The committee continues to consider that the powers of flexibility, judgement and discretion are critical to the successful execution of the policy.

In framing the policy, the committee has taken care to ensure that these important powers continue to be available:

- Sufficient flexibility to take account of future changes in the industry environment and in remuneration practice generally. This allows the committee to respond to changes in circumstances, for example in applying particular performance measures and/or weightings within the plans, or in broadening the comparator group for the relative returns measure, in order to evolve with the company's strategy, without the need for specific shareholder approval.
- Power to exercise judgement in making a qualitative assessment in certain circumstances. A number of measures are used for annual or long-term incentive awards, many of which are numerical in nature and require a quantitative assessment of performance. Others may require a qualitative assessment, such as the strategic progress measures in the performance share plan.
- Scope for the committee to exercise discretion, mainly where it is desirable to vary a formulaic outcome that would otherwise arise from the policy's implementation. The committee considers that the ability to exercise discretion, upwards or downwards, is important to ensure that a particular outcome is fair in light of the director's own performance, the company's overall performance and positioning under particular performance measures and outcomes for shareholders.

The committee may make minor amendments to the remuneration policy to aid its operation or implementation without seeking shareholder approvals (e.g. for regulatory, exchange control, tax or administrative purposes or to take account of a change in legislation).

The committee intends to provide appropriate disclosure on the use of flexibility, judgement and discretion so that shareholders can understand the basis for its decisions.

4. How will we safeguard against payments for failure?

Performance-based pay	A significant portion of remuneration varies with performance – where performance targets are not achieved, lower or no payments will be made under the plans.
Discretion	The committee may vary formulaic outcomes where these do not suitably reflect performance or other circumstances over the relevant performance period.
Malus and clawback	<p>The robust malus provisions enable the committee to reduce the size of award, cancel an unvested award, or impose further conditions on an award made under this policy, while the robust clawback provisions enable the committee to require participants to return some or all of an award after payment or vesting.</p> <p>The following events will trigger the application of either malus or clawback:</p> <ul style="list-style-type: none"> • Material failure impacting safety or environmental sustainability. • Material damage to the reputation of the group, or conduct by a participant which results in or is reasonably likely to result in such material damage. • Incorrect award outcomes due to miscalculation or based on incorrect information. • Restatement due to financial reporting failure or misstatement of audited results. • Material misconduct by a participant. • Fraud effected by or with the knowledge of a participant. <p>In addition, the following events will trigger the application of malus, where the event takes place prior to the vesting or payment of an award:</p> <ul style="list-style-type: none"> • Material downturn in financial performance of the group, or any part of it. • Conduct effected by or with the knowledge of a participant which resulted in significant losses to the group, or any part of it. • Such other exceptional circumstances that the committee consider to be similar in nature. <p>The company also operates a mandatory clawback policy that complies with the US Securities and Exchange Commission (SEC) requirements.</p>

Directors' remuneration report continued

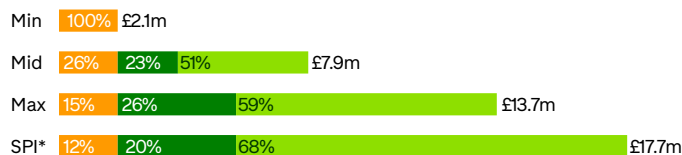
5. Differences from remuneration policy in the wider group

This executive director remuneration policy is structurally similar to remuneration for the majority of the wider workforce, but naturally differs in quantum, reflecting market norms for the differing size and complexity of roles, see [page 96](#) for more detail on these differences.

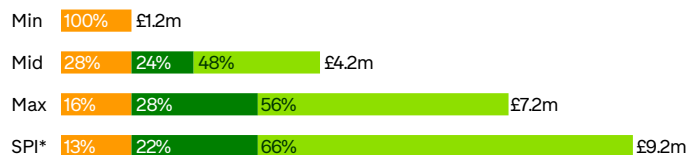
Illustrations of application of remuneration policy

The total remuneration opportunity for executive directors is strongly performance based and weighted to the long term. The charts below provide scenarios for the total remuneration of each individual who is an executive director at the date the policy comes into effect, at different levels of performance. The scenarios are calculated as prescribed by UK regulations.

Meg O'Neill



Kate Thomson



■ Fixed pay ■ Annual bonus ■ Performance shares * 50% share price increase

■ Fixed pay ■ Annual bonus ■ Performance shares * 50% share price increase

Due to rounding, the sum of the parts may not equal 100%.

Fixed components

For these illustrations salary, benefits and pension are the same in each scenario (annual values shown).

Salary

CEO (O'Neill)	£1,600,000	Meg's salary, upon appointment
CFO (Thomson)	£894,000	Kate's salary, effective from the 2026 AGM

Pensions and benefits

CEO (O'Neill)	£458,170	Based on cash in lieu of retirement benefits at 20% of salary, with an estimated £138k total for other benefits.
CFO (Thomson)	£261,179	Based on cash in lieu of retirement benefits at 20% of salary, with an estimated £82k total for other benefits.

Variable components

Variable pay under the policy comprises annual bonus and performance shares.

Scenario	Minimum	Mid	Maximum
	↓	↓	↓
Annual bonus (including cash and deferred elements)	Threshold not met Nil	50% of maximum 112.5% of salary	100% of maximum 225% of salary
Performance shares	Threshold not met CEO - Nil CFO - Nil	50% vesting CEO - 250% of salary CFO - 225% of salary	100% vesting CEO - 500% of salary CFO - 450% of salary

Recruitment policy

The committee expects any new executive director to be engaged on terms that are consistent with the policy. However, it recognizes that it cannot anticipate all circumstances in which any new executive director may be recruited. The committee may determine that it is in the interests of the company and shareholders to secure the services of a particular individual which may require it to take account of the terms of that individual's existing employment and/or their personal circumstances.

Accordingly, the committee will consider the following:

- The salary level of any new director is appropriate to their role and the competitive environment at the time of appointment. Where appropriate, it may appoint an individual on a lower salary (relative to any previous incumbent), then gradually increase salary levels as the individual gains experience in the role.
- Variable remuneration will be awarded within the parameters of the policy for current executive directors.
- The committee may tailor the vesting criteria for initial incentive awards depending on the specific circumstances.
- Where an existing employee is promoted to the board, the company may honour any existing commitments including maintaining any outstanding share awards.
- The committee would expect any new director to participate in the company pension and benefit schemes that are open to other employees (where appropriate, referencing the candidate's home country).
- Where an individual is relocating in order to take up the role, the company may provide certain benefits such as reasonable relocation expenses, accommodation for a period following appointment, assistance with visa applications or other immigration issues and ongoing arrangements such as repatriation assistance, tax filing assistance, annual flights home and a housing/utilities allowance. The company may meet any tax charges arising on relocation benefits.
- Where an individual would be forfeiting remuneration or employment terms in order to join the company, the committee may award appropriate compensation. The committee would require reasonable evidence of the nature and value of any forfeited arrangements and would, to the extent practicable, ensure any compensation was of comparable commercial value and capped as appropriate, considering the terms of the previous arrangement being forfeited (for example, the form and structure of award, timeframe, performance criteria and likelihood of vesting). Where appropriate, the committee prefers to deliver buy-outs in the form of restricted shares in the company.
- To facilitate any share awards on recruitment, the committee may rely on the Listing Rules exemption, which permits the grant of share awards, in unusual circumstances, to support the recruitment of an executive director, without seeking prior shareholder approval or making such awards under any other existing share plan.

In making any decision on the remuneration of a new director, the committee would balance shareholder expectations, current best practice and the circumstances of any new director. It would strive not to pay more than is necessary to recruit the right candidate and would give full details in the next remuneration report.

Service contract

Meg O'Neill's and Kate Thomson's service contracts are with BP p.l.c.

Each executive director is entitled to retirement benefits, as outlined on [page 118](#).

Each executive director is also entitled to the following contractual benefits:

- If appropriate for security reasons, a company car and driver is provided for business and private use, with the company bearing all normal employment, servicing, insurance and running costs. Alternatively, where not required for security reasons, a cash allowance may be paid instead.
- Medical and dental benefits, sick pay during periods of absence and assistance with the preparation of tax returns.
- Indemnification in accordance with applicable law.
- Participation in bonus or incentive arrangements at the committee's sole discretion.

In line with bp's policy on notice periods for executive directors, each executive director may terminate their employment by giving 12 months' written notice. In this event, for business reasons, the employer may not necessarily hold the executive director to their full notice period.

The employer may lawfully terminate the executive director's employment in the following ways:

- By giving the director 12 months' written notice.
- Without compensation, in circumstances where the employer is entitled to terminate for cause, as defined for the purposes of their service contract.

The company may lawfully terminate employment by making a lump sum payment in lieu of notice equal to 12 months' salary, or by monthly instalments rather than as a lump sum.

The lawful termination mechanisms described above are without prejudice to the employer's ability in appropriate circumstances to terminate in breach of the notice period referred to above, and thereby to be liable for damages to the executive director.

In the event of termination by the company, each executive director may have an entitlement to compensation in respect of their statutory rights under employment protection legislation in the UK and potentially elsewhere. Where appropriate, the company may also meet a director's reasonable legal expenses in connection with either their appointment or termination of their appointment.

Copies of the executive directors' service contracts, along with the non-executive director appointment letters, are available for inspection at the registered office of BP p.l.c.

Directors' remuneration report continued

Termination payments

In determining overall termination arrangements, the committee will distinguish between types of leaver and the circumstances of their leaving. The committee would also consider all relevant circumstances, including whether a contractual provision in the director's arrangements complied with best practice at the time of termination and the date the provision was agreed, as well as the performance of the director in certain respects.

Where appropriate, the committee may consider providing certain benefits relating to termination including the provision of outplacement support or reasonable costs associated with relocation back to an individual's home country. Should it become necessary to terminate an executive director's employment, and therefore to determine a termination payment, the committee's policy is as follows:

Termination payments	<p>The director's primary entitlement would be a termination payment in respect of their service agreement, as set out above. However the committee will consider mitigation to reduce the termination payment where appropriate to do so, taking into account the circumstances for leaving and the terms of the agreement.</p> <p>Mitigation would not be applicable where a contractual payment in lieu of notice is made.</p>	<p>If the departing director is eligible for an early retirement pension, the committee would consider, if relevant under the terms of the appropriate plan, the extent of any actuarial reduction that should be applied. UK directors who leave in circumstances approved by the committee may have a favourable actuarial reduction applied to their pensions (which to date has been 3%). Departing directors who leave in other circumstances may be subject to a greater reduction.</p>
Annual bonus	<p>The committee would consider whether the director should be entitled to an annual bonus in respect of the financial year in which the termination occurs.</p>	<p>Normally, any such bonus would be restricted to the director's actual period of service in that financial year and would be subject to deferral unless the committee determines otherwise.</p>
Share awards	<p>Share awards will be treated in accordance with the relevant plan rules. For awards granted under the executive directors' incentive plan (EDIP), the treatment can only be made in accordance with the framework approved by shareholders.</p> <p>The committee would consider whether conditional share awards held by the director should lapse on leaving or should, at the committee's discretion, be preserved. If awards are preserved, the award would normally continue until the vesting date. Awards may be pro-rated based on service over the performance period.</p>	<p>In deciding whether to exercise discretion to preserve EDIP awards, the committee would also consider the proximity of the award to its maturity date.</p> <p>To the extent that any such share award vests, the release of those shares to the former director will normally be made approximately one year after their date of termination (even if they would have been subject to a longer holding period had the executive remained in employment with bp).</p>

Remuneration in the wider group

The committee considers employment conditions in the bp group when establishing and implementing policy for executive directors to ensure the alignment of and context for principles and approach. In particular, the committee reviews the policy and makes decisions for the most senior leaders (the bp leadership team that reports to the CEO). Decisions regarding remuneration for employees outside the most senior leaders are the responsibility of the chief executive officer. The committee does not consult directly with employees when formulating the policy. However, feedback from employee focus groups and employee surveys, that are regularly reported to the board, provide views on a wide range of employee matters including pay.

The wider employee group participates in performance-based incentives. Throughout the group, salary and benefit levels are set in accordance with the prevailing relevant market conditions and practice in the countries in which employees are based. Differences between executive director pay policy and that of other employees reflect the senior position of the individuals, prevailing market conditions and corporate governance practices in respect of executive director remuneration. The key difference in policy for executive directors is that a greater proportion of total remuneration is delivered as performance-based incentives.

Engaging with shareholders

The committee carefully considers shareholder feedback each year and this input has been instrumental in shaping the current remuneration policy. As outlined in the chair's letter, for the 2026 policy review, over 40% of bp's shareholder register were consulted and the vast majority expressed support for broadly retaining the 2023 policy. The committee remains committed to maintaining an open and constructive dialogue with shareholders and will continue to consult before introducing any material changes to the remuneration policy.

Policy table – non-executive directors

The following table sets out the framework that will be used to determine the fees for non-executive directors during the term of this policy.

Non-executive chair	
Fees	
Approach	Remuneration is in the form of fees. Fees are currently paid in cash but the company may pay part or all of the fees in the form of shares. The level and structure of the chair's fee will primarily be compared against UK best practice.
Operation and opportunity	The quantum and structure of the non-executive chair's fee is reviewed annually by the remuneration committee, which makes a recommendation to the board.
Benefits and expenses	
Approach	The chair is provided with support and reasonable travelling expenses.
Operation and opportunity	The chair is provided with an office and full-time secretarial and administrative support in London and a contribution to an office and secretarial support in his home country as appropriate. A car and the use of a driver is provided in London, together with security assistance. All reasonable travelling and other expenses (including any relevant tax) incurred in carrying out his duties are reimbursed.
Non-executive directors	
Fees	
Approach	Remuneration is in the form of fees. Fees are currently paid in cash but the company may pay part or all of the fees in the form of shares. Remuneration practice is consistent with recognized best practice standards for non-executive directors and, as a UK-listed company, the level and structure of non-executive directors' remuneration will primarily be compared against UK best practice. Additional fees may be payable to reflect additional board responsibilities, for example, committee chairship and membership and for the role of senior independent director.
Operation and opportunity	The level and structure of non-executive directors' remuneration is reviewed by the chair, the CEO and the company secretary, who make a recommendation to the board. Non-executive directors do not vote on their own remuneration. Fee levels for non-executive directors are reviewed annually.
Benefits and expenses	
Approach	Non-executive directors are provided with administrative support and reasonable travelling expenses. Professional fees are reimbursed in the form of cash, payable following the provision of advice and assistance.
Operation and opportunity	Non-executive directors are reimbursed for all reasonable travelling and subsistence expenses (including any relevant tax) incurred in carrying out their duties. Professional fees incurred by non-executive directors based outside the UK in connection with advice and assistance on UK tax compliance matters are reimbursed.
Shareholding guidelines	
Approach	Chair and non-executive directors are encouraged to establish a holding in bp shares of the equivalent value of one year's base fee.

Letters of appointment for chair and non-executive directors

Approach	<p>The chair and non-executive directors each have letters of appointment. There is no term limit on a director's service, as bp proposes all directors for annual re-election by shareholders. There are no obligations arising from the non-executive directors' letters of appointment for remuneration or payments for loss of office, except for the chair whose appointment may be terminated in the following ways:</p> <ul style="list-style-type: none"> • By either party giving three months' written notice, or • By the company for cause (as set out in the letter of appointment) and without compensation. <p>The company may lawfully terminate the appointment by making a lump sum payment in lieu of notice equal to three months' fees. Copies of the executive directors' service contracts and non-executive directors' letters of appointment are available for inspection at the registered office of the company.</p>
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The maximum fees for non-executive directors are set in accordance with the Articles of Association.

Other disclosures

Appointment and succession plans

The chair, senior independent director (SID) and other independent non-executive directors (NEDs) each have letters of appointment with BP p.l.c. and do not serve, nor are they employed, in any executive capacity by bp. In line with the UK Corporate Governance Code (Code), all continuing directors are subject to annual re-election by shareholders at the Annual General Meeting (AGM), where letters of appointment for each NED are available for inspection. Details on the skills and experience of each director seeking election or re-election, as well as their individual contributions to the long-term success of the company, are set out in the Notice of AGM. In accordance with the Code, NEDs would not be expected to serve beyond nine years unless there are exceptional circumstances. On behalf of the board, the people, culture and governance committee reviews the formal appointment process and succession plans for the board. Appointments and succession plans are both based on merit and assessed against objective criteria with the promotion of diversity, equity and inclusion as central considerations. This includes diversity of gender, social and ethnic backgrounds as well as cognitive and personal strengths. In reviewing appointments and succession plans, due consideration is given to ensure the smooth transition of board members with specific responsibilities (e.g. committee chair roles) by allowing sufficient time for a detailed handover. This is balanced by the need to have new board members join at regular intervals such that, over time, there is a controlled approach to board members reaching the end of their tenure. All new directors receive a formal induction, tailored to their individual needs, skills and experience, taking account of any committees they join. These inductions include one-to-one meetings with members of the board and leadership team together with select members of senior management. Feedback is sought from directors undertaking their induction programmes to ensure they are continually updated and improved.

Further detail on board succession and tenure can be found in the people, culture and governance committee report on [page 89](#) and board composition disclosure on [page 72](#), respectively.

Time commitments

The expectation regarding time commitment for NEDs to effectively discharge their duties is set out in the directors' letters of appointment. The time commitment varies with the demands of bp business and other events. The NEDs' external time commitments – whether through executive, non-executive, advisory or other roles – are regularly reviewed by the company secretary to ensure that directors are able to allocate appropriate time to bp. A register of directors' time commitments and conflicts is maintained and is also reviewed annually by the people, culture and governance committee. The review process takes into account outside appointments and other external commitments and considers the complexity of the organization, the nature of the role, the sector (especially regulated and/or potentially competing sectors) and any leadership roles (e.g. a chair position). NEDs are also required to consult with the company secretary and chair before accepting any other role that may impact their ability to commit appropriate time to bp. The process for the approval of any new external appointment, significant or otherwise, for an existing director assesses the impact of that appointment on the director's time in order to ensure the director has sufficient capacity for their role with bp. As part of that same review process, a review of independence and potential conflicts of interest is undertaken, taking account of institutional investor and proxy advisor guidance and market best practice. Any external proposed commitments that could exceed the mandates set out in such guidance are given particular consideration. The board was satisfied that significant appointments undertaken during 2025 did not impact the directors' ability to prepare for and attend meetings, engage with stakeholders and participate in learning and development opportunities. The board has concluded that, notwithstanding external appointments held, each director is able to dedicate sufficient time to fulfil their bp duties. In compliance with the Code, none of the executive directors who served during 2025 held more than one non-executive directorship in a FTSE 100 company or other significant appointment throughout their tenure on the board. For more information on the external commitments of bp's directors, see [pages 73-75](#).

For information on board meetings held during 2025 and director attendance at board meetings, see [page 75](#).

Independence and conflicts of interest

All directors have a statutory duty to exercise independent judgement. Independence of NEDs is crucial in bringing constructive challenge to the chief executive officer (CEO) and the leadership team at board meetings, while providing support and guidance to promote meaningful discussion and, ultimately, informed and effective decision-making. In accordance with the criteria set out in the Code, the chair was considered independent at the time he was appointed. NEDs are required to provide sufficient information to allow the board to evaluate their independence prior to and following their appointment. In addition, each director has a statutory duty to disclose actual or potential conflicts of interest. Formal procedures are in place for new potential conflicts to be reported and recorded during the year. As a consequence of regular reviews in 2025, the board is satisfied that there were no matters giving rise to conflicts of interest which could not be authorized by the board. It has therefore concluded that all bp NEDs are independent.

Reporting in line with UK Listing Rule 6.6.6R(9)

As at 31 December 2025, 46% of the board comprises women, our senior independent director (SID), chief executive officer (CEO), chief financial officer (CFO) are women and three directors identify as from an ethnic minority background. Data for the below tables is collected on an annual basis through a standardized process under which each member of the board and executive management is asked to self-declare, or elect not to declare, their ethnic background and gender identity or sex. The information is correct as at 31 December 2025. For the purposes of this table, executive management includes bp's leadership team and the company secretary.

	Number of board members	Percentage of the board	Number of senior positions on the board (CEO, CFO, SID and chair)	Number in executive management	Percentage of executive management
Gender identity or sex					
Men	7	54%	1	5	55%
Women	6	46%	3	4	45%
Other categories	-	-	-	-	-
Not specified/prefer not to say	-	-	-	-	-
Ethnic background					
White British or other white (including minority-white groups)	10	77%	100%	7	78%
Mixed/Multiple Ethnic Groups	-	-	-	-	-
Asian/Asian British	3	23%	-	1	11%
Black/African/Caribbean/Black British	-	-	-	1	11%
Other ethnic group	-	-	-	-	-
Not specified/prefer not to say	-	-	-	-	-

Directors' statements

Statement of directors' responsibilities

The directors are responsible for preparing the annual report and the financial statements in accordance with applicable law and regulations. The directors are required by the Companies Act 2006 to prepare financial statements for each financial year that give a true and fair view of the financial position of the group and the parent company and the financial performance and cash flows of the group and parent company for that period. Under that law they are required to prepare the consolidated financial statements in accordance with International Financial Reporting Standards (IFRS) as adopted by the United Kingdom and applicable law and have elected to prepare the parent company financial statements in accordance with applicable United Kingdom law and United Kingdom accounting standards (United Kingdom generally accepted accounting practice), including FRS 101 'Reduced Disclosure Framework'. In preparing the consolidated financial statements the directors have also elected to comply with IFRS as issued by the International Accounting Standards Board (IASB) and IFRS as adopted by the European Union (EU).

In preparing those financial statements, the directors are required to:

- Select suitable accounting policies and then apply them consistently.
- Make judgements and estimates that are reasonable and prudent.
- Present information, including accounting policies, in a manner that provides relevant, reliable, comparable and understandable information.
- Provide additional disclosure when compliance with the specific requirements of IFRS is insufficient to enable users to understand the impact of particular transactions, other events and conditions on the group's financial position and financial performance.
- State that applicable accounting standards have been followed, subject to any material departures disclosed and explained in the parent company financial statements.
- Prepare the financial statements on the going concern basis unless it is inappropriate to presume that the company will continue in business.

The directors are responsible for keeping adequate accounting records that disclose with reasonable accuracy at any time the financial position of the group and company and enable them to ensure that the consolidated financial statements comply with the Companies Act 2006 and the parent company financial statements comply with the Companies Act 2006. They are also responsible for safeguarding the assets of the group and company and hence for taking reasonable steps for the prevention and detection of fraud and other irregularities.

Having made the requisite enquiries, so far as the directors are aware, there is no relevant audit information (as defined by Section 418(3) of the Companies Act 2006) of which the company's auditors are unaware, and the directors have taken all the steps they ought to have taken to make themselves aware of any relevant audit information and to establish that the company's auditors are aware of that information.

Each of the current directors, whose names and functions are listed on [pages 73-75](#), confirms that to the best of their knowledge:

- The consolidated financial statements, prepared on the basis of IFRS as issued by the IASB, IFRS as adopted by the United Kingdom and EU and in accordance with the provisions of the Companies Act 2006 as applicable to companies reporting under international accounting standards, give a true and fair view of the assets, liabilities, financial position and profit or loss of the group.
- The parent company financial statements, prepared in accordance with United Kingdom generally accepted accounting practice, give a true and fair view of the assets, liabilities, financial position, performance and cash flows of the company.
- The management report, which is incorporated in the strategic report and directors' report, includes a fair review of the development and performance of the business and the position of the group, together with a description of the principal risks and uncertainties that they face.

Albert Manifold
Chair
6 March 2026

UK Corporate Governance Code compliance

Throughout 2025 bp applied the principles of the UK Corporate Governance Code 2024 (Code) and has complied with all the provisions. The information set out in the directors' report, including the committee reports on [pages 82-117](#), is intended to provide an explanation of how bp applied the principles and complied with the provisions of the Code during the year. The Code can be found on the Financial Reporting Council website: frc.org.uk.

Risk management and internal control

Under the Code, the board is responsible for the company's risk management and internal control systems. In discharging this responsibility the board, through its governance principles, requires the chief executive officer to operate the company with a comprehensive system of controls and internal audit and to identify and manage the risks, including emerging risks, that are material to bp. In turn, the board, through its monitoring processes, satisfies itself that these material risks are identified and understood by management and that systems of risk management and internal control are in place to mitigate them. These systems are reviewed periodically by the board, have been in place for the year under review and up to the date of this report and are consistent with the requirements of Principle O of the Code.

The board has processes in place to:

- Assess the principal and emerging risks facing the company.
- Monitor the company's system of internal control (which includes the ongoing process for identifying, evaluating and managing the principal and emerging risks).
- Review the effectiveness of that system annually.

Acquired businesses which have not transitioned into bp's system of internal control and non-operated joint ventures and associates★ have not been dealt with as part of this process.

A description of the principal risks facing the company, including those that could potentially threaten its business model, future performance, solvency or liquidity, is set out in risk factors on [pages 67-70](#). During 2025 the board undertook a robust assessment of the principal and emerging risks facing the company. The principal means by which these risks are managed or mitigated are set out on [pages 60-66](#).

Directors' statements continued

In assessing the risks faced by the company and monitoring the system of internal control, the board and the audit and safety and sustainability committees requested, received and reviewed reports from executive management, including management of the business segments, corporate activities and any functions, at their regular meetings. A report by each of these committees, including its activities during the year, is set out on **pages 82-90**.

During 2025 the committees, as relevant, also met with management, the SVP internal audit and other monitoring and assurance functions (including group ethics & compliance, safety and operational risk, group control, group legal and group risk) and the external auditor. Responses by management to incidents that occurred were considered by the relevant committee or the board, as appropriate.

At a meeting in March 2026, the audit committee considered reports from the group risk function on the system of internal control and the function's categorization of significant failings or weaknesses. The audit committee also considered a report from internal audit on their assessment of bp's systems of internal control and risk management, based on audit work conducted during 2025. In considering these reports and assessments, the audit committee noted that bp's systems of internal control and risk management are designed to manage, rather than eliminate, the risk of failure to achieve business objectives and can only provide reasonable, and not absolute, assurance against material misstatement or loss.

The board then considered the review undertaken by the audit committee and the proposed disclosures outlining the company's risk management and internal control systems prior to publication of the annual report and accounts.

A statement regarding the company's internal controls over financial reporting is set out on **page 360**.

Longer-term viability

In accordance with provision 31 of the Code, the directors have assessed bp's prospects both at an operating and strategic level with some business planning processes extending out beyond the next ten years. However, the directors believe that a viability assessment period of three years remains appropriate given the nature of our business and exposure to short-term commodity pricing. This assessment is based on management's reasonable expectations of the position and performance of the company over this period, its internal detailed budgets and planning timeframes and the targets and aims that it has set out.

Our risk management system, described in how we manage risk starting on **page 60**, outlines our risk identification, assessment and management approach for all risks, including our principal risks, described starting on **page 67**.

Taking into account the company's current position and its principal risks, the directors have a reasonable expectation that the company will be able to continue in operation and meet its liabilities as they fall due over the next three years.

The directors' assessment included a review of the potential financial impact of, and the financial headroom that could be available in the event of, the most severe but plausible scenarios that could threaten the viability of the company. The assessment took into consideration the robust financial position of the group and the potential mitigations that management reasonably believes would be available to the company over this period. Mitigations considered include use and reallocation of cash, access to debt facilities and credit lines, raising of capital, reductions in capital expenditure★, divestments and dividend reductions.

The scenarios that have been modelled are based on the most severe but plausible outcomes and associated costs are based on actual experience where possible. The scenarios link to one or more of our principal risks described on **pages 67-70** and have been considered individually and as a cluster of events. They include:

- A significant process safety incident when operating facilities, drilling wells or transporting hydrocarbons. Process safety, personal safety and environmental risks, see **page 69**.
- A sustained significant decline in oil prices over three years. Commodity prices and market environment, see **page 67**.
- A significant cyber security incident. Digital, cyber security and data risk, see **page 68**.
- A loss of a significant market or producing asset. Legal, regulatory and ethical compliance, see **page 70**.

As an example of a cluster of events, bp models a risk scenario involving a significant process safety incident (when operating facilities, drilling wells or transporting hydrocarbons) during a low-price environment (i.e. where there is a sustained significant decline in oil prices over a three-year period).

The directors also considered the impact on viability from an extended pandemic scenario, as well as the potential risks associated with climate change and the transition to a lower carbon economy. They consider that the most likely impacts of these risks are broadly captured and modelled through the sustained low oil price and loss of a producing asset scenarios.

In assessing the prospects of the company, the directors noted that such assessment is subject to a degree of uncertainty that can be expected to increase looking out over time and, accordingly, that future outcomes cannot be guaranteed or predicted with certainty.

Fair, balanced and understandable

The board considers the annual report and financial statements, taken as a whole, is fair, balanced and understandable, and provides the information necessary for shareholders to assess the company's position and performance, business model and strategy.

Going concern

In accordance with provision 30 of the Code, the directors consider it appropriate to adopt the going concern basis of accounting in preparing the financial statements.

Forecast liquidity has been assessed under a number of stressed scenarios to support this assertion. Reverse stress tests performed indicated that the group will continue to operate as a going concern for at least 12 months from the date of approval of the financial statements even if the Brent price fell to zero. For further information on financial risk factors, including liquidity risk, see Financial statements – **Note 29**.

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Consolidated financial statements of the bp group

Independent auditor's report to the members of BP p.l.c.

Report on the audit of the financial statements

1. Opinion

In our opinion:

- the financial statements of BP p.l.c. (the 'parent company') and its subsidiaries (the 'group' or 'bp') give a true and fair view of the state of the group's and of the parent company's affairs as at 31 December 2025 and of the group's profit for the year then ended;
- the group financial statements have been properly prepared in accordance with United Kingdom adopted international accounting standards and IFRS Accounting Standards as issued by the International Accounting Standards Board (IASB) and as adopted by the European Union (EU);
- the parent company financial statements have been properly prepared in accordance with United Kingdom Generally Accepted Accounting Practice, including Financial Reporting Standard 101 'Reduced Disclosure Framework'; and
- the financial statements have been prepared in accordance with the requirements of the Companies Act 2006.

We have audited the financial statements of BP p.l.c. which comprise the:

- group and parent company income statements
- group and parent company statements of comprehensive income
- group and parent company statements of changes in equity
- group and parent company balance sheets
- group cash flow statement
- group related Notes 1 to 37 to the financial statements, including a summary of material accounting policy information and
- parent company related Notes 1 to 14 to the financial statements, including a summary of material accounting policy information.

The financial reporting framework that has been applied in the preparation of the group financial statements is applicable law, United Kingdom adopted international accounting standards and IFRS Accounting Standards as issued by the IASB and as adopted by the EU. The financial reporting framework that has been applied in the preparation of the parent company financial statements is applicable law and United Kingdom accounting standards, including FRS 101 'Reduced Disclosure Framework' (United Kingdom generally accepted accounting practice).

2. Basis for opinion

We conducted our audit in accordance with International Standards on Auditing (UK) (ISAs (UK)) and applicable law. Our responsibilities under those standards are further described in the auditor's responsibilities for the audit of the financial statements section of our report.

We are independent of the group and the parent company in accordance with the ethical requirements that are relevant to our audit of the financial statements in the UK, including the Financial Reporting Council's (the 'FRC's') Ethical Standard as applied to listed public interest entities, and we have fulfilled our other ethical responsibilities in accordance with these requirements. The non-audit services provided to the group and parent company for the year are disclosed in Note 36 to the financial statements.

We confirm that we have not provided any non-audit services prohibited by the FRC's Ethical Standard to the group or the parent company.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

3. Summary of our audit approach

Key audit matters	<p>The key audit matters that we identified in the current year were:</p> <ul style="list-style-type: none"> • potential impact of climate change and the energy transition • impairment of upstream oil and gas property, plant and equipment (PP&E) assets • decommissioning provisions • valuation of commodity financial derivatives, where fraud risks may arise in revenue recognition, and • management override of controls. <p>All key audit matters are consistent with those we identified in the prior year and the developments in fact patterns of these previously identified key audit matters are explained in the respective sections below.</p>
Materiality	The materiality that we used for the group financial statements was \$700 million (2024 \$800 million) which was determined based on cash flow from operations and underlying replacement cost profit before interest and tax.
Scoping	Our scope covered 160 consolidation units ('cons units'). Of these, 135 were subject to audits of one or more classes of transactions, account balances and disclosures and 25 were subject to specified audit procedures by the component audit teams or group audit team. These covered 75% of group revenue, 74% of PP&E and 72% of profit before tax. The remaining 815 cons units were subject to other procedures, including performing analytical reviews, making inquiries of management, and evaluating and testing management's group-wide controls.

4. Conclusions relating to going concern

In auditing the financial statements, we have concluded that the directors' use of the going concern basis of accounting in the preparation of the financial statements is appropriate.

Our evaluation of the directors' assessment of the group's and parent company's ability to continue to adopt the going concern basis of accounting included:

- assessing the financing facilities including the nature of the facilities and repayment terms;
- assessing management's identified potential mitigating actions and the appropriateness of the inclusion of these in the going concern assessment;
- testing the clerical accuracy of the going concern model;
- assessing the historical accuracy of forecasts prepared by management;
- performing our independent sensitivity analysis; and
- assessing the disclosures made within the financial statements.

Based on the work we have performed, we have not identified any material uncertainties relating to events or conditions that, individually or collectively, may cast significant doubt on the group's and parent company's ability to continue as a going concern for a period of at least twelve months from when the financial statements are authorised for issue.

In relation to the reporting on how the group has applied the UK Corporate Governance Code, we have nothing material to add or draw attention to in relation to the directors' statement in the financial statements about whether the directors considered it appropriate to adopt the going concern basis of accounting.

Our responsibilities and the responsibilities of the directors with respect to going concern are described in the relevant sections of this report.

5. Key audit matters

Key audit matters are those matters that, in our professional judgement, were of most significance in our audit of the financial statements of the current year and include the most significant assessed risks of material misstatement (whether or not due to fraud) that we identified. These matters included those which had the greatest effect on the overall audit strategy, the allocation of resources in the audit and directing the efforts of the engagement team.

Throughout the course of our audit, we identify risks of material misstatement ('risks'). We consider both the likelihood of a risk and the potential magnitude of a misstatement in making the assessment. Certain risks are classified as 'significant' or 'higher' depending on their severity. The category of the risk determines the level of evidence we seek in providing assurance that the associated financial statement item is not materially misstated.

The matters described below were addressed in the context of our audit of the financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

5.1 Potential impact of climate change and the energy transition (impacting PP&E, goodwill, intangible assets and provisions) – Notes 1, 4, 8, 14, 15 and 33 to the financial statements

Key audit matter description

Climate change impacts bp's business in a number of ways as set out in the strategic report on pages 2-71 of the Annual Report and Note 1 of the financial statements on page 160. It represents a strategic challenge and a key focus of management. The related risks that we have assessed for our audit are as follows:

- Forecast assumptions used in assessing the value-in-use of oil and gas PP&E assets within bp's balance sheet for impairment testing, in particular oil and gas price assumptions and their interrelationship with forecast emissions costs, may not appropriately reflect changes in supply and demand due to climate change and the energy transition (see 'Impairment of upstream oil and gas PP&E assets' below).
- The timing of expected future decommissioning expenditures in respect of oil and gas assets may need to be brought forward with a resulting increase in the present value of the associated liabilities due to the impact of climate change. In addition, there is an exposure to decommissioning obligations that may revert back to bp in respect of assets transferred to third parties through historical divestments. The risk of exposure is increased due to the impacts of climate change which have heightened long term financial resilience concerns for many industry participants. Furthermore, provisions for decommissioning refining assets, not generally recognised on the basis that the potential obligations cannot be measured given their indeterminate settlement dates, might need to be recognised if reductions in demand due to climate change curtail their operational lives (see 'Decommissioning provisions' below).
- The recoverability of certain of the group's \$4.0 billion total exploration and appraisal (E&A) assets capitalised as at 31 December 2025 (2024 \$4.4 billion) is potentially exposed to climate change and the global energy transition and macroeconomic risk factors (see Note 15). This is because a greater number of E&A projects may not proceed as a consequence of the energy transition or lower forecast future oil and gas prices. The determination of whether and when E&A costs should be written off, impaired, or retained on the balance sheet as E&A assets, remains complex and continues to require significant management judgement.
- The carrying value of goodwill associated with the transition businesses, specifically Archaea Energy and Lightsource bp, may no longer be recoverable due to increases in cost or lower forecast production or development rate reflecting the slowdown in the pace of energy transition adversely impacting the value of these projects and impacting investment decisions. Management performed an annual impairment test (which includes judgements in relation to forecast period, development rate, long term growth rate, discount rate, developer margin, capital expenditure and renewable natural gas revenue prices) to assess the recoverability of the goodwill, resulting in an impairment of \$2.0 billion as disclosed in Note 14.
- The useful economic lives of the group's refining assets may be shortened as society moves towards 'net zero' emissions targets and bp seeks to achieve its net zero ambition, such that the depreciation charge is materially understated. Of the total refining assets carried in the balance sheet, all but an immaterial residual value relating primarily to land and buildings will be fully depreciated by 2050. As disclosed in Note 1 to the accounts on page 161, management has concluded that demand for refined products is expected to remain sufficient for the existing refineries to continue operating for the duration of their remaining useful lives and hence no changes to the useful economic lives of its refinery assets were required.
- The carrying value of bp's refining assets within PP&E may no longer be recoverable, due to changes in supply and demand which arise among other things as a consequence of climate change and the energy transition. Management performed an assessment to identify potential impairment indicators in respect of the refinery portfolio. This considered all potential impairment indicators, including refining margin forecast, which could be impacted by changes in supply and demand due to climate change and the energy transition. As a result of management's impairment assessment, management identified indicators of impairment within the refining portfolio as at 31 December 2025 and concluded that no impairment charge needed to be recorded.
- The total goodwill balance as at 31 December 2025 is \$10.3 billion (2024 \$14.9 billion), of which \$7.1 billion relates to upstream oil and gas assets (2024 \$7.2 billion) and \$0.9 billion relates to the transition businesses in the gas & low carbon energy segment (2024 \$2.9 billion). The carrying value of goodwill may no longer be recoverable as a consequence of climate change and therefore may need to be impaired. For oil production & operations ('OP&O') and gas & low carbon energy ('G&LCE'), goodwill is allocated to upstream oil and gas CGUs in aggregate at the respective segment level. The most significant assumption in the upstream oil and gas related goodwill impairment tests affected by climate change relates to future oil and gas prices (see 'Impairment of upstream oil and gas PP&E assets' below). Given the significant level of headroom in the upstream oil and gas goodwill impairment tests, management identified no other assumption that could lead to a material misstatement of goodwill due to the energy transition and other climate change factors. The annual impairment test on goodwill related to transition businesses resulted in an aggregate impairment of \$2.0 billion (2024: nil). Management identified discount rates and growth assumptions as key assumptions that could be impacted by the pace of energy transition and other climate change factors. Disclosures in relation to sensitivities for goodwill are included within Note 14 on pages 197-198. The customers & products (C&P) segment has a goodwill balance of \$2.2 billion (2024 \$4.8 billion). The significant decrease is due to \$2.8 billion relating to the Castrol business (2024 \$2.6 billion) having been reclassified to within assets held for sale at 31 December 2025, with no indicators of impairment identified as a result of the announcement of the sale. Due to the substantial headroom in the most recent impairment test (as described in Note 14), management has assessed as remote the likelihood that the recoverable amount of goodwill is less than its carrying value.

- Climate change-related litigation brought against bp, as disclosed in Note 33 to the financial statements, may lead to an outflow of funds requiring provision.

The above considerations were a significant focus of management during the period which led to this being a matter that we communicated to the Audit Committee, and which had a significant effect on the overall audit strategy. We therefore identified this as a key audit matter. This matter was also discussed by the Audit Committee on page 87.

How the scope of our audit responded to the key audit matter

Overall response

We held discussions with management, with our Climate Change specialists and within the group engagement team to identify the areas where we felt climate change could have a potential impact on the financial statements.

We also continued to utilise a climate change steering committee comprising a group of senior partners and specialists with specific climate change and technical audit and accounting expertise within Deloitte to provide an independent challenge to our key decisions and conclusions with respect to this area.

Audit procedures

The audit response related to two of the audit risks identified is set out under the key audit matters for 'Impairment of upstream oil and gas PP&E assets' on pages 135-137 and 'Decommissioning provisions' on pages 138-140. Other procedures are as follows:

In respect of the recoverability of E&A assets capitalised as at 31 December 2025:

- We tested the relevant controls within the group's E&A write-off and impairment assessment processes; and
- We challenged and evaluated management's key E&A judgements with regards to the impairment criteria of IFRS 6. Where impairment indicators were identified, we corroborated key judgements with internal and external evidence for assets that remained on the balance sheet. This included analysing evidence of future E&A plans, budgets and capital allocation decisions, assessing management's key accounting judgement papers, reading meeting minutes and assessing licence documentation and evidence of active dialogue with partners and regulators including negotiations to renew licences or modify key terms.

In respect of the impairment tests performed on goodwill associated with the transition businesses, specifically Archaea Energy and Lightsource bp, performed at 31 December 2025:

- We tested the relevant controls over the impairment tests including controls over key assumptions;
- We independently evaluated bp's discount rates used in impairment tests with input from our valuation specialists, against relevant third-party market and peer data;
- We independently evaluated the long-term production rates for certain transition businesses with input from our Deloitte Landfill Production Specialists;
- We evaluated the appropriateness of other key assumptions including forecast period, development rate, long term growth rate, discount rate, developer margin, capital expenditure, and renewable natural gas revenue prices through assessment of bp's future plans and consistency with the capital frame; and
- We tested the mechanical accuracy of the impairment models.

We challenged management's assertion that no changes are required to the assessed useful economic lives of refining assets as a consequence of climate change factors. In doing this, we obtained third party reports assessing future refined petroleum product demand for those countries which are included in our group audit scope for the C&P segment. In particular, we considered the 2025 International Energy Agency (IEA) Oil Report, which shows a growth in demand for bp C&P's core products (petroleum and jet-fuel) from 2025 to 2030 of 1.0 mb/d, while gasoline also declines by 1.0 mb/d. We have further corroborated this assessment based on the IEA World Energy Outlook 2025, which expects that demand for refined petroleum products will peak before 2030 at 86 mb/d, around 0.7 mb/d above 2024 levels, and demand in 2035 will be 85 mb/d under the Stated Policies Scenario (STEPS), which we consider to be aligned with real-world data. This demonstrates that demand is expected to remain sufficient for at least the current remaining useful economic lives of the refineries such that current depreciation rates are appropriate; however, more consideration will be needed following 2030.

We considered the impact of potential changes in supply and demand on the group's refining portfolio and assessed internal and external market studies of future supply and demand. In relation to the refinery impairment tests performed by management, our audit procedures included:

- evaluating the valuation methodology and testing the integrity and mechanical accuracy of the impairment models;
- assessing the appropriateness of key assumptions and inputs to the impairment models, notably forecast local refining marker margins, discount rate and energy input costs;
- challenging and evaluating management's assumptions by reference to third party data where available and involvement of our valuation specialists;
- evaluating management's ability to forecast future cash flows and margins by comparing actual results with historical forecasts; and
- testing management's internal controls over the impairment test and related inputs.

We performed procedures to satisfy ourselves that, other than future oil and gas price assumptions, there were no other assumptions in management's oil and gas goodwill impairment tests in respect of which reasonably possible changes due to the energy transition and other climate change factors could cause goodwill to be materially misstated. We assessed the impact of climate change on C&P segment activities and we have not noted any factors to indicate impairment of goodwill due to climate change.

With regard to climate change litigation, we designed procedures specifically to respond to the risks that provisions could be understated or that contingent liability disclosures may be omitted or be inaccurate including:

- holding discussions with the group general counsel and other senior bp lawyers regarding climate change matters;
- conducting a search for climate change litigation and claims brought against the group;
- making written inquiries of, and holding discussions with, external legal counsel advising bp in relation to climate change litigation; and
- assessing the contingent liability disclosures in the annual report on pages 236-237.

We read the other information included in the Annual Report and considered (a) whether there was any material inconsistency between the other information and the financial statements; and (b) whether there was any material inconsistency between the other information and our understanding of the business based on audit evidence obtained and conclusions reached in the audit.

Key observations

Key observations in relation to oil and gas price assumptions used in oil and gas PP&E asset impairment tests, and the impact of climate change on decommissioning provisions are set out in the relevant key audit matter below.

We concluded that the key E&A assessments had been appropriately determined and the judgements management had made were appropriately supported. We did not identify any additional impairments or write-offs from the work we performed.

We are satisfied:

- with the results of our procedures relating to the carrying value of refining assets and that the impairments recorded are reasonable;
- with the results of our procedures relating to the assessment of the useful economic lives of refining assets and therefore depreciation charges, based on the market studies we read;
- with the results of our procedures relating to the carrying value associated with the transition businesses and that the impairments recorded are reasonable;
- with the sensitivity analysis disclosures around the energy transition and other climate change factors performed in respect of the goodwill balances, and that the group's goodwill balances are not materially misstated;
- with management's assertion that no provision should currently be made in respect of climate change litigation. Based on the audit evidence obtained both from internal and external legal counsel, we concluded that management's disclosure of the contingent liabilities in respect of these matters is appropriate; and
- that management's other disclosures in the Annual Report relating to climate change are consistent with the financial statements and our understanding of the business.

Whilst many of bp's oil and gas properties and refining assets are long term in nature, by 2050, the remaining carrying value of assets currently being depreciated will be immaterial, this date being the target set by the majority of governments with 'net zero' emissions targets and also by bp with five sustainability aims: net zero operations; net zero sales; people; biodiversity; and water. At current rates of depreciation, depletion and amortisation ('DD&A'), the average remaining depreciable life of the upstream oil and gas PP&E (within the OP&O and G&LCE segments) is five years and the refining assets (within the C&P segment) is twelve years.

5.2 Impairment of upstream oil and gas property, plant and equipment (PP&E) assets – Notes 1, 4 and 12 to the financial statements

<p>Key audit matter description</p>	<p>The group balance sheet as at 31 December 2025 includes PP&E of \$99 billion (2024 \$100 billion), of which \$55 billion (2024 \$56 billion) is oil and gas properties.</p> <p>Management's best estimate oil and gas price assumptions for value-in-use impairment tests were revised in 2025 as set out in Note 1 on pages 168-169.</p> <p>Management has also determined bp's 'best estimate' discount rate assumptions, as set out in Note 1 on page 168. bp's post-tax discount rate used for impairment testing for oil and gas assets in 2025 remained unchanged from prior year at 8% (2024 8%). Pre-tax discount rates applied in impairment tests were revised in some regions to reflect changes in local tax rates and country risk premiums. Reserves estimates for all oil and gas fields were also reviewed and updated where necessary at year-end.</p> <p>As required by International Accounting Standard (IAS) 36 'Impairment of Assets', management performed a review of all oil and gas cash generating units (CGUs) for indicators of impairment and impairment reversal as at 31 December 2025. As a result of management identifying impairment indicators during 2025, \$1 billion (2024 \$2 billion) of oil and gas CGU net impairment charges were recognised, principally due to an increase in certain capital expenditure forecasts and operating expenditure forecasts and certain reserves write downs.</p> <p>We identified three key management estimates in management's determination of the level of impairment charge and/or impairment reversal. These are:</p> <p>Oil and gas prices – bp's oil and gas price assumptions have a significant impact on many CGU impairment assessments performed across the OP&O and G&LCE segments and are inherently uncertain. The estimation of future prices is subject to increased uncertainty given climate change, the global energy transition, macro-economic factors and disruption in global supply due to ongoing geo-political conflicts. There is a risk that management do not forecast reasonable 'best estimate' oil and gas price forecasts when assessing CGUs for impairment charge and/or impairment reversal, leading to material misstatements. These price assumptions are highly judgmental and are pervasive inputs to bp's oil and gas CGU valuation. There is also a risk that management's oil and gas price related disclosures are not reasonable.</p> <p>bp's oil and gas price assumptions for value-in use impairment assessments are aligned with bp's investment appraisal assumptions, except that potential future emissions costs that could be borne by bp are included in investment appraisals as bp costs without assuming incremental revenue.</p> <p>As described in Note 1 on page 161, emissions costs forecasts interrelate with bp's oil and gas prices, because bp's price assumptions for value-in-use estimates represent 'net producer prices', i.e., net of any further emissions costs that may be enacted in the future. Management's judgement is that the potential impact of such further emissions costs being borne by producers including bp is not expected to have a material impact on bp's oil and gas CGU carrying values as costs would effectively be borne by oil and gas end users via overall higher commodity prices. There is a risk that management's judgement is not reasonable.</p> <p>Discount rates – Given the long timeframes involved, certain CGU impairment assessments are sensitive to the discount rate applied. Discount rates should reflect the return required by the market and the risks inherent in the cash flows being discounted. There is a risk that management does not assume reasonable discount rates, adjusted as applicable for country risks and relevant tax rates, leading to material misstatements. Determining a reasonable discount rate is highly judgmental and, consistent with price assumptions above, the discount rate assumption is also a pervasive input across bp's oil and gas CGU valuations, before adjustments for asset specific risks and tax rates.</p> <p>Reserves and resources estimates – A key input to certain CGU impairment assessments is the oil and gas production forecast, which is based on underlying reserves estimates and field specific development assumptions. Certain CGU production forecasts include specific risk adjusted resource volumes, in addition to proven and/or probable reserves estimates, that are inherently less certain than reserves; assumptions related to these volumes can be particularly judgmental. There is a risk that material misstatements could arise from unreasonable production forecasts for individually material CGUs and/or from the aggregation of systematic flaws in bp's reserves and resources estimation policies across the OP&O and G&LCE segments.</p> <p>We identified certain individual CGUs which we determined would be most at risk of material impairment charges as a result of a reasonably possible change in the oil and gas price assumptions. This population includes previously impaired assets which are also at risk of material impairment reversal resulting from potential oil and gas price assumption changes. We identified that a subset of these CGUs was also individually materially sensitive to the discount rate assumption. Further information regarding these sensitivities is given in Note 1 on page 167.</p> <p>Impairment charge and/or impairment reversal assessments of upstream oil and gas PP&E assets remain a key audit matter because recoverable values are reliant on forecast assumptions such as oil and gas prices, discount rates and reserves estimates, which are inherently judgmental and complex for management to estimate and challenging to audit. Additionally, the magnitude of the potential misstatement risk remains material to the group. This matter was discussed by the Audit Committee on page 87.</p>
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<p>How the scope of our audit responded to the key audit matter</p>	<p>We tested relevant internal controls over the estimation of oil and gas prices, discount rates, and reserve and resources estimates, as well as relevant internal controls over the performance of the impairment charge and/or impairment reversal assessments where we identified audit risks. In addition, we conducted the following substantive procedures.</p> <p>Oil and gas prices</p> <ul style="list-style-type: none"> • We independently developed a reasonable range of forecasts based on external data obtained, against which we compared management’s oil and gas price assumptions in order to challenge whether they are reasonable. • In developing this range, we obtained a variety of reputable and reliable third-party forecasts, peer information and other relevant market data. • In challenging and evaluating management’s price assumptions, we considered the extent to which they and each of the forecast pricing scenarios obtained from third parties reflect the impact of lower oil and gas demand due to climate change and the energy transition. • The 2015 Conference of the Parties (CoP) 21 Paris Agreement goals of ‘holding the increase in the global average temperature to well below 2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels’ was reaffirmed at CoP 30 in Brazil during November 2025. We specifically analysed third party forecasts stated, or interpreted by us, as being consistent with scenarios achieving the ‘well below 2°C goal’ and/or ‘1.5°C ambition’ and evaluated whether they presented contradictory audit evidence. • We challenged and evaluated management’s judgement, described in Note 1 on page 161, that the potential impact of further emission costs being borne by producers including bp is not expected to have a material impact on bp’s oil and gas CGU carrying values. We obtained evidence supporting that oil and gas price forecasts included in our reasonable range are forecast on a ‘net producer prices’ basis, (i.e., net of potential future emissions costs that are assumed to be borne by oil and gas end users), consistent with the basis of bp’s value-in-use price assumptions. • We assessed management’s disclosures in Note 1, including the sensitivity of forecast revenue cash inflows to lower oil and gas prices, and how climate change and the energy transition, potential future emissions costs and/or reduced demand scenarios may impact bp to a greater extent than currently anticipated in bp’s value-in-use estimates for oil and gas CGUs. <p>Discount rates</p> <ul style="list-style-type: none"> • We independently evaluated bp’s discount rates used in impairment tests with input from our valuation specialists, against relevant third-party market and peer data. • When performing procedures over specific assets, we assessed whether specific country risks and tax adjustments were reasonably reflected in bp’s discount rates. • We challenged and evaluated management’s disclosures in Note 1, including in relation to the sensitivity of discount rate assumptions. <p>Reserves and resources estimates</p> <p>Using the outputs from our data analytics tools which we used to visualise reserves and resources volumes, and with the assistance of our oil and gas reserves specialists, we:</p> <ul style="list-style-type: none"> • assessed bp’s reserves and resources estimation methods and policies for reasonableness; • assessed how these policies had been applied to a sample of bp’s reserves and resources estimates which included those that we judged to represent the greatest risk of material misstatement; • read and evaluated a sample of reports provided by management’s external reserves experts and assessed the scope of work and findings of these third parties; • assessed the competence, capability and objectivity of bp’s internal and external reserve experts, through understanding their relevant professional qualifications and experience; • assessed whether management’s production forecasts are consistent overall with bp’s strategy; • compared the production forecasts used in the impairment tests with management’s approved reserves and resources estimates; and • performed a retrospective assessment in order to assess management’s ability to accurately estimate reserves and resources and to check for indications of estimation bias over time.
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Key observations	<p>Oil and gas prices</p> <p>For the purpose of PP&E impairment tests, management is required under IAS 36 to apply its current 'best estimate' of future oil and gas prices. We determined that bp's 'best estimate' assumptions are reasonable when compared against a range of third-party forecasts and peer information that we identified as being appropriate for this purpose. In forming this view, we included each forecaster's 'base case', 'central case' or 'most likely' estimate.</p> <p>We further observed that, as well as publishing a 'base case', 'central case' or 'most likely' estimate, certain third-party price forecasters including the IEA published other price forecasts including some that were stated as, or were interpreted by us as being, 'well below 2°C goal' or '1.5°C ambition' scenarios. We observed that none of those third-party forecasters described their transition scenarios as their 'base case', 'central case' or 'most likely' estimate.</p> <p>Management notes on page 168 that they consider their 'best estimate' prices to be in line with a range of transition paths consistent with limiting global warming to well below 2°C as well as the ambition to limit global warming to no greater than 1.5°C. We observed that for bp's Brent price assumptions, whilst these were within the lower half of our range of 'best estimate' forecasts described above, they were within the higher half of our range of 'well below 2°C goal' and '1.5°C ambition' scenarios. For Henry Hub gas, management's updated gas price assumptions sit towards the top of our range until 2040 and then towards the middle until 2050. The positioning of bp's revised oil and gas forecasts within the range is broadly consistent with bp's positioning in the prior period range. We also noted other reputable third-party sources that set out or implied even higher prices under both 'well below 2°C goal' and '1.5°C ambition' scenarios, highlighting the large inherent uncertainty regarding transition pathways and the very wide range of potential price forecasts. Accordingly, we consider management's statement as set out above to be reasonable.</p> <p>By inquiry and analysis, we confirmed that the third-party oil and gas price forecasts used to develop our independent range are on a net producer price basis. Accordingly, we are satisfied management's judgement is reasonable that the potential impact of further emission costs being borne by bp is not expected to have a material impact on the group's oil and gas CGU carrying values.</p> <p>We reviewed the disclosures included in Note 1 to the accounts in respect of oil and gas price assumptions, including the sensitivity analysis presented therein. We observed that management's downside sensitivity, in which oil and gas prices are lower than the 'best estimate' in all future periods, is close to the bottom end of our range of third-party transition scenarios for Brent oil.</p> <p>Discount rates</p> <p>bp's post-tax nominal 8% discount rate used for impairment testing for oil and gas assets, was within the independent range calculated by our valuation specialists.</p> <p>We were also satisfied with the calculation of country risk premia. Accordingly, we are satisfied with the discount rates used in the impairment charge and impairment reversal testing.</p> <p>Reserves and resources</p> <p>We assessed the production forecasts used in the oil and gas CGU valuations that we tested to be reasonable and appropriately risked where applicable, for the purposes of management's impairment tests. We observed that in aggregate, management's production forecasts, as utilised in year-end oil and gas CGU impairment testing, are aligned with bp's best estimate of the future production of their existing oil and gas portfolio.</p>
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5.3 Decommissioning provisions – Notes 1 and 23 to the financial statements

<p>Key audit matter description</p>	<p>A decommissioning provision of \$12.3 billion is recorded in the financial statements as at 31 December 2025 (2024 \$11.8 billion). The estimation of decommissioning provisions is a highly judgemental area as it involves a number of key estimates related to the cost and timing of decommissioning, in particular inflation and discount rate assumptions.</p> <p>Management estimates that the average rate of forecast inflation applicable to the substantial majority of bp's decommissioning cost estimates is 1.5%, which is 0.5% lower than its estimated long term general inflation rate of 2%.</p> <p>The estimated undiscounted cost of the obligations and the timing of future payments are set out in Note 1 on page 176. Economic factors, future activities and the legislative environments that bp operates in are used to inform cost estimates, whereas the timing of decommissioning activities is dependent on cessation of production (CoP) dates, which are sensitive to changes in bp's price forecasts as price estimates determine economic cut off of oil and gas reserve estimates.</p> <p>bp maintained the discount rate used in calculating its decommissioning provisions at 4.5% as at 31 December 2025.</p> <p>Additionally, bp is exposed to decommissioning obligations that could revert back to the group in respect of historical divestments to third parties. Judgement is required to assess the potential risk of reversion and if applicable, the estimated exposure, for each historically divested asset. The risk of reversion could be elevated by the potential impact of the energy transition, in particular the potential for lower oil and gas prices in the longer term which could result in financial resilience concerns for some industry participants.</p> <p>Provisions for decommissioning refining assets, not generally recognised on the basis that the potential obligations cannot be measured given their indeterminate settlement dates, might need to be recognised if reductions in demand due to climate change curtail their operational lives. As disclosed in Note 1 on page 176 management concluded that, although obligations may arise if refineries cease manufacturing operations, they would only be recognised at the point when sufficient information became available to determine potential settlement dates. Accordingly, other than where a decision has been made to cease refining operations, no triggers for assessing the need to record a decommissioning provision have been identified.</p> <p>This matter was discussed by the Audit Committee on page 87.</p>
<p>How the scope of our audit responded to the key audit matter</p>	<p>Long term inflation rate</p> <ul style="list-style-type: none"> • We tested the relevant control related to the determination of the decommissioning specific inflation rate assumption. • We tested how management derived the decommissioning specific inflation rate assumption of 1.5%, and the evidence on which it is based, by gaining an understanding of the process used by management, testing management's calculations of the assumption, and evaluating the evidence relevant to management's assumption, both supporting and contradictory. • As the 1.5% decommissioning specific inflation rate assumption is determined by making an adjustment to management's 2.0% general long term inflation rate assumption, we evaluated the general long term inflation rate assumption used of 2.0%, comparing it against latest external market data. • We made inquiries and evaluated the competence, capability and objectivity of management's decommissioning experts who derived the decommissioning specific inflation rate. • We inspected analyst forecasts and reports in respect of the future decommissioning market and related costs for evidence of supporting and contradictory evidence, with particular focus on the future rig market. • We particularly considered the expectation that demand for oil and gas products and related activities will decrease, primarily in response to climate change and energy transition effects pivoting future energy industry investment and development activity towards renewable sources. We challenged and evaluated management's assessment of the impact this will have on the decommissioning market and the related inflation assumption. • We analysed historical trends of rig market rates against oil prices and historical inflation to evaluate management's assumption that the decommissioning inflation assumption does not inflate at the same rate as general inflation.

Cost and timing estimates

We tested the relevant controls over the year end decommissioning cost and timing assumptions used within management's decommissioning provision estimate.

We assessed the completeness and accuracy of the assets subject to decommissioning, including understanding the process to establish whether a legal or constructive obligation existed.

We gained an understanding of the process and technology used to model the provision, including the use of bp's decommissioning modelling platform by management's experts. We used data analytics to automatically extract and analyse cost estimate data to identify the key cost assumptions which the decommissioning model is most materially sensitive to.

We evaluated the reasonableness of changes in the key cost assumptions including rig rates, vessel rates, well plug and abandonment duration and non-productive time assumptions, with reference to internal and appropriate third-party data.

We assessed changes in assumptions for the estimated date of decommissioning and evaluated whether CoP dates used for decommissioning estimation are aligned with CoP assumptions in other areas, including PP&E impairment testing and oil and gas reserve estimation.

We assessed the accuracy of bp's disclosure of the estimated undiscounted cost of its obligations and the timing of future decommissioning payments.

Discount rates

We tested the relevant controls related to the determination of the discount rate assumption.

We assessed the reasonableness of management's methodology for determining the discount rate and recalculated the discount rate with reference to independent third party data, most notably US treasury bond yields.

Reversion risk

We obtained an understanding of bp's decommissioning reversion risk assessment process and tested relevant internal controls including those controls over the completeness and accuracy of the previously divested asset data.

We challenged and evaluated management's key judgements related to the decommissioning reversion risk and conclusions as to whether any additional provision should be recognised, or specific contingent liability disclosure made. We assessed the relevant internal and external evidence used in forming this judgement, including the financial health of the counterparty or counterparties in the ownership chain for the divested assets and the existence of any other pertinent factors which could indicate a higher probability of decommissioning obligations reverting to bp.

Potential decommissioning of refinery assets

We challenged and evaluated management's analysis which supported the judgement that no decommissioning provisions should be recognised in respect of refineries where there is ongoing activity and management has no current intention to cease these activities.

We have reviewed analysis undertaken by management, as well as third-party studies, of forecast demand for refined products in regions served by bp's refineries. Furthermore, we read external profitability benchmarking to assess the conclusion that the group's remaining refineries would likely remain operational for longer than many of their regional competitors, in the event of refining capacity reductions.

<p>Key observations</p>	<p>We concluded that the assumed inflation rate of 1.5% remains reasonable as a long-term inflation rate for decommissioning liabilities. With respect to the extent to which average future decommissioning cost inflation will differ from the general inflation rate, which is influenced by the demand and supply of rigs and other relevant services at the time future decommissioning occurs, we concluded that market forecasts support the assertion that demand for rigs will not increase in the long term as a result of the impact of the energy transition and therefore that inflation of rig costs will be limited.</p> <p>We concluded that the cost and timing assumptions used in the decommissioning provision calculation were reasonable and the assumptions are appropriately supported by industry data. The disclosure included on page 176 with respect to the estimated undiscounted cost of bp's decommissioning obligations and the timing of future decommissioning payments are consistent with these conclusions.</p> <p>Based on our audit procedures, we consider bp's 4.5% discount rate to be reasonable.</p> <p>No material additional decommissioning provisions have been made in respect of historical divestments where bp are exposed to decommissioning reversion risk as a result of the potential future bankruptcy of the current asset owner. Based on our review and challenge of management's assessment, we consider this judgement to be reasonable. We also consider the contingent liability disclosure to be reasonable.</p> <p>In respect of the group's refining assets, taking into consideration both the IEA demand forecasts and management's strategic plans for each of the group's refineries, we are satisfied that it is not currently possible for management to determine closure dates for the remaining operational refineries or estimate reliably a settlement date for any decommissioning obligations prior to a decision being made to cease refining operations. Accordingly, we have not identified any triggers that would require a decommissioning provision to be recorded.</p>
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5.4 Valuation of commodity financial derivatives, where fraud risks may arise in revenue recognition – Notes 1, 29 and 30 to the financial statements

<p>Key audit matter description</p>	<p>bp's supply, trading and shipping (ST&S) function is responsible for globally trading and risk managing the group's owned production as well as third party production. To discharge this responsibility, ST&S regularly executes commodity contracts, physically settled or otherwise, which are accounted for as a derivative and fair valued under IFRS 9. These contracts, therefore, result in unrealised gains/losses that are recognised on account of fair value movements in the associated derivative assets and liabilities.</p> <p>Determining the fair value of derivative assets and liabilities can be complex and subjective, particularly where the valuation is dependent on significant inputs which are not observable and are classified as level 3 in the fair value hierarchy set out in IFRS 13. This degree of subjectivity also makes such fair value estimates liable to potential fraud by management incorporating bias in the inputs used in determining fair values. Given the significant judgements, sensitivity to management assumptions, and the absolute value associated with these positions, we have identified a risk in respect of certain financial instruments where the valuation is dependent on significant unobservable inputs.</p> <p>Fair value measurements associated with unrealised commodity contracts are also impacted by the macroeconomic sentiment and outlook. In 2025, commodity markets continued to experience periods of volatility due to continuing uncertainty resulting from the planned energy transition, macro-economic factors such as inflation and interest rates, and disruptions in global supply due to geopolitical conflicts. In response to the volatility observed, we focused our audit efforts on the valuation of commodity derivatives and designed procedures to test for management bias.</p> <p>As at 31 December 2025, the group's total level 3 derivative financial assets were \$20.1 billion (2024 \$16.0 billion) and level 3 derivative financial liabilities were \$18.2 billion (2024 \$14.4 billion).</p> <p>This matter was discussed by the Audit Committee on page 88.</p>
<p>How the scope of our audit responded to the key audit matter</p>	<p>In response to the above, we analysed the population of these instruments to assess the level of unobservability of the inputs used in their valuation and then further disaggregated the population into different risk populations which in turn drove the nature, timing and extent of our audit procedures.</p> <p>Our use of advanced data analytics tools enabled automated visualisation of valuation data providing insights into trading positions and price curves. This allowed us to identify unusual trends, and focus our audit efforts on complex inputs, methodologies, and anomalies within the significant volume of derivative contracts, thereby enhancing the precision and the effectiveness of our valuation testing and our assessment of potential management bias.</p> <p>To address the complexities associated with auditing the valuation of instruments dependent on significant unobservable inputs, we included valuation specialists with significant quantitative and modelling expertise to assist in performing our audit procedures. Our valuation audit work included the following control and substantive procedures:</p> <ul style="list-style-type: none"> • We tested the group's valuation relevant controls including: <ul style="list-style-type: none"> – the model certification control, which is designed to review a model's theoretical soundness and the appropriateness of its valuation methodology; and – the independent price verification control, which is designed to review the appropriateness of valuation inputs that are not observable and are significant to the financial instrument's valuation. • We performed valuation testing procedures at interim and year-end balance sheet dates, including: <ul style="list-style-type: none"> – evaluating management's valuation methodologies against standard valuation practice and analysing whether a consistent framework is applied across the business period over period; – engaging our valuation specialists to challenge models, develop fair value estimates and evaluate consistency in management's modelling and input assumptions throughout the year; – comparing management's input assumptions against the expected assumptions of other market participants and observable market data; – independently validating price points on pricing curves; and – analysing whether there was any indication of management bias through evaluating the distribution of valuation differences where relevant.
<p>Key observations</p>	<p>Based on the evaluation of the results of the procedures noted above, we concluded that management's valuations relating to commodity derivatives were appropriate and we did not identify evidence of management bias in the valuation estimates or accounting entries that we tested.</p>

5.5 Management override of controls (potentially impacting all financial statement accounts)

Key audit matter description	<p>We conducted an assessment of the fraud risks arising from management override of controls by considering potential areas where the group's financial statements could be manipulated. In performing this assessment, we considered pressures or incentives to achieve certain measures due to the remuneration arrangements of people in Financial Reporting Oversight Roles (FRORs), including management and senior executives, as well as other incentives which could exist in light of bp's share buyback commitments communicated to its shareholders.</p> <p>Our considerations included the potential for:</p> <ul style="list-style-type: none">• inappropriate accounting estimates and judgements• the posting of fictitious or fraudulent journal entries or• inappropriate accounting for significant transactions that are outside the normal course of business for the entity. <p>During the year certain deficiencies were identified though we and management both identified mitigating controls to address the risk associated with the deficiencies. These included analytical reviews, controls over closing balances, period-end analytical review controls and certain automated business controls.</p> <p>This area had a significant bearing again this year on the allocation of audit resources and has been discussed with the Audit Committee throughout the year. Accordingly, we identified this as a key audit matter.</p>
How the scope of our audit responded to the key audit matter	<p>We tested the mitigating controls to respond to the risk of fraudulent journal entries. In addition, we:</p> <ul style="list-style-type: none">• made inquiries of individuals with different levels of responsibility involved in the financial reporting process about inappropriate or unusual activity relating to the processing of journal entries and other adjustments;• identified and tested relevant entity-level controls, in particular those related to the bp Code of Conduct, whistleblowing (bp OpenTalk) and controls monitoring financial reporting processes and financial results;• made inquiries of management and others within bp as appropriate, who deal with allegations, if any, of fraud raised by employees or other parties;• used our data analytics tools to identify and select journal entries and other adjustments that exhibit potential fraud characteristics for testing; and• tested journal entries and other adjustments recorded in the general ledger throughout the period, with a particular focus on adjustments that occur late in the financial close process. <p>We assessed accounting estimates for bias. A number of the most significant estimates are covered by the other Key Audit Matters set out above. This assessment included:</p> <ul style="list-style-type: none">• evaluating whether the judgements and decisions made by management in making the accounting estimates included in the financial statements, even if they are individually reasonable, indicate a possible bias on the part of bp's management that may represent a risk of material misstatement due to fraud; and• performing a retrospective analysis of management judgements and assumptions related to significant accounting estimates reflected in the financial statements of the prior year. <p>We considered whether there were any significant transactions that are outside the normal course of business, or that otherwise appear to be unusual due to their nature, timing or size.</p> <p>The risks and responses to the revenue recognition risk within the supply, trading and shipping function are set out on page 141.</p>
Key observations	<p>We were able to rely on the mitigating controls tested.</p> <p>Our testing of journal entries and other adjustments, selected through the use of our data analytics tools, did not identify any inappropriate items.</p> <p>We did not identify evidence of overall bias or any significant transactions that are outside the normal course of business for which the business rationale (or the lack thereof) of the transaction suggested that it may have been entered into to engage in fraudulent financial reporting or to conceal misappropriation of assets.</p>

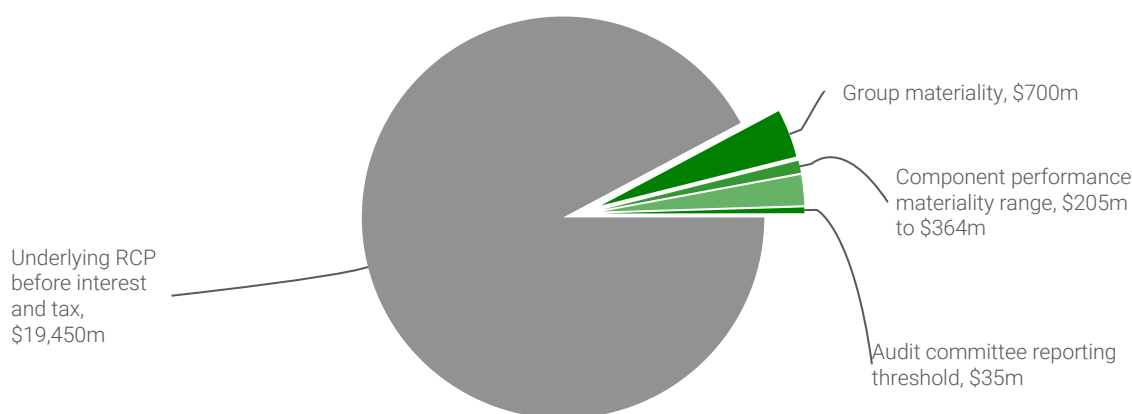
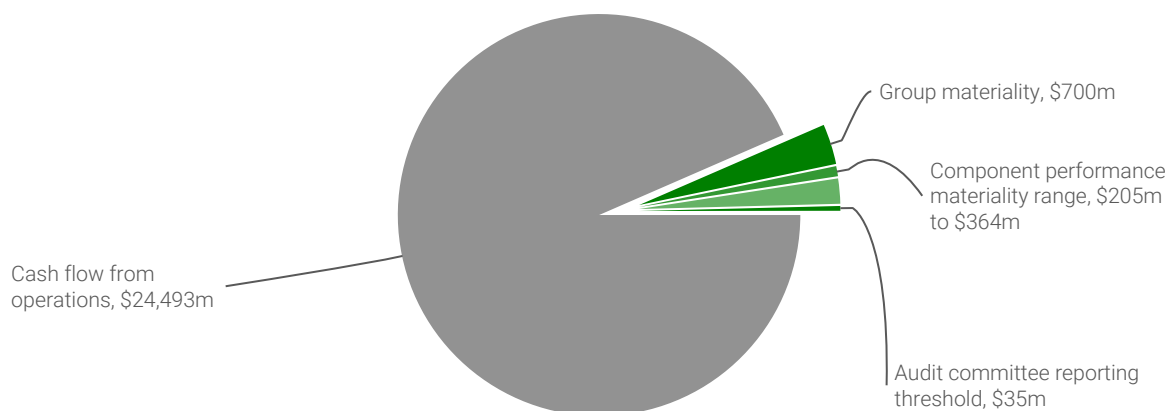
6. Our application of materiality

6.1 Materiality

We define materiality as the magnitude of misstatement in the financial statements that makes it probable that the economic decisions of a reasonably knowledgeable person would be changed or influenced. We use materiality both in planning the scope of our audit work and in evaluating the results of our work.

Based on our professional judgement, we determined materiality for the financial statements as a whole as follows:

	Group financial statements	Parent company financial statements
Materiality	<p>In 2025 we set materiality for both the group and parent company at \$700 million.</p> <p>In 2024, we used a materiality of \$800 million for both the group and parent company. The decrease in materiality is due to the downturn in the group's performance compared with prior year.</p>	
Basis for determining materiality	<p>Changing macroeconomic conditions, one-off transactions and strategic decisions had a significant impact on the group's profit before tax in 2025. We therefore determined that it is appropriate to use the benchmarks of most relevance to investors, being cash flow from operations and underlying replacement cost profit before interest and tax.</p> <p>Materiality was determined to be \$700 million (2024 \$800 million), which is 2.9% of cash flow from operations (2024 2.9%) and 3.6% of underlying replacement cost profit before tax (2024 3.9%).</p>	<p>We determined materiality for our audit of the standalone parent using 0.6% (2024 0.6%) of net assets.</p>
Rationale for the benchmark applied	<p>We conducted an assessment of which line items are the most important to investors and analysts by reading analyst reports and bp's communications to shareholders and lenders, as well as the communications of peer companies.</p> <p>Based on our review of analysts' reports, all analysts identified one or more cashflow metrics as a key operating metric, particularly net cash flow from operations. Also, based on our assessment of the latest results announcement Q&As, the focus of the investors has been on cash flow generation and the strength of the balance sheet, particularly from a net debt perspective given the current underlying performance of the group. We therefore focused on cash flow from operations in our determination of materiality for the current year.</p> <p>We further note that the alternative performance measure underlying replacement cost profit before interest and tax is one of the key metrics communicated by management in bp's results announcements and therefore is considered to be an appropriate benchmark.</p>	<p>The materiality determined for the standalone parent company is based on net assets as the company is non-trading and operates primarily as a holding company. We believe the net asset position is the most appropriate benchmark to use.</p>



6.2 Performance materiality

We set performance materiality at a level lower than materiality to reduce the probability that, in aggregate, uncorrected and undetected misstatements exceed the materiality for the financial statements as a whole.

	Group financial statements	Parent company financial statements
Performance materiality	Group and parent company performance materiality was set at 65% of materiality for the 2025 audit (2024 65% of materiality).	
Basis and rationale for determining performance materiality	Consistent with the prior year, performance materiality of 65% reflects the overall quality of the control environment, the magnitude of misstatements identified in the current and prior years, as well as the fact that management is generally willing to correct any such misstatements.	

6.3 Error reporting threshold

We agreed with the Audit Committee that we would report to the committee all audit differences in excess of \$35 million (2024 \$40 million), as well as differences below that threshold that, in our view, warranted reporting on qualitative grounds. We also report to the Audit Committee on disclosure matters that we identified when assessing the overall presentation of the financial statements.

7. An overview of the scope of our audit

7.1 Identification and scoping of components

As a result of the highly disaggregated nature of the group, with operations in over 80 countries through approximately 970 cons units, a significant portion of our audit planning effort was so that the scope of our work was appropriate in addressing the identified risks of material misstatement. We determined our components at the cons unit level as these serve as the lowest uniformly applied level of aggregation.

The factors that we considered when assessing the scope of the bp audit, and the level of work to be performed included the following:

- The determination of significance of an account balance and risks of material misstatement related to it, history of unusual or complex transactions, identification of significant audit issues or the potential for, or a history of, material misstatements. We used a bespoke scoping tool, developed using the company's general ledger data, to provide a preliminary scoping analysis and identify any unusual trends and items in untested populations.

- The effectiveness of the control environment and monitoring activities, including entity-level controls.
- The findings, observations and audit differences that we noted as a result of our 2024 audit engagement.

Our audit approach was generally to place reliance on management’s controls over financial reporting.

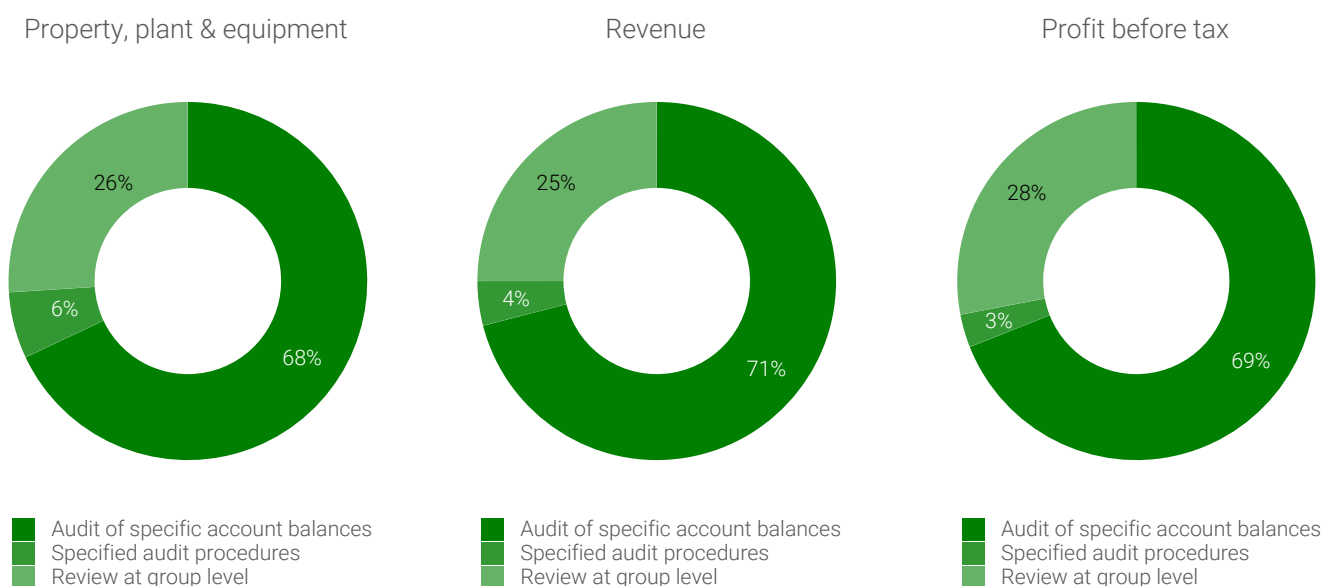
In order to obtain sufficient, appropriate audit evidence for the purposes of our audit of the financial statements, the group engagement team and component teams performed audits of one or more classes of transactions account balances and disclosures on 135 (2024 153) reporting cons units covering UK, US, Australia, Azerbaijan, Germany, Trinidad and Tobago, Mauritania & Senegal, Indonesia, Egypt, India and Abu Dhabi, with specific audit procedures performed at an additional 25 cons units (2024 25). Our component performance materiality range is \$205 million to \$364 million (2024 \$182 million to \$416 million).

In addition to the work performed at a component level, the group engagement team performed testing on the consolidation process.

The remaining cons units are not significant individually and include many small, low risk components and balances. On average, they each represent 0.03% of group revenue (2024 0.04%), 0.03% of property, plant and equipment (2024 0.04%) and 0.03% of profit before tax (2024 0.04%).

In our assessment of the residual balances not covered by the above procedures, we have considered the risk that there could be undetected and uncorrected misstatements that are material in the aggregate within the large number of geographically dispersed businesses, in particular within the C&P segment. This assessment included use of our analytic tools to interrogate data, preparation of trend analysis and comparison of business performance to market benchmark prices. We also tested management’s group-wide controls across a range of locations and segments. We concluded that through this additional risk assessment, we have reduced the audit risk of such misstatements arising to a sufficiently low level.

Our audit coverage of ‘Property, plant and equipment’, ‘Revenue’ and ‘Profit before tax’ is 74% (2024 73%), 75% (2024 69%) and 72% (2024 72%) respectively.



7.2 Our consideration of the control environment

Our audit approach was generally to place reliance on management’s relevant controls over all business cycles affecting in scope financial statement line items. We tested these controls through a combination of tests of inquiry, observation, inspection and re-performance.

In limited situations where we were not able to take a controls reliance approach due to controls being deficient and there not being sufficient mitigating or alternative controls we could rely on instead, we adopted a non-controls reliance approach. All control deficiencies which we considered to be significant were communicated to the Audit Committee. All other deficiencies were communicated to management. For all deficiencies identified we considered the impact and updated our audit plan accordingly.

The group’s financial systems environment is complex, with 103 separate IT systems scoped as being relevant to the audit for the following key locations (UK, US, Germany, Azerbaijan and Australia) as well as other minor locations. These systems are all directly or indirectly relevant to the entity’s financial reporting process.

We planned to rely on the General IT Controls (‘GITCs’) associated with these systems, and having tested controls over access security, change management, data centre operations and network operations, were able to do so.

7.3 Working with other auditors

The group audit team is responsible for the scope and direction of the audit process and providing direct oversight, review, and coordination of our component audit teams. We interacted regularly with the component Deloitte teams during each stage of the audit and reviewed key working papers. We maintained continuous and open dialogue with our component teams in addition to holding formal meetings quarterly to ensure that we were fully aware of their progress and results of their procedures.

Consistent with prior year, the senior statutory auditor and other group audit partners and staff conducted visits to meet with the component teams responsible for the audits of specified account balances during the year. These visits included attending planning meetings, discussing the audit approach including the risk assessments and any issues arising from the component team’s work, meetings with local management, and reviewing key audit working papers on higher and significant-risk areas to drive a consistent and high-quality audit. In addition, a global audit planning meeting was held in London for three days in July led by the senior statutory auditor and involving the group audit team, partners and

staff from all full scope component teams, audit teams responsible for testing at key Finance Business & Technology (FBT) locations and senior management from bp.

8. Other information

The other information comprises the information included in the annual report, other than the financial statements and our auditor's report thereon. The directors are responsible for the other information contained within the annual report.

We have nothing to report in this regard.

Our opinion on the financial statements does not cover the other information and, except to the extent otherwise explicitly stated in our report, we do not express any form of assurance conclusion thereon.

Our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the course of the audit, or otherwise appears to be materially misstated.

If we identify such material inconsistencies or apparent material misstatements, we are required to determine whether this gives rise to a material misstatement in the financial statements themselves. If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact.

9. Responsibilities of directors

As explained more fully in the statement of directors' responsibilities, the directors are responsible for the preparation of the financial statements and for being satisfied that they give a true and fair view, and for such internal control as the directors determine is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, the directors are responsible for assessing the group's and the parent company's ability to continue as a going concern, disclosing as applicable matters related to going concern and using the going concern basis of accounting unless the directors either intend to liquidate the group or the parent company or to cease operations, or have no realistic alternative but to do so.

10. Auditor's responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with ISAs (UK) will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

A further description of our responsibilities for the audit of the financial statements is located on the FRC's website at: frc.org.uk/auditorsresponsibilities. This description forms part of our auditor's report.

11. Extent to which the audit was considered capable of detecting irregularities, including fraud

Irregularities, including fraud, are instances of non-compliance with laws and regulations. We design procedures in line with our responsibilities, outlined above, to detect material misstatements in respect of irregularities, including fraud. The extent to which our procedures are capable of detecting irregularities, including fraud is detailed below.

11.1 Identifying and assessing potential risks related to irregularities

In identifying and assessing risks of material misstatement in respect of irregularities, including fraud and non-compliance with laws and regulations, we considered the following:

- our meetings throughout the year with the Group Head of Ethics and Compliance and reviews of bp's internal ethics and compliance reporting summaries, including those concerning investigations;
- enquiries of management, internal audit, and the Audit Committee, including obtaining and reviewing supporting documentation, concerning the group's policies and procedures relating to:
 - identifying, evaluating and complying with laws and regulations and whether they were aware of any instances of non-compliance;
 - detecting and responding to the risks of fraud and whether they have knowledge of any actual, suspected or alleged fraud; and
 - the internal controls established to mitigate risks related to fraud or non-compliance with laws and regulations;
- review of the terms of reference of the Fraud Governance Board set up by management to support the creation and delivery of the Group Fraud Risk Strategy, periodically monitor the threat outlook and review the risk appetite;
- review of the Fraud Governance Board's meeting minutes and its fraud risk assessment;
- the group's remuneration policies, key drivers for remuneration and bonus levels; and
- discussions among the engagement team regarding how and where fraud might occur in the financial statements and any potential indicators of fraud. The engagement team includes audit partners and staff who have extensive experience of working with companies in the same sectors as bp operates, and this experience was relevant to the discussion about where fraud risks may arise. The discussions also involved fraud specialists who advised the engagement team of fraud schemes that had arisen in similar sectors and industries, and they participated in the initial fraud risk assessment discussions.

In common with all audits under ISAs (UK), we are also required to perform specific procedures to respond to the risk of management override.

We also obtained an understanding of the legal and regulatory frameworks that the group operates in, focusing on provisions of those laws and regulations that had a direct effect on the determination of material amounts and disclosures in the financial statements. The key laws and regulations we considered in this context included the UK Companies Act, UK Corporate Governance Code, US Securities Exchange Act 1934 and relevant SEC regulations, as well as laws and regulations prevailing in each country in which we identified a full-scope component.

In addition, we considered provisions of other laws and regulations that do not have a direct effect on the financial statements but compliance with which may be fundamental to the group's ability to operate or to avoid a material penalty. These included the group's operating licences and environmental regulations.

11.2 Audit response to risks identified

As a result of performing the above, we did not identify any key audit matters related to the potential risk of non-compliance with laws and regulations. We did identify two key audit matters relating to fraud risks, as described above, being the valuation of commodity financial derivatives, and management override of controls. The key audit matters section of our report explains the matters in more detail and also describes the specific procedures we performed in response to those key audit matters.

In addition to the above, procedures to respond to risks identified included the following:

- reviewing the financial statement disclosures and testing to supporting documentation to assess compliance with provisions of relevant laws and regulations described as having a direct effect on the financial statements;
- enquiring of management, the Audit Committee and in-house legal counsel concerning actual and potential litigation and claims;
- obtaining confirmations from external legal counsel concerning open litigation and claims;
- performing analytical procedures to identify any unusual or unexpected relationships that may indicate risks of material misstatement due to fraud; and
- reading minutes of meetings of those charged with governance, reviewing internal audit reports and reviewing correspondence with HMRC and the IRS.

We also communicated relevant identified laws and regulations and potential fraud risks to all engagement team members including internal specialists and component audit teams and remained alert to any indications of fraud or non-compliance with laws and regulations throughout the audit.

Report on other legal and regulatory requirements

12. Opinions on other matters prescribed by the Companies Act 2006

In our opinion the part of the directors' remuneration report to be audited has been properly prepared in accordance with the Companies Act 2006.

In our opinion, based on the work undertaken in the course of the audit:

- The information given in the strategic report and the directors' report for the financial year for which the financial statements are prepared is consistent with the financial statements.
- The strategic report and the directors' report have been prepared in accordance with applicable legal requirements.

In the light of the knowledge and understanding of the group and the parent company and their environment obtained in the course of the audit, we have not identified any material misstatements in the strategic report or the directors' report.

13. Corporate Governance Statement

The Listing Rules require us to review the directors' statement in relation to going concern, longer-term viability and that part of the Corporate Governance Statement relating to the group's compliance with the provisions of the UK Corporate Governance Code specified for our review.

Based on the work undertaken as part of our audit, we have concluded that each of the following elements of the Corporate Governance Statement is materially consistent with the financial statements and our knowledge obtained during the audit:

- the directors' statement with regards to the appropriateness of adopting the going concern basis of accounting and any material uncertainties identified set out on page 128.
- the directors' explanation as to its assessment of the group's prospects, the period this assessment covers and why the period is appropriate set out on page 128.
- the directors' statement on fair, balanced and understandable set out on page 128.
- the board's confirmation that it has carried out a robust assessment of the emerging and principal risks set out on pages 127-128.
- the section of the annual report that describes the review of effectiveness of risk management and internal control systems set out on pages 127-128 and
- the section describing the work of the Audit Committee set out on pages 84-88.

14. Matters on which we are required to report by exception

14.1 Adequacy of explanations received and accounting records

Under the Companies Act 2006 we are required to report to you if, in our opinion:

- we have not received all the information and explanations we require for our audit or
- adequate accounting records have not been kept by the parent company, or returns adequate for our audit have not been received from branches not visited by us or
- the parent company financial statements are not in agreement with the accounting records and returns.

We have nothing to report in respect of these matters.

14.2 Directors' remuneration

Under the Companies Act 2006 we are also required to report if in our opinion certain disclosures of directors' remuneration have not been made or the part of the directors' remuneration report to be audited is not in agreement with the accounting records and returns.

We have nothing to report in respect of these matters.

15. Other matters which we are required to address

15.1 Auditor tenure

The board appointed Deloitte as the company's auditor with effect from 29 March 2018 to fill the vacancy arising from the resignation of the previous auditor. On 17 April 2025, shareholders resolved at the annual general meeting to reappoint Deloitte as auditor from the conclusion of the meeting until the conclusion of the annual general meeting to be held in 2026 and authorized the directors to set the audit fees.

The first accounting period we audited was the 12 month period ended 31 December 2018. The period of total uninterrupted engagement including previous renewals and reappointments of the firm is 8 years, covering the years ending 31 December 2018 to 31 December 2025.

15.2 Consistency of the audit report with the additional report to the Audit Committee

Our audit opinion is consistent with the additional report to the Audit Committee we are required to provide in accordance with ISAs (UK).

16. Use of our report

This report is made solely to the company's members, as a body, in accordance with Chapter 3 of Part 16 of the Companies Act 2006. Our audit work has been undertaken so that we might state to the company's members those matters we are required to state to them in an auditor's report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the company and the company's members as a body, for our audit work, for this report, or for the opinions we have formed.

In due course, as required by the Financial Conduct Authority (FCA) Disclosure Guidance and Transparency Rule (DTR) 4.1.15R – DTR 4.1.18R, these financial statements will form part of the Electronic Format Annual Financial Report filed on the National Storage Mechanism of the FCA in accordance with DTR 4.1.15R – DTR 4.1.18R. This auditor's report provides no assurance over whether the Electronic Format Annual Financial Report has been prepared in compliance with DTR 4.1.15R – DTR 4.1.18R.

Judith Tacon FCA (Senior statutory auditor)
For and on behalf of Deloitte LLP
Statutory Auditor
London, United Kingdom
6 March 2026

Report of Independent Registered Public Accounting Firm To the shareholders and board of directors of BP p.l.c.

Opinion on the financial statements

We have audited the accompanying consolidated group balance sheets of BP p.l.c. and subsidiaries (together 'bp' or 'the group') as at 31 December 2025 and 2024, the related consolidated group income statements, group statements of comprehensive income, group statements of changes in equity and group cash flow statements, for each of the three years in the period ended 31 December 2025, and the related notes (collectively referred to as the 'financial statements'). In our opinion, the financial statements present fairly, in all material respects, the financial position of the group as at 31 December 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended 31 December 2025, in accordance with United Kingdom adopted international accounting standards and IFRS Accounting Standards as issued by the International Accounting Standards Board (IASB) and as adopted by the European Union (EU).

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), bp's internal control over financial reporting as of 31 December 2025, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated 6 March 2026 expressed an unqualified opinion on bp's internal control over financial reporting.

Basis for opinion

These financial statements are the responsibility of bp's management. Our responsibility is to express an opinion on bp's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to bp in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current-period audit of the financial statements that were communicated or required to be communicated to the audit committee and that (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

1. Impairment of upstream oil and gas property, plant and equipment (PP&E) assets – Notes 1, 4 and 12 to the financial statements

Critical Audit Matter Description

The group balance sheet as at 31 December 2025 includes PP&E, of which \$55 billion is oil and gas properties.

Management's best estimate oil and gas price assumptions for value-in-use impairment tests were revised in 2025 as set out in Note 1 on pages 168-169.

Management has also determined bp's 'best estimate' discount rate assumptions, as set out in Note 1 on page 168. bp's post-tax discount rate used for impairment testing for oil and gas assets in 2025 remained unchanged from prior year at 8%. Pre-tax discount rates applied in impairment tests were revised in some regions to reflect changes in local tax rates and country risk premiums. Reserves estimates for all oil and gas fields were also reviewed and updated where necessary at year-end.

As required by International Accounting Standard (IAS) 36 'Impairment of Assets', management performed a review of all oil and gas cash generating units (CGUs) for indicators of impairment and impairment reversal as at 31 December 2025. As a result of management identifying impairment indicators during 2025, \$1 billion of oil and gas CGU net impairment charges were recognised, principally due to an increase in certain capital expenditure forecasts and operating expenditure forecasts and certain reserves write downs.

We identified three key management estimates in management's determination of the level of impairment charge and/or impairment reversal. These are:

Oil and gas prices – bp's oil and gas price assumptions have a significant impact on many CGU impairment assessments performed across the OP&O and G&LCE segments and are inherently uncertain. The estimation of future prices is subject to increased uncertainty given climate change, the global energy transition, macro-economic factors and disruption in global supply due to ongoing geo-political conflicts. There is a risk that management do not forecast reasonable 'best estimate' oil and gas price forecasts when assessing CGUs for impairment charge and/or impairment reversal, leading to material misstatements. These price assumptions are highly judgmental and are pervasive inputs to bp's oil and gas CGU valuation. There is also a risk that management's oil and gas price related disclosures are not reasonable.

Discount rates – Given the long timeframes involved, certain CGU impairment assessments are sensitive to the discount rate applied. Discount rates should reflect the return required by the market and the risks inherent in the cash flows being discounted. There is a risk that management does not assume reasonable discount rates, adjusted as applicable for country risks and relevant tax rates, leading to material misstatements. Determining a reasonable discount rate is highly judgmental and, consistent with price assumptions above, the discount rate assumption is also a pervasive input across bp's oil and gas CGU valuations, before adjustments for asset specific risks and tax rates.

Reserves and resources estimates – A key input to certain CGU impairment assessments is the oil and gas production forecast, which is based on underlying reserves estimates and field specific development assumptions. Certain CGU production forecasts include specific risk adjusted resource volumes, in addition to proven and/or probable reserves estimates, that are inherently less certain than reserves; assumptions related to these volumes can be particularly judgemental. There is a risk that material misstatements could arise from unreasonable production forecasts for individually material CGUs and/or from the aggregation of systematic flaws in bp's reserves and resources estimation policies across the OP&O and G&LCE segments.

We identified certain individual CGUs which we determined would be most at risk of material impairment charges as a result of a reasonably possible change in the oil and gas price assumptions. This population includes previously impaired assets which are also at risk of material impairment reversal resulting from potential oil and gas price assumption changes. We identified that a subset of these CGUs was also individually materially sensitive to the discount rate assumption. Further information regarding these sensitivities is given in Note 1 on page 169. Impairment charge and/or impairment reversal assessments of upstream oil and gas PP&E assets remain a critical audit matter because recoverable values are reliant on forecast assumptions such as oil and gas prices, discount rates and reserves estimates, which are inherently judgemental and complex for management to estimate and challenging to audit. Additionally, the magnitude of the potential misstatement risk remains material to the group.

How the Critical Audit Matter was addressed in the Audit

We tested relevant internal controls over the estimation of oil and gas prices, discount rates, and reserve and resources estimates, as well as relevant internal controls over the performance of the impairment charge and/or impairment reversal assessments where we identified audit risks. In addition, we conducted the following substantive procedures.

Oil and gas prices

- We independently developed a reasonable range of forecasts based on external data obtained, against which we compared management's oil and gas price assumptions in order to challenge whether they are reasonable.
- In developing this range, we obtained a variety of reputable and reliable third-party forecasts, peer information and other relevant market data.
- In challenging and evaluating management's price assumptions, we considered the extent to which they and each of the forecast pricing scenarios obtained from third parties reflect the impact of lower oil and gas demand due to climate change and the energy transition.
- The 2015 Conference of the Parties (CoP) 21 Paris Agreement goals of 'holding the increase in the global average temperature to well below 2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels' was reaffirmed at CoP 30 in Brazil during November 2025. We specifically analysed third party forecasts stated, or interpreted by us, as being consistent with scenarios achieving the Paris 'well below 2°C goal' and/or '1.5°C ambition' and evaluated whether they presented contradictory audit evidence.
- We assessed management's disclosures in Note 1, including the sensitivity of forecast revenue cash inflows to lower oil and gas prices, and how climate change and the energy transition, potential future emissions costs and/or reduced demand scenarios may impact bp to a greater extent than currently anticipated in bp's value-in-use estimates for oil and gas CGUs.

Discount rates

- We independently evaluated bp's discount rates used in impairment tests with input from our valuation specialists, against relevant third-party market and peer data.
- When performing procedures over specific assets, we assessed whether specific country risks and tax adjustments were reasonably reflected in bp's discount rates.
- We challenged and evaluated management's disclosures in Note 1, including in relation to the sensitivity of discount rate assumptions.

Reserves and resources estimates

Using the outputs from our data analytics tools which we used to visualise reserves and resources volumes, and with the assistance of our oil and gas reserves specialists, we:

- assessed bp's reserves and resources estimation methods and policies for reasonableness;
- assessed how these policies had been applied to a sample of bp's reserves and resources estimates;
- read and evaluated a sample of reports provided by management's external reserves experts and assessed the scope of work and findings of these third parties;
- assessed the competence, capability and objectivity of bp's internal and external reserve experts, through understanding their relevant professional qualifications and experience;
- assessed whether management's production forecasts are consistent overall with bp's strategy;
- compared the production forecasts used in the impairment tests with management's approved reserves and resources estimates; and
- performed a retrospective assessment in order to assess management's ability to accurately estimate reserves and resources and to check for indications of estimation bias over time.

2. Decommissioning provisions – Notes 1 and 23 to the financial statements

Critical Audit Matter Description

A decommissioning provision of \$12.3 billion is recorded in the financial statements as at 31 December 2025. The estimation of decommissioning provisions is a highly judgemental area as it involves a number of key estimates related to the cost and timing of decommissioning, in particular inflation and discount rate assumptions.

Management estimates that the average rate of forecast inflation applicable to the substantial majority of bp's decommissioning cost estimates is 1.5%, which is 0.5% lower than its estimated long term general inflation rate of 2%.

The estimated undiscounted cost of the obligations and the timing of future payments are set out in Note 1 on page 176. Economic factors, future activities and the legislative environments that bp operates in are used to inform cost estimates, whereas the timing of decommissioning activities is dependent on cessation of production (CoP) dates, which are sensitive to changes in bp's price forecasts as price estimates determine economic cut off of oil and gas reserve estimates.

bp maintained the discount rate used in calculating its decommissioning provisions at 4.5% as at 31 December 2025.

How the Critical Audit Matter was addressed in the Audit

Long term inflation rate

- We tested the relevant control related to the determination of the decommissioning specific inflation rate assumption.
- We tested how management derived the decommissioning specific inflation rate assumption of 1.5%, and the evidence on which it is based, by gaining an understanding of the process used by management, testing management's calculations of the assumption, and evaluating the evidence relevant to management's assumption, both supporting and contradictory.
- As the 1.5% decommissioning specific inflation rate assumption is determined by making an adjustment to management's 2.0% general long term inflation rate assumption, we evaluated the general long term inflation rate assumption used of 2.0%, comparing it against latest external market data.
- We made inquiries and evaluated the competence, capability and objectivity of management's decommissioning experts who derived the decommissioning specific inflation rate.
- We inspected analyst forecasts and reports in respect of the future decommissioning market and related costs for evidence of supporting and contradictory evidence, with particular focus on the future rig market.
- We particularly considered the expectation that demand for oil and gas products and related activities will decrease, primarily in response to climate change and energy transition effects pivoting future energy industry investment and development activity towards renewable sources. We challenged and evaluated management's assessment of the impact this will have on the decommissioning market and the related inflation assumption.
- We analysed historical trends of rig market rates against oil prices and historical inflation to evaluate management's assumption that the decommissioning inflation assumption does not inflate at the same rate as general inflation.

Cost and timing estimates

- We tested the relevant controls over the year end decommissioning cost and timing assumptions used within management's decommissioning provision estimate.
- We assessed the completeness and accuracy of the assets subject to decommissioning, including understanding the process to establish whether a legal or constructive obligation existed.
- We gained an understanding of the process and technology used to model the provision, including the use of bp's decommissioning modelling platform by management's experts. We used data analytics to automatically extract and analyse cost estimate data to identify the key cost assumptions which the decommissioning model is most materially sensitive to.
- We evaluated the reasonableness of changes in the key cost assumptions including rig rates, vessel rates, well plug and abandonment duration and non-productive time assumptions, with reference to internal and appropriate third-party data.
- We assessed changes in assumptions for the estimated date of decommissioning and evaluated whether CoP dates used for decommissioning estimation are aligned with CoP assumptions in other areas, including PP&E impairment testing and oil and gas reserve estimation.
- We assessed the accuracy of bp's disclosure of the estimated undiscounted cost of its obligations and the timing of future decommissioning payments.

Discount rates

- We tested the relevant controls related to the determination of the discount rate assumption.
- We assessed the reasonableness of management's methodology for determining the discount rate and recalculated the discount rate with reference to independent third-party data, most notably US treasury bond yields.

3. Valuation of commodity financial derivatives - Notes 1, 29 and 30 to the financial statements

Critical Audit Matter Description

bp's supply, trading and shipping (ST&S) function is responsible for globally trading and risk managing the group's owned production as well as third party production. To discharge this responsibility, ST&S regularly executes commodity contracts, physically settled or otherwise, which are accounted for as a derivative and fair valued under IFRS 9. These contracts, therefore, result in unrealised gains/losses that are recognised on account of fair value movements in the associated derivative assets and liabilities.

Determining the fair value of derivative assets and liabilities can be complex and subjective, particularly where the valuation is dependent on significant inputs which are not observable and are classified as level 3 in the fair value hierarchy set out in IFRS 13. This degree of subjectivity also makes such fair value estimates liable to potential fraud by management incorporating bias in the inputs used in determining fair values. Given the significant judgements, sensitivity to management assumptions, and the absolute value associated with these positions, we have identified a risk in respect of certain financial instruments where the valuation is dependent on significant unobservable inputs.

Fair value measurements associated with unrealised commodity contracts are also impacted by the macroeconomic sentiment and outlook. In 2025, commodity markets continued to experience periods of volatility due to continuing uncertainty resulting from the planned energy transition, macro-economic factors such as inflation and interest rates, and disruptions in global supply due to geopolitical conflicts. In response to the volatility observed, we focused our audit efforts on the valuation of commodity derivatives and designed procedures to test for management bias.

As at 31 December 2025, the group's total level 3 derivative financial assets were \$20.1 billion and level 3 derivative financial liabilities were \$18.2 billion.

How the Critical Audit Matter was addressed in the Audit

In response to the above, we analysed the population of these instruments to assess the level of unobservability of the inputs used in their valuation and then further disaggregated the population into different risk populations which in turn drove the nature, timing and extent of our audit procedures.

Our use of advanced data analytics tools enabled automated visualisation of valuation data providing insights into trading positions and price curves. This allowed us to identify unusual trends, and focus our audit efforts on complex inputs, methodologies, and anomalies within the significant volume of derivative contracts, thereby enhancing the precision and the effectiveness of our valuation testing and our assessment of potential management bias.

To address the complexities associated with auditing the valuation of instruments dependent on significant unobservable inputs, we included valuation specialists with significant quantitative and modelling expertise to assist in performing our audit procedures. Our valuation audit work included the following control and substantive procedures:

- We tested the group's valuation relevant controls including:
 - the model certification control, which is designed to review a model's theoretical soundness and the appropriateness of its valuation methodology; and
 - the independent price verification control, which is designed to review the appropriateness of valuation inputs that are not observable and are significant to the financial instrument's valuation.
- We performed valuation testing procedures at interim and year-end balance sheet dates, including:
 - evaluating management's valuation methodologies against standard valuation practice and analysing whether a consistent framework is applied across the business period over period;
 - engaging our valuation specialists to challenge models, develop fair value estimates and evaluate consistency in management's modelling and input assumptions throughout the year;
 - comparing management's input assumptions against the expected assumptions of other market participants and observable market data;
 - independently validating price points on pricing curves; and
 - analysing whether there was any indication of management bias through evaluating the distribution of valuation differences where relevant.

4. Impairment of E&A assets, goodwill associated with the transition businesses and refinery PP&E as a consequence, among other things, of climate change and the energy transition – Notes 1, 4, 8, 14 and 15 to the financial statements

Critical Audit Matter Description

Intangible Assets

The recoverability of certain of the group's \$4.0 billion total exploration and appraisal (E&A) assets capitalised as at 31 December 2025 is potentially exposed to climate change and the global energy transition and macroeconomic risk factors (see Note 15). This is because a greater number of E&A projects may not proceed as a consequence of the energy transition or lower forecast future oil and gas prices. The determination of whether and when E&A costs should be written off, impaired, or retained on the balance sheet as E&A assets, remains complex and continues to require significant management judgement.

Goodwill

The carrying value of goodwill associated with the transition businesses, specifically Archaea Energy and Lightsource bp, may no longer be recoverable due to increases in cost or lower forecast production or development rate reflecting the slowdown in the pace of energy transition adversely impacting the value of these projects, and impacting investment decisions. Management performed an annual impairment test (which includes judgements in relation to forecast period, development rate, long term growth rate, discount rate, developer margin, capital expenditure and renewable natural gas revenue prices) to assess the recoverability of the goodwill, resulting in an impairment of \$2.0 billion as disclosed in Note 14.

PP&E

The carrying value of bp's refining assets within PP&E may no longer be recoverable due to changes in supply and demand which arise among other things as a consequence of climate change and the energy transition. Management performed an assessment to identify potential impairment indicators in respect of the refinery portfolio. This considered all potential impairment indicators, including refining margin forecast, which could be impacted by changes in supply and demand due to climate change and the energy transition. As a result of management's impairment assessment, management identified indicators of impairment within the refining portfolio as at 31 December 2025 and concluded that no impairment charge needed to be recorded.

How the Critical Audit Matter Was Addressed in the Audit

Intangible Assets

In respect of the recoverability of E&A assets capitalised as at 31 December 2025:

- We tested the relevant controls within the group's E&A write-off and impairment assessment processes; and
- We challenged and evaluated management's key E&A judgements with regards to the impairment criteria of IFRS 6. Where impairment indicators were identified, we corroborated key judgements with internal and external evidence for assets that remained on the balance sheet. This included analysing evidence of future E&A plans, budgets and capital allocation decisions, assessing management's key accounting judgement papers, reading meeting minutes and assessing licence documentation and evidence of active dialogue with partners and regulators including negotiations to renew licences or modify key terms.

Goodwill

In respect of the impairment tests performed on goodwill associated with the transition businesses, specifically Archaea Energy and Lightsource bp, performed at 31 December 2025:

- We tested the relevant controls over the impairment tests including controls over key assumptions;
- We independently evaluated bp's discount rates used in impairment tests with input from our valuation specialists, against relevant third-party market and peer data;
- We independently evaluated the long-term production rates for certain transition businesses with input from our Deloitte Landfill Production Specialists;

- We evaluated the appropriateness of other key assumptions including forecast period, development rate, long term growth rate, discount rate, developer margin, capital expenditure, and renewable natural gas revenue prices through assessment of bp's future plans and consistency with the capital frame; and
- We tested the mechanical accuracy of the impairment models.

PP&E

In relation to the refinery impairment tests performed by management, our audit procedures included:

- Evaluating the valuation methodology and testing the integrity and mechanical accuracy of the impairment models;
- Assessing the appropriateness of key assumptions and inputs to the impairment models, notably forecast local refining marker margins, discount rate and energy input costs;
- Challenging and evaluating management's assumptions by reference to third party data where available and involvement of our valuation specialists;
- Evaluating management's ability to forecast future cash flows and margins by comparing actual results with historical forecasts; and
- Testing management's internal controls over the impairment test and related inputs.

/s/ Deloitte LLP

London
United Kingdom
6 March 2026

We have served as bp's auditor since 2018.

- 1. The maintenance and integrity of the BP p.l.c. web site is the responsibility of BP p.l.c.; the work carried out by the auditors does not involve consideration of these matters and, accordingly, the auditors accept no responsibility for any changes that may have occurred to the financial statements since they were initially presented on the web site.**
- 2. Legislation in the United Kingdom governing the preparation and dissemination of financial statements may differ from legislation in other jurisdictions.**

Report of Independent Registered Public Accounting Firm

To the shareholders and board of directors of BP p.l.c.

Opinion on internal control over financial reporting

We have audited the internal control over financial reporting of BP p.l.c. and its subsidiaries (the group) as of 31 December 2025, based on the criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the group maintained, in all material respects, effective internal control over financial reporting as of 31 December 2025, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by COSO. We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as at and for the year ended 31 December 2025, of the group and our report dated 6 March 2026 expressed an unqualified opinion on those financial statements.

Basis for opinion

The Group's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's report on internal control over financial reporting. Our responsibility is to express an opinion on the group's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the group in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and limitations of internal control over financial reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Deloitte LLP

London, United Kingdom

6 March 2026

Group income statement

For the year ended 31 December		\$ million		
	Note	2025	2024	2023
Sales and other operating revenues	6	189,335	189,185	210,130
Earnings from joint ventures - after interest and tax	16	(300)	909	67
Earnings from associates - after interest and tax	17	918	1,084	831
Interest and other income	7	1,609	2,773	1,635
Gains on sale of businesses and fixed assets	4	987	678	369
Total revenues and other income		192,549	194,629	213,032
Purchases	19	110,640	113,941	119,307
Production and manufacturing expenses		25,646	26,584	25,044
Production and similar taxes	5	1,698	1,799	1,779
Depreciation, depletion and amortization	5	17,822	16,622	15,928
Net impairment and losses on sale of businesses and fixed assets	4	6,037	6,995	5,857
Exploration expense	8	570	974	997
Distribution and administration expenses		17,494	16,417	16,772
Profit (loss) before interest and taxation		12,642	11,297	27,348
Finance costs	7	5,106	4,683	3,840
Net finance (income) expense relating to pensions and other post-employment benefits	24	(210)	(168)	(241)
Profit (loss) before taxation		7,746	6,782	23,749
Taxation	9	6,451	5,553	7,869
Profit (loss) for the year		1,295	1,229	15,880
Attributable to				
bp shareholders		55	381	15,239
Non-controlling interests		1,240	848	641
		1,295	1,229	15,880
Earnings per share				
Profit (loss) for the year attributable to bp shareholders				
Per ordinary share (cents)				
Basic	11	0.35	2.38	87.78
Diluted	11	0.34	2.32	85.85
Per ADS (dollars)				
Basic	11	0.02	0.14	5.27
Diluted	11	0.02	0.14	5.15

Group statement of comprehensive income

For the year ended 31 December		\$ million		
	Note	2025	2024	2023
Profit (loss) for the year		1,295	1,229	15,880
Other comprehensive income				
Items that may be reclassified subsequently to profit or loss				
Currency translation differences ^a		1,863	(1,292)	585
Exchange (gains) losses on translation of foreign operations reclassified to gain or loss on sale of businesses and fixed assets ^a		41	1,004	(2)
Cash flow hedges marked to market	30	287	155	1,065
Cash flow hedges reclassified to the income statement	30	(127)	(686)	(428)
Costs of hedging marked to market	30	27	(2)	(67)
Costs of hedging reclassified to the income statement	30	34	(2)	(11)
Share of items relating to equity-accounted entities, net of tax	16, 17	(4)	(12)	(192)
Income tax relating to items that may be reclassified	9	(22)	48	(10)
		2,099	(787)	940
Items that will not be reclassified to profit or loss				
Remeasurements of the net pension and other post-employment benefit liability or asset	24	(221)	(360)	(2,262)
Remeasurements of equity investments		(6)	(47)	51
Cash flow hedges that will subsequently be transferred to the balance sheet	30	5	(1)	15
Income tax relating to items that will not be reclassified ^a	9	55	734	745
		(167)	326	(1,451)
Other comprehensive income		1,932	(461)	(511)
Total comprehensive income		3,227	768	15,369
Attributable to				
bp shareholders		1,872	7	14,702
Non-controlling interests		1,355	761	667
		3,227	768	15,369

a See Note 32 for further information.

Group statement of changes in equity^a

	\$ million								
	Share capital and capital reserves	Treasury shares	Foreign currency translation reserve	Fair value reserves	Profit and loss account	bp shareholders' equity	Non-controlling interests		Total equity
							Hybrid bonds	Other interest	
At 1 January 2025	48,229	(9,030)	(2,196)	(288)	22,531	59,246	16,649	2,423	78,318
Profit for the year	–	–	–	–	55	55	799	441	1,295
Other comprehensive income	–	–	1,804	183	(170)	1,817	–	115	1,932
Total comprehensive income	–	–	1,804	183	(115)	1,872	799	556	3,227
Dividends ^b	–	–	–	–	(5,087)	(5,087)	–	(524)	(5,611)
Cash flow hedges transferred to the balance sheet, net of tax	–	–	–	(6)	–	(6)	–	–	(6)
Repurchase of ordinary share capital	–	(3,558)	–	–	(454)	(4,012)	–	–	(4,012)
Share-based payments, net of tax	35	3,917	–	–	(2,840)	1,112	–	–	1,112
Share of equity-accounted entities' changes in equity, net of tax	–	–	–	–	1	1	–	–	1
Issue of perpetual hybrid bonds	–	–	–	–	–	–	500	–	500
Redemption of perpetual hybrid bonds, net of tax	–	–	–	–	–	–	(1,200)	–	(1,200)
Payments on perpetual hybrid bonds	–	–	(9)	–	–	(9)	(793)	–	(802)
Transactions involving non-controlling interests, net of tax	–	–	–	–	(65)	(65)	–	2,538	2,473
At 31 December 2025	48,264	(8,671)	(401)	(111)	13,971	53,052	15,955	4,993	74,000
At 1 January 2024	48,013	(11,323)	(1,920)	174	35,339	70,283	13,566	1,644	85,493
Profit for the year	–	–	–	–	381	381	641	207	1,229
Other comprehensive income	–	–	(276)	(452)	354	(374)	–	(87)	(461)
Total comprehensive income	–	–	(276)	(452)	735	7	641	120	768
Dividends ^b	–	–	–	–	(5,018)	(5,018)	–	(375)	(5,393)
Cash flow hedges transferred to the balance sheet, net of tax	–	–	–	(10)	–	(10)	–	–	(10)
Repurchase of ordinary share capital	–	–	–	–	(7,302)	(7,302)	–	–	(7,302)
Share-based payments, net of tax	216	2,293	–	–	(1,426)	1,083	–	–	1,083
Issue of perpetual hybrid bonds	–	–	–	–	(22)	(22)	4,352	–	4,330
Redemption of perpetual hybrid bonds, net of tax	–	–	–	–	9	9	(1,300)	–	(1,291)
Payments on perpetual hybrid bonds	–	–	–	–	–	–	(610)	–	(610)
Transactions involving non-controlling interests, net of tax	–	–	–	–	216	216	–	1,034	1,250
At 31 December 2024	48,229	(9,030)	(2,196)	(288)	22,531	59,246	16,649	2,423	78,318
At 1 January 2023	47,873	(12,153)	(2,643)	(256)	34,732	67,553	13,390	2,047	82,990
Profit for the year	–	–	–	–	15,239	15,239	586	55	15,880
Other comprehensive income	–	–	728	431	(1,696)	(537)	–	26	(511)
Total comprehensive income	–	–	728	431	13,543	14,702	586	81	15,369
Dividends ^b	–	–	–	–	(4,831)	(4,831)	–	(403)	(5,234)
Cash flow hedges transferred to the balance sheet, net of tax	–	–	–	(1)	–	(1)	–	–	(1)
Repurchase of ordinary share capital	–	–	–	–	(8,167)	(8,167)	–	–	(8,167)
Share-based payments, net of tax	140	830	–	–	(301)	669	–	–	669
Share of equity-accounted entities' changes in equity, net of tax	–	–	–	–	1	1	–	–	1
Issue of perpetual hybrid bonds	–	–	–	–	(1)	(1)	176	–	175
Payments on perpetual hybrid bonds	–	–	(5)	–	–	(5)	(586)	–	(591)
Transactions involving non-controlling interests, net of tax	–	–	–	–	363	363	–	(81)	282
At 31 December 2023	48,013	(11,323)	(1,920)	174	35,339	70,283	13,566	1,644	85,493

^a See Note 32 for further information.

^b See Note 10 for further information.

Group balance sheet

At 31 December

		\$ million	
	Note	2025	2024
Non-current assets			
Property, plant and equipment	12	98,633	100,238
Goodwill	14	10,300	14,888
Intangible assets	15	8,197	9,646
Investments in joint ventures	16	13,400	12,291
Investments in associates	17	7,325	7,741
Other investments	18	857	1,292
		138,712	146,096
Fixed assets			
Loans		1,991	1,961
Trade and other receivables	20	2,376	1,815
Derivative financial instruments	30	20,957	16,114
Prepayments		608	548
Deferred tax assets	9	4,325	5,403
Defined benefit pension plan surpluses	24	7,771	7,457
		176,740	179,394
Current assets			
Loans		457	223
Inventories	19	22,499	23,232
Trade and other receivables	20	26,014	27,127
Derivative financial instruments	30	5,180	5,112
Prepayments		3,422	2,594
Current tax receivable		1,153	1,096
Other investments	18	158	165
Cash and cash equivalents	25	36,556	39,204
		95,439	98,753
Assets classified as held for sale	2	6,347	4,081
		101,786	102,834
		278,526	282,228
Total assets			
Current liabilities			
Trade and other payables	22	56,843	58,411
Derivative financial instruments	30	4,413	4,347
Accruals		5,572	6,071
Lease liabilities	28	2,832	2,660
Finance debt	26	3,356	4,474
Current tax payable		1,262	1,573
Provisions	23	4,709	3,600
		78,987	81,136
Liabilities directly associated with assets classified as held for sale	2	1,594	1,105
		80,581	82,241
Non-current liabilities			
Other payables	22	7,975	9,409
Derivative financial instruments	30	19,667	18,532
Accruals		1,834	1,326
Lease liabilities	28	11,739	9,340
Finance debt	26	54,602	55,073
Deferred tax liabilities	9	7,642	8,428
Provisions	23	15,670	14,688
Defined benefit pension plan and other post-employment benefit plan deficits	24	4,816	4,873
		123,945	121,669
		204,526	203,910
Total liabilities			
Net assets			
Equity		74,000	78,318
bp shareholders' equity	32	53,052	59,246
Non-controlling interests	32	20,948	19,072
	32	74,000	78,318

Albert Manifold Chair

Carol Howle Interim Chief executive officer

6 March 2026

Group cash flow statement

For the year ended 31 December		\$ million		
	Note	2025	2024	2023
Operating activities				
Profit (loss) before taxation		7,746	6,782	23,749
Adjustments to reconcile profit before taxation to net cash provided by operating activities				
Exploration expenditure written off	8	343	767	746
Depreciation, depletion and amortization	5	17,822	16,622	15,928
Impairment and (gain) loss on sale of businesses and fixed assets	4	5,050	6,317	5,488
Earnings from joint ventures and associates		(618)	(1,993)	(898)
Dividends received from joint ventures and associates		2,111	2,023	2,092
Remeasurement of joint ventures	3	–	(917)	–
Interest receivable		(1,352)	(1,512)	(1,265)
Interest received		1,223	1,450	1,119
Finance costs	7	5,106	4,683	3,840
Interest paid		(3,538)	(2,811)	(2,950)
Net finance expense relating to pensions and other post-employment benefits	24	(210)	(168)	(241)
Share-based payments		1,077	1,174	616
Net operating charge for pensions and other post-employment benefits, less contributions and benefit payments for unfunded plans	24	(152)	(182)	(193)
Net charge for provisions, less payments		1,294	(152)	(2,481)
(Increase) decrease in inventories		1,622	808	5,634
(Increase) decrease in other current and non-current assets		(4,286)	3,355	4,620
Increase (decrease) in other current and non-current liabilities		(2,156)	(188)	(13,592)
Income taxes paid		(6,589)	(8,761)	(10,173)
Net cash provided by operating activities		24,493	27,297	32,039
Investing activities				
Expenditure on property, plant and equipment, intangible and other assets		(13,221)	(15,297)	(14,285)
Acquisitions, net of cash acquired	3	(935)	53	(799)
Investment in joint ventures		(267)	(850)	(1,039)
Investment in associates		(110)	(143)	(130)
Total cash capital expenditure		(14,533)	(16,237)	(16,253)
Proceeds from disposals of fixed assets	4	1,142	328	133
Proceeds from disposals of businesses, net of cash disposed	4	1,714	2,578	1,193
Proceeds from loan repayments		173	81	55
Net cash used in investing activities		(11,504)	(13,250)	(14,872)
Financing activities				
Repurchase of shares		(4,486)	(7,127)	(7,918)
Lease liability payments		(3,091)	(2,833)	(2,560)
Proceeds from long-term financing		2,724	10,656	7,568
Repayments of long-term financing		(5,695)	(2,970)	(3,902)
Net increase (decrease) in short-term debt		(343)	(2,966)	(861)
Issue of perpetual hybrid bonds		500	4,330	175
Redemption of perpetual hybrid bonds	32	(1,200)	(1,288)	–
Payments relating to perpetual hybrid bonds		(1,196)	(1,053)	(1,008)
Payments relating to transactions involving non-controlling interests (other)		(2)	(21)	(187)
Receipts relating to transactions involving non-controlling interests (other)		2,474	1,353	546
Dividends paid				
bp shareholders	10	(5,059)	(5,003)	(4,809)
Non-controlling interests		(506)	(375)	(403)
Net cash provided by (used in) financing activities		(15,880)	(7,297)	(13,359)
Currency translation differences relating to cash and cash equivalents		246	(511)	27
Increase (decrease) in cash and cash equivalents		(2,645)	6,239	3,835
Cash and cash equivalents at beginning of year		39,269	33,030	29,195
Cash and cash equivalents at end of year^a		36,624	39,269	33,030

a 2025 and 2024 include cash and cash equivalents classified as assets held for sale in the group balance sheet. See Note 2 for further information.

Notes on financial statements

1. Material accounting policy information, significant judgements, estimates and assumptions

Authorization of financial statements and statement of compliance with International Financial Reporting Standards

The consolidated financial statements of BP p.l.c and its subsidiaries (collectively referred to as bp or the group) were approved and signed by the interim chief executive officer and chairman on 6 March 2026 having been duly authorized to do so by the board of directors. BP p.l.c. is a public limited company incorporated and domiciled in England and Wales. The consolidated financial statements have been prepared in accordance with IFRS Accounting Standards® (IFRS) as issued by the International Accounting Standards Board (IASB), IFRS as adopted by the UK, and European Union (EU), and in accordance with the provisions of the UK Companies Act 2006 as applicable to companies reporting under international accounting standards. IFRS as adopted by the UK does not differ from IFRS as adopted by the EU. IFRS as adopted by the UK and EU differs in certain respects from IFRS as issued by the IASB. The differences have no impact on the group's consolidated financial statements for the years presented. The material accounting policy information and accounting judgements, estimates and assumptions of the group are set out below.

Basis of preparation

The consolidated financial statements have been prepared on a going concern basis and in accordance with IFRSs and IFRS Interpretations Committee (IFRIC) interpretations issued and effective for the year ended 31 December 2025. The accounting policies that follow have been consistently applied to all years presented, except where otherwise indicated.

The consolidated financial statements are presented in US dollars and all values are rounded to the nearest million dollars (\$ million), except where otherwise indicated.

Material accounting policy information: use of judgements, estimates and assumptions

Inherent in the application of many of the accounting policies used in preparing the consolidated financial statements is the need for bp management to make judgements, estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities, and the reported amounts of revenues and expenses. Actual outcomes could differ from the estimates and assumptions used. The accounting judgements and estimates that have a significant impact on the results of the group are set out in boxed text below, and should be read in conjunction with the information provided in the Notes on financial statements.

The areas requiring the most significant judgement and estimation in the preparation of the consolidated financial statements are: accounting for the investments in Rosneft and Aker BP; exploration and appraisal intangible assets; the recoverability of asset carrying values, including the estimation of reserves; supplier financing arrangements; derivative financial instruments; provisions and contingencies; pensions and other post-employment benefits; and taxation. Judgements and estimates, not all of which are significant, made in assessing the impact of the current economic and geopolitical environment, and climate change and the transition to a lower carbon economy on the consolidated financial statements are also set out in boxed text below. Where an estimate has a significant risk of resulting in a material adjustment to the carrying amounts of assets and liabilities within the next financial year this is specifically noted within the boxed text.

Judgements and estimates made in assessing the impact of climate change and the transition to a lower carbon economy

Climate change and the transition to a lower carbon economy were considered in preparing the consolidated financial statements. These may have significant impacts on the currently reported amounts of the group's assets and liabilities discussed below and on similar assets and liabilities that may be recognized in the future. The group's assumptions for investment appraisal form part of an investment decision-making framework for currently unsanctioned future capital expenditure on property, plant and equipment, and intangibles including exploration and appraisal assets, that is designed to support the effective and resilient implementation of bp's strategy. The price assumptions used for investment appraisal include oil and gas price assumptions, which are producer prices and are therefore net of any future carbon prices that the purchaser may be required to pay, and an assumption of a single carbon emissions cost imposed on the producer in respect of operational greenhouse gas (GHG) emissions (carbon dioxide and methane) in order to incentivize engineering solutions to mitigate GHG emissions on projects. The group's oil and gas price assumptions for value-in-use impairment testing are aligned with those investment appraisal assumptions. The assumptions for future carbon emissions costs in value-in-use impairment testing differ from the investment appraisal assumptions and are described below.

Management has also not identified any off-balance sheet commodity purchase obligations to be onerous contracts as result of the transition to a lower carbon economy at 31 December 2025.

Impairment of property, plant and equipment and goodwill

The energy transition is likely to impact the future prices of commodities such as oil and natural gas which in turn may affect the recoverable amount of property, plant and equipment and goodwill in the oil and gas industry. Management's best estimate of oil and natural gas price assumptions for value-in-use impairment testing were revised during 2025. The revised price assumptions have been rebased in real 2024 terms. Brent oil prices in real 2024 terms were reduced in the short-term reflecting greater crude supply. Medium to long term prices steadily decline to a higher price of \$60 per barrel in 2050 continuing to reflect the assumption that the energy system decarbonises but at a slower rate. The price assumptions for Henry Hub gas price have been reduced in the short term, reflecting higher supply in the market. Prices then steadily increase in the medium term, as supply and demand rebalance before remaining steady at \$4.50 per mmBtu up to 2050. The revised assumptions for Brent oil and Henry Hub gas sit within the range of external scenarios considered by management and are in line with a range of transition paths, as collated into the Transition Scenario Catalogue we use in our TCFD assessment, that are considered by source data providers (such as IEA, UN PRI IPR and NGFS) to be consistent with holding the increase in the global average temperature to well below 2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

As noted above, the group's investment appraisal process includes a carbon emissions price series for the investment economics which is applied to bp's anticipated share of bp's forecast of the investment assets' scope 1 and 2 GHG emissions where they exceed defined thresholds, and is assumed to apply whether or not bp is the asset operator. However, for value-in-use impairment testing on bp's existing cash generating units (CGUs), consistent with all other relevant cash flows estimated, bp is required to reflect management's best estimate of any expected applicable carbon emission costs payable by bp, including where bp is not the operator, in the future for each jurisdiction in which the group has interests. This requires management's best estimate of how future changes to relevant carbon emission cost policies and/or legislation are likely to affect the future cash flows of the group's applicable CGUs, whether currently enacted or not. Future potential carbon pricing and/or costs of carbon emissions allowances are included in the value-in-use calculations to the extent management has sufficient information to make such an estimate. Currently this results in limited application of carbon price assumptions in value-in-use impairment tests given that carbon pricing legislation in most impacted jurisdictions where the group has interests is not in place and there is not sufficient information available as to the relevant policy makers' future intentions regarding carbon pricing to support an estimate. A key input into the determination of impairment is the assumption, aligned with bp's aim to reach net zero greenhouse gas emissions by 2050 or sooner, that the current recognized portfolio of oil and gas properties and refining assets will have an immaterial carrying value by 2050.

Where we consider that the outcome of a value-in-use impairment test could be significantly affected by a carbon price in place in any jurisdiction, this is incorporated into the value-in-use impairment testing cash flows. The most significant instances where a carbon price has been incorporated in the 2025 value-in-use impairment tests is for the UK North Sea. The assumptions for UK North Sea were £65/tCO₂e in 2026 gradually increasing to £243/tCO₂e in 2050.

However, as bp's forecast future prices are producer prices, the group considers it reasonable to assume that if, in addition to the costs already in place, further scope 1 and 2 emission costs were partially to be borne directly by oil and gas producers including bp in future and the prevalence of such costs were to become widespread, the gross oil and gas prices realized by producers would be correspondingly higher over the long term, resulting in no expected overall materially negative impacts on the group's net cash flows. See significant judgements and estimates: recoverability of asset carrying values for further information including sensitivity analysis in relation to reasonably possible changes in the price assumptions and carbon costs.

Production assumptions within upstream property, plant and equipment and goodwill value-in-use impairment tests reflect management's current best estimate of future production of the existing upstream portfolio. See significant judgements and estimates: recoverability of asset carrying values and **Note 14** for sensitivity analyses in relation to reasonably possible changes in production for upstream oil and gas properties and goodwill respectively.

For the customers & products segment, though the energy transition may impact demand for certain refined products in the future, management anticipates sufficiently robust demand for the remainder of each refinery's useful life.

Management will continue to review price assumptions as the energy transition progresses and this may result in impairment charges or reversals in the future.

Exploration and appraisal intangible assets

The energy transition may affect the future development or viability of exploration prospects. The recoverability of the group's exploration and appraisal intangible assets was considered during 2025. No significant write-offs were identified. These assets will continue to be assessed as the energy transition progresses. See significant judgement: exploration and appraisal intangible assets and **Note 8** for further information.

Property, plant and equipment – depreciation and expected useful lives

The energy transition may curtail the expected useful lives of oil and gas industry assets thereby accelerating depreciation charges. However, a significant majority of bp's existing upstream oil and natural gas properties are likely to have immaterial carrying values within the next 12 years and, as outlined in bp's strategy, oil and natural gas production will remain an important part of bp's business activities over that period. The significant majority of refining assets, recognized on the group's balance sheet at 31 December 2025 that are subject to depreciation, will be depreciated within the next 11 years; demand for refined products is expected to remain sufficient to support the remaining useful lives of existing assets. Therefore, management does not expect the useful lives of bp's reported property, plant and equipment to change and do not consider this to be a significant accounting judgement or estimate. Significant capital expenditure is still required for ongoing projects as well as renewal and/or replacement of aged assets and therefore the useful lives of future capital expenditure may be different. See material accounting policy: property, plant and equipment for more information.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Provisions: decommissioning

The energy transition may bring forward the decommissioning of oil and gas industry assets thereby increasing the present value of associated decommissioning provisions. The majority of bp's existing upstream oil and gas properties are expected to start decommissioning within the next two decades. Currently, the expected timing of decommissioning expenditures for the upstream oil and gas assets in the group's portfolio has not materially been brought forward. Management does not expect a reasonably possible change of two years in the expected timing of all decommissioning to have a material effect on the upstream decommissioning provisions, assuming cost assumptions remain unchanged.

Decommissioning cost estimates are based on the known regulatory and external environment. These cost estimates may change in the future, including as a result of the transition to a lower carbon economy. For refineries, decommissioning provisions are generally not recognized as the associated obligations have indeterminate settlement dates, typically driven by the cessation of manufacturing. Management does not expect manufacturing to cease at refineries within a determinate period of time, as existing property, plant and equipment is expected to be renewed or replaced. Management will continue to review facts and circumstances, including where cessation of manufacturing decisions have been made, to assess if decommissioning provisions need to be recognized. Decommissioning provisions relating to refineries at 31 December 2025 are not material. See significant judgements and estimates: provisions for further information.

Judgements and estimates made in assessing the impact of the geopolitical and economic environment

In preparing the consolidated financial statements, the following areas involving judgement and estimates were identified as most relevant with regards to the impact of the current geopolitical and economic environment.

Oil and gas price assumptions

Oil and gas price assumptions applied in value-in-use impairment testing have been updated (as noted above) including for inflation and have been rebased in real 2024 terms. See significant judgements and estimates: recoverability of asset carrying values for further information.

Discount rate assumptions

The discount rates used for impairment testing and provisions were reassessed during the year in light of changing economic and geopolitical outlooks. The impact on the nominal discount rate applied to provisions was determined not to be significant and so the rate remained unchanged from 2024. The post-tax impairment discount rate remained consistent with 2024 as did the risk premium applied to the majority of countries classified as higher-risk. See significant judgements and estimates: recoverability of asset carrying values and provisions for further information.

Pensions and other post-employment benefits

Volatility in financial markets impact assumptions used for determining the fair value of plan assets and the present value of defined benefit obligations in the group's defined benefit pension plans. See significant estimate: pensions and other post-employment benefits and **Note 24** for further information.

Basis of consolidation

The group financial statements consolidate the financial statements of BP p.l.c. and its subsidiaries drawn up to 31 December each year. Subsidiaries are consolidated from the date of their acquisition, being the date on which the group obtains control, including when control is obtained via potential voting rights, and continue to be consolidated until the date that control ceases.

The financial statements of subsidiaries are prepared for the same reporting year as the parent company, using consistent accounting policies. Intra-group balances and transactions, including unrealized profits arising from intra-group transactions, have been eliminated. Unrealized losses are eliminated unless the transaction provides evidence of an impairment of the asset transferred.

Non-controlling interests represent the equity in subsidiaries that is not attributable, directly or indirectly, to bp shareholders. Included within non-controlling interests are perpetual subordinated hybrid bonds issued by subsidiaries and for which the group has the unconditional right to avoid transferring cash or another financial asset to the holders. Profit or loss attributable to bp shareholders is adjusted to reflect the coupon/interest related to these hybrid bonds whether or not such distribution has been deferred.

Also, included within non-controlling interests are perpetual subordinated hybrid securities and certain equity instruments with preferred distribution rights issued by group subsidiaries.

Non-controlling interests are present ownership interests and entitle the holders to a share of the entity's net assets in the event of liquidation and are initially measured at either:

(a) fair value; or

(b) the present ownership instruments' proportionate share in the recognized amounts of the subsidiary's' identifiable net assets.

The group enters certain arrangements with non-controlling interest holders that have a complex equity structure with several classes of equity shares or are subject to other contractual arrangements. These arrangements specify different entitlements to net profit allocations, equity and liquidation preferences that differ from an ownership interest share of the entity's net assets. The group, for certain arrangements, also holds a discretionary option to redeem the equity shares held by non-controlling interest shareholders, which becomes exercisable upon the occurrence of a specified event or after a defined period. In such cases, the non-controlling interest balance within equity is initially measured at fair value and the non-controlling interest profit or loss allocation in line with the holders' economic entitlement. The non-controlling interest balance within equity is not subsequently remeasured to fair value or redemption value but is adjusted for the profit or loss allocation, dividends and other transactions with non-controlling interest holders.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Interests in other entities

Business combinations and goodwill

Business combinations are accounted for using the acquisition method. The identifiable assets acquired and liabilities assumed are recognized at their fair values at the acquisition date.

Goodwill is initially measured as the excess of the aggregate of the consideration transferred, the amount recognized for any non-controlling interest and the acquisition-date fair values of any previously held interest in the acquiree over the fair value of the identifiable assets acquired and liabilities assumed at the acquisition date. The amount recognized for any non-controlling interest is measured at the present ownership's proportionate share in the recognized amounts of the acquiree's identifiable net assets. At the acquisition date, any goodwill acquired is allocated to each of the cash-generating units, or groups of cash-generating units, expected to benefit from the combination's synergies. Following initial recognition, goodwill is measured at cost less any accumulated impairment losses. Goodwill arising on business combinations prior to 1 January 2003 is stated at the previous carrying amount under UK generally accepted accounting practice, less subsequent impairments.

Goodwill may arise upon investments in joint ventures and associates, being the surplus of the cost of investment over the group's share of the net fair value of the identifiable assets and liabilities. Any such goodwill is recorded within the corresponding investment in joint ventures and associates.

Goodwill may also arise upon acquisition of interests in joint operations that meet the definition of a business. The amount of goodwill separately recognized is the excess of the consideration transferred over the group's share of the net fair value of the identifiable assets and liabilities.

Interests in joint arrangements

The results, assets and liabilities of joint ventures are incorporated in these consolidated financial statements using the equity method of accounting as described below.

Certain of the group's activities, particularly in the oil production & operations and gas & low carbon energy segments, are conducted through joint operations. bp recognizes, on a line-by-line basis in the consolidated financial statements, its share of the assets, liabilities and expenses of these joint operations incurred jointly with the other partners, along with the group's revenue from the sale of its share of the output and any liabilities and expenses that the group has incurred in relation to the joint operation.

For joint arrangements in a separate entity, judgement may be required as to whether the arrangement should be classified as a joint venture or if the legal form, contractual arrangements or other facts and circumstances indicate that the group has rights to the assets and obligations for the liabilities of the arrangement, rather than rights to the net assets, and therefore should be classified as a joint operation. No such judgement made by the group is considered significant.

Interests in associates

The results, assets and liabilities of associates are incorporated in these consolidated financial statements using the equity method of accounting as described below.

Significant judgement: investment in Aker BP

Judgement is required in assessing the level of control or influence over another entity in which the group holds an interest. For bp, the judgement that the group has significant influence over Aker BP, a Norwegian oil and gas company, is significant.

As a consequence of this judgement, bp uses the equity method of accounting for its investment and bp's share of Aker BP's oil and natural gas reserves is included in the group's estimated net proved reserves of equity-accounted entities. If significant influence was not present, the investment would be accounted for as an investment in an equity instrument measured at fair value as described under 'Financial assets' below and no share of Aker BP's oil and natural gas reserves would be reported.

Significant influence is defined in IFRS as the power to participate in the financial and operating policy decisions of the investee but is not control or joint control of those decisions. Significant influence is presumed when an entity owns 20% or more of the voting power of the investee. Significant influence is presumed not to be present when an entity owns less than 20% of the voting power of the investee.

bp owned 15.9% of the voting shares at 31 December 2025. bp's senior vice president North Sea, Doris Reiter, was appointed a member of the Aker BP board during 2024. bp's other nominated director, group chief financial officer, Kate Thomson, has been a member of the Aker BP board since formation of that company in 2016. She is also a member of the Aker BP board's Audit and Risk Committee. bp also holds the voting rights at general meetings of shareholders conferred by its stake in Aker BP. bp's management considers, therefore, that the group continues to have significant influence at 31 December 2025.

Significant judgements and estimate: investment in Rosneft

Since the first quarter 2022, bp accounts for its interest in Rosneft and its other businesses with Rosneft within Russia, as financial assets measured at fair value within 'Other investments'. bp is not able to sell its Rosneft shares on the Moscow Stock Exchange and is unable to ascribe probabilities to possible outcomes of any exit process. It is considered by management that any measure of fair value, other than nil, would be subject to such high measurement uncertainty, considering the sanctions and restrictions implemented by Russia on Russian assets held by foreign investors, that no estimate would provide useful information even if it were accompanied by a description of the estimate made in producing it and an explanation of the uncertainties that affect the estimate. Accordingly, it is not currently possible to estimate any carrying value other than zero when determining the measurement of the interest in Rosneft and the other businesses with Rosneft within Russia as at 31 December 2025. Events or outcomes within the next financial year, that are different to those outlined above, could materially change the fair value of the investment.

Russia has imposed restrictions on the payments of dividends to certain foreign shareholders, including those based in the UK, requiring such dividends to be paid in roubles into restricted bank accounts and a requirement for approval of the Russian government for transfers from any such bank accounts out of Russia. Given the restrictions applicable to such accounts, management has made the significant judgement that the criteria for recognizing any dividend income from Rosneft and its other businesses with Rosneft within Russia, for the years to 31 December 2023, 31 December 2024 and 31 December 2025 have not been met.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

The equity method of accounting

Under the equity method, an investment is carried on the balance sheet at cost plus post-acquisition changes in the group's share of net assets of the entity, less distributions received and less any impairment in value of the investment. Loans advanced to equity-accounted entities that have the characteristics of equity financing are also included in the investment on the group balance sheet. The group income statement reflects the group's share of the results after tax of the equity-accounted entity, adjusted to account for depreciation, amortization and any impairment of the equity-accounted entity's assets based on their fair values at the date of acquisition. The group statement of comprehensive income includes the group's share of the equity-accounted entity's other comprehensive income. The group's share of amounts recognized directly in equity by an equity-accounted entity is recognized in the group's statement of changes in equity.

Financial statements of equity-accounted entities are typically prepared for the same reporting year as the group. Where material differences arise in the accounting policies used by the equity-accounted entity and those used by bp, adjustments are made to those financial statements to bring the accounting policies used into line with those of the group. Unrealized gains on transactions, apart from those that meet the definition of a derivative, between the group and its equity-accounted entities are eliminated to the extent of the group's interest in the equity-accounted entity. This includes unrealized gains arising on contribution of a business on formation of an equity-accounted entity.

Segmental reporting

The group's operating segments are established on the basis of those components of the group that are evaluated regularly by the chief executive officer, bp's chief operating decision maker, in deciding how to allocate resources and in assessing performance.

The accounting policies of the operating segments are the same as the group's accounting policies described in this note, except that IFRS requires that the measure of profit or loss disclosed for each operating segment is the measure that is provided regularly to the chief operating decision maker. For bp, this measure of profit or loss is replacement cost profit before interest and tax which reflects the replacement cost of inventories sold in the period and is arrived at by excluding inventory holding gains and losses from profit before interest and tax. Replacement cost profit for the group is not a recognized measure under IFRS.

During the first quarter 2025, the Archaea Energy business was moved from the customers & products segment to the gas & low carbon energy segment. The change in segmentation is consistent with a change in the way that resources are allocated, and performance is assessed by the chief operating decision maker, who for bp is the group chief executive.

Comparative information for 2024 has been restated where material to reflect the changes in reportable segments. For further information see **Note 5**.

Foreign currency translation

In individual subsidiaries, joint ventures and associates, transactions in foreign currencies are initially recorded in the functional currency of those entities at the spot exchange rate on the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are retranslated into the functional currency at the spot exchange rate on the balance sheet date. Any resulting exchange differences are included in the income statement, unless hedge accounting is applied. Non-monetary items, other than those measured at fair value, are not retranslated subsequent to initial recognition.

In the consolidated financial statements, the assets and liabilities of non-US dollar functional currency subsidiaries, joint ventures, associates, and related goodwill, are translated into US dollars at the spot exchange rate on the balance sheet date. The results and cash flows of non-US dollar functional currency subsidiaries, joint ventures and associates are translated into US dollars using average rates of exchange. In the consolidated financial statements, exchange adjustments arising when the opening net assets and the profits for the year retained by non-US dollar functional currency subsidiaries, joint ventures and associates are translated into US dollars are recognized in a separate component of equity and reported in other comprehensive income. Exchange gains and losses arising on long-term intra-group foreign currency borrowings used to finance the group's non-US dollar investments are also reported in other comprehensive income if the borrowings form part of the net investment in the subsidiary, joint venture or associate. On disposal or for certain partial disposals of a non-US dollar functional currency subsidiary, joint venture or associate, the related accumulated exchange gains and losses recognized in equity are reclassified from equity to the income statement.

Non-current assets held for sale

Non-current assets and disposal groups classified as held for sale are measured at the lower of carrying amount and fair value less costs to sell.

Significant non-current assets and disposal groups are classified as held for sale if their carrying amounts will be recovered through a sale transaction rather than through continuing use. This condition is regarded as met only when the sale is highly probable and the asset or disposal group is available for immediate sale in its present condition subject only to terms that are usual and customary for sales of such assets. Management must be committed to the sale, which should be expected to qualify for recognition as a completed sale within one year from the date of classification as held for sale, and actions required to complete the plan of sale should indicate that it is unlikely that significant changes to the plan will be made or that the plan will be withdrawn.

Property, plant and equipment and intangible assets are not depreciated or amortized, and equity accounting of associates and joint ventures is ceased once classified as held for sale.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Intangible assets

Intangible assets, other than goodwill, include expenditure on the exploration for and evaluation of oil and natural gas resources, biogas rights agreements, digital assets, patents, licences and trademarks and are stated at the amount initially recognized, less accumulated amortization and accumulated impairment losses.

Intangible assets are carried initially at cost unless acquired as part of a business combination. Any such asset is measured at fair value at the date of the business combination and is recognized separately from goodwill if the asset is separable or arises from contractual or other legal rights.

Intangible assets with a finite life, other than capitalized exploration and appraisal costs as described below, are amortized on a straight-line basis over their expected useful lives. For patents, licences and trademarks, expected useful life is the shorter of the duration of the legal agreement and economic useful life, and can range from three to fifteen years. The expected useful life of biogas rights agreements is the shorter of the duration of the legal agreement and economic useful life and can be up to 50 years. Digital asset costs generally have a useful life of three to five years.

The expected useful lives of assets and the amortization method are reviewed on an annual basis and, if necessary, changes in useful lives or the amortization method are accounted for prospectively.

Oil and natural gas exploration and appraisal expenditure

Oil and natural gas exploration and appraisal expenditure is accounted for using the principles of the successful efforts method of accounting as described below.

Licence and property acquisition costs

Exploration licence and leasehold property acquisition costs are capitalized within intangible assets and are reviewed at each reporting date to confirm that there is no indication that the carrying amount exceeds the recoverable amount. This review includes confirming that exploration drilling is still under way or planned or that it has been determined, or work is under way to determine, that the discovery is economically viable based on a range of technical and commercial considerations, and sufficient progress is being made on establishing development plans and timing. If no future activity is planned, the remaining balance of the licence and property acquisition costs is written off. Lower value licences are pooled and amortized on a straight-line basis over the estimated period of exploration. Upon internal approval for development and recognition of proved or sanctioned probable reserves of oil and natural gas, the relevant expenditure is transferred to property, plant and equipment.

Exploration and appraisal expenditure

Geological and geophysical exploration costs are recognized as an expense as incurred. Costs directly associated with an exploration well are initially capitalized as an intangible asset until the drilling of the well is complete and the results have been evaluated. These costs include employee remuneration, materials and fuel used, rig costs and payments made to contractors. If potentially commercial quantities of hydrocarbons are not found, the exploration well costs are written off. If hydrocarbons are found and, subject to further appraisal activity, are likely to be capable of commercial development, the costs continue to be carried as an asset. If it is determined that development will not occur, that is, the efforts are not successful, then the costs are expensed.

Costs directly associated with appraisal activity undertaken to determine the size, characteristics and commercial potential of a reservoir following the initial discovery of hydrocarbons, including the costs of appraisal wells where hydrocarbons were not found, are initially capitalized as an intangible asset. Upon internal approval for development and recognition of proved or sanctioned probable reserves, the relevant expenditure is transferred to property, plant and equipment. If development is not approved and no further activity is expected to occur, then the costs are expensed.

The determination of whether potentially economic oil and natural gas reserves have been discovered by an exploration well is usually made within one year of well completion, but can take longer, depending on the complexity of the geological structure. Exploration wells that discover potentially economic quantities of oil and natural gas and are in areas where major capital expenditure (e.g. an offshore platform or a pipeline) would be required before production could begin, and where the economic viability of that major capital expenditure depends on the successful completion of further exploration or appraisal work in the area, remain capitalized on the balance sheet as long as such work is under way or firmly planned.

Significant judgement: exploration and appraisal intangible assets

Judgement is required to determine whether it is appropriate to continue to carry costs associated with exploration wells and exploratory-type stratigraphic test wells on the balance sheet. This includes costs relating to exploration licences or leasehold property acquisitions. It is not unusual to have such costs remaining suspended on the balance sheet for several years while additional appraisal drilling and seismic work on the potential oil and natural gas field is performed or while the optimum development plans and timing are established. The costs are carried based on the current regulatory and political environment or any known changes to that environment. All such carried costs are subject to regular technical, commercial and management review on at least an annual basis to confirm the continued intent to develop, or otherwise extract value from, the discovery. Where this is no longer the case, the costs are immediately expensed.

The carrying amount of capitalized costs are included in **Note 8**.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Property, plant and equipment

Property, plant and equipment owned by the group is stated at cost, less accumulated depreciation and accumulated impairment losses. The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into the location and condition necessary for it to be capable of operating in the manner intended by management, the initial estimate of any decommissioning obligation, if applicable, and, for assets that necessarily take a substantial period of time to get ready for their intended use, directly attributable general or specific finance costs. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset.

Expenditure on major maintenance refits or repairs comprises the cost of replacement assets or parts of assets, inspection costs and overhaul costs. Where an asset or part of an asset that was separately depreciated is replaced and it is probable that future economic benefits associated with the item will flow to the group, the expenditure is capitalized and the carrying amount of the replaced asset is derecognized. Inspection costs associated with major maintenance programmes are capitalized and amortized over the period to the next inspection. Overhaul costs for major maintenance programmes, and all other maintenance costs are expensed as incurred.

Expenditure on the construction, installation and completion of infrastructure facilities such as platforms, pipelines and the drilling of development wells, including service and unsuccessful development or delineation wells, is capitalized within property, plant and equipment and is depreciated from the commencement of production.

Oil and natural gas properties, including certain related pipelines, are depreciated using a unit-of-production method. The cost of producing wells is amortized over proved developed reserves. Licence acquisition, common facilities and future decommissioning costs are amortized over total proved reserves. The unit-of-production rate for the depreciation of common facilities takes into account expenditures incurred to date, together with estimated future capital expenditure expected to be incurred relating to as yet undeveloped reserves expected to be processed through these common facilities. Information on the carrying amounts of the group's oil and natural gas properties, together with the amounts recognized in the income statement as depreciation, depletion and amortization is contained in **Note 12** and **Note 5** respectively.

Estimates of oil and natural gas reserves determined in accordance with US Securities and Exchange Commission (SEC) regulations, including the application of prices using 12-month historical price data in assessing the commerciality of technical volumes, are typically used to calculate depreciation, depletion and amortization charges for the group's oil and gas properties. Therefore, where this approach is adopted, charges are not dependent on management forecasts of future oil and gas prices.

The impact of changes in estimated proved reserves is dealt with prospectively by amortizing the remaining carrying value of the asset over the expected future production.

Other property, plant and equipment is depreciated on a straight-line basis over its expected useful life. The typical useful lives of the group's other property, plant and equipment on initial recognition are as follows:

Land improvements	15 to 25 years
Buildings	20 to 50 years
Refineries	20 to 30 years
Pipelines	10 to 50 years
Service stations	15 years
Office equipment	3 to 10 years
Fixtures and fittings	5 to 15 years

The expected useful lives and depreciation method of property, plant and equipment are reviewed on an annual basis and, if necessary, changes in useful lives or the depreciation method are accounted for prospectively. An item of property, plant and equipment is derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the item) is included in the income statement in the period in which the item is derecognized.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Impairment of property, plant and equipment, intangible assets, goodwill, and equity-accounted entities

The group assesses assets or groups of assets, called cash-generating units (CGUs), for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset or CGU may not be recoverable; for example, changes in the group's business plans, plans to dispose rather than retain assets, changes in the group's assumptions about discount rates, commodity prices, low plant utilization, evidence of physical damage or, for oil and gas assets, significant downward revisions of estimated reserves or increases in estimated future development expenditure or decommissioning costs. If any such indication of impairment exists, the group makes an estimate of the asset's or CGU's recoverable amount. Individual assets are grouped into CGUs for impairment assessment purposes at the lowest level at which there are identifiable cash inflows that are largely independent of the cash inflows of other groups of assets. A CGU's recoverable amount is the higher of its fair value less costs of disposal and its value in use. If it is probable that the value of the CGU will be primarily recovered through a disposal transaction, the expected disposal proceeds are considered in determining the recoverable amount. Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down to its recoverable amount.

The business segment plans, which are approved on an annual basis by senior management, are the primary source of information for the determination of value in use. They contain forecasts for oil and natural gas production, power generation, refinery throughputs, sales volumes for various types of refined products (e.g. gasoline and lubricants), revenues, costs and capital expenditure. Carbon taxes and costs of emissions allowances are included in estimates of future cash flows, where applicable, based on the regulatory environment in each jurisdiction in which the group operates. As an initial step in the preparation of these plans, various assumptions regarding market conditions, such as oil prices, natural gas prices, power prices, refining margins, refined product margins and cost inflation rates are set by senior management. These assumptions take account of existing prices, global supply-demand equilibrium for oil and natural gas, other macroeconomic factors and historical trends and variability. In assessing value in use, the estimated future cash flows are adjusted for the risks specific to the asset group to the extent that they are not already reflected in the discount rate and are discounted to their present value typically using a pre-tax discount rate that reflects current market assessments of the time value of money.

Fair value less costs of disposal is the price that would be received to sell the asset in an orderly transaction between market participants and does not reflect the effects of factors that may be specific to the group and not applicable to entities in general. Fair value may be determined by reference to agreed or expected sales proceeds, recent market transactions for similar assets or using discounted cash flow analyses. Where discounted cash flow analyses are used to calculate fair value less costs of disposal, estimates are made about the assumptions market participants would use when pricing the asset, CGU or group of CGUs containing goodwill and the test is performed on a post-tax basis.

An assessment is made at each reporting date as to whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. If such an indication exists, the recoverable amount is estimated. A previously recognized impairment loss is reversed only if there has been a change in the estimates used to determine the asset's or CGU's recoverable amount since the last impairment loss was recognized. If that is the case, the carrying amount of the asset or CGU is increased to the lower of its recoverable amount and the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the asset or CGU in prior years. Impairment reversals are recognized in profit or loss. After a reversal, the depreciation charge is adjusted in future periods to allocate the asset's or CGU's revised carrying amount, less any residual value, on a systematic basis over its remaining useful life.

Goodwill is reviewed for impairment annually or more frequently if events or changes in circumstances indicate the recoverable amount of the group of CGUs to which the goodwill relates should be assessed. In assessing whether goodwill has been impaired, the carrying amount of the group of CGUs to which goodwill has been allocated is compared with its recoverable amount. Where the recoverable amount of the group of CGUs is less than the carrying amount (including goodwill), an impairment loss is recognized. An impairment loss recognized for goodwill is not reversed in a subsequent period.

The group assesses investments in equity-accounted entities for impairment whenever there is objective evidence that the investment is impaired, after recognizing its share of any losses of the equity-accounted entity itself. If any such objective evidence of impairment exists, the carrying amount of the investment is compared with its recoverable amount, being the higher of its fair value less costs of disposal and value in use. If the carrying amount exceeds the recoverable amount, the investment is written down to its recoverable amount.

Significant judgements and estimates: recoverability of asset carrying values

Determination as to whether, and by how much, an asset, CGU, or group of CGUs containing goodwill is impaired involves management estimates on highly uncertain matters such as the effects of inflation and deflation on operating expenses, discount rates, capital expenditure, carbon pricing (where applicable), production profiles, reserves and resources, and future commodity prices, including the outlook for global or regional market supply-and-demand conditions for crude oil, natural gas, power and refined products. Judgement is required when determining the appropriate grouping of assets into a CGU or the appropriate grouping of CGUs for impairment testing purposes. For example, individual oil and gas properties may form separate CGUs whilst certain oil and gas properties with shared infrastructure may be grouped together to form a single CGU. Alternative groupings of assets or CGUs may result in a different outcome from impairment testing. See **Note 14** for details on how these groupings have been determined in relation to the impairment testing of goodwill.

As described above, the recoverable amount of an asset is the higher of its value in use and its fair value less costs of disposal. Fair value less costs of disposal may be determined based on expected sales proceeds or similar recent market transaction data.

Details of impairment charges and reversals recognized in the income statement are provided in **Note 4** and details on the carrying amounts of assets are shown in **Note 12, Note 14 and Note 15**.

The estimates for assumptions made in impairment tests in 2025 relating to discount rates and oil and gas properties are discussed below. Changes in the economic environment including as a result of the energy transition or other facts and circumstances may necessitate revisions to these assumptions and could result in a material change to the carrying values of the group's assets within the next financial year.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Discount rates

For discounted cash flow calculations, future cash flows are adjusted for risks specific to the CGU. Value-in-use calculations are typically discounted using a pre-tax discount rate based upon the cost of funding the group derived from an established model, adjusted to a pre-tax basis and incorporating a market participant capital structure and country risk premiums. Fair value less costs of disposal discounted cash flow calculations use a post-tax discount rate.

The discount rates applied in impairment tests are reassessed each year and, in 2025, the post-tax discount rate was 8% (2024 8%) other than for renewable power assets. Where the CGU is located in a country that was judged to be higher risk, an additional premium of 1% to 3% was reflected in the post-tax discount rate (2024 1% to 3%). The judgement of classifying a country as higher risk and the applicable premium takes into account various economic and geopolitical factors. The pre-tax discount rate, other than for renewable power assets, typically ranged from 9% to 18% (2024 9% to 20%) depending on the risk premium and applicable tax rate in the geographic location of the CGU. For renewable power assets tested on a value-in-use basis, primarily the CGUs for which goodwill was allocated following the Lightsources bp acquisition, a WACC-based post-tax discount rate of 7% was used. For renewable power assets tested on a fair-value basis, primarily offshore wind assets (including those in equity accounted entities), a post-tax cost of equity-based discount rate range of 8.75% to 9.5% (2024 8.75% to 9.5%) was used.

Oil and natural gas properties

For oil and natural gas properties in the oil production & operations and gas & low carbon energy segments, expected future cash flows are estimated using management's best estimate of future oil and natural gas prices, production and reserves and certain resources volumes. Forecast cash flows include the impact of all approved emission reduction projects. The estimated future level of production in all impairment tests is based on assumptions about future commodity prices, production and development costs, field decline rates, current fiscal regimes and other factors.

In 2025, the group identified oil and gas properties in these segments with carrying amounts totalling \$20,341 million (2024 \$17,853 million) where the headroom, based on the most recent impairment test performed in the year on those assets, was less than or equal to 20% of the carrying value. A change in the discount rate, reserves, resources or the oil and gas price assumptions in the next financial year may result in a recoverable amount of one or more of these assets above or below the current carrying amount and therefore there is a risk of impairment reversals or charges in that period. Management considers that reasonably possible changes in the discount rate or forecast revenue, arising from a change in oil and natural gas prices and/or production could result in a material change in their carrying amounts within the next financial year, see Sensitivity analyses, below.

The recoverability of intangible exploration and appraisal expenditure is covered under Oil and natural gas exploration, appraisal and development expenditure above.

Oil and natural gas prices

The price assumptions used for value-in-use impairment testing are based on those used for investment appraisal. bp's carbon emissions cost assumptions and their interrelationship with oil and gas prices are described in 'Judgements and estimates made in assessing the impact of climate change and the transition to a lower carbon economy' on [page 160](#). The investment appraisal price assumptions were recommended by the senior vice president economic & energy insights after considering a range of external price sets, and supply and demand profiles associated with various energy transition scenarios. They were reviewed and approved by management. As a result of the current uncertainty over the pace of transition to lower-carbon supply and demand and the social, political and environmental actions that will be taken to meet the goals of the Paris climate change agreement, the scenarios considered include those where those goals are met as well as those where they are not met.

During the year, bp's price assumptions applied in value-in-use impairment testing were revised. The revised price assumptions have been rebased in real 2024 terms. Brent oil prices in real 2024 terms were reduced to \$70 per barrel. Medium to long term prices steadily decline to a higher price of \$60 per barrel by 2050 continuing to reflect the assumption that the energy system decarbonizes but at a slower rate. The price assumptions for the Henry Hub price have been reduced in the near term, reflecting higher supply in the market. Prices then steadily increase in the medium term, as supply and demand remain steady at \$4.50 per mmBtu up to 2050. These price assumptions are derived from the central case investment appraisal assumptions. A summary of the group's revised price assumptions for Brent oil and Henry Hub gas, applied in 2025 and 2024, in real 2024 terms, is provided below. The assumptions represent management's best estimate of future prices at the balance sheet date, which sit within the range of external scenarios considered as appropriate for the purpose. They are considered by bp to be in line with a range of transition paths, as collated into the Transition Scenario Catalogue we use in our TCFD assessment, that are considered by source data providers (such as IEA, UN PRI IPR and NGFS) to be consistent with holding the increase in the global average temperature to well below 2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels. However, they do not correspond to any specific Paris-consistent scenario. An inflation rate of 2.0% - 3.0% (2024 2.0%-2.5%) is applied to determine the price assumptions in nominal terms.

The majority of bp's reserves and resources that support the carrying value of the group's existing oil and gas properties are expected to be produced over the next 12 years.

The recoverability of deferred tax assets is also affected by the group's oil and natural gas price assumptions as these could impact the estimate of future taxable profits. See [Note 9](#) for further information.

2025 price assumptions	2026	2030	2040	2050
Brent oil (\$/bbl)	70	70	67	60
Henry Hub gas (\$/mmBtu)	3.80	4.10	4.50	4.50
2024 price assumptions	2025	2030	2040	2050
Brent oil (\$/bbl)	71	71	64	50
Henry Hub gas (\$/mmBtu)	4.07	4.04	4.04	4.04

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Global oil production increased by 3mmb/d (3%) in 2025, with non-OPEC+ countries contributing nearly 60% of the growth. Global oil demand grew by only 0.8% in 2025, almost entirely accounted for by non-OECD countries, following sharp fall in oil demand from Brazil, India and China. The global supply/demand imbalance of around 2.2mmb/d weighed on prices, with Dated Brent down by nearly \$12 per barrel. While geopolitical risk (e.g., tariffs, sanctions) may support prices in the short-term, bp's long-term assumption for oil prices is lower than the 2025 average as oil demand is likely to fall such that the price levels needed to encourage sufficient investment to meet global oil demand will also be lower.

The US Henry Hub (HH) spot price averaged \$3.5 per mmBtu in 2025, up from \$2.2 per mmBtu in 2024 and the highest level since 2022, driven by increased LNG export demand and a colder-than-normal start to the year. Higher gas prices supported a recovery in drilling activity in non-associated (dry) shale plays which, combined with well productivity gains, increasing gas-to-oil ratios in the Permian, and increased pipeline connectivity, meant that US dry gas production grew by 4% year on year and reached record high levels. The level of US gas prices in 2025 was below bp's long term price assumption based on the judgment of the price level required to incentivize new production.

Oil and natural gas reserves

In addition to oil and natural gas prices, significant technical and commercial assessments are required to determine the group's estimated oil and natural gas reserves. Reserves estimates are regularly reviewed and updated. Factors such as the availability of geological and engineering data, reservoir performance data, acquisition and divestment activity and drilling of new wells all impact on the determination of the group's estimates of its oil and natural gas reserves. bp bases its reserves estimates on the requirement of reasonable certainty with rigorous technical and commercial assessments based on conventional industry practice and regulatory requirements.

Reserves assumptions for value-in-use tests reflect the reserves and resources that management currently intend to develop. The recoverable amount of oil and gas properties is determined using a combination of inputs including reserves, resources and production volumes. Risk factors may be applied to reserves and resources which do not meet the criteria to be treated as proved or probable.

Sensitivity analyses

Management considers discount rates, oil and natural gas prices and production to be the key sources of estimation uncertainty in determining the recoverable amount of upstream oil and gas assets. The sensitivity analyses below, in addition to covering the key sources of estimation uncertainty, also indicate how the energy transition, potential future carbon emissions costs for operational GHG emissions and/or reduced demand for oil and gas may further impact forecast revenue cash inflows to a greater extent than currently anticipated in the group's value-in-use estimates for oil and gas CGUs, if carbon emissions costs were to be implemented as a deduction against revenue cash flows. The analyses therefore represent a net revenue sensitivity.

A change in net revenue from upstream oil and gas properties can arise either due to changes in oil and natural gas prices, carbon emissions costs/carbon prices, changes in oil and natural gas production, or a combination of these.

Management tested the impact of changes in net revenue cash flows in value-in-use impairment testing under the following sensitivity analyses: an increase in net revenues of 8% in all years up to 2040, and 25% in all remaining years to 2050; and a decrease in net revenues of 20% in all years up to 2030, 35% in all subsequent years to 2040 and 50% in all remaining years to 2050.

Net revenue reductions of this magnitude in isolation could indicatively lead to a reduction in the carrying amount of bp's currently held upstream oil and gas properties in the range of \$20-21 billion which is approximately 34% of the associated net book value of property, plant and equipment as at 31 December 2025. If this net revenue reduction was due to reductions in prices in isolation, it reflects an indicative decrease in the carrying amount of using price assumptions for Brent oil trending broadly towards the bottom of the range of prices associated with the 'family' of scenarios in our Transition Scenario Catalogue considered, by source data providers, to be consistent with limiting global average temperature to 1.5°C above pre-industrial levels. This Catalogue of scenarios is also used in bp's TCFD resilience scenario analysis.

Net revenue increases of this magnitude in isolation could indicatively lead to an increase in the carrying amount of bp's currently held upstream oil and gas properties in the range of \$1-2 billion which is approximately 2-3% of the associated net book value of property, plant and equipment as at 31 December 2025. This potential increase in the carrying amount would arise due to reversals of previously recognized impairments and represents approximately 15% of the total impairment reversal capacity available at 31 December 2025. If this net revenue increase was due to increases in prices in isolation, it reflects an indicative increase in the carrying amount of using price assumptions for Brent oil trending broadly aligned with the top end until the mid-2040s, and then towards the mean average at 2050, of the range of prices associated with the Transition Scenario Catalogue of scenarios (which included the IEA's World Energy Outlook Net Zero Emissions by 2050 (NZE) scenario) considered by IEA to be consistent with limiting global average temperature to 1.5°C above pre-industrial levels.

These sensitivity analyses do not, however, represent management's best estimate of any impairment charges or reversals that might be recognized as they do not fully incorporate consequential changes that may arise, such as changes in costs and business plans and phasing of development. For example, costs across the industry are more likely to decrease as oil and natural gas prices fall. The analyses also assume the impact of increases in carbon price on operational GHG emissions are fully absorbed as a decrease in net revenue (and vice versa) rather than reflecting how carbon prices or other carbon emissions costs may ultimately be incorporated by the market. The above sensitivity analyses therefore do not reflect a linear relationship between net revenue and value that can be extrapolated. The interdependency of these inputs and factors plus the diverse characteristics of the group's upstream oil and gas properties limits the practicability of estimating the probability or extent to which the overall recoverable amount is impacted by changes to the price assumptions or production volumes.

Management also tested the impact of a one percentage point change in the discount rate used for value-in-use impairment testing of upstream oil and gas properties. This level of change reflects past experience of a reasonable change in rate that could arise within the next financial year. If the discount rate was one percentage point higher across all tests performed, the net impairment loss recognized in 2025 would have been approximately \$0.2 billion higher. If the discount rate was one percentage point lower, the net impairment loss recognized would have been approximately \$0.5 billion lower.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Management considers discount rate, renewable natural gas prices, and the level of capital expenditure and its consequential impact on production volumes to be the key sources of estimation uncertainty in determining the recoverable amount of the group's renewable natural gas assets owned by Archaea Energy.

A change in revenue from renewable natural gas assets could arise either due to changes in renewable natural gas prices, changes in renewable natural gas production, principally as a result of changes in capital invested, or a combination of both.

Management tested the impact of changes in net revenue cash flows on its value-in-use impairment testing. It is estimated that a reduction in revenue across all Archaea Energy assets of 10% would have resulted in an additional impairment charge of \$0.5 billion. It is estimated that an increase in revenue of 10% would have resulted in a reduction to the impairment charge of \$0.8 billion.

These sensitivity analyses do not, however, represent management's best estimate of any impairment charges or reversals that might be recognized as they do not fully incorporate consequential changes that may arise, such as changes in capital and operating costs, business plans and phasing of development. The above sensitivity analyses therefore do not reflect a linear relationship between net revenue and value that can be extrapolated. The interdependency of these inputs and factors limits the practicability of estimating the probability or extent to which the overall recoverable amount is impacted by changes to the price assumptions or production volumes.

It is estimated that an increase to the discount rate of 1% would have resulted in an additional impairment charge to Archaea Energy assets of \$0.3 billion. It is estimated that a decrease in the discount rate of 1% would have resulted in a reduction to the impairment charge of \$0.4 billion.

Management considers discount rates and refining margins to be the key sources of estimation uncertainty in determining the recoverable amount of refinery assets. The sensitivity analysis below, in addition to covering the key sources of estimation uncertainty, also indicates how the energy transition and/or reduced demand for refined products may further impact forecast cash inflows to a greater extent than currently anticipated in the group's value-in-use estimates for refinery CGUs.

Management tested the impact of a \$1 per barrel decrease in each refinery's future margin assumption in all years of the value-in-use estimate. A reduction of this magnitude in isolation could indicatively lead to a reduction in the carrying amount of bp's currently held refining property, plant and equipment in the range of \$1-2 billion.

This sensitivity analysis does not, however, represent management's best estimate of any impairment charges that might be recognized as it does not fully incorporate consequential changes that may arise, such as changes in costs and business plans and crude or product slates. The above sensitivity analysis therefore does not reflect a linear relationship between margins and value that can be extrapolated. The interdependency of these inputs and factors plus the varying configurations of the group's refineries limits the practicability of estimating the probability or extent to which the overall recoverable amount is impacted by changes to the margin assumptions.

Management also tested the impact of a one percentage point change in the discount rate used for value-in-use impairment testing of refinery assets. This level of change reflects past experience of a reasonable change in rate that could arise within the next financial year. If the discount rate was one percentage point higher across all tests performed, the net impairment loss recognized in 2025 would have been approximately \$0.5 billion higher. If the discount rate was one percentage point lower there would have been no impact on the net impairment loss recognized in 2025.

Goodwill

Irrespective of whether there is any indication of impairment, bp is required to test annually for impairment of goodwill acquired in business combinations. The group carries goodwill of \$10.3 billion on its balance sheet (2024 \$14.9 billion), principally relating to the Atlantic Richfield, Devon Energy, Reliance transactions and its transition businesses. Of this, \$7.1 billion relates to goodwill in the oil production & operations segment and to hydrocarbon CGUs within the gas & low carbon energy segment (2024 \$7.2 billion), for which oil and gas price and production assumptions are key sources of estimation uncertainty. A further \$0.9 billion relates to the transition businesses in the gas & low carbon energy segment (2024 \$2.9 billion), for which project development revenues and margins, terminal value growth rate and discount rate are key sources of estimation uncertainty. Sensitivities and additional information relating to impairment testing of goodwill in these segments are provided in **Note**

14.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Inventories

Inventories, other than inventories held for short-term trading purposes, are stated at the lower of cost and net realizable value. Cost is typically determined by the first-in first-out method and comprises direct purchase costs, cost of production, transportation and manufacturing expenses. Net realizable value is determined by reference to prices existing at the balance sheet date, adjusted where the sale of inventories after the reporting period gives evidence about their net realizable value at the end of the period.

Inventories held for short-term trading purposes are stated at fair value less costs to sell and any changes in fair value are recognized in the income statement.

Supplies are valued at the lower of cost on a weighted-average basis and net realizable value.

Leases

Agreements that convey the right to control the use of an identified asset for a period of time in exchange for consideration are accounted for as leases. The right to control is conveyed if bp has both the right to obtain substantially all of the economic benefits from, and the right to direct the use of, the identified asset throughout the period of use. An asset is identified if it is explicitly or implicitly specified by the agreement and any substitution rights held by the lessor over the asset are not considered substantive.

Agreements that convey the right to control the use of an intangible asset including rights to explore for or use hydrocarbons are not accounted for as leases. See material accounting policy information: intangible assets.

A lease liability is recognized on the balance sheet on the lease commencement date at the present value of future lease payments over the lease term. The discount rate applied is the rate implicit in the lease if readily determinable, otherwise an incremental borrowing rate is used. For the majority of the leases in the group, there is not sufficient information available to readily determine the rate implicit in the lease, and therefore the incremental borrowing rate is used. The incremental borrowing rate is determined based on factors such as the group's cost of borrowing, lessee legal entity credit risk, currency and lease term. The lease term is the non-cancellable period of a lease together with any periods covered by an extension option that bp is reasonably certain to exercise, or periods covered by a termination option that bp is reasonably certain not to exercise. The future lease payments included in the present value calculation are any fixed payments, payments that vary depending on an index or rate, payments due for the reasonably certain exercise of options and expected residual value guarantee payments. Repayments of principal are presented as financing cash flows and payments of interest are presented as operating cash flows.

Payments that vary based on factors other than an index or a rate such as usage, sales volumes or revenues are not included in the present value calculation and are recognized in the income statement and presented as operating cash flows. The lease liability is recognized on an amortized cost basis with interest expense recognized in the income statement over the lease term, except for where capitalized as exploration, appraisal or development expenditure.

The right-of-use asset is recognized on the balance sheet as property, plant and equipment at a value equivalent to the initial measurement of the lease liability adjusted for lease prepayments, lease incentives, initial direct costs and any restoration obligations. The right-of-use asset is depreciated typically on a straight-line basis over the lease term. The depreciation charge is recognized in the income statement except for where capitalized as exploration, appraisal or development expenditure. Right-of-use assets are assessed for impairment in line with the accounting policy for impairment of property, plant and equipment, intangible assets and goodwill.

Agreements may include both lease and non-lease components. Payments for lease and non-lease components are allocated on a relative stand-alone selling price basis except for leases of retail service stations where the group has elected not to separate non-lease payments from the calculation of the lease liability and right-of-use asset.

If the lease term at commencement of the agreement is less than 12 months, a lease liability and right-of-use asset are not recognized, and a lease expense is recognized in the income statement on a straight-line basis.

If a significant event or change in circumstances, within the control of bp, arises that affects the reasonably certain lease term or there are changes to the lease payments, the present value of the lease liability is remeasured using the revised term and payments, with the right-of-use asset adjusted by an equivalent amount.

Modifications to a lease agreement beyond the original terms and conditions are accounted for as a re-measurement of the lease liability with a corresponding adjustment to the right-of-use asset. Any gain or loss on modification is recognized in the income statement. Modifications that increase the scope of the lease at a price commensurate with the stand-alone selling price are accounted for as a separate new lease.

The group recognizes the full lease liability, rather than its working interest share, for leases entered into on behalf of a joint operation if the group has the primary responsibility for making the lease payments. This may be the case if for example bp, as operator of the joint operation, is the sole signatory to the lease agreement. In such cases, bp's working interest share of the right-of-use asset is recognized if it is jointly controlled by the group and the other joint operators, and a receivable is recognized for the share of the asset transferred to the other joint operators. If bp is a non-operator, a payable to the operator is recognized if they have the primary responsibility for making the lease payments and bp has joint control over the right-of-use asset, otherwise no balances are recognized.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Financial assets

Financial assets are recognized initially at fair value, normally being the transaction price. In the case of financial assets not measured at fair value through profit or loss, directly attributable transaction costs are also included. The subsequent measurement of financial assets depends on their classification, as set out below. The group derecognizes financial assets when the contractual rights to the cash flows expire or the rights to receive cash flows have been transferred to a third party and either substantially all of the risks and rewards of the asset have been transferred, or substantially all the risks and rewards of the asset have neither been retained nor transferred but control of the asset has been transferred. This includes the derecognition of receivables for which discounting arrangements are entered into.

The group classifies its financial asset debt instruments as measured at amortized cost, fair value through other comprehensive income or fair value through profit or loss. The classification depends on the business model for managing the financial assets and the contractual cash flow characteristics of the financial asset.

Financial assets measured at amortized cost

Financial assets are classified as measured at amortized cost when they are held in a business model the objective of which is to collect contractual cash flows and the contractual cash flows represent solely payments of principal and interest. Such assets are carried at amortized cost using the effective interest method if the time value of money is significant. Gains and losses are recognized in profit or loss when the assets are derecognized or impaired and when interest income is recognized using the effective interest method. This category of financial assets includes trade and other receivables.

Financial assets measured at fair value through other comprehensive income

Financial assets are classified as measured at fair value through other comprehensive income when they are held in a business model the objective of which is both to collect contractual cash flows and sell the financial assets, and the contractual cash flows represent solely payments of principal and interest.

Financial assets measured at fair value through profit or loss

Financial assets are classified as measured at fair value through profit or loss when the asset does not meet the criteria to be measured at amortized cost or fair value through other comprehensive income. Such assets are carried on the balance sheet at fair value with gains or losses recognized in the income statement. Derivatives, other than those designated as effective hedging instruments, are included in this category.

Investments in equity instruments

Investments in equity instruments are subsequently measured at fair value through profit or loss unless an election is made on an instrument-by-instrument basis to recognize fair value gains and losses in other comprehensive income.

Derivatives designated as hedging instruments in an effective hedge

Derivatives designated as hedging instruments in an effective hedge are carried on the balance sheet at fair value. The treatment of gains and losses arising from revaluation is described below in the accounting policy for derivative financial instruments and hedging activities.

Cash equivalents

Cash equivalents are held for the purpose of meeting short-term cash commitments and are short-term highly liquid investments that are readily convertible to known amounts of cash, are subject to insignificant risk of changes in value and generally have a maturity of three months or less from the date of acquisition. Cash equivalents are classified as financial assets measured at amortized cost or, in the case of certain money market funds, fair value through profit or loss.

Impairment of financial assets measured at amortized cost

The group assesses on a forward-looking basis the expected credit losses associated with financial assets measured at amortized cost at each balance sheet date. Expected credit losses are measured based on the maximum contractual period over which the group is exposed to credit risk. As lifetime expected credit losses are recognized for trade receivables and the tenor of substantially all other in-scope financial assets is less than 12 months there is no significant difference between the measurement of 12-month and lifetime expected credit losses for the group. The measurement of expected credit losses is a function of the probability of default, loss given default and exposure at default. The expected credit loss is estimated as the difference between the asset's carrying amount and the present value of the future cash flows the group expects to receive discounted at the financial asset's original effective interest rate. The carrying amount of the asset is adjusted, with the amount of the impairment gain or loss recognized in the income statement.

A financial asset or group of financial assets classified as measured at amortized cost is considered to be credit-impaired if there is reasonable and supportable evidence that one or more events that have a detrimental impact on the estimated future cash flows of the financial asset (or group of financial assets) have occurred. Financial assets are written off where the group has no reasonable expectation of recovering amounts due.

Equity instruments

Instruments are classified as either financial liabilities or as equity in accordance with the substance of the contractual arrangements. Instruments that cannot be settled in the group's own equity instruments and that include no contractual obligation to deliver cash or another financial asset or to exchange financial assets or financial liabilities with another entity that are potentially unfavourable are classified as equity.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Financial liabilities

Financial liabilities are recognized when the group becomes party to the contractual provisions of the instrument. The group derecognizes financial liabilities when the obligation specified in the contract is discharged, cancelled or expired. The measurement of financial liabilities depends on their classification, as follows:

Financial liabilities measured at fair value through profit or loss

Financial liabilities that meet the definition of held for trading are classified as measured at fair value through profit or loss. Such liabilities are carried on the balance sheet at fair value with gains or losses recognized in the income statement. Derivatives, other than those designated as effective hedging instruments, are included in this category.

Derivatives designated as hedging instruments in an effective hedge

Derivatives designated as hedging instruments in an effective hedge are carried on the balance sheet at fair value. The treatment of gains and losses arising from revaluation is described below in the accounting policy for derivative financial instruments and hedging activities.

Financial liabilities measured at amortized cost

All other financial liabilities are initially recognized at fair value, net of directly attributable transaction costs. For interest-bearing loans and borrowings this is typically equivalent to the fair value of the proceeds received, net of issue costs associated with the borrowing.

After initial recognition, other financial liabilities are subsequently measured at amortized cost using the effective interest method. Amortized cost is calculated by taking into account any issue costs and any discount or premium on settlement. Gains and losses arising on the repurchase, settlement or cancellation of liabilities are recognized in interest and other income and finance costs respectively.

This category of financial liabilities includes trade and other payables and finance debt.

Significant judgement: supplier financing arrangements

The group's trade payables include some supplier financing arrangements that utilize letter of credit facilities, promissory notes and reverse factoring. Judgement is required to assess the payables subject to these arrangements to determine whether they should continue to be classified as trade payables and give rise to operating cash flows or finance debt and financing cash flows. The criteria used in making this assessment include the payment terms for the amount due relative to terms commonly seen in the markets in which bp operates and whether the arrangements significantly change the nature of the liability. Liabilities subject to these arrangements with payment terms of up to approximately 60 days are generally considered to be trade payables and give rise to operating cash flows. See **Note 29** - Liquidity risk for further information.

Financial guarantees

The group issues financial guarantee contracts to make specified payments to reimburse holders for losses incurred if certain associates, joint ventures or third-party entities fail to make payments when due in accordance with the original or modified terms of a debt instrument such as a loan. The liability for a financial guarantee contract is initially measured at fair value and subsequently measured at the higher of the contract's estimated expected credit loss and the amount initially recognized less, where appropriate, cumulative amortization.

Derivative financial instruments and hedging activities

The group uses derivative financial instruments to manage certain exposures to fluctuations in foreign currency exchange rates, interest rates and commodity prices, as well as for trading purposes. These derivative financial instruments are recognized initially at fair value on the date on which a derivative contract is entered into and subsequently remeasured at fair value. Derivatives are carried as assets when the fair value is positive and as liabilities when the fair value is negative.

Contracts to buy or sell a non-financial item (for example, oil, oil products, gas or power) that can be settled net in cash, with the exception of contracts that were entered into and continue to be held for the purpose of the receipt or delivery of a non-financial item in accordance with the group's expected purchase, sale or usage requirements, are accounted for as financial instruments. Gains or losses arising from changes in the fair value of derivatives that are not designated as effective hedging instruments are recognized in the income statement.

If, at inception of a contract, the valuation cannot be supported by observable market data, any gain or loss determined by the valuation methodology is not recognized in the income statement but is deferred on the balance sheet and is commonly known as a 'day-one gain or loss'. This deferred gain or loss is recognized in the income statement over the life of the contract until substantially all the remaining contractual cash flows can be valued using observable market data at which point any remaining deferred gain or loss is recognized in the income statement. Changes in valuation subsequent to the initial valuation at inception of a contract are recognized immediately in the income statement.

For the purpose of hedge accounting, hedges are classified as:

- Fair value hedges when hedging exposure to changes in the fair value of a recognized asset or liability.
- Cash flow hedges when hedging exposure to variability in cash flows that is attributable to either a particular risk associated with a recognized asset or liability or a highly probable forecast transaction.

Hedge relationships are formally designated and documented at inception, together with the risk management objective and strategy for undertaking the hedge. The documentation includes identification of the hedging instrument, the hedged item or transaction, the nature of the risk being hedged, the existence at inception of an economic relationship and subsequent measurement of the hedging instrument's effectiveness in offsetting the exposure to changes in the hedged item's fair value or cash flows attributable to the hedged risk, the hedge ratio and sources of hedge ineffectiveness. Hedges meeting the criteria for hedge accounting are accounted for as follows:

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Fair value hedges

The change in fair value of a hedging derivative is recognized in profit or loss. The change in the fair value of the hedged item attributable to the risk being hedged is recorded as part of the carrying value of the hedged item and is also recognized in profit or loss, where it offsets. The group applies fair value hedge accounting when hedging interest rate risk and certain currency risks on fixed rate finance debt.

Fair value hedge accounting is discontinued only when the hedging relationship or a part thereof ceases to meet the qualifying criteria. This includes when the risk management objective changes or when the hedging instrument is sold, terminated or exercised. The accumulated adjustment to the carrying amount of a hedged item at such time is then amortized prospectively to profit or loss as finance interest expense over the hedged item's remaining period to maturity.

Cash flow hedges

The effective portion of the gain or loss on a cash flow hedging instrument is reported in other comprehensive income, while the ineffective portion is recognized in profit or loss. Amounts reported in other comprehensive income are reclassified to the income statement when the hedged transaction affects profit or loss.

Where the hedged item is a highly probable forecast transaction that results in the recognition of a non-financial asset or liability, such as a forecast foreign currency transaction for the purchase of property, plant and equipment, the amounts recognized within other comprehensive income are transferred to the initial carrying amount of the non-financial asset or liability. Where the hedged item is an equity investment, the amounts recognized in other comprehensive income remain in the separate component of equity until the hedged cash flows affect profit or loss or when accounting under the equity method is discontinued. Where the hedged item is recognized directly in profit or loss, the amounts recognized in other comprehensive income are reclassified to production and manufacturing expenses or sales and other operating revenues as appropriate.

Cash flow hedge accounting is discontinued only when the hedging relationship or a part thereof ceases to meet the qualifying criteria. This includes when the designated hedged forecast transaction or part thereof is no longer considered to be highly probable to occur, or when the hedging instrument is sold, terminated or exercised without replacement or rollover. When cash flow hedge accounting is discontinued amounts previously recognized within other comprehensive income remain in equity until the forecast transaction occurs and are reclassified to profit or loss or transferred to the initial carrying amount of a non-financial asset or liability as above. If the forecast transaction is no longer expected to occur, amounts previously recognized within other comprehensive income will be immediately reclassified to profit or loss.

Costs of hedging

The foreign currency basis spread of cross-currency interest rate swaps are excluded from hedge designations and accounted for as costs of hedging. Changes in fair value of the foreign currency basis spread are recognized in other comprehensive income to the extent that they relate to the hedged item.

For time-period related hedged items, the amount recognized in other comprehensive income is amortized to profit or loss on a straight line basis over the term of the hedging relationship.

Fair value measurement

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. The group categorizes assets and liabilities measured at fair value into one of three levels depending on the ability to observe inputs employed in their measurement. Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Level 2 inputs are inputs that are observable, either directly or indirectly, other than quoted prices included within level 1 for the asset or liability. Level 3 inputs are unobservable inputs for the asset or liability reflecting significant modifications to observable related market data or bp's assumptions about pricing by market participants.

Significant estimate and judgement: derivative financial instruments

In some cases the fair values of derivatives are estimated using internal models due to the absence of quoted prices or other observable, market-corroborated data. This primarily applies to the group's longer-term derivative contracts. The majority of these contracts are valued using models with inputs that include price curves for each of the different products that are built up from available active market pricing data (including volatility and correlation) and modelled using the maximum available external information. Additionally, where limited data exists for certain products, prices are determined using historical and long-term pricing relationships. The use of alternative assumptions or valuation methodologies may result in significantly different values for these derivatives. A reasonably possible change in the price assumptions used in the models relating to index price would not have a material impact on net assets and the Group income statement primarily as a result of offsetting movements between derivative assets and liabilities.

In some cases, judgement is required to determine whether contracts to buy or sell commodities meet the definition of a derivative or to determine appropriate presentation and classification of transactions in certain cases. In particular, contracts to buy and sell LNG are not considered to meet the definition as they are not considered capable of being net settled due to a lack of liquidity in the LNG market and the inability or lack of history of net settlement and are accounted for on an accruals basis, rather than as a derivative. Under IFRS, bp fair values the derivative financial instruments used to risk-manage the LNG contracts themselves, resulting in a measurement mismatch.

For more information, including the carrying amounts of level 3 derivatives, see **Note 30**.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Offsetting of financial assets and liabilities

Financial assets and liabilities are presented gross in the balance sheet unless both of the following criteria are met: the group currently has a legally enforceable right to set off the recognized amounts; and the group intends to either settle on a net basis or realize the asset and settle the liability simultaneously. A right of set off is the group's legal right to settle an amount payable to a creditor by applying against it an amount receivable from the same counterparty. The relevant legal jurisdiction and laws applicable to the relationships between the parties are considered when assessing whether a current legally enforceable right to set off exists.

Provisions and contingencies

Provisions are recognized when the group has a present legal or constructive obligation as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. Where appropriate, the future cash flow estimates are adjusted to reflect risks specific to the liability.

If the effect of the time value of money is material, provisions are determined by discounting the expected future cash flows at a pre-tax risk-free rate that reflects current market assessments of the time value of money. Where discounting is used, the increase in the provision due to the passage of time is recognized within finance costs. Provisions are discounted using a nominal discount rate of 4.5% (2024 4.5%).

Provisions are split between amounts expected to be settled within 12 months of the balance sheet date (current) and amounts expected to be settled later (non-current).

Contingent liabilities are possible obligations whose existence will only be confirmed by future events not wholly within the control of the group, or present obligations where it is not probable that an outflow of resources will be required or the amount of the obligation cannot be measured with sufficient reliability. Contingent liabilities are not recognized in the consolidated financial statements but are disclosed, if material, unless the possibility of an outflow of economic resources is considered remote.

Decommissioning

Liabilities for decommissioning costs are recognized when the group has an obligation to plug and abandon a well, dismantle and remove a facility or an item of plant and to restore the site on which it is located, and when a reliable estimate of that liability can be made. Where an obligation exists for a new facility or item of plant, such as oil and natural gas production or transportation facilities, this liability will be recognized on construction or installation. Similarly, where an obligation exists for a well, this liability is recognized when it is drilled. An obligation for decommissioning may also crystallize during the period of operation of a well, facility or item of plant through a change in legislation or through a decision to terminate operations; an obligation may also arise in cases where an asset has been sold but the subsequent owner is no longer able to fulfil its decommissioning obligations, for example due to bankruptcy. The amount recognized is the present value of the estimated future expenditure determined in accordance with local conditions and requirements. The provision for the costs of decommissioning wells, production facilities and pipelines at the end of their economic lives is estimated using existing technology, at future prices, depending on the expected timing of the activity, and discounted using a nominal discount rate.

An amount equivalent to the decommissioning provision is recognized as part of the corresponding intangible asset (in the case of an exploration or appraisal well) or property, plant and equipment. The decommissioning portion of the property, plant and equipment is subsequently depreciated at the same rate as the rest of the asset. Other than the unwinding of discount on or utilization of the provision, any change in the present value of the estimated expenditure is reflected as an adjustment to the provision and the corresponding asset where that asset is generating or is expected to generate future economic benefits.

Environmental expenditures and liabilities

Environmental expenditures that are required in order for the group to obtain future economic benefits from its assets are capitalized as part of those assets. Expenditures that relate to an existing condition caused by past operations that do not contribute to future earnings are expensed.

Liabilities for environmental costs are recognized when a clean-up is probable and the associated costs can be reliably estimated. Generally, the timing of recognition of these provisions coincides with the commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites.

The amount recognized is the best estimate of the expenditure required to settle the obligation. Provisions for environmental liabilities have been estimated using existing technology, at future prices and discounted using a nominal discount rate.

Emissions

Liabilities for emissions are recognized when the cumulative volumes of gases emitted by the group at the end of the reporting period exceed the allowances granted free of charge held for own use or a set baseline for emissions. The provision is measured at the best estimate of the expenditure required to settle the present obligation at the balance sheet date. It is based on the excess of actual emissions over the free allowances held or set baseline in tonnes (or other appropriate quantity) and is valued at the actual cost of any allowances that have been purchased and held for own use on a first-in-first-out (FIFO) basis, and, if insufficient allowances are held, for the remaining requirement on the basis of the spot market price of allowances at the balance sheet date. The majority of these provisions are typically settled within 12 months of the balance sheet date however certain schemes may have longer compliance periods. The cost of allowances purchased to cover a shortfall is recognized separately on the balance sheet as an intangible asset unless the emission allowances acquired or generated by the group are risk-managed by the trading and shipping function, then they are recognized on the balance sheet as inventory.

Restructuring provisions

Restructuring provisions are recognized where a detailed formal plan exists, and a valid expectation of risk of redundancy has been made to those affected but where the specific outcomes remain uncertain. Where formal redundancy offers have been made, the obligations for those amounts are reported as payables and, if not, as provisions if unpaid at the year-end.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Significant judgements and estimates: provisions

The group holds provisions for the future decommissioning of oil and natural gas production facilities and pipelines at the end of their economic lives. The largest decommissioning obligations facing bp relate to the plugging and abandonment of wells and the removal and disposal of oil and natural gas platforms and pipelines around the world. Most of these decommissioning events are many years in the future and the precise requirements that will have to be met when the removal event occurs are uncertain. Decommissioning technologies and costs are constantly changing, as are political, environmental, safety and public expectations. The timing and amounts of future cash flows are subject to significant uncertainty and estimation is required in determining the amounts of provisions to be recognized. Any changes in the expected future costs are reflected in both the provision and, where still recognized, the asset.

If oil and natural gas production facilities and pipelines are sold to third parties, judgement is required to assess whether the new owner will be unable to meet their decommissioning obligations, whether bp would then be responsible for decommissioning, and if so the extent of that responsibility. This typically requires assessment of the local legal requirements and the financial standing of the owner. If the standing deteriorates significantly, for example, bankruptcy of the owner, a provision may be required. The group has \$0.6 billion of decommissioning provisions recognized as at 31 December 2025 (2024 \$0.7 billion) for assets previously sold to third parties where the sale transferred the decommissioning obligation to the new owner. See **Note 33** for further information.

Decommissioning provisions associated with refineries are generally not recognized, as the potential obligations cannot be measured, given their indeterminate settlement dates. Obligations may arise if refineries cease manufacturing operations and any such obligations would be recognized in the period when sufficient information becomes available to determine potential settlement dates. See **Note 33** for further information.

The group performs periodic reviews of its refineries for any changes in facts and circumstances including those relating to the energy transition, that might require the recognition of a decommissioning provision. Portfolio strength and flexibility are such that the point of cessation of manufacturing at the group's operating refineries is not yet expected within a determinate time period, as existing property plant and equipment is expected to be renewed or replaced.

The provision for environmental liabilities is estimated based on current legal and constructive requirements, technology, price levels and expected plans for remediation. Actual costs and cash outflows can differ from current estimates because of changes in laws and regulations, public expectations, prices, discovery and analysis of site conditions and changes in clean-up technology.

The timing and amount of future expenditures relating to decommissioning and environmental liabilities are reviewed annually. The interest rate used in discounting the cash flows is reviewed quarterly. The nominal interest rate used to determine the balance sheet obligations at the end of 2025 was 4.5% (2024 4.5%), which was based on long-dated US government bonds interpolated to reflect the expected weighted average time to decommissioning. The weighted average period over which decommissioning and environmental costs are generally expected to be incurred is estimated to be approximately 16 years (2024 17 years) and 7 years (2024 7 years) respectively. Costs at future prices are typically determined by applying an inflation rate of 1.5% (2024 1.5%) to decommissioning costs and 2% (2024 2%) for all other provisions. A lower rate is typically applied to decommissioning as certain costs are expected to remain fixed at current or past prices.

The estimated phasing of undiscounted cash flows in real terms for upstream decommissioning is approximately \$5.7 billion (2024 \$5.5 billion) within the next 10 years, \$6.0 billion (2024 \$6.2 billion) in 10 to 20 years and the remainder of approximately \$7.0 billion (2024 \$6.7 billion) after 20 years. The timing and amount of decommissioning cash flows are inherently uncertain and therefore the phasing is management's current best estimate but may not be what will ultimately occur.

Further information about the group's provisions is provided in **Note 23**. Changes in assumptions in relation to the group's provisions could result in a material change in their carrying amounts within the next financial year. A 1.0 percentage point increase in the nominal discount rate applied could decrease the group's provision balances by approximately \$1.4 billion (2024 \$1.5 billion). The pre-tax impact on the group income statement would be a credit of approximately \$0.3 billion (2024 \$0.4 billion). This level of change reflects past experience of a reasonable change in rate that could arise within the next financial year.

The discounting impact on the group's decommissioning provisions for oil and gas properties in the oil productions & operations and gas & low carbon energy segments of a two-year change in the timing of expected future decommissioning expenditures is approximately \$0.7 billion (2024 \$0.3 billion). Management currently does not consider a change of greater than two years to be reasonably possible in the next financial year and therefore the timing of upstream decommissioning expenditure is not a key source of estimation uncertainty.

If all expected future decommissioning expenditures were 10% higher, then these decommissioning provisions would increase by approximately \$1.2 billion (2024 \$1.2 billion) and a pre-tax charge of approximately \$0.3 billion (2024 \$0.4 billion) would be recognized. A one percentage point increase in the inflation rate applied to upstream decommissioning costs to determine the nominal cash flows could increase the decommissioning provision by approximately \$1.8 billion (2024 \$1.7 billion) with a pre-tax charge of approximately \$0.4 billion (2024 \$0.5 billion).

As described in **Note 33**, the group is subject to claims and actions for which no provisions have been recognized. The facts and circumstances relating to particular cases are evaluated regularly in determining whether a provision relating to a specific litigation should be recognized or revised. Accordingly, significant management judgement relating to provisions and contingent liabilities is required, since the outcome of litigation is difficult to predict.

Employee benefits

Wages, salaries, bonuses, social security contributions, paid annual leave and sick leave are accrued in the period in which the associated services are rendered by employees of the group. Deferred bonus arrangements that have a vesting date more than 12 months after the balance sheet date are valued on an actuarial basis using the projected unit credit method and amortized on a straight-line basis over the service period until the award vests. The material accounting policy information for pensions and other post-employment benefits are described below.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Pensions and other post-employment benefits

The cost of providing benefits under the group's defined benefit plans is determined separately for each plan using the projected unit credit method, which attributes entitlement to benefits to the current period to determine current service cost and to the current and prior periods to determine the present value of the defined benefit obligation. Past service costs, resulting from either a plan amendment or a curtailment (a reduction in future obligations as a result of a material reduction in the plan membership), are recognized immediately when the company becomes committed to a change.

Net interest expense relating to pensions and other post-employment benefits, which is recognized in the income statement, represents the net change in present value of plan obligations and the value of plan assets resulting from the passage of time, and is determined by applying the discount rate to the present value of the benefit obligation at the start of the year, and to the fair value of plan assets at the start of the year, taking into account expected changes in the obligation or plan assets during the year.

Remeasurements of the defined benefit liability and asset, comprising actuarial gains and losses, and the return on plan assets (excluding amounts included in net interest described above) are recognized within other comprehensive income in the period in which they occur and are not subsequently reclassified to profit and loss.

The defined benefit pension plan surplus or deficit recognized on the balance sheet for each plan comprises the difference between the present value of the defined benefit obligation (using a discount rate based on high quality corporate bonds) and the fair value of plan assets out of which the obligations are to be settled directly. Fair value is based on market price information and, in the case of quoted securities, is the published bid price. Defined benefit pension plan surpluses are only recognized to the extent they are recoverable, either by way of a refund from the plan or reductions in future contributions to the plan.

Contributions to defined contribution plans are recognized in the income statement in the period in which they become payable.

Significant estimate: pensions and other post-employment benefits

Accounting for defined benefit pensions and other post-employment benefits involves making significant estimates when measuring the group's pension plan surpluses and deficits. These estimates require assumptions to be made about many uncertainties.

Pensions and other post-employment benefit assumptions are reviewed by management at the end of each year. These assumptions are used to determine the projected benefit obligation at the year end and hence the surpluses and deficits recorded on the group's balance sheet and pension and other post-employment benefit expense for the following year.

The assumptions that are the most significant to the amounts reported are the discount rate, inflation rate and mortality levels. Assumptions about these variables are based on the environment in each country. The assumptions used vary from year to year, with resultant effects on future net income and net assets. Changes to some of these assumptions, in particular the discount rate and inflation rate, could result in material changes to the carrying amounts of the group's pension and other post-employment benefit obligations within the next financial year. Any differences between these assumptions and the actual outcome will also affect future net income and net assets.

The values ascribed to these assumptions and a sensitivity analysis of the impact of changes in the assumptions on the benefit expense and obligation used are provided in **Note 24**.

Income taxes

Income tax expense represents the sum of current tax and deferred tax.

Income tax is recognized in the income statement, except to the extent that it relates to items recognized in other comprehensive income or directly in equity, in which case the related tax is recognized in other comprehensive income or directly in equity.

Current tax is based on the taxable profit for the period. Taxable profit differs from net profit as reported in the income statement because it is determined in accordance with the rules established by the applicable taxation authorities. It therefore excludes items of income or expense that are taxable or deductible in other periods as well as items that are never taxable or deductible. The group's liability for current tax is calculated using tax rates and laws that have been enacted or substantively enacted by the balance sheet date.

Deferred tax is provided, using the liability method, on temporary differences at the balance sheet date between the tax bases of assets and liabilities and their carrying amounts for financial reporting purposes. Deferred tax liabilities are recognized for all taxable temporary differences except:

- Where the deferred tax liability arises on the initial recognition of goodwill.
- Where the deferred tax liability arises on the initial recognition of an asset or liability in a transaction that is not a business combination, at the time of the transaction, affects neither accounting profit nor taxable profit or loss and, at the time of the transaction, does not give rise to equal taxable and deductible temporary differences.
- In respect of taxable temporary differences associated with investments in subsidiaries and associates and interests in joint arrangements, where the group is able to control the timing of the reversal of the temporary differences and it is probable that the temporary differences will not reverse in the foreseeable future.

Deferred tax assets are recognized for deductible temporary differences, carry-forward of unused tax credits and unused tax losses, to the extent that it is probable that taxable profit will be available against which the deductible temporary differences and the carry-forward of unused tax credits and unused tax losses can be utilized, except where the deferred tax asset relating to the deductible temporary difference arises from the initial recognition of an asset or liability in a transaction that is not a business combination, at the time of the transaction, affects neither accounting profit nor taxable profit or loss and, at the time of the transaction, does not give rise to equal taxable and deductible temporary differences.

In respect of deductible temporary differences associated with investments in subsidiaries and associates and interests in joint arrangements, deferred tax assets are recognized only to the extent that it is probable that the temporary differences will reverse in the foreseeable future and taxable profit will be available against which the temporary differences can be utilized.

The carrying amount of deferred tax assets is reviewed at each balance sheet date and reduced to the extent that it is no longer probable or increased to the extent that it is probable that sufficient taxable profit will be available to allow all or part of the deferred tax asset to be utilized.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply in the period when the asset is realized or the liability is settled, based on tax rates (and tax laws) that have been enacted or substantively enacted at the balance sheet date. Deferred tax assets and liabilities are not discounted.

Deferred tax assets and liabilities are offset only when there is a legally enforceable right to set off current tax assets against current tax liabilities and when the deferred tax assets and liabilities relate to income taxes levied by the same taxation authority on either the same taxable entity or different taxable entities where there is an intention to settle the current tax assets and liabilities on a net basis or to realize the assets and settle the liabilities simultaneously.

Where tax treatments are uncertain, if it is considered probable that a taxation authority will accept the group's proposed tax treatment, income taxes are recognized consistent with the group's income tax filings. If it is not considered probable, the uncertainty is reflected within the carrying amount of the applicable tax asset or liability using either the most likely amount or an expected value, depending on which method better predicts the resolution of the uncertainty.

The computation of the group's income tax expense and liability involves the interpretation of applicable tax laws and regulations in many jurisdictions throughout the world. The resolution of tax positions taken by the group, through negotiations with relevant tax authorities or through litigation, can take several years to complete and in some cases it is difficult to predict the ultimate outcome. Therefore, judgement is required to determine whether provisions for income taxes are required and, if so, estimation is required of the amounts that could be payable.

In addition, the group has carry-forward tax losses and tax credits in certain taxing jurisdictions that are available to offset against future taxable profit. However, deferred tax assets are recognized only to the extent that it is probable that taxable profit will be available against which the unused tax losses or tax credits can be utilized. Management judgement is exercised in assessing whether this is the case and estimates are required to be made of the amount of future taxable profits that will be available. Such judgements are inherently impacted by estimates affecting future taxable profits such as oil and natural gas prices and decommissioning expenditure, see 'Significant judgements and estimates: recoverability of asset carrying values and provisions'.

The group is subject to legislation which implements the OECD Pillar Two Model rules in the UK and many other countries around the world. The legislation is designed to ensure a minimum effective tax rate of 15% in each country in which the group operates. In the UK this includes an income inclusion rule and a domestic minimum tax. In line with the amendments to IAS 12, the exception from recognising and disclosing information about deferred tax assets and liabilities related to Pillar Two income taxes has been applied.

In October 2024, the UK government announced changes (effective from 1 November 2024) to the Energy Profits Levy including a 3% increase in the rate taking the headline rate of tax on North Sea profits to 78%, an extension to the period of application of the Levy to 31 March 2030 and the removal of the Levy's main investment allowance. The changes to the rate and to the investment allowance were substantively enacted in 2024. The extension of the Levy to 31 March 2030 was substantively enacted in 2025 resulting in a non-cash deferred tax charge of \$539 million in the year.

On 11 July 2025, the German federal government substantively enacted a number of changes to its tax legislation, including a 5% reduction in the corporate income tax rate by 2032. The reduction in the tax rate will be phased in by means of a 1% reduction each year between 2028 and 2032 and resulted in a non-cash deferred tax charge of \$235 million in the year.

Significant judgement and estimate: taxation

The value of deferred tax assets and liabilities is an area involving inherent uncertainty and estimation and balances are therefore subject to risk of material change as a result of underlying assumptions and judgements used, in particular the forecast of future profitability used to determine the recoverability of deferred tax, for example future oil and gas prices, see 'Significant judgement and estimates - Recoverability of asset carrying values'. It is impracticable to disclose the extent of the possible effects of profitability assumptions on the group's deferred tax assets. It is reasonably possible that to the extent that actual outcomes differ from management's estimates, material income tax charges or credits, and material changes in current and deferred tax assets or liabilities, may arise within the next financial year and in future periods.

Judgement is required when determining whether a particular tax is an income tax or another type of tax (for example, a production tax). The attributes of the tax, including whether it is calculated on profits or another measure such as production or revenues, the extent of deductibility of costs and the interaction with existing income taxes, are considered in determining the classification of the tax. Accounting for deferred tax is applied to income taxes as described above but is not applied to other types of taxes; rather such taxes are recognized in the income statement in accordance with the applicable accounting policy such as Provisions and contingencies.

This judgement is considered significant only in relation to the group's taxes payable under the fiscal terms of bp's onshore concession in Abu Dhabi. These are principally reported as income taxes rather than as production taxes.

For more information see **Note 9** and **Note 33**.

Customs duties and sales taxes

Customs duties and sales taxes that are passed on or charged to customers are excluded from revenues and expenses. Assets and liabilities are recognized net of the amount of customs duties or sales tax except:

- Customs duties or sales taxes incurred on the purchase of goods and services which are not recoverable from the taxation authority are recognized as part of the cost of acquisition of the asset.
- Receivables and payables are stated with the amount of customs duty or sales tax included.

The net amount of sales tax recoverable from, or payable to, the taxation authority is included within receivables or payables in the balance sheet.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Own equity instruments – treasury shares

The group's holdings in its own equity instruments are shown as deductions from shareholders' equity. Treasury shares represent bp shares repurchased and available for specific and limited purposes. For accounting purposes, shares held in Employee Share Ownership Plans (ESOPs) to meet the future requirements of the employee share-based payment plans are treated in the same manner as treasury shares and are, therefore, included in the consolidated financial statements as treasury shares. The cost of treasury shares subsequently sold or reissued is calculated on a weighted-average basis. Consideration, if any, received for the sale of such shares is also recognized in equity. No gain or loss is recognized in the income statement on the purchase, sale, issue or cancellation of equity shares. Shares repurchased and immediately cancelled are not shown as treasury shares. Instead, the nominal amount is transferred to the capital redemption reserve and any difference to the purchase price is shown as a deduction from the profit and loss account reserve in the group statement of changes in equity.

Revenue and other income

Revenue from contracts with customers is recognized when or as the group satisfies a performance obligation by transferring control of a promised good or service to a customer. The transfer of control of oil, natural gas, natural gas liquids, LNG, petroleum and chemical products, and other items usually coincides with title passing to the customer and the customer taking physical possession. The group principally satisfies its performance obligations at a point in time; the amounts of revenue recognized relating to performance obligations satisfied over time are not significant.

When, or as, a performance obligation is satisfied, the group recognizes as revenue the amount of the transaction price that is allocated to that performance obligation. The transaction price is the amount of consideration to which the group expects to be entitled. The transaction price is allocated to the performance obligations in the contract based on standalone selling prices of the goods or services promised.

Contracts for the sale of commodities are typically priced by reference to quoted prices. Revenue from term commodity contracts is recognized based on the contractual pricing provisions for each delivery. Certain of these contracts have pricing terms based on prices at a point in time after delivery has been made. Revenue from such contracts is initially recognized based on relevant prices at the time of delivery and subsequently adjusted as appropriate. All revenue from these contracts, both that recognized at the time of delivery and that from post-delivery price adjustments, is disclosed as revenue from contracts with customers.

Sales and purchase of commodities accounted for under IFRS 15 are presented on a gross basis in Revenue from contracts with customers and Purchases respectively. Physically settled derivatives which represent trading or optimization activities are presented net alongside financially settled derivative contracts in Other operating revenues within Sales and other operating income. Certain physically settled sale and purchase derivative contracts which are not part of trading and optimization activities are presented gross within Other operating revenues and Purchases respectively. Changes in the fair value of derivative assets and liabilities prior to physical delivery are also classified as other operating revenues.

Physical exchanges with counterparties in the same line of business in order to facilitate sales to customers are reported net, as are sales and purchases made with a common counterparty, as part of an arrangement similar to a physical exchange.

Where the group acts as agent on behalf of a third party to procure or market energy commodities, any associated fee income is recognized but no purchase or sale is recorded.

Sales and other transactions through which the group loses control of solar projects developed under Lightsource bp's develop-to-sell business model are accounted for as revenues from contracts with customers.

Interest income is recognized as the interest accrues (using the effective interest rate, that is, the rate that exactly discounts estimated future cash receipts through the expected life of the financial instrument to the net carrying amount of the financial asset).

Dividend income from investments is recognized when the shareholders' right to receive the payment is established.

Finance costs

Finance costs directly attributable to the acquisition, construction or production of qualifying assets, which are assets that necessarily take a substantial period of time to get ready for their intended use, are added to the cost of those assets until such time as the assets are substantially ready for their intended use. All other finance costs are recognized in the income statement in the period in which they are incurred.

Updates to material accounting policy information

Impact of new International Financial Reporting Standards

There are no new or other amended standards or interpretations adopted from 1 January 2025 onwards, that have a significant impact on the consolidated financial statements for 2025.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Not yet adopted

Amendments to IFRS 9 'Financial Instruments' relating to the settlement of liabilities through electronic payment systems are effective for annual periods beginning on or after 1 January 2026. bp will adopt the amendments in the financial reporting period commencing 1 January 2026 using the modified retrospective approach. The amendments clarify the timing of derecognition of financial instruments and whilst they permit financial liabilities to be derecognized before the settlement date if certain criteria are met, the group is not expected to make this election. Management has considered the amendments and does not anticipate any material effect on the Group's financial position or results. The expected impact on transition is a \$34 million increase to cash and cash equivalents.

IFRS 18 'Presentation and Disclosure in Financial Statements' will supersede IAS 1 'Presentation of Financial Statements' and is effective for annual periods beginning on or after 1 January 2027. IFRS 18 (and consequential amendments made to IAS 7 'Statement of Cash Flows', IAS 8 'Accounting Policies: Changes in Accounting Estimates and Errors', IAS 33 'Earnings per share' and IFRS 7 'Financial Instruments: Disclosures') introduces several new requirements that are expected to impact the presentation and disclosure of the Group's consolidated financial statements. These new requirements include:

- Requirements to classify all income and expenses included in the statement of profit or loss into one of five categories and to present two new mandatory subtotals.
- Requirement to use the operating profit subtotal as the starting point for the indirect method of reporting cash flows from operating activities in the statement of cash flows.
- Specific classification requirements for interest paid/received and dividends received in the statement of cash flows such that interest and dividend receipts are included as investing cash flows and interest paid as financing cash flows.
- Required disclosures about certain non-GAAP measures ('management defined performance measures') in a single note to the financial statements
- Enhanced guidance on the aggregation of information across all the primary financial statements and the notes.

The group's evaluation of the effect of adopting IFRS 18 is ongoing but it is currently anticipated that IFRS 18 will have a significant impact on the presentation of the Group's financial statements and related disclosures.

2. Non-current assets held for sale

The carrying amount of assets classified as held for sale at 31 December 2025 is \$6,347 million (2024 \$4,081 million), with associated liabilities of \$1,594 million (2024 \$1,105 million).

gas & low carbon energy

On 24 October 2024, bp completed the acquisition of the remaining 50.03% of Lightsource bp. The acquisition included certain assets for which sales processes were in progress at the acquisition date. The carrying amount of assets classified as held for sale at 31 December 2025 is \$1,916 million (2024 \$1,702 million), with associated liabilities of \$1,254 million (2024 \$1,050 million). The sale of the majority of these assets and liabilities completed in February 2026. Completions of the sales of the remaining assets and liabilities are expected to occur in 2026.

customers & products

On 24 December 2025, bp announced an agreement with Stonepeak to divest a 65% shareholding in the Castrol business with bp retaining a 35% interest through a holding in a newly incorporated entity. Cash proceeds are estimated at \$6 billion. The transaction is expected to complete by the end of 2026, subject to regulatory approvals. The carrying amount of assets classified as held for sale at 31 December 2025 is \$4,431 million including \$2,760 million of goodwill that arose on the acquisition of Castrol in 2000, with associated liabilities of \$340 million. Net working capital, which at 31 December 2025 was approximately \$1.2 billion, has not been classified as assets and associated liabilities held for sale. The working capital balances as at completion will be transferred to the buyer. At 31 December 2025, there are also associated cumulative foreign exchange losses within reserves of approximately \$1.6 billion. Such reserves are expected to be recycled to the group income statement at completion. The shares to be held by Stonepeak are subject to preferred distributions, the effect of which is that bp does not expect to recognize income or dividends from the investment in the short to medium term.

Transactions that have been either classified as held for sale at 31 December 2024 or during 2025, but were completed by 31 December 2025, are described below.

gas & low carbon energy

On 9 December 2024, bp and JERA Co., Inc. agreed to combine their offshore wind businesses to form a new standalone, equally-owned joint venture - JERA Nex bp. On 1 August 2025, this transaction was completed. bp contributed its development projects in the UK, Germany and US into the joint venture. The related assets and liabilities of those projects, which had been classified as held for sale since the announcement of the transaction, were derecognized at completion.

On 16 September 2024, bp announced that it planned to sell its US onshore wind energy business, bp Wind Energy and on 18 July 2025 the sale of the business to LS Power was announced. bp Wind Energy has interests in ten operating onshore wind energy assets across seven US states. The transaction completed on 9 December 2025. The related assets and liabilities of those projects, previously classified as held for sale, were derecognized on that date.

oil production & operations

On 31 January 2025 bp and Devon Energy agreed to dissolve their Eagle Ford partnership and divide up the assets. The dissolution completed on 1 April 2025.

customers & products

On 9 July 2025, bp announced the sale of its Netherlands mobility & convenience and bp pulse businesses to Catom BV. The transaction includes bp's Dutch retail sites, EV charging hubs and the associated fleet business. The sale completed on 1 December 2025.

The total assets and liabilities held for sale at 31 December 2025 and 2024, which are in the gas & low carbon energy and customers & products segments, are set out in the table below.

	\$ million	
	2025	2024
Property, plant and equipment	2,542	1,981
Goodwill	2,817	–
Intangible assets	165	333
Investments in associates	20	–
Investments in joint ventures	18	1,182
Other investments	65	–
Inventories	11	–
Cash	68	65
Trade and other receivables	292	520
Deferred tax assets	349	–
Assets classified as held for sale	6,347	4,081
Trade and other payables	(87)	(264)
Lease liabilities	(109)	(58)
Finance debt	(1,143)	(720)
Provisions	(75)	(63)
Deferred tax liabilities	(11)	–
Defined benefit pension plan and other post-employment benefit plan deficits	(169)	–
Liabilities directly associated with assets classified as held for sale	(1,594)	(1,105)

4. Disposals and impairment – continued

Disposals

Disposal proceeds and principal gains and losses on disposals by segment are described below.

	\$ million		
	2025	2024	2023
Proceeds from disposals of fixed assets	1,142	328	133
Proceeds from disposals of businesses, net of cash disposed	1,714	2,578	1,193
	2,856	2,906	1,326
By business			
gas & low carbon energy	1,702	840	536
oil production & operations	272	1,699	333
customers & products	840	291	436
other businesses & corporate	42	76	21
	2,856	2,906	1,326

Proceeds from disposals of businesses in 2025 includes proceeds relating to the sale of the US onshore wind business and the disposal of the Netherlands mobility & convenience and bp pulse businesses, as well as other smaller amounts. Proceeds from disposals of businesses in 2024 includes \$594 million relating to the formation of a new joint venture, Arcius Energy, in Egypt, as well as \$1,331 million relating to Alaska and \$252 million relating to Canada, both prior period disposals. At 31 December 2025, deferred consideration relating to disposals amounted to \$48 million receivable within one year (2024 \$112 million and 2023 \$141 million) and \$247 million receivable after one year (2024 \$244 million and 2023 \$217 million). The amounts of deferred consideration are reported within Trade and other receivables in Other receivables in the group balance sheet. In addition, contingent consideration receivable relating to disposals amounted to \$85 million at 31 December 2025 (2024 \$190 million and 2023 \$1,694 million). The contingent consideration at 31 December 2025 primarily relates to the prior period disposal of certain assets in the North Sea. These amounts of contingent consideration are reported within Other investments on the group balance sheet - see **Note 18** for further information.

Gains and losses on sale of businesses and fixed assets, and closures

gas & low carbon energy

In 2025 losses principally arose upon the formation of a new offshore wind joint venture JERA Nex bp.

oil production & operations

In 2025 gains principally relate to a disposal in the North Sea and an asset exchange in bpx.

In 2023 gains principally related to prior period disposals in the US and Canada.

customers & products

In 2024 losses principally related to a loss of \$1,132 million arising from the divestment of our Türkiye ground fuels business.

Summarized financial information relating to the sale of businesses is shown in the table below.

The principal transactions categorized as a business disposal in 2025 were the formation of a new offshore wind joint venture, JERA Nex bp, in which bp contributed its development projects in the UK, Germany and US into the joint venture; the disposal of the Netherlands mobility & convenience and bp pulse businesses; the sale of the US onshore wind business; and an asset exchange in bpx.

The principal transactions categorized as a business disposal in 2024 were the divestment of our Türkiye ground fuels business, the new joint venture transaction with ADNOC in Egypt and a transaction relating to the prior period disposal in Alaska.

The principal transactions categorized as a business disposal in 2023 were the sale of the upstream business in Algeria to Eni and the disposal of the bp-Husky Toledo refinery to Cenovus Energy.

4. Disposals and impairment – continued

	\$ million		
	2025	2024	2023
Non-current assets	3,998	1,775	1,145
Current assets	571	1,985	557
Non-current liabilities	(320)	(548)	(60)
Current liabilities	(213)	(424)	(454)
Total carrying amount of net assets disposed	4,036	2,788	1,188
Recycling of foreign exchange on disposal	41	943	–
Costs on disposal	54	123	57
	4,131	3,854	1,245
Gains (losses) on sale of businesses	358	(888)	158
Total consideration	4,489	2,966	1,403
Non-cash consideration	(3,133)	(1,003)	(51)
Consideration received (receivable)	358	615	(159)
Proceeds from the sale of businesses, net of cash disposed^a	1,714	2,578	1,193

a Proceeds are stated net of cash and cash equivalents disposed of \$61 million (2024 \$500 million and 2023 \$33 million).

Impairments

Impairment losses and impairment reversals in each segment are described below. For information on significant estimates and judgements made in relation to impairments see Impairment of property, plant and equipment, intangibles, goodwill and equity-accounted entities within **Note 1**. See also **Note 12**, and **Note 15** for further information on impairments by asset category.

gas & low carbon energy

The 2025 impairment loss of \$4,146 million includes \$3,537 million relating to the transition businesses, principally Archaea Energy and Lightsource bp, and \$609 million relating to the upstream gas business, principally Mauritania and Senegal. The impairments arose as a result of revised assumptions including capital and operating expenditure and the impact of market conditions on project development. The recoverable amount of all CGUs for which impairment charges were recognized in 2025 is \$8,805 million.

The 2024 impairment loss of \$3,310 million includes amounts in Mauritania & Senegal (\$1,495 million), which principally arose as a result of increased forecast future expenditure, and a number of other individually immaterial impairments across the segment principally as a result of portfolio management. The recoverable amounts of these cash generating units (CGUs) were based on value in use or fair value less costs of disposal calculations, as appropriate. The recoverable amount of all CGUs for which impairment charges were recognized in 2024 is \$5,025 million.

The 2023 impairment loss of \$2,213 million primarily relates to losses incurred in respect of certain assets in Mauritania & Senegal (\$1,434 million) and principally arose as a result of increased forecast future expenditure. A further \$565 million relates to producing assets in Trinidad and arose as a result of changes to the group's oil and gas price and discount rate assumptions and activity phasing. The recoverable amount of all CGUs for which impairment charges or reversals were recognized in 2023 in total, based on their value in use, is \$4,811 million.

oil production & operations

Impairment losses and reversals in all years relate primarily to producing assets.

The 2025 impairment loss of \$454 million primarily arose as a result of changes to reserves and decommissioning provisions mainly driven by foreign exchange in the North Sea (\$397 million). The recoverable amount of all CGUs for which impairment charges or reversals were recognized in 2025 in total, based on their value in use, is \$2,058 million.

The 2024 impairment loss of \$1,155 million primarily arose as a result of changes to reserves and tax assumptions in the North Sea (\$1,035 million). The recoverable amount of all CGUs for which impairment charges or reversals were recognized in 2024 in total, based on their value in use, is \$8,705 million.

The 2023 impairment loss of \$1,840 million primarily arose as a result of changes to the group's oil and gas price and discount rate assumptions, activity phasing and disposal decisions in relation to certain assets in North Sea (\$852 million) and in bpx energy (\$802 million). The recoverable amount of all CGUs for which impairment charges or reversals were recognized in 2023 in total, based on their value in use, is \$14,072 million.

customers & products

The 2025 impairment loss of \$926 million primarily relates to strategy implementation in the products business. The recoverable amount of all CGUs for which impairment charges or reversals were recognized in 2025 in total, based on their value in use, is \$49 million.

The 2024 impairment loss of \$1,144 million primarily arises from the ongoing review of the Gelsenkirchen refinery in Germany (\$807 million) and a number of other individually immaterial impairments across the segment, principally as a result of changes to economic assumptions. The recoverable amount of the CGUs were based on value-in-use calculations. The recoverable amount of all CGUs for which impairment charges or reversals were recognized in 2024 in total, based on their value-in-use, is \$57 million.

The 2023 impairment loss of \$1,614 million primarily relates to strategy implementation and changes to economic assumptions in the products business including an impairment of the Gelsenkirchen refinery in Germany (\$1,336 million). The recoverable amounts of the CGUs were based on value-in-use calculations. The recoverable amount of all CGUs for which impairment charges or reversals were recognized in 2023 in total, based on their value in use, is \$327 million.

5. Segmental analysis

The group's organizational structure reflects the various activities in which bp is engaged as well as how performance and resource allocation is evaluated by the chief operating decision maker. At 31 December 2025, bp has three reportable segments: Gas & low carbon energy, Oil production & operations, and Customers & products. Each are managed separately, with decisions taken for the segment as a whole, and represent a single operating segment that does not result from aggregating two or more segments.

Gas & low carbon energy comprises regions with upstream businesses that predominantly produce natural gas, gas marketing and trading activities and the group's solar, wind, hydrogen and Archaea Energy business.

Oil production & operations comprises regions with upstream activities that predominantly produce crude oil.

Customers & products comprises the group's customer-focused businesses, which includes convenience and retail fuels, EV charging, as well as Castrol, aviation, B2B, midstream and bp bioenergy. It also comprises our products businesses which include refining and oil trading.

Other businesses and corporate also comprises the group's shipping and treasury functions, and corporate activities worldwide.

Change in segmentation

For 2025, our Archaea Energy business has moved from the customers & products segment to the gas & low carbon energy segment. The change in segmentation is consistent with a change in the way that resources are allocated, and performance is assessed by the chief operating decision maker, who for bp is the group chief executive.

Comparative information for 2024 and 2023 has been restated where material to reflect the changes in reportable segments.

The accounting policies of the operating segments are the same as the group's accounting policies described in **Note 1**. However, IFRS requires that the measure of profit or loss disclosed for each operating segment is the measure that is provided regularly to the chief operating decision maker for the purposes of performance assessment and resource allocation. For bp, this measure of profit or loss is replacement cost profit or loss before interest and tax which reflects the replacement cost of supplies by excluding from profit or loss before interest and tax inventory holding gains and losses^a. Replacement cost profit or loss before interest and tax for the group is not a recognized measure under IFRS.

Sales between segments are made at prices that approximate market prices, taking into account the volumes involved. Segment revenues and segment results include transactions between business segments. These transactions and any unrealized profits and losses are eliminated on consolidation, unless unrealized losses provide evidence of an impairment of the asset transferred. Sales to external customers by region are based on the location of the group subsidiary which made the sale. The UK region includes the UK-based international activities of customers & products.

All surpluses and deficits recognized on the group balance sheet in respect of pension and other post-employment benefit plans are allocated to Other businesses and corporate. However, the periodic expense relating to these plans is allocated to the operating segments based upon the business in which the employees work.

Certain financial information is provided separately for the US as this is an individually material country for bp, and for the UK as this is bp's country of domicile.

a Inventory holding gains and losses represent:

- the difference between the cost of sales calculated using the replacement cost of inventory and the cost of sales calculated on the first-in first-out (FIFO) method after adjusting for any changes in provisions where the net realizable value of the inventory is lower than its cost. Under the FIFO method, which we use for IFRS reporting of inventories other than for trading inventories, the cost of inventory charged to the income statement is based on its historical cost of purchase or manufacture, rather than its replacement cost. In volatile energy markets, this can have a significant distorting effect on reported income. The amounts disclosed as inventory holding gains and losses represent the difference between the charge to the income statement for inventory on a FIFO basis (after adjusting for any related movements in net realizable value provisions) and the charge that would have arisen based on the replacement cost of inventory. For this purpose, the replacement cost of inventory is calculated using data from each operation's production and manufacturing system, either on a monthly basis, or separately for each transaction where the system allows this approach.
- an adjustment relating to certain trading inventories that are not price risk managed which relate to a minimum inventory volume that is required to be held to maintain underlying business activities. This adjustment represents the movement in fair value of the inventories due to prices, on a grade-by-grade basis, during the period. This is calculated from each operation's inventory management system on a monthly basis using the discrete monthly movement in market prices for these inventories.

The amounts disclosed are not separately reflected in the financial statements as a gain or loss. No adjustment is made in respect of the cost of inventories held as part of a trading position and certain other temporary inventory positions that are price risk-managed.

5. Segmental analysis – continued

	\$ million					
						2025
By business	gas & low carbon energy	oil production & operations	customers & products	other businesses & corporate	Consolidation adjustment and eliminations	Total group
Segment revenues						
Sales and other operating revenues	40,333	24,527	148,783	2,232	(26,540)	189,335
Less: sales and other operating revenues between segments	(1,832)	(22,876)	(43)	(1,789)	26,540	–
Third party sales and other operating revenues	38,501	1,651	148,740	443	–	189,335
Earnings from joint ventures and associates – after interest and tax	(501)	690	430	(1)	–	618
Segment results						
Replacement cost profit (loss) before interest and taxation	1,330	8,558	4,100	(40)	45	13,993
Inventory holding gains (losses) ^a	–	2	(1,353)	–	–	(1,351)
Profit (loss) before interest and taxation	1,330	8,560	2,747	(40)	45	12,642
Finance costs						(5,106)
Net finance income relating to pensions and other post-employment benefits						210
Profit before taxation						7,746
Other income statement items						
Depreciation, depletion and amortization						
US	235	4,992	1,994	89	–	7,310
Non-US	4,734	2,727	2,151	900	–	10,512
Charges for provisions, net of write-back of unused provisions, including change in discount rate	37	302	3,180	666	–	4,185
Segment assets						
Investments in joint ventures and associates	7,005	10,488	3,230	2	–	20,725
Additions to non-current assets ^b	7,188	9,782	4,617	885	–	22,472

a See explanation of inventory holding gains and losses on page 185.

b Includes additions to property, plant and equipment; goodwill; intangible assets; investments in joint ventures; and investments in associates.

5. Segmental analysis – continued

	\$ million					
	2024					
By business	gas & low carbon energy ^a	oil production & operations	customers & products ^a	other businesses & corporate	Consolidation adjustment and eliminations	Total group
Segment revenues						
Sales and other operating revenues	32,628	25,637	155,401	2,290	(26,771)	189,185
Less: sales and other operating revenues between segments	(1,585)	(23,237)	(317)	(1,632)	26,771	–
Third party sales and other operating revenues	31,043	2,400	155,084	658	–	189,185
Earnings from joint ventures and associates – after interest and tax	504	1,100	393	(4)	–	1,993
Segment results						
Replacement cost profit (loss) before interest and taxation ^a	3,052	10,789	(1,043)	(988)	(25)	11,785
Inventory holding gains (losses) ^b	–	(9)	(479)	–	–	(488)
Profit (loss) before interest and taxation^a	3,052	10,780	(1,522)	(988)	(25)	11,297
Finance costs						(4,683)
Net finance income relating to pensions and other post-employment benefits						168
Profit before taxation						6,782
Other income statement items						
Depreciation, depletion and amortization						
US	95	4,421	2,142	89	–	6,747
Non-US	4,740	2,376	1,815	944	–	9,875
Charges for provisions, net of write-back of unused provisions, including change in discount rate	38	92	2,602	231	–	2,963
Segment assets						
Investments in joint ventures and associates ^a	6,111	10,730	3,183	8	–	20,032
Additions to non-current assets ^{a c}	12,098	7,296	6,700	1,045	–	27,139

a Restated for material items to reflect the move of our Archaea Energy business from the customers & products segment to the gas & low carbon energy segment.

b See explanation of inventory holding gains and losses on page 185.

c Includes additions to property, plant and equipment; goodwill; intangible assets; investments in joint ventures; and investments in associates.

5. Segmental analysis – continued

						\$ million
						2023
By business	gas & low carbon energy ^a	oil production & operations	customers & products ^a	other businesses & corporate	Consolidation adjustment and eliminations	Total group
Segment revenues						
Sales and other operating revenues	50,297	24,904	160,215	2,657	(27,943)	210,130
Less: sales and other operating revenues between segments	(1,808)	(23,708)	(367)	(2,060)	27,943	–
Third party sales and other operating revenues	48,489	1,196	159,848	597	–	210,130
Earnings from joint ventures and associates – after interest and tax	(677)	1,164	427	(16)	–	898
Segment results						
Replacement cost profit (loss) before interest and taxation	14,080	11,191	4,230	(903)	(14)	28,584
Inventory holding gains (losses) ^b	1	–	(1,237)	–	–	(1,236)
Profit (loss) before interest and taxation	14,081	11,191	2,993	(903)	(14)	27,348
Finance costs						(3,840)
Net finance income relating to pensions and other post-employment benefits						241
Profit before taxation						23,749
Other income statement items						
Depreciation, depletion and amortization						
US	96	3,554	1,883	85	–	5,618
Non-US	5,584	2,138	1,665	923	–	10,310
Charges for provisions, net of write-back of unused provisions, including change in discount rate	139	35	2,007	152	–	2,333
Segment assets						
Investments in joint ventures and associates ^a	5,404	10,721	4,096	28	–	20,249
Additions to non-current assets ^{a c}	5,451	7,384	8,791	1,075	–	22,701

a Restated for material items to reflect the move of our Archaea Energy business from the customers & products segment to the gas & low carbon energy segment.

b See explanation of inventory holding gains and losses on page 185.

c Includes additions to property, plant and equipment; goodwill; intangible assets; investments in joint ventures; and investments in associates.

	\$ million		
	2025		
By geographical area	US	Non-US	Total
Revenues			
Third party sales and other operating revenues ^a	56,703	132,632	189,335
Other income statement items			
Production and similar taxes	175	1,523	1,698
Non-current assets			
Non-current assets ^{b c}	61,269	77,194	138,463

a Non-US region includes UK \$28,714 million

b Non-US region includes UK \$21,529 million

c Includes property, plant and equipment; goodwill; intangible assets; investments in joint ventures; investments in associates; and non-current prepayments.

	\$ million		
	2024		
By geographical area	US	Non-US	Total
Revenues			
Third party sales and other operating revenues ^a	58,804	130,381	189,185
Other income statement items			
Production and similar taxes	149	1,650	1,799
Non-current assets			
Non-current assets ^{b c}	63,415	81,937	145,352

a Non-US region includes UK \$24,577 million.

b Non-US region includes UK \$25,354 million.

c Includes property, plant and equipment; goodwill; intangible assets; investments in joint ventures; investments in associates; and non-current prepayments.

5. Segmental analysis – continued

	\$ million		
	2023		
By geographical area	US	Non-US	Total
Revenues			
Third party sales and other operating revenues ^a	60,577	149,553	210,130
Other income statement items			
Production and similar taxes	136	1,643	1,779
Non-current assets			
Non-current assets ^{b,c}	64,238	83,816	148,054

a Non-US region includes UK \$39,975 million.

b Non-US region includes UK \$23,949 million.

c Includes property, plant and equipment; goodwill; intangible assets; investments in joint ventures; investments in associates; and non-current prepayments.

6. Sales and other operating revenues

	\$ million		
	2025	2024	2023
Crude oil	2,063	2,219	2,413
Oil products	114,207	121,019	128,969
Natural gas, LNG and NGLs	27,477	24,464	29,541
Non-oil products and other revenues from contracts with customers	15,132	13,362	10,298
Revenue from contracts with customers	158,879	161,064	171,221
Other operating revenues ^a	30,456	28,121	38,909
Total sales and other operating revenues	189,335	189,185	210,130

a Principally relates to commodity derivative transactions including sales of bp own production in trading books.

An analysis of third-party sales and other operating revenues by segment and region is provided in **Note 5**.

The group's sales to customers of crude oil and oil products were substantially all made by the customers & products segment. The group's sales to customers of natural gas, LNG and NGLs were made by the gas & low carbon energy segment. A significant majority of the group's sales of non-oil products and other revenues from contracts with customers were made by the customers & products segment.

7. Income statement analysis

	\$ million		
	2025	2024	2023
Interest and other income			
Interest income from			
Financial assets measured at amortized cost	1,203	1,308	1,034
Financial assets measured at fair value through profit or loss	129	181	215
Other income ^a	277	1,284	386
	1,609	2,773	1,635
Currency exchange losses charged to the income statement ^b	(295)	541	74
Expenditure on research and development	274	301	298
Costs relating to the Gulf of America oil spill (pre-interest and tax) ^c	31	51	57
Finance costs			
Interest expense on lease liabilities	704	468	363
Interest expense on other liabilities measured at amortized cost ^d	3,419	3,483	3,115
Capitalized at 4.69% (2024 4.94% and 2023 4.88%) ^e	(142)	(382)	(514)
Finance debt risk management activities ^f	(22)	104	(35)
Unwinding of discount on provisions	675	617	504
Unwinding of discount on other payables measured at amortized cost	472	393	407
	5,106	4,683	3,840

a 2024 includes a \$427 million gain relating to the remeasurement of bp's previously held interests in bp Bunge Bioenergia and Lightsource bp and \$498 million relating to the remeasurement of certain US assets excluded from the Lightsource bp acquisition. See Note 3 for further information.

b Excludes exchange gains and losses arising on financial instruments measured at fair value through profit or loss.

c Included within production and manufacturing expenses.

d 2023 includes a loss of \$49 million associated with the buyback of finance debt.

e Tax relief on capitalized interest is approximately \$36 million (2024 \$53 million and 2023 \$130 million).

f Includes temporary valuation differences related to the group's interest rate and foreign currency exchange risk management associated with finance debt.

8. Exploration for and evaluation of oil and natural gas resources

The following financial information represents the amounts included within the group totals relating to activity associated with the exploration for and evaluation of oil and natural gas resources. All such activity is recorded within the gas & low carbon energy and oil production & operations segments.

For information on significant judgements made in relation to oil and natural gas accounting see Intangible assets in Note 1.

	\$ million		
	2025	2024	2023
Exploration and evaluation costs			
Exploration expenditure written off	343	767	746
Other exploration costs	227	207	251
Exploration expense for the year	570	974	997
Impairment losses	26	6	20
Intangible assets – exploration and appraisal expenditure ^a	3,963	4,438	4,328
Liabilities	33	76	109
Net assets	3,930	4,362	4,219
Cash used in operating activities	227	207	251
Cash used in investing activities	1,169	1,513	1,039

a Amount capitalized at 31 December 2025, 2024 and 2023 relates to assets in various regions. This includes \$536 million in the Brazil region (2024 \$395 million, 2023 \$418 million), \$776 million in the Middle East and North Africa region (2024 \$1,289 million, 2023 \$1,182 million) and \$609 million in the Azerbaijan Georgia and Türkiye region (2024 \$651 million, 2023 \$631 million).

9. Taxation

Tax on profit

	\$ million		
	2025	2024	2023
Current tax			
Charge for the year ^a	6,501	7,187	9,048
Adjustment in respect of prior years	(188)	234	(373)
	6,313	7,421	8,675
Deferred tax			
Origination and reversal of temporary differences in the current year ^b	(537)	(1,851)	(238)
Adjustment in respect of prior years ^c	675	(17)	(568)
	138	(1,868)	(806)
Tax charge on profit	6,451	5,553	7,869

a 2025 includes a charge of \$55 million (2024 \$4 million charge) in respect of Pillar Two income taxes.

b 2025 includes a charge of \$539 million in respect of the two-year extension of the UK Energy Profits Levy to 31 March 2030 and a charge of \$235 million in respect of a change in the tax rate in Germany. 2024 includes a charge of \$96 million in respect of the 3% increase in the UK Energy Profits Levy from 1 November 2024. See Note 1 for further information.

c The adjustment in respect of prior years reflects the reassessment of the deferred tax balances for prior periods in light of changes in facts and circumstances during the year, including changes to price assumptions and profit forecasts (2025 \$558 million charge, 2024 \$190 million credit and 2023 \$263 million credit). 2024 also includes a charge of \$213 million (2023 \$232 million credit) in respect of a revision to the deferred tax impact of the UK Energy Profits Levy.

In 2025, the total tax credit recognized within other comprehensive income was \$33 million (2024 \$782 million credit and 2023 \$735 million credit). In 2025 and 2023 this primarily comprises the deferred tax impact of the remeasurements of the net pension and other post-employment benefit liability or asset. In 2024 this primarily comprises a \$658 million credit in respect of the reduction in the deferred tax liability on defined benefit pension plan surpluses following the reduction in the rate of the authorized surplus payments tax charge in the UK from 35% to 25%. See Note 32 for further information.

The total tax credit recognized directly in equity was \$33 million (2024 \$167 million charge and 2023 \$56 million charge). In 2025 this relates to share-based payments. In 2024 this mainly relates to share-based payments and transactions involving non-controlling interests. In 2023 this mainly relates to transactions involving non-controlling interests.

9. Taxation – continued

Reconciliation of the effective tax rate

The following table provides a reconciliation of the group weighted average statutory corporate income tax rate to the effective tax rate of the group on profit or loss before taxation.

	\$ million		
	2025	2024	2023
Profit (loss) before taxation	7,746	6,782	23,749
Tax charge (credit) on profit or loss	6,451	5,553	7,869
Effective tax rate	83%	82%	33%
			%
Tax rate computed at the weighted average statutory rate ^a	55	66	34
Increase (decrease) resulting from			
Tax reported in equity-accounted entities	(5)	(7)	(2)
Adjustments in respect of prior years	6	3	(4)
Deferred tax not recognized	5	5	2
Disposal impacts	–	5	–
Foreign exchange	(4)	5	–
Items not deductible for tax purposes ^b	11	5	2
Tax rate change effect of UK Energy Profits Levy ^c	7	1	–
Impact of Germany tax rate change	3	–	–
Other ^d	5	(1)	1
Effective tax rate	83	82	33

a Calculated based on the statutory corporate income tax rate applicable in the countries in which the group operates, weighted by the profits and losses before tax in the respective countries.

b 2025 reflects the impact of limited tax relief on impairment charges.

c 2025 comprises the deferred tax impact of the two-year extension of the UK Energy Profits Levy to 31 March 2030. 2024 comprises the deferred tax impact of a 3% increase in the UK Energy Profits Levy on existing temporary differences.

d Includes the impact of adjustments arising in countries where income tax is paid on our behalf by our government partners for which there is no deferred tax effect. 2024 includes the impact of the non-taxable gain relating to the remeasurement of bp's pre-existing 49.97% interest in Lightsource bp and the remeasurement of certain US assets excluded from the Lightsource bp acquisition.

Deferred tax

	\$ million	
	2025	2024
Analysis of movements during the year in the net deferred tax liability		
At 1 January	3,025	5,349
Exchange adjustments	(63)	57
Charge (credit) for the year in the income statement	138	(1,868)
Charge (credit) for the year in other comprehensive income	(33)	(807)
Charge (credit) for the year in equity	(33)	167
Acquisitions and disposals	283	127
At 31 December	3,317	3,025

9. Taxation – continued

The following table provides an analysis of deferred tax in the income statement and the balance sheet by category of temporary difference:

	\$ million				
	Income statement			Balance sheet	
	2025	2024	2023	2025	2024
Deferred tax liability					
Depreciation	(897)	(1,337)	(1,552)	15,474	16,333
Pension plan surpluses	(3)	62	133	1,860	1,789
Derivative financial instruments	37	40	12	106	58
Other taxable temporary differences ^a	37	(352)	10	824	663
	(826)	(1,587)	(1,397)	18,264	18,843
Deferred tax asset					
Depreciation	993	(229)	(166)	(1,544)	(2,373)
Lease liabilities	(395)	(209)	(176)	(2,375)	(1,952)
Pension plan and other post-employment benefit plan deficits	48	28	(60)	(552)	(623)
Decommissioning, environmental and other provisions	(314)	425	563	(5,981)	(5,623)
Derivative financial instruments	(48)	(9)	(14)	(277)	(268)
Tax credits	(111)	(43)	(67)	(1,047)	(937)
Loss carry forward	580	194	296	(1,852)	(2,285)
Other deductible temporary differences ^b	211	(438)	215	(1,319)	(1,757)
	964	(281)	591	(14,947)	(15,818)
Net deferred tax charge (credit) and net deferred tax liability	138	(1,868)	(806)	3,317	3,025
Of which – deferred tax liabilities				7,642	8,428
– deferred tax assets				4,325	5,403

a The 2025 and 2024 balance sheet amounts do not include any temporary differences that are individually significant.

b The 2025 and 2024 balance sheet amounts include amounts relating to share based payments and other items.

Of the \$4,325 million of deferred tax assets recognized on the group balance sheet at 31 December 2025 (2024 \$5,403 million), \$2,795 million (2024 \$3,232 million) relates to entities that have suffered a loss in either the current or preceding period. For 2025, this mainly includes \$1,613 million in Germany, \$473 million in Senegal and \$388 million in Mauritania (2024 mainly included \$1,680 million in Germany, \$744 million in Mauritania and \$609 million in Senegal). For 2025, these amounts are supported by forecasts consistent with bp's future oil and gas price assumptions (see **Note 1** for further information) and other assumptions used for impairment testing, and for Germany forecast profits associated with the customers & products businesses that indicate sufficient future taxable profits will be available to utilize such assets within any applicable expiry period.

A summary of temporary differences, unused tax credits and unused tax losses for which deferred tax has not been recognized is shown in the table below.

At 31 December	\$ billion	
	2025	2024
Unused US state tax losses ^a	2.9	2.3
Unused tax losses – other jurisdictions ^b	9.4	7.3
Unused tax credits	36.7	33.3
of which – arising in the UK ^c	33.2	29.1
– arising in the US ^d	3.5	4.2
Deductible temporary differences ^e	28.3	23.4
Taxable temporary differences associated with investments in subsidiaries and equity-accounted entities	0.7	0.7

a For 2025 the majority of the unused tax losses have no fixed expiry date.

b 2025 and 2024 mainly relate to Brazil, UK and Canada. The majority of the unused tax losses have no fixed expiry date.

c The UK unused tax credits arise predominantly in overseas branches of UK entities based in jurisdictions with higher statutory corporate income tax rates than the UK. No deferred tax asset has been recognized on these tax credits as they are unlikely to have value in the future; UK taxes on these overseas branches are largely mitigated by double tax relief in respect of overseas tax. These tax credits have no fixed expiry date.

d The US unused tax credits predominantly comprise foreign tax credits. No deferred tax asset has been recognized on these tax credits as they are unlikely to have value in the future. For 2025 these tax credits expire in the period 2026-2035.

e 2025 and 2024 mainly comprise fixed asset temporary differences in overseas branches of UK entities. Substantially all of the temporary differences have no expiry date.

Impact of previously unrecognized deferred tax or write-down of deferred tax assets on tax charge	\$ million		
	2025	2024	2023
Current tax benefit relating to the utilization of previously unrecognized deferred tax assets	101	87	360
Deferred tax benefit arising from the reversal of a previous write-down of deferred tax assets	11	14	3
Deferred tax benefit relating to the recognition of previously unrecognized deferred tax assets	156	280	332
Deferred tax expense arising from the write-down of a previously recognized deferred tax asset	725	111	54

10. Dividends

The quarterly dividend which is expected to be paid on 27 March 2026 in respect of the fourth quarter 2025 is 8.320 cents per ordinary share (\$0.4992 per American Depositary Share (ADS)). The corresponding amount in sterling will be announced on 17 March 2026.

	Pence per share			Cents per share			\$ million		
	2025	2024	2023	2025	2024	2023	2025	2024	2023
Dividends announced and paid in cash									
Preference shares							1	1	1
Ordinary shares									
March	6.1761	5.6922	5.5507	8.000	7.270	6.610	1,257	1,218	1,183
June	5.8993	5.6825	5.3089	8.000	7.270	6.610	1,237	1,204	1,152
September	6.1942	6.0498	5.7320	8.320	8.000	7.270	1,288	1,297	1,249
December	6.2394	6.2959	5.7367	8.320	8.000	7.270	1,276	1,283	1,224
	24.5090	23.7204	22.3283	32.640	30.540	27.760	5,059	5,003	4,809
Dividend announced, paid in March 2026				8.320			1,280		

The amount of unclaimed dividends recognized as a liability in other payables at 31 December 2025 is \$134 million (2024 \$106 million).

The board decided not to offer a scrip dividend alternative in respect of any dividends announced since the third quarter 2019, including the fourth quarter 2025 dividend expected to be paid on 27 March 2026.

The financial statements for the year ended 31 December 2025 do not reflect the dividend announced on 10 February 2026 and which is expected to be paid on 27 March 2026; this will be treated as an appropriation of profit in the year ending 31 December 2026.

11. Earnings per share

	Cents per share		
	2025	2024	2023
Per ordinary share			
Basic earnings per share	0.35	2.38	87.78
Diluted earnings per share	0.34	2.32	85.85

	Dollars per share		
	2025	2024	2023
Per American Depositary Share (ADS) ^a			
Basic earnings per share	0.02	0.14	5.27
Diluted earnings per share	0.02	0.14	5.15

a One ADS is equivalent to six ordinary shares.

Basic earnings per ordinary share amounts are calculated by dividing the profit for the year attributable to bp ordinary shareholders by the weighted average number of ordinary shares outstanding during the year.

The weighted average number of shares outstanding includes certain shares that will be issuable in the future under employee share-based payment plans and excludes treasury shares, which includes shares held by the Employee Share Ownership Plan trusts (ESOPs).

For the diluted earnings per share calculation, the weighted average number of shares outstanding during the year is adjusted for the average number of shares that are potentially issuable in connection with employee share-based payment plans. If the inclusion of potentially issuable shares would decrease loss per share, the potentially issuable shares are excluded from the weighted average number of shares outstanding used to calculate diluted earnings per share.

	\$ million		
	2025	2024	2023
Profit (loss) attributable to bp shareholders	55	381	15,239
Less: dividend requirements on preference shares	1	1	1
Less: (gain) loss on redemption of perpetual hybrid bonds ^a	–	(10)	–
Profit (loss) for the year attributable to bp ordinary shareholders	54	390	15,238

	Shares thousand		
	2025	2024	2023
Basic weighted average number of ordinary shares ^b	15,586,782	16,385,535	17,360,288
Potential dilutive effect of ordinary shares issuable under employee share-based payment plans	326,218	431,129	389,790
Weighted average number of ordinary shares outstanding used to calculate diluted earnings per share	15,913,000	16,816,664	17,750,078

	Shares thousand		
	2025	2024	2023
Basic weighted average number of ordinary shares – ADS equivalent	2,597,797	2,730,922	2,893,381
Potential dilutive effect of ordinary shares (ADS equivalent) issuable under employee share-based payment plans	54,369	71,855	64,965
Weighted average number of ordinary shares (ADS equivalent) outstanding used to calculate diluted earnings per share	2,652,166	2,802,777	2,958,346

a See Note 32 - non-controlling interests for further information.

b Excludes treasury shares. See Note 31 for further information.

11. Earnings per share – continued

The number of ordinary shares outstanding at 31 December 2025, excluding treasury shares, and including certain shares that will be issuable in the future under employee share-based payment plans was 15,377,210,044 (2024 15,851,028,983). Between 31 December 2025 and 13 February 2026, the latest practicable date before the completion of these financial statements, there was a net decrease of 48,533,512 of ordinary shares primarily as a result of share buy backs. For additional information on share buy backs see **Note 31**.

Employee share-based payment plans

The group operates share and share option plans for directors and certain employees to obtain ordinary shares and ADSs in the company.

The following table shows the number of shares potentially issuable under equity-settled employee share option plans, including the number of options outstanding, the number of options exercisable at the end of each year, and the corresponding weighted average exercise prices. The dilutive effect of these plans at 31 December is also shown.

Share options	2025		2024	
	Number of options ^{a,b} thousand	Weighted average exercise price \$	Number of options ^{a,b} thousand	Weighted average exercise price \$
Outstanding	382,873	4.21	533,895	4.15
Exercisable	345,112	4.23	2,931	3.38
Dilutive effect	80,562	n/a	140,971	n/a

a Numbers of options shown are ordinary share equivalents (one ADS is equivalent to six ordinary shares).

b At 31 December 2025 the quoted market price of one bp ordinary share was £4.33 (2024 £3.93).

In addition, the group operates a number of equity-settled employee share plans under which share units are granted to the group's senior leaders and certain other employees. These plans typically have a three-year performance or restricted period during which the units accrue net notional dividends which are treated as having been reinvested. Leaving employment will normally preclude the conversion of units into shares, but special arrangements apply for participants that leave for qualifying reasons. The number of shares that are expected to vest each year under employee share plans are shown in the table below. The dilutive effect of the employee share plans at 31 December is also shown.

Share plans	2025	2024
	Number of shares ^a thousand	Number of shares ^a thousand
Vesting		
Within one year	155,555	271,216
1 to 2 years	116,997	134,342
2 to 3 years	105,074	102,525
3 to 4 years	366	956
Over 4 years	43	118
	378,035	509,157
Dilutive effect	161,105	269,796

a Numbers of shares shown are ordinary share equivalents (one ADS is equivalent to six ordinary shares).

There has been a net increase of 30,497,988 in the number of potential ordinary shares relating to employee share-based payment plans between 31 December 2025 and 13 February 2026.

12. Property, plant and equipment (PP&E)

	\$ million							
	Land and land improvements	Buildings	Oil and gas properties ^a	Plant, machinery and equipment	Fittings, fixtures and office equipment	Transportation	Oil depots, storage tanks and service stations	Total
Cost - owned PP&E								
At 1 January 2025	4,060	1,167	184,304	48,731	2,315	2,687	12,417	255,681
Exchange adjustments	299	47	–	1,403	78	19	1,011	2,857
Additions	23	131	9,896	2,667	89	125	784	13,715
Acquisitions	–	18	–	68	–	–	3	89
Transfers from intangible assets	–	–	3,593	–	–	–	–	3,593
Reclassified as assets held for sale	(72)	(69)	(923)	(1,755)	(137)	(3)	(314)	(3,273)
Deletions and disposals	(299)	(4)	(2,074)	(1,047)	(176)	(38)	(693)	(4,331)
At 31 December 2025	4,011	1,290	194,796	50,067	2,169	2,790	13,208	268,331
Depreciation - owned PP&E								
At 1 January 2025	876	520	128,091	26,929	1,716	1,933	6,561	166,626
Exchange adjustments	60	17	–	961	50	8	629	1,725
Charge for the year	47	60	11,458	1,741	138	102	771	14,317
Impairment losses	11	5	568	1,224	–	11	42	1,861
Impairment reversals	(10)	–	(9)	(3)	–	(4)	(2)	(28)
Transfers from intangible assets	–	–	2,285	–	–	–	–	2,285
Reclassified as assets held for sale	(9)	(41)	(423)	(967)	(102)	(2)	(187)	(1,731)
Deletions and disposals	(28)	(4)	(1,843)	(795)	(167)	(36)	(472)	(3,345)
At 31 December 2025	947	557	140,127	29,090	1,635	2,012	7,342	181,710
Owned PP&E - net book amount at 31 December 2025	3,064	733	54,669	20,977	534	778	5,866	86,621
Right-of-use assets - net book amount at 31 December 2025 ^b	–	1,894	748	1,863	–	2,311	5,196	12,012
Total PP&E - net book amount at 31 December 2025	3,064	2,627	55,417	22,840	534	3,089	11,062	98,633
Cost - owned PP&E								
At 1 January 2024	3,924	992	185,346	47,384	2,290	2,958	12,224	255,118
Exchange adjustments	(213)	(35)	–	(864)	(43)	(23)	(637)	(1,815)
Additions	352	222	7,899	3,039	138	144	1,042	12,836
Acquisitions	60	148	–	1,235	57	80	70	1,650
Transfers from intangible assets	–	–	391	–	–	–	–	391
Reclassified as assets held for sale	(25)	(41)	(3,210)	(747)	(1)	–	–	(4,024)
Deletions and disposals	(38)	(119)	(6,122)	(1,316)	(126)	(472)	(282)	(8,475)
At 31 December 2024	4,060	1,167	184,304	48,731	2,315	2,687	12,417	255,681
Depreciation - owned PP&E								
At 1 January 2024	838	553	123,442	25,671	1,684	2,292	6,363	160,843
Exchange adjustments	(52)	(9)	–	(536)	(24)	(9)	(388)	(1,018)
Charge for the year	58	43	10,626	1,553	157	91	731	13,259
Impairment losses	70	–	2,418	1,260	1	9	82	3,840
Impairment reversals	–	–	(420)	(4)	–	(3)	–	(427)
Reclassified as assets held for sale	(6)	(4)	(2,168)	(367)	(1)	–	–	(2,546)
Deletions and disposals	(32)	(63)	(5,807)	(648)	(101)	(447)	(227)	(7,325)
At 31 December 2024	876	520	128,091	26,929	1,716	1,933	6,561	166,626
Owned PP&E - net book amount at 31 December 2024	3,184	647	56,213	21,802	599	754	5,856	89,055
Right-of-use assets - net book amount at 31 December 2024 ^b	–	1,613	41	1,431	10	2,589	5,499	11,183
Total PP&E - net book amount at 31 December 2024	3,184	2,260	56,254	23,233	609	3,343	11,355	100,238
Assets under construction included above								
At 31 December 2025								11,653
At 31 December 2024								10,722
Depreciation charge for the year on right-of-use assets								
2025		342	55	728	3	1,026	874	3,028
2024		215	30	640	3	1,109	882	2,878

a For information on significant estimates and judgements made in relation to the estimation of oil and natural reserves see Property, plant and equipment within Note 1.

b \$1,072 million (2024 \$867 million) of drilling rig right-of-use assets and \$2,119 million (2024 \$2,455 million) of shipping vessel right-of-use assets are included in Plant, machinery and equipment and Transportation respectively.

13. Capital commitments

Authorized future capital expenditure for property, plant and equipment (excluding right-of-use assets) by group companies for which contracts had been signed at 31 December 2025 amounted to \$14,639 million (2024 \$13,642 million, 2023 \$10,354 million). bp has contracted capital commitments amounting to \$2,238 million (2024 \$3,392 million, 2023 \$1,580 million) in relation to joint ventures and \$89 million (2024 \$59 million, 2023 \$105 million) in relation to associates.

14. Goodwill and impairment review of goodwill

	\$ million	
	2025	2024
Cost		
At 1 January	15,530	13,176
Exchange adjustments	397	(179)
Acquisitions and other additions	(89)	2,734
Reclassified as assets held for sale	(2,756)	(79)
Deletions and disposals	(133)	(122)
At 31 December	12,949	15,530
Impairment losses		
At 1 January	642	704
Exchange adjustments	30	(2)
Impairment losses for the year	2,009	–
Deletions and disposals	(32)	(60)
At 31 December	2,649	642
Net book amount at 31 December	10,300	14,888
Net book amount at 1 January	14,888	12,472

Impairment review of goodwill

	\$ million	
	2025	2024
Goodwill at 31 December		
gas & low carbon energy ^a	3,185	5,166
oil production & operations	4,870	4,925
customers & products ^a	2,245	4,797
other businesses & corporate	–	–
	10,300	14,888

a 2024 restated to reflect the move of our Archaea Energy business from the customers & products segment to the gas & low carbon energy segment.

Goodwill acquired through business combinations has been allocated to groups of cash-generating units (CGUs) that are expected to benefit from the synergies of the acquisition. For oil production & operations goodwill is allocated to CGUs in aggregate at the segment level, for gas & low carbon energy, goodwill is allocated to the hydrocarbon CGUs ('upstream gas businesses') within the segment and to Lightsource bp (LSbp) and Archaea Energy ('transition businesses'). For customers and products, goodwill has been allocated to Castrol, US Fuels, European Fuels and Other.

For information on significant estimates and judgements made in relation to impairments see Impairment of property, plant and equipment, intangible assets and goodwill in **Note 1**.

gas & low carbon energy and oil production & operations

	\$ million						\$ million	
	gas & low carbon energy						oil production & operations	
	2025			2024			2025	2024
	Upstream gas businesses	Transition businesses	Total	Upstream gas businesses	Transition businesses	Total ^a		
Goodwill ^a	2,260	925	3,185	2,228	2,938	5,166	4,870	4,925
Excess of recoverable amount over carrying amount	2,917	–	2,917	2,026	n/a	2,026	13,748	12,432

a Restated to reflect the move of Archaea Energy from the customers & products segment to the gas & low carbon energy segment.

The table above shows the carrying amount of goodwill for the segments at the period end and the excess of the recoverable amount over the carrying amount (headroom) at the date of the most recent test. The recoverable amounts for the upstream gas businesses and transition businesses are based on value-in-use calculations. The increase in headroom for the goodwill impairment tests for the upstream gas businesses is due to the passage of time and price impacts. For oil production & operations management have rolled-forward the most recent detailed calculation as the criteria set out in IAS 36 for doing so were met.

During 2025 impairment charges of \$2,009 million were recognized against the transition businesses goodwill balance. The impairment charges arose as a result of changes in assumptions including future capital and operating expenditure and project development. No impairment of the goodwill in the upstream gas businesses was recognized in 2025 or 2024. No impairment of the goodwill in oil production & operations was recognized during 2025 or 2024.

14. Goodwill and impairment review of goodwill – continued

Upstream gas businesses and oil production & operations

The value in use for relevant CGUs in both the upstream gas businesses and oil production & operations is based on the cash flows expected to be generated by the projected production profiles up to the expected dates of cessation of production of each field, based on appropriately risked estimates of reserves and resources. Midstream and supply and trading activities and equity-accounted entities are generally not included in the impairment reviews of goodwill, as they do not represent part of the grouping of CGUs to which the goodwill balances relate and which are used to monitor the goodwill balances for internal management purposes. Where such activities form part of wider CGUs to which goodwill relates they are reflected in the test. As the production profile and related cash flows can be estimated from bp's past experience, management believes that the cash flows generated over the estimated life of field is the appropriate basis upon which to assess goodwill and individual assets for impairment in both the upstream gas businesses and oil & production operations. The estimated date of cessation of production depends on the interaction of a number of variables, such as the recoverable quantities of hydrocarbons, the production profile of the hydrocarbons, the cost of the development of the infrastructure necessary to recover the hydrocarbons, production costs, the contractual duration of the production concession and the selling price of the hydrocarbons produced. As each field has specific reservoir characteristics and economic circumstances, the cash flows of each field are computed using appropriate individual economic models and key assumptions agreed by bp management.

Estimated production volumes and cash flows up to the date of cessation of production on a field-by-field basis, including operating and capital expenditure, are derived from the business segment plans. The production profiles used are consistent with the reserve and resource volumes approved as part of bp's centrally controlled process for the estimation of proved and probable reserves and total resources.

The average production for the purposes of goodwill impairment testing in the upstream gas businesses over the next 15 years is 146 mmbob per year (2024 154 mmbob per year) and in the oil production and operations segment is 400 mmbob per year (2024 400 mmbob per year). Production assumptions used for the goodwill impairment tests in both the upstream gas businesses and oil production & operations reflect management's best estimate of future production of the existing portfolio at the time of the calculation.

The weighted-average pre-tax discount rate used in the review for the oil production & operations segment is 17%, and 11% for the gas businesses (2024 17% for the oil production & operations segment and 11% for the gas businesses).

The most recent reviews for impairment for the oil production & operations and the upstream gas businesses were carried out in the fourth quarter. The key assumptions used in the value-in-use calculations are oil and natural gas prices, production volumes and the discount rate. The value-in-use calculations have been prepared for the purposes of determining whether the goodwill balances were impaired. For the upstream gas businesses, estimated future cash flows were prepared on the basis of certain assumptions prevailing at the time of the tests. For the oil production & operations segment, as permitted by IAS 36, the detailed calculations for recoverable amounts performed in 2024 were used as a basis for the 2025 impairment tests. The recoverable amounts, key assumptions and sensitivity calculations for 2025 are prepared using the remaining future cashflows from the 2024 detailed calculations. The headrooms for 2025 do not represent the headrooms that would result if a test was run based on discounted future cashflows estimated using 2025 data and assumptions. The actual outcomes may differ from the assumptions made. For example, reserves and resources estimates and production forecasts are subject to revision as further technical information becomes available and economic conditions change. Due to economic developments, regulatory change and emissions reduction activity arising from climate concern and other factors, future commodity prices and other assumptions may differ from the forecasts used in the calculations.

Sensitivities to different variables have been estimated using certain simplifying assumptions. For example, lower oil and gas price or production sensitivities do not fully reflect the specific impacts for each contractual arrangement and will not capture all favourable impacts that may arise from cost deflation or savings. A detailed calculation at any given price or production profile may, therefore, produce a different result.

It is estimated that an 11% (2024 11%) reduction in revenue throughout each year of the remaining life of those assets, either as a result of adverse price or production conditions or a combination of each, would cause the recoverable amount to be equal to the carrying amount of goodwill and related net non-current assets of the oil production and operations segment. For the gas businesses a 9% (2024 6%) reduction would have the same result.

It is estimated that no reasonably possible change in the discount rate would cause the recoverable amount to be equal to the carrying amount of goodwill and related net non-current assets.

Transition businesses

The transition businesses goodwill relates to the acquisitions of Archaea Energy and Lightsource bp. Cash flows were derived from the approved business plans.

For Archaea Energy, cash flows are derived from the approved business plan, which covers the period up to 2050. To determine the value in use, approved business plan cash flows were discounted and aggregated with a terminal value.

For Lightsource bp, cash flows for a period of 10 years were discounted and aggregated with a terminal value. Management considers the use of 10 years of plan cash flows before adding a terminal value to be appropriate reflecting the maturity of the business with an early stage development portfolio and other aspects of business model changes such that 10 years reflected an appropriate 'steady state' of development project sales and other income from which terminal value cash flows could be determined.

The assumptions to which the impairment tests are most sensitive are for Lightsource bp, the solar project sell-down unit margin, terminal value growth rate and the discount rate and for Archaea Energy renewable natural gas prices, and the level of capital expenditure and its consequential impact on production volumes and discount rate. These assumptions are affected by market conditions. Discount rate assumptions are based on the group's impairment discount rates as disclosed in **Note 1**. Other assumptions are based on management experience. The steady long-term growth rate used in the Lightsource bp goodwill impairment test terminal value is a risk-adjusted rate reflecting assumptions about inflation and project development growth.

It is estimated that a 1% decrease in the discount rates applied to the transition businesses would have resulted in a reduction to the goodwill impairment charges of \$1.7 billion. It is estimated that a 1% increase to the discount rates would have resulted in an increase to the goodwill impairment charge of \$0.9 billion.

These discount rate sensitivity analyses do not take into account any effect on the goodwill impairment test that would arise from first applying the changes in assumptions to the underlying assets of the businesses.

14. Goodwill and impairment review of goodwill – continued

Lightsource bp project development margins could change as a result of changes in sales prices achieved, development costs incurred or changes in the number of projects sold. It is estimated that a 10% increase to project development unit margin would have resulted in a reduction to the goodwill impairment charge of \$0.4 billion. It is estimated that a 10% decrease in project development unit margin would have resulted in an increase to the goodwill impairment charge of \$0.5 billion. It is estimated that a 1% increase to the terminal value growth rate would have resulted in a reduction to the goodwill impairment charge of \$1.0 billion. It is estimated that a 1% decrease in the terminal value growth rate would have resulted in an increase to the goodwill impairment charge of \$0.6 billion.

These sensitivity analyses do not, however, represent management's best estimate of any impairment charges or reversals that might be recognized as they do not fully incorporate consequential changes that may arise, such as changes in capital and operating costs, business plans and phasing of development. The above sensitivity analyses therefore do not reflect a linear relationship between development margins or growth rate and value that can be extrapolated. The interdependency of these inputs and factors limits the practicability of estimating the probability or extent to which the overall recoverable amount is impacted by changes to the price assumptions or production volumes.

Given the impairment charges taken in the year, the recoverable amount of the transition businesses CGUs' goodwill is equal to its carrying amount. Therefore, no disclosures regarding what changes in assumptions would cause headroom to be eroded have been provided. Also reflecting that goodwill impairment reversals are not permitted by IFRS the sensitivities identified above are provided to give context to the estimates taken at December 2025. No reversals to goodwill would arise should the estimates be changed favourably in the year ended December 2026.

customers & products

	2025					2024				
	Castrol	US Fuels	European Fuels	Other	Total	Castrol	US Fuels	European Fuels	Other	Total ^a
Goodwill ^a	–	844	823	578	2,245	2,615	828	801	553	4,797

a Restated to reflect the move of our Archaea Energy business from the customers & products segment to the gas & low carbon energy segment.

Cash flows for each group of CGUs are derived from the business segment plans, which cover a period of up to five years. To determine the value in use for each of the groups of cash-generating units, cash flows for a period of 10 years, are discounted and aggregated with a terminal value. Pre-tax discount rates ranging from 10-12% are applied. It is estimated that no reasonably possible change in the key assumptions used in the US Fuels and European Fuels goodwill impairment assessments would cause the recoverable amount to be equal to the carrying amount of goodwill and related net non-current assets.

No material impairment of the goodwill balances in customers & products was recognized during 2025.

Castrol

The goodwill associated with Castrol was reclassified to assets held for sale during the year.

15. Intangible assets

	2025				2024			
	Exploration and appraisal expenditure ^a	Biogas rights agreements	Other intangibles	Total	Exploration and appraisal expenditure ^a	Biogas rights agreements	Other intangibles	Total
Cost								
At 1 January	13,053	2,990	7,550	23,593	13,075	2,989	7,117	23,181
Exchange adjustments	–	–	350	350	–	–	(171)	(171)
Acquisitions ^b	–	–	28	28	–	–	351	351
Additions	1,213	1	544	1,758	1,539	193	904	2,636
Transfers to property, plant and equipment	(3,593)	–	–	(3,593)	(391)	–	–	(391)
Reclassified as assets held for sale	–	–	(667)	(667)	(1)	–	(385)	(386)
Deletions and disposals	(3,057)	(8)	(311)	(3,376)	(1,169)	(192)	(266)	(1,627)
At 31 December	7,616	2,983	7,494	18,093	13,053	2,990	7,550	23,593
Amortization								
At 1 January	8,615	557	4,775	13,947	8,747	105	4,338	13,190
Exchange adjustments	–	–	215	215	–	–	(97)	(97)
Exploration expenditure written off	343	–	–	343	767	–	–	767
Charge for the year	–	93	736	829	–	114	717	831
Impairment losses	26	710	41	777	6	344	108	458
Impairment reversals	–	(84)	–	(84)	(2)	–	–	(2)
Transfers to property, plant and equipment	(2,285)	–	–	(2,285)	–	–	–	–
Reclassified as assets held for sale	–	–	(502)	(502)	–	–	(53)	(53)
Deletions and disposals	(3,046)	(7)	(291)	(3,344)	(903)	(6)	(238)	(1,147)
At 31 December	3,653	1,269	4,974	9,896	8,615	557	4,775	13,947
Net book amount at 31 December	3,963	1,714	2,520	8,197	4,438	2,433	2,775	9,646
Net book amount at 1 January	4,438	2,433	2,775	9,646	4,328	2,884	2,779	9,991

a For further information see Intangible assets within Note 1 and Note 8.

b 2024 primarily relates to the acquisition of GETEC ENERGIE GmbH.

16. Investments in joint ventures

The following table provides aggregated summarized financial information for the group's joint ventures as it relates to the amounts recognized in the group income statement and on the group balance sheet.

	Income statement			Balance sheet	
	Earnings from joint ventures - after interest and tax			Investments in joint ventures	
	2025	2024	2023	2025	2024
Azule Energy	406	504	700	5,080	5,109
Other joint ventures	(706)	405	(633)	8,320	7,182
	(300)	909	67	13,400	12,291

The joint venture that is material to the group at 31 December 2025 is Azule Energy, which was formed during 2022 and in which bp owns a 50% stake.

bp classifies its investment in Azule Energy Holdings Limited as a joint venture because, per the terms of the shareholders' agreements, bp has joint control over Azule Energy. Azule Energy Holdings Limited is based in Angola and its functional currency is USD.

The following table provides summarized financial information relating to Azule Energy for 2025, 2024 and 2023. This information is presented on a 100% basis and reflects adjustments made by bp to Azule Energy's own results in applying the equity method of accounting. bp adjusts Azule Energy Holdings Limited's results for the accounting required under IFRS relating to bp's purchase of its interests in Azule Energy Holdings Limited.

The operational and financial information is based on preliminary operational and financial results of Azule Energy Holdings Limited for 2025, 2024 and 2023. Actual results may differ from these amounts - immaterial adjustments to the 2023 numbers for Azule Energy Holdings Limited have been included in the 2024 numbers.

	\$ million		
	Gross amount		
	2025	2024	2023
Sales and other operating revenues	4,426	5,410	5,164
Profit (loss) before interest and taxation	1,266	1,896	2,146
Finance costs	304	512	400
Profit (loss) before taxation^a	962	1,384	1,746
Taxation	150	376	346
Profit (loss) for the year	812	1,008	1,400
Other comprehensive income	–	–	–
Total comprehensive income	812	1,008	1,400
Non-current assets	22,564	20,584	
Current assets ^b	4,010	3,384	
Total assets	26,574	23,968	
Current liabilities ^c	5,056	3,576	
Non-current liabilities ^d	11,358	10,174	
Total liabilities	16,414	13,750	
Net assets	10,160	10,218	
Less: non-controlling interests	–	–	
	10,160	10,218	

a Azule Energy includes depreciation and amortisation of \$2,729 million (2024 \$2,844 million and 2023 \$2,768 million), interest income of \$nil (2024 \$nil and 2023 \$nil) and interest expense of \$303 million (2024 \$513 million and 2023 \$407 million).

b Azule Energy includes cash and cash equivalents of \$596 million (2024 \$570 million).

c Azule Energy includes current financial liabilities of \$4,635 million (2024 \$3,417 million).

d Azule Energy includes non-current financial liabilities of \$5,827 million (2024 \$3,426 million).

The group received dividends of \$437 million from Azule Energy Holdings Limited in 2025 (2024 \$463 million and 2023 \$708 million).

16. Investments in joint ventures – continued

The following table provides aggregated summarized financial information relating to the group's share of joint ventures.

	\$ million								
	2025			2024			2023		
	Azule Energy	Other	Total	Azule Energy	Other	Total	Azule Energy	Other	Total
Sales and other operating revenues	2,213	10,030	12,243	2,705	12,164	14,869	2,582	13,705	16,287
Profit (loss) before interest and taxation	633	(61)	572	948	(74)	874	1,073	8	1,081
Finance costs	152	398	550	256	249	505	200	421	621
Profit (loss) before taxation	481	(459)	22	692	(323)	369	873	(413)	460
Taxation	75	247	322	188	(729)	(541)	173	219	392
Non-controlling interest	–	–	–	–	1	1	–	1	1
Profit (loss) for the year	406	(706)	(300)	504	405	909	700	(633)	67
Other comprehensive income	–	–	–	–	(3)	(3)	–	45	45
Total comprehensive income	406	(706)	(300)	504	402	906	700	(588)	112
Non-current assets	11,282	18,162	29,444	10,292	13,871	24,163			
Current assets	2,005	3,960	5,965	1,692	4,363	6,055			
Total assets	13,287	22,122	35,409	11,984	18,234	30,218			
Current liabilities	2,528	3,398	5,926	1,788	2,914	4,702			
Non-current liabilities	5,679	7,244	12,923	5,087	5,057	10,144			
Total liabilities	8,207	10,642	18,849	6,875	7,971	14,846			
Net assets	5,080	11,480	16,560	5,109	10,263	15,372			
Less: non-controlling interests	–	(90)	(90)	–	(11)	(11)			
	5,080	11,390	16,470	5,109	10,252	15,361			
Group investment in joint ventures									
Group share of net assets (as above)	5,080	11,390	16,470	5,109	10,252	15,361			
Cumulative impairment charge	–	(3,066)	(3,066)	–	(3,066)	(3,066)			
Loans made by group companies to joint ventures	–	(4)	(4)	–	(4)	(4)			
	5,080	8,320	13,400	5,109	7,182	12,291			

Transactions between the group and its joint ventures are summarized below.

	\$ million					
	2025		2024		2023	
Product	Sales	Amount receivable at 31 December	Sales	Amount receivable at 31 December	Sales	Amount receivable at 31 December
Sales to joint ventures						
LNG, crude oil and oil products, natural gas	2,470	469	3,653	507	3,585	501
Purchases from joint ventures						
LNG, crude oil and oil products, natural gas, refinery operating costs, plant processing fees	2,230	426	2,952	468	3,328	427

In the normal course of business, bp enters into various arm's length transactions with joint ventures including fixed price commitments to sell and to purchase commodities, forward sale and purchase contracts and agency agreements.

The terms of the outstanding balances receivable from joint ventures are typically 30 to 45 days. The balances are unsecured and will be settled in cash. There are no significant provisions for doubtful debts relating to these balances and no significant expense recognized in the income statement in respect of bad or doubtful debts. Dividends receivable are not included in the table above.

The majority of sales to joint ventures in 2025 relate to heating oil, gasoline, diesel and lubricant product transactions with Mobene and Ocwen Energy. The majority of purchases from joint ventures in 2025 relate to crude oil and oil products transactions with Azule Energy.

bp's share of net impairment charges recognized by joint ventures in 2025 was \$1,111 million (2024 \$477 million and 2023 \$1,285 million) of which \$1,082 million charge (2024 \$nil and 2023 \$1,152 million) was in the gas and low carbon energy segment and \$29 million charge (2024 \$477 million charge and 2023 \$133 million charge) was in the oil production & operations segment. The 2025 charges in the gas and low carbon energy segment principally relate to Archaea Energy and offshore wind. The 2023 charges in the gas and low carbon energy segment principally related to the group's US offshore wind investments.

17. Investments in associates

The following table provides aggregated summarized financial information for the group's associates as it relates to the amounts recognized in the group income statement and on the group balance sheet. There were no individually material associates to the Group at 31 December 2025.

Summarized financial information for the group's share of associates is shown below.

	\$ million		
	bp share		
	2025	2024	2023
Sales and other operating revenues	13,374	12,859	11,396
Profit before interest and taxation	1,940	2,389	2,279
Finance costs	32	41	41
Profit (loss) before taxation	1,908	2,348	2,238
Taxation	990	1,264	1,407
Profit (loss) for the year	918	1,084	831
Other comprehensive income	(4)	(9)	(237)
Total comprehensive income	914	1,075	594
Non-current assets	12,089	11,395	
Current assets	3,915	4,230	
Total assets	16,004	15,625	
Current liabilities	2,997	3,009	
Non-current liabilities	5,714	4,886	
Total liabilities	8,711	7,895	
Net assets	7,293	7,730	
Group investment in associates			
Group share of net assets (as above)	7,293	7,730	
Loans made by group companies to associates	32	11	
	7,325	7,741	

Transactions between the group and its associates are summarized below.

	\$ million					
	2025		2024		2023	
Product	Sales	Amount receivable at 31 December	Sales	Amount receivable at 31 December	Sales	Amount receivable at 31 December
Sales to associates						
LNG, crude oil and oil products, natural gas	1,034	348	844	148	1,009	368
	2025		2024		2023	
Product	Purchases	Amount payable at 31 December	Purchases	Amount payable at 31 December	Purchases	Amount payable at 31 December
Purchases from associates						
Crude oil and oil products, natural gas, transportation tariff	6,708	2,052	7,034	2,223	5,473	2,607

In the normal course of business, bp enters into various arm's length transactions with associates including fixed price commitments to sell and to purchase commodities, forward sale and purchase contracts and agency agreements.

The terms of the outstanding balances receivable from associates are typically 30 to 45 days. The balances are unsecured and will be settled in cash. There are no significant provisions for doubtful debts relating to these balances and no significant expense recognized in the income statement in respect of bad or doubtful debts. Dividends receivable are not included in the table above.

The majority of purchases from associates in 2025, 2024 and 2023 relate to crude oil and oil products transactions with Aker BP. Sales to associates are related to various entities.

bp has commitments amounting to \$6,993 million (2024 \$7,921 million), primarily in relation to contracts with its associates for the purchase of transportation capacity. For information on capital commitments in relation to associates see **Note 13**.

bp's share of impairment charges taken by associates in 2025 was \$265 million (2024 \$14 million).

18. Other investments

	\$ million			
	2025		2024	
	Current	Non-current	Current	Non-current
Equity investments ^a	–	816	–	1,095
Contingent consideration	60	25	55	136
Other	98	16	110	61
	158	857	165	1,292

a The majority of equity investments are unlisted.

Unlisted equity investments are measured using observable recent market prices where available. The majority of investments are measured using models with inputs that may include recent share price data, discounted future cash flows and other available active market pricing data using the maximum available market information and bp's understanding of the associated company's performance and prospects. Contingent consideration relates to amounts arising on disposals which are financial assets classified as measured at fair value through profit or loss.

19. Inventories

	2025		2024	
Crude oil	2,789		3,007	
Natural gas	697		548	
Emissions allowances	843		549	
Refined petroleum and petrochemical products	5,803		6,627	
	10,132		10,731	
Trading inventories	8,665		8,977	
Supplies	2,105		1,946	
Biological assets	112		178	
Solar projects	1,485		1,400	
	22,499		23,232	
Cost of inventories expensed in the income statement	110,640		113,941	

The inventory valuation at 31 December 2025 is stated net of a provision of \$475 million (2024 \$388 million) to write down inventories to their net realizable value, of which \$277 million (2024 \$199 million) relates to hydrocarbon inventories. The net charge to the income statement in the year in respect of inventory net realizable value provisions was \$137 million (2024 \$77 million credit), of which \$73 million charge (2024 \$104 million credit) related to hydrocarbon inventories.

Trading inventories are valued using quoted benchmark prices adjusted as appropriate for location and quality differentials. They are predominantly categorized within level 2 of the fair value hierarchy.

20. Trade and other receivables

	\$ million			
	2025		2024	
	Current	Non-current	Current	Non-current
Financial assets				
Trade receivables	21,107	6	21,659	502
Amounts receivable from joint ventures and associates	817	–	655	–
Other receivables	2,882	1,755	3,524	808
	24,806	1,761	25,838	1,310
Non-financial assets				
Sales taxes and production taxes	1,032	509	1,165	356
Other receivables	176	106	124	149
	1,208	615	1,289	505
	26,014	2,376	27,127	1,815

In both 2025 and 2024 the group entered into non-recourse arrangements to discount certain receivables in support of supply and trading activities and the management of credit risk.

Trade and other receivables are predominantly non-interest bearing.

See **Note 29** for further information.

21. Valuation and qualifying accounts

	\$ million					
	2025		2024		2023	
	Trade and other receivables	Fixed asset investments	Trade and other receivables	Fixed asset investments	Trade and other receivables	Fixed asset investments
At 1 January	995	3,298	1,424	3,183	636	3,050
Charged to costs and expenses	23	179	(90)	140	866	176
Charged to other accounts ^a	10	–	(7)	–	1	(1)
Deductions	(90)	(62)	(332)	(25)	(79)	(42)
At 31 December	938	3,415	995	3,298	1,424	3,183

a Principally exchange adjustments.

Valuation and qualifying accounts relating to trade and other receivables comprise expected credit loss allowances. The expected credit loss allowance comprises \$811 million (2024 \$858 million, 2023 \$1,301 million) relating to receivables that were credit-impaired at the end of the year and \$127 million (2024 \$137 million, 2023 \$123 million) relating to receivables that were not credit-impaired at the end of the year.

Valuation and qualifying accounts relating to fixed asset investments comprise impairment provisions for investments in equity-accounted entities.

Valuation and qualifying accounts are deducted in the balance sheet from the assets to which they apply. For further information on the group's credit risk management policies and how the group recognizes and measures expected losses see **Note 29**.

22. Trade and other payables

	\$ million			
	2025		2024	
	Current	Non-current	Current	Non-current
Financial liabilities				
Trade payables	37,082	–	38,636	–
Amounts payable to joint ventures and associates	2,477	1	2,690	1
Payables for capital expenditure and acquisitions	3,054	85	3,670	309
Payables related to the Gulf of America oil spill	1,520	5,735	1,126	6,830
Other payables	7,771	457	7,358	678
	51,904	6,278	53,480	7,818
Non-financial liabilities				
Sales taxes, customs duties, production taxes and social security	2,001	55	2,121	54
Other payables	2,938	1,642	2,810	1,537
	4,939	1,697	4,931	1,591
	56,843	7,975	58,411	9,409

Materially all of bp's trade payables have payment terms of less than 60 days and give rise to operating cash flows.

Trade and other payables, other than those relating to the Gulf of America oil spill, are predominantly interest free. See **Note 29** (c) for further information.

Payables related to the Gulf of America oil spill include amounts payable under the 2016 consent decree and settlement agreement with the United States and five Gulf coast states, including amounts payable for natural resource damages, state claims and Clean Water Act penalties. On a discounted basis the amounts included in payables related to the Gulf of America oil spill for these elements of the agreements are \$3,207 million payable over seven years, \$1,748 million payable over eight years and \$2,276 million payable over seven years respectively at 31 December 2025. Reported within net cash provided by operating activities in the group cash flow statement is a net cash outflow of \$1,169 million (2024 outflow of \$1,192 million, 2023 outflow of \$1,280 million) related to the Gulf of America oil spill, which includes payments made in relation to these agreements. For full details of these agreements, see bp Annual Report and Form 20-F 2015 - Legal Proceedings.

Payables related to the Gulf of America oil spill at 31 December 2025 also include amounts payable for settled economic loss and property damage claims which are payable over a period of up to two years.

23. Provisions

	\$ million					
	Decommissioning	Environmental	Litigation and claims	Emissions	Other ^c	Total
At 1 January 2025	11,758	1,518	701	2,330	1,981	18,288
Exchange adjustments	159	15	6	99	144	423
Acquisitions	—	—	26	—	3	29
New and increase in existing provisions ^a	528	325	362	3,052	1,329	5,596
Write-back of unused provisions ^a	(2)	(73)	(20)	(83)	(707)	(885)
Unwinding of discount ^b	530	63	20	—	62	675
Utilization	(17)	(297)	(188)	(1,834)	(522)	(2,858)
Reclassified to other payables	(540)	(2)	(108)	—	(2)	(652)
Reclassified as liabilities directly associated with assets held for sale	(21)	(31)	(2)	—	(21)	(75)
Deletions	(142)	(18)	(1)	—	(1)	(162)
At 31 December 2025	12,253	1,500	796	3,564	2,266	20,379
Of which – current	824	319	100	2,709	757	4,709
– non-current	11,429	1,181	696	855	1,509	15,670

a Recognized in the Group income statement, other than changes in decommissioning provisions related to owned assets.

b Recognized in the Group income statement

c Other includes provisions for onerous contracts and restructuring costs.

The decommissioning provision primarily comprises the future cost of decommissioning oil and natural gas wells, facilities and related pipelines. The environmental provision includes provisions for costs related to the control, abatement, clean-up or elimination of environmental pollution relating to soil, groundwater, surface water and sediment contamination. The litigation and claims category includes provisions for matters related to, for example, commercial disputes, product liability, and allegations of exposures of third parties to toxic substances. Emissions provisions primarily relate to obligations under the U.S. Environmental Protection Agency Renewable Fuel Standard Program and are driven by the amount of the obligations outstanding and current price of the related credits. The provision will principally be settled through allowances already held as inventory in the group balance sheet.

For information on significant estimates and judgements made in relation to provisions, see Provisions and contingencies within **Note 1**.

Gulf of America oil spill

The group has recognized certain assets, payables and provisions and incurs certain residual costs relating to the Gulf of America oil spill that occurred in 2010. For further information see **Notes 7, 22, 29 and 33**. The litigation and claims provision presented in the table above includes the latest estimate for the remaining costs associated with the Gulf of America oil spill. The amounts payable may differ from the amount provided and the timing of payments is uncertain.

24. Pensions and other post-employment benefits

Most group companies have pension plans, the forms and benefits of which vary with conditions and practices in the countries concerned. Pension benefits may be provided through defined contribution plans (money purchase schemes) or defined benefit plans (final salary and other types of schemes with committed pension benefit payments). For defined contribution plans, retirement benefits are determined by the value of funds arising from contributions paid in respect of each employee. For defined benefit plans, retirement benefits are based on such factors as an employee's pensionable salary and length of service. Defined benefit plans may be funded or unfunded. The assets of funded plans are generally held in separately administered trusts.

For information on significant estimates and judgements made in relation to accounting for these plans see Pensions and other post-employment benefits in **Note 1**.

The defined benefit pension obligation in the UK consists primarily of a closed funded final salary pension plan under which retired employees draw the majority of their benefit as an annuity. This pension plan is governed by a corporate trustee whose board is composed of four member-nominated directors, four company-nominated directors, one independent director and one independent chair nominated by the company. The trustee board is required by law to act in the best interests of the plan participants and is responsible for setting certain policies, such as investment policies of the plan.

Employees in the UK are eligible for membership of defined contribution plans established with third-party providers.

In the US, all pension benefits now accrue under a cash balance formula. Benefits previously accrued under final salary formulas are legally protected. Retiring US employees typically take their pension benefit in the form of a lump sum payment upon retirement. The plan is funded and its assets are overseen by a fiduciary Investment Committee. At the end of 2025 the committee was composed of five bp employees appointed by the president of bp Corporation North America Inc. (the appointing officer). The Investment Committee is required by law to act in the best interests of the plan participants and is responsible for setting certain policies, such as the investment policies of the plan. US employees are also eligible to participate in a defined contribution (401k) plan in which employee contributions are matched with company contributions.

In the US, group companies also provide post-employment healthcare to eligible retired employees and their dependents (and, in certain legacy cases, life insurance coverage); the entitlement to these benefits is based on the date of hire, the employee remaining in service until a specified age and completion of a minimum period of service.

In the Eurozone, there are defined benefit pension plans in Germany, France, the Netherlands and other countries. In Germany and France, the majority of the pensions are unfunded. In Germany, the group's largest Eurozone plan, employees receive a pension and also have a choice to supplement their core pension through salary sacrifice. For employees who joined since 2002, the core pension benefit is a career average plan with retirement benefits based on such factors as an employee's pensionable salary and length of service. The returns on the notional contributions made by both the company and employees are based on the interest rate which is set out in German tax law. Retired German employees take their pension benefit typically in the form of an annuity. The German plans are governed by legal agreements between bp and the works council or between bp and the trade union.

Following agreement with the works council, a proportion of the existing defined benefit plans covering approximately 60% of the total active membership in Germany were closed to future accrual on 31 December 2025 resulting in a net past service cost of \$6 million being recognized in the income statement. Affected employees became eligible for new cash balance arrangements from 1 January 2026.

In the Netherlands, new legislation came into effect in 2023 for domestic pension plans requiring that new pension benefit accruals be exclusively held in defined contribution plans from 1 January 2028 at the latest. In light of these requirements, and, following agreement with the Dutch retail and refinery works councils, the existing defined benefit plans were closed to future accrual on 31 August 2025 resulting in a curtailment gain of \$40 million being recognized in the income statement. A new defined contribution plan for members of the defined benefits plans, as well as for new members, came into effect on 1 September 2025.

The level of contributions to funded defined benefit plans is the amount needed to provide adequate funds to meet pension obligations as they fall due. During 2025 the aggregate level of contributions was \$46 million (2024 \$69 million and 2023 \$42 million) along with \$49 million of refunds from closed plans (2024 \$nil and 2023 \$nil). The aggregate level of contributions in 2026 is expected to be approximately \$100 million and includes contributions in all countries that we expect to be required to make contributions by law or under contractual agreements, as well as an allowance for discretionary funding.

For the primary UK defined benefit plan there is a funding agreement between the group and the trustee. On a three year cycle, a schedule of contributions is agreed covering the next five years. The schedule of contributions is next scheduled to be updated after the 31 December 2026 formal actuarial valuation. No contractually committed funding was due at 31 December 2025.

The surplus relating to the primary UK defined benefit pension plan is recognized on the balance sheet on the basis that the company is entitled to a refund of any remaining assets once all members have left the plan.

Minimum pension funding in the US is determined by legislation and is supplemented by discretionary contributions. No contributions were made into the US pension plan in 2025 and no statutory funding requirement is expected in the next 12 months.

The surplus relating to the US pension fund is recognized on the balance sheet on the basis that economic benefit can be gained from the surplus through a reduction in future contributions.

There was no minimum funding requirement for the US plan, and no significant minimum funding requirements in other countries at 31 December 2025.

Following the closure of the Netherlands defined benefit plans to future accrual, the group's ability to access the surplus of \$277 million at 31 December 2025 is now fully restricted as the company does not have a right to a refund and can no longer gain an economic benefit through a reduction contributions. Consequently, the net defined benefit asset recognized on the balance sheet for these plans is now fully capped at zero.

The obligation and cost of providing pensions and other post-employment benefits is assessed annually using the projected unit credit method. The date of the most recent actuarial review was 31 December 2025. The UK defined benefit plans are subject to a formal actuarial valuation every three years; valuations are required more frequently in many other countries. The most recent formal actuarial valuation of the primary UK defined benefit pension plan was as at 31 December 2023. A valuation of the US plan and largest Eurozone plans are carried out annually.

24. Pensions and other post-employment benefits – continued

The material financial assumptions used to estimate the benefit obligations of the various plans are set out below. The assumptions are reviewed by management at the end of each year and are used to evaluate the accrued benefit obligation at 31 December and pension expense for the following year.

			UK		US		Eurozone		%
Financial assumptions used to determine benefit obligation	2025	2024	2023	2025	2024	2023	2025	2024	2023
Discount rate for plan liabilities	5.6	5.5	4.8	5.4	5.6	5.0	4.2	3.5	3.6
Rate of increase for pensions in payment	2.7	2.9	2.8	—	—	—	1.8	1.8	2.1
Rate of increase in deferred pensions	2.7	2.9	2.8	—	—	—	0.6	0.6	0.7
Inflation for plan liabilities	2.9	3.1	3.0	2.0	2.0	2.0	2.0	2.0	2.4

			UK		US		Eurozone		%
Financial assumptions used to determine benefit expense	2025	2024	2023	2025	2024	2023	2025	2024	2023
Discount rate for plan service cost ^a	N/A	N/A	N/A	5.7	5.0	5.2	3.7	3.7	4.3
Discount rate for plan other finance expense	5.5	4.8	5.0	5.6	5.0	5.2	3.5	3.6	4.2
Inflation for plan service cost ^a	N/A	N/A	N/A	2.0	2.0	2.0	2.0	2.4	2.1

a UK discount rate and inflation rate assumptions are not relevant in determining the benefit expense for the closed UK plan. Rates for the remaining small worldwide plan administered/reported through the UK are 5.6% (2024 5.0% and 2023 5.0%) and 2.1% (2024 1.9% and 2023 1.9%) respectively.

The discount rate assumptions are based on third-party AA corporate bond indices and for our largest plans in the UK, US and the Eurozone we use yields that reflect the maturity profile of the expected benefit payments. The inflation rate assumptions for our UK and US plans are based on the difference between the yields on index-linked and fixed-interest long-term government bonds. In other countries, including the Eurozone, we use this approach, or advice from the local actuary depending on the information available. The inflation assumptions are used to determine the rate of increase for pensions in payment and the rate of increase in deferred pensions where there is such an increase.

In addition to the financial assumptions, we regularly review the demographic and mortality assumptions. The mortality assumptions reflect best practice in the countries in which we provide pensions and have been chosen with regard to applicable published tables adjusted where appropriate to reflect the experience of the group and an extrapolation of past longevity improvements into the future. bp's most substantial pension liabilities are in the UK, the US and the Eurozone where our mortality assumptions are as follows:

			UK		US		Eurozone		Years
Mortality assumptions	2025	2024	2023	2025	2024	2023	2025	2024	2023
Life expectancy at age 60 for a male currently aged 60	27.1	27.0	27.4	25.2	25.1	25.0	26.4	26.2	26.1
Life expectancy at age 60 for a male currently aged 40	28.9	28.9	29.2	26.9	26.8	26.7	28.9	28.6	28.6
Life expectancy at age 60 for a female currently aged 60	28.9	29.0	29.2	28.2	28.1	28.1	29.5	29.5	29.3
Life expectancy at age 60 for a female currently aged 40	30.4	30.5	30.6	29.7	29.6	29.6	31.7	31.7	31.6

Pension plan assets are generally held in trusts, the primary objective of which is to accumulate assets sufficient to meet the obligations of the plans. The assets of the trusts are invested in a manner consistent with fiduciary obligations and principles that reflect current practices in portfolio management.

A proportion of the assets are held in equities, which are expected to generate a higher level of return over the long term, with an acceptable level of risk. In order to provide reasonable assurance that no single security or type of security has an unwarranted impact on the total portfolio, the investment portfolios are highly diversified.

The trustee's long-term investment objective for the primary UK defined benefit plan is to invest the plan's assets in a responsible manner that considers downside risk such that the assets are expected to be sufficient to pay benefits as and when they fall due. The UK plan uses a liability driven investment (LDI) approach for part of the portfolio, investing primarily in government bonds to economically hedge against the effect of the most significant plan liability assumptions of interest rate and inflation rate. This is partly funded by short-term sale and repurchase agreements, whereby the plan borrows money using existing bonds as security and which will be bought back at a specified price at an agreed future date. The funds raised are used to invest in further bonds to increase the proportion of assets which match the plan liabilities. The borrowings are shown separately in the analysis of pension plan assets in the table below.

During 2025, the trustee extended its derisking strategy for the primary UK defined benefit plan by completing a bulk annuity buy-in transaction with Legal & General Assurance Society Limited covering approximately 12% of the plan's liabilities. The buy-in was paid for by way of transfer of \$2,183 million of government issued bonds from the plan assets in exchange for a stream of cashflows to the plan replicating payments due to relevant members.

The group was not legally relieved of the primary responsibility for the obligation and the benefits continue to be payable by the plan. The difference of \$148 million between the buy-in purchase price (\$2,183 million) and the defined benefit liability covered by the policy (\$2,035 million) was accounted for in other comprehensive income.

For the primary UK defined benefit plan there is an agreement with the trustee to at least maintain the proportion of assets with liability matching characteristics and review over time. There is a similar agreement in place for the primary US plan. During 2025, excluding qualifying insurance policies in the UK, the asset allocation policies of the primary UK and US plans remained unchanged.

24. Pensions and other post-employment benefits – continued

The current asset allocation policy for the major plans at 31 December 2025 was as follows:

Asset category	UK	US
	%	%
Total equity (including private equity)	8	19
Bonds/cash (including LDI)	85	81
Property/real estate	7	–

The amounts invested under the LDI programme by the primary UK pension plan as at 31 December 2025 were \$3,702 million (2024 \$4,970 million) of government-issued nominal bonds and \$10,805 million (2024 \$11,105 million) of index-linked bonds.

Some of the group's pension plans in the Eurozone and other countries use derivative financial instruments as part of their asset mix to manage the level of risk. The fair value of these instruments is included in other assets in the table below.

The group's main pension plans do not invest directly in either securities or property/real estate of the company or of any subsidiary.

The fair values of the various categories of assets held by the defined benefit plans at 31 December are presented in the table below, including the effects of derivative financial instruments. Movements in the fair value of plan assets during the year are shown in detail in the table on [page 208](#).

	\$ million				
	UK ^a	US ^b	Eurozone	Other	Total
Fair value of pension plan assets					
At 31 December 2025					
Listed equities – developed markets	725	137	84	181	1,127
– emerging markets	29	17	10	70	126
Private equity ^c	1,871	910	–	–	2,781
Government issued nominal bonds ^d	3,761	1,369	901	214	6,245
Government issued index-linked bonds ^d	10,805	–	85	8	10,898
Corporate bonds ^d	5,383	2,790	70	236	8,479
Property ^e	2,487	–	6	13	2,506
Cash	574	83	912	106	1,675
Other ^f	3,232	46	(58)	11	3,231
Debt (repurchase agreements) used to fund liability driven investments	(4,278)	–	–	–	(4,278)
	24,589	5,352	2,010	839	32,790
At 31 December 2024					
Listed equities – developed markets	963	113	341	230	1,647
– emerging markets	32	13	55	75	175
Private equity ^c	1,916	950	–	2	2,868
Government issued nominal bonds ^d	5,027	1,317	690	223	7,257
Government issued index-linked bonds ^d	11,105	–	78	7	11,190
Corporate bonds ^d	6,088	2,763	605	261	9,717
Property ^e	2,344	–	84	19	2,447
Cash	416	67	100	78	661
Other ^f	1,039	36	54	14	1,143
Debt (repurchase agreements) used to fund liability driven investments	(5,664)	–	–	–	(5,664)
	23,266	5,259	2,007	909	31,441
At 31 December 2023					
Listed equities – developed markets	862	97	333	232	1,524
– emerging markets	28	12	51	66	157
Private equity ^c	2,022	1,014	–	2	3,038
Government issued nominal bonds ^d	6,285	1,457	746	285	8,773
Government issued index-linked bonds ^d	13,177	–	88	–	13,265
Corporate bonds ^d	6,144	2,802	605	166	9,717
Property ^e	2,437	–	92	17	2,546
Cash	453	59	82	85	679
Other ^f	1,123	33	55	391	1,602
Debt (repurchase agreements) used to fund liability driven investments	(6,485)	–	–	–	(6,485)
	26,046	5,474	2,052	1,244	34,816

a Bonds held by the UK pension plans are denominated in sterling or hedged back to sterling to minimize foreign currency exposure. Property held by the UK pension plans is in the United Kingdom.

b Bonds held by the US pension plans are denominated in US dollars or hedged back to USD to minimize foreign currency exposure.

c Private equity is valued at fair value based on the most recent transaction price or third-party net asset, revenue or earnings based valuations that generally result in the use of significant unobservable inputs.

d Bonds held by pension plans are predominantly valued using observable market data based inputs other than quoted market prices in active markets.

e Properties are valued based on an analysis of recent market transactions supported by market knowledge derived from third-party professional valuers that generally result in the use of significant unobservable inputs.

f Other includes qualifying insurance policies in the UK amounting to \$2,159 million representing the asset associated with the buy in outlined on page 206. The fair value of these insurance policies is equal to the value of the defined benefit obligations to which these policies relate. Other included insurance policies arising from annuity buy-in in Canada amounting to \$374 million in 2023. Completion of a buy-out in 2024 reduced these amounts to \$nil.

24. Pensions and other post-employment benefits – continued

	\$ million				
	2025				
	UK	US	Eurozone	Other	Total
Analysis of the amount charged to profit or loss					
Current service cost ^a	47	157	56	25	285
Past service cost ^b	–	–	(39)	–	(39)
Settlement ^b	–	–	11	–	11
Operating charge (credit) relating to defined benefit plans	47	157	28	25	257
Payments to defined contribution plans	180	179	7	35	401
Total operating charge (credit)	227	336	35	60	658
Interest income on plan assets ^a	(1,322)	(286)	(78)	(38)	(1,724)
Interest on plan liabilities	976	300	190	48	1,514
Other finance (income) expense	(346)	14	112	10	(210)
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets	(613)	120	(225)	(1)	(719)
Change in financial assumptions underlying the present value of the plan liabilities	453	(242)	436	8	655
Change in demographic assumptions underlying the present value of the plan liabilities	(26)	–	–	(1)	(27)
Experience gains and losses arising on the plan liabilities	15	(40)	(102)	(3)	(130)
Remeasurements recognized in other comprehensive income	(171)	(162)	109	3	(221)
Movements in benefit obligation during the year					
Benefit obligation at 1 January	17,324	5,524	5,002	1,007	28,857
Exchange adjustments	1,301	–	646	50	1,997
Operating charge relating to defined benefit plans	47	157	28	25	257
Interest cost	976	300	190	48	1,514
Contributions by plan participants	8	–	2	5	15
Benefit payments (funded plans) ^c	(1,160)	(313)	(95)	(64)	(1,632)
Benefit payments (unfunded plans) ^c	(10)	(145)	(246)	(11)	(412)
Reclassified as assets held for sale	(24)	–	(161)	(77)	(262)
Disposals	–	–	(1)	–	(1)
Remeasurements	(442)	282	(334)	(4)	(498)
Benefit obligation at 31 December^{a d e}	18,020	5,805	5,031	979	29,835
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	23,266	5,259	2,007	909	31,441
Exchange adjustments	1,757	–	257	43	2,057
Interest income on plan assets ^{a e}	1,322	286	78	38	1,724
Contributions by plan participants	8	–	2	5	15
Contributions by and refunds to employers (funded plans)	9	–	16	(28)	(3)
Benefit payments (funded plans) ^c	(1,160)	(313)	(95)	(64)	(1,632)
Reclassified as assets held for sale	–	–	(30)	(63)	(93)
Remeasurements ^f	(613)	120	(225)	(1)	(719)
Fair value of plan assets at 31 December ^g	24,589	5,352	2,010	839	32,790
Surplus (deficit) at 31 December	6,569	(453)	(3,021)	(140)	2,955
Represented by					
Asset recognized	6,697	921	93	60	7,771
Liability recognized	(128)	(1,374)	(3,114)	(200)	(4,816)
	6,569	(453)	(3,021)	(140)	2,955
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	6,696	921	84	29	7,730
Unfunded	(127)	(1,374)	(3,105)	(169)	(4,775)
	6,569	(453)	(3,021)	(140)	2,955
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(17,893)	(4,431)	(1,926)	(810)	(25,060)
Unfunded	(127)	(1,374)	(3,105)	(169)	(4,775)
	(18,020)	(5,805)	(5,031)	(979)	(29,835)

a The costs of managing plan investments are offset against the investment return, the costs of administering pension plan benefits are generally included in current service cost and the costs of administering other post-employment benefit plans are included in the benefit obligation. Following the closure of the primary UK pension plan, current service cost in the UK consists of \$36 million of costs of administering that plan and \$11 million of current service cost from the remaining small worldwide plans administered and reported through the UK.

b Past service costs predominantly reflect curtailment impacts from the closure of plans in the Netherlands and Germany to future accrual. Settlements represent losses associated with restructuring activity in Germany.

c The benefit payments amount shown above comprises \$1,975 million benefits and \$12 million settlements, plus \$57 million of plan expenses incurred in the administration of the benefit.

d The benefit obligation for the US is made up of \$4,602 million for pension liabilities and \$1,203 million for other post-employment benefit liabilities (which are unfunded and are primarily retiree medical liabilities). The benefit obligation for the Eurozone includes \$2,976 million for pension liabilities in Germany which is largely unfunded.

24. Pensions and other post-employment benefits – continued

- e Includes \$346 million (2024 \$155 million) representing assets ceilings in plans in the Netherlands (see page 205), Switzerland and the UK. Movements in the asset ceiling during 2025 were interest cost of \$8 million and remeasurements of \$183 million.
- f The actual return on plan assets is made up of the sum of the interest income on plan assets and the remeasurement of plan assets as disclosed above.
- g The fair value of plan assets includes borrowings related to the LDI programme as described on page 207.

	\$ million				
	2024				
	UK	US	Eurozone	Other	Total
Analysis of the amount charged to profit or loss					
Current service cost ^a	48	160	62	23	293
Past service cost ^b	–	–	(1)	–	(1)
Settlement ^b	(1)	–	–	–	(1)
Operating charge (credit) relating to defined benefit plans	47	160	61	23	291
Payments to defined contribution plans	161	192	8	35	396
Total operating charge (credit)	208	352	69	58	687
Interest income on plan assets ^a	(1,218)	(267)	(70)	(49)	(1,604)
Interest on plan liabilities	909	283	184	60	1,436
Other finance (income) expense	(309)	16	114	11	(168)
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets	(2,388)	(239)	65	83	(2,479)
Change in financial assumptions underlying the present value of the plan liabilities	1,496	403	103	(48)	1,954
Change in demographic assumptions underlying the present value of the plan liabilities	194	(8)	1	2	189
Experience gains and losses arising on the plan liabilities	15	(34)	2	(7)	(24)
Remeasurements recognized in other comprehensive income	(683)	122	171	30	(360)
Movements in benefit obligation during the year					
Benefit obligation at 1 January	19,579	5,837	5,537	1,371	32,324
Exchange adjustments	(352)	–	(355)	(66)	(773)
Operating charge relating to defined benefit plans	47	160	61	23	291
Interest cost	909	283	184	60	1,436
Contributions by plan participants	7	–	2	7	16
Benefit payments (funded plans) ^c	(1,153)	(243)	(89)	(427)	(1,912)
Benefit payments (unfunded plans) ^c	(8)	(152)	(232)	(12)	(404)
Disposals	–	–	–	(2)	(2)
Remeasurements	(1,705)	(361)	(106)	53	(2,119)
Benefit obligation at 31 December^{a,d}	17,324	5,524	5,002	1,007	28,857
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	26,046	5,474	2,052	1,244	34,816
Exchange adjustments	(473)	–	(139)	(61)	(673)
Interest income on plan assets ^{a,e}	1,218	267	70	49	1,604
Contributions by plan participants	7	–	2	7	16
Contributions by employers (funded plans)	9	–	46	14	69
Benefit payments (funded plans) ^c	(1,153)	(243)	(89)	(427)	(1,912)
Remeasurements ^e	(2,388)	(239)	65	83	(2,479)
Fair value of plan assets at 31 December ^f	23,266	5,259	2,007	909	31,441
Surplus (deficit) at 31 December	5,942	(265)	(2,995)	(98)	2,584
Represented by					
Asset recognized	6,083	1,009	273	92	7,457
Liability recognized	(141)	(1,274)	(3,268)	(190)	(4,873)
	5,942	(265)	(2,995)	(98)	2,584
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	6,083	1,009	261	48	7,401
Unfunded	(141)	(1,274)	(3,256)	(146)	(4,817)
	5,942	(265)	(2,995)	(98)	2,584
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(17,183)	(4,250)	(1,746)	(861)	(24,040)
Unfunded	(141)	(1,274)	(3,256)	(146)	(4,817)
	(17,324)	(5,524)	(5,002)	(1,007)	(28,857)

a The costs of managing plan investments are offset against the investment return, the costs of administering pension plan benefits are generally included in current service cost and the costs of administering other post-employment benefit plans are included in the benefit obligation. Following the closure of the primary UK pension plan, current service cost in the UK consists of \$38 million of costs of administering that plan and \$10 million of current service cost from the remaining small worldwide plans administered and reported through the UK.

b Past service costs predominantly reflect minor plan changes in France. Settlements represent changes in small worldwide plans administered and reported throughout the UK.

c The benefit payments amount shown above comprises \$1,907 million benefits and \$352 million settlements relating to the buy-out in Canada, plus \$57 million of plan expenses incurred in the administration of the benefit.

24. Pensions and other post-employment benefits – continued

- d The benefit obligation for the US is made up of \$4,428 million for pension liabilities and \$1,096 million for other post-employment benefit liabilities (which are unfunded and are primarily retiree medical liabilities). The benefit obligation for the Eurozone includes \$3,086 million for pension liabilities in Germany which is largely unfunded.
- e The actual return on plan assets is made up of the sum of the interest income on plan assets and the remeasurement of plan assets as disclosed above.
- f The fair value of plan assets includes borrowings related to the LDI programme as described on page 207.

	\$ million				
	2023				
	UK	US	Eurozone	Other	Total
Analysis of the amount charged to profit or loss					
Current service cost ^a	44	156	47	21	268
Past service cost ^b	4	–	5	(2)	7
Settlement ^b	–	–	–	3	3
Operating charge (credit) relating to defined benefit plans	48	156	52	22	278
Payments to defined contribution plans	132	158	7	36	333
Total operating charge (credit)	180	314	59	58	611
Interest income on plan assets ^a	(1,259)	(274)	(78)	(56)	(1,667)
Interest on plan liabilities	869	297	194	66	1,426
Other finance (income) expense	(390)	23	116	10	(241)
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets	(677)	45	82	28	(522)
Change in financial assumptions underlying the present value of the plan liabilities	(649)	28	(508)	(24)	(1,153)
Change in demographic assumptions underlying the present value of the plan liabilities	(230)	(5)	8	–	(227)
Experience gains and losses arising on the plan liabilities	(320)	45	(84)	(1)	(360)
Remeasurements recognized in other comprehensive income	(1,876)	113	(502)	3	(2,262)

- a The costs of managing plan investments are offset against the investment return, the costs of administering pension plan benefits are generally included in current service cost and the costs of administering other post-employment benefit plans are included in the benefit obligation. Following the closure of the primary UK pension plan, current service cost in the UK consists of \$34 million of costs of administering that plan and \$10 million of current service cost from the remaining small worldwide plans administered and reported through the UK.
- b Past service costs predominantly represent largely offsetting income and costs due to the removal of some benefits for members in Turkish plans and their replacement with new arrangements administered and reported through the UK. There was also a \$5 million past service cost in France relating to statutory retirement age changes. Settlements represent charges for special termination benefits arising as a result of early retirements.

Sensitivity analysis

The discount rate, inflation and the mortality assumptions all have a significant effect on the amounts reported. A one-percentage point change, in isolation, in certain assumptions as at 31 December 2025 for the group's pensions and other post-employment benefit expense would have had the effects shown in the tables below. The effects shown for the expense in 2026 comprise the total of current service cost and net finance income or expense.

	\$ million					
	UK		US		One percentage point Eurozone	
	Increase	Decrease	Increase	Decrease	Increase	Decrease
Discount rate^a						
Effect on expense in 2026	(186)	168	(44)	46	(2)	(5)
Effect on obligation at 31 December 2025	(1,803)	2,185	(465)	614	(497)	604
Inflation rate^b						
Effect on expense in 2026	90	(82)	8	(6)	22	(20)
Effect on obligation at 31 December 2025	1,613	(1,464)	39	(33)	480	(414)

- a The amounts presented reflect that the discount rate is used to determine the asset interest income as well as the interest cost on the obligation.
- b The amounts presented reflect the total impact of an inflation rate change on the assumptions for rate of increase in salaries, pensions in payment and deferred pensions.

	\$ million		
	One year increase		
	UK	US	Eurozone
Longevity			
Effect on expense in 2026	33	4	9
Effect on obligation at 31 December 2025	593	60	189

24. Pensions and other post-employment benefits – continued

Estimated future benefit payments and the weighted average duration of defined benefit obligations

The expected benefit payments, which reflect expected future service, as appropriate, but exclude plan expenses, and the weighted average duration of the defined benefit obligations at 31 December 2025 are as follows:

Estimated future benefit payments					\$ million
	UK	US	Eurozone	Other	Total
2026	1,190	467	324	61	2,042
2027	1,212	463	325	55	2,055
2028	1,219	458	320	56	2,053
2029	1,233	467	319	55	2,074
2030	1,234	473	312	54	2,073
2031 - 2035	6,214	2,383	1,431	285	10,313
					Years
Weighted average duration	11.1	9.2	12.5	12.6	

25. Cash and cash equivalents

	\$ million	
	2025	2024
Cash	17,158	16,414
Triparty repos and term bank deposits	12,691	14,453
Other cash equivalents	6,707	8,337
	36,556	39,204

Cash and cash equivalents comprise cash in hand; current balances with banks and similar institutions; deposits and triparty repos of three months or less with banks and similar institutions; money market funds and treasury bills. The carrying amounts of cash, triparty repos, term bank deposits and treasury bills approximate their fair values. Substantially all of the other cash equivalents are categorized within level 1 of the fair value hierarchy.

Cash and cash equivalents at 31 December 2025 includes \$4,725 million (2024 \$4,844 million) that is restricted. The restricted cash balances include amounts required to cover initial margin on trading exchanges and certain cash balances which are subject to exchange controls.

The group holds \$6,434 million (2024 \$5,774 million) of cash and cash equivalents outside the UK and it is not expected that any significant tax will arise on repatriation.

26. Finance debt

	\$ million					
	2025			2024		
	Current	Non-current	Total	Current	Non-current	Total
Borrowings	3,356	54,602	57,958	4,474	55,073	59,547

The main elements of current borrowings are the current portion of long-term borrowings that is due to be repaid in the next 12 months of \$3,003 million (2024 \$3,793 million) and issued commercial paper of \$200 million (2024 \$500 million). Finance debt does not include accrued interest of \$552 million (2024 \$585 million), which is reported within other payables. As part of actively managing its debt portfolio, during the year the group bought back \$2.0 billion (2024 \$nil) of finance debt consisting entirely of US dollar bonds. These transactions have no significant impact on net debt or gearing.

The following table shows the weighted-average interest rates achieved through a combination of borrowings and derivative financial instruments entered into to manage interest rate and currency exposures.

	Fixed rate debt			Floating rate debt		Total
	Weighted average interest rate %	Weighted average time for which rate is fixed Years	Amount \$ million	Weighted average interest rate %	Amount \$ million	Amount \$ million
						2025
US dollar	5	8	41,018	4	16,486	57,504
Other currencies	6	4	246	6	208	454
			41,264		16,694	57,958
						2024
US dollar	4	8	41,145	5	17,847	58,992
Other currencies	6	3	396	6	159	555
			41,541		18,006	59,547

26. Finance debt - continued

Fair values

The estimated fair value of finance debt is shown in the table below together with the carrying amount as reflected in the balance sheet.

Long-term borrowings in the table below include the portion of debt that matures in the 12 months from 31 December 2025, whereas in the group balance sheet the amount is reported within current finance debt.

The carrying amount of the group's short-term borrowings, comprising mainly of commercial paper, approximates their fair value. The fair values of the significant majority of the group's long-term borrowings are determined using quoted prices in active markets, and so fall within level 1 of the fair value hierarchy. Where quoted prices are not available, quoted prices for similar instruments in active markets are used and such measurements are therefore categorized in level 2 of the fair value hierarchy.

	\$ million			
	2025		2024	
	Fair value	Carrying amount	Fair value	Carrying amount
Short-term borrowings	353	353	681	681
Long-term borrowings	54,582	57,605	54,285	58,866
Total finance debt	54,935	57,958	54,966	59,547

27. Capital disclosures and net debt

The group defines capital as total equity plus net debt. Our financial framework seeks to support the pursuit of value growth for shareholders while maintaining a secure financial base.

The group monitors capital on the basis of gearing, that is, the ratio of net debt to the total of net debt plus total equity. Net debt is calculated as finance debt, as shown in the balance sheet, plus the fair value of associated derivative financial instruments that are used to hedge foreign exchange and interest rate risks relating to finance debt for which hedge accounting is applied, less cash and cash equivalents. Net debt and gearing are non-IFRS measures. bp believes these measures provide useful information to investors. Net debt enables investors to see the economic effect of finance debt, related hedges and cash and cash equivalents in total. Gearing enables investors to see how significant net debt is relative to total equity. The derivatives are reported on the balance sheet within the headings 'Derivative financial instruments'. All components of equity are included in the denominator of the calculation.

At 31 December 2025, gearing was 23.1% (2024 22.7%).

At 31 December	\$ million	
	2025	2024
Finance debt	57,958	59,547
Less: fair value asset (liability) of hedges related to finance debt ^a	(780)	(2,654)
	58,738	62,201
Less: cash and cash equivalents	36,556	39,204
Net debt	22,182	22,997
Total equity	74,000	78,318
Gearing	23.1%	22.7%

^a Derivative financial instruments entered into for the purpose of managing foreign currency exchange risk associated with net debt with a fair value liability position of \$94 million (2024 liability of \$166 million) are not included in the calculation of net debt shown above as hedge accounting was not applied for these instruments.

Certain subsidiaries in the group have externally imposed capital requirements and have been in compliance with these requirements throughout the year.

27. Capital disclosures and net debt - continued

An analysis of changes in liabilities arising from financing activities is provided below.

	\$ million				
	Finance debt	Currency swaps ^a	Lease liabilities	Partner payable for leases entered into on behalf of joint operations	Total liabilities arising from financing activities
At 1 January 2025	59,547	4,113	12,000	37	75,697
Exchange adjustments	127	–	399	2	528
Net financing cash flow	(3,290)	(22)	(3,091)	(2)	(6,405)
Fair value (gains) losses	1,664	(3,044)	–	–	(1,380)
New and remeasured leases/joint operations payables	–	–	5,449	(4)	5,445
Other movements	(90)	–	(186)	(2)	(278)
At 31 December 2025	57,958	1,047	14,571	31	73,607
At 1 January 2024	51,954	2,978	11,121	30	66,083
Exchange adjustments	(39)	–	(272)	(1)	(312)
Net financing cash flow	4,761	(27)	(2,833)	(14)	1,887
Fair value (gains) losses	(840)	1,162	–	–	322
New and remeasured leases/joint operations payables	–	–	3,441	24	3,465
Other movements ^b	3,711	–	543	(2)	4,252
At 31 December 2024	59,547	4,113	12,000	37	75,697

a Currency swaps include cross currency interest rate swaps.

b Includes \$3,726 million of finance debt and \$585 million of lease liabilities acquired as part of the Lightsource bp and bp Bunge Bioenergia business combinations.

The finance debt and currency swap balances above do not include accrued interest, which is reported within other receivables and other payables on the balance sheet and for which the associated cash flows are presented as operating cash flows in the group cash flow statement. The currency swaps are reported on the balance sheet within the headings 'Derivative financial instruments' and are subsets of both derivatives held for trading and derivatives designated in fair value hedge relationships as detailed in **Note 30**. When hedge accounting is applied to these derivatives they are included in the calculation of net debt shown above.

In addition to the liabilities included in the table above the group has accrued \$448 million (2024 \$922 million) at the balance sheet date for shares repurchased between the end of the reporting period and 10 February 2026 (2024 11 February 2025). \$4,486 million (2024 \$7,127 million) is included in financing activities in the group cash flow statement for the cash used to repurchase shares during the year.

28. Leases

The group leases a number of assets as part of its activities. This primarily includes drilling rigs in the oil production & operations and gas & low carbon energy segments and retail service stations, oil depots and storage tanks in the customer & products segment as well as office accommodation and vessel charters across the group. The weighted-average remaining lease term for the total lease portfolio is around nine years (2024 eight years). Some leases have payments that vary with market interest or inflation rates. Certain leases contain residual value guarantees, which may be triggered in certain circumstances such as if market values have significantly declined at the conclusion of the lease.

The table below shows the timing of the undiscounted cash outflows for the lease liabilities included on the balance sheet.

	\$ million	
	2025	2024
Undiscounted lease liability cash flows due:		
Within 1 year	3,596	3,237
1 to 2 years	2,906	2,418
2 to 3 years	2,222	1,798
3 to 4 years	1,620	1,394
4 to 5 years	1,481	1,099
5 to 10 years	4,076	3,039
Over 10 years	3,435	1,283
	19,336	14,268
Impact of discounting	(4,765)	(2,268)
Lease liabilities at 31 December	14,571	12,000
Of which – current	2,832	2,660
– non-current	11,739	9,340

28. Leases - continued

The group may enter into lease arrangements a number of years before taking control of the underlying asset due to construction lead times or to secure future operational requirements. The total undiscounted amount for future commitments for leases not yet commenced as at 31 December 2025 is \$2,953 million (2024 \$5,311 million). The majority of this future commitment relates to pipelines that are under construction in the Gulf of America from 2026.

	\$ million	
	2025	2024
Total cash outflow for amounts included in lease liabilities	3,727	3,283
Expense for variable payments not included in the lease liability ^a	61	45
Short-term lease expense ^a	286	499
Additions to right-of-use assets in the period	4,349	3,781
Gain (loss) on sale and leaseback transactions	1	–

^a The cash outflows for amounts not included in lease liabilities approximate the income statement expenses disclosed above.

An analysis of right-of-use assets and depreciation is provided in **Note 12**. An analysis of lease interest expense is provided in **Note 7**.

29. Financial instruments and financial risk factors

The accounting classification of each category of financial instruments and their carrying amounts are set out below.

		\$ million			
At 31 December 2025	Note	Measured at amortized cost	Mandatorily measured at fair value through profit or loss	Derivative hedging instruments	Total carrying amount
Financial assets					
Other investments	18	–	1,015	–	1,015
Loans		1,991	457	–	2,448
Trade and other receivables	20	26,567	–	–	26,567
Derivative financial instruments	30	–	25,892	245	26,137
Cash and cash equivalents	25	31,777	4,779	–	36,556
Financial liabilities					
Trade and other payables	22	(58,182)	–	–	(58,182)
Derivative financial instruments	30	–	(23,056)	(1,024)	(24,080)
Accruals		(7,406)	–	–	(7,406)
Lease liabilities	28	(14,571)	–	–	(14,571)
Finance debt	26	(57,958)	–	–	(57,958)
		(77,782)	9,087	(779)	(69,474)

		\$ million			
At 31 December 2024	Note	Measured at amortized cost	Mandatorily measured at fair value through profit or loss	Derivative hedging instruments	Total carrying amount
Financial assets					
Other investments	18	26	1,431	–	1,457
Loans		1,807	377	–	2,184
Trade and other receivables	20	27,148	–	–	27,148
Derivative financial instruments	30	–	21,226	–	21,226
Cash and cash equivalents	25	32,547	6,657	–	39,204
Financial liabilities					
Trade and other payables	22	(61,298)	–	–	(61,298)
Derivative financial instruments	30	–	(20,224)	(2,655)	(22,879)
Accruals		(7,397)	–	–	(7,397)
Lease liabilities	28	(12,000)	–	–	(12,000)
Finance debt	26	(59,547)	–	–	(59,547)
		(78,714)	9,467	(2,655)	(71,902)

The fair value of finance debt is shown in **Note 26**. For all other financial instruments within the scope of IFRS 9, the carrying amount is either the fair value, or approximates the fair value.

Information on gains and losses on derivative financial assets and financial liabilities classified as measured at fair value through profit or loss is provided in the derivative gains and losses section of **Note 30**. Fair value gains and losses related to other assets and liabilities classified as measured at fair value through profit or loss totalled a net loss of \$354 million (2024 net gain of \$1 million and 2023 net loss of \$11 million). Dividend income of \$19 million (2024 \$24 million and 2023 \$18 million) from investments in equity instruments classified as measured at fair value through profit or loss is presented within other income.

29. Financial instruments and financial risk factors – continued

Interest income and expenses arising on financial instruments are disclosed in **Note 7**.

Financial risk factors

The group is exposed to a number of different financial risks arising from ordinary business exposures as well as its use of financial instruments including market risks relating to commodity prices; foreign currency exchange rates and interest rates; credit risk; and liquidity risk.

The group financial risk committee (GFRC) advises the chief financial officer (CFO) who oversees the management of these risks. The GFRC is chaired by the CFO and consists of a group of senior managers including the SVPs tax and treasury, central financial planning & analysis, mergers & acquisitions and business development, finance supply, trading and shipping, and the group controller. The purpose of the committee is to advise on financial risks and the appropriate financial risk governance framework for the group. The committee provides assurance to the CFO and the chief executive officer (CEO), and via the CEO to the board, that the group's financial risk-taking activity is governed by appropriate policies and procedures and that financial risks are identified, measured and managed in accordance with group policies and group risk appetite.

The group's trading activities in the oil, natural gas, LNG and power markets are managed within the supply, trading and shipping business. Treasury holds foreign exchange and interest-rate products in the financial markets to hedge group exposures related to debt and hybrid bond issuance; the compliance, control and risk management processes for these activities are managed within the treasury business. All other foreign exchange and interest rate activities within financial markets are performed within the supply, trading and shipping business and are also underpinned by the compliance, control and risk management infrastructure common to the activities of bp's supply, trading and shipping business. All derivative activity is carried out by specialist teams that have the appropriate skills, experience and supervision. These teams are subject to close financial and management control.

The supply, trading and shipping business maintains formal governance processes that provide oversight of market risk, credit risk and operational risk associated with trading activity. A policy and risk committee approves value-at-risk delegations, reviews incidents and validates risk-related policies, methodologies and procedures. A commitments committee approves the trading of new products, instruments and strategies and material commitments.

In addition, the supply, trading and shipping business undertakes derivative activity for risk management purposes under a control framework as described more fully below.

(a) Market risk

Market risk is the risk or uncertainty arising from possible market price movements and their impact on the future performance of a business. The primary commodity price risks that the group is exposed to include oil, natural gas and power prices that could adversely affect the value of the group's financial assets, liabilities or expected future cash flows. The group has developed a control framework aimed at managing the volatility inherent in certain of its ordinary business exposures. In accordance with the control framework the group enters into various transactions using derivatives for risk management purposes.

The major components of market risk are commodity price risk, foreign currency exchange risk and interest rate risk, each of which is discussed below.

(i) Commodity price risk

The group's supply, trading and shipping business is responsible for delivering value across the overall crude, oil products, gas, LNG and power supply chains. As such, it routinely enters into spot and term physical commodity contracts in addition to optimising physical storage, pipeline and transportation capacity. These activities expose the group to commodity price risk which is managed by entering into oil, natural gas and power swaps, options and futures.

The group measures market risk exposure arising from its risk managed trading positions using value-at-risk techniques based on Monte Carlo simulation models. These techniques make a statistical assessment of the market risk arising from possible future changes in market prices over a one-day holding period within a 95% confidence level. Risk managed trading activity is subject to value-at-risk and other limits for each trading activity and the aggregate of all trading activity. The calculation of potential changes in value within the risk managed period considers positions, historical price movements and the correlation of these price movements. Models are regularly reviewed against actual fair value movements to ensure integrity is maintained. The value-at-risk measure is supplemented by stress testing and scenario analysis through simulating the financial impact of certain physical, economic and geo-political scenarios. The value-at-risk measure in respect of the aggregated risk managed trading positions at 31 December 2025 was \$34 million (2024 \$42 million) whereas the average value-at-risk measure for the period was \$49 million (2024 \$35 million). This measure incorporates the effect of diversification reflecting the offsetting risks across the trading portfolio. Alternative measures are used to monitor exposures which are not risk managed and for which value-at-risk techniques are not appropriate.

(ii) Foreign currency exchange risk

Since bp has global operations, fluctuations in foreign currency exchange rates can have a significant effect on the group's reported results and future expenditure commitments. The effects of most exchange rate fluctuations are absorbed in business operating results through changing cost competitiveness, lags in market adjustment to movements in rates and translation differences accounted for on specific transactions. For this reason, the total effect of exchange rate fluctuations is not identifiable separately in the group's reported results. The main underlying economic currency of the group's cash flows is the US dollar. This is because bp's major product, oil, is priced internationally in US dollars. bp's foreign currency exchange management policy is to limit economic and material transactional exposures arising from currency movements against the US dollar. The group co-ordinates the handling of foreign currency exchange risks centrally, by netting off naturally-occurring opposite exposures wherever possible and then managing any material residual foreign currency exchange risks.

Most of the group's borrowings are in US dollars or are hedged with respect to the US dollar. At 31 December 2025, the total foreign currency borrowings not swapped into US dollars amounted to \$454 million (2024 \$555 million). The group also has in issue perpetual subordinated hybrid bonds in euro, sterling and US dollars. Whilst the contractual terms of these instruments allow the group to defer coupon payments and the repayment of principal indefinitely, the group has chosen to manage the foreign currency exposure relating to the non-US dollar hybrid bonds to their respective first call periods.

The group manages the net residual foreign currency exposures by constantly reviewing the foreign currency economic value at risk and aims to manage such risk to keep the 12-month foreign currency value at risk below \$400 million. At no point over the past three years did the value at risk exceed the maximum risk limit. A continuous assessment is made in respect of the group's foreign currency exposures to capture hedging requirements.

29. Financial instruments and financial risk factors – continued

During the year, hedge accounting was applied to foreign currency exposure to highly probable forecast capital expenditure commitments. The group fixes the US dollar cost of non-US dollar supplies by using currency forwards for the highly probable forecast capital expenditure. At 31 December 2025 the most significant open contracts in place were for USD equivalent amounts of \$84 million Australian dollars (2024 \$92 million sterling).

Where the group enters into foreign currency exchange contracts for entrepreneurial trading purposes the activity is controlled using trading value-at-risk techniques as explained in (i) commodity price risk above.

(iii) Interest rate risk

bp is also exposed to interest rate risk from the possibility that changes in interest rates will affect future cash flows or the fair values of its financial instruments, principally finance debt. While the group issues debt and hybrid bonds in a variety of currencies based on market opportunities, it uses derivatives to swap the economic exposure to a floating rate basis, mainly to US dollar floating, but in certain defined circumstances maintains a US dollar fixed rate exposure for a proportion of debt. The proportion of floating rate debt net of interest rate swaps at 31 December 2025 was 29% of total finance debt outstanding (2024 30%). The weighted average interest rate on finance debt at 31 December 2025 was 5% (2024 5%) and the weighted average maturity of fixed rate debt was eight years (2024 eight years).

The group's earnings are sensitive to changes in interest rates on the element of the group's finance debt that is contractually floating rate or has been swapped to floating rates. If the interest rates applicable to these floating rate instruments of \$16,694 million (2024 \$18,006 million) (see **Note 26**) were to have changed by one percentage point on 1 January 2026, it is estimated that the group's finance costs for 2026 would change by approximately \$167 million (2024 \$180 million).

(b) Credit risk

Credit risk is the risk that a customer or counterparty to a financial instrument will fail to perform or fail to pay amounts due causing financial loss to the group and arises from cash and cash equivalents, derivative financial instruments and deposits with financial institutions and principally from credit exposures to customers relating to outstanding receivables. Credit exposure also exists in relation to guarantees issued by group companies under which the outstanding exposure incremental to that recognized on the balance sheet at 31 December 2025 was \$708 million (2024 \$655 million) in respect of liabilities of joint ventures and associates and \$659 million (2024 \$585 million) in respect of liabilities of other third parties. An amount of \$170 million (2024 \$146 million) is recorded as a liability at 31 December 2025 in relation to these guarantees. For all guarantees, maturity dates vary, and the guarantees will terminate on payment and/or cancellation of the obligation. In general, a payment under the guarantee contract would be triggered by failure of the guaranteed party to fulfil its obligation covered by the guarantee.

The group has a credit policy, approved by the CFO, that is designed to ensure that consistent processes are in place throughout the group to measure and control credit risk. Credit risk is considered as part of the risk-reward balance of doing business. On entering into any business contract the extent to which the arrangement exposes the group to credit risk is considered. Key requirements of the policy include segregation of credit approval authorities from any sales, marketing or trading teams authorized to incur credit risk; the establishment of credit systems and processes to ensure that all counterparty exposure is rated and that all counterparty exposure and limits can be monitored and reported; and the timely identification and reporting of any non-approved credit exposures and credit losses. While each segment is responsible for its own credit risk management and reporting consistent with group policy, treasury holds group-wide credit risk authority and oversight responsibility for exposure to banks and financial institutions.

For the purposes of financial reporting the group calculates expected loss allowances based on the maximum contractual period over which the group is exposed to credit risk. Lifetime expected credit losses are recognized for trade receivables and the credit risk associated with the significant majority of financial assets measured at amortized cost is considered to be low. Since the tenor of substantially all of the group's in-scope financial assets is less than 12 months there is no significant difference between the measurement of 12-month and lifetime expected credit losses. Expected loss allowances for financial guarantee contracts are typically lower than their initial fair value less, where appropriate, amortization. Financial assets are considered to be credit-impaired when there is reasonable and supportable evidence that one or more events that have a detrimental impact on the estimated future cash flows of the financial asset have occurred. This includes observable data concerning significant financial difficulty of the counterparty; a breach of contract; concession being granted to the counterparty for economic or contractual reasons relating to the counterparty's financial difficulty, that would not otherwise be considered; it becoming probable that the counterparty will enter bankruptcy or other financial re-organization or an active market for the financial asset disappearing because of financial difficulties. The group also applies a rebuttable presumption that an asset is credit-impaired when contractual payments are more than 30 days past due. Where the group has no reasonable expectation of recovering a financial asset in its entirety or a portion thereof, for example where all legal avenues for collection of amounts due have been exhausted, the financial asset (or relevant portion) is written off.

The measurement of expected credit losses is a function of the probability of default, loss given default (i.e. the magnitude of the loss after recovery if there is a default) and the exposure at default (i.e. the asset's carrying amount). The group allocates a credit risk rating to exposures based on data that is determined to be predictive of the risk of loss, including but not limited to external ratings. Probabilities of default derived from historical, current and future-looking market data are assigned by credit risk rating with a loss given default based on historical experience and relevant market and academic research applied by exposure type. Experienced credit judgement is applied to ensure probabilities of default are reflective of the credit risk associated with the group's exposures. Credit enhancements that would reduce the group's credit losses in the event of default are reflected in the calculation when they are considered integral to the related asset.

The maximum credit exposure associated with financial assets is equal to the carrying amount. The group does not aim to remove credit risk entirely but expects to experience a certain level of credit losses. As at 31 December 2025, the group had in place credit enhancements designed to mitigate approximately \$9.3 billion (2024 \$8.2 billion) of credit risk related to assets in the scope of IFRS 9's impairment requirements. Credit enhancements include standby and documentary letters of credit, bank guarantees, and insurance which are typically taken out with financial institutions who have investment grade credit ratings. Reports are regularly prepared and presented to the GFRC that cover the group's overall credit exposure and expected loss trends, exposure by segment, and overall quality of the portfolio.

29. Financial instruments and financial risk factors – continued

Management information used to monitor credit risk, which reflects the impact of credit enhancements, indicates that the risk profile of financial assets which are subject to review for impairment under IFRS 9 is as set out in the table below.

As at 31 December	2025	2024
AAA to AA-	14 %	12 %
A+ to A-	52 %	50 %
BBB+ to BBB-	13 %	16 %
BB+ to BB-	11 %	10 %
B+ to B-	6 %	8 %
CCC+ and below	4 %	4 %

Movements in the impairment provision for trade and other receivables are shown in **Note 21**.

Financial instruments subject to offsetting, enforceable master netting arrangements and similar agreements

The following table shows the amounts recognized for financial assets and liabilities which are subject to offsetting arrangements on a gross basis, and the amounts offset in the balance sheet.

Amounts which cannot be offset under IFRS, but which could be settled net under the terms of master netting agreements if certain conditions arise, and collateral received or pledged, are also presented in the table to show the total net exposure of the group.

						\$ million
	Gross amounts of recognized financial assets (liabilities)	Amounts set off	Net amounts presented on the balance sheet	Related amounts not set off in the balance sheet		Net amount
At 31 December 2025						
Derivative assets	28,414	(2,277)	26,137	(7,491)	(544)	18,102
Derivative liabilities	(26,357)	2,277	(24,080)	7,491	101	(16,488)
Trade and other receivables	14,055	(6,385)	7,670	(1,555)	(170)	5,945
Trade and other payables	(17,308)	6,385	(10,923)	1,555	8	(9,360)
At 31 December 2024						
Derivative assets	23,779	(2,553)	21,226	(5,624)	(362)	15,240
Derivative liabilities	(25,432)	2,553	(22,879)	5,624	294	(16,961)
Trade and other receivables	17,832	(9,445)	8,387	(1,532)	(206)	6,649
Trade and other payables	(20,289)	9,445	(10,844)	1,532	12	(9,300)

(c) Liquidity risk

Liquidity risk is the risk that suitable sources of funding for the group's business activities may not be available. The group's liquidity is managed centrally with operating units forecasting their cash and currency requirements to the central treasury function. Unless restricted by local regulations, generally subsidiaries pool their cash surpluses to the treasury function, which will then arrange to fund other subsidiaries' requirements, or invest any net surplus in the market or arrange for necessary external borrowings, while managing the group's overall net currency positions. While there is the potential for concerns about the energy transition to impact banks' or debt investors' appetite to finance hydrocarbon activity, we do not anticipate any material change to the group's funding or liquidity in the short to medium term as a result of such concerns.

The group benefits from open credit provided by suppliers who generally sell on five to 60-day payment terms in accordance with industry norms. bp utilizes various arrangements in order to manage its working capital and reduce volatility in cash flow. This includes discounting receivables and, in the supply and trading businesses, managing inventory, collateral and supplier payment terms within a maximum of 60 days.

It is normal practice in the oil and gas supply and trading business for customers and suppliers to utilize letters of credit (LCs) facilities to mitigate credit and non-performance risk. Consequently, LCs facilitate active trading in a global market where credit and performance risk can be significant. In common with the industry, bp routinely provides LCs to some of its suppliers.

The group has committed LC facilities totalling \$10,350 million (2024 \$12,130 million), allowing LCs to be issued for a maximum 24-month duration. The facilities are held with 17 international banks.

In certain circumstances, the supplier has the option to request accelerated payment from the LC provider in order to further reduce their exposure. bp's payments are made to the provider of the LC rather than the supplier according to the original contractual payment terms. At 31 December 2025, a portion of the group's trade payables which were subject to the LC arrangements were payable to LC providers, with no material exposure to any individual provider. If these facilities were not available, this could result in renegotiation of payment terms with suppliers such that payment terms were shorter.

The group sometimes uses promissory notes to pay its suppliers and other counterparties. This is primarily done to facilitate the counterparty accelerating its cash inflow without also accelerating the group's related cash outflow. For instance, if a supplier to the group's supply, trading and shipping business would like prepayment or early-payment for a supply of goods, the group may issue a promissory note (payable at a future date) in favour of that supplier on the supplier's desired cash inflow date, which that supplier can then convert to cash by selling it to a finance provider on the same-day. The majority of promissory notes the group issues accrue interest on the principal amount of the note at a fixed rate stated on the note from issuance to maturity. This is done to give the supplier or other counterparty certainty about the amount they will receive when they sell the note. It also gives the group flexibility to select the maturity date of the note without that impacting the net present value of the note on its issuance date. The maturity date the group selects for any promissory note that is for the purchase of goods by its supply and trading business will be no more than 60 days after the group takes (or expects to take) title to those goods.

29. Financial instruments and financial risk factors – continued

A portion of the group's trade payables form part of a reverse factoring arrangement with select suppliers.

Suppliers' participation in the reverse factoring arrangement is voluntary. Suppliers that participate have the option to receive early payment on invoices from the group's external finance provider. If suppliers choose to receive early payment, they pay a fee to the finance provider. If they opt not to receive early payment, they will pay no fee to the finance provider and will be paid the full invoice amount on the invoice due date. The group provides data about invoices subject to the arrangement directly to the finance provider. This data includes the invoice due date and the maturity date for each invoice. The invoice due date is the date the supplier would have been entitled to receive payment from the group had the invoice not been made subject to the reverse factoring arrangement. The maturity date, which is the date the group will settle that invoice by paying the finance provider, will, in some cases, be the same as the invoice due date. In other cases, it will be a date selected by the group that is no more than 60 days after the group has taken title to the goods to which the invoice relates. If the group selects a maturity date that is after the invoice due date, the group pays the finance provider a fee.

Management does not consider the reverse factoring arrangement to result in excessive concentrations of liquidity risk, in part because the finance provider has the option to (and does) sub-participate portions of the financings to other finance providers. The arrangements have been established for a variety of reasons, including to ease the administrative burden of managing high volumes of invoices from some suppliers, to facilitate some suppliers having the option to accelerate when they receive payment, often at a lower cost than that supplier's usual cost of borrowing, and, in some cases, to manage the working capital and reduce volatility in cash flow of the group's supply and trading business. The group has not derecognized the original trade payables relating to the arrangements because the original liability is not substantially modified on entering into the arrangements.

Additional information about the group's trade payables that are subject to supplier finance arrangements is provided in the table below.

	2025			2024		
	Letters of Credit	Promissory Notes	Reverse Factoring Arrangements	Letters of Credit	Promissory Notes	Reverse Factoring Arrangements
Carrying amount of liabilities (\$ million)						
Presented within trade and other payables	5,596	1,356	1,018	7,431	1,778	390
of which suppliers have received payment from the financial institution	5,247	1,356	1,018	7,016	1,778	390
Range of payment due dates (days)						
Liabilities that are part of the arrangement	6 to 60	30 to 60	30 to 60	8 to 57	30 to 60	30 to 60
Trade payables that are not part of the arrangement	8 to 60	6 to 60	7 to 60	6 to 60	6 to 60	6 to 60

The group does not provide any collateral to the external finance provider.

There were no material business combinations or foreign exchange differences that would affect the liabilities under the supplier finance arrangement in either period.

There were no significant non-cash changes in the carrying amount of financial liabilities subject to the supplier finance arrangements. The payments to the bank are included within operating cash flows because they continue to be part of the normal operating cycle of the group and their principal nature remains operating – i.e., payment for the purchase of goods and services.

If these facilities were not available, this could result in renegotiation of payment terms with suppliers such that settlement periods were shorter.

Standard & Poor's Ratings long-term credit rating for bp is A- (stable) and Moody's Investors Service rating is A1 (stable) and the Fitch Ratings' long-term credit rating is A+ (stable).

During 2025, \$239 million (2024 \$9 billion) of long-term taxable bonds were issued with terms of nine years. In addition the group issued perpetual hybrid capital securities with a US dollar equivalent value of \$500 million (2024 \$4.3 billion). Commercial paper is issued at competitive rates to meet short-term borrowing requirements as and when needed.

As a further liquidity measure, the group continues to maintain suitable levels of cash and cash equivalents, amounting to \$36.6 billion at 31 December 2025 (2024 \$39.2 billion), primarily invested with highly rated banks or money market funds and readily accessible at immediate and short notice. As at 31 December 2025, the group had substantial amounts of undrawn borrowing facilities available, consisting of a committed \$8.0 billion credit facility and \$4.0 billion of standby facilities, available for five years. These facilities are held with 33 international banks and borrowings via these facilities would be at pre-agreed rates.

The group manages liquidity risk associated with derivative contracts, other than derivative hedging instruments, based on the expected maturities of both derivative assets and liabilities as indicated in **Note 30**. Management does not currently anticipate any cash flows, other than noted below, that could be of a significantly different amount or could occur earlier than the expected maturity analysis provided.

29. Financial instruments and financial risk factors – continued

The table below shows the timing of undiscounted cash outflows relating to finance debt, trade and other payables and accruals. As part of actively managing the group's debt portfolio it is possible that cash flows in relation to finance debt could be accelerated from the profile provided.

	2025				2024			
	Trade and other payables ^a	Accruals	Finance debt ^b	Interest on finance debt	Trade and other payables ^a	Accruals	Finance debt ^b	Interest on finance debt
Within one year	51,907	5,572	3,312	2,227	53,663	6,071	4,402	2,490
1 to 2 years	1,331	319	6,628	1,995	1,670	260	4,716	2,217
2 to 3 years	1,203	181	6,007	1,717	1,177	150	6,449	1,947
3 to 4 years	1,190	161	4,235	1,480	1,139	130	5,649	1,678
4 to 5 years	1,186	172	3,680	1,312	1,138	125	3,928	1,447
5 to 10 years	2,413	496	15,775	4,136	3,889	375	17,301	4,877
Over 10 years	126	505	13,292	5,347	157	286	13,947	6,198
	59,356	7,406	52,929	18,214	62,833	7,397	56,392	20,854

a 2025 includes \$8,367 million (2024 \$9,520 million) in relation to the Gulf of America oil spill, of which \$6,834 million (2024 \$8,383 million) matures in greater than one year.

b Not included in the table above are amounts not expected to be paid in cash but for which a cash flow could occur in specific circumstances and for which the earliest repayment periods are \$758 million within 4-5 years, \$4,070 million within 5-10 years and \$719 million over 10 years. For 2024 the equivalent amounts were \$528 million within 2-3 years and \$3,283 million in 5-10 years.

The table below shows the timing of cash outflows for derivative financial instruments entered into for the purpose of managing interest rate and foreign currency exchange risk, whether or not hedge accounting is applied, based upon contractual payment dates. As part of actively managing the group's debt portfolio it is possible that cash flows in relation to associated derivatives could be accelerated from the profile provided. The amounts reflect the gross settlement amount where the pay leg of a derivative will be settled separately from the receive leg, as in the case of cross-currency swaps hedging non-US dollar finance debt or hybrid bonds. The swaps are with high investment-grade counterparties and therefore the settlement-day risk exposure is considered to be negligible. Not shown in the table are the gross settlement amounts (inflows) for the receive leg of derivatives that are settled separately from the pay leg, which amount to \$25,612 million at 31 December 2025 (2024 \$24,206 million) to be received on the same day as the related cash outflows.

	2025			2024		
	Derivative assets	Derivative liabilities	Total	Derivative assets	Derivative liabilities	Total
Cash outflows for derivative financial instruments at 31 December						
Within one year	1,812	3,324	5,136	–	1,718	1,718
1 to 2 years	2,009	1,068	3,077	–	5,136	5,136
2 to 3 years	1,085	658	1,743	–	3,077	3,077
3 to 4 years	–	3,696	3,696	–	1,743	1,743
4 to 5 years	1,330	225	1,555	–	3,696	3,696
5 to 10 years	3,071	4,443	7,514	–	8,307	8,307
Over 10 years	498	1,465	1,963	–	2,486	2,486
	9,805	14,879	24,684	–	26,163	26,163

For further information on our derivative financial instruments, see **Note 30**.

30. Derivative financial instruments

In the ordinary course of business the group enters into derivative financial instruments (derivatives) to manage its normal business exposures in relation to commodity prices, foreign currency exchange rates and interest rates, including management of the balance between floating rate and fixed rate debt, consistent with its risk management policies and objectives. An outline of the group's financial risks and the objectives and policies pursued in relation to those risks is set out in **Note 29**. Additionally, the group has a well-established entrepreneurial trading operation that is undertaken in conjunction with these activities using a similar range of contracts.

For information on significant estimates and judgements made in relation to the valuation of derivatives see Derivative financial instruments within **Note 1**.

The fair values of derivative financial instruments at 31 December are set out below.

Exchange traded derivatives are valued using closing prices provided by the exchange as at the balance sheet date. These derivatives are categorized within level 1 of the fair value hierarchy. Exchange traded derivatives are typically considered settled through the (normally daily) payment or receipt of variation margin.

Over-the-counter (OTC) financial swaps, forwards and physical commodity sale and purchase contracts are generally valued using readily available information in the public markets and quotations provided by brokers and price index developers. These quotes are corroborated with market data and are categorized within level 2 of the fair value hierarchy.

In certain less liquid markets, or for longer-term contracts, forward prices are not as readily available. In these circumstances, OTC financial swaps and physical commodity sale and purchase contracts are valued using internally developed methodologies that consider historical relationships between various commodities, and that result in management's best estimate of fair value. These contracts are categorized within level 3 of the fair value hierarchy.

30. Derivative financial instruments – continued

Financial OTC and physical commodity options are valued using industry standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and contractual prices for the underlying instruments, as well as other relevant economic factors. The degree to which these inputs are observable in the forward markets determines whether the option is categorized within level 2 or level 3 of the fair value hierarchy.

	\$ million			
	2025		2024	
	Fair value asset	Fair value liability	Fair value asset	Fair value liability
Derivatives held for trading				
Currency derivatives	549	(720)	343	(1,738)
Oil price derivatives	1,509	(1,315)	1,350	(1,071)
Natural gas price derivatives	14,974	(13,781)	11,533	(10,506)
Power price derivatives	8,605	(7,046)	7,905	(6,893)
Other derivatives	255	(194)	95	(16)
	25,892	(23,056)	21,226	(20,224)
Cash flow hedges				
Currency forwards	–	–	–	–
	–	–	–	–
Fair value hedges				
Currency swaps	245	(1,022)	–	(2,651)
Interest rate swaps	–	(2)	–	(4)
	245	(1,024)	–	(2,655)
	26,137	(24,080)	21,226	(22,879)
Of which – current	5,180	(4,413)	5,112	(4,347)
– non-current	20,957	(19,667)	16,114	(18,532)

Derivatives held for trading

The group maintains active trading positions in a variety of derivatives. The contracts may be entered into for risk management purposes, to satisfy supply requirements or for entrepreneurial trading. Certain contracts are classified as held for trading, regardless of their original business objective, and are recognized at fair value with changes in fair value recognized in the income statement. Trading activities are undertaken by using a range of contract types in combination to create incremental gains by arbitraging prices between markets, locations and time periods. The net of these exposures is monitored using market value-at-risk techniques as described in **Note 29**.

The following tables show further information on the fair value of derivatives and other financial instruments held for trading purposes.

Derivative assets held for trading have the following fair values and maturities.

	\$ million						
	2025						
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	130	90	32	26	63	208	549
Oil price derivatives	1,277	130	52	42	6	2	1,509
Natural gas price derivatives	2,116	1,057	857	747	662	9,535	14,974
Power price derivatives	1,653	1,211	790	531	408	4,012	8,605
Other derivatives	1	2	226	1	–	25	255
	5,177	2,490	1,957	1,347	1,139	13,782	25,892
	\$ million						
	2024						
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	197	19	10	7	7	103	343
Oil price derivatives	1,004	156	78	53	55	4	1,350
Natural gas price derivatives	2,337	923	628	556	503	6,586	11,533
Power price derivatives	1,571	990	627	426	396	3,895	7,905
Other derivatives	4	4	–	85	–	2	95
	5,113	2,092	1,343	1,127	961	10,590	21,226

30. Derivative financial instruments – continued

Derivative liabilities held for trading have the following fair values and maturities.

	\$ million						
	2025						
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	(192)	(20)	(14)	(196)	(12)	(286)	(720)
Oil price derivatives	(1,155)	(138)	(15)	(6)	(1)	–	(1,315)
Natural gas price derivatives	(1,748)	(917)	(705)	(605)	(545)	(9,261)	(13,781)
Power price derivatives	(1,268)	(996)	(677)	(504)	(336)	(3,265)	(7,046)
Other derivatives	(18)	(7)	(169)	–	–	–	(194)
	(4,381)	(2,078)	(1,580)	(1,311)	(894)	(12,812)	(23,056)

	\$ million						
	2024						
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	(111)	(529)	(172)	(4)	(562)	(360)	(1,738)
Oil price derivatives	(975)	(65)	(16)	(6)	(9)	–	(1,071)
Natural gas price derivatives	(2,075)	(836)	(515)	(409)	(363)	(6,308)	(10,506)
Power price derivatives	(1,062)	(779)	(569)	(401)	(471)	(3,611)	(6,893)
Other derivatives	(6)	(1)	–	(9)	–	–	(16)
	(4,229)	(2,210)	(1,272)	(829)	(1,405)	(10,279)	(20,224)

The following table shows the fair value of derivative assets and derivative liabilities held for trading, analysed by maturity period and by methodology of fair value estimation. This information is presented on a gross basis, that is, before netting by counterparty.

	\$ million						
	2025						
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Fair value of derivative assets							
Level 1	131	17	6	–	–	–	154
Level 2	4,813	1,541	940	296	198	156	7,944
Level 3	1,585	1,339	1,199	1,105	983	13,860	20,071
	6,529	2,897	2,145	1,401	1,181	14,016	28,169
Less: netting by counterparty	(1,352)	(407)	(188)	(54)	(42)	(234)	(2,277)
	5,177	2,490	1,957	1,347	1,139	13,782	25,892
Fair value of derivative liabilities							
Level 1	(131)	(18)	(5)	(1)	(1)	–	(156)
Level 2	(4,337)	(1,284)	(700)	(395)	(59)	(235)	(7,010)
Level 3	(1,265)	(1,183)	(1,063)	(969)	(876)	(12,811)	(18,167)
	(5,733)	(2,485)	(1,768)	(1,365)	(936)	(13,046)	(25,333)
Less: netting by counterparty	1,352	407	188	54	42	234	2,277
	(4,381)	(2,078)	(1,580)	(1,311)	(894)	(12,812)	(23,056)
Net fair value	796	412	377	36	245	970	2,836

	\$ million						
	2024						
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Fair value of derivative assets							
Level 1	157	35	7	2	–	–	201
Level 2	5,037	1,457	551	330	134	107	7,616
Level 3	1,516	1,175	948	839	858	10,626	15,962
	6,710	2,667	1,506	1,171	992	10,733	23,779
Less: netting by counterparty	(1,597)	(575)	(163)	(44)	(31)	(143)	(2,553)
	5,113	2,092	1,343	1,127	961	10,590	21,226
Fair value of derivative liabilities							
Level 1	(124)	(20)	(7)	(2)	–	–	(153)
Level 2	(4,491)	(1,868)	(625)	(189)	(717)	(289)	(8,179)
Level 3	(1,211)	(897)	(803)	(682)	(719)	(10,133)	(14,445)
	(5,826)	(2,785)	(1,435)	(873)	(1,436)	(10,422)	(22,777)
Less: netting by counterparty	1,597	575	163	44	31	143	2,553
	(4,229)	(2,210)	(1,272)	(829)	(1,405)	(10,279)	(20,224)
Net fair value	884	(118)	71	298	(444)	311	1,002

30. Derivative financial instruments – continued

Level 3 derivatives

The following table shows the changes during the year in the net fair value of derivatives held for trading purposes within level 3 of the fair value hierarchy.

	\$ million					
	Oil price	Natural gas price	Power price	Currency	Other	Total
Fair value contracts at 1 January 2025	30	394	(306)	12	2	132
Gains (losses) recognized in the income statement	85	62	466	115	23	751
Sales	–	–	84	–	–	84
Settlements	(50)	(113)	(113)	(18)	–	(294)
Transfers out of level 3	(8)	(412)	(146)	–	1	(565)
Net fair value of contracts at 31 December 2025	57	(69)	(15)	109	26	108
Deferred day-one gains (losses)						1,796
Derivative asset (liability)						1,904

	\$ million					
	Oil price	Natural gas price	Power price	Currency	Other	Total
Fair value contracts at 1 January 2024	107	599	(120)	219	2	807
Gains (losses) recognized in the income statement	(26)	(90)	129	(193)	–	(180)
Purchases	–	–	31	–	–	31
Settlements	(38)	(100)	(377)	(14)	–	(529)
Transfers out of level 3	(13)	(15)	31	–	–	3
Net fair value of contracts at 31 December 2024	30	394	(306)	12	2	132
Deferred day-one gains (losses)						1,385
Derivative asset (liability)						1,517

The amount recognized in the income statement for the year relating to level 3 held-for-trading derivatives still held at 31 December 2025 was a \$514 million gain (2024 \$193 million loss related to derivatives still held at 31 December 2024).

Derivative gains and losses

The group enters into derivative contracts including futures, options, swaps and certain forward sales and forward purchases contracts, relating to both currency and commodity trading activities. Gains or losses arise on contracts entered into for risk management purposes, optimization activity and entrepreneurial trading. They also arise on certain contracts that are for normal procurement or sales activity for the group but that are required to be fair valued under accounting standards. These gains and losses are included within sales and other operating revenues in the income statement. Also included within this line item are gains and losses on inventory held for trading purposes. The total amount relating to all these items was a net gain of \$11,206 million (2024 \$9,726 million net gain and 2023 \$19,786 million net gain). This number does not include gains and losses on the change in value of contracts which are not recognized under IFRS such as transportation and storage contracts, but does include the associated financially settled contracts. The net amounts for actual gains and losses relating to these derivative contracts and all related items therefore differ significantly from the amounts disclosed above.

As outlined in **Note 1 - Significant estimate and judgement: derivative financial instruments**, LNG contracts are only recognized in the financial statements when associated cargoes are lifted. The embedded value in these contracts is not recognized and is subject to underlying commodity price volatility. bp generally price risk manages the exposure to LNG cargoes due for delivery in the near term where there is a liquid market. It does so on a portfolio basis using derivative instruments amongst other price risk management strategies. Under IFRS, these derivative instruments, which are subject to similar price volatility, are recorded at fair value through profit and loss at each reporting period, which creates an accounting mismatch in the financial statements between the accounting for LNG contracts and the derivatives used for risk management. For the years ended 31 December 2025 and 31 December 2024, there were no material gains or losses recorded on the associated derivative positions. For the year ended 31 December 2023, there were material gains recognized on the associated derivative positions due to the movement in the underlying commodity prices.

The group also enters into derivative contracts relating to foreign currency risk management activities including contracts that the group has entered into to manage the foreign currency exposure relating to the non-US dollar hybrid bonds to their respective first call periods. The change in the unrealized value of these contracts was a net gain of \$1,187 million (2024 \$404 million net loss and 2023 \$632 million net gain). Where the derivative is economically hedging finance debt, gains and losses on such derivative contracts are included within finance costs. Where the derivative is managing non-US hybrid bond exposure gains and loss are included within production and manufacturing expenses. Where these gains and losses arise on derivatives hedging finance debt they are largely offset by opposing net foreign exchange differences on retranslation of the associated non-US dollar debt. The net amounts for actual gains and losses relating to these derivative contracts and all related items therefore differ significantly from the amounts disclosed above.

Cash flow hedges

(i) Foreign currency risk of highly probable forecast capital expenditure

At 31 December 2025, the group held currency forwards designated as hedging instruments in cash flow hedge relationships of highly probable forecast non-US dollar capital expenditure. **Note 29** outlines the group's approach to foreign currency exchange risk management. When the highly probable forecast capital expenditure designated as a hedged item occurs, a non-financial asset is recognized and is presented within the fixed asset section of the balance sheet.

30. Derivative financial instruments – continued

The group claims hedge accounting only for the spot value of the currency exposure in line with the strategy to fix the volatility in the spot exchange rate element. The fair value on the instrument attributable to forward points and foreign currency basis spreads is taken immediately to the income statement.

The group applies hedge accounting where there is an economic relationship between the hedged item and hedging instrument. The existence of an economic relationship is determined at inception and prospectively by comparing the critical terms of the hedging instrument and those of the hedged item. The group enters into hedging derivatives that match the currency and notional of the hedged items on a 1:1 hedge ratio basis. The hedge ratio is determined by comparing the notional amount of the derivative with the notional designated on the forecast transaction. The group determines the extent to which it hedges highly probable forecast capital expenditures on a project by project basis.

The group has identified the following sources of ineffectiveness, which are not expected to be material:

- counterparty's credit risk, the group mitigates counterparty credit risk by entering into derivative transactions with high credit quality counterparties; and
- differences in settlement timing between the derivative and hedged items. The latter impacts the discount factor used in the calculation of the hedge ineffectiveness. The group mitigates differences in timing between the derivatives and hedged items by applying a rolling strategy and by hedging currency pairs from stable economies. The group's cash flow hedge designations are highly effective as the sources of ineffectiveness identified are expected to result in minimal hedge ineffectiveness.

The group has not designated any net positions as hedged items in cash flow hedges of foreign currency risk.

(ii) Commodity price risk of highly probable forecast sales

During the period the group held Henry Hub NYMEX futures designated as hedging instruments in cash flow hedge relationships of certain highly probable forecast future sales. Henry Hub NYMEX futures are subject to daily settlement, where their fair value at the end of each day is required to be cash settled, such that the carrying amount of these hedging instruments within continuing hedge relationships is always zero at the end of each day.

The group is exposed to the variability in the gas price, but only applied hedge accounting to the risk of Henry Hub price movements for a percentage of future gas sales from its BPX Energy business.

The group applied hedge accounting in relation to these highly probable future sales where there was an economic relationship between the hedged item and hedging instrument. The existence of an economic relationship was determined at inception and prospectively by comparing the critical terms of the hedging instrument and those of the hedged item. The group entered into hedging derivatives that matched the notional amounts of the hedged items on a 1:1 hedge ratio basis. The hedge ratio was determined by comparing the notional amount of the derivative with the notional amount designated on the forecast transaction.

The hedge was highly effective due to the price index of the hedging instruments matching the price index of the hedged item. The group did not designate any net positions as hedged items in cash flow hedges of commodity price risk.

The tables below summarize the change in the fair value of hedging instruments and the hedged item used to calculate ineffectiveness in the period.

	\$ million		
	Change in fair value of hedging instrument used to calculate ineffectiveness	Change in fair value of hedged item used to calculate ineffectiveness	Hedge ineffectiveness recognized in profit or (loss)
At 31 December 2025			
Cash flow hedges			
Foreign exchange risk			
Highly probable forecast capital expenditure	–	–	–
Commodity price risk			
Highly probable forecast sales	287	(287)	–
At 31 December 2024			
Cash flow hedges			
Foreign exchange risk			
Highly probable forecast capital expenditure	–	–	–
Commodity price risk			
Highly probable forecast sales	155	(155)	–

30. Derivative financial instruments – continued

The tables below summarize the carrying amount and nominal amount of the derivatives designated as hedging instruments in cash flow hedge relationships.

	Carrying amount of hedging instrument		Nominal amounts of hedging instruments	
	Assets	Liabilities	\$ million	mmBtu
	\$ million	\$ million		
At 31 December 2025				
Cash flow hedges				
Foreign exchange risk				
Highly probable forecast capital expenditure	–	–	87	
Commodity price risk				
Highly probable forecast sales	–	–		(686)
At 31 December 2024				
Cash flow hedges				
Foreign exchange risk				
Highly probable forecast capital expenditure	–	–	95	
Commodity price risk				
Highly probable forecast sales	–	–		(209)

All hedging instruments are presented within derivative financial instruments on the group balance sheet.

Of the nominal amount of hedging instruments at 31 December 2025 relating to highly probable forecast capital expenditure, \$67 million matures within 12 months (2024 \$95 million) and \$20 million matures within one to two years of the balance sheet date (2024 \$nil). Of the nominal amount of hedging instruments at 31 December 2025 relating to highly probable forecast sales, 420 mmBtu matures within 12 months (2024 209 mmBtu) and 266 mmBtu matures within one to two years of the balance sheet date (2024 \$nil).

The table below summarizes the weighted average exchange rates and the weighted average sales price in relation to the derivatives designated as hedging instruments in cash flow hedge relationships at 31 December.

	Weighted average price/rate			
	2025		2024	
	Forecast capital expenditure	Forecast sales	Forecast capital expenditure	Forecast sales
At 31 December				
Sterling/US dollar	1.35		1.25	
Euro/US dollar	–		1.04	
Australian dollar/US dollar	0.67		–	
Henry Hub \$/mmBtu		4.01		3.38

Fair value hedges

At 31 December 2025, the group held interest rate and cross-currency interest rate swap contracts as fair value hedges of the interest rate risk and foreign currency risk arising from group fixed rate debt issuances. **Note 29** outlines the group's approach to interest rate and foreign currency exchange risk management. The interest rate swaps are used to convert US dollar denominated fixed rate borrowings into floating rate debt. The cross-currency interest rate swaps are used to convert sterling, euro, Australian dollar, Japanese yen, Swiss franc, Hong Kong dollar and Norwegian krone denominated fixed rate borrowings into US dollar floating rate debt. The group manages all risks derived from debt issuance, such as credit risk, however, the group applies hedge accounting only to certain components of interest rate and foreign currency risk in order to minimize hedge ineffectiveness. The interest rate and foreign currency exposures are identified and hedged on an instrument-by-instrument basis.

For interest rate exposures, the group designates as a fair value hedge the benchmark interest rate component only. This is an observable and reliably measurable component of interest rate risk. For foreign currency exposures, the group excludes from the designation the foreign currency basis spread component implicit in the cross-currency interest rate swaps. This is separately calculated at hedge designation, is recognized in other comprehensive income over the life of the hedge and amortized to the income statement on a straight-line basis, in accordance with the group's policy on costs of hedging.

30. Derivative financial instruments – continued

The group applies hedge accounting where there is an economic relationship between the hedged item and the hedging instrument. The existence of an economic relationship is determined initially by comparing the critical terms of the hedging instrument and those of the hedged item and it is prospectively assessed using linear regression analysis. The group issues fixed rate debt and enters into interest rate and cross-currency interest rate swaps with critical terms that match those of the debt and on a 1:1 hedge ratio basis. The hedge ratio is determined by comparing the notional amount of the derivative with the notional amount of the debt. The hedge relationship is designated for the full term and notional value of the debt. Both the hedging instrument and the hedged item are expected to be held to maturity.

The group has identified the following sources of ineffectiveness, which are not expected to be material:

- derivative counterparty's credit risk which is not offset by the hedged item. This risk is mitigated by entering into derivative transactions only with high credit quality counterparties; and
- sensitivity to interest rate between the hedged item and the derivatives. This is driven by differences in payment frequencies between the instrument and the bond.

The tables below summarize the change in the fair value of hedging instruments and the hedged item used to calculate ineffectiveness in the period. The signage convention for changes in fair value presented in this table is consistent with that presented in **Note 27**.

	\$ million		
	Change in fair value of hedging instrument used to calculate ineffectiveness	Change in fair value of hedged item used to calculate ineffectiveness	Hedge ineffectiveness recognized in profit or (loss)
At 31 December 2025			
Fair value hedges			
Interest rate risk on finance debt	(2)	2	–
Interest rate and foreign currency risk on finance debt	(1,850)	1,797	53
At 31 December 2024			
Fair value hedges			
Interest rate risk on finance debt	–	1	(1)
Interest rate and foreign currency risk on finance debt	927	(772)	(155)

The tables below summarize the carrying amount of the derivatives designated as hedging instruments in fair value hedge relationships at 31 December.

	\$ million			
	Carrying amount of hedging instrument	Assets	Liabilities	Nominal amounts of hedging instruments
At 31 December 2025				
Fair value hedges				
Interest rate risk on finance debt	–	–	(2)	149
Interest rate and foreign currency risk on finance debt	245	245	(1,022)	16,304
At 31 December 2024				
Fair value hedges				
Interest rate risk on finance debt	–	–	(4)	132
Interest rate and foreign currency risk on finance debt	–	–	(2,651)	15,887

All hedging instruments are presented within derivative financial instruments on the group balance sheet and are categorized within level 2 of the fair value hierarchy. Ineffectiveness arising on fair value hedges is included within finance costs in the income statement.

The tables below summarize the profile by tenor of the nominal amount of the derivatives designated as hedging instruments in fair value hedge relationships at 31 December.

	\$ million							
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	5-10 years	Over 10 years	Total
At 31 December 2025								
Fair value hedges								
Interest rate risk on finance debt	149	–	–	–	–	–	–	149
Interest rate and foreign currency risk on finance debt	2,045	1,525	1,843	1,166	1,095	7,099	1,531	16,304
At 31 December 2024								
Fair value hedges								
Interest rate risk on finance debt	–	132	–	–	–	–	–	132
Interest rate and foreign currency risk on finance debt	1,614	1,819	1,346	1,627	1,047	6,521	1,913	15,887

30. Derivative financial instruments – continued

The table below summarizes the weighted average floating interest rate and the weighted average exchange rates in relation to the derivatives designated as hedging instruments in fair value hedge relationships at 31 December.

At 31 December	2025		2024	
	Interest rate swaps	Cross-currency interest rate swaps	Interest rate swaps	Cross-currency interest rate swaps
Interest rate	4.84 %	5.64 %	5.45 %	6.34 %
Sterling/US dollar		1.28		1.28
Euro/US dollar		1.13		1.13
Hong Kong dollar/US dollar		0.13		–
Canadian dollar/US dollar		–		0.78
Australian dollar/ US dollar		0.67		0.67
Japanese Yen/ US dollar		0.01		0.01
Swiss Franc/US dollar		1.18		1.18

The tables below summarize the carrying amount, and the accumulated fair value adjustments included within the carrying amount, of the hedged items designated in fair value hedge relationships at 31 December.

	\$ million			
	Carrying amount of hedged item	Accumulated fair value adjustment included in the carrying amount of hedged items		Discontinued hedges
	Liabilities	Assets	Liabilities	
At 31 December 2025				
Fair value hedges				
Interest rate risk on finance debt	(149)	1	–	(85)
Interest rate and foreign currency risk on finance debt	(16,281)	1,201	(35)	134
At 31 December 2024				
Fair value hedges				
Interest rate risk on finance debt	(156)	3	–	(160)
Interest rate and foreign currency risk on finance debt	(16,295)	1,017	–	143

The hedged item for all fair value hedges is presented within finance debt on the group balance sheet.

30. Derivative financial instruments – continued

Movement in reserves related to hedge accounting

The table below provides a reconciliation of the cash flow hedge and costs of hedging reserves on a pre-tax basis by risk category. The signage convention of this table is consistent with that presented in **Note 32**.

	\$ million			
	Cash flow hedge reserve		Costs of hedging reserve	
	Highly probable forecast capital expenditure	Highly probable forecast sales	Interest rate and foreign currency risk on finance debt	Total
At 1 January 2025	3	(2)	(186)	(185)
Recognized in other comprehensive income				
Cash flow hedges marked to market	5	287	–	292
Cash flow hedges reclassified to the income statement - hedged item affected profit or loss	–	(127)	–	(127)
Costs of hedging marked to market	–	–	27	27
Costs of hedging reclassified to the income statement	–	–	34	34
	5	160	61	226
Cash flow hedges transferred to the balance sheet	(6)	–	–	(6)
At 31 December 2025	2	158	(125)	35

	\$ million			
	Cash flow hedge reserve		Costs of hedging reserve	
	Highly probable forecast capital expenditure	Highly probable forecast sales	Interest rate and foreign currency risk on finance debt	Total
At 1 January 2024	14	529	(182)	361
Recognized in other comprehensive income				
Cash flow hedges marked to market	(1)	155	–	154
Cash flow hedges reclassified to the income statement - hedged item affected profit or loss	–	(686)	–	(686)
Costs of hedging marked to market	–	–	(2)	(2)
Costs of hedging reclassified to the income statement	–	–	(2)	(2)
	(1)	(531)	(4)	(536)
Cash flow hedges transferred to the balance sheet	(10)	–	–	(10)
At 31 December 2024	3	(2)	(186)	(185)

All of the cash flow hedge reserve balances at 31 December 2025 and amounts reclassified from these cash flow hedge reserves into profit or loss during the year relate to continuing hedge relationships. The amounts reclassified are presented in sales and other operating revenues in the income statement.

Costs of hedging relates to the foreign currency basis spreads of hedging instruments used to hedge the group's interest rate and foreign currency risk on debt which is a time-period related item.

31. Called-up share capital

The allotted, called up and fully paid share capital at 31 December was as follows:

	2025		2024		2023	
	Shares thousand	\$ million	Shares thousand	\$ million	Shares thousand	\$ million
Issued						
8% cumulative first preference shares of £1 each ^a	7,233	12	7,233	12	7,233	12
9% cumulative second preference shares of £1 each ^a	5,473	9	5,473	9	5,473	9
		21		21		21
Ordinary shares of 25 cents each						
At 1 January	16,662,465	4,165	17,900,800	4,475	19,097,783	4,774
Issue of new shares for employee share-based payment plans	–	–	–	–	66,000	17
Repurchase of ordinary share capital	(835,649)	(209)	(1,238,335)	(310)	(1,262,983)	(316)
Repurchases transferred to treasury shares	659,497	165	–	–	–	–
At 31 December	16,486,313	4,121	16,662,465	4,165	17,900,800	4,475
		4,142		4,186		4,496

a The nominal amount of 8% cumulative first preference shares and 9% cumulative second preference shares that can be in issue at any time shall not exceed £10,000,000 for each class of preference shares.

Voting on substantive resolutions tabled at a general meeting is on a poll. On a poll, shareholders present in person or by proxy have two votes for every £5 in nominal amount of the first and second preference shares held and one vote for every ordinary share held. On a show-of-hands vote on other resolutions (procedural matters) at a general meeting, shareholders present in person or by proxy have one vote each.

In the event of the winding up of the company, preference shareholders would be entitled to a sum equal to the capital paid up on the preference shares, plus an amount in respect of accrued and unpaid dividends and a premium equal to the higher of (i) 10% of the capital paid up on the preference shares and (ii) the excess of the average market price of such shares on the London Stock Exchange during the previous six months over par value.

During 2025 the company repurchased 836 million (2024 1,238 million) ordinary shares for a total consideration of \$4,486 million (2024 \$7,127 million, including transaction costs of \$24 million (2024 \$38 million)). 176 million shares repurchased were cancelled and 659 million shares were held as treasury shares. The repurchased shares represented 5.1% of ordinary share capital. A further 74 million ordinary shares were repurchased between the end of the reporting period and 13 February 2026, the latest practicable date before the completion of these financial statements, for a total cost of \$450 million of which \$448 million has been accrued at 31 December 2025. The number of shares in issue is reduced when shares are repurchased and cancelled, but is not reduced in respect of the repurchases transferred to treasury shares.

Treasury shares^a

	2025		2024		2023	
	Shares thousand	Nominal value \$ million	Shares thousand	Nominal value \$ million	Shares thousand	Nominal value \$ million
At 1 January	812,021	204	1,077,079	271	1,124,927	281
Purchases for settlement of employee share plans	660,765	165	8,302	2	24,688	6
Issue of new shares for employee share-based payment plans	–	–	–	–	71,039	19
Shares re-issued for employee share-based payment plans	(363,198)	(92)	(273,360)	(69)	(143,575)	(35)
At 31 December	1,109,588	277	812,021	204	1,077,079	271
Of which – shares held in treasury by bp	857,433	214	481,474	121	726,339	183
– shares held in ESOP trusts	252,118	63	330,510	83	350,704	88
– shares held by bp's US share plan administrator ^b	37	–	37	–	36	–

a See Note 32 for definition of treasury shares.

b Held in the form of ADSs to meet the requirements of employee share-based payment plans in the US.

For each year presented, the balance of shares held in treasury by bp at 1 January represents 2.9% (2024 4.1% and 2023 4.9%) of the called-up ordinary share capital of the company.

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32. Capital and reserves

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Total share capital and capital reserves
At 1 January 2025	4,186	14,031	2,806	27,206	48,229
Profit (loss) for the year	–	–	–	–	–
Items that may be reclassified subsequently to profit or loss					
Currency translation differences (including reclassifications)	–	–	–	–	–
Cash flow hedges and costs of hedging (including reclassifications)	–	–	–	–	–
Share of items relating to equity-accounted entities, net of tax	–	–	–	–	–
Items that will not be reclassified to profit or loss					
Remeasurements of the net pension and other post-employment benefit liability or asset	–	–	–	–	–
Remeasurements of equity investments	–	–	–	–	–
Cash flow hedges that will subsequently be transferred to the balance sheet	–	–	–	–	–
Total comprehensive income	–	–	–	–	–
Dividends	–	–	–	–	–
Cash flow hedges transferred to the balance sheet, net of tax	–	–	–	–	–
Repurchases of ordinary share capital	(44)	–	44	–	–
Share-based payments, net of tax ^b	–	35	–	–	35
Share of equity-accounted entities' changes in equity, net of tax	–	–	–	–	–
Issue of perpetual hybrid bonds	–	–	–	–	–
Redemption of perpetual hybrid bonds, net of tax	–	–	–	–	–
Payments on perpetual hybrid bonds	–	–	–	–	–
Transactions involving non-controlling interests, net of tax	–	–	–	–	–
At 31 December 2025	4,142	14,066	2,850	27,206	48,264
At 1 January 2024	4,496	13,815	2,496	27,206	48,013
Profit (loss) for the year	–	–	–	–	–
Items that may be reclassified subsequently to profit or loss					
Currency translation differences (including reclassifications) ^a	–	–	–	–	–
Cash flow hedges and costs of hedging (including reclassifications)	–	–	–	–	–
Share of items relating to equity-accounted entities, net of tax	–	–	–	–	–
Other	–	–	–	–	–
Items that will not be reclassified to profit or loss					
Remeasurements of the net pension and other post-employment benefit liability or asset	–	–	–	–	–
Remeasurements of equity investments	–	–	–	–	–
Cash flow hedges that will subsequently be transferred to the balance sheet	–	–	–	–	–
Total comprehensive income	–	–	–	–	–
Dividends	–	–	–	–	–
Cash flow hedges transferred to the balance sheet, net of tax	–	–	–	–	–
Repurchases of ordinary share capital	(310)	–	310	–	–
Share-based payments, net of tax ^b	–	216	–	–	216
Issue of perpetual hybrid bonds	–	–	–	–	–
Redemption of perpetual hybrid bonds, net of tax	–	–	–	–	–
Payments on perpetual hybrid bonds	–	–	–	–	–
Transactions involving non-controlling interests, net of tax	–	–	–	–	–
At 31 December 2024	4,186	14,031	2,806	27,206	48,229

a Includes \$942 million recycling of cumulative foreign exchange losses from reserves relating to the sale of bp's Türkiye ground fuels business to Petrol Ofisi, offset by movements in Pound Sterling against the US dollar.

b Movements in treasury shares relate to employee share-based payment plans.

32. Capital and reserves – continued

\$ million										
Treasury shares	Foreign currency translation reserve	Investments in equity instruments	Cash flow hedges	Costs of hedging	Total fair value reserves	Profit and loss account	bp shareholders' equity	Non-controlling interests		Total equity
								Hybrid bonds	Other interest	
(9,030)	(2,196)	(3)	(98)	(187)	(288)	22,531	59,246	16,649	2,423	78,318
–	–	–	–	–	–	55	55	799	441	1,295
–	1,804	1	–	–	1	–	1,805	–	115	1,920
–	–	–	122	61	183	–	183	–	–	183
–	–	–	–	–	–	(4)	(4)	–	–	(4)
–	–	–	–	–	–	(166)	(166)	–	–	(166)
–	–	(6)	–	–	(6)	–	(6)	–	–	(6)
–	–	–	5	–	5	–	5	–	–	5
–	1,804	(5)	127	61	183	(115)	1,872	799	556	3,227
–	–	–	–	–	–	(5,087)	(5,087)	–	(524)	(5,611)
–	–	–	(6)	–	(6)	–	(6)	–	–	(6)
(3,558)	–	–	–	–	–	(454)	(4,012)	–	–	(4,012)
3,917	–	–	–	–	–	(2,840)	1,112	–	–	1,112
–	–	–	–	–	–	1	1	–	–	1
–	–	–	–	–	–	–	–	500	–	500
–	–	–	–	–	–	–	–	(1,200)	–	(1,200)
–	(9)	–	–	–	–	–	(9)	(793)	–	(802)
–	–	–	–	–	–	(65)	(65)	–	2,538	2,473
(8,671)	(401)	(8)	23	(126)	(111)	13,971	53,052	15,955	4,993	74,000
(11,323)	(1,920)	38	319	(183)	174	35,339	70,283	13,566	1,644	85,493
–	–	–	–	–	–	381	381	641	207	1,229
–	(276)	(1)	–	–	(1)	–	(277)	–	(87)	(364)
–	–	–	(406)	(4)	(410)	–	(410)	–	–	(410)
–	–	–	–	–	–	(12)	(12)	–	–	(12)
–	–	–	–	–	–	(1)	(1)	–	–	(1)
–	–	–	–	–	–	367	367	–	–	367
–	–	(40)	–	–	(40)	–	(40)	–	–	(40)
–	–	–	(1)	–	(1)	–	(1)	–	–	(1)
–	(276)	(41)	(407)	(4)	(452)	735	7	641	120	768
–	–	–	–	–	–	(5,018)	(5,018)	–	(375)	(5,393)
–	–	–	(10)	–	(10)	–	(10)	–	–	(10)
–	–	–	–	–	–	(7,302)	(7,302)	–	–	(7,302)
2,293	–	–	–	–	–	(1,426)	1,083	–	–	1,083
–	–	–	–	–	–	(22)	(22)	4,352	–	4,330
–	–	–	–	–	–	9	9	(1,300)	–	(1,291)
–	–	–	–	–	–	–	–	(610)	–	(610)
–	–	–	–	–	–	216	216	–	1,034	1,250
(9,030)	(2,196)	(3)	(98)	(187)	(288)	22,531	59,246	16,649	2,423	78,318

32. Capital and reserves – continued

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Total share capital and capital reserves
At 1 January 2023	4,795	13,692	2,180	27,206	47,873
Profit (loss) for the year	–	–	–	–	–
Items that may be reclassified subsequently to profit or loss					
Currency translation differences (including reclassifications)	–	–	–	–	–
Cash flow hedges and costs of hedging (including reclassifications)	–	–	–	–	–
Share of items relating to equity-accounted entities, net of tax	–	–	–	–	–
Items that will not be reclassified to profit or loss					
Remeasurements of the net pension and other post-employment benefit liability or asset	–	–	–	–	–
Remeasurements of equity investments	–	–	–	–	–
Cash flow hedges that will subsequently be transferred to the balance sheet	–	–	–	–	–
Total comprehensive income	–	–	–	–	–
Dividends	–	–	–	–	–
Cash flow hedges transferred to the balance sheet, net of tax	–	–	–	–	–
Repurchases of ordinary share capital	(316)	–	316	–	–
Share-based payments, net of tax ^a	17	123	–	–	140
Share of equity-accounted entities' changes in equity, net of tax	–	–	–	–	–
Issue of perpetual hybrid bonds	–	–	–	–	–
Payments on perpetual hybrid bonds	–	–	–	–	–
Transactions involving non-controlling interests, net of tax	–	–	–	–	–
At 31 December 2023	4,496	13,815	2,496	27,206	48,013

a Movements in treasury shares relate to employee share-based payment plans.

32. Capital and reserves – continued

\$ million										
Treasury shares	Foreign currency translation reserve	Investments in equity instruments	Cash flow hedges	Costs of hedging	Total fair value reserves	Profit and loss account	bp shareholders' equity	Non-controlling interests		Total equity
								Hybrid bonds	Other interest	
(12,153)	(2,643)	–	(183)	(73)	(256)	34,732	67,553	13,390	2,047	82,990
–	–	–	–	–	–	15,239	15,239	586	55	15,880
–	728	–	–	–	–	–	728	–	26	754
–	–	–	488	(110)	378	–	378	–	–	378
–	–	–	–	–	–	(192)	(192)	–	–	(192)
–	–	–	–	–	–	(1,504)	(1,504)	–	–	(1,504)
–	–	38	–	–	38	–	38	–	–	38
–	–	–	15	–	15	–	15	–	–	15
–	728	38	503	(110)	431	13,543	14,702	586	81	15,369
–	–	–	–	–	–	(4,831)	(4,831)	–	(403)	(5,234)
–	–	–	(1)	–	(1)	–	(1)	–	–	(1)
–	–	–	–	–	–	(8,167)	(8,167)	–	–	(8,167)
830	–	–	–	–	–	(301)	669	–	–	669
–	–	–	–	–	–	1	1	–	–	1
–	–	–	–	–	–	(1)	(1)	176	–	175
–	(5)	–	–	–	–	–	(5)	(586)	–	(591)
–	–	–	–	–	–	363	363	–	(81)	282
(11,323)	(1,920)	38	319	(183)	174	35,339	70,283	13,566	1,644	85,493

32. Capital and reserves – continued

Share capital

The balance on the share capital account represents the aggregate nominal value of all ordinary and preference shares in issue, including treasury shares.

Share premium account

The balance on the share premium account represents the amounts received in excess of the nominal value of the ordinary and preference shares.

Capital redemption reserve

The balance on the capital redemption reserve represents the aggregate nominal value of all the ordinary shares repurchased and cancelled.

Merger reserve

The balance on the merger reserve represents the premium arising where the fair value of the consideration given is in excess of the nominal value of the ordinary shares issued in an acquisition made by the issue of shares where merger relief under the Companies Act applies.

Treasury shares

Treasury shares represent bp shares repurchased and available for specific and limited purposes. For accounting purposes shares held in Employee Share Ownership Plans (ESOPs) and bp's US share plan administrator to meet the future requirements of the employee share-based payment plans are treated in the same manner as treasury shares and are, therefore, included in the financial statements as treasury shares. The ESOPs are funded by the group and have waived their rights to dividends in respect of such shares held for future awards. Until such time as the shares held by the ESOPs vest unconditionally to employees, the amount paid for those shares is shown as a reduction in shareholders' equity. Assets and liabilities of the ESOPs are recognized as assets and liabilities of the group.

Investments in equity instruments

This reserve records the change in fair value of investments in equity instruments for which the group has elected to recognize fair value gains and losses in other comprehensive income.

Foreign currency translation reserve

The foreign currency translation reserve records exchange differences arising from the translation of the financial statements of foreign operations. Upon disposal of foreign operations, the related accumulated exchange differences are reclassified to the income statement.

Cash flow hedges

This reserve records the portion of the gain or loss on a hedging instrument in a cash flow hedge that is determined to be an effective hedge. For further information on the accounting for cash flow hedges see **Note 1** - Derivative financial instruments and hedging activities.

Costs of hedging

This reserve records the change in fair value of the foreign currency basis spread of financial instruments to which cost of hedge accounting has been applied. The accumulated amount relates to time-period related hedged items and is amortized to profit or loss over the term of the hedging relationship. For further information on the accounting for costs of hedging see **Note 1** - Derivative financial instruments and hedging activities.

Profit and loss account

The balance held on this reserve is the accumulated retained profits of the group.

Non-controlling interests

Non-controlling interests represent the equity in subsidiaries that is not attributable, directly or indirectly, to bp shareholders. Included within non-controlling interests are perpetual subordinated hybrid bonds, perpetual subordinated hybrid securities and certain equity instruments with preferred distributions issued by group subsidiaries. The contractual terms of these instruments allow the group to defer coupon payments, equity distributions and repayment of principal indefinitely. However, the terms and conditions of each instrument stipulate the circumstances in which deferred payments and/or the principal amount of the instrument becomes payable. These circumstances, which include the announcement of a bp p.l.c. ordinary share or parity equity dividend distribution, are within the group's control.

Perpetual subordinated hybrid bonds are issued by BP Capital Markets p.l.c., a group subsidiary, in euro, sterling and US dollars. During the year BP Capital Markets p.l.c. redeemed \$1.2 billion of the non-call 2025 4.375% US dollar hybrid bonds issued in 2020. As at 31 December 2025 the total population of hybrid bonds include redemption options exercisable at the group's discretion from March 2026 to March 2035 (the first 'call date'), on specified dates thereafter, or in the event of specific circumstances (such as a change in IFRS or tax regime) as set out in the individual terms of each issue. Coupons are fixed for an initial period up to dates from June 2026 to June 2035 at rates of 3.25% to 6.45% and reset to rates determined by the contractual terms of each instrument on certain dates thereafter. Whilst the contractual terms of these instruments allow the group to defer coupon payments and the repayment of principal indefinitely, the group has chosen to swap the non-US dollar hybrid bonds to a USD floating interest rate up to their respective first call periods. Payments made to and profit attributed to these hybrid bonds in the year totalled \$644 million (2024 \$485 million) and \$640 million (2024 \$517 million) respectively. The amount of hybrid bonds included in non-controlling interests at the end of the year was \$13.5 billion (2024 \$14.6 billion).

Perpetual subordinated hybrid securities issued by group subsidiaries include \$1,000 million (2024 \$500 million), specifically earmarked to fund BP Alternative Energy Investments Ltd including the funding of Lightsource bp and \$1,500 million (2024 \$1500 million) specifically earmarked to fund a floating, production, storage and offloading vessel (FPSO) used in one of the group's major projects. Payments made to and profit attributed to perpetual hybrid securities in the year totalled \$158 million (2024 \$125 million) and \$159 million (2024 \$125 million) respectively. The amount of perpetual subordinated hybrid securities included within non-controlling interests at the end of the year was \$2.5 billion (2024 \$2.0 billion).

32. Capital and reserves – continued

Equity instruments with preferred distributions issued by group subsidiaries include \$958 million of proceeds in 2025 from the sale of a 25% non-controlling interest in the subsidiary that holds bp's 12% interest in the entity that owns Trans-Anatolian natural gas pipeline and proceeds of \$1,500 million the sale of a 49% and 50%, respectively, in non-controlling interests in the group subsidiaries that hold interests in Permian and Eagle Ford midstream assets. Proceeds in 2024 of \$1,330 million comprise \$500 million of proceeds from the sale of a 49% interest in a subsidiary that holds certain Gulf of America midstream assets; and \$830 million of proceeds from the sale of a 25% non-controlling interest in the subsidiary that holds bp's 20% interest in the entity that holds the Trans Adriatic natural gas pipeline. In these transactions, the group retains control over the ability to defer equity distributions which are not guaranteed, and investors have no right to redeem their shares other than in certain circumstances that are within the group's control. The amount associated with equity instruments with preferred or other structured distributions included within non-controlling interests at the end of the year was approximately \$4.5 billion (2024 \$1.6 billion).

The pre-tax amounts of each component of other comprehensive income, and the related amounts of tax, are shown in the table below.

	\$ million		
	2025		
	Pre-tax	Tax	Net of tax
Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including reclassifications)	1,904	16	1,920
Cash flow hedges (including reclassifications)	160	(38)	122
Costs of hedging (including reclassifications)	61	–	61
Share of items relating to equity-accounted entities, net of tax	(4)	–	(4)
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension and other post-employment benefit liability or asset	(221)	55	(166)
Remeasurements of equity investments	(6)	–	(6)
Cash flow hedges that will subsequently be transferred to the balance sheet	5	–	5
Other comprehensive income	1,899	33	1,932
			\$ million
			2024
	Pre-tax	Tax	Net of tax
Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including reclassifications)	(288)	(76)	(364)
Cash flow hedges (including reclassifications)	(531)	125	(406)
Costs of hedging (including reclassifications)	(4)	–	(4)
Share of items relating to equity-accounted entities, net of tax	(12)	–	(12)
Other	–	(1)	(1)
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension and other post-employment benefit liability or asset ^a	(360)	727	367
Remeasurements of equity investments	(47)	7	(40)
Cash flow hedges that will subsequently be transferred to the balance sheet	(1)	–	(1)
Other comprehensive income	(1,243)	782	(461)
			\$ million
			2023
	Pre-tax	Tax	Net of tax
Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including reclassifications)	583	171	754
Cash flow hedges (including reclassifications)	637	(149)	488
Costs of hedging (including reclassifications)	(78)	(32)	(110)
Share of items relating to equity-accounted entities, net of tax	(192)	–	(192)
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension and other post-employment benefit liability or asset	(2,262)	758	(1,504)
Remeasurements of equity investments	51	(13)	38
Cash flow hedges that will subsequently be transferred to the balance sheet	15	–	15
Other comprehensive income	(1,246)	735	(511)

^a 2024 includes a \$658-million credit in respect of the reduction in the deferred tax liability on defined benefit pension plan surpluses following the reduction in the rate of the authorized surplus payments tax charge in the UK from 35% to 25%.

33. Contingent liabilities and legal proceedings

Contingent liabilities

There were contingent liabilities at 31 December 2025 in respect of guarantees and indemnities entered into as part of the ordinary course of the group's business. No material losses are likely to arise from such contingent liabilities. Further information on financial guarantees is included in **Note 29**.

In the normal course of the group's business, bp group entities are subject to legal and regulatory proceedings arising out of current and past operations, including matters related to commercial disputes, product liability, antitrust, commodities trading, premises-liability claims, consumer protection, general health, safety, climate change and environmental claims and allegations of exposures of third parties to toxic substances, such as lead pigment in paint, asbestos and other chemicals. The amounts claimed could be significant and could be material to the group's results of operations, financial position or liquidity. While it is difficult to predict the ultimate outcome in some cases, bp expects that the impact of current legal and regulatory proceedings on the group's results of operations, liquidity or financial position will not be material.

The group files tax returns in many jurisdictions across the world. Various tax authorities are currently examining these returns, which contain matters that could be subject to differing interpretations of applicable tax laws and regulations. The resolution of tax positions through negotiations with relevant tax authorities, or through litigation, can take several years to complete and the amounts could be significant and could, in aggregate, be material to the group's results of operations, financial position or liquidity. While it is difficult to predict the ultimate outcome in some cases, bp does not expect there to be any material impact upon the group's results of operations, financial position or liquidity.

The group is subject to numerous national and local health, safety and environmental laws and regulations concerning its products, operations and other activities. These laws and regulations may require the group to take future action to remediate the effects on the environment of prior disposal or release of chemicals or petroleum substances by the group or other parties. Such contingencies may exist for various sites including refineries, chemical plants, oil fields, commodities extraction sites, service stations, terminals and waste disposal sites. In addition, the group may have obligations relating to prior asset sales or closed facilities. The ultimate requirement for remediation and its costs are inherently difficult to estimate. However, the estimated cost of environmental obligations has been provided in these accounts in accordance with the group's accounting policies. While the amounts of future possible costs that are not provided for could be significant and material to the group's results of operations in the period in which they are recognized, it is not possible to estimate the amounts involved. bp does not expect these costs to have a material impact on the group's results of operations, financial position or liquidity.

If production and manufacturing facilities and pipelines are sold to third parties and the subsequent owner is unable to meet their decommissioning obligations it is possible that, in certain circumstances, bp could be partially or wholly responsible for decommissioning. The group estimates that for production facilities, approximately \$17 billion (2024 \$16 billion) of associated decommissioning obligations were previously transferred to third parties. While the amounts associated with decommissioning provisions reverting to the group could be material, bp is not currently aware of any such material cases that have a greater than remote chance of reverting to the group. Furthermore, as described in Provisions and contingencies within **Note 1**, decommissioning provisions associated with customers & products facilities are not generally recognized as the potential obligations cannot be measured given their indeterminate settlement dates.

By their nature, it is not practicable to estimate the potential financial impact or possible timing of the above contingencies as there are significant uncertainties that are dependent on various factors that are not within the group's control.

Contingent liabilities related to the Gulf of America oil spill

For information on legal proceedings relating to the Deepwater Horizon oil spill, see Legal proceedings below. Any outstanding Deepwater Horizon related claims are not expected to have a material impact on the group's financial performance.

Legal proceedings

Proceedings relating to the Deepwater Horizon oil spill

BP Exploration & Production Inc. (BPXP) was lease operator of Mississippi Canyon, Block 252 in the Gulf of America, where the semi-submersible rig Deepwater Horizon was deployed at the time of the 20 April 2010 explosion and fire and resulting oil spill (the Incident). Lawsuits and claims arising from the Incident were brought principally in US federal and state courts. The remaining proceedings arising from the Incident broadly seek penalties, costs, damages and compensation for alleged environmental, personal injury, health and economic harm as a result of the Incident. bp believes that impact of the remaining proceedings on the group's financial position or liquidity will not be material and in future reports will not report on legal proceedings relating to the Incident absent any material developments.

33. Contingent liabilities and legal proceedings – continued

Other legal proceedings

Climate change

BP p.l.c., BP America Inc. and BP Products North America Inc. are co-defendants with other oil and gas companies in approximately 32 lawsuits brought in various state and federal courts on behalf of various governmental and private parties. The lawsuits generally assert claims under a variety of legal theories seeking to hold the defendant companies responsible for impacts allegedly caused by and/or relating to climate change. Underlying many of the legal theories are allegations regarding deceptive communication and disinformation to the public. The lawsuits seek remedies including payment of money and other forms of equitable relief. If such suits were successful, the cost of the remedies sought in the various cases could be substantial. Defendants spent several years seeking to have the cases filed in state court removed to federal courts, however Defendants' attempts were ultimately unsuccessful. Accordingly, nearly all the cases are proceeding in various state courts. As a group, the lawsuits generally remain at relatively early stages in the litigation process. While it is not possible to predict the outcome of these legal actions, bp believes that it has valid defences, and it intends to defend such actions vigorously.

Louisiana Coastal restoration

Six coastal parishes and the State of Louisiana have filed over 40 separate lawsuits in state courts in Louisiana against various oil and gas companies seeking damages for coastal erosion. bp entities were named defendants in 17 of these cases. The lawsuits allege that the defendants' historical operations in oil and gas fields within the Louisiana onshore coastal zone failed to comply with state permits and/or were conducted without the required coastal use permits. The scope and scale of plaintiffs' damages demands are significant and unprecedented, including substantial remediation costs, natural resource (ecological impact) damages and the claimed costs for restoring coastal wetlands allegedly impacted by oil and gas field operations.

Defendants removed all of these lawsuits to federal court and the removals were contested by plaintiffs, eventually resulting in a decision from the US Fifth Circuit Court of Appeals rejecting defendants' "federal officer" jurisdiction removal grounds in one of two lead cases – *Plaquemines Parish v. Riverwood, et al.* At the time, the US Supreme Court declined to hear defendants' petition challenging the ruling. In 2024, the US Fifth Circuit issued a further ruling rejecting "federal officer" jurisdiction in a subset of the removed cases contested on a related removal theory. Co-defendant Chevron filed a renewed writ of certiorari petition with the US Supreme Court challenging the US Fifth Circuit's remand decision. On 16 June 2025, the US Supreme Court granted Chevron's petition in *Chevron USA Inc. v. Plaquemines Parish*. Oral argument was held on January 12, 2026 and a decision in the appeal is expected during the Court's current term which ends in June.

Following remand of the other lead removal case, *Cameron Parish v. Auster, et al.*, in which bp was the principal defendant, bp entered into a settlement agreement and release with the plaintiffs in late 2023 in respect of all state and local governmental claims arising within Cameron Parish. The terms of the settlement agreement and release are confidential and have not had and are not expected to have in the future, a significant effect on the company's financial position or profitability.

Atlantic Richfield Company, a bp affiliate, was a named defendant along with Chevron in *Plaquemines Parish v. Rozel, et al.*, another coastal restoration damages case set for trial in March 2025. A state trial court initially ruled in favour of Atlantic Richfield's motion for summary judgment and dismissed it from the case, but following a motion by plaintiffs for reconsideration, the court reversed its summary judgment ruling and reinstated Atlantic Richfield as a defendant. The plaintiffs' claims against Atlantic Richfield were severed from the March 2025 trial, and the case proceeded to trial against Chevron alone. In April 2025, following a three-week trial, the jury returned a verdict against Chevron awarding plaintiffs \$745 million. The court has yet to establish a new trial date for the plaintiffs' now separate claims against Atlantic Richfield. All other post-trial activity in the case has been paused pending a decision from the US Supreme Court on Chevron's petition.

No bp entity is a named defendant in any of the other active Louisiana Coastal restoration docket cases with a trial date, all of which remain in the early stages of litigation. In addition, four private landowners have filed separate claims in the state courts in Jefferson and Plaquemines Parishes of Louisiana for restoration damages related to alleged impacts to their marshlands associated with historic oil field operations. bp entities are defendants in two of these private landowner cases, having been previously dismissed from a third.

While it is not possible to predict the outcomes of these novel legal actions, bp believes that it has valid defences, and it intends to defend such actions vigorously.

34. Remuneration of senior management and non-executive directors

Remuneration of directors

	\$ million		
	2025	2024	2023
Total for all directors			
Emoluments	11	8	8
Amounts received under incentive schemes ^a	3	5	6
Total	14	13	14

^a Excludes amounts relating to past directors.

Emoluments

These amounts comprise fees paid to the non-executive chair and the non-executive directors and, for executive directors, salary and benefits earned during the relevant financial year, plus cash bonuses awarded for the year.

Remuneration of directors and senior management

	\$ million		
	2025	2024	2023
Total for all senior management and non-executive directors			
Short-term employee benefits	34	22	31
Pensions and other post-employment benefits	–	–	–
Share-based payments ^a	28	26	12
Termination benefits	–	3	–
Total	62	51	43

^a 2023 includes a reversal of \$14 million relating to the lapse of Bernard Looney's outstanding share awards in prior years.

Senior management comprises members of the leadership team.

Short-term employee benefits

These amounts comprise fees and benefits paid to the non-executive chair and non-executive directors, as well as salary, benefits and cash bonuses for senior management. Deferred annual bonus awards, to be settled in shares, are included in share-based payments.

Pensions and other post-employment benefits

The amounts represent the estimated cost to the group of providing pensions and other post-employment benefits to senior management in respect of the current year of service measured in accordance with IAS 19 'Employee Benefits'.

Share-based payments

This is the cost to the group of senior management's participation in share-based payment plans, as measured by the fair value of options and shares granted, accounted for in accordance with IFRS 2 'Share-based Payments'.

Termination benefits

Termination benefits include compensation to senior management for loss of office.

Related party transactions

Transactions between the group and its significant joint ventures and associates are summarized in Financial statements – **Note 16** and **Note 17**. In the ordinary course of its business, the group enters into transactions with various organizations with which some of its directors or executive officers are associated. Except as described in this report, the group did not have any material transactions or transactions of an unusual nature with, and did not make loans to, related parties in the period commencing 1 January 2025 to 13 February 2026.

35. Employee costs and numbers

	\$ million								
	2025	2024		2023					
Employee costs									
Wages and salaries ^a	9,295	8,601		7,835					
Social security costs	1,166	1,032		943					
Share-based payments ^b	847	1,088		1,131					
Pension and other post-employment benefit costs	448	519		370					
	11,756	11,240		10,279					

	2025			2024			2023		
	US	Non-US	Total	US	Non-US	Total	US	Non-US	Total
Average number of employees ^c									
gas & low carbon energy	1,000	5,200	6,200	900	4,400	5,300	900	3,700	4,600
oil production & operations	3,300	6,000	9,300	3,300	5,700	9,000	3,100	5,500	8,600
customers & products ^d	27,100	43,700	70,800	27,500	38,000	65,500	19,500	36,300	55,800
other businesses and corporate	1,200	10,700	11,900	1,400	9,800	11,200	1,400	9,000	10,400
	32,600	65,600	98,200	33,100	57,900	91,000	24,900	54,500	79,400

a Includes termination costs of \$467 million (2024 \$336 million and 2023 \$96 million).

b The group provides certain employees with shares and share options as part of their remuneration packages. The majority of these share-based payment arrangements are equity-settled.

c Reported to the nearest 100.

d Includes 38,900 (2024 40,700 and 2023 33,800) service station staff.

e Includes 9,100 (2024 1,700 and 2023 0) agricultural, operational and seasonal workers in Brazil.

36. Auditor's remuneration

	\$ million		
	2025	2024	2023
Fees			
The audit of the company annual accounts ^a	42	40	38
The audit of accounts of subsidiaries of the company	17	17	15
Total audit	59	57	53
Audit-related assurance services ^b	5	4	4
Total audit and audit-related assurance services	64	61	57
Non-audit and other assurance services	9	4	3
Services relating to bp pension plans	1	1	1
	74	66	61

a Fees in respect of the audit of the accounts of BP p.l.c. including the group's consolidated financial statements.

b Includes interim reviews and audit of internal control over financial reporting and non-statutory audit services.

2025 includes \$0.5 million of additional fees for 2024. 2024 includes \$1.3 million of additional fees for 2023. 2023 includes \$0.2 million of additional fees for 2022. Auditor's remuneration is included in the income statement within distribution and administration expenses.

Tax services (in relation to income tax, indirect tax compliance, employee tax services and tax advisory services) were \$nil in all periods presented.

The audit committee has established pre-approval policies and procedures for the engagement of Deloitte to render audit and certain assurance and other services. The audit fees payable to Deloitte were considered as part of the audit tender process in 2016 and challenged by the audit committee through comparison with the audit pricing proposals of the other bidding firms. Changes in audit fees subsequent to the audit tender, including matters relevant to the 2025 audit, have been reviewed and challenged by the Audit Committee, before being approved. Deloitte performed further assurance services that were not prohibited by regulatory or other professional requirements and were pre-approved by the Committee. Deloitte is engaged for these services when its expertise and experience of bp are important. Most of this work is of an audit-related or assurance nature. During 2025, no audit-related fees, tax fees or other non-audit fees were approved by the audit committee pursuant to the de minimis exception to the pre-approval requirement provided by paragraph (c)(7)(i) (C) of Rule 2-01 of Regulation S-X.

Under SEC regulations, the remuneration of the auditor of \$74 million (2024 \$66 million and 2023 \$61 million) is required to be presented as follows: audit \$59 million (2024 \$57 million and 2023 \$53 million); other audit-related \$5 million (2024 \$4 million and 2023 \$4 million); tax \$nil (2024 \$nil and 2023 \$nil); and all other fees \$10 million (2024 \$5 million and 2023 \$4 million).

37. Subsidiaries, joint arrangements and associates^a

The more important subsidiaries, joint arrangements and associates of the group at 31 December 2025 and the group percentage of ordinary share capital (to nearest whole number) are set out below. The group's share of the assets and liabilities of the more important unincorporated joint arrangements are held by subsidiaries listed in the table below. Those subsidiaries held directly by the parent company are marked with an asterisk (*), the percentage owned being that of the group unless otherwise indicated. A complete list of undertakings of the group is included in **Note 13** in the parent company financial statements of BP p.l.c. which are filed with the Registrar of Companies in the UK, along with the group's annual report.

Subsidiaries	%	Country of incorporation	Principal activities
International			
BP Corporate Holdings Limited	100	England & Wales	Investment holding
BP Exploration Operating Company Limited	100	England & Wales	Exploration and production
*BP Gamma Holdings Limited	100	England & Wales	Investment holding
*BP Global Investments Limited	100	England & Wales	Investment holding
*BP International Limited	100	England & Wales	Integrated oil operations
BP Oil International Limited	100	England & Wales	Integrated oil operations
*Castrol Group Holdings Limited	100	Scotland	Investment holding
Azerbaijan			
BP Exploration (Caspian Sea) Limited	100	England & Wales	Exploration and production
BP Exploration (Azerbaijan) Limited	100	England & Wales	Exploration and production
Germany			
BP Europa SE	100	Germany	Refining and marketing
Trinidad and Tobago			
BP Trinidad and Tobago LLC	70	US	Exploration and production
UK			
BP Capital Markets p.l.c.	100	England & Wales	Finance
Lightsource BP Renewable Energy Investments Limited	100	England & Wales	Onshore renewables
US			
*BP Holdings North America Limited	100	England & Wales	Investment holding
Atlantic Richfield Company	100	US	Exploration and production, refining and marketing
BP America Inc.	100	US	
BP America Production Company	100	US	
BP Company North America Inc.	100	US	
BP Corporation North America Inc.	100	US	
BP Products North America Inc.	100	US	
The Standard Oil Company	100	US	
Archaea Energy Inc.	100	US	Bioenergy
BP Capital Markets America Inc.	100	US	Finance
Joint arrangements			
Angola			
Azule Energy Holdings Limited	50	England & Wales	Exploration and production

a There were no important associates in the group at 31 December 2025.

Supplementary information on oil and natural gas (unaudited)

The regional analysis presented below is on a continent basis, with separate disclosure for countries that contain 15% or more of the total proved reserves (for subsidiaries plus equity-accounted entities^a), in accordance with SEC and FASB requirements.

Oil and gas reserves – certain definitions

Unless the context indicates otherwise, the following terms have the meanings shown below:

Proved oil and gas reserves

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

- (i) The area of the reservoir considered as proved includes:
 - (A) The area identified by drilling and limited by fluid contacts, if any; and
 - (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.
- (ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
- (iii) Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
- (iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:
 - (A) Successful testing by a pilot project in an area of the reservoir with properties no more favourable than in the reservoir as a whole, the operation of an installed programme in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or programme was based; and
 - (B) The project has been approved for development by all necessary parties and entities, including governmental entities.
- (v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Undeveloped oil and gas reserves

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

- (i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
- (ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.
- (iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Developed oil and gas reserves

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

- (i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
- (ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

For details on bp's proved reserves and production compliance and governance processes, see [pages 340-349](#).

^a See Note 1 - Investment in Rosneft.

Oil and natural gas exploration and production activities

								\$ million	
								2025	
	Europe		North America		South America	Africa	Asia	Australasia	Total
	UK	Rest of Europe	US	Rest of North America					
Subsidiaries									
Capitalized costs at 31 December^{a b}									
Gross capitalized costs									
Proved properties	28,834	–	79,193	10	15,476	19,635	44,989	6,793	194,930
Unproved properties	418	–	632	1,981	1,188	968	1,633	796	7,616
	29,252	–	79,825	1,991	16,664	20,603	46,622	7,589	202,546
Accumulated depreciation	24,342	–	48,293	1,604	13,017	19,949	30,750	5,945	143,900
Net capitalized costs	4,910	–	31,532	387	3,647	654	15,872	1,644	58,646
Costs incurred for the year ended 31 December^{a b}									
Acquisition of properties									
Proved	–	–	957	–	–	–	5	–	962
Unproved	–	–	13	–	1	–	4	–	18
	–	–	970	–	1	–	9	–	980
Exploration and appraisal costs ^c	46	–	519	38	473	249	41	43	1,409
Development	581	–	4,461	–	686	226	2,180	253	8,387
Total costs	627	–	5,950	38	1,160	475	2,230	296	10,776
Results of operations for the year ended 31 December^a									
Sales and other operating revenues ^d									
Third parties	107	–	1,136	–	942	656	4,282	1,409	8,532
Sales between businesses	2,705	–	13,187	–	790	139	6,558	540	23,919
	2,812	–	14,323	–	1,732	795	10,840	1,949	32,451
Exploration expenditure	36	–	321	(6)	154	20	32	13	570
Production costs	547	–	2,552	1	311	353	565	99	4,428
Production taxes	(62)	–	175	–	318	–	1,241	26	1,698
Other costs (income) ^e	(95)	9	2,571	23	28	(56)	39	90	2,609
Depreciation, depletion and amortization	1,454	–	4,966	3	1,178	530	3,224	436	11,791
Net impairments and (gains) losses on sale of businesses and fixed assets	249	4	(74)	–	(19)	121	11	(2)	290
	2,129	13	10,511	21	1,970	968	5,112	662	21,386
Profit (loss) before taxation ^f	683	(13)	3,812	(21)	(238)	(173)	5,728	1,287	11,065
Allocable taxes	703	–	882	(11)	18	678	4,228	460	6,958
Results of operations	(20)	(13)	2,930	(10)	(256)	(851)	1,500	827	4,107

a These tables contain information relating to oil and natural gas exploration and production activities of subsidiaries, which includes bp's share of oil and natural gas exploration and production activities of joint operations. They do not include any costs relating to the Gulf of America oil spill. Amounts relating to the management and ownership of crude oil and natural gas pipelines, LNG liquefaction and transportation operations are excluded. In addition, bp's midstream activities of marketing and trading of natural gas, power and NGLs in the US, Canada, UK, Asia and Europe are excluded. The most significant midstream pipeline interests include the South Caucasus Pipeline, the Baku-Tbilisi-Ceyhan pipeline, the Trans Adriatic Pipeline and the Trans Anatolian Pipeline. Major LNG activities are located in Trinidad, Indonesia and Australia.

b Costs of decommissioning are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

c Includes exploration and appraisal drilling expenditures and pre development studies, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.

d Presented net of transportation costs, purchases and sales taxes.

e Includes property taxes and other government take. The UK region includes a \$275-million gain which is offset by corresponding charges primarily in the US region, relating to the group self-insurance programme.

f Excludes the unwinding of the discount on provisions and payables amounting to \$480 million which is included in finance costs in the group income statement.

Oil and natural gas exploration and production activities – continued

								\$ million	
								2025	
	Europe		North America	South America	Africa	Asia	Australasia	Total	
	UK	Rest of Europe	US	Rest of North America					
Equity-accounted entities (bp share)									
Capitalized costs at 31 December^{a b}									
Gross capitalized costs									
Proved properties	–	6,480	–	–	13,188	11,832	11,654	–	43,154
Unproved properties	–	767	–	–	97	533	–	–	1,397
	–	7,247	–	–	13,285	12,365	11,654	–	44,551
Accumulated depreciation	–	3,805	–	–	7,393	4,251	3,477	–	18,926
Net capitalized costs	–	3,442	–	–	5,892	8,114	8,177	–	25,625
Costs incurred for the year ended 31 December^{a c d}									
Acquisition of properties ^b									
Proved	–	–	–	–	–	–	–	–	–
Unproved	–	–	–	–	–	–	–	–	–
Exploration and appraisal costs ^c	–	55	–	–	3	153	–	–	211
Development	–	1,193	–	–	571	2,379	806	–	4,949
Total costs	–	1,248	–	–	574	2,532	806	–	5,160
Results of operations for the year ended 31 December^a									
Sales and other operating revenues ^e									
Third parties	–	1,698	–	–	853	2,700	1,777	–	7,028
Sales between businesses	–	–	–	–	955	–	–	–	955
	–	1,698	–	–	1,808	2,700	1,777	–	7,983
Exploration expenditure	–	55	–	–	–	18	–	–	73
Production costs	–	186	–	–	483	651	647	–	1,967
Production taxes	–	–	–	–	267	27	–	–	294
Other costs (income)	–	2	–	–	116	(124)	24	–	18
Depreciation, depletion and amortization	–	481	–	–	451	1,484	816	–	3,232
Net impairments and losses on sale of businesses and fixed assets	–	321	–	–	–	129	–	–	450
	–	1,045	–	–	1,317	2,185	1,487	–	6,034
Profit (loss) before taxation	–	653	–	–	491	515	290	–	1,949
Allocable taxes	–	651	–	–	76	343	121	–	1,191
Results of operations	–	2	–	–	415	172	169	–	758

a These tables contain information relating to oil and natural gas exploration and production activities of equity-accounted entities. Amounts relating to the management and ownership of crude oil and natural gas pipelines, LNG liquefaction, transportation operations as well as downstream and other activities are excluded.

b Costs of decommissioning are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

c Includes exploration and appraisal drilling expenditures and pre development studies, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.

d The amounts shown reflect bp's share of equity-accounted entities' costs incurred, and not the costs incurred by bp in acquiring an interest in equity-accounted entities.

e Presented net of sales tax.

Oil and natural gas exploration and production activities – continued

								\$ million	
								2024	
	Europe		North America		South America	Africa	Asia	Australasia	Total
	UK	Rest of Europe	US	Rest of North America					
Subsidiaries									
Capitalized costs at 31 December^{a b}									
Gross capitalized costs									
Proved properties	29,781	–	72,248	8	14,427	18,756	42,709	6,504	184,433
Unproved properties	411	–	3,012	1,936	2,760	2,471	1,701	762	13,053
	30,192	–	75,260	1,944	17,187	21,227	44,410	7,266	197,486
Accumulated depreciation	24,269	–	44,067	1,602	13,450	20,373	27,528	5,506	136,795
Net capitalized costs	5,923	–	31,193	342	3,737	854	16,882	1,760	60,691
Costs incurred for the year ended 31 December^{a b}									
Acquisition of properties									
Proved	–	–	52	–	–	–	–	–	52
Unproved	–	–	21	–	2	–	–	–	23
	–	–	73	–	2	–	–	–	75
Exploration and appraisal costs ^c	57	–	655	102	294	508	82	59	1,757
Development	629	–	3,829	–	661	1,334	1,363	137	7,953
Total costs	686	–	4,557	102	957	1,842	1,445	196	9,785
Results of operations for the year ended 31 December^a									
Sales and other operating revenues ^d									
Third parties	182	–	1,859	–	1,090	2,094	4,515	1,888	11,628
Sales between businesses	2,762	–	13,035	–	163	–	7,410	362	23,732
	2,944	–	14,894	–	1,253	2,094	11,925	2,250	35,360
Exploration expenditure	1	–	463	97	137	188	55	33	974
Production costs	539	–	2,645	1	399	230	617	106	4,537
Production taxes	(4)	–	149	–	248	–	1,366	40	1,799
Other costs (income) ^e	(221)	(8)	2,455	23	47	49	(59)	116	2,402
Depreciation, depletion and amortization	1,234	–	4,394	3	1,206	543	3,116	477	10,973
Net impairments and (gains) losses on sale of businesses and fixed assets	1,058	14	(471)	(19)	(259)	2,312	(1)	(1)	2,633
	2,607	6	9,635	105	1,778	3,322	5,094	771	23,318
Profit (loss) before taxation ^f	337	(6)	5,259	(105)	(525)	(1,228)	6,831	1,479	12,042
Allocable taxes	195	(1)	1,194	(14)	(203)	291	5,003	557	7,022
Results of operations	142	(5)	4,065	(91)	(322)	(1,519)	1,828	922	5,020

a These tables contain information relating to oil and natural gas exploration and production activities of subsidiaries, which includes bp's share of oil and natural gas exploration and production activities of joint operations. They do not include any costs relating to the Gulf of America oil spill. Amounts relating to the management and ownership of crude oil and natural gas pipelines, LNG liquefaction and transportation operations are excluded. In addition, bp's midstream activities of marketing and trading of natural gas, power and NGLs in the US, Canada, UK, Asia and Europe are excluded. The most significant midstream pipeline interests include the South Caucasus Pipeline, the Baku-Tbilisi-Ceyhan pipeline, the Trans Adriatic Pipeline and the Trans Anatolian Pipeline. Major LNG activities are located in Trinidad, Indonesia and Australia.

b Costs of decommissioning are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

c Includes exploration and appraisal drilling expenditures and pre development studies, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.

d Presented net of transportation costs, purchases and sales taxes.

e Includes property taxes and other government take. The UK region includes a \$313-million gain which is offset by corresponding charges primarily in the US region, relating to the group self-insurance programme.

f Excludes the unwinding of the discount on provisions and payables amounting to \$460 million which is included in finance costs in the group income statement.

Oil and natural gas exploration and production activities – continued

								\$ million	
								2024	
	Europe		North America	South America	Africa	Asia	Australasia	Total	
	UK	Rest of Europe	US	Rest of North America					
Equity-accounted entities (bp share)									
Capitalized costs at 31 December^{a b}									
Gross capitalized costs									
Proved properties	–	5,211	–	–	12,185	10,181	10,848	–	38,425
Unproved properties	–	705	–	–	130	344	–	–	1,179
	–	5,916	–	–	12,315	10,525	10,848	–	39,604
Accumulated depreciation	–	2,968	–	–	7,284	3,209	2,661	–	16,122
Net capitalized costs	–	2,948	–	–	5,031	7,316	8,187	–	23,482
Costs incurred for the year ended 31 December^{a c d}									
Acquisition of properties ^b									
Proved	–	–	–	–	–	–	–	–	–
Unproved	–	–	–	–	–	26	–	–	26
	–	–	–	–	–	26	–	–	26
Exploration and appraisal costs ^c	–	58	–	–	5	54	–	–	117
Development	–	761	–	–	821	1,105	901	–	3,588
Total costs	–	819	–	–	826	1,185	901	–	3,731
Results of operations for the year ended 31 December^a									
Sales and other operating revenues ^e									
Third parties ^f	–	1,943	–	–	840	2,692	1,854	–	7,329
Sales between businesses ^f	–	–	–	–	1,127	–	–	–	1,127
	–	1,943	–	–	1,967	2,692	1,854	–	8,456
Exploration expenditure	–	51	–	–	–	8	–	–	59
Production costs	–	145	–	–	812	560	574	–	2,091
Production taxes	–	–	–	–	324	37	–	–	361
Other costs (income) ^g	–	26	–	–	134	142	25	–	327
Depreciation, depletion and amortization	–	453	–	–	477	1,431	965	–	3,326
Net impairments and losses on sale of businesses and fixed assets	–	65	–	–	849	–	–	–	914
	–	740	–	–	2,596	2,178	1,564	–	7,078
Profit (loss) before taxation	–	1,203	–	–	(629)	514	290	–	1,378
Allocable taxes ^g	–	931	–	–	(766)	296	120	–	581
Results of operations	–	272	–	–	137	218	170	–	797

a These tables contain information relating to oil and natural gas exploration and production activities of equity-accounted entities. Amounts relating to the management and ownership of crude oil and natural gas pipelines, LNG liquefaction, transportation operations as well as downstream and other activities are excluded.

b Costs of decommissioning are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

c Includes exploration and appraisal drilling expenditures and pre development studies, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.

d The amounts shown reflect bp's share of equity-accounted entities' costs incurred, and not the costs incurred by bp in acquiring an interest in equity-accounted entities.

e Presented net of sales tax.

f South America third parties sales and sales between businesses split has been restated.

g Africa other costs (income) have been restated and consequently the allocable taxes.

Oil and natural gas exploration and production activities – continued

								\$ million	
								2023	
	Europe		North America		South America	Africa	Asia	Australasia	Total
	UK	Rest of Europe	US	Rest of North America					
Subsidiaries									
Capitalized costs at 31 December^{a b}									
Gross capitalized costs									
Proved properties	29,127	–	70,404	6	17,475	20,763	4,135	6,331	185,457
Unproved properties	369	–	3,057	1,917	2,565	2,739	1,691	737	13,075
	29,496	–	73,461	1,923	20,040	23,502	43,042	7,068	198,532
Accumulated depreciation	22,018	–	42,364	1,592	15,712	21,132	24,431	4,998	132,247
Net capitalized costs	7,478	–	31,097	331	4,328	2,370	18,611	2,070	66,285
Costs incurred for the year ended 31 December^{a b}									
Acquisition of properties									
Proved	–	–	13	–	–	–	–	–	13
Unproved	–	–	51	–	2	6	–	–	59
	–	–	64	–	2	6	–	–	72
Exploration and appraisal costs ^c	123	–	356	123	114	270	145	100	1,231
Development	484	–	4,690	–	713	863	1,424	32	8,206
Total costs	607	–	5,110	123	829	1,139	1,569	132	9,509
Results of operations for the year ended 31 December^a									
Sales and other operating revenues ^d									
Third parties	206	–	665	–	1,348	3,227	4,801	1,765	12,012
Sales between businesses	3,483	–	12,705	–	20	22	7,731	412	24,373
	3,689	–	13,370	–	1,368	3,249	12,532	2,177	36,385
Exploration expenditure	46	–	348	93	54	413	25	18	997
Production costs	477	–	2,382	2	360	232	588	111	4,152
Production taxes	13	–	136	–	229	–	1,357	44	1,779
Other costs (income) ^e	(171)	–	2,144	13	115	304	(35)	145	2,515
Depreciation, depletion and amortization	1,063	–	3,532	–	1,351	1,546	2,844	412	10,748
Net impairments and (gains) losses on sale of businesses and fixed assets	819	(18)	701	(100)	671	1,430	(1)	(4)	3,498
	2,247	(18)	9,243	8	2,780	3,925	4,778	726	23,689
Profit (loss) before taxation ^f	1,442	18	4,127	(8)	(1,412)	(676)	7,754	1,451	12,696
Allocable taxes	365	19	889	(3)	(565)	439	5,317	451	6,912
Results of operations	1,077	(1)	3,238	(5)	(847)	(1,115)	2,437	1,000	5,784

a These tables contain information relating to oil and natural gas exploration and production activities of subsidiaries, which includes bp's share of oil and natural gas exploration and production activities of joint operations. They do not include any costs relating to the Gulf of America oil spill. Amounts relating to the management and ownership of crude oil and natural gas pipelines, LNG liquefaction and transportation operations are excluded. In addition, bp's midstream activities of marketing and trading of natural gas, power and NGLs in the US, Canada, UK, Asia and Europe are excluded. The most significant midstream pipeline interests include the South Caucasus Pipeline, the Baku-Tbilisi-Ceyhan pipeline, the Trans Adriatic Pipeline and the Trans Anatolian Pipeline. Major LNG activities are located in Trinidad, Indonesia and Australia.

b Costs of decommissioning are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

c Includes exploration and appraisal drilling expenditures and pre development studies, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.

d Presented net of transportation costs, purchases and sales taxes.

e Includes property taxes and other government take. The UK region includes a \$287-million gain which is offset by corresponding charges primarily in the US region, relating to the group self-insurance programme.

f Excludes the unwinding of the discount on provisions and payables amounting to \$390 million which is included in finance costs in the group income statement.

Oil and natural gas exploration and production activities – continued

								\$ million	
								2023	
	Europe		North America	South America	Africa	Asia	Australasia	Total	
	UK	Rest of Europe	US	Rest of North America					
Equity-accounted entities (bp share)									
Capitalized costs at 31 December^{a b}									
Gross capitalized costs									
Proved properties	–	4,432	–	–	12,530	8,590	9,947	–	35,499
Unproved properties	–	652	–	–	125	372	–	–	1,149
	–	5,084	–	–	12,655	8,962	9,947	–	36,648
Accumulated depreciation	–	2,420	–	–	6,807	1,812	1,696	–	12,735
Net capitalized costs	–	2,664	–	–	5,848	7,150	8,251	–	23,913
Costs incurred for the year ended 31 December^{a c d}									
Acquisition of properties ^b									
Proved	–	–	–	–	–	–	–	–	–
Unproved	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–
Exploration and appraisal costs ^c	–	42	–	–	7	44	–	–	93
Development	–	584	–	–	687	844	942	–	3,057
Total costs	–	626	–	–	694	888	942	–	3,150
Results of operations for the year ended 31 December^a									
Sales and other operating revenues ^e									
Third parties ^f	–	2,159	–	–	963	2,550	1,716	–	7,388
Sales between businesses ^f	–	–	–	–	1,107	–	–	–	1,107
	–	2,159	–	–	2,070	2,550	1,716	–	8,495
Exploration expenditure	–	41	–	–	–	44	–	–	85
Production costs	–	169	–	–	715	427	374	–	1,685
Production taxes	–	–	–	–	332	52	–	–	384
Other costs (income) ^g	–	21	–	–	257	42	8	–	328
Depreciation, depletion and amortization	–	455	–	–	451	1,344	1,144	–	3,394
Net impairments and losses on sale of businesses and fixed assets	–	141	–	–	–	15	–	–	156
	–	827	–	–	1,755	1,924	1,526	–	6,032
Profit (loss) before taxation	–	1,332	–	–	315	626	190	–	2,463
Allocable taxes ^g	–	1,124	–	–	127	280	117	–	1,648
Results of operations	–	208	–	–	188	346	73	–	815

a These tables contain information relating to oil and natural gas exploration and production activities of equity-accounted entities. Amounts relating to the management and ownership of crude oil and natural gas pipelines, LNG liquefaction, transportation operations as well as downstream and other activities are excluded.

b Costs of decommissioning are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

c Includes exploration and appraisal drilling expenditures and pre development studies, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.

d The amounts shown reflect bp's share of equity-accounted entities' costs incurred, and not the costs incurred by bp in acquiring an interest in equity-accounted entities.

e Presented net of sales tax.

f South America third parties sales and sales between businesses split has been restated.

g Africa other costs (income) have been restated and consequently the allocable taxes.

Movements in estimated net proved reserves

Crude oil ^{a,b}	million barrels							2025	
	Europe		North America		South America	Africa	Asia	Australasia	Total
	UK	Rest of Europe	US	Rest of North America					
Subsidiaries									
At 1 January									
Developed	104	–	653	–	1	1	716	9	1,483
Undeveloped	63	–	472	–	4	–	305	1	846
	167	–	1,125	–	5	1	1,021	10	2,329
Changes attributable to									
Revisions of previous estimates	(40)	–	39	–	2	3	75	1	80
Improved recovery	–	–	13	–	–	–	–	–	13
Purchases of reserves-in-place	–	–	40	–	–	–	–	–	40
Discoveries and extensions	–	–	1	–	–	1	3	–	5
Production	(29)	–	(146)	–	(2)	(3)	(110)	(3)	(292)
Sales of reserves-in-place	(1)	–	(31)	–	–	–	–	–	(33)
	(70)	–	(84)	–	–	1	(32)	(2)	(186)
At 31 December^c									
Developed	56	–	599	–	1	2	691	6	1,354
Undeveloped	41	–	443	–	4	–	298	3	788
	97	–	1,042	–	6	2	989	8	2,143
Equity-accounted entities (bp share)^d									
At 1 January									
Developed	–	76	–	10	271	94	107	–	558
Undeveloped	–	42	–	–	217	77	3	–	339
	–	118	–	10	488	170	110	–	896
Changes attributable to									
Revisions of previous estimates	–	14	–	–	(40)	21	35	–	30
Improved recovery	–	1	–	–	3	–	–	–	4
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	4	–	–	29	1	–	–	34
Production	–	(20)	–	(1)	(19)	(29)	(29)	–	(98)
Sales of reserves-in-place	–	(1)	–	–	–	–	–	–	(1)
	–	(3)	–	(1)	(26)	(7)	6	–	(31)
At 31 December									
Developed	–	70	–	9	278	97	113	–	566
Undeveloped	–	45	–	–	184	67	4	–	299
	–	115	–	9	461	163	117	–	865
Total subsidiaries and equity-accounted entities (bp share)									
At 1 January									
Developed	104	76	653	10	271	95	823	9	2,041
Undeveloped	63	42	472	–	221	77	308	1	1,184
	167	118	1,125	10	493	171	1,131	10	3,225
At 31 December									
Developed	56	70	599	9	279	98	804	6	1,920
Undeveloped	41	45	443	–	188	67	302	3	1,088
	97	115	1,042	9	467	165	1,105	8	3,008

a Crude oil includes condensate and bitumen. Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

b Because of rounding, some totals may not exactly agree with the sum of their component parts.

c Includes 1.7 million barrels of crude oil in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

d Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

Movements in estimated net proved reserves – continued

									million barrels	
Natural gas liquids ^{a,b}		Europe		North America		South America	Africa	Asia	Australasia	Total
		UK	Rest of Europe	US	Rest of North America					2025
Subsidiaries										
At 1 January										
Developed		2	–	202	–	1	–	–	1	206
Undeveloped		–	–	246	–	–	–	–	–	246
		3	–	447	–	1	–	–	1	452
Changes attributable to										
Revisions of previous estimates		1	–	(1)	–	2	–	–	–	1
Improved recovery		–	–	1	–	–	–	–	–	1
Purchases of reserves-in-place		–	–	25	–	–	–	–	–	25
Discoveries and extensions		–	–	–	–	–	–	–	–	–
Production ^c		(1)	–	(41)	–	(2)	–	–	–	(45)
Sales of reserves-in-place		(1)	–	(16)	–	–	–	–	–	(17)
		(1)	–	(32)	–	(1)	–	–	–	(35)
At 31 December										
Developed		1	–	204	–	–	–	–	1	206
Undeveloped		–	–	212	–	–	–	–	–	212
		1	–	415	–	–	–	–	1	417
Equity-accounted entities (bp share)^d										
At 1 January										
Developed		–	3	–	–	3	10	–	–	16
Undeveloped		–	5	–	–	–	–	–	–	6
		–	8	–	–	4	10	–	–	22
Changes attributable to										
Revisions of previous estimates		–	–	–	–	1	2	–	–	3
Improved recovery		–	–	–	–	–	–	–	–	–
Purchases of reserves-in-place		–	–	–	–	–	–	–	–	–
Discoveries and extensions		–	–	–	–	–	–	–	–	–
Production		–	(1)	–	–	–	(2)	–	–	(3)
Sales of reserves-in-place		–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–
At 31 December										
Developed		–	3	–	–	4	10	–	–	17
Undeveloped		–	5	–	–	–	–	–	–	5
		–	8	–	–	4	10	–	–	22
Total subsidiaries and equity-accounted entities (bp share)										
At 1 January										
Developed		2	3	202	–	4	10	–	1	222
Undeveloped		–	5	246	–	–	–	–	–	252
		3	8	447	–	4	10	–	1	474
At 31 December										
Developed		1	3	204	–	4	10	–	1	222
Undeveloped		–	5	212	–	–	–	–	–	217
		1	8	415	–	4	10	–	1	439

a Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

b Because of rounding, some totals may not exactly agree with the sum of their component parts.

c Excludes NGLs from processing plants in which an interest is held of 2 thousand barrels per day for equity-accounted entities.

d Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

Movements in estimated net proved reserves – continued

								million barrels	
Total liquids ^{a,b}								2025	
	Europe		North America		South America	Africa	Asia	Australasia	Total
	UK	Rest of Europe	US	Rest of North America					
Subsidiaries									
At 1 January									
Developed	106	–	855	–	1	1	716	10	1,689
Undeveloped	63	–	718	–	4	–	305	1	1,092
	169	–	1,573	–	6	1	1,021	11	2,781
Changes attributable to									
Revisions of previous estimates	(40)	–	37	–	4	3	75	1	81
Improved recovery	–	–	14	–	–	–	–	–	14
Purchases of reserves-in-place	–	–	65	–	–	–	–	–	65
Discoveries and extensions	–	–	2	–	–	1	3	–	6
Production ^c	(30)	–	(186)	–	(4)	(3)	(110)	(3)	(337)
Sales of reserves-in-place	(2)	–	(48)	–	–	–	–	–	(49)
	(72)	–	(116)	–	–	–	(32)	(2)	(221)
At 31 December^d									
Developed	57	–	802	–	1	2	691	7	1,560
Undeveloped	41	–	655	–	4	–	298	3	1,000
	98	–	1,457	–	5	2	989	9	2,560
Equity-accounted entities (bp share)^e									
At 1 January									
Developed	–	78	–	10	274	103	107	–	573
Undeveloped	–	47	–	–	217	77	3	–	344
	–	125	–	10	491	180	110	–	918
Changes attributable to									
Revisions of previous estimates	–	14	–	–	(39)	22	35	–	33
Improved recovery	–	1	–	–	3	–	–	–	4
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	4	–	–	29	1	–	–	34
Production	–	(21)	–	(1)	(19)	(31)	(29)	–	(101)
Sales of reserves-in-place	–	(1)	–	–	–	–	–	–	(1)
	–	(3)	–	(1)	(26)	(7)	6	–	(31)
At 31 December									
Developed	–	73	–	9	282	106	113	–	582
Undeveloped	–	50	–	–	184	67	4	–	304
	–	123	–	9	465	173	117	–	887
Total subsidiaries and equity-accounted entities (bp share)									
At 1 January									
Developed	106	78	855	10	275	105	823	10	2,263
Undeveloped	63	47	718	–	222	77	308	1	1,436
	169	125	1,573	10	497	182	1,131	11	3,699
At 31 December									
Developed	57	73	802	9	283	108	804	7	2,143
Undeveloped	41	50	655	–	188	67	302	3	1,304
	98	123	1,457	9	471	175	1,105	9	3,447

a Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

b Because of rounding, some totals may not exactly agree with the sum of their component parts.

c Excludes NGLs from processing plants in which an interest is held of 2 thousand barrels per day for equity-accounted entities.

d Also includes 1.7 million barrels in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

e Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

Movements in estimated net proved reserves – continued

		billion cubic feet							2025	
Natural gas ^{a,b}		Europe		North America		South America	Africa	Asia	Australasia	Total
		UK	Rest of Europe	US	Rest of North America					
Subsidiaries										
At 1 January										
Developed		162	–	2,600	–	379	161	3,026	1,254	7,582
Undeveloped		29	–	2,412	–	350	–	1,320	431	4,542
		190	–	5,012	–	730	161	4,346	1,685	12,124
Changes attributable to										
Revisions of previous estimates		24	–	2,419	–	257	74	172	51	2,996
Improved recovery		–	–	8	–	–	–	–	–	8
Purchases of reserves-in-place		–	–	208	–	–	–	–	–	208
Discoveries and extensions		–	–	1	–	170	65	111	2	349
Production ^c		(84)	–	(664)	–	(385)	(177)	(602)	(293)	(2,205)
Sales of reserves-in-place		(42)	–	(93)	–	–	–	–	–	(135)
		(102)	–	1,878	–	41	(38)	(318)	(240)	1,220
At 31 December^d										
Developed		76	–	3,009	–	413	123	2,660	947	7,227
Undeveloped		12	–	3,881	–	358	–	1,368	498	6,117
		88	–	6,890	–	771	123	4,028	1,445	13,344
Equity-accounted entities (bp share)^e										
At 1 January										
Developed		–	49	–	4	1,053	536	43	–	1,686
Undeveloped		–	111	–	–	651	215	–	–	976
		–	160	–	4	1,704	751	43	–	2,662
Changes attributable to										
Revisions of previous estimates		–	17	–	–	(36)	48	(1)	–	27
Improved recovery		–	1	–	–	1	–	–	–	2
Purchases of reserves-in-place		–	–	–	–	–	–	–	–	–
Discoveries and extensions		–	2	–	–	141	2	–	–	145
Production ^c		–	(21)	–	–	(126)	(113)	(3)	–	(263)
Sales of reserves-in-place		–	(1)	–	–	–	–	–	–	(1)
		–	(2)	–	(1)	(20)	(64)	(4)	–	(90)
At 31 December										
Developed		–	51	–	4	1,000	516	39	–	1,610
Undeveloped		–	108	–	–	684	171	–	–	962
		–	158	–	4	1,684	687	39	–	2,572
Total subsidiaries and equity-accounted entities (bp share)										
At 1 January										
Developed		162	49	2,600	4	1,433	697	3,070	1,254	9,268
Undeveloped		29	111	2,412	–	1,001	215	1,320	431	5,518
		190	160	5,012	4	2,434	911	4,390	1,685	14,786
At 31 December										
Developed		76	51	3,009	4	1,413	639	2,699	947	8,837
Undeveloped		12	108	3,881	–	1,042	171	1,368	498	7,079
		88	158	6,890	4	2,455	810	4,067	1,445	15,916

a Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

b Because of rounding, some totals may not exactly agree with the sum of their component parts.

c Includes 114 billion cubic feet of natural gas consumed in operations, 71 billion cubic feet in subsidiaries, 43 billion cubic feet in equity-accounted entities.

d Includes 231 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

e Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

Movements in estimated net proved reserves – continued

		million barrels of oil equivalent ^c							2025	
Total hydrocarbons ^{a,b}		Europe	North America	South America	Africa	Asia	Australasia	Total		
		UK	Rest of Europe	US	Rest of North America					
Subsidiaries										
At 1 January										
Developed		134	–	1,303	–	67	29	1,237	226	2,997
Undeveloped		68	–	1,134	–	65	–	533	76	1,875
		202	–	2,437	–	131	29	1,770	302	4,871
Changes attributable to										
Revisions of previous estimates		(36)	–	454	–	48	15	105	10	597
Improved recovery		–	–	15	–	–	–	–	–	15
Purchases of reserves-in-place		–	–	101	–	–	–	–	–	101
Discoveries and extensions		–	–	2	–	29	12	22	–	66
Production ^{d,e}		(44)	–	(301)	–	(71)	(34)	(214)	(54)	(717)
Sales of reserves-in-place		(9)	–	(64)	–	–	–	–	–	(73)
		(89)	–	208	–	7	(6)	(87)	(43)	(10)
At 31 December^f										
Developed		70	–	1,321	–	73	23	1,150	170	2,806
Undeveloped		43	–	1,324	–	66	–	534	88	2,055
		113	–	2,645	–	138	23	1,683	258	4,861
Equity-accounted entities (bp share)^g										
At 1 January										
Developed		–	87	–	11	456	196	115	–	864
Undeveloped		–	66	–	–	330	114	3	–	513
		–	153	–	11	785	310	118	–	1,377
Changes attributable to										
Revisions of previous estimates		–	17	–	–	(45)	31	35	–	37
Improved recovery		–	2	–	–	3	–	–	–	5
Purchases of reserves-in-place		–	–	–	–	–	–	–	–	–
Discoveries and extensions		–	4	–	–	53	1	–	–	59
Production ^e		–	(25)	–	(1)	(41)	(50)	(29)	–	(146)
Sales of reserves-in-place		–	(1)	–	–	–	–	–	–	(1)
		–	(3)	–	(1)	(29)	(18)	6	–	(47)
At 31 December										
Developed		–	81	–	10	454	195	120	–	860
Undeveloped		–	68	–	–	302	96	4	–	470
		–	150	–	10	756	292	123	–	1,330
Total subsidiaries and equity-accounted entities (bp share)										
At 1 January										
Developed		134	87	1,303	11	522	225	1,352	226	3,860
Undeveloped		68	66	1,134	–	394	114	535	76	2,387
		202	153	2,437	11	917	339	1,888	302	6,248
At 31 December										
Developed		70	81	1,321	10	527	218	1,269	170	3,666
Undeveloped		43	68	1,324	–	367	96	537	88	2,525
		113	150	2,645	10	894	315	1,807	258	6,191

a Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

b Because of rounding, some totals may not exactly agree with the sum of their component parts.

c 5.8 billion cubic feet of natural gas = 1 million barrels of oil equivalent.

d Excludes NGLs from processing plants in which an interest is held of 2 thousand barrels per day for equity-accounted entities.

e Includes 20 million barrels of oil equivalent of natural gas consumed in operations, 12 million barrels of oil equivalent in subsidiaries, 7 million barrels of oil equivalent in equity-accounted entities.

f Includes 41 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

g Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

Movements in estimated net proved reserves – continued

Crude oil ^{a,b}	million barrels								2024
	Europe		North America		South America	Africa	Asia	Australasia	Total
	UK	Rest of Europe	US	Rest of North America					
Subsidiaries									
At 1 January									
Developed	129	–	713	–	3	5	729	11	1,590
Undeveloped	74	–	352	–	5	–	323	1	755
	203	–	1,065	–	7	6	1,052	12	2,345
Changes attributable to									
Revisions of previous estimates	(12)	–	54	–	2	5	77	1	128
Improved recovery	–	–	2	–	–	–	–	–	2
Purchases of reserves-in-place	1	–	–	–	–	1	–	–	2
Discoveries and extensions	–	–	143	–	–	–	–	–	143
Production	(25)	–	(138)	–	(2)	(7)	(109)	(3)	(284)
Sales of reserves-in-place	–	–	(1)	–	(3)	(4)	–	–	(7)
	(36)	–	61	–	(2)	(5)	(31)	(2)	(16)
At 31 December^c									
Developed	104	–	653	–	1	1	716	9	1,483
Undeveloped	63	–	472	–	4	–	305	1	846
	167	–	1,125	–	5	1	1,021	10	2,329
Equity-accounted entities (bp share)^d									
At 1 January									
Developed	–	89	–	11	275	99	115	–	588
Undeveloped	–	45	–	–	253	88	2	–	387
	–	133	–	11	528	187	117	–	976
Changes attributable to									
Revisions of previous estimates	–	4	–	–	(25)	10	19	–	8
Improved recovery	–	1	–	–	–	–	–	–	1
Purchases of reserves-in-place	–	–	–	–	–	5	–	–	5
Discoveries and extensions	–	–	–	–	18	–	–	–	18
Production	–	(21)	–	(1)	(20)	(30)	(25)	–	(97)
Sales of reserves-in-place	–	–	–	–	(14)	–	–	–	(15)
	–	(16)	–	(1)	(41)	(16)	(6)	–	(80)
At 31 December									
Developed	–	76	–	10	271	94	107	–	558
Undeveloped	–	42	–	–	217	77	3	–	339
	–	118	–	10	488	170	110	–	896
Total subsidiaries and equity-accounted entities (bp share)									
At 1 January									
Developed	129	89	713	11	278	104	844	11	2,179
Undeveloped	74	45	352	–	258	88	324	1	1,142
	203	133	1,065	11	536	192	1,168	12	3,321
At 31 December									
Developed	104	76	653	10	271	95	823	9	2,041
Undeveloped	63	42	472	–	221	77	308	1	1,184
	167	118	1,125	10	493	171	1,131	10	3,225

a Crude oil includes condensate and bitumen. Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

b Because of rounding, some totals may not exactly agree with the sum of their component parts.

c Includes 1.5 million barrels of crude oil in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

d Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

Movements in estimated net proved reserves – continued

	million barrels								2024
Natural gas liquids ^{a,b}	Europe		North America		South America	Africa	Asia	Australasia	Total
	UK	Rest of Europe	US	Rest of North America					
Subsidiaries									
At 1 January									
Developed	3	–	180	–	–	–	–	1	184
Undeveloped	–	–	217	–	–	–	–	–	217
	3	–	397	–	–	–	–	1	401
Changes attributable to									
Revisions of previous estimates	–	–	89	–	2	–	–	1	93
Improved recovery	–	–	–	–	–	–	–	–	–
Purchases of reserves-in-place	–	–	1	–	–	–	–	–	1
Discoveries and extensions	–	–	4	–	–	–	–	–	4
Production ^c	(1)	–	(39)	–	(2)	–	–	(1)	(43)
Sales of reserves-in-place	–	–	(4)	–	–	–	–	–	(4)
	(1)	–	51	–	–	–	–	–	51
At 31 December^d									
Developed	2	–	202	–	1	–	–	1	206
Undeveloped	–	–	246	–	–	–	–	–	246
	3	–	447	–	1	–	–	1	452
Equity-accounted entities (bp share)^e									
At 1 January									
Developed	–	3	–	–	3	14	–	–	19
Undeveloped	–	5	–	–	1	–	–	–	6
	–	8	–	–	4	14	–	–	25
Changes attributable to									
Revisions of previous estimates	–	1	–	–	–	(2)	–	–	(1)
Improved recovery	–	–	–	–	–	–	–	–	–
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	–	–	–	–	–
Production	–	(1)	–	–	–	(2)	–	–	(3)
Sales of reserves-in-place	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	(4)	–	–	(4)
At 31 December									
Developed	–	3	–	–	3	10	–	–	16
Undeveloped	–	5	–	–	–	–	–	–	6
	–	8	–	–	4	10	–	–	22
Total subsidiaries and equity-accounted entities (bp share)									
At 1 January									
Developed	3	3	180	–	3	14	–	1	204
Undeveloped	–	5	217	–	1	–	–	–	223
	3	8	397	–	4	14	–	1	427
At 31 December									
Developed	2	3	202	–	4	10	–	1	222
Undeveloped	–	5	246	–	–	–	–	–	252
	3	8	447	–	4	10	–	1	474

a Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

b Because of rounding, some totals may not exactly agree with the sum of their component parts.

c Excludes NGLs from processing plants in which an interest is held of 2 thousand barrels per day for equity-accounted entities.

d Includes 0.2 million barrels of NGL in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

e Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

Movements in estimated net proved reserves – continued

Total liquids ^{a,b}	million barrels								2024
	Europe		North America		South America	Africa	Asia	Australasia	Total
	UK	Rest of Europe	US	Rest of North America					
Subsidiaries									
At 1 January									
Developed	132	–	893	–	3	6	729	11	1,775
Undeveloped	75	–	568	–	5	–	323	1	971
	207	–	1,462	–	7	6	1,052	13	2,746
Changes attributable to									
Revisions of previous estimates	(11)	–	144	–	4	6	77	2	221
Improved recovery	–	–	2	–	–	–	–	–	2
Purchases of reserves-in-place	1	–	1	–	–	1	–	–	3
Discoveries and extensions	–	–	146	–	–	–	–	–	147
Production ^c	(27)	–	(177)	–	(3)	(7)	(109)	(4)	(326)
Sales of reserves-in-place	–	–	(5)	–	(3)	(4)	–	–	(11)
	(37)	–	111	–	(2)	(5)	(31)	(1)	35
At 31 December^d									
Developed	106	–	855	–	1	1	716	10	1,689
Undeveloped	63	–	718	–	4	–	305	1	1,092
	169	–	1,573	–	6	1	1,021	11	2,781
Equity-accounted entities (bp share)^e									
At 1 January									
Developed	–	92	–	11	278	113	115	–	608
Undeveloped	–	49	–	–	254	88	2	–	393
	–	141	–	11	532	200	117	–	1,001
Changes attributable to									
Revisions of previous estimates	–	5	–	–	(25)	8	19	–	8
Improved recovery	–	1	–	–	–	–	–	–	1
Purchases of reserves-in-place	–	–	–	–	–	5	–	–	5
Discoveries and extensions	–	–	–	–	18	–	–	–	18
Production	–	(22)	–	(1)	(20)	(32)	(25)	–	(100)
Sales of reserves-in-place	–	–	–	–	(14)	–	–	–	(15)
	–	(16)	–	(1)	(41)	(20)	(6)	–	(84)
At 31 December									
Developed	–	78	–	10	274	103	107	–	573
Undeveloped	–	47	–	–	217	77	3	–	344
	–	125	–	10	491	180	110	–	918
Total subsidiaries and equity-accounted entities (bp share)									
At 1 January									
Developed	132	92	893	11	281	118	844	11	2,382
Undeveloped	75	49	568	–	259	88	324	1	1,365
	207	141	1,462	11	540	206	1,168	13	3,747
At 31 December									
Developed	106	78	855	10	275	105	823	10	2,263
Undeveloped	63	47	718	–	222	77	308	1	1,436
	169	125	1,573	10	497	182	1,131	11	3,699

a Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

b Because of rounding, some totals may not exactly agree with the sum of their component parts.

c Excludes NGLs from processing plants in which an interest is held of 2 thousand barrels per day for equity-accounted entities.

d Also includes 1.7 million barrels in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

e Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

Movements in estimated net proved reserves – continued

Natural gas ^{a,b}	billion cubic feet							2024	
	Europe		North America		South America	Africa	Asia	Australasia	Total
	UK	Rest of Europe	US	Rest of North America					
Subsidiaries									
At 1 January									
Developed	221	–	2,672	–	931	518	3,051	1,550	8,942
Undeveloped	34	–	3,229	–	503	207	1,672	358	6,003
	255	–	5,901	–	1,434	724	4,722	1,907	14,944
Changes attributable to									
Revisions of previous estimates	12	–	(241)	–	(174)	133	237	(40)	(73)
Improved recovery	–	–	1	–	–	–	–	–	1
Purchases of reserves-in-place	3	–	34	–	–	46	–	–	83
Discoveries and extensions	–	–	32	–	8	–	11	142	193
Production ^c	(80)	–	(639)	–	(423)	(340)	(625)	(325)	(2,432)
Sales of reserves-in-place	–	–	(76)	–	(115)	(402)	–	–	(594)
	(65)	–	(889)	–	(704)	(564)	(376)	(222)	(2,821)
At 31 December^d									
Developed	162	–	2,600	–	379	161	3,026	1,254	7,582
Undeveloped	29	–	2,412	–	350	–	1,320	431	4,542
	190	–	5,012	–	730	161	4,346	1,685	12,124
Equity-accounted entities (bp share)^e									
At 1 January									
Developed	–	67	–	4	1,027	463	46	–	1,608
Undeveloped	–	110	–	–	621	188	–	–	919
	–	177	–	4	1,648	651	46	–	2,527
Changes attributable to									
Revisions of previous estimates	–	1	–	–	(32)	(59)	–	–	(89)
Improved recovery	–	2	–	–	–	–	–	–	2
Purchases of reserves-in-place	–	–	–	–	–	205	–	–	205
Discoveries and extensions	–	–	–	–	221	–	–	–	221
Production ^c	–	(20)	–	–	(129)	(46)	(2)	–	(199)
Sales of reserves-in-place	–	–	–	–	(4)	–	–	–	(5)
	–	(18)	–	–	56	100	(2)	–	135
At 31 December									
Developed	–	49	–	4	1,053	536	43	–	1,686
Undeveloped	–	111	–	–	651	215	–	–	976
	–	160	–	4	1,704	751	43	–	2,662
Total subsidiaries and equity-accounted entities (bp share)									
At 1 January									
Developed	221	67	2,672	4	1,958	981	3,096	1,550	10,549
Undeveloped	34	110	3,229	–	1,125	394	1,672	358	6,922
	255	177	5,901	4	3,082	1,375	4,768	1,907	17,471
At 31 December									
Developed	162	49	2,600	4	1,433	697	3,070	1,254	9,268
Undeveloped	29	111	2,412	–	1,001	215	1,320	431	5,518
	190	160	5,012	4	2,434	911	4,390	1,685	14,786

a Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

b Because of rounding, some totals may not exactly agree with the sum of their component parts.

c Includes 100 billion cubic feet of natural gas consumed in operations, 62 billion cubic feet in subsidiaries, 38 billion cubic feet in equity-accounted entities.

d Includes 219 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

e Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

Movements in estimated net proved reserves – continued

Total hydrocarbons ^{a,b}	million barrels of oil equivalent ^c							2024	
	Europe		North America		South America	Africa	Asia	Australasia	Total
	UK	Rest of Europe	US	Rest of North America					
Subsidiaries									
At 1 January									
Developed	170	–	1,354	–	163	95	1,255	279	3,316
Undeveloped	81	–	1,125	–	91	36	611	63	2,006
	251	–	2,479	–	255	131	1,866	341	5,323
Changes attributable to									
Revisions of previous estimates	(9)	–	102	–	(26)	28	118	(5)	208
Improved recovery	–	–	2	–	–	–	–	–	2
Purchases of reserves-in-place	1	–	7	–	–	9	–	–	17
Discoveries and extensions	–	–	152	–	1	–	2	25	180
Production ^{d,e}	(41)	–	(287)	–	(76)	(66)	(216)	(60)	(746)
Sales of reserves-in-place	–	–	(18)	–	(22)	(73)	–	–	(113)
	(49)	–	(42)	–	(123)	(102)	(96)	(40)	(451)
At 31 December^f									
Developed	134	–	1,303	–	67	29	1,237	226	2,997
Undeveloped	68	–	1,134	–	65	–	533	76	1,875
	202	–	2,437	–	131	29	1,770	302	4,871
Equity-accounted entities (bp share)^g									
At 1 January									
Developed	–	103	–	12	455	192	123	–	885
Undeveloped	–	68	–	–	361	120	2	–	552
	–	172	–	12	816	313	124	–	1,437
Changes attributable to									
Revisions of previous estimates	–	5	–	–	(30)	(2)	19	–	(8)
Improved recovery	–	1	–	–	–	–	–	–	1
Purchases of reserves-in-place	–	–	–	–	–	40	–	–	40
Discoveries and extensions	–	–	–	–	56	–	–	–	56
Production ^e	–	(26)	–	(1)	(42)	(40)	(26)	–	(135)
Sales of reserves-in-place	–	–	–	–	(15)	–	–	–	(16)
	–	(19)	–	(1)	(31)	(3)	(7)	–	(60)
At 31 December									
Developed	–	87	–	11	456	196	115	–	864
Undeveloped	–	66	–	–	330	114	3	–	513
	–	153	–	11	785	310	118	–	1,377
Total subsidiaries and equity-accounted entities (bp share)									
At 1 January									
Developed	170	103	1,354	12	618	287	1,378	279	4,201
Undeveloped	81	68	1,125	–	453	156	613	63	2,558
	251	172	2,479	12	1,071	444	1,991	341	6,759
At 31 December									
Developed	134	87	1,303	11	522	225	1,352	226	3,860
Undeveloped	68	66	1,134	–	394	114	535	76	2,387
	202	153	2,437	11	917	339	1,888	302	6,248

a Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

b Because of rounding, some totals may not exactly agree with the sum of their component parts.

c 5.8 billion cubic feet of natural gas = 1 million barrels of oil equivalent.

d Excludes NGLs from processing plants in which an interest is held of 2 thousand barrels per day for equity-accounted entities.

e Includes 17 million barrels of oil equivalent of natural gas consumed in operations, 11 million barrels of oil equivalent in subsidiaries, 6 million barrels of oil equivalent in equity-accounted entities.

f Includes 41 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

g Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

Movements in estimated net proved reserves – continued

Crude oil ^{a,b}	million barrels							Total	
	Europe		North America	South America	Africa	Asia	Australasia		
	UK	Rest of Europe	US	Rest of North America					
Subsidiaries									
At 1 January									
Developed	153	–	679	–	4	24	717	20	1,596
Undeveloped	109	–	527	–	5	2	356	1	1,000
	261	–	1,206	–	9	26	1,073	21	2,596
Changes attributable to									
Revisions of previous estimates	(32)	–	(60)	–	(1)	(3)	85	(6)	(15)
Improved recovery	–	–	14	–	–	–	–	–	14
Purchases of reserves-in-place	–	–	14	–	–	–	–	–	14
Discoveries and extensions	–	–	17	–	–	–	1	–	18
Production	(27)	–	(123)	–	(1)	(11)	(107)	(4)	(274)
Sales of reserves-in-place	–	–	(1)	–	–	(6)	–	–	(7)
	(58)	–	(141)	–	(2)	(20)	(21)	(9)	(252)
At 31 December^c									
Developed	129	–	713	–	3	5	729	11	1,590
Undeveloped	74	–	352	–	5	–	323	1	755
	203	–	1,065	–	7	6	1,052	12	2,345
Equity-accounted entities (bp share)^d									
At 1 January									
Developed	–	90	–	5	276	127	95	–	592
Undeveloped	–	16	–	7	244	74	1	–	342
	–	106	–	12	520	201	96	–	935
Changes attributable to									
Revisions of previous estimates	–	6	–	–	7	15	43	–	71
Improved recovery	–	21	–	–	4	–	–	–	24
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	22	–	–	19	–	–	–	41
Production	–	(22)	–	(1)	(20)	(30)	(23)	–	(95)
Sales of reserves-in-place	–	–	–	–	–	–	–	–	–
	–	27	–	(1)	9	(14)	20	–	41
At 31 December									
Developed	–	89	–	11	275	99	115	–	588
Undeveloped	–	45	–	–	253	88	2	–	387
	–	133	–	11	528	187	117	–	976
Total subsidiaries and equity-accounted entities (bp share)									
At 1 January									
Developed	153	90	679	5	279	151	812	20	2,188
Undeveloped	109	16	527	7	249	76	358	1	1,343
	261	106	1,206	12	529	227	1,169	21	3,531
At 31 December									
Developed	129	89	713	11	278	104	844	11	2,179
Undeveloped	74	45	352	–	258	88	324	1	1,142
	203	133	1,065	11	536	192	1,168	12	3,321

a Crude oil includes condensate and bitumen. Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

b Because of rounding, some totals may not exactly agree with the sum of their component parts.

c Includes 2.2 million barrels of crude oil in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

d Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

Movements in estimated net proved reserves – continued

Natural gas liquids ^{a,b}									million barrels
									2023
	Europe		North America		South America	Africa	Asia	Australasia	Total
	UK	Rest of Europe	US	Rest of North America					
Subsidiaries									
At 1 January									
Developed	6	–	181	–	1	6	–	1	196
Undeveloped	–	–	236	–	–	1	–	–	237
	6	–	417	–	1	7	–	1	432
Changes attributable to									
Revisions of previous estimates	(1)	–	(14)	–	–	–	–	1	(14)
Improved recovery	–	–	15	–	–	–	–	–	16
Purchases of reserves-in-place	–	–	12	–	–	–	–	–	12
Discoveries and extensions	–	–	–	–	–	–	–	–	–
Production ^c	(2)	–	(31)	–	(1)	(1)	–	(1)	(35)
Sales of reserves-in-place	–	–	(3)	–	–	(6)	–	–	(9)
	(3)	–	(20)	–	(1)	(7)	–	–	(31)
At 31 December^d									
Developed	3	–	180	–	–	–	–	1	184
Undeveloped	–	–	217	–	–	–	–	–	217
	3	–	397	–	–	–	–	1	401
Equity-accounted entities (bp share)^e									
At 1 January									
Developed	–	4	–	–	3	17	–	–	23
Undeveloped	–	–	–	–	1	9	–	–	10
	–	4	–	–	4	26	–	–	34
Changes attributable to									
Revisions of previous estimates	–	–	–	–	1	(11)	–	–	(10)
Improved recovery	–	1	–	–	–	–	–	–	1
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	4	–	–	–	–	–	–	4
Production	–	(1)	–	–	–	(1)	–	–	(3)
Sales of reserves-in-place	–	–	–	–	–	–	–	–	–
	–	4	–	–	–	(12)	–	–	(8)
At 31 December									
Developed	–	3	–	–	3	14	–	–	19
Undeveloped	–	5	–	–	1	–	–	–	6
	–	8	–	–	4	14	–	–	25
Total subsidiaries and equity-accounted entities (bp share)									
At 1 January									
Developed	6	4	181	–	4	23	–	1	219
Undeveloped	–	–	236	–	1	10	–	–	247
	6	4	417	–	5	33	–	1	466
At 31 December									
Developed	3	3	180	–	3	14	–	1	204
Undeveloped	–	5	217	–	1	–	–	–	223
	3	8	397	–	4	14	–	1	427

a Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

b Because of rounding, some totals may not exactly agree with the sum of their component parts.

c Excludes NGLs from processing plants in which an interest is held of 2 thousand barrels per day for equity-accounted entities.

d Includes 0 million barrels of NGL in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

e Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

Movements in estimated net proved reserves – continued

Total liquids ^{a,b}	million barrels							2023	
	Europe		North America		South America	Africa	Asia	Australasia	Total
	UK	Rest of Europe	US	Rest of North America					
Subsidiaries									
At 1 January									
Developed	159	–	860	–	5	30	717	20	1,791
Undeveloped	109	–	763	–	5	3	356	1	1,237
	267	–	1,623	–	11	33	1,073	22	3,029
Changes attributable to									
Revisions of previous estimates	(33)	–	(74)	–	(1)	(3)	85	(5)	(30)
Improved recovery	–	–	29	–	–	–	–	–	29
Purchases of reserves-in-place	–	–	25	–	–	–	–	–	25
Discoveries and extensions	–	–	17	–	–	–	1	–	18
Production ^c	(29)	–	(154)	–	(3)	(12)	(107)	(4)	(309)
Sales of reserves-in-place	–	–	(4)	–	–	(12)	–	–	(17)
	(61)	–	(161)	–	(3)	(27)	(21)	(9)	(283)
At 31 December^d									
Developed	132	–	893	–	3	6	729	11	1,775
Undeveloped	75	–	568	–	5	–	323	1	971
	207	–	1,462	–	7	6	1,052	13	2,746
Equity-accounted entities (bp share)^e									
At 1 January									
Developed	–	94	–	5	278	144	95	–	616
Undeveloped	–	16	–	7	245	83	1	–	352
	–	110	–	12	523	227	96	–	968
Changes attributable to									
Revisions of previous estimates	–	6	–	–	7	4	43	–	61
Improved recovery	–	22	–	–	4	–	–	–	26
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	26	–	–	19	–	–	–	45
Production	–	(23)	–	(1)	(20)	(31)	(23)	–	(98)
Sales of reserves-in-place	–	–	–	–	–	–	–	–	–
	–	31	–	(1)	9	(27)	20	–	33
At 31 December									
Developed	–	92	–	11	278	113	115	–	608
Undeveloped	–	49	–	–	254	88	2	–	393
	–	141	–	11	532	200	117	–	1,001
Total subsidiaries and equity-accounted entities (bp share)									
At 1 January									
Developed	159	94	860	5	283	174	812	20	2,407
Undeveloped	109	16	763	7	250	86	358	1	1,590
	267	110	1,623	12	534	260	1,169	22	3,997
At 31 December									
Developed	132	92	893	11	281	118	844	11	2,382
Undeveloped	75	49	568	–	259	88	324	1	1,365
	207	141	1,462	11	540	206	1,168	13	3,747

a Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

b Because of rounding, some totals may not exactly agree with the sum of their component parts.

c Excludes NGLs from processing plants in which an interest is held of 2 thousand barrels per day for equity-accounted entities.

d Also includes 2.2 million barrels in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

e Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

Movements in estimated net proved reserves – continued

Natural gas ^{a,b}								billion cubic feet	
	Europe		North America		South America	Africa	Asia	Australasia	Total
	UK	Rest of Europe	US	Rest of North America					2023
Subsidiaries									
At 1 January									
Developed	360	–	2,655	–	1,077	1,021	2,594	1,684	9,392
Undeveloped	41	–	3,154	–	748	221	2,125	407	6,696
	401	–	5,809	–	1,825	1,242	4,719	2,091	16,087
Changes attributable to									
Revisions of previous estimates	(54)	–	212	–	34	42	563	100	897
Improved recovery	9	–	254	–	–	–	–	–	263
Purchases of reserves-in-place	–	–	206	–	–	–	–	–	206
Discoveries and extensions	–	–	5	–	14	–	34	–	53
Production ^c	(100)	–	(560)	–	(439)	(462)	(594)	(284)	(2,439)
Sales of reserves-in-place	–	–	(25)	–	–	(97)	–	–	(123)
	(146)	–	92	–	(391)	(518)	3	(184)	(1,143)
At 31 December^d									
Developed	221	–	2,672	–	931	518	3,051	1,550	8,942
Undeveloped	34	–	3,229	–	503	207	1,672	358	6,003
	255	–	5,901	–	1,434	724	4,722	1,907	14,944
Equity-accounted entities (bp share)^e									
At 1 January									
Developed	–	72	–	3	974	534	43	–	1,627
Undeveloped	–	5	–	2	606	154	–	–	767
	–	77	–	5	1,580	689	43	–	2,394
Changes attributable to									
Revisions of previous estimates	–	12	–	–	8	4	5	–	29
Improved recovery	–	25	–	–	22	–	–	–	47
Purchases of reserves-in-place	–	–	–	–	132	–	–	–	132
Discoveries and extensions	–	85	–	–	118	–	–	–	203
Production ^c	–	(22)	–	–	(128)	(41)	(2)	–	(194)
Sales of reserves-in-place	–	–	–	–	(84)	–	–	–	(84)
	–	101	–	(1)	68	(38)	3	–	133
At 31 December									
Developed	–	67	–	4	1,027	463	46	–	1,608
Undeveloped	–	110	–	–	621	188	–	–	919
	–	177	–	4	1,648	651	46	–	2,527
Total subsidiaries and equity-accounted entities (bp share)									
At 1 January									
Developed	360	72	2,655	3	2,051	1,556	2,637	1,684	11,018
Undeveloped	41	5	3,154	2	1,355	375	2,125	407	7,463
	401	77	5,809	5	3,405	1,931	4,762	2,091	18,481
At 31 December									
Developed	221	67	2,672	4	1,958	981	3,096	1,550	10,549
Undeveloped	34	110	3,229	–	1,125	394	1,672	358	6,922
	255	177	5,901	4	3,082	1,375	4,768	1,907	17,471

a Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

b Because of rounding, some totals may not exactly agree with the sum of their component parts.

c Includes 99 billion cubic feet of natural gas consumed in operations, 62 billion cubic feet in subsidiaries, 36 billion cubic feet in equity-accounted entities.

d Includes 430 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

e Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

Movements in estimated net proved reserves – continued

Total hydrocarbons ^{a,b}	million barrels of oil equivalent ^c							2023	
	Europe		North America	South America	Africa	Asia	Australasia	Total	
	UK	Rest of Europe	US	Rest of North America					
Subsidiaries									
At 1 January									
Developed	221	–	1,318	–	191	206	1,164	311	3,411
Undeveloped	116	–	1,306	–	134	41	723	72	2,392
	337	–	2,624	–	325	247	1,887	382	5,802
Changes attributable to									
Revisions of previous estimates	(42)	–	(37)	–	5	5	182	12	125
Improved recovery	2	–	73	–	–	–	–	–	75
Purchases of reserves-in-place	–	–	61	–	–	–	–	–	61
Discoveries and extensions	–	–	18	–	2	–	7	–	27
Production ^{d,e}	(46)	–	(251)	–	(78)	(92)	(210)	(53)	(730)
Sales of reserves-in-place	–	–	(9)	–	–	(29)	–	–	(38)
	(86)	–	(145)	–	(71)	(116)	(21)	(41)	(480)
At 31 December^f									
Developed	170	–	1,354	–	163	95	1,255	279	3,316
Undeveloped	81	–	1,125	–	91	36	611	63	2,006
	251	–	2,479	–	255	131	1,866	341	5,323
Equity-accounted entities (bp share)^g									
At 1 January									
Developed	–	106	–	6	446	236	102	–	896
Undeveloped	–	17	–	7	349	110	1	–	485
	–	123	–	13	796	346	103	–	1,381
Changes attributable to									
Revisions of previous estimates	–	8	–	–	9	5	44	–	66
Improved recovery	–	26	–	–	7	–	–	–	34
Purchases of reserves-in-place	–	–	–	–	–	23	–	–	23
Discoveries and extensions	–	41	–	–	39	–	–	–	80
Production ^e	–	(27)	–	(1)	(42)	(38)	(23)	–	(131)
Sales of reserves-in-place	–	–	–	–	(15)	–	–	–	(15)
	–	48	–	(1)	(2)	(11)	21	–	56
At 31 December									
Developed	–	103	–	12	455	192	123	–	885
Undeveloped	–	68	–	–	361	120	2	–	552
	–	172	–	12	816	313	124	–	1,437
Total subsidiaries and equity-accounted entities (bp share)									
At 1 January									
Developed	221	106	1,318	6	637	442	1,266	311	4,307
Undeveloped	116	17	1,306	7	484	151	724	72	2,877
	337	123	2,624	13	1,121	593	1,990	382	7,183
At 31 December									
Developed	170	103	1,354	12	618	287	1,378	279	4,201
Undeveloped	81	68	1,125	–	453	156	613	63	2,558
	251	172	2,479	12	1,071	444	1,991	341	6,759

a Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

b Because of rounding, some totals may not exactly agree with the sum of their component parts.

c 5.8 billion cubic feet of natural gas = 1 million barrels of oil equivalent.

d Excludes NGLs from processing plants in which an interest is held of 2 thousand barrels per day for equity-accounted entities.

e Includes 17 million barrels of oil equivalent of natural gas consumed in operations, 11 million barrels of oil equivalent in subsidiaries, 6 million barrels of oil equivalent in equity-accounted entities.

f Includes 41 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

g Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

Standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves

The following tables set out the standardized measure of discounted future net cash flows, and changes therein, relating to crude oil and natural gas production from the group's estimated proved reserves. This information is prepared in compliance with FASB Oil and Gas Disclosures requirements.

Future net cash flows have been prepared on the basis of certain assumptions which may or may not be realized. These include the timing of future production, the estimation of crude oil and natural gas reserves and the application of average crude oil and natural gas prices and exchange rates from the previous 12 months. Furthermore, both proved reserves estimates and production forecasts are subject to revision as further technical information becomes available and economic conditions change. bp cautions against relying on the information presented because of the highly arbitrary nature of the assumptions on which it is based and its lack of comparability with the historical cost information presented in the financial statements.

								\$ million	
								2025	
	Europe		North America		South America	Africa	Asia	Australasia	Total
	UK	Rest of Europe	US	Rest of North America					
At 31 December									
Subsidiaries									
Future cash inflows ^a	7,600	–	93,300	–	5,000	600	93,300	11,500	211,300
Future production cost ^b	8,500	–	39,300	–	3,300	200	34,500	3,600	89,400
Future development cost ^b	800	–	15,300	–	1,200	100	13,500	1,600	32,500
Future taxation ^c	(100)	–	6,000	–	100	–	33,100	1,600	40,700
Future net cash flows	(1,600)	–	32,700	–	400	300	12,200	4,700	48,700
10% annual discount ^d	(700)	–	12,900	–	(500)	–	4,300	1,600	17,600
Standardized measure of discounted future net cash flows ^e	(900)	–	19,800	–	900	300	7,900	3,100	31,100
Equity-accounted entities (bp share)^f									
Future cash inflows ^a	–	10,100	–	–	36,800	12,300	8,100	–	67,300
Future production cost ^b	–	4,300	–	–	18,500	4,800	4,100	–	31,700
Future development cost ^b	–	1,300	–	–	3,900	1,000	2,800	–	9,000
Future taxation ^c	–	3,500	–	–	3,700	1,800	400	–	9,400
Future net cash flows	–	1,000	–	–	10,700	4,700	800	–	17,200
10% annual discount ^d	–	100	–	–	6,300	1,100	200	–	7,700
Standardized measure of discounted future net cash flows	–	900	–	–	4,400	3,600	600	–	9,500
Total subsidiaries and equity-accounted entities									
Standardized measure of discounted future net cash flows	(900)	900	19,800	–	5,300	3,900	8,500	3,100	40,600

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

	\$ million		
	Subsidiaries	Equity-accounted entities (bp share)	Total subsidiaries and equity-accounted entities
Sales and transfers of oil and gas produced, net of production costs	(21,400)	(5,400)	(26,800)
Development costs for the current year as estimated in previous year	6,000	3,200	9,200
Extensions, discoveries and improved recovery, less related costs	1,000	800	1,800
Net changes in prices and production cost	(11,100)	(3,100)	(14,200)
Revisions of previous reserves estimates	4,200	600	4,800
Net change in taxation	11,300	1,700	13,000
Future development costs	(1,100)	100	(1,000)
Net change in purchase and sales of reserves-in-place	–	(100)	(100)
Addition of 10% annual discount	3,800	1,100	4,900
Total change in the standardized measure during the year^g	(7,300)	(1,100)	(8,400)

a The marker prices used were Brent \$69.5/bbl, Henry Hub \$3.4/mmBtu.

b Production costs, which include production taxes and also fixed commitment costs associated with probable/contingent volumes, and development costs relating to future production of proved reserves are based on the continuation of existing economic conditions. Future decommissioning costs are included.

c Taxation is computed with reference to appropriate year-end statutory corporate income tax rates.

d Future net cash flows from oil and natural gas production are discounted at 10% regardless of the group assessment of the risk associated with its producing activities.

e Non-controlling interests in BP Trinidad and Tobago LLC amounted to \$271 million.

f The standardized measure of discounted future net cash flows of equity-accounted entities includes standardized measure of discounted future net cash flows of equity-accounted investments of those entities.

g Total change in the standardized measure during the year includes the effect of exchange rate movements.

Standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves – continued

								\$ million	
								2024	
	Europe		North America		South America	Africa	Asia	Australasia	Total
	UK	Rest of Europe	US	Rest of North America					
At 31 December									
Subsidiaries									
Future cash inflows ^a	15,100	–	99,300	–	3,700	600	107,300	15,200	241,200
Future production cost ^b	11,800	–	39,100	–	2,900	100	37,800	3,900	95,600
Future development cost ^b	1,000	–	15,300	–	500	100	11,200	2,100	30,200
Future taxation ^c	2,200	–	7,100	–	100	100	42,800	2,400	54,700
Future net cash flows	100	–	37,800	–	200	300	15,500	6,800	60,700
10% annual discount ^d	100	–	15,400	–	(300)	–	4,900	2,200	22,300
Standardized measure of discounted future net cash flows ^e	–	–	22,400	–	500	300	10,600	4,600	38,400
Equity-accounted entities (bp share)^f									
Future cash inflows ^a	–	11,700	–	–	4,160	15,100	8,400	–	76,800
Future production cost ^b	–	4,100	–	–	20,900	5,400	4,200	–	34,600
Future development cost ^b	–	2,000	–	–	4,100	2,200	2,900	–	11,200
Future taxation ^c	–	4,300	–	–	4,600	2,200	400	–	11,500
Future net cash flows	–	1,300	–	–	12,000	5,300	900	–	19,500
10% annual discount ^d	–	300	–	–	7,000	1,400	200	–	8,900
Standardized measure of discounted future net cash flows	–	1,000	–	–	5,000	3,900	700	–	10,600
Total subsidiaries and equity-accounted entities									
Standardized measure of discounted future net cash flows	–	1,000	22,400	–	5,500	4,200	11,300	4,600	49,000

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

	\$ million		
	Subsidiaries	Equity-accounted entities (bp share)	Total subsidiaries and equity-accounted entities
Sales and transfers of oil and gas produced, net of production costs	(25,700)	(5,300)	(31,000)
Development costs for the current year as estimated in previous year	5,100	2,900	8,000
Extensions, discoveries and improved recovery, less related costs	400	300	700
Net changes in prices and production cost	(7,300)	(1,800)	(9,100)
Revisions of previous reserves estimates	2,500	300	2,800
Net change in taxation	11,200	2,100	13,300
Future development costs	(1,400)	(600)	(2,000)
Net change in purchase and sales of reserves-in-place	(1,400)	800	(600)
Addition of 10% annual discount	5,000	1,100	6,100
Total change in the standardized measure during the year^g	(11,600)	(200)	(11,800)

a The marker prices used were Brent \$81.17/bbl, Henry Hub \$2.07/mmBtu.

b Production costs, which include production taxes, and development costs relating to future production of proved reserves are based on the continuation of existing economic conditions. Future decommissioning costs are included.

c Taxation is computed with reference to appropriate year-end statutory corporate income tax rates.

d Future net cash flows from oil and natural gas production are discounted at 10% regardless of the group assessment of the risk associated with its producing activities.

e Non-controlling interests in BP Trinidad and Tobago LLC amounted to \$164 million.

f The standardized measure of discounted future net cash flows of equity-accounted entities includes standardized measure of discounted future net cash flows of equity-accounted investments of those entities.

g Total change in the standardized measure during the year includes the effect of exchange rate movements.

Standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves – continued

								\$ million	
								2023	
	Europe		North America		South America	Africa	Asia	Australasia	Total
	UK	Rest of Europe	US	Rest of North America					
At 31 December									
Subsidiaries									
Future cash inflows ^a	19,400	–	100,200	–	6,800	4,400	118,300	18,000	267,100
Future production cost ^b	11,900	–	37,500	–	4,300	600	39,600	4,500	98,400
Future development cost ^b	1,200	–	12,100	–	1,000	500	8,500	1,400	24,700
Future taxation ^c	4,100	–	8,400	–	500	1,100	49,900	3,800	67,800
Future net cash flows	2,200	–	42,200	–	1,000	2,200	20,300	8,300	76,200
10% annual discount ^d	900	–	16,300	–	(300)	400	6,300	2,600	26,200
Standardized measure of discounted future net cash flows ^e	1,300	–	25,900	–	1,300	1,800	14,000	5,700	50,000
Equity-accounted entities (bp share)^f									
Future cash inflows ^a	–	13,700	–	–	44,600	15,200	9,000	–	82,500
Future production cost ^b	–	3,700	–	–	20,700	5,500	4,700	–	34,600
Future development cost ^b	–	2,100	–	–	5,200	2,300	3,100	–	12,700
Future taxation ^c	–	6,000	–	–	5,900	2,100	400	–	14,400
Future net cash flows	–	1,900	–	–	12,800	5,300	800	–	20,800
10% annual discount ^d	–	500	–	–	7,600	1,700	200	–	10,000
Standardized measure of discounted future net cash flows	–	1,400	–	–	5,200	3,600	600	–	10,800
Total subsidiaries and equity-accounted entities									
Standardized measure of discounted future net cash flows	1,300	1,400	25,900	–	6,500	5,400	14,600	5,700	60,800

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

	\$ million		
	Subsidiaries	Equity-accounted entities (bp share)	Total subsidiaries and equity-accounted entities
Sales and transfers of oil and gas produced, net of production costs	(36,500)	(6,500)	(43,000)
Development costs for the current year as estimated in previous year	6,000	2,200	8,200
Extensions, discoveries and improved recovery, less related costs	500	800	1,300
Net changes in prices and production cost	(50,800)	(7,100)	(57,900)
Revisions of previous reserves estimates	2,500	1,300	3,800
Net change in taxation	30,000	5,100	35,100
Future development costs	(1,000)	(300)	(1,300)
Net change in purchase and sales of reserves-in-place	(800)	–	(800)
Addition of 10% annual discount	9,100	1,400	10,500
Total change in the standardized measure during the year^g	(41,000)	(3,100)	(44,100)

a The marker prices used were Brent \$83.27/bbl, Henry Hub \$2.58/mmBtu.

b Production costs, which include production taxes, and development costs relating to future production of proved reserves are based on the continuation of existing economic conditions. Future decommissioning costs are included.

c Taxation is computed with reference to appropriate year-end statutory corporate income tax rates.

d Future net cash flows from oil and natural gas production are discounted at 10% regardless of the group assessment of the risk associated with its producing activities.

e Non-controlling interests in BP Trinidad and Tobago LLC amounted to \$392 million.

f The standardized measure of discounted future net cash flows of equity-accounted entities includes standardized measure of discounted future net cash flows of equity-accounted investments of those entities.

g Total change in the standardized measure during the year includes the effect of exchange rate movements.

Operational and statistical information

The following tables present operational and statistical information related to production, drilling, productive wells and acreage. Figures include amounts attributable to assets held for sale.

Crude oil and natural gas production

The following table shows crude oil, natural gas liquids and natural gas production for the years ended 31 December 2025, 2024 and 2023.

Production for the year^{a b}

	Europe		North America	South America	Africa	Asia	Australasia	Total	
	UK	Rest of Europe	US	Rest of North America					
Subsidiaries^c									
Crude oil ^d	thousand barrels per day								
2025	78	–	399	–	5	8	302	8	800
2024	70	–	376	–	4	19	297	9	775
2023	74	–	335	–	4	29	293	10	745
Natural gas liquids	thousand barrels per day								
2025	4	–	111	–	6	–	–	1	123
2024	4	–	107	–	4	1	–	2	117
2023	5	–	88	–	4	2	–	2	100
Natural gas ^e	million cubic feet per day								
2025	203	–	1,751	–	1,045	453	1,597	799	5,847
2024	197	–	1,690	–	1,145	904	1,655	882	6,474
2023	247	–	1,486	–	1,191	1,236	1,578	774	6,512
Equity-accounted entities (bp share)									
Crude oil ^d	thousand barrels per day								
2025	–	55	–	–	56	78	79	–	268
2024	–	58	–	–	56	82	69	–	266
2023	–	60	–	–	57	82	62	–	261
Natural gas liquids	thousand barrels per day								
2025	–	2	–	–	1	5	–	–	8
2024	–	2	–	–	1	6	–	–	9
2023	–	3	–	–	1	6	–	–	9
Natural gas ^e	million cubic feet per day								
2025	–	54	–	–	284	264	–	–	603
2024	–	55	–	–	300	85	–	–	440
2023	–	58	–	–	299	74	–	–	432

a Production excludes royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

b Because of rounding, some totals may not exactly agree with the sum of their component parts.

c All of the oil and liquid production from Canada is bitumen.

d Crude oil includes condensate.

e Natural gas production excludes gas consumed in operations.

Operational and statistical information – continued

Productive oil and gas wells and acreage

The following tables show the number of gross and net productive oil and natural gas wells and total gross and net developed and undeveloped oil and natural gas acreage in which the group and its equity-accounted entities had interests as at 31 December 2025. A 'gross' well or acre is one in which a whole or fractional working interest is owned, while the number of 'net' wells or acres is the sum of the whole or fractional working interests in gross wells or acres. Productive wells are producing wells and wells capable of production. Developed acreage is the acreage within the boundary of a field, on which development wells have been drilled, which could produce the reserves; while undeveloped acres are those on which wells have not been drilled or completed to a point that would permit the production of commercial quantities, whether or not such acres contain proved reserves.

	Europe		North America	South America	Africa	Asia	Australasia	Total ^a	
	UK	Rest of Europe	US	Rest of North America					
Number of productive wells at 31 December 2025									
Oil wells ^b									
– gross	120	126	973	8	4,927	807	3,004	–	9,965
– net	69	20	631	2	2,417	77	667	–	3,883
Gas wells ^c									
– gross	31	9	3,819	–	1,233	92	197	91	5,472
– net	7	1	2,163	–	402	41	74	22	2,710
Oil and natural gas acreage at 31 December 2025									
									thousands of acres
Developed									
– gross	72	83	1,504	8	1,242	626	1,355	838	5,727
– net	44	13	972	2	370	125	286	157	1,969
Undeveloped ^d									
– gross	434	2,257	3,771	9,237	9,950	21,019	10,641	7,998	65,308
– net	339	358	3,253	6,193	4,801	8,408	5,805	3,364	32,521

a Because of rounding, some totals may not exactly agree with the sum of their component parts.

b Includes approximately 169 gross (32 net) multiple completion wells (more than one formation producing into the same well bore).

c Includes approximately 11 gross (5 net) multiple completion wells. If one of the multiple completions in a well is an oil completion, the well is classified as an oil well.

d Undeveloped acreage includes leases and concessions.

Net oil and gas wells completed or abandoned

The following table shows the number of net productive and dry exploratory and development oil and natural gas wells completed or abandoned in the years indicated by the group and its equity-accounted entities. Productive wells include wells in which hydrocarbons were encountered and the drilling or completion of which, in the case of exploratory wells, has been suspended pending further drilling or evaluation. A dry well is one found to be incapable of producing hydrocarbons in sufficient quantities to justify completion.

	Europe		North America	South America	Africa	Asia	Australasia	Total ^a	
	UK	Rest of Europe	US	Rest of North America					
2025									
Exploratory									
Productive	–	0.3	0.6	–	2.9	2.7	0.4	–	6.9
Dry	–	0.6	0.3	–	1.0	–	0.6	–	2.6
Development									
Productive	4.4	0.3	172.2	–	68.5	6.1	51.4	0.2	303.0
Dry	–	–	4.9	–	0.6	0.4	1.2	–	7.1
2024									
Exploratory									
Productive	–	–	0.7	–	0.5	0.4	0.7	–	2.3
Dry	–	–	1.0	0.8	0.5	–	0.5	–	2.8
Development									
Productive	1.5	0.5	149.0	–	69.3	2.5	55.1	–	277.8
Dry	–	–	15.0	–	–	1.1	0.5	–	16.6
2023									
Exploratory									
Productive	–	–	2.0	–	–	–	0.8	0.4	3.2
Dry	0.5	–	0.8	0.5	–	–	0.2	–	2.0
Development									
Productive ^b	2.6	0.6	141.9	0.1	85.2	4.2	39.7	0.4	274.7
Dry	–	–	–	–	–	–	0.4	–	0.4

a Because of rounding, some totals may not exactly agree with the sum of their component parts.

b Includes correction of 2023 productive wells

Operational and statistical information – continued

Drilling and production activities in progress

The following table shows the number of exploratory and development oil and natural gas wells in the process of being drilled by the group and its equity-accounted entities as of 31 December 2025. Suspended development wells and long-term suspended exploratory wells are also included in the table.

	Europe		North America	South America	Africa	Asia	Australasia	Total ^a	
	UK	Rest of Europe	US	Rest of North America					
At 31 December 2025									
Exploratory									
Gross	–	–	–	–	2.0	1.0	1.0	–	4.0
Net	–	–	–	–	0.8	0.5	0.1	–	1.4
Development									
Gross	3.0	9.5	49.0	–	29.0	14.0	63.0	–	167.5
Net	1.8	1.5	36.4	–	11.3	1.8	21.3	–	74.1

a Because of rounding, some totals may not exactly agree with the sum of their component parts.

Parent company financial statements of BP p.l.c.

Company income statement

For the year ended 31 December		\$ million	
	Note	2025	2024
Dividend income		10,640	15,654
Interest and other income		6,521	7,100
Total income		17,161	22,754
Administrative and other expenses		(680)	(764)
Net impairment of fixed asset investments	2	–	(539)
Impairment reversal of fixed asset investments	2	539	–
Gain / (loss) on termination of operations		4	(28)
Gain on sale of fixed assets investments		15	–
Profit before interest and taxation		17,039	21,423
Interest payable to subsidiaries		(9,351)	(10,594)
Net finance income (expense) relating to pensions	4	347	310
Profit (loss) before taxation		8,035	11,139
Taxation	6	(79)	(70)
Profit (loss) for the year		7,956	11,069

Company statement of comprehensive income

For the year ended 31 December		\$ million	
	Note	2025	2024
Profit for the year		7,956	11,069
Other comprehensive income			
Items that may be reclassified subsequently to profit or loss			
Currency translation differences		457	(122)
		457	(122)
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension liability or asset	4	(167)	(684)
Income tax relating to items that will not be reclassified	6	(71)	866
		(238)	182
Other comprehensive income		219	60
Total comprehensive income		8,175	11,129

Company balance sheet

At 31 December

		\$ million	
	Note	2025	2024
Non-current assets			
Investments	2	178,085	177,349
Receivables	3	809	850
Defined benefit pension plan surpluses	4	6,696	6,083
		185,590	184,282
Current assets			
Receivables	3	2,673	6,185
Cash and cash equivalents		166	143
		2,839	6,328
Total assets		188,429	190,610
Current liabilities			
Payables	5	9,491	11,949
Net current liabilities		(6,652)	(5,621)
Total assets less current liabilities		178,938	178,661
Non-current liabilities			
Payables	5	53,454	53,488
Deferred tax liabilities	6	1,659	1,509
Defined benefit pension plan deficits	4	128	122
		55,241	55,119
Total liabilities		64,732	67,068
Net assets		123,697	123,542
Capital and reserves^a			
Profit and loss account			
Brought forward		85,789	88,193
Profit (loss) for the year		7,956	11,069
Other movements		(8,652)	(13,473)
		85,093	85,789
Called-up share capital	7	4,142	4,186
Share premium account		14,066	14,031
Other capital and reserves		20,396	19,536
		123,697	123,542

^a See Statement of changes in equity on page 271 for further information.

The financial statements on **pages 269-333** were approved and signed by the interim chief executive officer on 6 March 2026 having been duly authorized to do so by the board of directors:

Carol Howle Interim Chief executive officer

Company statement of changes in equity^a

								\$ million
	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Treasury shares	Foreign currency translation reserve	Profit and loss account	Total equity
At 1 January 2025	4,186	14,031	2,806	26,509	(9,030)	(749)	85,789	123,542
Profit for the year	–	–	–	–	–	–	7,956	7,956
Other comprehensive income	–	–	–	–	–	457	(238)	219
Total comprehensive income	–	–	–	–	–	457	7,718	8,175
Dividends	–	–	–	–	–	–	(5,087)	(5,087)
Repurchases of ordinary share capital ^a	(44)	–	44	–	(3,558)	–	(454)	(4,012)
Share-based payments, net of tax	–	35	–	–	3,917	–	(2,873)	1,079
At 31 December 2025	4,142	14,066	2,850	26,509	(8,671)	(292)	85,093	123,697
At 1 January 2024	4,496	13,815	2,496	26,509	(11,323)	(627)	88,193	123,559
Profit for the year	–	–	–	–	–	–	11,069	11,069
Other comprehensive income	–	–	–	–	–	(122)	182	60
Total comprehensive income	–	–	–	–	–	(122)	11,251	11,129
Dividends	–	–	–	–	–	–	(5,018)	(5,018)
Repurchases of ordinary share capital	(310)	–	310	–	–	–	(7,302)	(7,302)
Share-based payments, net of tax	–	216	–	–	2,293	–	(1,335)	1,174
At 31 December 2024	4,186	14,031	2,806	26,509	(9,030)	(749)	85,789	123,542

a See Note 7 for further information.

Notes on financial statements

1. Material accounting policy information, significant judgements, estimates and assumptions

Authorization of financial statements and statement of compliance with Financial Reporting Standard 101 'Reduced Disclosure Framework' (FRS 101)

The financial statements of BP p.l.c. for the year ended 31 December 2025 were approved and signed by the interim chief executive officer on 6 March 2026 having been duly authorized to do so by the board of directors. The company meets the definition of a qualifying entity under Financial Reporting Standard 100 'Application of Financial Reporting Requirements' (FRS 100) issued by the Financial Reporting Council. Accordingly, these financial statements have been prepared in accordance with FRS 101 and in accordance with the provisions of the UK Companies Act 2006.

Basis of preparation

The financial statements have been prepared on a going concern basis and in accordance with the Companies Act 2006 and applicable UK accounting standards.

The financial statements have been prepared under the historical cost convention. Historical cost is generally based on the fair value of the consideration given in exchange for the assets.

As permitted by FRS 101, the company has taken advantage of the disclosure exemptions available in relation to:

- (a) the requirements of paragraphs 10(d), 10(f), 16, 38A, 38B, 38C, 38D, 40A, 40B, 40C, 40D, 111 and 134 to 136 of IAS 1 'Presentation of Financial Statements';
- (b) the requirements of IAS 7 'Statement of Cash Flows' (excluding paragraphs 1 to 44E, 44H(b)(ii) and 45 to 63 which are not applicable);
- (c) the requirements of paragraphs 30 and 31 of IAS 8 'Accounting Policies, Changes in Accounting Estimates and Errors' in relation to standards not yet effective;
- (d) the requirements of paragraphs 17 and 18A of IAS 24 'Related Party Disclosures';
- (e) the requirements of IAS 24 'Related Party Disclosures' to disclose related party transactions entered into between two or more members of a group, provided that any subsidiary which is a party to the transaction is wholly owned by such a member;
- (f) the requirements of paragraphs 130(f)(ii), 130(f)(iii), 134(d) to 134(f) and 135(c)-135(e) of IAS 36, Impairment of Assets;
- (g) the requirements of paragraphs 45(b) and 46 to 52 of IFRS 2 'Share-based Payment';
- (h) the requirements of IFRS 7 'Financial Instruments: Disclosures'; and
- (i) the requirement of the second sentence of paragraph 110 and paragraphs 113(a), 114, 115, 118, 119(a) to (c), 120 to 127 and 129 of IFRS 15 'Revenue from Contracts with Customers'.

Where required, equivalent disclosures are given in the consolidated financial statements of BP p.l.c.

The financial statements are presented in US dollars and all values are rounded to the nearest million dollars (\$ million), except where otherwise indicated.

There are no new IFRS Accounting Standards or amended standards or interpretations adopted from 1 January 2025 onwards that have a significant impact on the financial statements.

IFRS 18 'Presentation and Disclosure in Financial Statements' will supersede IAS 1 'Presentation of Financial Statements' and is effective for annual periods beginning on or after 1 January 2027. IFRS 18 (and consequential amendments made to IAS 7 'Statement of Cash Flows', IAS 8 'Accounting Policies: Changes in Accounting Estimates and Errors', IAS 33 'Earnings per share' and IFRS 7 'Financial Instruments: Disclosures') introduces several new requirements that are expected to impact the presentation and disclosure of the Company's financial statements. These new requirements include:

- Requirements to classify all income and expenses included in the statement of profit or loss into one of five categories and to present two new mandatory subtotals.
- Requirement to use the operating profit subtotal as the starting point for the indirect method of reporting cash flows from operating activities in the statement of cash flows.
- Specific classification requirements for interest paid/received and dividends received in the statement of cash flows such that interest and dividend receipts are included as investing cash flows and interest paid as financing cash flows.

The Company's evaluation of the effect of adopting IFRS 18 is ongoing but it is currently anticipated that IFRS 18 may have a significant impact on the presentation of the Company's financial statements and related disclosures

Material accounting policy information: use of judgements, estimates and assumptions

Inherent in the application of many of the accounting policies used in preparing the financial statements is the need for bp management to make judgements, estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities, and the reported amounts of revenues and expenses. Actual outcomes could differ from the estimates and assumptions used. The accounting judgements and estimates that have a significant impact on the results of the Company are set out in boxed text below, and should be read in conjunction with the information provided in the Notes on financial statements.

The areas requiring the most significant judgement and estimation in the preparation of the financial statements are the recoverability of investment carrying values and pensions. Judgements and estimates, not all of which are significant, made in assessing the impact of the current economic and geopolitical environment, and climate change and the transition to a lower carbon economy on the financial statements are also set out in boxed text below. Where an estimate has a significant risk of resulting in a material adjustment to the carrying amounts of assets and liabilities within the next financial year this is specifically noted within the boxed text.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Judgements and estimates made in assessing the impact of climate change and the transition to a lower carbon economy

Climate change and the transition to a lower carbon economy were considered in preparing the financial statements. These may have significant impacts on the currently reported amounts of the Company's assets and liabilities discussed below.

Impairment of investments

The recoverable amounts of the Company's investments in subsidiaries are closely linked to the carrying value of property, plant and equipment and goodwill in the individual subsidiaries. The energy transition is likely to impact the future prices of commodities such as oil and natural gas which in turn may affect the recoverable amount of property, plant and equipment and goodwill in the oil and gas industry. Management's best estimate of oil and natural gas price assumptions for value-in-use impairment testing were revised during 2025. The revised price assumptions have been rebased in real 2024 terms. Brent oil prices in real 2024 terms were reduced in the short-term reflecting greater crude supply. Medium to long term prices steadily decline to a higher price of \$60 per barrel in 2050 continuing to reflect the assumption that the energy system decarbonises but at a slower rate. The price assumptions for Henry Hub gas price have been reduced in the short term, reflecting higher supply in the market. Prices then steadily increase in the medium term, as supply and demand rebalance before remaining steady at \$4.50 per mmBtu up to 2050. The revised assumptions for Brent oil and Henry Hub gas sit within the range of external scenarios considered by management and are in line with a range of transition paths, as collated into the Transition Scenario Catalogue we use in our TCFD assessment, that are considered by source data providers (such as IEA, UN PRI IPR and NGFS) to be consistent with holding the increase in the global average temperature to well below 2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels.

Judgements and estimates made in assessing the impact of the geopolitical and economic environment

In preparing the consolidated financial statements, the following areas involving judgement and estimates were identified as most relevant with regards to the impact of the current geopolitical and economic environment.

Going concern

Liquidity and financing is managed within bp under pooled group-wide arrangements which include the Company. As part of assuring the going concern basis of preparation for the Company, the ability and intent of the bp group to support the Company has been taken into consideration. The most recent bp group financial statements (see pages 129 to 240) continue to be prepared on a going concern basis. Forecast liquidity has been assessed under a number of stressed scenarios, including a significant decline in oil prices over the 12-month period. Reverse stress tests performed indicated that the group will continue to operate as a going concern for at least 12 months from the date of approval of the consolidated financial statements even if the Brent price fell to zero. In addition, group management of bp have confirmed that the existing intra-group funding and liquidity arrangements as currently constituted are expected to continue for the foreseeable future, being no less than twelve months from the approval of these financial statements. No material uncertainties over going concern or significant judgements or estimates in the assessment were identified. Accordingly, the Company will be able to draw on support from the bp group for the foreseeable future and these financial statements have therefore been prepared on the going concern basis.

Pensions

The volatility in the financial markets during 2025 impacted the assumptions used for determining the fair value of plan assets and the present value of defined benefit obligations in the Company's defined benefit pension plans. See significant estimate: pensions and Note 4 for further information.

Investments

Investments in subsidiaries are recorded at cost. The Company assesses investments for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If any such indication of impairment exists, the Company makes an estimate of its recoverable amount. Where the carrying amount of an investment exceeds its recoverable amount, the investment is considered impaired and is written down to its recoverable amount. Where these circumstances have reversed, the impairment previously made is reversed to the extent of the original cost of the investment.

Significant judgements and estimates: recoverability of asset carrying values

Determination as to whether, and by how much, an investment holding company chain (defined as each direct subsidiary and its own investments), is impaired involves management estimates on highly uncertain matters such as the effects of inflation and deflation on operating expenses, discount rates, capital expenditure, carbon pricing (where applicable), production profiles, reserves and resources, and future commodity prices, including the outlook for global or regional market supply-and-demand conditions for crude oil, natural gas and refined products. Determination as to whether, and by how much, an asset or CGU is impaired involves similar estimates.

The recoverable amount of an asset is the higher of its value in use and its fair value less costs of disposal. Fair value less costs of disposal may be determined based on expected sales proceeds or similar recent market transaction data. Details of impairment charges recognized in the profit and loss account and the carrying amounts of investments are shown in Note 2. The estimates for assumptions made in impairment tests in 2025 relating to discount rates and oil and gas properties are discussed below. It is impracticable to reliably determine the extent of any impacts of changes in the assumptions used to determine the recoverable amounts of the company's investments given the diverse characteristics of the underlying assets and the interdependency of the various inputs. Changes in the economic environment including as a result of the energy transition or other facts and circumstances may necessitate revisions to these assumptions and could result in a material change to the carrying values of the Company's assets within the next financial year.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Discount rates

For discounted cash flow calculations, future cash flows are adjusted for risks specific to the CGU. Value-in-use calculations are typically discounted using a pre-tax discount rate based upon the cost of funding the Company derived from an established model, adjusted to a pre-tax basis and incorporating a market participant capital structure and country risk premiums. Fair value less costs of disposal discounted cash flow calculations use a post-tax discount rate.

The discount rates applied in impairment tests are reassessed each year and, in 2025, the post-tax discount rate was 8% (2024 8%) other than for renewable power assets. Where the CGU is located in a country that was judged to be higher risk, an additional premium of 1% to 3% was reflected in the post-tax discount rate (2024 1% to 3%). The judgement of classifying a country as higher risk and the applicable premium takes into account various economic and geopolitical factors. The pre-tax discount rate, other than for renewable power assets, typically ranged from 9% to 18% (2024 9% to 20%) depending on the risk premium and applicable tax rate in the geographic location of the CGU. For renewable power assets tested on a value-in-use basis, primarily the CGUs for which goodwill was allocated following the Lightsource bp acquisition, a WACC-based post-tax discount rate of 7% was used. For renewable power assets tested on a fair-value basis, primarily offshore wind assets (including those in equity accounted entities), a post-tax cost of equity-based discount rate range of 8.75% to 9.5% (2024 8.75% to 9.5%) was used.

Oil and natural gas properties

For upstream oil and natural gas properties in subsidiaries, expected future cash flows are estimated using management's best estimate of future oil and natural gas prices, and production and reserves and certain resources volumes. The estimated future level of production in all impairment tests is based on assumptions about future commodity prices, production and development costs, field decline rates, current fiscal regimes and other factors. A change in the discount rate, reserves, resources or the oil and gas price assumptions in the next financial year may result in a recoverable amount of one or more of these assets above or below the current carrying amount and therefore there is a risk of impairment reversals or charges in that period. Management consider that reasonably possible changes in the discount rate or forecast revenue, arising from a change in oil and natural gas prices and/or production could result in a material change in their carrying amounts within the next financial year.

Oil and natural gas prices

The price assumptions used for value-in-use impairment testing are based on those used for investment appraisal. bp's carbon emissions cost assumptions and their interrelationship with oil and gas prices are described in 'Judgements and estimates made in assessing the impact of climate change and the transition to a lower carbon economy' on page 160. The investment appraisal price assumptions were recommended by the senior vice president economic & energy insights after considering a range of external price sets, and supply and demand profiles associated with various energy transition scenarios. They were reviewed and approved by management. As a result of the current uncertainty over the pace of transition to lower-carbon supply and demand and the social, political and environmental actions that will be taken to meet the goals of the Paris climate change agreement, the scenarios considered include those where those goals are met as well as those where they are not met.

During the year, bp's price assumptions applied in value-in-use impairment testing were revised. The revised price assumptions have been rebased in real 2024 terms. Brent oil prices in real 2024 terms were reduced to \$70 per barrel. Medium to long term prices steadily decline to a higher price of \$60 per barrel by 2050 continuing to reflect the assumption that the energy system decarbonizes but at a slower rate. The price assumptions for the Henry Hub price have been reduced in the near term, reflecting higher supply in the market. Prices then steadily increase in the medium term, as supply and demand remain steady at \$4.50 per mmBtu up to 2050. These price assumptions are derived from the central case investment appraisal assumptions. A summary of the group's revised price assumptions for Brent oil and Henry Hub gas, applied in 2025 and 2024, in real 2024 terms, is provided below. The assumptions represent management's best estimate of future prices at the balance sheet date, which sit within the range of external scenarios considered as appropriate for the purpose. They are considered by bp to be in line with a range of transition paths, as collated into the Transition Scenario Catalogue we use in our TCFD assessment, that are considered by source data providers (such as IEA, UN PRI IPR and NGFS) to be consistent with holding the increase in the global average temperature to well below 2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels. However, they do not correspond to any specific Paris-consistent scenario. An inflation rate of 2.0% - 3.0% (2024 2.0%-2.5%) is applied to determine the price assumptions in nominal terms.

2025 price assumptions	2026	2030	2040	2050
Brent oil (\$/bbl)	70	70	67	60
Henry Hub gas (\$/mmBtu)	3.80	4.10	4.50	4.50

2024 price assumptions	2025	2030	2040	2050
Brent oil (\$/bbl)	71	71	64	50
Henry Hub gas (\$/mmBtu)	4.07	4.04	4.04	4.04

Oil and natural gas reserves

In addition to oil and natural gas prices, significant technical and commercial assessments are required to determine the Company's estimated oil and natural gas reserves. Reserves estimates are regularly reviewed and updated. Factors such as the availability of geological and engineering data, reservoir performance data, acquisition and divestment activity and drilling of new wells all impact on the determination of the Company's estimates of its oil and natural gas reserves. bp bases its reserves estimates on the requirement of reasonable certainty with rigorous technical and commercial assessments based on conventional industry practice and regulatory requirements.

Reserves assumptions for value-in-use tests reflect the reserves and resources that management currently intend to develop. The recoverable amount of oil and gas properties is determined using a combination of inputs including reserves, resources and production volumes. Risk factors may be applied to reserves and resources which do not meet the criteria to be treated as proved or probable.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Foreign currency translation

The functional and presentation currency of the financial statements is US dollars. Transactions in foreign currencies are initially recorded in the functional currency of those entities at the spot exchange rate on the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are retranslated into the functional currency at the spot exchange rate on the balance sheet date. Any resulting exchange differences are included in the income statement, unless hedge accounting is applied. Non-monetary items, other than those measured at fair value, are not retranslated subsequent to initial recognition.

Exchange adjustments arising when the opening net assets and the profits for the year retained by a non-US dollar functional currency branch are translated into US dollars and are recognized in a separate component of equity and reported in other comprehensive income. Income statement transactions are translated into US dollars using the average exchange rate for the reporting period.

Financial guarantees

The Company enters into financial guarantee contracts with its subsidiaries. The liability for a financial guarantee contract is initially measured at fair value and subsequently measured at the higher of the contract's estimated expected credit loss and the amount initially recognized less, where appropriate, cumulative amortization.

Pensions and other post-employment benefits

The defined benefit pension plans are plans that share risks between entities under common control. In each instance BP p.l.c. is the principal employer and carries the whole plan surplus or deficit on its balance sheet. The cost of providing benefits under the Company's defined benefit plans is determined separately for each plan using the projected unit credit method, which attributes entitlement to benefits to the current period to determine current service cost and to the current and prior periods to determine the present value of the defined benefit obligation. Past service costs, resulting from either a plan amendment or a curtailment (a reduction in future obligations as a result of a material reduction in the plan membership), are recognized immediately when the company becomes committed to a change.

Net interest expense relating to pensions and other post-employment benefits, which is recognized in the income statement, represents the net change in present value of plan obligations and the value of plan assets resulting from the passage of time, and is determined by applying the discount rate to the present value of the benefit obligation at the start of the year, and to the fair value of plan assets at the start of the year, taking into account expected changes in the obligation or plan assets during the year.

Remeasurements of the defined benefit liability and asset, comprising actuarial gains and losses, and the return on plan assets (excluding amounts included in net interest described above) are recognized within other comprehensive income in the period in which they occur and are not subsequently reclassified to profit and loss.

The defined benefit pension plan surplus or deficit recognized on the balance sheet for each plan comprises the difference between the present value of the defined benefit obligation (using a discount rate based on high quality corporate bonds) and the fair value of plan assets out of which the obligations are to be settled directly. Fair value is based on market price information and, in the case of quoted securities, is the published bid price. Defined benefit pension plan surpluses are only recognized to the extent they are recoverable, either by way of a refund from the plan or reductions in future contributions to the plan.

Contributions to defined contribution plans are recognized in the income statement in the period in which they become payable.

Significant estimate: pensions and other post-employment benefits

Accounting for defined benefit pensions involves making significant estimates when measuring the Company's pension plan surpluses and deficits. These estimates require assumptions to be made about many uncertainties.

Pension assumptions are reviewed by management at the end of each year. These assumptions are used to determine the projected benefit obligation at the year end and hence the surpluses and deficits recorded on the company's balance sheet, and pension expense for the following year. The assumptions used are provided in Note 4.

The assumptions that are the most significant to the amounts reported are the discount rate, inflation rate and mortality levels. Assumptions about these variables are based on the environment in each country. The assumptions used vary from year to year, with resultant effects on future net income and net assets. Changes to some of these assumptions, in particular the discount rate and inflation rate, could result in material changes to the carrying amounts of the company's pension obligations within the next financial year for the UK plan. Any differences between these assumptions and the actual outcome will also affect future net income and net assets.

The values ascribed to these assumptions and a sensitivity analysis of the impact of changes in the assumptions on the benefit expense and obligation used are provided in Note 4.

Income taxes

Income tax expense represents the sum of current tax and deferred tax.

Income tax is recognized in the income statement, except to the extent that it relates to items recognized in other comprehensive income or directly in equity, in which case the related tax is recognized in other comprehensive income or directly in equity.

Current tax is based on the taxable profit for the period. Taxable profit differs from net profit as reported in the income statement because it is determined in accordance with the rules established by the applicable taxation authorities. It therefore excludes items of income or expense that are taxable or deductible in other periods as well as items that are never taxable or deductible. The Company's liability for current tax is calculated using tax rates and laws that have been enacted or substantively enacted by the balance sheet date.

Deferred tax is provided, using the liability method, on temporary differences at the balance sheet date between the tax bases of assets and liabilities and their carrying amounts for financial reporting purposes.

Deferred tax liabilities are recognized for taxable temporary differences.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Deferred tax assets are only recognized to the extent that it is probable that they will be realized in the future.

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply in the period when the asset is realized or the liability is settled, based on tax rates (and tax laws) that have been enacted or substantively enacted at the balance sheet date. Deferred tax assets and liabilities are not discounted. See Note 6 for further details.

The Company is subject to legislation which implements the OECD Pillar Two Model rules in the UK and many other countries around the world. The legislation is designed to ensure a minimum effective tax rate of 15% in each country in which the group operates. In the UK this includes an income inclusion rule and a domestic minimum tax. In line with the amendments to IAS 12, the exception from recognising and disclosing information about deferred tax assets and liabilities related to Pillar Two income taxes has been applied.

Financial assets

Financial assets are recognized initially at fair value, normally being the transaction price. In the case of financial assets not measured at fair value through profit or loss, directly attributable transaction costs are also included. The subsequent measurement of financial assets depends on their classification, as set out below. The Company derecognizes financial assets when the contractual rights to the cash flows expire or the rights to receive cash flows have been transferred to a third party and either substantially all of the risks and rewards of the asset have been transferred, or substantially all the risks and rewards of the asset have neither been retained nor transferred but control of the asset has been transferred.

Financial assets measured at amortized cost

Financial assets are classified as measured at amortized cost when they are held in a business model the objective of which is to collect contractual cash flows and the contractual cash flows represent solely payments of principal and interest. Such assets are carried at amortized cost using the effective interest method if the time value of money is significant. Gains and losses are recognized in profit or loss when the assets are derecognized or impaired and when interest income is recognized using the effective interest method. This category of financial assets includes receivables.

Cash equivalents

Cash equivalents are held for the purpose of meeting short-term cash commitments and are short-term highly liquid investments that are readily convertible to known amounts of cash, are subject to insignificant risk of changes in value and generally have a maturity of three months or less from the date of acquisition. Cash equivalents are classified as financial assets measured at amortized cost or, in the case of certain money market funds, fair value through profit or loss.

Financial liabilities

All financial liabilities held by the Company are classified as financial liabilities measured at amortized cost. Financial liabilities include other payables, accruals, and amounts payable to subsidiaries. The Company determines the classification of its financial liabilities at initial recognition.

Financial liabilities measured at amortized cost

All financial liabilities are initially recognized at fair value, net of directly attributable transaction costs. For interest-bearing loans and borrowings this is typically equivalent to the fair value of the proceeds received, net of issue costs associated with the borrowing.

After initial recognition, financial liabilities are subsequently measured at amortized cost using the effective interest method. Amortized cost is calculated by taking into account any issue costs and any discount or premium on settlement. Gains and losses arising on the repurchase, settlement or cancellation of liabilities are recognized in interest and other income and finance costs respectively.

2. Investments

	\$ million		
	Subsidiaries	Associates	
	Shares	Shares	Total
Cost			
At 1 January 2025	181,548	9	181,557
Additions	229	–	229
Disposals	(32)	–	(32)
At 31 December 2025	181,745	9	181,754
Amounts provided			
At 1 January 2025	4,208	–	4,208
Reversals	(539)	–	(539)
At 31 December 2025	3,669	–	3,669
Cost			
At 1 January 2024	181,406	9	181,415
Additions	203	–	203
Disposals	(61)	–	(61)
At 31 December 2024	181,548	9	181,557
Amounts provided			
At 1 January 2024	3,674	–	3,674
Additions	539	–	539
Reversals	(5)	–	(5)
At 31 December 2024	4,208	–	4,208
At 31 December 2025	178,076	9	178,085
At 31 December 2024	177,340	9	177,349

At 31 December 2025, the carrying amount of the company's net assets of \$123.7 billion (2024 \$123.5 billion) exceeded the group's market capitalisation of \$91.1 billion (2024 \$79.6 billion). As a result, management performed an impairment test of the company's major investments in line with the requirements of IAS 36 Impairment of Assets. Management considered the performance of investments and impairment tests performed by the company's subsidiaries. Taking into account the increase in the group's market capitalisation and a reduction in the deficits between the carrying amount of the company's major investments compared with the underlying net assets, compared to 2024, management concluded that an impairment reversal was required, relating to improvement of value in use and fair value less cost to sell. An impairment reversal of \$539 million was recognized against BP Global Investments Limited. Notwithstanding that there have been certain impairments within some of the group's operating subsidiaries during the year, no further impairment provisions were determined to be required in respect of the company's investments in subsidiaries.

The more important subsidiaries of the company at 31 December 2025 and the percentage holding of ordinary share capital (to the nearest whole number) are set out below. For a full list of related undertakings see **Note 13**.

Subsidiaries	%	Country of incorporation	Principal activities
International			
BP Global Investments Limited	100	England & Wales	Investment holding
BP International Limited	100	England & Wales	Integrated oil operations
Castrol Group Holdings Limited	100	Scotland	Investment holding
BP Gamma Holdings Limited	100	England & Wales	Investment holding
Canada			
BP Holdings Canada Limited	100	England & Wales	Investment holding
US			
BP Holdings North America Limited	100	England & Wales	Investment holding

On 24 December 2025, bp announced an agreement with Stonepeak to divest a 65% shareholding in the Castrol business with bp retaining a 35% interest through a holding in a newly incorporated entity. The Castrol Group Holdings Limited group will form part of that sale, in addition to other related undertakings held by other investments in subsidiaries.

The carrying value of the investment in BP International Limited at 31 December 2025 was \$76,253 million (2024 \$76,206 million).

3. Receivables

	\$ million			
	2025		2024	
	Current	Non-current	Current	Non-current
Amounts receivable from subsidiaries	2,673	809	6,184	850
Amounts receivable from associates	–	–	1	–
	2,673	809	6,185	850

The company has current receivables of \$2,583 million on Internal Funding Accounts (IFAs) receivable from BP International Limited (2024 \$5,988 million). These balances form a key part of the bp group's liquidity and funding arrangements under its centralised treasury funding model. Whilst IFA credit balances are legally repayable on demand, in practice they have no termination date. IFA debit balances can also be accessed by BP International Limited at short notice.

4. Pensions

The defined benefit pension obligation consists primarily of a closed funded final salary pension plan in the UK under which retired employees draw the majority of their benefit as an annuity. This pension plan is governed by a corporate trustee whose board is composed of four member-nominated directors, four company-nominated directors, an independent director, and an independent chair nominated by the company. The trustee board is required by law to act in the best interests of the plan participants and is responsible for setting certain policies, such as investment policies of the plan.

Employees in the UK are eligible for membership of defined contribution plans established with third-party providers.

The level of contributions to funded defined benefit plans is the amount needed to provide adequate funds to meet pension obligations as they fall due.

For the primary UK defined benefit plan there is a funding agreement between the company and the trustee. On a three year cycle a schedule of contributions is agreed covering the next five years. The schedule of contributions is next scheduled to be updated after the 31 December 2026 formal actuarial valuation. No contractually committed funding was due at 31 December 2025.

The surplus relating to the primary UK defined benefit plan is recognized on the balance sheet on the basis that the company is entitled to a refund of any remaining assets once all members have left the plan.

The obligation and cost of providing the pension benefits is assessed annually using the projected unit credit method. The date of the most recent actuarial review was 31 December 2025. The primary UK defined benefit plan is subject to a formal actuarial valuation every three years. The most recent formal actuarial valuation of the primary UK defined benefit plan was as at 31 December 2023.

The material financial assumptions used to estimate the benefit obligations of the plans are set out below. The assumptions are reviewed by management at the end of each year and are used to evaluate the accrued benefit obligation at 31 December and pension expense for the following year.

Financial assumptions used to determine benefit obligation	%	
	2025	2024
Discount rate for plan liabilities	5.6	5.5
Rate of increase for pensions in payment	2.7	2.9
Rate of increase in deferred pensions	2.7	2.9
Inflation for plan liabilities	2.9	3.1

Financial assumptions used to determine benefit expense	%	
	2025	2024
Discount rate for plan other finance expense	5.5	4.8

The discount rate assumption is based on third-party AA corporate bond indices and we use yields that reflect the maturity profile of the expected benefit payments. The inflation rate assumption is based on the difference between the yields on index-linked and fixed-interest long-term government bonds. The inflation assumption is used to determine the rate of increase for pensions in payment and the rate of increase in deferred pensions where there is such an increase.

In addition to the financial assumptions, we regularly review the demographic and mortality assumptions. The mortality assumptions reflect best practice in the UK and have been chosen with regard to the latest available published tables adjusted to reflect the experience of the plans and an extrapolation of past longevity improvements into the future. For the main pension plan the mortality assumptions are as follows:

Mortality assumptions	Years	
	2025	2024
Life expectancy at age 60 for a male currently aged 60	27.1	27.0
Life expectancy at age 60 for a male currently aged 40	28.9	28.9
Life expectancy at age 60 for a female currently aged 60	28.9	29.0
Life expectancy at age 60 for a female currently aged 40	30.4	30.5

The assets of the primary plan are held in a trust, the primary objective of which is to accumulate assets sufficient to meet the obligations of the plan. The assets of the trusts are invested in a manner consistent with fiduciary obligations and principles that reflect current practices in portfolio management.

A proportion of the assets are held in equities, which are expected to generate a higher level of return over the long term, with an acceptable level of risk. In order to provide reasonable assurance that no single security or type of security has an unwarranted impact on the total portfolio, the investment portfolios are highly diversified.

The parent company financial statements of BP p.l.c. on pages 269-333 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

4. Pensions - continued

The trustee's long-term investment objective for the primary defined benefit plan is to invest the plan's assets in a responsible manner that considers downside risk such that the assets are expected to be sufficient to pay benefits as and when they fall due.

The primary plan uses a liability driven investment (LDI) approach for part of the portfolio, investing primarily in government bonds to economically hedge against the effect of the most significant plan liability assumptions of interest rate and inflation rate. This is partly funded by short-term sale and repurchase agreements, whereby the plan borrows money using existing bonds as security and which will be bought back at a specified price at an agreed future date. The funds raised are used to invest in further bonds to increase the proportion of assets which match the plan liabilities. The borrowings are shown separately in the analysis of pension plan assets in the table below.

During 2025 the trustee extended its derisking strategy for the primary defined benefit plan by completing a bulk annuity buy-in transaction with Legal & General Assurance Society Limited covering approximately 12% of the plan's liabilities. The buy-in was paid for by way of transfer of \$2,183 million of government issued bonds from the plan assets in exchange for a stream of cashflows to the plan replicating payments due to relevant members.

The group was not legally relieved of the primary responsibility for the obligation and the benefits continue to be payable by the plan. The difference of \$148 million between the buy-in purchase price (\$2,183 million) and the defined benefit liability covered by the policy (\$2,035 million) was accounted for in other comprehensive income.

For the primary defined benefit plan there is an agreement with the trustee to at least maintain the proportion of assets with liability matching characteristics and review over time. During 2025, excluding qualifying insurance policies, the asset allocation policy remained unchanged.

The company's asset allocation policy for the primary plan at December 2025 was as follows:

Asset category	%
Total equity (including private equity)	8
Bonds/cash (including LDI)	85
Property/real estate	7

The amounts invested under the LDI programme by the primary UK pension plan as at 31 December 2025 were \$3,702 million (2024 \$4,970 million) of government-issued nominal bonds and \$10,805 million (2024 \$11,105 million) of index-linked bonds.

The primary plan does not invest directly in either securities or property/real estate of the company or of any subsidiary.

The fair values of the various categories of assets held by the defined benefit plans at 31 December are presented in the table below, including the effects of derivative financial instruments. Movements in the fair value of plan assets during the year are shown in detail in the table on [page 280](#).

	\$ million	
	2025	2024
Fair value of pension plan assets		
Listed equities – developed markets	725	963
– emerging markets	29	32
Private equity ^a	1,871	1,916
Government issued nominal bonds ^b	3,761	5,027
Government issued index-linked bonds ^b	10,805	11,105
Corporate bonds ^b	5,383	6,088
Property ^c	2,487	2,344
Cash	574	416
Other ^d	3,232	1,039
Debt (repurchase agreements) used to fund liability driven investments	(4,278)	(5,664)
	24,589	23,266

a Private equity is valued at fair value based on the most recent third-party net asset, revenue or earnings based valuations that generally result in the use of significant unobservable inputs.

b Bonds held are denominated in sterling or hedged back to sterling to minimize foreign currency exposure, and are predominantly valued using observable market data based inputs other than quoted market prices in active markets.

c Property held is all located in the United Kingdom and is valued based on an analysis of recent market transactions supported by market knowledge derived from third-party professional valuers that generally result in the use of significant unobservable inputs.

d Other includes qualifying insurance policies in the UK amounting to \$2,159 million representing the asset associated with the buy in outlined on page 279. The fair value of these insurance policies is equal to the value of the defined benefit obligations to which these policies relate.

4. Pensions – continued

	\$ million	
	2025	2024
Analysis of the amount charged to profit or loss		
Current service cost ^a	47	48
Settlement	–	(1)
Operating charge / (credit) relating to defined benefit plans	47	47
Payments to defined contribution plan	180	161
Total operating charge / (credit)	227	208
Interest income on plan assets ^b	(1,322)	(1,218)
Interest on plan liabilities	975	908
Other finance (income)	(347)	(310)
Analysis of the amount recognized in other comprehensive income		
Actual asset return less interest income on pension plan assets	(613)	(2,388)
Change in financial assumptions underlying the present value of the plan liabilities	453	1,498
Change in demographic assumptions underlying the present value of plan liabilities	(26)	194
Experience gains and losses arising on the plan liabilities	19	12
Remeasurements recognized in other comprehensive income	(167)	(684)

a The costs of managing plan investments are offset against the investment return. Following the closure of the main UK pension plan current service cost consists of \$36 million of the costs of administering the pension plan and \$11 million of current service cost from the remaining small worldwide schemes administered and reported through the UK.

b The actual return on plan assets is made up of the sum of the interest income on plan assets and the remeasurement of plan assets as disclosed above.

	\$ million	
	2025	2024
Movements in benefit obligation during the year		
Benefit obligation at 1 January	17,305	19,558
Exchange adjustments	1,300	(352)
Operating charge relating to defined benefit plans	47	47
Interest cost	975	908
Contributions by plan participants	8	7
Benefit payments (funded plans) ^a	(1,160)	(1,153)
Benefit payments (unfunded plans) ^a	(8)	(6)
Remeasurements	(446)	(1,704)
Benefit obligation at 31 December	18,021	17,305
Movements in fair value of plan assets during the year		
Fair value of plan assets at 1 January	23,266	26,046
Exchange adjustments	1,757	(473)
Interest income on plan assets ^b	1,322	1,218
Contributions by plan participants	8	7
Contributions by employers (funded plans)	9	9
Benefit payments (funded plans) ^a	(1,160)	(1,153)
Remeasurements ^b	(613)	(2,388)
Fair value of plan assets at 31 December ^{c d}	24,589	23,266
Surplus at 31 December	6,568	5,961
Represented by		
Asset recognized	6,696	6,083
Liability recognized	(128)	(122)
	6,568	5,961
The surplus may be analysed between funded and unfunded plans as follows		
Funded	6,696	6,083
Unfunded	(128)	(122)
	6,568	5,961
The defined benefit obligation may be analysed between funded and unfunded plans as follows		
Funded	(17,893)	(17,183)
Unfunded	(128)	(122)
	(18,021)	(17,305)

a The benefit payments amount shown above comprises \$1,131 million benefits (2024 \$1,121 million) plus \$37 million (2024 \$38 million) of plan expenses incurred in the administration of the benefit.

b The actual return on plan assets is made up of the sum of the interest income on plan assets and the remeasurement of plan assets as disclosed above.

c Reflects \$24,265 million of assets held in the BP Pension Fund (2024 \$22,964 million) and \$281 million held in the BP Global Pension Trust (2024 \$260 million), as well as \$34 million representing the company's share of Merchant Navy Officers Pension Fund (2024 \$33 million) and \$9 million of Merchant Navy Ratings Pension Fund (2024 \$9 million).

d The fair value of plan assets includes borrowings related to the LDI programme as described on page 279.

4. Pensions – continued

Sensitivity analysis

The discount rate, inflation and the mortality assumptions all have a significant effect on the amounts reported. A one-percentage point change, in isolation, in certain assumptions as at 31 December 2025 for the company's plans would have had the effects shown in the table below. The effects shown for the expense in 2026 comprise the total of current service cost and net finance income or expense.

	\$ million	
	One percentage point Increase	Decrease
Discount rate^a		
Effect on pension expense in 2026	(186)	168
Effect on pension obligation at 31 December 2025	(1,803)	2,185
Inflation rate^b		
Effect on pension expense in 2026	90	(82)
Effect on pension obligation at 31 December 2025	1,613	(1,464)

a The amounts presented reflect that the discount rate is used to determine the asset interest income as well as the interest cost on the obligation.

b The amounts presented reflect the total impact of an inflation rate change on the assumptions for rate of increase in pensions in payment and deferred pensions.

One additional year of longevity in the mortality assumptions would increase the 2026 pension expense by \$33 million and the pension obligation at 31 December 2025 by \$593 million.

Estimated future benefit payments and the weighted average duration of defined benefit obligations

The expected benefit payments, which reflect expected future service, as appropriate, but exclude plan expenses, and the weighted average duration of the defined benefit obligations at 31 December 2025 are as follows:

	\$ million
Estimated future benefit payments	
2026	1,190
2027	1,212
2028	1,219
2029	1,233
2030	1,234
2031 - 2035	6,214
	Years
Weighted average duration	11.1

5. Payables

	2025		2024	
	Current	Non-current	Current	Non-current
Amounts payable to subsidiaries	8,801	53,395	10,807	53,436
Accruals	458	–	934	–
Deferred income	2	4	–	–
Other payables	230	55	208	52
	9,491	53,454	11,949	53,488

Included in current amounts payable to subsidiaries are interest-bearing payables with BP Finance p.l.c. and BP Gamma Holdings Limited. The interest-bearing payable of \$5,066 million (2024 \$5,072 million) with BP Finance p.l.c. has interest charged based on a 3-month Term SOFR rate plus 12 basis points with a maturity date of April 2030. Though the loan with BP Finance p.l.c. is due in 2030, the loan is repayable at one business day's notice. It is disclosed as a non-current receivable in the financial statements of BP Finance p.l.c., given the counterparty has no intent to call the loan at short notice. The interest-bearing payable of \$3,500 million (2024 \$5,500 million) with BP Gamma Holdings Limited has interest charged based on a 3-month Term SOFR rate plus 6 basis points with a maturity date of December 2026 and repayable at two business day's notice. Though the loan with BP Gamma Holdings Limited is due in 2026, the loan is auto-renewal. It is disclosed as a non-current receivable in the financial statements of BP Gamma Holdings Limited, given the counterparty has no intent to withdraw the loan within the next year.

Non-current amounts payable to subsidiaries includes an interest-bearing payable of \$52,585 million with BP International Limited issued in December 2021 (2024 \$52,585 million), with interest being charged based on a 3-month Term SOFR rate plus 101 basis points and a maturity date of December 2028. The loan includes a prepayment clause for BP p.l.c. to repay part or all of the loan before maturity whilst the lender has no right to call the loan other than in the event of the company being in default. As such it is disclosed as non-current in both the company and BP International Limited's financial statements.

5. Payables – continued

The maturity profile of the non-current financial liabilities included in the balance sheet at 31 December is shown in the table below. These amounts are included within payables.

	\$ million	
	2025	2024
Due within		
1 to 2 years	54	62
2 to 5 years	52,736	52,752
More than 5 years	664	674
	53,454	53,488

6. Taxation

	\$ million	
	2025	2024
Tax charge included in total comprehensive income		
Deferred tax		
Origination and reversal of temporary differences in the current year	150	(798)
This comprises:		
Taxable temporary differences relating to pensions	150	(798)
Deferred tax		
Deferred tax liability		
Pensions ^a	1,659	1,509
Net deferred tax liability	1,659	1,509
Analysis of movements during the year		
At 1 January	1,509	2,305
Charge (credit) for the year in the income statement	79	70
Charge (credit) for the year in other comprehensive income ^a	71	(866)
At 31 December	1,659	1,509

a 2024 reflects a \$658 million reduction in the deferred tax liability on defined benefit pension plan surpluses following the reduction in the rate of the authorized surplus payments tax charge in the UK from 35% to 25%.

At 31 December 2025, deferred tax assets of \$973 million on other temporary differences; \$32 million relating to pensions, \$225 million relating to income losses and \$716 million relating to other deductible temporary differences (2024 \$913 million on other temporary differences, \$27 million relating to pensions; \$206 million relating to income losses and \$680 million relating to other deductible temporary differences) were not recognized as it is not considered probable that suitable taxable profits will be available in the company from which the future reversal of the underlying temporary differences can be deducted. There is no fixed expiry date for the unrecognized temporary differences.

7. Called-up share capital

The allotted, called-up and fully paid share capital at 31 December was as follows:

	2025		2024	
	Shares thousand	\$ million	Shares thousand	\$ million
Issued				
8% cumulative first preference shares of £1 each ^a	7,233	12	7,233	12
9% cumulative second preference shares of £1 each ^a	5,473	9	5,473	9
		21		21
Ordinary shares of 25 cents each				
At 1 January	16,662,465	4,165	17,900,800	4,475
Repurchase of ordinary share capital	(835,649)	(209)	(1,238,335)	(310)
Repurchases transferred to treasury shares	659,497	165	–	–
At 31 December	16,486,313	4,121	16,662,465	4,165
		4,142		4,186

a The nominal amount of 8% cumulative first preference shares and 9% cumulative second preference shares that can be in issue at any time shall not exceed £10,000,000 for each class of preference shares.

7. Called-up share capital – continued

Voting on substantive resolutions tabled at a general meeting is on a poll. On a poll, shareholders present in person or by proxy have two votes for every £5 in nominal amount of the first and second preference shares held and one vote for every ordinary share held. On a show-of-hands vote on other resolutions (procedural matters) at a general meeting, shareholders present in person or by proxy have one vote each.

In the event of the winding up of the company, preference shareholders would be entitled to a sum equal to the capital paid up on the preference shares, plus an amount in respect of accrued and unpaid dividends and a premium equal to the higher of (i) 10% of the capital paid up on the preference shares and (ii) the excess of the average market price of such shares on the London Stock Exchange during the previous six months over par value.

During 2025 the company repurchased 836 million ordinary shares for a total consideration of \$4,486 million (2024 \$7,127 million, including transaction costs of \$24 million (2024 \$38 million)). 176 million shares repurchased were cancelled and 659 million shares were held as treasury shares. The repurchased shares represented 5.1% of ordinary share capital. A further 74 million ordinary shares were repurchased between the end of the reporting period and 13 February 2026, the latest practicable date before the completion of these financial statements, for a total cost of \$450 million of which \$448 million has been accrued at 31 December 2025. The number of shares in issue is reduced when shares are repurchased and cancelled, but is not reduced in respect of the repurchases transferred to treasury shares.

Treasury shares^a

	2025		2024	
	Shares thousand	Nominal value \$ million	Shares thousand	Nominal value \$ million
At 1 January	812,021	204	1,077,079	271
Purchases for settlement of employee share plans	660,765	165	8,302	2
Shares re-issued for employee share-based payment plans	(363,198)	(92)	(273,360)	(69)
At 31 December	1,109,588	277	812,021	204
Of which - shares held in treasury by bp	857,433	214	481,474	121
- shares held in ESOP trusts	252,118	63	330,510	83
- shares held by bp's US plan administrator ^b	37	—	37	—

a See Note 8 for definition of treasury shares.

b Held by the company in the form of ADSs to meet the requirements of employee share-based payment plans in the US.

For each year presented, the balance of shares held in treasury by bp at 1 January represents 2.9% (2024 4.1% and 2023 4.9%) of the called-up ordinary share capital of the company.

8. Capital and reserves

See statement of changes in equity for details of all reserves balances.

Share capital

The balance on the share capital account represents the aggregate nominal value of all ordinary and preference shares in issue, including treasury shares.

Share premium account

The balance on the share premium account represents the amounts received in excess of the nominal value of the ordinary and preference shares.

Capital redemption reserve

The balance on the capital redemption reserve represents the aggregate nominal value of all the ordinary shares repurchased and cancelled.

Merger reserve

The balance on the merger reserve represents the premium arising where the fair value of the consideration given is in excess of the nominal value of the ordinary shares issued in an acquisition made by the issue of shares where merger relief under the Companies Act applies.

Treasury shares

Treasury shares represent bp shares repurchased and available for specific and limited purposes. For accounting purposes, shares held in Employee Share Ownership Plans (ESOPs) and by bp's US share plan administrator to meet the future requirements of the employee share-based payment plans are treated in the same manner as treasury shares and are, therefore, included in the financial statements as treasury shares. The ESOPs are funded by the company and have waived their rights to dividends in respect of such shares held for future awards. Until such time as the shares held by the ESOPs vest unconditionally to employees, the amount paid for those shares is shown as a reduction in shareholders' equity. Assets and liabilities of the ESOPs are recognized as assets and liabilities of the company.

Foreign currency translation reserve

The foreign currency translation reserve records exchange differences arising from the translation of the financial information of the foreign currency branch. Upon disposal of foreign operations, the related accumulated exchange differences are recycled to the income statement.

Profit and loss account

The balance held on this reserve is the accumulated retained profits of the company.

The profit and loss account reserve includes \$24,581 million (2024 \$23,932 million), the distribution of which is limited by statutory or other restrictions.

The financial statements for the year ended 31 December 2025 do not reflect the dividend announced on 10 February 2026 and which is expected to be paid on 27 March 2026; this will be treated as an appropriation of profit in the year ending 31 December 2026.

9. Financial guarantees and other contingencies

The company has issued guarantees to third parties and other bp subsidiaries in case of the failure, on the part of certain bp subsidiaries, to pay current liabilities and obligations pertaining to business operations. The amounts guaranteed by the company, at 31 December 2025, for these arrangements is \$405 million (2024 \$412 million). The company guarantees finance debt and lease obligations of certain bp group subsidiaries. Maturity dates vary and guarantees will terminate on full payment and/or cancellation of the obligation. As of 31 December 2025, maximum guaranteed amounts pertaining to debt and lease arrangements were \$67,855 million (2024 \$69,054 million). These maximum amounts are more than the actual guaranteed exposure of amounts recognized at the balance sheet date as well as more than remaining obligations under the guaranteed contracts. The recognized liability due to provided financial guarantees was \$815 million at the balance sheet date (2024 \$854 million). The liability was included within Payables.

Performance under all the above guarantees would be triggered by a financial default of the guaranteed entity and, as such, are currently not expected to have any material effect.

As part of normal ongoing business operations and consistent with generally accepted industry practices, the company also executes contracts involving standard indemnities and guarantees for the respective businesses in which bp operates as well as indemnities specific to transactions, including the sale of businesses. This includes a guarantee of subsidiaries' liabilities under the Consent Decree between the United States, the Gulf states and bp and under the settlement agreement with the Gulf states in relation to the Gulf of America oil spill. The company has also issued uncapped guarantees for certain subsidiaries' liabilities under the Plaintiffs' Steering Committee agreement relating to the Gulf of America oil spill. See **Note 33** in the consolidated group financial statements of BP p.l.c. for further information. The company regularly evaluates the probability of having to incur costs associated with these indemnities and does not believe such matters will have a material adverse effect on its results of operations and cash flow.

The company believes that guarantees and other off-balance sheet commitments do not currently, nor could reasonably have in the future, a material effect on its financial position, income and expenses, liquidity, investments or financial resources.

9. Financial guarantees and other contingencies – continued

Subsidiary audit exemptions

The following UK subsidiaries will take advantage of the audit exemption set out within Section 479A of the Companies Act 2006 supported by guarantees issued by BP p.l.c. over their liabilities as at 31 December 2025.

Name	Company number
Atlantic 2/3 UK Holdings Limited	04075308
BP Adua Ltd	16130095
BP Adua Operating Co. Ltd	16130094
BP Africa Oil Limited	11807924
BP Australia Swaps Management Limited	08298838
BP Corporate Holdings Limited	04116177
BP East Kalimantan CBM Limited	06383221
BP Energy Company of Kirkuk Ltd	16140733
BP Energy Europe Limited	SC107896
BP Eta Holdings Limited	14846392
BP Exploration (D230) Limited	11796185
BP Exploration (Shafag-Asiman) Limited	07731386
BP Exploration Argentina Limited	12000539
BP Exploration North Africa Limited	05335927
BP Exploration Orinoco Limited	00598148
BP Gaea II Ltd	16397618
BP Gaea Limited	16397609
BP Global Solutions Limited	13464292
BP Holdings Canada Limited	08274009
BP Integrated Solutions Limited	13448827
BP Investments Asia Limited	05639411
BP Iota Holdings Limited	14860361
BP Kappa Holdings Limited	14860118
BP Lambda Holdings Limited	14860102
BP Pension Escrow Limited	12097961
BP Pensions Limited	01337112
BP Properties Limited	00699446
BP Retail Properties Limited	12735096
BP Scale Up Factory Limited	11700098
BP Theta Holdings Limited	14860376
BP Zeta Holdings Limited	14846404
Guangdong Investments Limited	04622996
Kenilworth Oil Company Limited	00273831
Open Energi Limited	03838585
Pearl River Delta Investments Limited	04622959
Puls8 Ltd	SC650262

9. Financial guarantees and other contingencies – continued

Dormant company filing exemptions

The following UK dormant subsidiaries will take advantage of the exemption to prepare and file individual accounts with Companies House set out within Sections 394A and 448A of the Companies Act 2006 supported by guarantees issued by BP p.l.c. over their liabilities as at 31 December 2025.

Name	Company number
Amoco U.K. Petroleum Limited	00799710
BP (Barbican) Limited	01150608
BP Benevolent Fund Trustees Limited	00455852
BP Express Shopping Limited	00211858
Britannic Investments Iraq Limited	08116088
Cadman DBP Limited	00178353
Iraq Petroleum Company Limited	09646587
Ropemaker Deansgate Limited	04342803
Ropemaker Properties Limited	00759094
The BP Share Plans Trustees Limited	01454944

10. Auditor's remuneration

Note 36 to the consolidated financial statements provides details of the remuneration of the company's auditor on a group basis.

11. Directors' remuneration

	\$ million	
	2025	2024
Remuneration of directors		
Total for all directors		
Emoluments	11	8
Amounts awarded under incentive schemes ^a	3	5
Total	14	13

a Excludes amounts relating to past directors.

Emoluments

These amounts comprise fees paid to the non-executive chair and the non-executive directors and, for executive directors, salary and benefits earned during the relevant financial year, plus cash bonuses awarded for the year.

Directors' remuneration costs are borne by other undertakings within the group.

12. Employee costs and numbers

	\$ million	
	2025	2024
Employee costs		
Wages and salaries	1,058	1,168
Social security costs	186	202
	1,244	1,370
Average number of employees		
gas & low carbon energy	420	520
oil production & operations	242	192
customers & products	1,447	1,650
other businesses and corporate	2,049	2,235
	4,158	4,597

The employee costs noted above relate to those employees with contracts of employment in the name of BP p.l.c.. These costs are borne by other undertakings within the group.

13. Related undertakings of the group

In accordance with Section 409 of the Companies Act 2006, a full list of related undertakings, showing the registered office address and the effective equity owned by the bp group as at 31 December 2025 is disclosed below.

Unless otherwise stated, all interests are indirectly held by BP p.l.c.

All subsidiary undertakings are controlled by the group and their results are fully consolidated in the group's financial statements.

Subsidiaries

Company by country of incorporation and registered office address	Ownership interest	%
Albania		
Rruga Ibrahim Rugova, Sky Tower, Tirana, Kati 9/1, Albania		
BP Albania SHPK	Ordinary	100.00
Argentina		
Av. Cordoba 315 Piso 8, Buenos Aires, 1054, Argentina		
Latin Energy Argentina S.A.	Ordinary	100.00
Australia		
CBW Level 19, 181 William Street, Melbourne VIC 3000, Australia		
3725 Sharp Development Pty Ltd	Ordinary	100.00
433 Link Development Company Pty Ltd	Ordinary	100.00
892 Yarrawonga Development Pty Ltd	Ordinary	100.00
Bilby FinCo Pty Ltd	Ordinary	100.00
Bilby HoldCo Pty Ltd	Ordinary	100.00
Canola Borrower HoldCo Pty Ltd	Ordinary	100.00
Canola Borrower Pty Ltd	Ordinary	100.00
Goorambat Landco Pty Ltd	Ordinary	100.00
Goulburn River BESS FinCo Pty Limited	Ordinary	100.00
Goulburn River BESS Fund Pty Limited	Ordinary	100.00
Goulburn River BESS HoldCo Pty Limited	Ordinary	100.00
Goulburn River BESS Trust	Units	100.00
Goulburn River FinCo Pty Limited	Ordinary	100.00
Goulburn River Fund Pty Limited	Ordinary	100.00
Goulburn River HoldCo 2 Pty Limited	Ordinary	100.00
Goulburn River Trust	Units	100.00
Lightsource Asset Management Australia Pty Ltd	Ordinary	100.00
Lightsource Australia SPV 2 Pty Ltd	Ordinary	100.00
Lightsource Australia SPV 3 Pty Ltd	Ordinary	100.00
Lightsource Australia SPV 4 Pty Ltd	Ordinary	100.00
Lightsource Development Services Australia Pty Ltd	Ordinary	100.00
Lightsource Energy Markets Pty Ltd	Ordinary	100.00
Lightsource Labs Australia Pty Limited	Ordinary	100.00
Lightsource LS Labs Australia Operations Pty Ltd	Ordinary	100.00
Lightsource Renewable Energy (Australia) Pty Ltd	Ordinary	100.00
Lower Wonga FinCo Pty Ltd	Ordinary	100.00
Lower Wonga Fund Pty Ltd	Ordinary	100.00
Lower Wonga Solar Farm Pty Ltd	Ordinary	100.00
Lower Wonga Trust	Ordinary	100.00
LS Australia Equity HoldCo1 Pty Ltd	Ordinary	100.00
LS Australia FinCo 1 Pty Ltd	Ordinary	100.00
LS Australia FinCo 2 Pty Ltd	Ordinary	100.00
LS Australia FinCo 3 Pty Ltd	Ordinary	100.00
LS Australia HoldCo 1 Pty Ltd	Ordinary	100.00
LS Land Holdings Pty Ltd	Ordinary	100.00
Sandy Creek BESS FinCo Pty Ltd	Ordinary	100.00
Sandy Creek BESS Fund Pty Ltd	Ordinary	100.00
Sandy Creek BESS HoldCo Pty Ltd	Ordinary	100.00

13. Related undertakings of the group – continued

Sandy Creek BESS Trust	Units	100.00
Sandy Creek Solar FinCo Pty Limited	Ordinary	100.00
Sandy Creek Solar Fund Pty Limited	Ordinary	100.00
Sandy Creek Solar HoldCo 2 Pty Limited	Ordinary	100.00
Sandy Creek Solar Trust	Units	100.00
Sun Spot 3 Pty Ltd	Ordinary	100.00
Wellington LandCo Pty Ltd	Ordinary	100.00
Wellington North Solar Farm Pty Ltd	Ordinary	100.00
West Mokoan Solar Farm Pty Ltd	Ordinary	100.00
West Wyalong FinCo Pty Ltd	Ordinary	100.00
West Wyalong Fund Pty Ltd	Ordinary	100.00
West Wyalong HoldCo 2 Pty Ltd	Ordinary	100.00
West Wyalong Trust	Units	100.00
Woolooga BESS FinCo Pty Limited	Ordinary	100.00
Woolooga BESS Fund Pty Limited	Ordinary	100.00
Woolooga BESS HoldCo 2 Pty Limited	Ordinary	100.00
Woolooga BESS Trust	Ordinary	100.00
Woolooga FinCo Pty Ltd	Ordinary	100.00
Woolooga Fund Pty Ltd	Ordinary	100.00
Woolooga HoldCo 2 Pty Ltd	Ordinary	100.00
Woolooga Trust	Units	100.00
Woonga Creek BESS FinCo Pty Limited	Ordinary	100.00
Woonga Creek BESS Fund Pty Limited	Ordinary	100.00
Woonga Creek BESS HoldCo Pty Limited	Ordinary	100.00
Woonga Creek BESS Trust	Units	100.00
Wunghnu Solar Farm FinCo Pty Ltd	Ordinary	100.00
Level 10, QV1 Building, 250 St Georges Terrace, Perth, WA 6000, Australia		
BP Developments Australia Pty. Ltd.	Ordinary	100.00
BP Developments Holdings Australia Pty Ltd	Ordinary	100.00
Level 17, 717 Bourke Street, Docklands VIC 3008, Australia		
Air Refuel Pty Ltd	Ordinary A; Ordinary B	100.00
BASS Holdings Trust	Membership Interest	51.00
BASS Management Pty Ltd	Ordinary	51.00
BASS NZ Head Trust	Membership Interest	51.00
BASS NZ Management Pty Ltd	Ordinary	51.00
BASS NZ Sub Management Pty Ltd	Ordinary	51.00
BASS NZ Sub Trust	Membership Interest	51.00
BP Alternative Energy Australia Pty Ltd	Ordinary	100.00
BP Australia Employee Share Plan Proprietary Limited	Ordinary	100.00
BP Australia Group Pty Ltd	Ordinary; Preference	100.00
BP Australia Investments Pty Ltd	Ordinary	100.00
BP Australia Pty Ltd	Ordinary	100.00
BP Australia Shipping Pty Ltd ^a	Ordinary	100.00
BP Australia Supply Pty Ltd	Ordinary	100.00
BP Bulwer Island Pty Ltd	Ordinary; Ordinary A; Ordinary B	100.00
BP Energy Australia Pty Ltd	Ordinary	100.00
BP Finance Australia Pty Ltd	Ordinary	100.00
BP Low Carbon Australia (CCS) Pty Ltd	Ordinary	100.00
BP Low Carbon Australia Pty Ltd	Ordinary	100.00
BP Oil Australia Pty Ltd	Ordinary	100.00
BP Refinery (Kwinana) Proprietary Limited	Ordinary	100.00

The parent company financial statements of BP p.l.c. on pages 269-333 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

13. Related undertakings of the group – continued

BP Regional Australasia Holdings Pty Ltd	Ordinary	100.00
BP Solar Pty Ltd	Ordinary	100.00
Brian Jasper Nominees Pty Ltd	Ordinary	100.00
Burmah Castrol Australia Pty Ltd	Ordinary; Redeemable preference	100.00
Castrol Australia Pty. Limited	Ordinary	100.00
Castrol Holdings Australia Pty Ltd	Ordinary	100.00
Centrel Pty Ltd	Ordinary	100.00
Elite Customer Solutions Pty Ltd	Ordinary	100.00
International Bunker Supplies Pty Ltd	Ordinary	100.00
No. 1 Riverside Quay Proprietary Limited	Ordinary	100.00
West Kimberley Fuels Pty Ltd	Ordinary	100.00
Level 17, 717 Bourke Street, Docklands, VIC 2003, Australia		
Andrash Alkimos Pty Ltd	Ordinary	100.00
Andrash Angle Vale Pty Ltd	Ordinary	100.00
Andrash Briens Rd Pty Ltd	Ordinary	100.00
Andrash Burton Pty Ltd	Ordinary	100.00
Andrash Christies Beach Pty Ltd	Ordinary	100.00
Andrash Davoren Park 1 Pty Ltd	Ordinary	100.00
Andrash Elizabeth South Pty Ltd	Ordinary	100.00
Andrash Erskine Pty Ltd	Ordinary	100.00
Andrash Express (Semaphore) Pty Ltd	Ordinary	100.00
Andrash Express Mt Barker Pty Ltd	Ordinary	100.00
Andrash Gawler East Carwash Pty Ltd	Ordinary	100.00
Andrash Gawler East Pty Ltd	Ordinary	100.00
Andrash Gepps Cross Pty Ltd	Ordinary	100.00
Andrash Greenfields Pty Ltd	Ordinary	100.00
Andrash Hayborough Pty Ltd	Ordinary	100.00
Andrash Hindmarsh Pty Ltd	Ordinary	100.00
Andrash Lonsdale Pty Ltd	Ordinary	100.00
Andrash Murray Bridge 2 Pty Ltd	Ordinary	100.00
Andrash Newco 2 Pty Ltd	Ordinary	100.00
Andrash Newco 3 Pty Ltd	Ordinary	100.00
Andrash Newco 1 Pty Ltd	Ordinary	100.00
Andrash Newenham Pty Ltd	Ordinary	100.00
Andrash Newton Pty Ltd	Ordinary	100.00
Andrash North Brighton Pty Ltd	Ordinary	100.00
Andrash North Pty Ltd	Ordinary	100.00
Andrash Nuriootpa Pty Ltd	Ordinary	100.00
Andrash Panorama Pty Ltd	Ordinary	100.00
Andrash Paradise Pty Ltd	Ordinary	100.00
Andrash Port Adelaide Pty Ltd	Ordinary	100.00
Andrash Prospect Pty Ltd	Ordinary	100.00
Andrash Salisbury Downs Pty Ltd	Ordinary	100.00
Andrash Salisbury Pty Ltd	Ordinary	100.00
Andrash Seaford 1 Pty Ltd	Ordinary	100.00
Andrash South Pty Ltd	Ordinary	100.00
Andrash Trademarks Pty Ltd	Ordinary	100.00
Andrash Unley Pty Ltd	Ordinary	100.00
Andrash Victor Harbor Pty Ltd	Ordinary	100.00
Andrash Virginia 2 Pty Ltd	Ordinary	100.00
Andrash Wholesale Fuel Pty Ltd	Ordinary	100.00

13. Related undertakings of the group – continued

Andrash Wholesale Fuel Sa Pty Ltd	Ordinary	100.00
Andrash Womma Rd Pty Ltd	Ordinary	100.00
Austria		
Am Belvedere 10, 1100 Wien, Austria		
bp Retail Real Estate GmbH	Ordinary	100.00
CASTROL Austria GmbH	Ordinary	100.00
Castrol Österreich Lubricants GmbH	Ordinary	100.00
Überseeallee 1, 20457 Hamburg, Germany		
bp Austria GmbH	Ordinary	100.00
bp Retail Austria GmbH	Ordinary	100.00
Azerbaijan		
153 Neftchilar Avenue, Baku, AZ1010, Azerbaijan		
BP-AIOC Exploration (TISA) LLC	Membership Interest	65.88
TISA Education Complex LLC	Membership Interest	65.88
Belgium		
Langerbruggekaai 18, Gent, 9000, Belgium		
BP Iraq N.V.	Ordinary	100.00
Castrol Belgium B.V.	Ordinary	100.00
Brazil		
Al Santos, 74, Andar 7 Conj 72 Sala 53, Cerqueira Cesar, Sao Paulo, 01.418-000, Brazil		
Lightsource Milagres Holding 1 S.A.	Ordinary	100.00
Alameda Santos, 74, 7th floor, suite 72, room 111, Cerqueira César, Municipality of São Paulo, São Paulo, 01418-000, Brazil		
Lightsource Bom Lugar Holding 1 S.A.	Ordinary	100.00
Lightsource Bom Lugar Holding 2 S.A.	Ordinary	100.00
Alameda Santos, 74, 7th floor, suite 72, room 43, Cerqueira César, Municipality of São Paulo, São Paulo, 01418-000, Brazil		
Lightsource Brasil Energia Renovável Participações S.A.	Ordinary	100.00
Alameda Santos, 74, 7th floor, suite 72, room 44, Cerqueira César, Municipality of São Paulo, São Paulo, 01418-000, Brazil		
Lightsource Brasil Energia Renovável Ltda	Ordinary	100.00
Avenida das Américas 3434, Bloco 7, Sala 301 a 308 (parte), Barra da Tijuca, Rio de Janeiro, 22640-102, Brazil		
BP Brasil Ltda.	Ordinary	100.00
BP Energy do Brasil Ltda.	Ordinary	100.00
Castrol Brasil Ltda.	Ordinary	100.00
Avenida das Nações Unidas, 12.399, 4° andar, cj. 41B, sala 01, São Paulo, Brazil		
BP Bioenergy Products Ltda.	Ordinary	100.00
Avenida das Nações Unidas, n° 12.399, 4° andar, Brooklin Paulista, São Paulo, CEP 04578-000, Brazil		
BP Bioenergy S.A.	Ordinary	100.00
Avenida das Nações Unidas, n° 12.399, 4° andar, salas 43A e 44A, Torre C, Edifício Landmark, Brooklin Paulista, São Paulo/SP, CEP 04578-000, Brazil		
Air BP Brasil Ltda.	Ordinary	100.00
BP Biocombustíveis Ltda.	Ordinary	100.00
Avenida das Nações Unidas, n° 12.399, salas 62,63 e 64, lado B, 6° andar, Edifício Landmark, São Paulo/SP, CEP 04578-000, Brazil		
BP Comercializadora de Energia Ltda.	Ordinary	100.00
Estado do Rio Grande do Norte, Sítio Retiro, S/N, Estrada Caraúbas sentido Mirandas, Km 15, lado esquerdo, Zona Rural, Cidade de Caraúbas, CEP 59780-000, Brazil		
Lightsource Caraúbas Geração de Energia Ltda	Ordinary	100.00
Estrada de São Romão, KM23, S/N, Zona Rural, Fazenda São Francisco, Buritizeiro/MG, CEP 39280-000, Brazil		
Lightsource Andorinhas Geração de Energia Ltda.	Ordinary	100.00
Estrada Mossoró sentido Jaguaruana, S/N, Km 48, lado esquerdo, Zona Rural, Sítio Aroeira Grande, Município de Baraúna/RN, CEP 59695-000, Brazil		
Lightsource Jaguar Geração de Energia Ltda	Ordinary	100.00
Estrada Municipal Itumbiara / Chacoiera Dourada, Fazenda Jandaia, Gleba B, Goiás, Itumbiara, 75516-126, Brazil		
Itumbiara Bioenergia S.A	Ordinary	100.00

The parent company financial statements of BP p.l.c. on pages 269-333 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

13. Related undertakings of the group – continued

Estrada que liga Brejo Santo a Vila Conceição, porteira da Caatinga Grande, S/N, Zona Rural, Sítio Ludovico, Município de Brejo Santo/CE, CEP 63260-000, Brazil		
Lightsource Milagres Expansão Geração de Energia Ltda	Ordinary	100.00
Fazenda Água Amarela, S/N, Itapegipe, Minas Gerais, 38240-000, Brazil		
Itapagipe Bioenergia Ltda.	Ordinary	100.00
Fazenda Guariroba, SN, Zona Rural, Pontes Gestal, São Paulo, 15500-000, Brazil		
Guariroba Bioenergia Ltda	Ordinary	100.00
Fazenda Moema, s/n, Rural, Orindiuva, São Paulo, 15480-000, Brazil		
Moema Bioenergia S.A	Ordinary	100.00
Fazenda Recanto, Zona Rural, CEP 38.300-898, Minas Gerais, Ituiutaba, Brazil		
Ituiutaba Bioenergia Ltda	Ordinary	100.00
Fazenda Santa Bárbara, S/N, Distrito de Zelândia, Santa Juliana, Minas Gerais, 38175-000, Brazil		
Santa Juliana Bioenergia Ltda.	Ordinary	100.00
Fazenda São Bento da Ressaca, S/N, Zona Rural, Frutal, Minas Gerais, 38200-000, Brazil		
Frutal Bioenergia Ltda.	Ordinary	100.00
Fazenda Terra Nova, located at Rod. Padre Cicero (CE 153), S/N, KM 58, Lima Campos,Ceara, Ico, 63.435-000, Brazil		
Lightsource Bom Lugar IV Geração de Energia S.A.	Ordinary	100.00
Lightsource Bom Lugar IX Geração de Energia S.A.	Ordinary	100.00
Lightsource Bom Lugar V Geração de Energia S.A.	Ordinary	100.00
Lightsource Bom Lugar VI Geração de Energia S.A.	Ordinary	100.00
Lightsource Bom Lugar VII Geração de Energia S.A.	Ordinary	100.00
Lightsource Bom Lugar VIII Geração de Energia S.A.	Ordinary	100.00
Fazenda Vista Alegre I, KM 25, S/N, Zona Rural, Jaíba/ MG, CEP 39508-000, Brazil		
Lightsource Pomar do Sertão Geração de Energia Ltda.	Ordinary	100.00
KM 2.4 Sítio Cajueiro road - KM491 BR 116 KM 492, Caatinga Grande Zona Rural, Municipality of Abaiara, State of Ceará, 63.240.000, Brazil		
Lightsource Milagres I Geração de Energia S.A	Ordinary	100.00
Lightsource Milagres II Geração de Energia S.A	Ordinary	100.00
Lightsource Milagres III Geração de Energia S.A	Ordinary	100.00
Lightsource Milagres IV Geração de Energia S.A	Ordinary	100.00
Lightsource Milagres V Geração de Energia S.A	Ordinary	100.00
Rod. BA 827, S/N, KM 05 Estrada do Cantinho dos Afritos, Fazenda Divino Espirito Santo, City of Barreiras, State of Bahia, 47.819-899, Brazil		
Lightsource Rio Branco Geração de Energia Ltda	Ordinary	100.00
Rodovia GO 410, km 51 à esquerda, Fazenda Canadá, s/n, Zona Rural, Sala 01 Estado de Goiás, Edéia, 75940-000, Brazil		
Tropical Bioenergia S.A	Ordinary	100.00
Tropical Biogás Ltda	Ordinary	100.00
Rodovia Iaciara sentido Alvorada, Margem Direita, S/N, Zona Rural, Fazenda Ferradura e Campo Aberto, Município de Posse/GO, CEP 73900-000, Brazil		
Lightsource Guara Geracao de Energia Ltda	Ordinary	100.00
Rodovia SP - 463 Elyeser Montenegro Magalhães, KM 186, S/N, Zona Rural,São Paulo, Ouroeste, 15685-000, Brazil		
OUROESTE BIOENERGIA LTDA.	Ordinary	100.00
Rodovia TO 010 KM 20, S/N, Zona Rural, Cidade de Pedro Afonso, Tocantins, 77710-000, Brazil		
Pedro Afonso Bioenergia Ltda.	Ordinary	100.00
Rua Principal, Fazenda Recanto, Zona Rural, Caixa Postal 01, Minas Gerais, Ituiutaba, 38.300-898, Brazil		
Campina Verde Bioenergia LTDA	Ordinary	100.00
Sítio Paus Pretos, S/N, BR 316, Rood Floresta/Petrolandia, Km 314, Floresta/PE, Zip Code 56400-000, Brazil		
Lightsource Flor Geração de Energia Ltda.	Ordinary	100.00
British Virgin Islands		
Craigmuir Chambers, P.O. Box 71, Road Town, Tortola, British Virgin Islands		
BP Egypt East Delta Marine Corporation	Ordinary; Preference	100.00
BP Middle East Enterprises Corporation	Ordinary	100.00

13. Related undertakings of the group – continued

Ocorian Corporate Services (BVI) Limited, Jayla Place, Wickhams Cay 1, PO Box 3190, Tortola, Road Town, VG1110, British Virgin Islands

Wiriagar Overseas Ltd	Ordinary	100.00
Canada		
1100, 635 - 8th Avenue SW, Calgary AB T2P 3M3, Canada		
Terre de Grace Partnership	Partnership interest	75.00
1741 Lower Water Street, Suite 600, Halifax, NS, B3J 0J2, Canada		
BP Canada Energy Group ULC	Ordinary	100.00
240 Fourth Avenue SW, Calgary AB T2P 2H8, Canada		
563916 Alberta Ltd.	Preference	33.33
Dome Beaufort Petroleum Limited	Ordinary	100.00
900, 1959 Upper Water Street, Halifax, NS, B3J 3N2, Canada		
BP Canada Energy Development Company	Ordinary	100.00
Chile		
Av. Américo Vespucio Sur No. 100, of. 1101, Las Condes, Santiago, Chile		
Burmah Chile SpA	Ordinary	100.00
China		
12, Floor 26, Inner 101, Floor 4-43, Building 1, No. 161 Jinze Road, Fengtai District, Beijing		
Beijing BP Advanced Mobility Limited	Membership Interest	100.00
1-3 Floors, Unit D2, Zhimajie 1958 Innovation and Entrepreneurship Park, No. 220, Huashan Road, Zhongyuan District, Zhengzhou City, China		
Zhengzhou BP Xiaoju New Energy Co., Ltd	Membership Interest	89.09
201-D069, No.13 and No.15 Fujia Middle Street, Nansha District, Guangzhou, China		
Guangdong Jintian Technology Co., Ltd.	Membership Interest	100.00
307-1, 3rd Floor, No. 7-1, Yushan Avenue, Guodian Sub-district, Licheng District, Jinan City, Shandong Province, China		
Jinan BP Xiaoju New Energy Co., Ltd.	Membership Interest	89.09
4-2-506, Rongchuang Rongsheng Plaza, Binhai-Zhongguancun Science and Technology Park, Tianjin Economic and Technological Development Zone, Tianjin, China		
Tianjin BP Advanced Mobility Limited	Membership Interest	100.00
501, Unit 1, Building 12, Changtang Fourth District, Fotang Town, Yiwu City, Jinhua City, Zhejiang Province, China		
Jinhua BP Xiaoju New Energy Co., Ltd.	Membership Interest	89.09
808-02, Building 2, No.16, Xingao Road, Niutang Town, Wujin District, Changzhou City, Jiangsu Province, China		
Changzhou BP Xiaoju New Energy Co., Ltd.	Membership Interest	89.09
D69, Floor 3, Block 1, Phase 6, Tianan Nanhai Digital New Town, No.12, Jianping Road, Guicheng Street, Nanhai District, Foshan city, China		
Foshan BP Xiaoju New Energy Co., Ltd.	Membership Interest	89.09
Floor 3, Building 5, 255 Guiqiao Road, Shanghai Pilot Free Trade Zone, China		
Castrol (Shanghai) Management Co., Ltd	Membership Interest	100.00
No 833, South Guang Zhou Avenue, Guangzhou Province, Haizhu District, China		
BP Guangdong Limited	Membership Interest	90.00
No. 06-03, 5th Floor, Building 1, Modern-International Design Phase 1, Guandong Street, No. 41, Guanggu Avenue, East Lake New Technology Development Zone, Wuhan (Wuhan Free Trade Zone), Hubei Province, China		
Wuhan BP Advanced Mobility Limited	Membership Interest	100.00
No. 302-2401, No. 6-2 Tong'an Second Road, Fushan New Area Street, Shibei District, Qingdao City, Shandong Province, China		
Qingdao BP Advanced Mobility Limited	Membership Interest	100.00
No. 3-6-23, 1st Floor, Building 7, No. 130 Xiazhongdukou, Shapingba Street, Shapingba District, Chongqing, China		
Chongqing BP Advanced Mobility Limited	Membership Interest	100.00
No. 399 Dongfeng highway, Dongping Town, Chongming District, (Dongping Economic Development, Shanghai City, China		
Shanghai Quanzhi New Energy Co., Ltd.	Membership Interest	89.09
No. 6, Floor 1, Building A, No. 2, West Tao Hong Street, Shi Ma Village, Jun He Street, Guangzhou, China		
Guangdong Jintian New Energy Automobile Co., Ltd.	Membership Interest	100.00
No.2, North Chuangang Road, Nangang Industrial Zone, Tianjin Economic Development Area, Tianjin, China		
Castrol (Tianjin) Lubricants Co., Ltd	Membership Interest	100.00

The parent company financial statements of BP p.l.c. on pages 269-333 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

13. Related undertakings of the group – continued

No.9 Bin Jiang South Road, Petrochemical Industrial Park, Taicang Gangkou Development Zone, Jiangsu Province, China BP (China) Industrial Lubricants Limited	Membership Interest	100.00
Room 04, second floor, No.17, Zhuyoujiayuan, Binhu District, Wuxi City, China Wuxi BP Xiaoju New Energy Co., Ltd.	Membership Interest	89.09
Room 0512,7th Floor, Building No.3 4, Lvdiilianshengguoji, Jinhuyuan Street, Guanshanyuan District, Guiyang City, China GuiYang City BP Xiaoju New Energy Technology Co. Ltd.	Membership Interest	89.09
Room 1001, 10th Floor, Building A2, Xiangjiang Times Business Square, No.179 Xiandao Road, Yuelu District, Hunan, Changsha, China BP (Hunan) Petroleum Company Limited	Membership Interest	100.00
Room 1008-A018, Kangfengdasha, No.188, Fuqiang Road, Yuhua District, Shijiazhuang City, China Shijiazhuang City BP Xiaoju New Energy Technology Co. Ltd.	Membership Interest	89.09
Room 102, No. 1, Shixin Road, Shiqiao Street, Panyu District, Guangzhou, China Guangzhou Jintian New Energy Technology Co., Ltd.	Membership Interest	100.00
Room 1107-2A258, Building 1, Aerospace City Center Square, Shenzhouwu Road, National Civil Aerospace Industry Base, Xi'an City, Shaanxi Province, China BP (Xi'an) Advanced Mobility Limited	Membership Interest	100.00
Room 1109, 1028 Panyu Road, Xuhui District, Shanghai, China Castrol (Shanghai) Auto Service Technology Ltd	Membership Interest	65.00
Room 1-2201, Sijian Meilin Mansion, No. 48-15 Wuyingshan Middle Road, Tianqiao District, Shandong, Ji'nan, China BP (Shandong) Petroleum Co., Ltd	Membership Interest	100.00
Room 1-2313, Building No.20, No.216, Gucheng Road, Luolong District, Luoyang City, China Luoyang BP Xiaoju New Energy Co., Ltd.	Membership Interest	89.09
Room 1703B051, 17th Floor, Building 1, Gaoxin SOHO, Yinlan Road, Science Avenue, Zhengzhou High-tech Industrial Development Zone, Henan Province Zhengzhou BP Advanced Mobility Limited	Membership Interest	100.00
Room 201, 2nd floor, Building 3, Industrial Research and Development, Xingong Standard Factory Building, No. 31, Songbai Road, Santang Town, Xingning District, Nanning City, Guangxi Province, China Nanning BP Xiaoju New Energy Co., Ltd.	Membership Interest	89.09
Room 201, Complex A, Qianwan Road 1, Qianhai Shenzhen-Hong Kong Cooperation Zone, Shenzhen City, China BP Xiaoju New Energy (Shenzhen) Co., Ltd.	Membership Interest	89.09
Room 2103, 10 Hua Xia Road, Tianhe District, Guangzhou, PR, China BP (Guangzhou) Advanced Mobility Limited	Ordinary	100.00
Room 2106-072, Gongxiaodasha, No.599, Wuyi Road, Dingwangtai Street, Furong District, Changsha City, China Changsha BP Xiaoju New Energy Co., Ltd.	Membership Interest	89.09
Room 215, Building #5, No. 72, Nanxiang Er Road, Guangzhou, China Guangzhou Jintian Linkage New Energy Technology Co., Ltd.	Membership Interest	100.00
Room 2-1-7, 1st Floor, Building 7, No.130 Xiazhong Dukou, Shapingba District, Chongqing, China Chongqing BP Xiaoju New Energy Co., Ltd.	Membership Interest	89.09
Room 222-1, Building 1, Wanya Famous City, Qiantang New District, Hangzhou City, Zhejiang Province, China Hangzhou BP Xiaoju New Energy Co., Ltd.	Membership Interest	89.09
Room 2233, second floor, Aofeng Street Resettlement House #1, No. 50 Aofeng Road, Aofeng Street, Fuzhou City, Taijiang District, China Fujian BP Xiaoju New Energy Co., Ltd	Membership Interest	89.09
Room 2245, Area G, Building 10, Yaxi International Slow City Town, Gaochun District, Nanjing City, Jiangsu Province, China Nanjing BP Advanced Mobility Limited	Membership Interest	100.00
Room 2305, Floor 20, Building 29, Yard 8, West Cultural Park Road, Beijing Economic and Technological Development Zone, Beijing, China Beijing BP Xiaoju New Energy Co., Ltd.	Membership Interest	89.09
Room 2-521, Building A, No.6 Huafeng Road, Huaming Hi-tech Industrial Zone, Dongli District, Tianjin city, China Tianjin BP Xiaoju New Energy Co., Ltd.	Membership Interest	89.09
Room 306 D21, third floor, No.64, Shiji Road, Shiji Street, Panyu District, Guangzhou City, China Guangzhou BP Xiaoju New Energy Co., Ltd.	Membership Interest	89.09
Room 3075, Building No.2, No.8, Jinpu Road, Industrial Zone, Suzhou City, China Suzhou BP Xiaoju New Energy Co., Ltd.	Membership Interest	89.09

13. Related undertakings of the group – continued

Room 309, 3rd Floor, 2nd Floor, Southwest International Business Port, West Square, Taiyuan South Station, Taiyuan City, Xiandian District, China	Taiyuan BP Xiaoju New Energy Co., Ltd.	Membership Interest	89.09
Room 3122, 3rd Floor, Building 3, No. 36, Baiyang Street, Qiantang District, Hangzhou, Zhejiang Province, China	Hangzhou BP Advanced Mobility Limited	Membership Interest	100.00
Room 3313, No.19, Jinmengxiang Road, Xiangzhou District, Zhuhai City, China	Zhuhai BP Xiaoju New Energy Co., Ltd.	Membership Interest	89.09
Room 339, 3rd Floor, Building A, No. 1605, Wenzhou Avenue, Huangyu Village, Sanyang Sub-district, Ouhai District, Wenzhou City, Zhejiang Province, China	Wenzhou BP Xiaoju New Energy Co., Ltd.	Membership Interest	89.09
Room 3726, Building 3, No. 89 Shuanggao Road, Gaochun Economic Development Zone, Nanjing, Gaochun District, China	Nanjing BP Xiaoju New Energy Co., Ltd.	Membership Interest	89.09
Room 402-12, No.90-96 Science Avenue (even), Huangpu District, Guangzhou, China	Guangzhou Huangpu BP Xiaoju New Energy Technology Co., Ltd.	Membership Interest	89.09
Room 421, Floor 4, Building 8, No. 388, North Section of Yizhou Avenue, High-tech Zone, Chengdu city, China	Chengdu BP Xiaoju New Energy Co., Ltd.	Membership Interest	89.09
Room 432, 4th Floor, (No. 2 Scientific Research Complex Building), No. 36, Shuxiawang Road, Beihai Sub-district, Yuecheng District, Shaoxing City, Zhejiang Province, China	Shaoxing BP Xiaoju New Energy Co., Ltd.	Membership Interest	89.09
Room 505, 5th Floor, Building 6, No. 599, Century City South Road, Chengdu High-tech Zone, China (Sichuan) Pilot Free Trade Zone, China	Chengdu BP Advanced Mobility Limited	Membership Interest	100.00
Room 668, fourth floor, No.8, Dongcheng Guangming Road, Dongcheng Street, Dongguan City, China	Dongguan BP Xiaoju New Energy Co., Ltd.	Membership Interest	89.09
Room 708-168, 7th Floor, Building C, Hangchuang Plaza, Shenzhou 4th Road, National Civil Aerospace Industry Base, Xi'an, Shaanxi, China	Xi'an BP Xiaoju New Energy Co., Ltd.	Membership Interest	89.09
Room 7088-594, No.1558, Jiangnan Road, High-tech District, Ningbo City, China	Ningbo BP Xiaoju New Energy Co., Ltd.	Membership Interest	89.09
Room 716, Block C, Future Science and Technology Plaza, No.136, Xiuzhou Avenue, Xincheng Street, Zhejiang Province, Jiaxing City, China	Jiaxing BP Xiaoju New Energy Co., Ltd.	Membership Interest	89.09
Room 820, 8th Floor, Hilton Hotel, Platinum Bay World Trade Center, 1100, Section 3, Xiaoxiang North Road, Hunan Province, Changsha City, Yuelu District, China	Changsha BP Advanced Mobility Limited	Membership Interest	100.00
Room -829, 1st Floor, D2 District, Fuxing City, No. 32 Binhai Avenue, Binhai Street, Longhua District, Haikou City, Hainan Province, China	Hainan BP Xiaoju New Energy Co., Ltd.	Membership Interest	89.09
Room A313, No.258, Donghai Road, Haiwan Street, Taizhouwan New District, Taizhou City, China	Taizhou BP Xiaoju New Energy Co., Ltd.	Membership Interest	89.09
Room C2256, Maker Space, Building A, Baoye Centre, No.31, Jiansheyi Road, Qingshan District, Wuhan City, China	Wuhan BP Xiaoju New Energy Technology Co., Ltd.	Membership Interest	89.09
Unit 01, 6th Floor (actual 5th), No.90 Qirong Road, China (Shanghai) Pilot Free Trade Zone, China	BP (China) Holdings Limited	Membership Interest	100.00
Colombia			
Calle 80 No.11-42 Oficina 901, Bogota, 110111, Colombia	Castrol Colombia Ltda.	Ordinary	100.00
	GOAM 1 C.I.S.A.S	Ordinary	100.00
Croatia			
Savska cesta 32, Zagreb, Croatia	Air BP Croatia d.o.o.	Ordinary	100.00
Denmark			
Kampmannsgade 2. 1604 København V, Denmark	BP Aviation A/S	Ordinary	100.00
	Castrol Denmark A/S	Ordinary	100.00

The parent company financial statements of BP p.l.c. on pages 269-333 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

13. Related undertakings of the group – continued

Egypt		
Plot No 14d03, The Southern Business district of Cairo, Festival City - New Cairo, Cairo, Egypt		
BP Marketing Egypt LLC	Ordinary	100.00
Castrol Egypt Lubricants S.A.E.	Ordinary	51.00
Castrol Egypt Marketing SSC	Ordinary	100.00
Finland		
Öljytie 4, 01530 Vantaa, Finland		
Air BP Finland Oy	Ordinary	100.00
France		
1165 rue Jean-René Guilibert Gauthier de la Lauzière – CS 20583, Aix-les-Milles Cedex 02, 13290, France		
Lightsource France Development SAS	Ordinary	100.00
Lightsource France SPV 1 SAS	Ordinary	100.00
Lightsource France SPV 2 SAS	Ordinary	100.00
Lightsource France SPV 3 SAS	Ordinary	100.00
Lightsource France SPV 4 SAS	Ordinary	100.00
Lightsource France SPV 5 SAS	Ordinary	100.00
Lightsource France SPV 6 SAS	Ordinary	100.00
Lightsource France SPV 7 SAS	Ordinary	100.00
Campus Saint Christophe, Bâtiment Galilée 3, 10 Avenue de l'Entreprise, Cergy Cedex, 95863, France		
BP France	Ordinary	100.00
Castrol France Sas	Ordinary	100.00
Produits Metallurgie Doittau	Ordinary	100.00
Société de Gestion de Dépôts d'Hydrocarbures - GDH	Ordinary	100.00
SRHP	Ordinary	100.00
Germany		
Alexander-von-Humboldt-Straße 1, Gelsenkirchen, 45896, Germany		
Gelsenkirchen Raffinerie Netz GmbH	Ordinary	100.00
Ruhr Oel GmbH	Ordinary	100.00
An der Börse 4, 30159 Hannover, Germany		
Dritte Energieversorgungsvorratsgesellschaft mbH	Ordinary	100.00
FORTAS Energie Gas GmbH	Ordinary	100.00
GETEC ENERGIE GmbH	Ordinary	100.00
GEWI GmbH	Ordinary	81.28
An der Steinkuhle 2 d-e, 39128 Magdeburg, Germany		
GETEC Daten-und Abrechnungsmangement GmbH	Ordinary	100.00
c/o WeWork, Kemperplatz 1, Berlin, 10785, Germany		
Lightsource Development Deutschland GmbH	Ordinary	100.00
Lightsource GP GmbH	Ordinary	100.00
Lightsource LP1 GmbH	Ordinary	100.00
Margarete-Steiff-Straße 1-3, 24558 Henstedt-Ulzburg, Germany		
EEG Energie- Einkaufs- und Service GmbH	Ordinary	100.00
Raffineriestraße 1, Lingen, 49808, Germany		
Lingen Green Hydrogen GmbH & Co. KG	Ordinary	100.00
Lingen Green Hydrogen Management GmbH	Ordinary	100.00
Sportallee 6, 22335 Hamburg, Germany		
TGH Tankdienst-Gesellschaft Hamburg GbR	Partnership interest	66.67
Timmerhellstr. 28, Mülheim/Ruhr, 45478, Germany		
DHC Solvent Chemie GmbH	Ordinary	100.00
Überseeallee 1, 20457 Hamburg, Germany		
Aral Deutschland SE & Co. KG	Membership Interest	100.00
BP Energy Holdings GmbH	Ordinary	100.00
BP Europa SE ^b	Ordinary	100.00

13. Related undertakings of the group – continued

bp Fuels Germany SE & Co. KG	Membership Interest	100.00
BP Lingen Green Hydrogen Verwaltung GmbH	Ordinary	100.00
BP Olex Fanal Mineralöl GmbH	Ordinary	100.00
bp Services Germany SE & Co. KG	Membership Interest	100.00
Castrol Deutschland Verwaltungsgesellschaft mbH	Ordinary	100.00
Castrol Germany GmbH	Ordinary	100.00
Wittener Straße 45, 44789 Bochum, Germany		
Aral Aktiengesellschaft	Ordinary	100.00
B2Mobility GmbH	Ordinary	100.00
bp Business Services Germany GmbH	Ordinary	100.00
Trafineo GmbH & Co. KG	Partnership interest	75.00
Trafineo Service GmbH	Ordinary	75.00
Trafineo Verwaltungs-GmbH	Ordinary	75.00
Ghana		
Atlantic Tower, 4th Floor, Liberation Road, Airport City, Accra, Ghana		
BP Ghana Ltd	Ordinary	100.00
Greece		
1, Proteos & 51, Anapafseos str, 15235 Vrilissia, Attica, Greece		
RAPI SA	Ordinary	62.51
26A, Ioannou Apostolopoulou, 15231, Chalandri, Attica, Greece		
BP Oil Hellenic S.M.S.A.	Ordinary	100.00
Castrol Hellas Single Member Societe Anonyme	Ordinary	100.00
68, Vasilisis Sofias Ave., Athens, 115 28, Greece		
AI ENERGY SINGLE MEMBER P.C.	Ordinary	100.00
Akarnanika Photovoltaic Systems Single-Member Private Company	Ordinary	100.00
Enipeas Single Member S.A.	Ordinary	100.00
Lightsource Renewable Energy Greece Development Single Member S.A.	Ordinary	100.00
Lightsource Renewable Energy Greece Projects 3 SINGLE MEMBER S.A.	Ordinary	100.00
Lightsource Renewable Greece BESS 1 S.A.	Ordinary	100.00
Lightsource Renewable Greece BESS 2 S.A.	Ordinary	100.00
Local Community of Kyrakalis, number 0, Municipality of Grevena, 51100, Greece		
Clean Energy 1 S.M.S.A.	Ordinary	100.00
Clean Energy 4 S.M.S.A.	Ordinary	100.00
Green Energy Plus 1 S.M.S.A.	Ordinary	100.00
Green Energy Plus 2 S.M.S.A.	Ordinary	100.00
Green Energy Plus 7 S.M.S.A.	Ordinary	100.00
Guernsey		
Suite 1 North, First Floor, Albert House, South Esplanade, St Peter Port, GY1 1AJ, Guernsey		
BP Pensions (Overseas) Limited ^c	Ordinary	100.00
Jupiter Insurance Limited	Ordinary	100.00
Hong Kong		
Room 1218, Space Wai Yip Street, 11,12, Rooftop, 133 Wai Yip Street, Kowloon, Hong Kong		
Castrol (China) Limited	Ordinary	100.00
Hungary		
1133 Budapest, Árbóc utca 1-3, Hungary		
BP Business Service Centre KFT	Membership Interest	100.00
Castrol Lubricants Hungary KFT	Ordinary	100.00
Iceland		
Skogarhlid 12, 105, Reykjavik, Iceland		
Air BP Iceland	Ordinary	100.00

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13. Related undertakings of the group – continued

India		
2nd,3rd & 4th Floor, 201,301,401, Bldg. No. 6, R4, KRC Infrastructure & Projects Pvt. Ltd. SEZ, Kharadi, Pune 411014, India		
BP Business Solutions India Private Limited	Ordinary	100.00
Bldg 8, 7,8,9th Flr, Sr No, 144/145,Commerzone, Yerwada, Pune City, Maharashtra, 411006, India		
Castrol Services Private Limited	Ordinary	100.00
Technopolis Knowledge Park, Mahakali Caves Road, Andheri (East), Mumbai 400093, India		
BP India Private Limited	Ordinary	100.00
Castrol India Limited	Ordinary	51.00
Indonesia		
Arkadia Green Park, Tower G, 2nd Floor, Jl. Letjend TB Simatupang Kav. 88, Jakarta Selatan, Pasar Minggu, 12520, Indonesia		
PT Jasatama Petroindo	Ordinary A; Ordinary B	100.00
Arkadia Green Park, Tower G, 3rd floor, Jl. Let. Jen. TB Simatupang Kav. 88, Jakarta Selatan, Jakarta 12520, Indonesia		
PT Castrol Indonesia	Ordinary	68.30
JL. Raya Merak KM 117,DS Gerem, Gerem Grogol, Banten, Cilegon, Indonesia		
PT Castrol Manufacturing Indonesia	Ordinary	68.30
Iraq		
Pier 1, Khor Al Zubair, Basrah, Iraq		
Water Way Trading and Petroleum Services LLC	Ordinary	100.00
Royal Tulip Al Rasheed Hotel, Baghdad Tower, PO Box 8070, Baghdad, Iraq		
Phoenix Petroleum Services, Limited Liability Company	Ordinary	100.00
Ireland		
Fifth Floor Block D, Iveagh Court, Harcourt Road, Dublin 2, D02 VH94, Ireland		
Lightsource Ireland Development Holdings Limited	Ordinary	100.00
Lightsource Ireland SPV 6 Limited	Ordinary	100.00
Lightsource Renewable Energy Ireland Limited	Ordinary	100.00
One Spencer Dock, North Wall Quay, Dublin 1, Ireland		
Castrol (Ireland) Limited	Ordinary	100.00
Italy		
Piazza Borromeo, 12, Milano, 20123, Italy		
BP Italia Holdings SpA	Ordinary	100.00
Via Gaetano De Castillia, 23, Milan, MI, 20124, Italy		
BP Italia SpA	Ordinary	100.00
Via Giacomo Leopardi 7, Milano, 20123, Italy		
Belenos s.r.l.	Quotas	65.00
HF Solar 3 S.r.l.	Quotas	100.00
HF Solar 4 S.r.l.	Quotas	100.00
HF Solar 5 S.r.l.	Quotas	100.00
Lightsource Renewable Energy Italy Development, S.r.l.	Quotas	100.00
Lightsource Renewable Energy Italy Finco s.r.l.	Quotas	100.00
Lightsource Renewable Energy Italy Holdings S.r.l.	Quotas	100.00
Lightsource Renewable Energy Italy SPV 1 s.r.l.	Quotas	100.00
Lightsource Renewable Energy Italy SPV 10 s.r.l.	Quotas	100.00
Lightsource Renewable Energy Italy SPV 12 S.R.L.	Quotas	100.00
Lightsource Renewable Energy Italy SPV 13 S.R.L.	Quotas	100.00
Lightsource Renewable Energy Italy SPV 14 S.R.L.	Quotas	100.00
Lightsource Renewable Energy Italy SPV 15 S.R.L.	Quotas	100.00
Lightsource Renewable Energy Italy SPV 16 S.R.L.	Quotas	100.00
Lightsource Renewable Energy Italy SPV 17 S.R.L.	Quotas	100.00
Lightsource Renewable Energy Italy SPV 18 S.R.L.	Quotas	100.00
Lightsource Renewable Energy Italy SPV 19 S.R.L.	Quotas	100.00
Lightsource Renewable Energy Italy SPV 2 s.r.l.	Quotas	100.00
Lightsource Renewable Energy Italy SPV 20 S.R.L.	Quotas	100.00

13. Related undertakings of the group – continued

Lightsource Renewable Energy Italy SPV 21 S.R.L.	Quotas	100.00
Lightsource Renewable Energy Italy SPV 22 S.R.L.	Quotas	100.00
Lightsource Renewable Energy Italy SPV 23 S.R.L.	Quotas	100.00
Lightsource Renewable Energy Italy SPV 24 S.R.L.	Quotas	100.00
Lightsource Renewable Energy Italy SPV 25 S.R.L.	Quotas	100.00
Lightsource Renewable Energy Italy SPV 26 S.R.L.	Quotas	100.00
Lightsource Renewable Energy Italy SPV 27 S.R.L.	Quotas	100.00
Lightsource Renewable Energy Italy SPV 28 S.R.L.	Quotas	100.00
Lightsource Renewable Energy Italy SPV 29 S.R.L.	Quotas	100.00
Lightsource Renewable Energy Italy SPV 30 S.R.L.	Quotas	100.00
Lightsource Renewable Energy Italy SPV 31 S.R.L.	Quotas	100.00
Lightsource Renewable Energy Italy SPV 32 S.R.L.	Quotas	100.00
Lightsource Renewable Energy Italy SPV 33 S.R.L.	Quotas	100.00
Lightsource Renewable Energy Italy SPV 4 s.r.l.	Quotas	100.00
Lightsource Renewable Energy Italy SPV 8 s.r.l.	Quotas	100.00
Lightsource Renewable Energy Italy SPV 9 s.r.l.	Quotas	100.00
Pollon s.r.l.	Quotas	65.00
Via Venti Settembre, 69, Palermo, 90141, Italy		
Marsala Energie S.r.l.	Quotas	100.00
Melilli Energie S.r.l.	Quotas	100.00
ML Energie Rinnovabili S.r.l.	Quotas	100.00
Viale Francesco Scaduto, 2d, Palermo, 90144, Italy		
HF Solar 10 S.r.l.	Quotas	100.00
Japan		
15th Fl. Roppongi Hills Mori Tower, 10-1 Roppongi 6-chome, Minato-ku, Tokyo106-6115, Japan		
BP Japan K.K.	Ordinary	100.00
TK K.K.	Ordinary	100.00
Annan House 33-35 Palmerston Road, 4th Floor, Aberdeen, Scotland, AB11 5QP		
Lightsource Renewable Energy Development Japan SPV1 GK	Ordinary	100.00
c/o Forvis Mazars Japan Co., Ltd., Akasaka Intercity 5F, 1-11-44 Akasaka, Minato-ku, Tokyo, 107-0052, Japan		
GK Flor De Loto56	Membership Interest	100.00
Lightsource Renewable Energy Development Japan GK	Membership Interest	100.00
East Tower 20F, Gate City Ohsaki, 1-11-2 Osaki, Shinagawa-ku, Tokyo, Japan		
BP Castrol KK	Ordinary	64.84
BP Lubricants KK	Ordinary	64.84
Castrol KK	Ordinary	64.84
Roppongi Hills Mori Tower 33F, 6-10-1, Roppongi, Minato-ku, Tokyo, Japan		
BP Energy Japan KK	Ordinary	100.00
Korea (the Republic of)		
#125 DD-01, 14F, 416 Hangang-daero, Jung-gu, Seoul, 04637, Korea (the Republic of)		
SK Devco Solar Power Plant Co., Ltd.	Ordinary	100.00
#125 DD-02, 14F, 416 Hangang-daero, Jung-gu, Seoul, 04637, Korea (the Republic of)		
LS Renewable Energy Co., Ltd.	Ordinary	100.00
#125 DD-03, 14F, 416 Hangang-daero, Jung-gu, Seoul, 04637, Korea (the Republic of)		
Gangjin Solar Power Plant Co., Ltd.	Ordinary	100.00
#125 DD-04, 14F, 416 Hangang-daero, Jung-gu, Seoul, 04367, Korea (the Republic of)		
Haenam Solar Power Plant Co., Ltd.	Ordinary	100.00
#132, 14F, 416 Hangang-daero, Jung-gu, Seoul, 04637, Korea (the Republic of)		
Lightsource Renewable Energy Development South Korea Co., Ltd	Ordinary	100.00
19th Floor, 302, Teheran-ro, Gangnam-gu, Seoul, Korea (the Republic of)		
BP Korea Limited	Ordinary	100.00

13. Related undertakings of the group – continued

Luxembourg		
Bâtiment B, 36 route de Longwy, L-8080 Bertrange, Luxembourg		
Aral Luxembourg S.A.	Ordinary	100.00
Aral Tankstellen Services Sarl	Ordinary	100.00
Malaysia		
Level 9, Tower 5, Avenue 7, The Horizon Bangsar South City, No. 8, Jalan Kerinchi, Kuala Lumpur, 59200, Malaysia		
Aspac Lubricants (Malaysia) Sdn. Bhd.	Ordinary	63.03
BP Business Service Centre Asia Sdn Bhd	Ordinary	100.00
BP Castrol Lubricants (Malaysia) Sdn. Bhd.	Ordinary	63.03
BP Malaysia Holdings Sdn. Bhd.	Ordinary	70.00
Mexico		
Avenida Santa Fe 505, Col. Cruz Manca Santa Fe, Delegacion Cuajimalpa, Mexico		
BP Energía México, S. de R.L. de C.V.	Ordinary; Ordinary B	100.00
BP Estaciones y Servicios Energéticos, Sociedad Anónima de Capital Variable	Ordinary A; Ordinary B	100.00
BP Exploration Mexico, S.A. De C.V.	Ordinary A; Ordinary B	100.00
BP Servicios de Combustibles S.A. de C.V.	Ordinary A; Ordinary B	100.00
BP Servicios territoriales, S.A. de C.V.	Ordinary A; Ordinary B	100.00
BUSINESS TECHNOLOGY CENTER DE COMBUSTIBLES MEXICO, S.A. DE C.V.	Ordinary	100.00
Castrol Mexico, S.A. de C.V.	Ordinary A; Ordinary B	100.00
Mes Tecnología En Servicios Y Energia, S.A. De C.V.	Ordinary A; Ordinary B	100.00
Mozambique		
Torres Rani, Avenida Marginal, Talhão 141, 6° andar, Maputo, Mozambique		
BP Mocambique Limitada	Ordinary	100.00
Netherlands		
Boompjes 40, NL 3011 XB, Rotterdam, Netherlands		
ConceptsnSolutions B.V.	Ordinary	87.50
Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, England, United Kingdom		
BP Capital Markets B.V.	Ordinary	100.00
BP Energy Europe B.V.	Ordinary	100.00
d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands		
Amoco Canada International Holdings B.V.	Ordinary	100.00
Amoco Exploration Holdings B.V.	Ordinary	100.00
Amoco Trinidad Gas B.V.	Ordinary	100.00
BP Canada International Holdings B.V.	Ordinary	100.00
BP Commodity Supply B.V.	Ordinary	100.00
BP Egypt East Tanka B.V.	Ordinary	100.00
BP Egypt Production B.V.	Ordinary	100.00
BP Egypt Ras El Barr B.V.	Ordinary	100.00
BP Egypt West Mediterranean (Block B) B.V.	Ordinary	100.00
BP Holdings B.V.	Ordinary	100.00
BP Holdings International B.V.	Ordinary	100.00
BP Management International B.V.	Ordinary	100.00
BP Muturi Holdings B.V.	Ordinary	100.00
BP Nederland Holdings B.V.	Ordinary	100.00
bp Netherlands B.V.	Ordinary	100.00
BP Netherlands Upstream B.V.	Ordinary	100.00
BP Raffinaderij Rotterdam B.V.	Ordinary	100.00
BPNE International B.V.	Ordinary	100.00
Castrol B.V.	Ordinary	100.00
Castrol Holdings Europe B.V.	Ordinary	100.00
Castrol Nederland B.V.	Ordinary	100.00
Foseco Holding International B.V.	Ordinary	100.00

13. Related undertakings of the group – continued

Nijverheidsstraat 5, 7641 AB, Wierden, Netherlands		
Energie Makelaar B.V.	Ordinary	84.99
Stadsplateau 27, 27-29, Utrecht, 3521AZ, Netherlands		
Lightsource Renewable Energy Netherlands Development B.V.	Ordinary	100.00
Lightsource Renewable Energy Netherlands Holdings B.V.	Ordinary	100.00
Zonneweide LS 4 B.V.	Ordinary	100.00
Zonneweide LS 5 B.V.	Ordinary	100.00
Zonneweide LS 6 B.V.	Ordinary	100.00
Zonneweide LS 7 B.V.	Ordinary	100.00
Zonneweide LS 8 B.V.	Ordinary	100.00
Überseeallee 1, 20457, Hamburg, Germany		
BP Holdings Central Europe B.V.	Ordinary	100.00
New Zealand		
Corporate Services New Zealand Limited, Level 5, 79 Queen Street, Auckland, 1010, New Zealand		
Lightsource Development Services New Zealand Limited	Ordinary	100.00
LSNZ Glorit Holdco Limited	Ordinary	100.00
LSNZ Kowhai Park EquityCo Limited	Ordinary	100.00
LSNZ Kowhai Park HoldCo Limited	Ordinary	100.00
LSNZ Stratford HoldCo Limited	Ordinary	100.00
Level 2, Stantec Building 105 Carlton Gore Road Newmarket Auckland, 1023, New Zealand		
BP New Zealand Holdings Limited	Ordinary	100.00
BP Oil New Zealand Limited	Ordinary	100.00
BP Pacific Investments Ltd	Ordinary	100.00
Castrol New Zealand Limited	Ordinary	100.00
Coro Trading NZ Limited	Ordinary	100.00
Europa Oil NZ Limited	Ordinary	100.00
Nigeria		
Heritage Place, 13th Floor, 21 Lugard Avenue, Lagos, Ikoyi, Nigeria		
BP Global West Africa Limited	Ordinary	100.00
Lekki Free Zone, Opposite Tiye Town, Akodo Road, Off Lekki-Epe Coastal Road, Lagos, Nigeria		
BP Lekki FZE	Ordinary	100.00
Norway		
Fjordalléen 16, Oslo, 0250, Norway		
Air BP Norway AS	Membership Interest	100.00
Castrol Norway AS	Ordinary	100.00
Oman		
PO Box 2309, Salalah, 211, Oman		
BP Global Investments Salalah & Co LLC	Ordinary	100.00
Rock Garden Plaza – Phase 1 Building, PO Box 545, PC 118, Oman		
BP Duqm Hydrogen SPC	Ordinary	100.00
Special Economic Zone at Duqm, PO Box 1649, PC 130, Oman		
BP Hydrogen Operator SPC	Ordinary	100.00
Pakistan		
D-67/1, Block # 4, Scheme # 5, Clifton, Karachi, Pakistan		
Castrol Pakistan (Private) Limited	Ordinary	100.00
Peru		
Av. Camino Real Nro. 456 Int. 1202 Urb. Centro Comercial Camino Real Lima, San Isidro, Lima, Peru		
CASTROL DEL PERU S.A.C.	Ordinary	100.00
Philippines		
2nd Floor AGS Building, 446 EDSA, Makati City 1211, Philippines		
Castrol Philippines, Inc.	Ordinary	100.00

The parent company financial statements of BP p.l.c. on pages 269-333 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

13. Related undertakings of the group – continued

Poland		
ul. Grzybowska 2/29, Warszawa, 00-131, Poland		
Lightsource Development Polska sp. z o.o.	Ordinary	100.00
LS 1 sp. z.o.o.	Ordinary	100.00
LS 10 sp. z o.o.	Ordinary	100.00
LS 11 sp. z o.o.	Ordinary	100.00
LS 12 sp. z o.o.	Ordinary	100.00
LS 13 sp. z.o.o.	Ordinary	100.00
LS 14 sp. z.o.o.	Ordinary	100.00
LS 2 sp. z.o.o.	Ordinary	100.00
LS 3 sp. z.o.o.	Ordinary	100.00
LS 4 sp. z.o.o.	Ordinary	100.00
LS 5 sp. z.o.o.	Ordinary	100.00
LS 6 sp. z.o.o.	Ordinary	100.00
LS 7 sp. z.o.o.	Ordinary	100.00
LS 8 sp. z o.o.	Ordinary	100.00
LS 9 sp. z.o.o.	Ordinary	100.00
RD PV Produkcja 5 Spółka Z Ograniczona Odpowiedzialnoscia	Ordinary	100.00
ul. Grzybowska 62, Warszawa, 00-844, Poland		
Castrol CEE spółka z ograniczoną odpowiedzialnością	Ordinary	100.00
ul. Pawia 9, Małopolskie, Kraków, 31-154, Poland		
BP Polska Services Sp. z o.o.	Membership Interest	100.00
Portugal		
Lagoas Park, Edifício 3, Porto Salvo, Oeiras, 2740-266, Portugal		
BP Portugal -Comercio de Combustiveis e Lubrificantes SA	Ordinary	100.00
Castrol Portugal, S.A.	Ordinary	100.00
Fuelplane- Sociedade Abastecedora De Aeronaves, Unipessoal, Lda	Ordinary	100.00
Sociedade de Promocao Imobiliaria Quinta do Loureiro, SA	Ordinary	100.00
Rua Castilho, No 50, Lisboa, 1250-071, Portugal		
Coherent Modernity Lda	Quotas	100.00
Coloursflow - Unipessoal Lda	Quotas	100.00
Dapsun - Investimentos e Consultoria, LDA.	Ordinary	50.50
Forest Constellation - Unipessoal Lda	Quotas	100.00
Ignichoice Renewable Energy V, Unipessoal LDA	Quotas	100.00
Ignidap – Energias Renováveis, Unipessoal Lda	Quotas	100.00
Lightsource Development Portugal, Unipessoal Lda	Ordinary	100.00
Lightsource Renewable Energy Portugal (HoldCo), Lda.	Quotas	100.00
LSbp Portugal SPV 1, Unipessoal LDA	Quotas	100.00
LSbp Portugal SPV 2, Unipessoal LDA	Quotas	100.00
LSbp Portugal SPV 3, Unipessoal LDA	Ordinary	100.00
LSbp Portugal SPV 4, Unipessoal LDA	Ordinary	100.00
LSbp SPV 5, Unipessoal LDA	Ordinary	100.00
Ramison – Consultoria e Energias Renováveis, Unipessoal Lda.	Quotas	100.00
Solid Tomorrow - Energia Unipessoal Lda	Quotas	100.00
Suninger - Consultoria e Energias Renováveis, Unipessoal Lda	Quotas	100.00
Tolerantdiagonal - Lda	Quotas	100.00
Romania		
District 3, 5 Halelor street, 3rd Floor, Bucharest, Romania		
Castrol Lubricants RO S.R.L	Ordinary	100.00
Otopeni, 224E Calea Bucurestilor, within International Airport - Băneasa, Aurel Vlaicu - platform 2, Ilfov county, Romania		
Air BP Sales Romania S.R.L.	Ordinary	100.00

13. Related undertakings of the group – continued

Otopeni, 59 Aurel Vlaicu Street, Otopeni, Ilfov County, Romania		
Romanian Fuelling Services S.R.L.	Ordinary	100.00
Russian Federation		
Berzarina str., 36, building1, Shchukino Municipal District, Moscow, 123060, Russian Federation		
Limited liability company Setra Lubricants	Membership Interest	100.00
Senegal		
Route de Ouakam x Corniche Ouest, Immeuble Alphadio Barry, Dakar, Senegal		
BP Oil Senegal S.A.	Ordinary	100.00
Singapore		
38 Beach Road, #29-11, South Beach Tower, 189767, Singapore		
Lightsource Singapore Renewables Holdings Private Limited	Ordinary	100.00
Lightsource Singapore Renewables Private Limited	Ordinary	100.00
7 Straits View #26-01, Marina One East Tower, 018936, Singapore		
BP Asia Pacific Pte Ltd ^o	Ordinary	100.00
BP Energy Asia Pte. Limited	Ordinary	100.00
BP Exploration (Xazar) Pte. Ltd.	Ordinary	100.00
BP Maritime Services (Singapore) Pte. Limited	Ordinary	100.00
BP Singapore Pte. Limited	Ordinary	100.00
Castrol Singapore PTE. Limited	Ordinary	100.00
Slovakia		
Karadžičova 2, Bratislava, 815 32, Slovakia		
Blueprint Power Slovakia s.r.o.	Membership Interest	100.00
South Africa		
199 Oxford Road, Oxford Parks, Dunkeld, Johannesburg, GP, 2196, South Africa		
BP Southern Africa Proprietary Limited	Ordinary	75.00
Castrol Southern Africa (Pty) Ltd	Ordinary; Ordinary A	100.00
ECM Markets SA (Pty) Ltd	Ordinary	75.00
Spain		
Calle Alcalá número 63, Madrid, 28014, Spain		
ISC Greenfield 12, S.L.	Ordinary	100.00
Parque FV Borealis, S.L.	Ordinary	100.00
Parque FV Polaris, S.L.	Ordinary	100.00
Calle José Ortega y Gasset, número 100, 5^a planta, Madrid, 28006, Spain		
Alejandria Power, S.L.U.	Ordinary	100.00
Castellana Power, S.L.U.	Ordinary	100.00
Castiinversiones Renovables, S.L.	Ordinary	100.00
Global Aljarafe, S.L.U.	Ordinary	100.00
Global Aroche, S.L.U.	Ordinary	100.00
Global Atarazana, S.L.U.	Ordinary	100.00
Global Baterno, S.L.U.	Ordinary	100.00
Global Baza, S.L.U.	Ordinary	100.00
Global Brenes, S.L.U.	Ordinary	100.00
Global Cotolengo, S.L.U.	Ordinary	100.00
Global Daimon, S.L.	Ordinary	100.00
Global Meguro, S.L.	Ordinary	100.00
Global Tarquinia, S.L.U.	Ordinary	100.00
Global Toyosu, S.L.	Ordinary	100.00
Global Treviso, S.L.U.	Ordinary	100.00
Global Valdenoches, S.L.U.	Ordinary	100.00
Global Zalmuna, S.L.	Ordinary	100.00
Inversiones Energy Madrid, S.L.U.	Ordinary	100.00
ISC Greenfield 7, S.L.	Ordinary	100.00

The parent company financial statements of BP p.l.c. on pages 269-333 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

13. Related undertakings of the group – continued

Lightsource Europe Asset Management, SL	Ordinary	100.00
Lightsource Renewable Energy Garnacha, S.L.	Ordinary	100.00
Lightsource Renewable Energy Spain Development, SL	Ordinary	100.00
Lightsource Renewable Energy Spain Holdings, SL	Ordinary	100.00
Lightsource Renewable Energy Spain SPV 1, SL	Ordinary	100.00
Lightsource Renewable Energy Trading, SL	Ordinary	100.00
Lightsource Spain O&M, SL	Ordinary	100.00
Rin Power, S.L.U.	Ordinary	100.00
Sinfonia Solar Energy Power, S.L.U.	Ordinary	100.00
Calle Quintanadueñas, 6, (Edificio Arq borea), Madrid, 28050, Spain		
BP Energy Solutions Sociedad de Valores, S.A	Ordinary	100.00
BP Espana, S.A. Unipersonal	Ordinary	100.00
BP Gas & Power Iberia, S.A	Ordinary	100.00
BP Refined Products Trading Iberia, S.L.	Ordinary	100.00
BP Solar Espana, S.A. Unipersonal	Ordinary A; Ordinary B	100.00
Castrol España, S.L. Sociedad Unipersonal	Ordinary	100.00
Markoil, S.A. Unipersonal	Ordinary	100.00
Polígono Industrial "El Serrallo", s/n 12100 Grao de Castellón, Castellón de la Plana, Spain		
BP Energía España, S.A. Unipersonal	Ordinary	100.00
Castellón Green Hydrogen Phase 2, S.L.	Ordinary	100.00
Sweden		
Box 8107, Stockholm, 10420, Sweden		
Air BP Sweden AB	Ordinary	100.00
Hemvärnsgatan, 171 54, Solna, Sweden		
Castrol Sweden AB	Ordinary	100.00
Switzerland		
Baarschtrasse 139, Zug, 6300, Switzerland		
Castrol Switzerland GmbH	Ordinary	100.00
Taiwan (Province of China)		
16F., No. 97, Songren Rd., Xinyi Dist., Taipei City, 110050, Taiwan (Province of China)		
Lu Yang Co., Ltd	Ordinary	100.00
57F.-1, No. 7, Sec. 5, Xinyi Rd., Xinyi Dist., Taipei City, 11049, Taiwan (Province of China)		
BP Taiwan Marketing Limited	Ordinary	100.00
No. 97, 16th Floor Songren Road, Xinyi District, Taipei, 110050, Taiwan (Province of China)		
Hui-Meng Energy Co., Ltd.	Ordinary	100.00
Lightsource Renewable Energy Development Taiwan Limited	Ordinary	100.00
Lightsource Renewable Energy SPV 1 Taiwan Limited	Ordinary	100.00
Lightsource Renewable Energy SPV 2 Taiwan Limited	Ordinary	100.00
Lightsource Renewable Energy SPV 3 Taiwan Limited	Ordinary	100.00
Thailand		
23rd Fl. Rajanakarn Bldg, 3 South Sathon Road, Yannawa South Sathon, Bangkok 10120, Thailand		
BP - Castrol (Thailand) Limited	Ordinary	57.59
SOFAS Limited	Ordinary (100.00%); Preference (58.99%)	63.09
39/77-78 Moo 2 Rama II Road, Tambon Bangkrachao, Amphur Muang, Samutsakorn 74000, Thailand		
BP Holdings (Thailand) Limited	Ordinary (80.10%); Preference (99.07%)	81.18
BP Oil (Thailand) Limited	Ordinary (93.64%); Preference (81.18%)	90.40
Trinidad and Tobago		
5-5A Queen's Park West, Port-of-Spain, Trinidad and Tobago		
BP Alternative Energy Trinidad and Tobago Limited	Ordinary	100.00
BP Trinidad & Tobago LNG Holdings Limited	Ordinary	100.00

13. Related undertakings of the group – continued

BP Trinidad Processing Limited	Ordinary	100.00
Mayaro Initiative for Private Enterprise Development	Ordinary	70.00
Türkiye		
Degirmen yolu cad. No:28, Asia OfisPark K:3 Icerenkoy-Atasehir, Istanbul, 34752, Türkiye		
BP Dogal Gaz Ticaret Anonim Sirketi	Ordinary	100.00
İçerenköy Mah, Degirmen Yolu Cad, Mengerler Blok No: 28/1 İç Kapi No: 12, Atasehir/Istanbul, Türkiye		
Castrol Madeni Yağlar Ticaret Anonim Şirketi	Ordinary	100.00
United Arab Emirates		
8th Floor, Standard Chartered Tower, Downtown, Dubai, United Arab Emirates		
BP Middle East LLC	Ordinary	100.00
Castrol Lubricants Middle East LLC	Ordinary	100.00
United Kingdom		
1 More London Place, London, SE1 2AF, England, United Kingdom		
Lytt Limited	Ordinary	100.00
1 Wellheads Avenue, Dyce, Aberdeen, AB21 7PB, United Kingdom		
BP Energy Europe Limited	Ordinary	100.00
BP Exploration Company Limited	Ordinary	100.00
Britannic Strategies Limited	Ordinary	100.00
Britoil Limited	Ordinary	100.00
Castrol Group Holdings Limited ^F	Ordinary	100.00
Puls8 Ltd	Ordinary	100.00
10 Upper Berkeley Street, London, W1H 7PE, United Kingdom		
Horizon 38 Management Company Limited	Membership Interest	53.50
11 Black Horse Lane, Ipswich, Suffolk, IP1 2EF, England, United Kingdom		
Manormaker (Nominee No. 1) Limited	Ordinary	100.00
Manormaker (Nominee No. 2) Limited	Ordinary	100.00
Manormaker GP Limited	Ordinary	100.00
The Manormaker Limited Partnership	Membership Interest	100.00
33 Cavendish Square, London, W1G 0PW, United Kingdom		
Ropemaker Exempt Unit Trust	Membership Interest	100.00
5 Temple Square, Temple Street, Liverpool, L2 5RH, England & Wales, United Kingdom		
Amoco (Fiddich) Limited	Ordinary	100.00
BP Amoco Exploration (Faroes) Limited	Ordinary	100.00
BP Car Fleet Limited ^F	Ordinary	100.00
BP Oil Llandarcy Refinery Limited	Ordinary	100.00
BP Oil Logistics UK Limited	Ordinary	100.00
BP UK Fatima Limited	Ordinary	100.00
BXL Plastics Limited	Ordinary	100.00
Castrol (U.K.) Limited	Ordinary	100.00
Charge Your Car Limited	Ordinary A; Ordinary B	100.00
Elektromotive Limited	Ordinary	100.00
Lightsource Impact 1 Limited	Ordinary	100.00
Lightsource Impact 2 Limited	Ordinary	100.00
Lightsource India Maharashtra 1 Holdings Limited	Ordinary	100.00
Lightsource India Maharashtra 1 Limited	Ordinary	100.00
Lightsource Renewable Energy India Projects Limited	Ordinary	100.00
Lightsource SPV 258 Limited	Ordinary	100.00
Lightsource SPV 259 Limited	Ordinary	100.00
7th Floor, 33 Holborn, London, EC1N 2HU, England, United Kingdom		
Goulburn River HoldCo 1 Limited	Ordinary	100.00
Lightsource Asset Holdings (Australia) Limited	Ordinary	100.00
Lightsource Asset Holdings (Europe) Limited	Ordinary	100.00

The parent company financial statements of BP p.l.c. on pages 269-333 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

13. Related undertakings of the group – continued

Lightsource Asset Holdings (Spain) Limited	Ordinary	100.00
Lightsource Asset Holdings (UK) Limited	Ordinary	100.00
Lightsource Asset Holdings (USA) Limited	Ordinary	100.00
Lightsource Asset Holdings 1 Limited	Ordinary	100.00
Lightsource Asset Holdings 2 Limited	Ordinary	100.00
Lightsource Asset Holdings 3 Limited	Ordinary	100.00
Lightsource Asset Management Limited	Ordinary	100.00
Lightsource Australia FinCo Holdings Limited	Ordinary	100.00
Lightsource Bodegas 2 Limited	Ordinary	100.00
Lightsource Bodegas 3 Limited	Ordinary	100.00
Lightsource Bodegas 4 Limited	Ordinary	100.00
Lightsource Bodegas Limited	Ordinary	100.00
Lightsource BP Renewable Energy Investments Holdings Limited	Ordinary	100.00
Lightsource BP Renewable Energy Investments Limited	Ordinary A; Ordinary C; Ordinary D; Ordinary E; Ordinary F; Ordinary G	100.00
Lightsource Brazil Holdings 1 Limited	Ordinary	100.00
Lightsource Brazil Holdings 2 Limited	Ordinary	100.00
Lightsource Commercial Rooftops Limited	Ordinary	100.00
Lightsource Construction Management Limited	Ordinary	100.00
Lightsource Corinthian Limited	Ordinary	100.00
Lightsource Cosecha Limited	Ordinary	100.00
Lightsource Development Services Limited	Ordinary	100.00
Lightsource Egypt Holdings Limited	Ordinary	100.00
Lightsource Elk Hill 2 Solar Limited	Ordinary	100.00
Lightsource Elk Hill Solar 2 Holdings Limited	Ordinary	100.00
Lightsource Finca 2 Limited	Ordinary	100.00
Lightsource Finca 3 Limited	Ordinary	100.00
Lightsource Finca Limited	Ordinary	100.00
Lightsource France Holdings UK Limited	Ordinary	100.00
Lightsource Grace 1 Limited	Ordinary	100.00
Lightsource Grace 2 Limited	Ordinary	100.00
Lightsource Grace 3 Limited	Ordinary	100.00
Lightsource Holdings 1 Limited	Ordinary	100.00
Lightsource Holdings 2 Limited	Ordinary	100.00
Lightsource Holdings 3 Limited	Ordinary	100.00
Lightsource Iberia Greenfield Holdings Limited	Ordinary	100.00
Lightsource Iberia Project Holdings Limited	Ordinary	100.00
Lightsource India Holdings Limited	Ordinary	100.00
Lightsource India Limited	Ordinary A (100.00%)	51.00
Lightsource Kingfisher Holdings Limited	Ordinary	100.00
Lightsource Labs 1 Limited	Ordinary	100.00
Lightsource Manzanilla Limited	Ordinary	100.00
Lightsource Operations 1 Limited	Ordinary	100.00
Lightsource Operations 2 Limited	Ordinary	100.00
Lightsource Operations 3 Limited	Ordinary	100.00
Lightsource Operations Services Limited	Ordinary	100.00
Lightsource Poland Holdings (UK) Limited	Ordinary	100.00
Lightsource Property 1 Limited	Ordinary	100.00
Lightsource Property 2 Limited	Ordinary	100.00
Lightsource Renewable Energy (India) Limited	Ordinary	100.00
Lightsource Renewable Energy Asia Pacific Holdings Limited	Ordinary	100.00
Lightsource Renewable Energy Australia Holdings Limited	Ordinary	100.00

13. Related undertakings of the group – continued

Lightsource Renewable Energy Greece Holdings (UK) Limited	Ordinary	100.00
Lightsource Renewable Energy Greece Holdings 2 (UK) Limited	Ordinary	100.00
Lightsource Renewable Energy Greece Projects 2 Limited	Ordinary	100.00
Lightsource Renewable Energy Holdings Limited	Ordinary	100.00
Lightsource Renewable Energy Iberia Holdings Limited	Ordinary	100.00
Lightsource Renewable Energy India Assets Limited	Ordinary	100.00
Lightsource Renewable Energy India Holdings Limited	Ordinary	100.00
Lightsource Renewable Energy Italy Holdings Limited	Ordinary	100.00
Lightsource Renewable Energy Limited	Ordinary	100.00
Lightsource Renewable Energy Moristel Limited	Ordinary	100.00
Lightsource Renewable Energy Netherlands Holdings Limited	Ordinary	100.00
Lightsource Renewable Energy New Zealand Holdings Limited	Ordinary	100.00
Lightsource Renewable Energy Poland Projects 1 Limited	Ordinary	100.00
Lightsource Renewable Energy Poland Projects 2 Limited	Ordinary	100.00
Lightsource Renewable Energy Portugal Holdings Limited	Ordinary	100.00
Lightsource Renewable Energy Portugal Projects 1 Limited	Ordinary	100.00
Lightsource Renewable Energy Portugal Projects 2 Limited	Ordinary	100.00
Lightsource Renewable Energy Tempranillo Limited	Ordinary	100.00
Lightsource Renewable Energy Verdejo Limited	Ordinary	100.00
Lightsource Renewable Global Development Limited	Ordinary	100.00
Lightsource Renewable Services Limited	Ordinary	100.00
Lightsource Renewable Taiwan UK Holdings Limited	Ordinary	100.00
Lightsource Renewable UK Development Limited	Ordinary	100.00
Lightsource Residential Rooftops (PPA) Limited	Ordinary	100.00
Lightsource Residential Rooftops Limited	Ordinary	100.00
Lightsource SPV 101 Limited	Ordinary	100.00
Lightsource SPV 108 Limited	Ordinary	100.00
Lightsource SPV 114 Limited	Ordinary	100.00
Lightsource SPV 118 Limited	Ordinary	100.00
Lightsource SPV 127 Limited	Ordinary	100.00
Lightsource SPV 128 Limited	Ordinary	100.00
Lightsource SPV 130 Limited	Ordinary	100.00
Lightsource SPV 138 Limited	Ordinary	100.00
Lightsource SPV 140 Limited	Ordinary	100.00
Lightsource SPV 145 Limited	Ordinary	100.00
Lightsource SPV 149 Limited	Ordinary	100.00
Lightsource SPV 151 Limited	Ordinary	100.00
Lightsource SPV 162 Limited	Ordinary	100.00
Lightsource SPV 166 Limited	Ordinary	100.00
Lightsource SPV 167 Limited	Ordinary	100.00
Lightsource SPV 171 Limited	Ordinary	100.00
Lightsource SPV 176 Limited	Ordinary	100.00
Lightsource SPV 179 Limited	Ordinary	100.00
Lightsource SPV 18 Limited	Ordinary	100.00
Lightsource SPV 183 Limited	Ordinary	100.00
Lightsource SPV 184 Limited	Ordinary	100.00
Lightsource SPV 185 Limited	Ordinary	100.00
Lightsource SPV 189 Limited	Ordinary	100.00
Lightsource SPV 19 Limited	Ordinary	100.00
Lightsource SPV 191 Limited	Ordinary	100.00
Lightsource SPV 192 Limited	Ordinary	100.00
Lightsource SPV 199 Limited	Ordinary	100.00

13. Related undertakings of the group – continued

Lightsource SPV 201 Limited	Ordinary	100.00
Lightsource SPV 202 Limited	Ordinary	100.00
Lightsource SPV 203 Limited	Ordinary	100.00
Lightsource SPV 204 Limited	Ordinary	100.00
Lightsource SPV 212 Limited	Ordinary	100.00
Lightsource SPV 213 Limited	Ordinary	100.00
Lightsource SPV 214 Limited	Ordinary	100.00
Lightsource SPV 215 Limited	Ordinary	100.00
Lightsource SPV 217 Limited	Ordinary	100.00
Lightsource SPV 222 Limited	Ordinary	100.00
Lightsource SPV 232 Limited	Ordinary	100.00
Lightsource SPV 233 Limited	Ordinary	100.00
Lightsource SPV 236 Limited	Ordinary	100.00
Lightsource SPV 247 Limited	Ordinary	100.00
Lightsource SPV 25 Limited	Ordinary	100.00
Lightsource SPV 263 Limited	Ordinary	100.00
Lightsource SPV 264 Limited	Ordinary	100.00
Lightsource SPV 265 Limited	Ordinary	100.00
Lightsource SPV 286 Limited	Ordinary	100.00
Lightsource SPV 287 Limited	Ordinary	100.00
Lightsource SPV 288 Limited	Ordinary	100.00
Lightsource SPV 29 Limited	Ordinary	100.00
Lightsource SPV 35 Limited	Ordinary	100.00
Lightsource SPV 41 Limited	Ordinary	100.00
Lightsource SPV 47 Limited	Ordinary	100.00
Lightsource SPV 56 Limited	Ordinary	100.00
Lightsource SPV 60 Limited	Ordinary	100.00
Lightsource SPV 73 Limited	Ordinary	100.00
Lightsource SPV 78 Limited	Ordinary	100.00
Lightsource SPV 88 Limited	Ordinary	100.00
Lightsource SPV 91 Limited	Ordinary	100.00
Lightsource SPV 98 Limited	Ordinary	100.00
Lightsource Titan Borrower AUD Limited	Ordinary	100.00
Lightsource Titan Borrower EUR Limited	Ordinary	100.00
Lightsource Titan Borrower GBP Limited	Ordinary	100.00
Lightsource Titan Borrower USD Limited	Ordinary	100.00
Lightsource Titan Limited	Ordinary	100.00
Lightsource Trading Limited	Ordinary	100.00
Lightsource Trinidad Holdings (UK) Limited	Ordinary	100.00
Lightsource Viking 1 Limited	Ordinary	100.00
Lightsource Viking 2 Limited	Ordinary	100.00
Lightsource Viking Limited	Ordinary	100.00
Lightsource Xenium 1 Limited	Ordinary	100.00
Lightsource Xenium 2 Limited	Ordinary	100.00
Sandy Creek Solar HoldCo 1 Limited	Ordinary	100.00
West Wyalong HoldCo 1 Limited	Ordinary	100.00
Woolooga BESS HoldCo 1 Limited	Ordinary	100.00
Woolooga HoldCo 1 Limited	Ordinary	100.00
Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, England, United Kingdom		
Air BP Limited	Ordinary	100.00
Amoco U.K. Petroleum Limited	Ordinary	100.00
Ashford Truckstop Freehold Limited	Ordinary	100.00

13. Related undertakings of the group – continued

Atlantic 2/3 UK Holdings Limited	Ordinary	100.00
BP (Abu Dhabi) Limited	Ordinary	100.00
BP (Barbican) Limited ^c	Ordinary	100.00
BP (Gibraltar) Limited	Ordinary	100.00
BP (GTA Mauritania) Finance Limited	Ordinary	100.00
BP (GTA Senegal) Finance Limited	Ordinary	100.00
BP ADUA Limited	Ordinary	100.00
BP ADUA Operating Company Limited	Ordinary	100.00
BP Advanced Mobility Limited	Ordinary	100.00
BP Africa Limited ^c	Ordinary	100.00
BP Africa Oil Limited	Ordinary	100.00
BP Agung I Limited	Ordinary	100.00
BP Agung II Limited	Ordinary	100.00
BP Alternative Energy Investments Limited	Ordinary	100.00
BP America Limited	Ordinary	100.00
BP Andaman II Ltd	Ordinary	100.00
BP Asia Pacific Holdings Limited	Ordinary	100.00
BP Australia Swaps Management Limited	Ordinary	100.00
BP Benevolent Fund Trustees Limited ^c	Ordinary	100.00
BP Biofuels Brazil Investments Limited	Ordinary	100.00
BP Biofuels Investments Limited	Ordinary	100.00
BP Capital Markets p.l.c.	Ordinary	100.00
BP Carbon Trading Limited	Ordinary	100.00
BP CCUS UK LTD	Ordinary	100.00
BP CCUS UK NEP Limited	Ordinary	100.00
BP Chemicals Limited	Ordinary	100.00
BP Continental Holdings Limited	Ordinary	100.00
BP Corporate Holdings Limited	Ordinary	100.00
BP D230 Limited	Ordinary	100.00
BP East Kalimantan CBM Limited	Ordinary	100.00
BP Eastern Mediterranean Limited	Ordinary	100.00
BP Energy Colombia Limited	Ordinary	100.00
BP Energy Company of Kirkuk Limited	Ordinary	100.00
BP Eta Holdings Limited	Ordinary	100.00
BP Exploration (Alpha) Limited	Ordinary	100.00
BP Exploration (Azerbaijan) Limited	Ordinary	100.00
BP Exploration (Caribbean) Limited	Ordinary	100.00
BP Exploration (Caspian Sea) Limited	Ordinary	100.00
BP Exploration (D230) Limited	Ordinary	100.00
BP Exploration (Delta) Limited	Ordinary	100.00
BP Exploration (Epsilon) Limited	Ordinary	100.00
BP Exploration (Shafag-Asiman) Limited	Ordinary	100.00
BP Exploration (Shah Deniz) Limited	Ordinary	100.00
BP Exploration (South Atlantic) Limited	Ordinary	100.00
BP Exploration (STP) Limited	Ordinary	100.00
BP Exploration Argentina Limited	Ordinary	100.00
BP Exploration Beta Limited	Ordinary	100.00
BP Exploration Company (Middle East) Limited	Ordinary	100.00
BP Exploration Indonesia Limited	Ordinary	100.00
BP Exploration Libya Limited	Ordinary	100.00
BP Exploration Mediterranean Limited	Ordinary	100.00
BP Exploration North Africa Limited	Ordinary	100.00

The parent company financial statements of BP p.l.c. on pages 269-333 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

13. Related undertakings of the group – continued

BP Exploration Operating Company Limited	Ordinary	100.00
BP Exploration Orinoco Limited	Ordinary	100.00
BP Exploration Services India Limited	Ordinary	100.00
BP Express Shopping Limited	Ordinary	100.00
BP Finance p.Lc.	Ordinary	100.00
BP Gaea II Limited	Ordinary	100.00
BP Gaea Limited	Ordinary	100.00
BP Gamma Holdings Limited ^c	Ordinary	100.00
BP Gas & Power Investments Limited	Ordinary	100.00
BP Gas Marketing Limited	Ordinary	100.00
BP Global Investments Limited ^c	Ordinary	100.00
BP Global Solutions Limited	Ordinary	100.00
BP Greece Limited	Ordinary	100.00
BP Holdings Canada Limited ^c	Ordinary	100.00
BP Holdings Iraq Ltd	Ordinary	100.00
BP Holdings North America Limited ^c	Ordinary; Cumulative redeemable preference	100.00
BP Hydrogen and CCS Development Company Limited	Ordinary	100.00
BP Integrated Solutions Limited	Ordinary	100.00
BP International Limited ^c	Ordinary	100.00
BP Investment Management Limited	Ordinary	100.00
BP Investments Asia Limited	Ordinary	100.00
BP Iota Holdings Limited	Ordinary	100.00
BP Iran Limited	Ordinary	100.00
BP Kappa Holdings Limited	Ordinary	100.00
BP Karabagh Limited	Ordinary	100.00
BP Karabagh Operating Company Limited	Ordinary	100.00
BP Koppa Limited	Ordinary	100.00
BP Kuwait Limited	Ordinary	100.00
BP Lambda Holdings Limited	Ordinary	100.00
BP Marine Limited	Ordinary	100.00
BP Mauritania Investments Limited	Ordinary	100.00
BP Middle East Limited ^c	Ordinary	100.00
BP Mocambique Limited	Ordinary	100.00
BP Motion Holdings Limited	Ordinary	100.00
BP New Ventures Middle East Limited	Ordinary	100.00
BP NZT Power Holdings Limited	Ordinary	100.00
BP Oil International Limited	Ordinary	100.00
BP Oil UK Limited	Ordinary; Non- cumulative non- redeemable preference shares	100.00
BP Oil Vietnam Limited	Ordinary	100.00
BP Oil Yemen Limited	Ordinary	100.00
BP Oman H2 Limited	Ordinary	100.00
BP Pension Escrow Limited	Ordinary	100.00
BP Pension Trustees Limited ^c	Ordinary	100.00
BP Pensions Limited ^c	Ordinary	100.00
BP Pipelines (BTC) Limited	Ordinary	100.00
BP Pipelines (SCP) Limited	Ordinary	100.00
BP Pipelines (TANAP) Limited	Ordinary A	78.21
BP Pipelines TAP Limited	Ordinary A; Ordinary B	75.00
BP Poseidon Limited	Ordinary	100.00

13. Related undertakings of the group – continued

BP Properties Limited ^c	Ordinary	100.00
BP Retail Properties Limited	Ordinary	100.00
BP Russian Investments Limited	Ordinary	100.00
BP Scale Up Factory Limited	Ordinary	100.00
BP Secretaries Limited	Ordinary	100.00
BP Senegal Investments Limited	Ordinary	100.00
BP Services International Limited	Ordinary	100.00
BP Shafag-Asiman Limited	Ordinary	100.00
BP Shipping Limited	Ordinary	100.00
BP South America Holdings Ltd	Ordinary	100.00
BP Subsea Well Response Limited	Ordinary	100.00
BP Technology Ventures Limited	Ordinary	100.00
BP Theta Holdings Limited	Ordinary	100.00
BP UK Retained Holdings Limited	Ordinary	100.00
BP Zeta Holdings Limited	Ordinary	100.00
Britannic Energy Trading Limited	Ordinary	100.00
Britannic Investments Iraq Limited	Ordinary	100.00
Britannic Marketing Limited	Ordinary	100.00
Britannic Trading Limited	Ordinary	100.00
Cadman DBP Limited	Ordinary	100.00
Castrol Holdings Americas Limited	Ordinary	100.00
Castrol Holdings International Limited	Ordinary	100.00
Castrol Offshore Limited	Ordinary	100.00
Chargemaster Limited	Ordinary	100.00
Exmoor Nominee Limited	Ordinary	51.00
Exmoor Properties GP Limited	Ordinary	51.00
Exmoor Properties PF LP	Membership Interest	51.00
GTA FPSO Company Ltd	Ordinary	100.00
Guangdong Investments Limited	Ordinary	100.00
H2 Teesside Limited	Ordinary	100.00
Iraq Petroleum Company Limited	Ordinary	100.00
Kenilworth Oil Company Limited ^c	Ordinary	100.00
Lubricants UK Limited	Ordinary	100.00
Open Energi Limited	Ordinary	100.00
Pearl River Delta Investments Limited	Ordinary	100.00
Ropemaker Deansgate Limited	Ordinary	100.00
Ropemaker Properties Limited	Ordinary	100.00
The BP Share Plans Trustees Limited ^c	Ordinary	100.00
Viceroy Investments Limited	Ordinary	100.00
Regus Business Centre, Cromac Square, Belfast, BT2 8LA, Northern Ireland, United Kingdom		
Lightsource Renewable Energy (NI) Limited	Ordinary	100.00
Lightsource SPV 266 (NI) Limited	Ordinary	100.00
Technology Centre, Whitchurch Hill, Pangbourne, Reading, RG8 7QR, United Kingdom		
Castrol Limited	Ordinary	100.00
United States		
1200 South Pine Island Road, Plantation, FL 33324, United States		
Landfill Energy Systems Florida LLC	Membership Interest	100.00
160 Mine Lake Ct., Ste. 200, Raleigh, NC, 27615-6417, United States		
Big Run Power Producers, LLC	Membership Interest	100.00
1833 South Morgan Road, Oklahoma City OK 73128, United States		
BPX Midstream LLC	Membership Interest	51.00

The parent company financial statements of BP p.l.c. on pages 269-333 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

13. Related undertakings of the group – continued

1999 Bryan St., STE 900, Dallas, TX, 75201, United States		
Acamar Energy Project, LLC	Membership Interest	100.00
Arche Energy Project, LLC	Membership Interest	100.00
Atria Energy Project, LLC	Membership Interest	100.00
BP Solar SHH, LLC	Membership Interest	100.00
BP Solar SHP, LLC	Membership Interest	100.00
BPX Operating Company	Ordinary	100.00
Cassiopeia Energy Project, LLC	Membership Interest	100.00
Cepheus Energy Project, LLC	Membership Interest	100.00
Cressida Energy Project, LLC	Membership Interest	100.00
Elanor Energy Project, LLC	Membership Interest	100.00
Gulf Coast Environmental Systems, LLC (dba Conifer Systems LLC)	Membership Interest	100.00
Maia Energy Project, LLC	Membership Interest	100.00
Minkar Energy Project, LLC	Membership Interest	100.00
Mira Energy Project, LLC	Membership Interest	100.00
Nashira Energy Project, LLC	Membership Interest	100.00
Nunki Energy Project LLC	Membership Interest	100.00
Persei Energy Project, LLC	Membership Interest	100.00
Rigel Energy Project, LLC	Membership Interest	100.00
Spica Energy Project, LLC	Membership Interest	100.00
Subra Energy Project, LLC	Membership Interest	100.00
Tania Energy Project, LLC	Membership Interest	100.00
Tesni Energy Project, LLC	Membership Interest	100.00
Toro Energy of Indiana, LLC	Membership Interest	60.00
Zibal Energy Project, LLC	Membership Interest	100.00
2405 York Road, Ste 201, Lutherville Timonium, MD, 21093-2264, United States		
BP Products North America Inc.	Ordinary	100.00
251 East Ohio Street, Suite 500, Indianapolis IN 46204, United States		
Standard Oil Company, Inc.	Ordinary	100.00
2595 Interstate Drive, Suite 103, Harrisburg, PA 17110, United States		
PEI Power II, LLC	Membership Interest	100.00
PEI Power LLC	Membership Interest	100.00
2711 Centerville Road, Suite 400, Wilmington, DE, 19808, United States		
Amoco Oil Holding Company	Ordinary	100.00
Amoco Pipeline Holding Company	Ordinary	100.00
BP International Services Company	Ordinary	100.00
28 Liberty Street, New York, NY, 10005, United States		
Modern Innovative Energy, LLC	Membership Interest	100.00
Seneca Energy II, LLC	Membership Interest	100.00
2908 Poston Avenue, Nashville, TN 37203, United States		
Tennessee Renewable Group LLC	Membership Interest	100.00
306 W. Main Street, Suite 512, Frankfort, KY, 40601, United States		
Fresh-Serve Bakeries LLC	Membership Interest	100.00
Thornton Transportation LLC	Membership Interest	100.00
334, North Senate Avenue, Indianapolis, IN, 46204-1708, United States		
BP Corporation North America Inc.	Ordinary	100.00
BP Foundation Incorporated	Membership Interest	100.00
Whiting Clean Energy, Inc.	Membership Interest	100.00
3410 Belle Chase Way, Suite 600, Lansing, MI, 48911, United States		
Canton Renewables, LLC	Membership Interest	100.00
3800 North Central Avenue, Suite 460, Phoenix, AZ, 85012, United States		
Sargas Energy Project, LLC	Membership Interest	100.00

13. Related undertakings of the group – continued

400 Cornerstone Drive, Suite 240, Williston VT 05495, United States		
Saturn Insurance Inc.	Ordinary	100.00
4400 Easton Commons Way , Suite 125, Columbus OH 43219, United States		
Baltimore Ennis Land Company, Inc.	Ordinary	100.00
Exomet, Inc.	Ordinary	100.00
The Standard Oil Company	Ordinary	100.00
45 Memorial Circle, Augusta ME 04330, United States		
BP Pipelines (North America) Inc.	Ordinary	100.00
501 Westlake Park Boulevard, TX 77079, Houston, United States		
BP Hardin Energy Holding Company LLC	Membership Interest	100.00
7 St. Paul Street, Suite 820, Baltimore MD 21202, United States		
TA HQ LLC	Membership Interest	100.00
701 South Carson Street Suite 200, Carson City, NV, 89701, United States		
Amoco Marketing Environmental Services Company	Ordinary	100.00
80 State Street, Albany, NY, United States		
Model City Energy, LLC	Membership Interest	100.00
814 Thayer Avenue, Bismarck, ND, 58501-4018, United States		
The Anaconda Company	Ordinary	100.00
8585 Old Dairy Rd STE 208, Juneau, AK, 99801, United States		
Frontier Operation Services, LLC	Membership Interest	100.00
920 North King Street, 2nd Floor, Wilmington DE 19801, United States		
BPRY Caribbean Ventures LLC	Membership Interest	70.00
921 S. Orchard St. Ste G, Boise ID 83705, United States		
IGI Resources, Inc.	Ordinary	100.00
Bank of America Center, 16th Floor, 1111 East Main Street, Richmond, VA, 23219, United States		
Amoco Environmental Services Company	Ordinary; Preference	100.00
c/o Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808, United States		
Andromedae Energy Project, LLC	Membership Interest	100.00
Astro Solar Investor 2, LLC	Membership Interest	100.00
Astro Solar Transfer Holdings, LLC	Class C Membership Interest	50.56
Big Bronco Solar, LLC	Membership Interest	100.00
Big Bronco Storage, LLC	Membership Interest	100.00
Big Elk Solar, LLC	Membership Interest	100.00
Birch Solar 1, LLC	Membership Interest	100.00
Buffalo Plains Solar, LLC	Membership Interest	100.00
Buffalo Plains Storage, LLC	Membership Interest	100.00
Buzz Energy Project, LLC	Membership Interest	100.00
Canal Road Solar, LLC	Membership Interest	100.00
Champion Solar 1, LLC	Membership Interest	100.00
Chester Solar Energy, LLC	Membership Interest	100.00
Concord Solar Construction Holdings, LLC	Membership Interest	100.00
Concord Solar Construction, LLC	Membership Interest	100.00
Concord Solar Holdings 1, LLC	Membership Interest	100.00
Concord Solar Holdings, LLC	Membership Interest	100.00
Cottontail Solar 3, LLC	Membership Interest	100.00
Cottontail Solar 4, LLC	Membership Interest	100.00
Cottontail Solar 7, LLC	Membership Interest	100.00
Cottontail Solar 9, LLC	Membership Interest	100.00
Crawford Solar, LLC	Membership Interest	100.00
Crossvine Solar Holdings, LLC	Membership Interest	100.00
Desert Pine Solar, LLC	Membership Interest	100.00

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13. Related undertakings of the group – continued

Desert Pine Storage, LLC	Membership Interest	100.00
Draconis Energy Project, LLC	Membership Interest	100.00
Driver Solar Holdings, LLC	Membership Interest	100.00
Driver Solar, LLC	Membership Interest	100.00
Electra Solar, LLC	Membership Interest	100.00
Elk Hill Solar 1 Holdings, LLC	Membership Interest	100.00
Elk Hill Solar 1 Storage, LLC	Membership Interest	100.00
Elk Hill Solar 1, LLC	Membership Interest	100.00
Elk Hill Solar 2 Holdings, LLC	Membership Interest	100.00
Elk Hill Solar 2, LLC	Membership Interest	100.00
Endurance Solar Holdings 1, LLC	Membership Interest	100.00
Endurance Solar Holdings 2, LLC	Membership Interest	100.00
Endurance Solar Holdings, LLC	Membership Interest	100.00
Endurance Solar Investor 1, LLC	Membership Interest	100.00
Endurance Solar Investor 2, LLC	Membership Interest	100.00
Endurance Solar Manager, LLC	Membership Interest	100.00
Endurance Solar Transfer Holdings, LLC	Membership Interest	100.00
Falcon Lake Storage, LLC	Membership Interest	100.00
Fiddle Leaf Solar Land Holdings, LLC	Membership Interest	100.00
Fiddle Leaf Solar, LLC	Membership Interest	100.00
Golden Plains Solar, LLC	Membership Interest	100.00
Golden Plains Storage, LLC	Membership Interest	100.00
Granite Hill Solar Land Holdings, LLC	Membership Interest	100.00
Granite Hill Solar, LLC	Membership Interest	100.00
Hazelnut Solar, LLC	Membership Interest	100.00
Hazelnut Storage, LLC	Membership Interest	100.00
Inverness Solar, LLC	Membership Interest	100.00
Jones City Energy Storage Class B, LLC	Membership Interest	100.00
Jones City Energy Storage Holdings, LLC	Membership Interest	100.00
Jones City Energy Storage, LLC	Membership Interest	100.00
Kirkham Solar Farms I, LLC	Membership Interest	100.00
Kirkham Solar Farms II, LLC	Membership Interest	100.00
Lightsource Beacon 2, LLC	Membership Interest	100.00
Lightsource Beacon 3, LLC	Membership Interest	100.00
Lightsource Beacon Holdings, LLC	Membership Interest	100.00
Lightsource Beacon, LLC	Membership Interest	100.00
Lightsource Novus Solar Holdings, LLC	Membership Interest	100.00
Lightsource Osprey Holdings A, LLC	Membership Interest	100.00
Lightsource Osprey Holdings B, LLC	Membership Interest	100.00
Lightsource Renewable Energy Asset Holdings 1, LLC	Membership Interest	100.00
Lightsource Renewable Energy Asset Management Holdings, LLC	Membership Interest	100.00
Lightsource Renewable Energy Asset Management, LLC	Membership Interest	100.00
Lightsource Renewable Energy Assets Holdings, LLC	Membership Interest	100.00
Lightsource Renewable Energy Austin Holdings, LLC	Membership Interest	100.00
Lightsource Renewable Energy Development, LLC	Membership Interest	100.00
Lightsource Renewable Energy Equipment, LLC	Membership Interest	100.00
Lightsource Renewable Energy Operations, LLC	Membership Interest	100.00
Lightsource Renewable Energy Services Holdings, LLC	Membership Interest	100.00
Lightsource Renewable Energy Services, Inc.	Ordinary	100.00
Lightsource Renewable Energy Solar Construction Corp 1, LLC	Membership Interest	100.00
Lightsource Renewable Energy Solar Construction Holdings, LLC	Membership Interest	100.00
Lightsource Renewable Energy Solar Construction, LLC	Membership Interest	100.00

13. Related undertakings of the group – continued

Lightsource Renewable Energy Spares, LLC	Membership Interest	100.00
Lightsource Renewable Energy Trading, LLC	Membership Interest	100.00
Lightsource Renewable Energy US, LLC	Membership Interest	100.00
LSBP NE Development, LLC	Membership Interest	100.00
Mayapple Solar Holdings 1, LLC	Membership Interest	100.00
Mayapple Solar Holdings, LLC	Membership Interest	100.00
Mayapple Solar, LLC	Membership Interest	100.00
Merrillville Energy Storage, LLC	Membership Interest	100.00
Merrillville Solar Holdings, LLC	Membership Interest	100.00
Merrillville Solar Land Holdings, LLC	Membership Interest	100.00
Merrillville Solar, LLC	Membership Interest	100.00
Mound Creek Storage, LLC	Membership Interest	100.00
Mountain Daisy Solar, LLC	Membership Interest	100.00
Mountain Holly Solar, LLC	Membership Interest	100.00
Mowata Solar Class B, LLC	Membership Interest	100.00
Mowata Solar Holdings, LLC	Membership Interest	100.00
Mowata Solar, LLC	Membership Interest	100.00
Osprey Solar Holdings A, LLC	Membership Interest	100.00
Osprey Solar Holdings B, LLC	Membership Interest	100.00
Paper Shell Solar 1, LLC	Membership Interest	100.00
Peony Solar 1, LLC	Membership Interest	100.00
Peony Solar 2 Storage, LLC	Membership Interest	100.00
Peony Solar 2, LLC	Membership Interest	100.00
Petro Franchise Systems LLC	Membership Interest	100.00
Pikes Peak Energy Storage Holdings, LLC	Membership Interest	100.00
Pikes Peak Energy Storage, LLC	Membership Interest	100.00
Pine Burr Solar 1, LLC	Membership Interest	100.00
Pine Cone Solar 2, LLC	Membership Interest	100.00
Pine Cone Solar 3, LLC	Membership Interest	100.00
Pine Cone Solar, LLC	Membership Interest	100.00
Poplar Solar 1, LLC	Membership Interest	100.00
Roscoe Solar, LLC	Membership Interest	100.00
Shorebird Solar, LLC	Membership Interest	100.00
Snowdrop Solar, LLC	Membership Interest	100.00
Starr Solar Ranch LLC	Membership Interest	100.00
Sycamore Trail Land Holdings, LLC	Membership Interest	100.00
Sycamore Trail Solar, LLC	Membership Interest	100.00
TA Franchise Systems LLC	Membership Interest	100.00
TA Operating LLC	Membership Interest	100.00
TA Operating Montana LLC	Partnership interest	100.00
TAI 1 LLC	Membership Interest	100.00
Theta Solar US Holdings B, LLC	Membership Interest	100.00
Theta Solar US Holdings, LLC	Membership Interest	53.22
Trinity River Solar 1, LLC	Membership Interest	100.00
Tulip Hills Solar, LLC	Membership Interest	100.00
Tulip Hills Storage, LLC	Membership Interest	100.00
Western Russet Solar, LLC	Membership Interest	100.00
White Trillium Solar, LLC	Membership Interest	100.00
Whitetail Solar 6, LLC	Membership Interest	100.00
Yellow Leaf Energy Storage, LLC	Membership Interest	100.00
Corporation Service Company 1127 Broadway Street NE, Suite 310 Salem, OR, 17110, United States		
Finley BioEnergy LLC	Membership Interest	100.00

The parent company financial statements of BP p.l.c. on pages 269-333 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

13. Related undertakings of the group – continued

Corporation Service Company, 100 Shockoe Slip, 2nd Floor, Richmond, VA, 23219, VA, 23219, United States

Collegiate Clean Energy, LLC	Membership Interest	100.00
INGENCO Wholesale Power, L.L.C.	Membership Interest	100.00

Corporation Service Company, 211 E. 7th Street, Suite 620, Austin, TX, 78701, United States

Shaula Energy Project II, LLC	Membership Interest	100.00
Shaula Energy Project III, LLC	Membership Interest	100.00
Shaula Energy Project, LLC	Membership Interest	100.00
Telesto Energy Project, LLC	Membership Interest	100.00
Thalassa Energy Project, LLC	Membership Interest	100.00

Corporation Trust Center, 1209 Orange Street, Wilmington, DE, 19801, United States

AE Cedar Creek Holdings LLC	Membership Interest	100.00
AH Medora LFG, LLC	Membership Interest	100.00
AHJRLIFG, LLC	Membership Interest	100.00
AHMLFG, LLC	Membership Interest	100.00
Air BP Canada LLC	Membership Interest	100.00
AM/PM International Inc.	Ordinary	100.00
American Oil Company	Ordinary	100.00
Amoco (U.K.) Exploration Company, LLC	Membership Interest	100.00
Amoco Chemical (Europe) S.A.	Ordinary	100.00
Amoco International Petroleum Company	Ordinary	100.00
Amoco Louisiana Fractionator Company	Ordinary	100.00
Amoco Main Pass Gathering Company	Ordinary	100.00
Amoco Netherlands Petroleum Company	Ordinary	100.00
Amoco Norway Oil Company	Ordinary	100.00
Amoco Overseas Exploration Company	Ordinary	100.00
Amoco Properties Incorporated	Ordinary	100.00
Amoco Remediation Management Services Corporation	Ordinary	100.00
Amoco Research Operating Company	Ordinary	100.00
Amoco Somalia Petroleum Company	Ordinary	100.00
Amoco Sulfur Recovery Company	Ordinary	100.00
Anaconda Arizona, Inc.	Ordinary	100.00
Archaea CCS LLC	Membership Interest	100.00
Archaea Energy II LLC	Membership Interest	100.00
Archaea Energy Inc.	Ordinary	100.00
Archaea Energy Marketing LLC	Membership Interest	100.00
Archaea Energy Operating LLC	Membership Interest	100.00
Archaea Energy Services LLC	Membership Interest	100.00
Archaea Holdings, LLC	Membership Interest	100.00
Archaea Infrastructure, LLC	Membership Interest	100.00
Archaea Operating LLC	Membership Interest	100.00
Archaea Real Estate Holdings LLC	Membership Interest	100.00
ARCO British Limited, LLC	Membership Interest	100.00
ARCO El-Djazair Holdings Inc.	Ordinary	100.00
ARCO Environmental Remediation, L.L.C.	Membership Interest	100.00
ARCO Midcon LLC	Membership Interest	100.00
Aria Energy East LLC	Membership Interest	100.00
Aria Energy LLC	Membership Interest	100.00
Aria Energy Operating LLC	Membership Interest	100.00
Artemisia Geothermal Resources Inc.	Ordinary	100.00
Assai Energy, LLC	Membership Interest	100.00
Atlantic Richfield Company	Ordinary; Preference	100.00
Azule Energy US Gas LLC	Membership Interest	50.00

13. Related undertakings of the group – continued

Beacon Wind Land LLC	Membership Interest	100.00
Biofuels Coyote Canyon Biogas, LLC	Membership Interest	100.00
BioFuels San Bernardino Biogas, LLC	Membership Interest	100.00
Blue Pier Energy Solutions LLC	Membership Interest	100.00
Blueprint Power Technologies LLC	Membership Interest	100.00
BP Alternative Energy North America Inc.	Ordinary	100.00
BP America Chemicals Company	Ordinary	100.00
BP America Foreign Investments Inc.	Ordinary	100.00
BP America Inc.	Ordinary; Ordinary B	100.00
BP America Production Company	Ordinary	100.00
BP AMI Leasing, Inc.	Ordinary	100.00
BP Argentina Exploration Company	Ordinary	100.00
BP Argentina Holdings LLC	Membership Interest	100.00
BP Berau Ltd.	Ordinary	100.00
BP Biofuels North America LLC	Membership Interest	100.00
BP Biofuels US Investments LLC	Membership Interest	100.00
BP Bomberai Ltd.	Ordinary	100.00
BP Brazil Tracking L.L.C.	Membership Interest	100.00
BP Canada Energy Marketing Corp.	Membership Interest	100.00
BP Canada Investments Inc.	Ordinary	100.00
BP Capital Markets America Inc.	Ordinary	100.00
BP Carbon Solutions LLC	Membership Interest	100.00
BP Caribbean Company	Ordinary	100.00
BP Central Pipelines LLC	Membership Interest	51.00
BP Chemical Remediation Holdings LLC	Membership Interest	100.00
BP China Exploration and Production Company	Ordinary	100.00
BP Company North America Inc.	Ordinary; Redeemable preference	100.00
BP Containment Response System Holdings LLC	Membership Interest	100.00
BP Egypt Company	Ordinary	100.00
BP Energy Company	Ordinary	100.00
BP Energy Holding Company LLC	Membership Interest	100.00
BP Energy Retail Company California LLC	Membership Interest	100.00
BP Energy Retail Company LLC	Membership Interest	100.00
BP Exploration & Production Inc.	Ordinary; Preference	100.00
BP Latin America LLC	Membership Interest	100.00
BP Latin America Upstream Services Inc.	Ordinary	100.00
BP Louisiana Energy Park LLC	Membership Interest	100.00
BP Lubricants USA Inc.	Ordinary	100.00
BP Mariner Holding Company LLC	Membership Interest	100.00
BP Midstream Partners GP LLC	Membership Interest	100.00
BP Midstream Partners Holdings LLC	Membership Interest	100.00
BP Midstream Partners LP	Ordinary	100.00
BP Midwest Product Pipelines Holdings LLC	Membership Interest	51.00
BP Nutrition Inc.	Ordinary	100.00
BP Offshore Response Company LLC	Membership Interest	100.00
BP Oil Pipeline Company	Ordinary	100.00
BP Oil Shipping Company, USA	Ordinary	100.00
BP One Pipeline Company LLC	Membership Interest	51.00
BP Pakistan (Badin) Inc.	Ordinary	100.00
BP Pakistan Exploration and Production, Inc.	Ordinary	100.00
BP Pipelines (Alaska) Inc.	Ordinary	100.00

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13. Related undertakings of the group – continued

BP Pulse Fleet North America Inc.	Ordinary	100.00
BP SC Holdings LLC	Membership Interest	100.00
BP Scale Up Factory North America Inc.	Ordinary	100.00
BP Solar Holding LLC	Membership Interest	100.00
BP Solar International Inc.	Ordinary	100.00
BP Southern Cone Company	Ordinary	100.00
BP Technology Ventures Inc.	Ordinary	100.00
BP Trinidad and Tobago LLC	Membership Interest	70.00
BP Wiriagar Ltd.	Ordinary	100.00
BPX (Eagle Ford) Gathering LLC	Membership Interest	75.00
BPX (Karnes) Gathering LLC	Membership Interest	100.00
BPX (Permian) Gathering JV LLC	Membership Interest	51.00
BPX Eagleford JV Holdings LLC	Membership Interest	100.00
BPX Energy Inc.	Ordinary	100.00
BPX Permian JV Holdings LLC	Membership Interest	100.00
BPX Production Company	Ordinary	100.00
Burmah Castrol Holdings Inc.	Ordinary	100.00
Casitas Pipeline Company	Ordinary	100.00
Castrol Caribbean & Central America Inc.	Ordinary	100.00
Cefari RNG OKC, LLC	Membership Interest	100.00
Cherry Island Renewable Energy, LLC	Membership Interest	100.00
CH-Twenty, Inc.	Ordinary	100.00
CII Methane Management III, LLC	Membership Interest	100.00
CII Methane Management IV, LLC	Membership Interest	100.00
EIF KC Landfill Gas, LLC	Membership Interest	100.00
Element Markets Renewable Natural Gas, LLC	Membership Interest	100.00
Elm Holdings Inc.	Ordinary	100.00
Emerald City Renewables LLC	Membership Interest	100.00
Foseco Holding, Inc.	Membership Interest	100.00
Foseco, Inc.	Ordinary	100.00
Gardena Holdings Inc.	Ordinary	100.00
Industrial Power Generating Company, LLC	Membership Interest	100.00
INGENCO Renewable Development LLC	Membership Interest	100.00
Innovative Energy Systems, LLC	Membership Interest	100.00
Innovative/Colonie, LLC	Membership Interest	100.00
Innovative/DANC, LLC	Membership Interest	100.00
Innovative/Fulton, LLC	Membership Interest	100.00
Ken-Chas Reserve Company	Ordinary	100.00
LES Operations Services LLC	Membership Interest	100.00
LES Renewable NG LLC	Membership Interest	100.00
Lightning Renewables, LLC	Membership Interest	60.00
Mardi Gras Transportation System Company LLC	Membership Interest	100.00
Mavrix, LLC	Membership Interest	100.00
Mountain City Remediation, LLC	Membership Interest	100.00
North America Funding Company	Ordinary	100.00
Remediation Management Services Company	Ordinary	100.00
Richfield Oil Corporation	Ordinary	100.00
RNG Moovers, LLC	Class B Membership Interest	95.00
Rochelle Energy LLC	Membership Interest	100.00
Saturn Renewables Holdings LLC	Membership Interest	50.00
South Shelby RNG, LLC	Membership Interest	100.00

13. Related undertakings of the group – continued

Southern Ridge Pipeline Holding Company	Ordinary	100.00
Thorntons LLC	Membership Interest	100.00
Timberline Energy, LLC	Class A Membership Interest	100.00
TLK Holding Company LLC	Membership Interest	100.00
TLK Operating Company LLC	Membership Interest	100.00
Toledo Refinery Holding Company LLC	Membership Interest	100.00
Union Texas International Corporation	Ordinary	100.00
Western Geo Land Acquisition LLC	Membership Interest	100.00
Westlake Houston Development, LLC	Membership Interest	100.00
Zeus Renewables LLC	Membership Interest	100.00
Zimmerman Energy LLC	Membership Interest	100.00
CT Corporation System 300 Montvue Road, Knoxville, TN 37919-5546, United States		
CERF Shelby, LLC	Membership Interest	100.00
Uruguay		
Dr. Luis Bonavita 1294, Oficina 2302, Montevideo, Uruguay		
BP Bioenergy Montevideo S.A.	Ordinary	100.00
Viet Nam		
Room 20.01, 20th Floor, The Nexus Tower, 3A-3B Ton Duc Thang Street, Sai Gon Ward, Ho Chi Minh City, Viet Nam		
Castrol BP Petco Limited Liability Company	Membership Interest	65.00
Zimbabwe		
Barking Road, Willowvale, Harare, Zimbabwe		
Castrol Zimbabwe (Private) Limited	Membership Interest	100.00

13. Related undertakings of the group – continued

Related undertakings other than subsidiaries

Company by country of incorporation and registered office address	Ownership interest	%
Albania		
Air BP Albania Sh.A., Aeroporti Nderkombetar i Tiranes, "Nene Tereza", Post Box 2933 in Tirana, Albania		
Air BP Albania SHA	Ordinary	50.00
Argentina		
Av Ingeniero Emilio Mitre 574 Ciudad de Campana Provincia de Buenos Aires Argentina		
Lition Energy Holding Argentina S.A.U.	Ordinary	36.96
Av. Leandro N. Alem 1180, piso 11º, Buenos Aires, Argentina		
Field Services Enterprise S.A.	Ordinary	50.00
Lithos Desarrollos Energeticos S.A.	Ordinary	50.00
Lithos Energia S.A.	Ordinary	36.96
Lithos Minerales Del Norte S.A.	Ordinary	33.26
Lithos Recursos Mineros S.A.	Ordinary	36.96
Parque Eolico Del Sur S.A.	Ordinary	27.50
San Matías Pipeline S.A.	Ordinary	50.00
Terminal CP.S.L.	Ordinary	50.00
Vientos Ombu III S.A.	Ordinary	25.00
Calle 14, No 781, Piso 2, Oficina 3, Ciudad de La Plata, Provincia de Buenos Aires, Argentina		
Barranca Sur Minera S.A.	Ordinary	50.00
Carlos María Della Paolera 265, Piso 22, Ciudad Autónoma de Buenos Aires, Argentina		
RSE & RCE S.A.U.	Ordinary	50.00
Florida 1, Piso 10, Buenos Aires, Argentina		
Oleoductos del Valle (Oldelval) S.A.	Ordinary	50.00
Francisco Behr 20, Barrio Pueyrredon, Comodoro Rivadavia, Provincia del Chubut, Argentina		
Manpetrol S.A.	Ordinary	50.00
Juramento 433, Salta, PProvincia de Salta, Argentina		
Alqa Lithium S.A.	Ordinary	36.96
Lavalle 190, piso 6 Depto L, Buenos Aires, Argentina		
Vientos Patagonicos Chubut Norte III S.A.	Ordinary	24.50
Vientos Sudamericanos Chubut Norte IV S.A.	Ordinary	24.50
O'Higgins N° 194, Rio Grande, Argentina		
Pan American Fueguina S.A.	Ordinary	50.00
Pan American Sur S.A.	Ordinary	50.00
Australia		
11 Lagoon Court, Samford Valley, QLD 4520, Australia		
Australasian Lubricants Manufacturing Company Pty Ltd	Ordinary A	50.00
34 Kent Road, Mascot, NSW 2020, Australia		
5B Holdings Pty Limited	Preference Series B (27.47%)	9.80
390, Suite 4; Level 18, St Kila Road, Melbourne, VIC, 3004, Australia		
Australian Terminal Operations Management Pty Ltd	Ordinary	50.00
Brookfield Place Tower II, Level 10, 123 St Georges Terrace Perth, WA 6000, Australia		
Australian Renewable Energy Hub Pty Ltd	Ordinary	65.04
Level 10, 12 Creek Street, Brisbane, QLD 4000, Australia		
Ocwen Energy Pty Ltd	Ordinary	49.50
Level 13, 16-20 Bridge Street, Sydney, NSW 2000, Australia		
XPANSIV Limited	Ordinary (18.87%); Preference Series A (26.16%)	19.43
Level 26, Mia Yellagonga Tower 3 1 Spring Street Perth WA 6000, Australia		
North West Shelf Lifting Coordinator Pty Ltd	Ordinary B (100.00%)	16.67

13. Related undertakings of the group – continued

Austria		
Am Tankhafen 4, 4020 Linz, Austria		
TLM Tanklager Management GmbH	Membership Interest	49.00
Brucknerstraße 4, 1040 Wien, Austria		
ABG Autobahn-Betriebe GmbH	Membership Interest	32.58
Innsbrucker Bundesstraße 95, 5020 Salzburg, Austria		
Salzburg Fuelling GmbH	Membership Interest	50.00
Radlpaßstraße 6, 8502 Lannach, Austria		
Erdol-Lagergesellschaft m.b.H.	Membership Interest	23.00
Trabrennstraße 6-8 3, Wien, A-1020, Austria		
Aircraft Refuelling Company GmbH	Membership Interest	33.33
Bahamas		
Trinity Place Annex, Corner of Frederick & Shirley Streets, P.O. Box N-4805, Nassau, Bahamas		
PAE E & P Bolivia Limited	Ordinary	50.00
Pan American Energy Investments Ltd.	Ordinary	50.00
Bolivia (Plurinational State of)		
Av San Martin 1700, Cuarto Anillo, Edificio Centro Empresarial Equipetrol, Piso 6, Zona Oeste, Equipetrol Norte, Santa Cruz de la Sierra, Bolivia (Plurinational State of)		
YPFB Chaco S.A.	Ordinary	50.00
Cuarto anillo, Avda. Ovidio Barbery N° 4200, Edificio Torre, e/ Jaime Román y Victor Pinto, Equipetrol Norte, Santa Cruz de la Sierra, Bolivia (Plurinational State of)		
PAE Oil & Gas Bolivia Ltda.	Ordinary	50.00
Brazil		
1675 South State Street, Suite B, Dover, Kent Country, DE, 19901 US, Brazil		
Pan American Energy Energias Renovaveis Ltda.	Ordinary	50.00
Avenida Atlântica, no. 1.130, 2nd floor (part), Copacabana,RJ, Rio de Janeiro, 22021-000, Brazil		
NFX Combustíveis Marítimos Ltda.	Ordinary	50.00
Avenida Paris, 4077, Suite 3, Cascata,São Paulo State, Paulínia, 13046-061, Brazil		
Terminal de Combustíveis Paulínia S.A.	Ordinary	50.00
City of Rio de Janeiro, State of Rio de Janeiro, Rua Voluntarios da Patria 113, 11th floor, Botafogo, 22270-000, Brazil		
Gas Natural Acu S.A.	Ordinary	30.00
Fazenda Saco Dantas, S/N, Área 3 e Área 4, Praia do Açú, São João da Barra, Rio de Janeiro, 28.200-000, Brazil		
UTE GNA II Geração de Energia S.A.	Ordinary	33.50
No. 804, 5th floor, Glória, Rio de Janeiro, Rio de Janeiro, 22210-010, Brazil		
Gas Natural Açú Infraestrutura S.A.	Ordinary	27.91
Praça Gago Coutinho, 540 – Ed. Aeroporto Internacional de Salvador – Box Air BP, city of Salvador, State of Bahia, 41.602-065, Brazil		
Air BP Petrobahia Ltda.	Ordinary	50.00
Rodovia Doutor Mendel Steinbruch 10.800, Distrito Industrial, Maracanaú, Ceara, 61.939-906, Brazil		
Ventos De Santa Virginia Energias Renovaveis S.A.	Ordinary	50.00
Ventos De Santo Ubaldo Energias Renovaveis S.A.	Ordinary	50.00
Ventos De Santo Urbano I Energias Renovaveis S.A.	Ordinary	50.00
Ventos De Sao Romualdo Energias Renovaveis S.A.	Ordinary	50.00
Ventos De Sao Teofano Energias Renovaveis S.A.	Ordinary	50.00
Ventos De Sao Teonas Energias Renovaveis S.A.	Ordinary	50.00
Ventos De Sao Thomas Energias Renovaveis S.A.	Ordinary	50.00
Ventos De Sao Tilao Energias Renovaveis S.A.	Ordinary	50.00
Rua Funchal 418, 24 andar, conjunto 2401C, parte 12, Vila Olimpia, Sao Paulo, Estado de Sao Paulo, CP 04551-060, Brazil		
Novo Horizonte Holding I Ltda.	Quotas	50.00
Novo Horizonte Holding II Ltda.	Ordinary	50.00
Pan American Energy Comercializadora De Energia Ltda.	Ordinary	50.00
Ventos De Sao Vigilio Energias Renovaveis S.A.	Ordinary	50.00
Ventos De Sao Vladimir Energias Renovaveis S.A.	Ordinary	50.00

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13. Related undertakings of the group – continued

Rua Manoel da Nóbrega nº1280, 10º andar, Sao Paulo, Sao Paulo, 04001-902, Brazil		
Pan American Energy do Brasil Ltda.	Membership Interest	50.00
Rua Voluntários da Pátria, No. 113, 11 floor, Botafogo, 22.270-000, Brazil		
Açu Trucked LNG S.A.	Membership Interest	30.00
Canada		
#3, 10524 42nd Street SE, Calgary AB, Canada		
Cold Bore Technology Inc	Series C preferred stock (48.65%)	12.84
13800 Steveston Hwy, Richmond, BC, V6W 1A8, Canada		
Saltworks Technologies Inc	Series A4 preferred (100.00%)	4.67
1600, 333 7 Th Avenue S.W., Calgary, AB, T2P 2Z1, Canada		
Eavor Technologies Inc.	Preference A (42.11%); Series B (9.59%)	16.60
Cayman Islands		
P.O. Box 309, Ugland House, 113 South Church Street, George Town, Cayman Islands		
Azerbaijan Gas Supply Company Limited	Ordinary	23.99
Azerbaijan International Operating Company	Ordinary	30.37
BTC International Investment Co.	Membership Interest	30.10
Georgian Pipeline Company	Ordinary	30.37
South Caucasus Pipeline Company Limited	Membership Interest	29.99
South Caucasus Pipeline Holding Company Limited	Membership Interest	29.99
South Caucasus Pipeline Option Gas Company Limited	Ordinary	29.99
The Baku-Tbilisi-Ceyhan Pipeline Company	Membership Interest	30.10
Chile		
Nueva de Lyon N° 145, piso 12, oficina 1203, Edificio Costa, Santiago de Chile, Chile		
Pan American Energy Chile Limitada	Ordinary	50.00
China		
#1812, Level 17, 162 Nansha Street Gangqian Avenue South, Nansha District, Guangzhou, China		
Guangzhou Gangfa Petrochemical Terminal Co. Ltd.	Membership Interest	20.00
10-11/FTime Finance Center, No.4001 Shennan Dadao, Futian Street, Futian District, Guangdong Province, Shenzhen, China		
Guangdong Dapeng LNG Company Limited	Membership Interest	30.00
2024-0066, Room 306 3rd Floor, Office Building 9, Chengye Road, West Coast Comprehensive Bonded Zone, China		
BP SPG Energy Trading Co., Ltd.	Membership Interest	49.00
5th Floor, Guangsha Ruiming Building, No. 231 Moganshan Road, Xihu District, Hangzhou, Zhejiang Province, China		
BP Sinopec (ZheJiang) Petroleum Co., Ltd	Membership Interest	40.00
A3#608, Dongjiang Commercial Center, #599 Eerduosi Road, Free Trade Zone (Dongjiang Free Trade Zone), China		
Xin Ying Energy Marketing Co., Ltd.	Membership Interest	50.00
Building 1, Unit 1, Floor 1, No. 8, Chemical Industry Fifth Road, Chemical Industry Zone, Qingshan District, Wuhan, 430085, China		
Castrol DongFeng Lubricant Co., Ltd	Membership Interest	50.00
Floor 7, 1, Jichang Avenue, Shenzhen City, Guangdong Province, China		
Shenzhen Cheng Yuan Aviation Oil Company Limited	Membership Interest	25.00
Room 1022, Building 1, No. 40 Chengmen Road, Damen Town, Dongtou District, Wenzhou City, Zhejiang Province, China		
Zhejiang Yingneng LNG Company Ltd.	Membership Interest	51.00
Room 526, No.13, Longxue Avenue middle, Nansha District, Guangzhou, China		
BP Guangzhou Development Oil Products Company Limited	Membership Interest	40.00
Room A, building B, 5th floor, no. 22 Gangkou road, Jiangmen, China		
BP Petro China Jiangmen Fuels Co., Ltd.	Membership Interest	49.00
Room B1, 11th Floor, No.22 Gang Kou Yi Road, Peng Jiang District, Guangdong Province, Jiangmen, China		
BP PetroChina Petroleum Co., Ltd	Membership Interest	49.00
Trucking Loading Station of Guangdong Dapeng LNG, Pingtou Corner, Xiasha Village, Dapeng Street, Dapeng New District, Shenzhen, China		
Shenzhen Dapeng LNG Marketing Company Limited	Membership Interest	30.00

13. Related undertakings of the group – continued

Cuba		
Calle 6 No 319, esq 5ta. Ave., Miramar, Playa, La Habana, Cuba		
Castrol Cuba S.A.	Ordinary	50.00
Cyprus		
90 Archiepiskopou str, Dromolaxia – Meneou, 7020 Larnaca, Cyprus		
LCA Aviation Fuelling Systems Limited	Ordinary	35.00
Denmark		
GA Centervej 1, Billund, DK-7190, Denmark		
Billund Refuelling I/S	Membership Interest	50.00
Kampmannsgade 2. 1604 København V, Denmark		
JERA Nex bp Danmark ApS	Ordinary	50.00
Kastrup Lufthavn, 2770 Kastrup, Denmark		
Danish Refuelling Services I/S	Membership Interest	50.00
Danish Tankage Services I/S	Membership Interest	50.00
Egypt		
14 Kamal El Tawil ST, Zamalek, Cairo, Egypt		
Lightsource BP Hassan Allam Developments for Renewable Energy S.A.E	Ordinary	50.00
85 El Nasr Road, Cairo, Egypt		
Natural Gas Vehicles Company "NGVC"	Ordinary	40.00
Al Shaheed St., Nasr City, Cairo, Egypt		
El Burg Offshore Company (EBOC)	Ordinary	20.00
El Temsah Petroleum Company "PETROTEMSAH"	Ordinary	25.00
Mediterranean Gas Co. "MEDGAS"	Ordinary	25.00
Building No. 349 & 351, Third Sector of City Centre, Fifth Settlement, New Cairo, Egypt		
United Gas Derivatives Company "UGDC"	Ordinary	33.33
Plot no 212, 2nd Sector, 5th Settlement, New Cairo, Egypt		
North El Burg Petroleum Company "PETRONEB"	Ordinary	25.00
Pharaonic Petroleum Company "PhPC"	Ordinary	25.00
France		
1 Place Gustave Eiffel, Rungis, 94150, France		
Société d'Avitaillement et de Stockage de Carburants Aviation "SASCA"	Membership Interest	40.00
27 Route du Bassin Numéro 6, Gennevilliers, 92230, France		
Société de Gestion de Produits Pétroliers - SOGEPP	Ordinary	37.00
3 Rue des Vignes, Aéroport Charles de Gaulle, Tremblay en France, 93290, France		
Fuelling Aviation Service - FAS	Membership Interest	50.00
562 Avenue du Parc de l'Ile, Nanterre, 92000, France		
Entrepot petrolier de Chambery	Ordinary	32.00
65 Rue d'Italie, Colombier-Saugnieu, 69124, France		
Stockage de Carburant d'Aviation Lyon	Membership Interest	40.00
Aéroport Bale Mulhouse, Saint-Louis, 68300, France		
Stockage de Carburant d'Aviation	Membership Interest	40.00
Aéroport Toulouse-Blagnac, Blagnac, 31700, France		
Stockage de Carburant d'Aviation Toulouse	Membership Interest	40.00
Germany		
Am Stadthafen 60, 45881 Gelsenkirchen, Germany		
TransTank GmbH	Ordinary	50.00
An der Börse 4, 30159 Hannover, Germany		
Getigy GmbH	Ordinary	51.00
An der Braker Bahn 22, 26122 Oldenburg, Germany		
Klaus Köhn GmbH	Ordinary	50.00
Köhn & Plambeck GmbH & Co. KG	Partnership interest	50.00

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13. Related undertakings of the group – continued

Brunnenstraße 19-21, Berlin, 10119, Germany		
Digital Charging Solutions GmbH	Membership Interest	33.33
Flughafenstraße 100, 90411, Nürnberg, Germany		
TGN Tankdienst-Gesellschaft Nurnberg GbR	Membership Interest	33.30
Godorfer Hauptstraße 186, 50997 Köln, Germany		
Rhein-Main-Rohrleitungstransportgesellschaft mbH	Ordinary	35.00
Hermann-Oberth-Str. 23, D-85640 Putzbrunn, Germany		
Phelas GmbH	Seed (28.13%)	11.04
Jenfelder Allee 80, Hamburg, 22039, Germany		
STDG Strassentransport Dispositions Gesellschaft mbH	Ordinary	50.00
Konsul-Smidt-Strasse 14, 28217 Bremen, Germany		
Etzel-Kavernenbetriebsgesellschaft mbH & Co. KG	Partnership interest	33.33
Etzel-Kavernenbetriebs-Verwaltungsgesellschaft mbH	Ordinary	33.33
Lingsforter Str. 21, Straelen, 47638, Germany		
Tecklenburg GmbH	Ordinary	50.00
Luisenstraße 5 a, 26382 Wilhelmshaven, Germany		
Ammenn GmbH	Ordinary	50.00
Kurt Ammenn GmbH & Co. KG	Partnership interest	50.00
Rheinstraße 36, 49090 Osnabrück, Germany		
Fip Verwaltungs GmbH	Ordinary	50.00
Heinrich Fip GmbH & Co. KG	Partnership interest	50.00
Saganer Straße 31, 90475 Nürnberg, Germany		
Beer Energien GmbH & Co. KG	Membership Interest	50.00
Beer GmbH	Ordinary	50.00
Schopenstehl 20 20095, Hamburg Germany		
GVÖ Gebinde-Verwertungsgesellschaft der Mineralölwirtschaft mbH	Ordinary	20.36
Sportallee 6, 22335 Hamburg, Germany		
Dusseldorf Fuelling Services GbR	Membership Interest	33.00
Hamburg Fuelling Services (HFS) GbR	Partnership interest	50.00
Hamburg Tank Service (HTS) GbR	Partnership interest	33.00
Langenhagen Fuelling Services (LFS) GbR	Partnership interest	50.00
Tanklager-Gesellschaft Hannover-Langenhagen (TGHL) GbR	Partnership interest	50.00
TGK Tanklagergesellschaft Koln-Bonn	Partnership interest	25.00
Turbo Fuel Services Sachsen (TFSS) GbR	Partnership interest	20.00
St.-Cajetan-Str. 43, 81669 München, Germany		
Coulomb GmbH	Ordinary	50.00
Enbase Power GmbH	Ordinary	37.45
Überseeallee 1, 20457 Hamburg, Germany		
Flughafen Hannover Pipeline Verwaltungsgesellschaft mbH	Ordinary	50.00
Flughafen Hannover Pipelinegesellschaft mbH & Co. KG	Partnership interest	50.00
Vancouverstraße 2a, 20457 Hamburg, Germany		
bp Offshore Wind Deutschland GmbH	Ordinary	50.00
bp OFW Management 1 GmbH	Ordinary	50.00
bp OFW Management 2 GmbH	Ordinary	50.00
bp OFW Management 3 GmbH	Ordinary	50.00
Wesermünder Straße 1, 27729 Hambergen, Germany		
Tecklenburg GmbH & Co. Energiebedarf KG	Partnership interest	50.00
Westfalendamm 166, 44141 Dortmund, Germany		
DOPARK GmbH	Ordinary	29.48
Wittener Straße 45, 44789 Bochum, Germany		
CSG Convenience Service GmbH	Ordinary	24.80

13. Related undertakings of the group – continued

Zum Ölhafen 207, 26384 Wilhelmshaven, Germany		
Nord-West Oelleitung GmbH	Ordinary	59.33
Ghana		
Number 1, Rehoboth Place, Dade Street, North Labone Estates, Accra, Greater Accra, Accra Metropolitan, P. O. BOX CT327, Ghana		
BP West Africa Supply Limited	Ordinary	50.00
Greece		
2,Vouliagmenis Ave & Papaflessa, 16777 Elliniko, Attika, Athens, Greece		
Gissco S.A.	Ordinary	50.00
International airport "El. Venizelos", Athens, Greece		
SAFCO SA	Ordinary	33.33
India		
1207-1212,A2, Palladium, Nr., Orchid Wood Opp. Divyabhaskar, Corporate Rd, Makarba, Ahmedabad, India		
Blu-Smart Mobility Private Limited	Preference Series A (60.25%); Preference Series A1 (30.14%); Preference Series A2 (53.54%);Preference Series B (1.37%)	15.00
3rd Floor, Maker Chambers IV, 222, Nariman Point, Mumbai, 400 021, India		
Reliance BP Mobility Limited	Ordinary	49.00
RBML Solutions India Ltd	Ordinary	49.00
Magenta House, Plot No. D-285, MIDC, Turbhe, Navi Mumbai, India, 400705		
Magenta EV Solutions Private Limited	Preference (53.47%)	20.89
No.10, Jawahar Road, Madurai, Tamil Nadu 625002, India, India		
TVS Automobile Solutions Private Limited	Compulsory convertible preference shares (38.10%)	3.62
Unit Nos.71 & 73 7th Floor, Maker Maxity, 2nd North Avenue, Bandra - Kurla Complex, Bandra (East), Mumbai 400 051, Maharashtra, India		
India Gas Solutions Private Limited	Ordinary	50.00
Indonesia		
AKR Tower 25th floor, Jalan Panjang No.5, Kebon Jeruk, Jakarta Barat, 11530, Indonesia		
PT. Aneka Petroindo Raya	Ordinary	49.90
PT. Dirgantara Petroindo Raya	Ordinary	49.90
Iraq		
Iraqi Airways HQ Building, Baghdad International Airport, Baghdad, Iraq		
United Iraqi Company for Airports and Ground Handling Services Limited (MASIL)	Ordinary	19.60
Naz City, Building J, Suite 10 Erbil, Iraq		
Mach Monument Aviation Fuelling Co. Ltd.	Ordinary	70.00
Ireland		
70 Northumberland Road,Ballsbridge, Dublin, Ireland		
BLS Bulk Liquid Storage Cork Limited	Membership Interest	30.00
Israel		
3 Shenkar Street, Herzelia, Israel		
StoreDot Ltd.	Preference Series C (21.47%); Preference Series D (14.45%)	5.07
Italy		
Via Emilia 1, 20097 San Donato Milanese, Italy		
Azule Energy Angola S.p.A	Membership Interest	50.00
Via Sardegna, Rome, 38 00187, Italy		
Air BP Italia Spa	Ordinary	50.00
Japan		
4-2 Otemachi 1-chome, Chiyoda-ku, Tokyo, Japan		
Ishikari Offshore Wind LLC	Ordinary	49.00

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13. Related undertakings of the group – continued

Yamagata Yuza Offshore Wind LLC	Ordinary	25.00
Mexico		
Av. Paseo de la Reforma 505 piso 32, Colonia Cuauhtémoc, Delegación Cuauhtémoc (06500), CDMX, Mexico		
EMSEP S.A. de C.V.	Ordinary	50.00
Torre A, piso 4, oficina 402, Calzada Legaria 549, Colonia 10 de Abril, Delegación Miguel Hidalgo, Ciudad de Mexico, C. P. 11250, Mexico		
Hokchi Energy S.A. de C.V.	Ordinary	50.00
Netherlands		
3196 KC Vondelingenplaat-Rt., Harbour number 3045, Butaanweg 215, Netherlands		
Rotterdam-Rijn-Pijpleiding Maatschappij N.V.	Ordinary	44.40
Anchorageaan 6, 1118LD Luchthaven Schiphol, Netherlands		
Gezamenlijke Tankdienst Schiphol B.V.	Ordinary	50.00
Bos en Lommerplein 280, Amsterdam, 1055RW, Netherlands		
Lightsource BP Hassan Allam Holdings B.V.	Ordinary	50.00
d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands		
Azule Energy Angola (Block 18) B.V.	Ordinary	50.00
Vaals B.V.	Ordinary	50.00
Vaals HoldCo B.V.	Ordinary	50.00
Moezelweg 101, 3198LS Europoort, Rotterdam, Netherlands		
Maatschap Europoort Terminal	Partnership interest	50.00
Oude Vijfhuizerweg 6, 1118LV Luchthaven, Schiphol, Netherlands		
Aircraft Fuel Supply B.V.	Ordinary	22.22
Rijndwarsweg 3, 3198 LK Europoort, Rotterdam, Netherlands		
BP AOC Pumpstation Maatschap	Membership Interest	50.00
BP Esso AOC Maatschap	Partnership interest	22.80
Maasvlakte Europoort Pipeline Maatschap	Partnership interest	50.00
Team Terminal B.V.	Ordinary	22.80
Stadsplateau 27, 10th floor, 3521AZ Utrecht, Netherlands		
BP Offshore Renewables Energy B.V.	Ordinary	50.00
Strawinskylaan 1725, 1077XX Amsterdam, Netherlands		
Azule Energy Angola B.V.	Ordinary	50.00
Azule Energy Angola Production B.V.	Ordinary	50.00
Routex B.V.	Ordinary	25.00
Van Asch van Wijck 53, Amersfoort, 3811LP, Netherlands		
H2-Fifty B.V.	Ordinary	50.00
New Zealand		
149 Roscommon Road, Wiri, Puhinui 2104, New Zealand		
Wiri Oil Services Limited	Ordinary	27.78
17 Innovation Road, Islington, Christchurch, 8042, New Zealand		
RD Petroleum Limited	Ordinary	49.00
247 Cameron Road, Tauranga, 3110, New Zealand		
McFall Fuel Limited	Ordinary	49.00
RMF Holdings Limited	Ordinary	49.00
Level 2, Harbour City Tower, 29 Brandon Street, Wellington Central, Wellington, 6011, New Zealand		
Glorit Solar I GP Limited	Ordinary	50.00
Glorit Solar I LP	Partnership interest	50.00
Glorit Solar P GP Limited	Ordinary	50.00
Glorit Solar P LP	Partnership interest	50.00
Kowhai Park I GP Limited	Ordinary	50.00
Kowhai Park I LP	Partnership interest	50.00
Kowhai Park P GP Limited	Ordinary	50.00
Kowhai Park P LP	Partnership interest	50.00

13. Related undertakings of the group – continued

Level 7, 187 Featherston Street, Wellington Central, Wellington, 6011, New Zealand		
New Zealand Oil Services Limited	Ordinary	50.00
Norway		
Postboks 133, Gardermoen, NO-2061, Norway		
Gardermoen Fuelling Services AS	Ordinary	33.33
Postboks 134, Gardermoen, NO-2061, Norway		
Oslo Lufthavns Tankanlegg AS	Ordinary	33.33
Trondheim Lufthavn Værnes, 7502 Stjørdal, Norway		
Flytanking AS	Ordinary	50.00
Oman		
PO Box 261, Postal Code 118, Sultanate of Oman, Oman		
Hyport Coordination Company LLC	Ordinary	49.00
Paraguay		
Av. España 1369 esquina San Rafael, Asunción, Paraguay		
Axion Energy Paraguay S.R.L.	Membership Interest	50.00
Peru		
Avenida Ricardo Rivera Navarrete n.501 / room 1602, Lima, Peru		
Air BP PBF del Peru S.A.C.	Ordinary	50.00
Poland		
Grunwaldzka 472B, 80-309, Gdansk, Poland		
Air BP Aramco Poland sp. z o. o.	Ordinary	50.00
Plac Rodta 8, PL-70-419, Szczecin, Poland		
GEWI Sp Z.O.O	Ordinary	38.20
Portugal		
Edifício GOC, Sala SABA - Aeroporto de Lisboa, Lisboa, Portugal		
SABA- Sociedade Abastecedora de Aeronaves, Lda	Ordinary	25.00
Lagoas Park, Edifício 3, Porto Salvo, Oeiras, 2740-266, Portugal		
Charging Together, Unipessoal LDA	Ordinary	50.00
Russian Federation		
119071, Moscow, municipal district Donskoy, ul Malaya Kaluzhskaya, 15, premises 1A/1, Russian Federation		
Limited Liability Company Yermak Neftegaz	Membership Interest	49.00
Srednelenskoye Limited Liability Company	Membership Interest	49.00
629830 Yamalo-Nenetskiy Anatomy Region, city of Gubkinskiy, Russian Federation		
LLC "Kharampurneftegaz"	Membership Interest	49.00
Pervomayskaya street, 32A, Sakha (Yakutiya) Republic, Lensk, 678144, Russian Federation		
Lensky Nefteprovod Limited Liability Company	Membership Interest	20.00
Limited Liability Company TYNGD	Membership Interest	20.00
Saudi Arabia		
Industrial Area Unit No 1, Yanbu Alsenayea, 46481 - 4659, Saudi Arabia		
Arabian Production and Marketing Lubricants Company Limited	Ordinary	50.00
P O Box 6369, Jeddah 21442, Saudi Arabia		
Peninsular Aviation Services Company Limited ^d	Ordinary	50.00
Singapore		
12 Marina Boulevard, #35-01 MBFC Tower 3, Singapore, 018982, Singapore		
BP Sinopec Marine Fuels Pte. Ltd.	Ordinary	50.00
8 Temasek Boulevard #31-02, Suntec City Tower 3, Singapore 038988, Singapore		
China Aviation Oil (Singapore) Corporation Ltd	Ordinary	20.06
South Africa		
135 Honshu Road, Islandview, Durban, 4052, South Africa		
Blendcor (Pty) Limited	Ordinary B	37.50
199 Oxford Road, Oxford Parks, Dunkeld, Johannesburg, GP, 2196, South Africa		
Masana Petroleum Solutions (Pty) Ltd	Ordinary	37.88

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13. Related undertakings of the group – continued

Island View Site 3 Complex, 135 Honshu Road, Island View, Durban, Kwazulu-Natal 4091, South Africa		
Shell and BP South African Petroleum Refineries (Pty) Ltd	Ordinary A	37.50
Spain		
163, Paseo de la Castellana, planta baja, Madrid, 28046, Spain		
Charging Together, S.L.	Ordinary	50.00
4, Torre Iberdrola, Plaza Euskadi 5, planta 9, Bilbao, 48009, Spain		
Pan American Energy, S.L.	Membership Interest	50.00
Southern Cone Development, S.L.	Ordinary	50.00
Calle Lituania n° 10, Castellón de la Plana, Spain		
Fundación para la Eficiencia Energética de la Comunidad Valenciana	Membership Interest	33.33
Calle Orense 4 5a, Madrid, 28020, Spain		
Guillena Nivel II, S.L.	Ordinary	50.08
Calle Pedro Teixeira, 8 (edificio Iberia Mart), 8º, 28020 Madrid, Spain		
Servicios Logísticos de Combustibles de Aviación, S.L.	Ordinary	50.00
Calle Quintanadueñas, 6, (Edificio Arqboorea), Madrid, 28050, Spain		
Snowmass Offshore Wind Spain, S.L.	Ordinary	50.00
Campus Empresarial Arbea - Edificio No 1, Carretera Fuencarral a Alcobendas (M-603), km 3.8, Alcobendas, Madrid, Spain		
Hokchi Iberica, S.L.	Ordinary	50.00
L13 ENERGY INVESTMENTS S.L.	Quotas	36.96
Li3 Energy Holding, S.L.	Ordinary	36.96
PAE Desarrollos Energeticos, S.L.	Ordinary	50.00
PAE Energy Holding, S.L.	Membership Interest	50.00
Pan American Energy Group, S.L.	Ordinary B	50.00
Pan American Energy Iberica, S.L.	Ordinary	50.00
Cardenal Marcelo Spinola, 42, 28016 Madrid, Spain		
Olmedo Renovables 400 kV, A.I.E.	Membership Interest	30.24
Carretera de San Andrés/n, La Jurada-María Jiménez, Santa Cruz de Tenerife, Spain		
Terminales Canarios, S.L.	Ordinary	50.00
Paseo De La Castellana 91 4º 4 Madrid, Spain		
Gómez Narro Renovables 132 kV, A.I.E	Membership Interest	45.45
Polígono Industrial "El Serrallo", s/n 12100 Grao de Castellón, Castellón de la Plana, Spain		
Castellón Green Hydrogen, S.L.	Ordinary	50.00
Sweden		
Box 135, 190 46 Arlanda, Sweden		
A Flygbranslehantering AB	Ordinary	25.00
Box 2154, Landvetter, 438 14, Sweden		
Gothenburg Fuelling Company AB	Ordinary	33.33
Box 22, SE 230 32 Malmö-Sturup, Sweden		
Malmö Fuelling Services AB	Ordinary	33.33
Box 7, 190 45 Arlanda, Sweden		
Stockholm Fuelling Services Aktiebolag	Ordinary	25.00
Switzerland		
Aéroport International de Genève 17, Route de Pré-Bois, Case postale 346, Switzerland		
Saraco SA	Ordinary	20.00
Zwüscheiteich, Rümlang, 8153, Switzerland		
TAR - Tankanlage Ruemlang AG	Ordinary	27.32
Thailand		
23rd Fl. Rajanakarn Bldg, 3 South Sathon Road, Yannawa South Sathon, Bangkok 10120, Thailand		
Pacroy (Thailand) Co., Ltd.	Ordinary (100.00%); Preference (0.82%)	39.50

13. Related undertakings of the group – continued

Trinidad and Tobago		
48-50 Sackville Street, Port of Spain, Trinidad and Tobago		
Solar Photovoltaic Holding Company of Trinidad and Tobago Limited	Ordinary	35.00
Princes Court, Cor. Pembroke & Keate Street, Port-of-Spain, Trinidad and Tobago		
Atlantic LNG 4 Company of Trinidad and Tobago Unlimited	Ordinary	37.78
Atlantic LNG Company of Trinidad and Tobago	Ordinary	47.15
Türkiye		
Söğütözü Caddesi, Koç Kuleleri B Blok Söğütözü Mahallesi 2B/37, Çankaya/Ankara, 06510, Türkiye		
TANAP Dogalgaz İletim Anonim Sirketi	Ordinary C (100.00%)	9.38
United Arab Emirates		
Building 01, Office 01 Central Park, Masdar City, Abu Dhabi, UAE, United Arab Emirates		
The Catalyst Limited	Ordinary	50.00
Middle East Lubricants Company LLC, po box 1699, Dubai, United Arab Emirates		
Middle East Lubricants Company LLC	Ordinary	40.00
P O Box- 97, Sharjah, United Arab Emirates		
Sharjah Aviation Services Co. LLC	Ordinary B	49.00
P.O. Box 261143, Dubai, United Arab Emirates		
Emoil Petroleum Storage FZCO	Ordinary	20.00
P.O.Box 261781, Dubai, United Arab Emirates		
EMDAD Aviation Fuel Storage FZCO	Ordinary	33.33
Sharjah 42244, Sharjah, UAE, Sharjah, United Arab Emirates		
Sharjah Pipeline Company LLC	Ordinary	24.01
Unit GD-GB-00-15-BC-26, Level 15, Gate District Gate Building, Dubai International Financial Center, 74777, United Arab Emirates		
Basra Energy Company Limited	Ordinary	49.00
United Kingdom		
1 Wellheads Avenue, Dyce, Aberdeen, AB21 7PB, United Kingdom		
S&JD Robertson North Air Limited	Ordinary	49.00
125, Old Broad Street, London, EC2N 1AR, England, United Kingdom		
Azule Energy Exploration (Angola) Limited	Ordinary	50.00
Azule Energy Exploration Angola (KB) Limited	Ordinary	50.00
Azule Energy Holdings Limited	Ordinary	50.00
Azule Energy Limited	Ordinary	50.00
33 Cavendish Square, London, W1G 0PW, United Kingdom		
Great Ropemaker Partnership (G.P.) Limited	Ordinary B	50.00
Great Ropemaker Property (Nominee 1) Limited	Ordinary	50.00
Great Ropemaker Property (Nominee 2) Limited	Ordinary	50.00
Great Ropemaker Property Limited	Ordinary	50.00
The Great Ropemaker Partnership	Membership Interest	50.00
5-7 Alexandra Road, Hemel Hempstead, Hertfordshire, HP2 5BS, England, United Kingdom		
British Pipeline Agency Limited	Ordinary	50.00
United Kingdom Oil Pipelines Limited	Ordinary	22.00
Walton-Gatwick Pipeline Company Limited	Ordinary	42.33
West London Pipeline and Storage Limited	Ordinary	30.50
6th Floor, 60 Gracechurch Street, London, EC3V 0HR, United Kingdom		
Gasrec Ltd	Ordinary A (39.50%)	30.71
C/O ERNST & YOUNG LLP, The Paragon Counterslip, Bristol, BS1 6BX, United Kingdom		
Green Biofuels Limited	Ordinary	30.00
Calshot Way Central Area, Heathrow Airport, Hounslow, Middlesex, TW6 1PY, United Kingdom		
Aviation Fuel Services Limited	Ordinary	25.00
Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, England, United Kingdom		
Arcius Energy Egypt Limited	Ordinary	51.00

The parent company financial statements of BP p.l.c. on pages 269-333 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

13. Related undertakings of the group – continued

Arcius Energy Limited	Ordinary	51.00
Jera Nex bp Development Company Limited	Ordinary	50.00
JERA Nex bp Limited	Ordinary	50.00
Jera Nex bp North East Limited	Ordinary	50.00
JERA Nex bp UK Holding Limited	Ordinary	50.00
JERA NEX OSW LTD	Ordinary	50.00
Net Zero North Sea Storage Holdings Limited	Ordinary	45.00
Net Zero North Sea Storage Ltd	Ordinary	45.00
Net Zero Teesside Power Holdings Limited	Ordinary	75.00
Net Zero Teesside Power Limited	Ordinary	75.00
Shafag (Jabrayil) Solar Limited	Ordinary	40.01
Eni House, 10 Ebury Bridge Road, London, SW1W 8PZ, England, United Kingdom		
Solenova Limited	Ordinary	25.00
VIC CBM Limited	Ordinary	50.00
Virginia Indonesia Co. CBM Limited	Ordinary	50.00
Johnston Carmichael, Bishop's Court, 29 Albyn Place, Aberdeen, AB10 1YL, Scotland, United Kingdom		
bp Aberdeen Hydrogen Energy Limited	Ordinary B	44.61
Mclaren Building Suite, 14a McLaren Building, 46 Priory Queensway, Birmingham, B4 7LR, United Kingdom		
Grid Edge Limited	Preferred Series A (60.00%); Preferred Series A 2 (58.68%)	24.89
Mw1 Building 557 Shoreham Road, Heathrow Airport, London, TW6 3RT, United Kingdom		
Aviation Service (Iraq) Limited	Ordinary B	40.00
One Bartholomew Close, London, EC1A 7BL, United Kingdom		
Manchester Airport Storage and Hydrant Company Limited	Ordinary	25.00
Oxbotica Uhq 8050 Alec Issigonis Way, Oxford Business Park North, Oxford, Oxfordshire, OX4 2HW, England, United Kingdom		
Oxa Autonomy Ltd	Ordinary (1.10%); Preference Series B (17.79%); Preference Series C (22.37%)	11.26
Shell Centre, London, SE1 7NA, United Kingdom		
Shell Mex and B.P. Limited	Ordinary B	40.00
SM Realisations Limited (In Liquidation)	Membership Interest	40.00
The Consolidated Petroleum Company Limited	Ordinary B	50.00
The Consolidated Petroleum Supply Company Limited ^e	Ordinary	50.00
Suite 44 (C/O Best4Business Accountants), Beaufort Court, Admirals Way, London, E14 9XL, United Kingdom		
Pentland Aviation Fuelling Services Limited	Ordinary A; Ordinary B	66.67
Unit 9 Armstrong Mall, Southwood Business Park, Farnborough, GU14 0NR, England, United Kingdom		
Blue Ocean Seismic Services Limited	Preference Series A (51.28%)	31.25
Windsor House, Cornwall Road, Harrogate, England, HG1 2PW, United Kingdom		
C-Capture Limited	Preference Series A (23.17%)	18.75
United States		
108 Lakeland Avenue, Dover, Kent, DE, 19901		
Azule Energy Gas Supply Services Inc.	Ordinary	50.00
160 Greentree Drive, Suite 101, City of Dover, County of Kent, DE, 19901, United States		
Zubie, Inc.	Membership Interest	20.30
2140 S. Dupont Highway, Camden, County of Kent, DE, 19934, United States		
Beyond Limits, Inc.	Preference Series B (100.00%); Preference Series C (20.07%)	12.25
2312 N. Miami Ave., Miami, Florida 33127, United States		
BEEFFREE HOLDINGS INC.	Preference Series A (60.85%)	14.12

13. Related undertakings of the group – continued

2344B Walsh Ave, Santa Clara, 95051, California, United States

Electronic Cooling Solutions, Inc	Ordinary	51.00
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2710 Gateway Oaks Drive, Suite 150N Sacramento, CA, 95833-3505, United States

East Travel Plaza LLC	Membership Interest	40.00
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Petro Travel Plaza LLC	Membership Interest	40.00
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40600 Ann Arbor Road E STE 201, Plymouth, MI 48170, United States

Sunshine Gas Producers, LLC	Membership Interest	60.00
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615 South DuPont Highway, Dover, South of Kent, DE, 19901, United States

Fulcrum BioEnergy, Inc.	Preference D-2 (100.00%); Preference D-4 (7.54%); Preference D-4-1 (61.43%); Preference D-7 (88.24%)	17.94
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850 New Burton Road, Suite 201, Dover, Delaware, 19902, United States

SeaPort Midstream Partners, LLC	Membership Interest	49.00
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WasteFuel Global, Inc.	Series B preferred stock (99.50%)	2.63
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920 North King Street, 2nd Floor, Wilmington DE 19801, United States

Atlantic 2/3 Holdings LLC	Membership Interest	47.15
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Atlantic 4 Holdings LLC	Membership Interest	37.78
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c/o Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808, United States

Apis Innovation Inc.	Ordinary	37.43
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Arche Energy Project Class B, LLC	Membership Interest	50.00
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Arche Energy Project Holdings, LLC	Membership Interest	50.00
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Arche Energy Project Tenant, LLC	Membership Interest	50.00
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Astro Solar Construction Holdings, LLC	Membership Interest	53.22
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Astro Solar Construction, LLC	Membership Interest	53.22
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Astro Solar Holdings 1, LLC	Membership Interest	53.22
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Astro Solar Holdings 2, LLC	Membership Interest	53.22
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Astro Solar Manager, LLC	Membership Interest	53.22
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Bass Solar Class B, LLC	Membership Interest	53.22
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Bass Solar Construction, LLC	Membership Interest	53.22
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Bass Solar Holdings 1, LLC	Membership Interest	53.22
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Bass Solar Holdings 2, LLC	Membership Interest	53.22
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Bass Solar Holdings, LLC	Class B Membership Interest	53.22
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Bellflower Solar 1, LLC	Membership Interest	53.22
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Bighorn Solar 1, LLC	Membership Interest	53.22
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Bighorn Solar Class B, LLC	Membership Interest	53.22
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Bighorn Solar Construction, LLC	Membership Interest	53.22
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Bighorn Solar Holdings 1, LLC	Membership Interest	53.22
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Bighorn Solar Holdings 2, LLC	Membership Interest	53.22
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Bighorn Solar Holdings, LLC	Class B Membership Interest	53.22
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Black Bear Alabama Solar 1, LLC	Membership Interest	27.40
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Black Bear Alabama Solar Holdings 1, LLC	Membership Interest	53.22
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Black Bear Alabama Solar Holdings 2, LLC	Membership Interest	53.22
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Black Bear Alabama Solar Holdings, LLC	Membership Interest	27.40
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Black Bear Alabama Solar Land Holdings, LLC	Membership Interest	53.22
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Black Bear Alabama Solar Manager, LLC	Membership Interest	53.22
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Briar Creek Solar 1, LLC	Membership Interest	53.22
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Cardinal Solar Class B, LLC	Membership Interest	53.22
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Cardinal Solar Construction Holdings, LLC	Membership Interest	53.22
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Cardinal Solar Construction, LLC	Membership Interest	53.22
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The parent company financial statements of BP p.l.c. on pages 269-333 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

13. Related undertakings of the group – continued

Cardinal Solar Holdings 1, LLC	Membership Interest	53.22
Cardinal Solar Holdings 2, LLC	Membership Interest	53.22
Cardinal Solar Holdings, LLC	Class B Membership Interest	53.22
Continental Divide Solar I, LLC	Membership Interest	53.22
Continental Divide Solar II, LLC	Membership Interest	53.22
Continental Divide Solar Land Holdings, LLC	Membership Interest	53.22
Cottontail Solar 1, LLC	Membership Interest	53.22
Cottontail Solar 2, LLC	Membership Interest	53.22
Cottontail Solar 5, LLC	Membership Interest	53.22
Cottontail Solar 6, LLC	Membership Interest	53.22
Cottontail Solar 8, LLC	Membership Interest	53.22
Cottontail Solar Class B, LLC	Membership Interest	53.22
Cottontail Solar Construction Holdings, LLC	Membership Interest	53.22
Cottontail Solar Construction, LLC	Membership Interest	53.22
Cottontail Solar Holdings 1, LLC	Membership Interest	53.22
Cottontail Solar Holdings 2, LLC	Membership Interest	53.22
Cottontail Solar Holdings, LLC	Class B Membership Interest	53.22
Elm Branch Solar 1, LLC	Membership Interest	53.22
Glade CD Solar Holdings, LLC	Membership Interest	53.22
Glade Solar Class B, LLC	Membership Interest	53.22
Glade Solar Construction Holdings, LLC	Membership Interest	53.22
Glade Solar Construction, LLC	Membership Interest	53.22
Glade Solar Holdings 1, LLC	Membership Interest	53.22
Glade Solar Holdings 2, LLC	Membership Interest	53.22
Glade Solar Holdings, LLC	Class B Membership Interest	53.22
Glade Solar Land Holdings, LLC	Membership Interest	53.22
Honeysuckle Solar, LLC	Membership Interest	53.22
Impact Solar 1, LLC	Membership Interest	53.22
Impact Solar Class B, LLC	Membership Interest	53.22
Impact Solar Construction, LLC	Membership Interest	53.22
Impact Solar Holdings 1, LLC	Membership Interest	53.22
Impact Solar Holdings 2, LLC	Membership Interest	53.22
Impact Solar Holdings, LLC	Class B Membership Interest	53.22
IoTecha Corp	Series C preferred stock (52.73%)	14.15
Irongate Solar Holdings 1, LLC	Membership Interest	50.00
Irongate Solar Holdings 2, LLC	Membership Interest	50.00
Johnson Corner Solar I, LLC	Membership Interest	53.22
Jones City Solar Class A, LLC	Membership Interest	50.00
Jones City Solar Class B, LLC	Membership Interest	50.00
Jones City Solar Holdings, LLC	Membership Interest	50.00
Jones City Solar II Class A, LLC	Membership Interest	50.00
Jones City Solar II Class B, LLC	Membership Interest	50.00
Jones City Solar II Holdings, LLC	Membership Interest	50.00
Jones City Solar II, LLC	Membership Interest	50.00
Jones City Solar, LLC	Membership Interest	50.00
Juliet Energy Project Class B, LLC	Membership Interest	50.00
Juliet Energy Project Holdings, LLC	Membership Interest	50.00
Juliet Energy Project, LLC	Membership Interest	50.00
Maverick Solar Class B, LLC	Membership Interest	53.22

13. Related undertakings of the group – continued

Maverick Solar Construction, LLC	Membership Interest	53.22
Maverick Solar Holdings 1, LLC	Membership Interest	53.22
Maverick Solar Holdings 2, LLC	Membership Interest	53.22
Maverick Solar Holdings, LLC	Class B Membership Interest	53.22
Novus Solar Holdings 1, LLC	Membership Interest	50.00
Novus Solar Holdings, LLC	Class B Membership Interest	50.00
Peacock Energy Project Class B, LLC	Membership Interest	50.00
Peacock Energy Project Holdings, LLC	Membership Interest	50.00
Peacock Energy Project, LLC	Membership Interest	50.00
Petro Travel Plaza Holdings LLC	Membership Interest	40.00
Prairie Ronde Solar Class B, LLC	Membership Interest	53.22
Prairie Ronde Solar Farm, LLC	Membership Interest	53.22
Prairie Ronde Solar Holdings, LLC	Class B Membership Interest	53.22
Starr Solar Ranch 1, LLC	Membership Interest	50.56
Sun Mountain Solar 1, LLC	Membership Interest	53.22
Titan Partners LLC	Membership Interest	25.00
TX Gulf Solar 1, LLC	Membership Interest	50.56
Viridos, Inc.	Series A preferred stock (33.37%); Junior preferred stock (12.16%); Ordinary A (11.54%)	6.79
Whitetail Solar 1, LLC	Membership Interest	53.22
Whitetail Solar 2, LLC	Membership Interest	53.22
Whitetail Solar 3, LLC	Membership Interest	53.22
Whitetail Solar Land Holdings, LLC	Membership Interest	53.22
Wildflower Solar I, LLC	Membership Interest	53.22
Wildflower Solar Land Holdings, LLC	Membership Interest	53.22
Corporation Trust Center, 1209 Orange Street, Wilmington, DE, 19801, United States		
Advanced Ionics, Inc.	Series A-1 (40.91%)	13.99
Ash Grove Renewable Energy, LLC	Membership Interest	47.50
Atlas RNG LLC	Membership Interest	50.00
Aurum Renewables LLC	Class B Membership Interest	60.00
Beacon Wind Holdings LLC	Membership Interest	50.00
Beacon Wind LLC	Membership Interest	50.00
BP Central Atlantic Offshore Wind Holdings LLC	Membership Interest	50.00
BP Central Atlantic Offshore Wind LLC	Membership Interest	50.00
BP Gulf of Mexico Midstream Holding LLC	Membership Interest	51.00
BP Northwest Offshore Wind Holdings LLC	Membership Interest	50.00
BP Northwest Offshore Wind LLC	Membership Interest	50.00
BP Offshore Wind America Development LLC	Membership Interest	50.00
BP Offshore Wind America Holding Company LLC	Membership Interest	50.00
BP Offshore Wind America LLC	Membership Interest	50.00
Caesar Oil Pipeline Company, LLC	Membership Interest	28.56
CE BP Renew Co, LLC	Membership Interest	50.00
CE bp Renew Dynamic Co I, LLC	Membership Interest	40.00
CE bp Renew Dynamic Co II, LLC	Membership Interest	47.50
CE bp Renew Dynamic Co III, LLC	Membership Interest	40.00
CES Biogas LLC	Membership Interest	60.00
Chicap Pipe Line Company	Ordinary	28.65
Clean Eagle RNG, LLC	Membership Interest	50.00

The parent company financial statements of BP p.l.c. on pages 269-333 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

13. Related undertakings of the group – continued

Cleopatra Gas Gathering Company, LLC	Membership Interest	27.03
Corteva BP LLC	Membership Interest	50.00
Drumgoon Digester Renewable Energy, LLC	Membership Interest	40.00
East Valley Development, LLC	Membership Interest	50.00
Eden RNG LLC	Membership Interest	50.00
Endymion Oil Pipeline Company, LLC	Membership Interest	33.15
Green Meadows RNG LLC	Membership Interest	50.00
HPP SD Holdings, LLC	Membership Interest	20.70
Janus RNG LLC	Membership Interest	50.00
KM Phoenix Holdings LLC	Membership Interest	25.00
Marshall Ridge Renewable Energy, LLC	Membership Interest	40.00
Midwest Alliance For Clean Hydrogen, LLC	Membership Interest	26.20
Olympic Pipe Line Company LLC	Membership Interest	35.70
Pan American Energy US LLC	Membership Interest	51.00
Pan RNG LLC	Membership Interest	50.00
Proteus Oil Pipeline Company, LLC	Membership Interest	33.15
Saturn Renewables LLC	Partnership interest	50.00
Snowmass US Offshore Wind Holding LLC	Membership Interest	50.00
Tri-Cross Renewable Energy, LLC	Membership Interest	47.50
UGID Broad Mountain, LLC	Membership Interest	60.00
Ursa Major Marine Holdings, LLC	Membership Interest	33.33
Van Winkle Digester Renewable Energy, LLC	Membership Interest	47.50
VF Renewable Energy, LLC	Membership Interest	40.00
Uruguay		
Colonia 810, Oficina 403, Montevideo, Uruguay		
Baplor S.A.	Ordinary	50.00
Pan American Energy Holdings S.A.	Ordinary	50.00
Pan American Energy Uruguay S.A.	Ordinary	50.00
Viet Nam		
Level 17-18, The Nexus Building, 3A-3B Ton Duc Thang, Sai Gon Ward, Ho Chi Minh City, Viet Nam		
Castrol Gogoro Mobility Joint Stock Company	Ordinary	50.00
Zimbabwe		
Block 1 Tendeseka Office Park, Samora Machel Av/Renfrew Road, Harare, Zimbabwe		
Central African Petroleum Refineries (Pvt) Ltd	Membership Interest	20.75

- a 1% interest held directly by BP p.l.c.
b 0.01% interest held directly by BP p.l.c.
c 100% interest held directly by BP p.l.c.
d 50% interest held directly by BP p.l.c.
e 5% interest held directly by BP p.l.c.

Additional disclosures

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Additional information

Capital expenditure★

	\$ million		
	2025	2024	2023
Capital expenditure			
Organic capital expenditure★	13,613	16,135	14,998
Inorganic capital expenditure ^{ab} ★	920	102	1,255
	14,533	16,237	16,253
Capital expenditure by segment			
gas & low carbon energy ^{ac}	3,410	5,842	4,773
oil production & operations	6,760	6,198	6,278
customers & products ^{abc}	4,071	3,789	4,761
other businesses & corporate	292	408	441
	14,533	16,237	16,253
Capital expenditure by geographical area			
US	6,129	6,566	8,105
Non-US	8,404	9,671	8,148
	14,533	16,237	16,253

a 2025 includes the final payment for the bp Bunge Bioenergia acquisition. 2024 includes the cash acquired net of acquisition payments on completion of the bp Bunge Bioenergia and Lightsource bp acquisitions.

b 2023 includes \$1.1 billion in respect of the TravelCenters of America acquisition.

c 2024 and 2023 have been restated to reflect the move of our Archaea Energy business from the customers & products segment to the gas & low carbon energy segment.

Adjusting items

Adjusting items are items that bp discloses separately because it considers such disclosures to be meaningful and relevant to investors. They are items that management considers to be important to period-on-period analysis of the group's results and are disclosed in order to enable investors to better understand and evaluate the group's reported financial performance. An analysis of adjusting items is shown in the table below.

	\$ million		
	2025	2024	2023
gas & low carbon energy			
Gain on sale of businesses and fixed assets ^a	258	297	19
Net impairment and losses on sale of businesses and fixed assets ^{ab}	(4,448)	(3,521)	(2,221)
Environmental and related provisions	–	–	–
Restructuring, integration and rationalization costs ^c	(2)	(25)	–
Fair value accounting effects ^{de} ★	1,270	(1,550)	8,859
Other ^f	(1,115)	1,048	(1,299)
	(4,037)	(3,751)	5,358
oil production & operations			
Gain on sale of businesses and fixed assets ^a	407	144	297
Net impairment and losses on sale of businesses and fixed assets ^a	(552)	(790)	(1,819)
Environmental and related provisions	(268)	5	54
Restructuring, integration and rationalization costs ^c	(67)	(15)	(1)
Fair value accounting effects	–	–	–
Other ^g	(376)	(492)	(121)
	(856)	(1,148)	(1,590)
customers & products			
Gain on sale of businesses and fixed assets ^a	317	190	44
Net impairment and losses on sale of businesses and fixed assets ^{abh}	(1,030)	(2,600)	(1,757)
Environmental and related provisions	(68)	(99)	(97)
Restructuring, integration and rationalization costs ^c	(241)	(123)	–
Fair value accounting effects ^e	(207)	(81)	(86)
Other ⁱ	57	(847)	(287)
	(1,172)	(3,560)	(2,183)
other businesses & corporate			
Gain on sale of businesses and fixed assets ^a	5	39	1
Net impairment and losses on sale of businesses and fixed assets ^a	(5)	(19)	(41)
Environmental and related provisions ^j	(320)	(87)	(604)
Restructuring, integration and rationalization costs ^c	(210)	(59)	38
Fair value accounting effects ^e	1,157	(221)	630
Gulf of America oil spill	(31)	(51)	(57)
Other	12	18	(4)
	608	(380)	(37)
Total before interest and taxation	(5,457)	(8,839)	1,548
Finance costs ^k	(428)	(505)	(405)
Total before taxation	(5,885)	(9,344)	1,143
Taxation on adjusting items ^{lm}	246	1,495	972
Taxation - tax rate change effect ⁿ	(774)	(316)	232
Total after taxation ^o	(6,413)	(8,165)	2,347

a See Financial statements – Note 4 for further information.

b 2024 has been restated for material items to reflect the move of our Archaea Energy business from the customers & products segment to the gas & low carbon energy segment.

c Restructuring charges are classified as adjusting items where they relate to an announced major group restructuring. A major group restructuring is a restructuring programme affecting more than one of the group's operating segments that is expected to result in charges of more than \$1 billion over a defined period. 2024 includes charges for provisions arising from the groups transformation project that was announced on 16 January 2024.

d Under IFRS bp marks-to-market the value of the hedges used to risk-manage LNG contracts, but not the contracts themselves, resulting in a mismatch in accounting treatment. The fair value accounting effect includes the change in value of LNG contracts that are being risk-managed, and the underlying result reflects how bp risk-manages its LNG contracts.

e For further information, including the nature of fair value accounting effects reported in each segment, see page 379.

f 2025 includes \$1,082 million of impairment charges recognized through equity-accounted earnings primarily relating to the Archaea Energy and offshore wind businesses. 2024 includes a \$508 million gain relating to the remeasurement of bp's pre-existing 49.97% interest in Lightsource bp, and \$498 million relating to the remeasurement of certain US assets excluded from the Lightsource bp acquisition (see Note 3 for further information). 2023 includes \$1,140 million of impairment charges recognized through equity-accounted earnings relating to our US offshore wind projects.

g 2024 includes \$429 million of impairment charges recognized through equity-accounted earnings relating to our interest in Pan American Energy Group.

h For 2024, see Financial statements – Note 2 for further information.

i 2024 includes recognition of onerous contract provisions related to the Gelsenkirchen refinery. The unwind of these provisions will be reported as an adjusting item as the contractual obligations are settled.

j 2023 primarily relates to charges related to the control, abatement, clean-up or elimination of environmental pollution and legal settlements.

k All periods presented include the unwinding of discounting effects relating to Gulf of America oil spill payables and the income statement impact of temporary valuation differences related to the group's interest rate and foreign currency exchange risk management associated with finance debt. 2025 and 2024 include the unwinding of discounting effects relating to certain onerous contract provisions. 2023 includes the income statement impact associated with the buyback of finance debt.

l All periods include certain foreign exchange effects on tax as adjusting items. These amounts represent the impact of: (i) foreign exchange on deferred tax balances arising from the conversion of local currency tax base amounts into functional currency; and (ii) taxable gains and losses from the retranslation of US dollar-denominated intra-group loans to local currency.

m 2025 includes limited tax relief on impairment charges and the impact of the reassessment of the recognition of deferred tax assets.

n All periods include revisions to the deferred tax impact of the introduction of the UK Energy Profits Levy (EPL) on temporary differences existing at the opening balance sheet date. The EPL increases the headline rate of tax on taxable profits from bp's North Sea business to 78%. In 2025 a two-year extension of the EPL to 31 March 2030 was substantively enacted. 2025 also includes the deferred tax impact of a change in the tax rate in Germany. See Note 1 for further information.

o 2023 includes a \$146-million charge for the EU Solidarity Contribution.

Non-IFRS information on fair value accounting effects

The impacts of fair value accounting effects, relative to management's internal measure of performance, are set out below. Further information on fair value accounting effects is provided on [page 379](#).

	\$ million		
	2025	2024	2023
gas & low carbon energy			
Unrecognized (gains) losses brought forward from previous period	(2,674)	(1,125)	(9,960)
Favourable (adverse) impact relative to management's measure of performance	1,270	(1,550)	8,859
Exchange translation gains (losses) on fair value accounting effects	(5)	1	(24)
Unrecognized (gains) losses carried forward	(1,409)	(2,674)	(1,125)
customers & products			
Unrecognized (gains) losses brought forward from previous period	(96)	(17)	79
Favourable (adverse) impact relative to management's measure of performance	(207)	(81)	(86)
Exchange translation gains (losses) on fair value accounting effects	–	2	(10)
Unrecognized (gains) losses carried forward	(303)	(96)	(17)
other businesses & corporate			
Unrecognized (gains) losses brought forward from previous period	(1,146)	(925)	(1,555)
Favourable (adverse) impact relative to management's measure of performance ^a	1,157	(221)	630
Unrecognized (gains) losses carried forward	11	(1,146)	(925)
Group			
Unrecognized (gains) losses brought forward from previous period	(3,916)	(2,067)	(11,436)
Favourable (adverse) impact relative to management's measure of performance	2,220	(1,852)	9,403
Exchange translation gains (losses) on fair value accounting effects	(5)	3	(34)
Unrecognized (gains) losses carried forward	(1,701)	(3,916)	(2,067)
Favourable (adverse) impact relative to management's measure of performance – by region			
gas & low carbon energy			
US	376	(582)	900
Non-US	894	(968)	7,959
	1,270	(1,550)	8,859
customers & products			
US	(58)	(214)	(18)
Non-US	(149)	133	(68)
	(207)	(81)	(86)
other businesses & corporate			
US	–	–	–
Non-US	1,157	(221)	630
	1,157	(221)	630
	2,220	(1,852)	9,403
Taxation credit (charge)	(206)	325	(915)
	2,014	(1,527)	8,488

a Includes changes in the fair value of derivatives entered into by the group to manage currency exposure and interest rate risks relating to hybrid bonds to their respective first call periods. For further information see page 379.

Net debt including leases

Net debt including leases★ is shown in the table below.

	\$ million	
At 31 December	2025	2024
Net debt ^a ★	22,182	22,997
Lease liabilities	14,571	12,000
Net partner (receivable) payable for leases entered into on behalf of joint operations★	(1,067)	(88)
Net debt including leases	35,686	34,909
Total equity	74,000	78,318
Gearing including leases★	32.5%	30.8%

a See Financial statements – Note 27 for a reconciliation of net debt to finance debt, which is the nearest equivalent measure to net debt on an IFRS basis.

Liquidity and capital resources

Financial framework

The financial framework sets out how we allocate the cash we generate to deliver dividends to shareholders, strengthen our balance sheet and invest with discipline to grow the value of bp.

A resilient dividend is our first capital allocation priority. Based on our current forecasts and subject to the board's discretion each quarter, the dividend is expected to increase by at least 4% per ordinary share a year.

Net debt★ at 31 December 2025 was \$22.2 billion^a and is expected to reduce over time to a targeted range of \$14-18 billion by the end of 2027, reflecting the full allocation of excess cash★ to the balance sheet, in service of optimizing financing costs and to accelerate strengthening of the balance sheet. bp is committed to strengthening the balance sheet and we continue to target improving our credit metrics within an 'A' grade credit range.

When considering our capital structure; we also look at other instruments including hybrid bonds and securities or obligations such as leases and Gulf of America settlement liabilities. At year-end 2025, the total net debt, hybrid bonds and securities, leases and Gulf of America settlement liabilities was \$57.8 billion.

Capital expenditure in 2025 was \$14.5 billion, including \$0.9 billion of inorganic capital expenditure★. We expect capital expenditure of around \$13.0-13.5 billion in 2026 including inorganic expenditure. We believe this level of capital expenditure supports progressively growing earnings per ordinary share in the long term. Within this frame we are allocating capital to our highest returning opportunities across the portfolio.

In 2025 the return on average capital employed★ was 13.9%^b at an average of \$69 per barrel. The return on average capital employed is targeted to be over 16%^c in 2027 at \$70 per barrel in 2024 real terms, and assuming bp planning assumptions, as we execute our reset strategy. This is supported by a target compound annual growth rate in adjusted free cash flow★ of over 20%^c from 2024 to 2027 and subject to the same price and planning assumptions.

- a The nearest equivalent IFRS measure is finance debt at the end of 2025 of \$58.0 billion.
- b The nearest equivalent IFRS measures of numerator and denominator are profit for the year attributable to bp shareholders for 2025 of \$0.1 billion and total equity at the end of 2025 of \$74.0 billion respectively. Profit for attributable to bp shareholders divided by total equity at 31 December 2025 was 0.1%.
- c This is on a price adjusted basis and is assuming a hypothetical price environment of \$70/bbl Brent, \$4/mmBtu Henry Hub, and \$10.3/bbl refining indicator margin (all 2024 real) and assumptions about the impact of these market prices on underlying replacement cost profit before tax.

Distributions to shareholders

The dividend is determined in US dollars, the economic currency of bp, and the dividend level is reviewed by the board each quarter. The quarterly dividend was increased from 8.000 to 8.320 cents per ordinary share per quarter in the second quarter of 2025.

The total dividend distributed to bp shareholders in 2025 was \$5.1 billion (2024 \$5.0 billion). This dividend was all paid in cash to shareholders.

Based on our current forecasts and subject to the board's discretion each quarter, the dividend is expected to increase by at least 4% per ordinary share a year.

At the fourth quarter 2025 results in February 2026, the board decided to suspend share buybacks; excess cash is now fully allocated to the balance sheet, in service of optimizing financing costs and strengthening the balance sheet.

In 2025 bp executed \$4.5 billion of share buybacks (2024 \$7.1 billion), including fees and stamp duty. Since 1 January 2026 an additional \$450 million shares have been repurchased up to 13 February 2026, including fees and stamp duty.

Financing the group's activities

The group's principal commodities, oil and gas, are priced internationally in US dollars. Group policy has generally been to minimize economic exposure to currency movements by financing

operations with US dollar debt. Where debt and hybrid bonds are issued in other currencies, they are generally swapped back to US dollars using derivative contracts, or else hedged by maintaining offsetting cash positions in the same currency. Cash balances of the group are mainly held in US dollars or swapped to US dollars, and holdings are well diversified to reduce concentration risk. The group is not, therefore, exposed to significant currency risk regarding its cash or borrowings. Also see Risk factors on [page 67](#) for further information on risks associated with prices and markets, and Financial statements – [Note 29](#).

The group's finance debt at 31 December 2025 amounted to \$58.0 billion (2024 \$59.5 billion). Of the total finance debt, \$3.4 billion is classified as short term at the end of 2025 (2024 \$4.5 billion). See Financial statements – [Note 26](#) for more information on the short-term balance. Net debt was \$22.2 billion at the end of 2025, a decrease of \$0.8 billion from the 2024 year-end position of \$23.0 billion. BP p.l.c. fully and unconditionally guarantees securities issued by BP Capital Markets p.l.c. and BP Capital Markets America Inc., which are 100%-owned finance subsidiaries of BP p.l.c.

At 31 December 2025 the group held a balance of \$16.0 billion (2024 \$16.6 billion) issued perpetual subordinated hybrid instruments consisting of \$13.5 billion (2024 \$14.6 billion) hybrid bonds and \$2.5 billion (2024 \$2.0 billion) hybrid securities. Proceeds from hybrid securities are typically earmarked to fund specific project or investment activities. As the group has the unconditional right to avoid transfer of cash or another financial asset in relation to these hybrid instruments, which were issued by group subsidiaries, they are classified as equity instruments and reported within non-controlling interest.

The ratio of finance debt to finance debt plus total equity at 31 December 2025 was 43.9% (2024 43.2%). Gearing was 23.1% at the end of 2025 (2024 22.7%). See Financial statements – [Note 27](#) for finance debt, which is the nearest equivalent measure on an IFRS basis, and for further information on net debt.

Cash and cash equivalents of \$36.6 billion at 31 December 2025 (2024 \$39.2 billion) are included in net debt. We manage our cash position so that the group has adequate cover to respond to potential short-term market liquidity, short-term price environment volatility, and expect to maintain a robust cash position.

The group also has an undrawn committed \$8 billion credit facility and undrawn committed standby facilities of \$4 billion (see Financial statements – [Note 29](#) for more information).

We believe that the group's resilient balance sheet and strong investment grade credit rating will allow the group to meet its known contractual and other obligations in both the short and long term with the group having sufficient working capital, taking into account the amounts of undrawn borrowing facilities, access to capital markets, levels of cash and cash equivalents and its ongoing ability to generate cash through operations. This belief is subject to a degree of uncertainty that can be expected to increase looking out over time and, accordingly, that future outcomes cannot be guaranteed or predicted with certainty.

bp utilizes various arrangements in order to manage its working capital including discounting of receivables and, in the supply and trading business, the active management of supplier payment terms, inventory and collateral.

Standard & Poor's Ratings' long-term credit rating for BP p.l.c. is A- (stable), the Moody's Investors Service rating is A1 (stable) and the Fitch Ratings' long-term credit rating is A+ (stable).

The group's sources of funding, its access to capital markets and maintaining a strong cash position are described in Financial statements – [Note 25](#) and [Note 29](#). Further information on the management of liquidity risk and credit risk, and the maturity profile and fixed/floating rate characteristics of the group's debt are also provided in Financial statements – [Note 26](#) and [Note 29](#).

The information above contains forward-looking statements, which by their nature involve risk and uncertainty because they relate to events and depend on circumstances that will or may occur in the future and are outside the control of bp. You are urged to read the Cautionary statement on [page 362](#) and Risk factors on [page 67](#), which describe the

risks and uncertainties that may cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements.

Off-balance sheet arrangements

At 31 December 2025, the group's share of third-party finance debt and lease liabilities of equity-accounted entities was \$10.8 billion (2024 \$8.0 billion). These amounts are not reflected in the group's debt on the balance sheet. The group has issued third-party guarantees under which amounts outstanding, incremental to amounts recognized on the balance sheet at 31 December 2025, were \$708 million (2024 \$655 million) in respect of liabilities of joint ventures★ and associates★ and \$659 million (2024 \$585 million) in respect of liabilities of other third parties. Of these amounts, \$708 million (2024 \$655 million) of the joint ventures and associates guarantees relate to borrowings and, for other third-party guarantees, \$408 million (2024 \$430 million) relate to guarantees of borrowings.

Contractual obligations

The following table summarizes the group's capital expenditure commitments for property, plant and equipment at 31 December 2025 and the proportion of that expenditure for which contracts have been placed.

	\$ million		
	Payments due by period		
Capital expenditure	Less than 1 year	More than 1 year	Total
Committed	13,049	16,724	29,773
of which is contracted	7,517	7,122	14,639

Capital expenditure is considered to be committed when the project has received the appropriate level of internal management approval. For joint operations★, the net bp share is included in the amounts above.

In addition, at 31 December 2025 the group had committed to capital expenditure relating to investments in equity-accounted entities amounting to \$2,896 million. Contracts were in place for \$2,327 million of this total.

The following table summarizes the group's principal contractual obligations at 31 December 2025, distinguishing between those for which a liability is recognized on the balance sheet and those for which no liability is recognized. See Financial framework above for bp's approach to capital allocation and Financing the group's activities above for bp's plan and ability to generate and obtain cash in the short and long term. Also see Financial statements – **Note 23** for more information on provisions, **Note 24** on pensions and other post-employment benefits, **Note 26** on borrowings, **Note 28** on leases, **Note 29** and **Note 30** on derivatives and financial instruments.

	\$ million		
	Payments due by period		
Expected payments by period under contractual obligations	Less than 1 year	More than 1 year	Total
Balance sheet obligations			
Borrowings ^a	5,539	65,604	71,143
Lease liabilities ^b	3,596	15,740	19,336
Decommissioning liabilities ^c	812	23,759	24,571
Environmental liabilities ^c	318	1,611	1,929
Gulf of America oil spill liabilities ^d	1,533	6,834	8,367
Pensions and other post-employment benefits ^e	490	11,864	12,354
	12,288	125,412	137,700
Off-balance sheet obligations			
Unconditional purchase obligations ^f			
Crude oil and oil products	48,271	2,689	50,960
Natural gas and LNG	16,685	50,880	67,565
Chemicals and other refinery feedstocks	1,290	1,695	2,985
Power	6,693	13,802	20,495
Utilities	56	324	380
Transportation	1,993	14,118	16,111
Use of facilities and services	3,124	16,762	19,886
	78,112	100,270	178,382
Total	90,400	225,682	316,082

- a Expected payments include interest totalling \$18,214 million (less than 1 year \$2,227 million, more than 1 year \$15,987 million).
- b Expected payments include interest totalling \$4,765 million (less than 1 year \$728 million, more than 1 year \$4,037 million).
- c The amounts presented are undiscounted.
- d The amounts presented are undiscounted. Gulf of America oil spill liabilities are included in the group balance sheet, on a discounted basis, within other payables. See Financial statements – Note 22 for further information.
- e Represents the expected future contributions to funded pension plans and payments by the group for unfunded pension plans, and the expected future payments for other post-employment benefits.
- f Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms (such as fixed or minimum purchase volumes, timing of purchase and pricing provisions). Agreements that do not specify all significant terms, or that are not enforceable, are excluded. The amounts shown include arrangements to secure long-term access to supplies of crude oil, natural gas, feedstocks and pipeline systems. In addition, the amounts shown for 2026 include purchase commitments existing at 31 December 2025 entered into principally to meet the group's short-term manufacturing and marketing requirements. The price risk associated with these crude oil, natural gas and power contracts is discussed in Financial statements – Note 29.

Commitments for the delivery of oil and gas

We sell crude oil, natural gas and liquefied natural gas under a variety of contractual obligations. Some of these contracts specify the delivery of fixed and determinable quantities. For the period from 2026 to 2028 worldwide, we are contractually committed to deliver approximately 288 million barrels of oil, 6,288 billion cubic feet of natural gas, and 70Mt of liquefied natural gas. The commitments principally relate to group subsidiaries★ based in Azerbaijan, Oman, Trinidad and Tobago, the UK and the US. We expect to fulfil these delivery commitments with production from our proved developed reserves and supplies from existing contracts, supplemented by market purchases as necessary.

Oil and gas disclosures for the group

Analysis by region

Our oil and gas operations are set out below by geographical area, with associated significant events for 2025. bp's percentage working interest in oil and gas assets is shown in brackets. Working interest is the cost-bearing ownership share of an oil or gas lease. Consequently, the percentages disclosed for certain agreements do not necessarily reflect the percentage interests in proved reserves, production or revenue.

In addition to exploration, development and production activities, our oil production & operations (OP&O) and gas businesses also include certain midstream and liquefied natural gas (LNG) supply activities. Midstream activities involve the management of crude oil and natural gas pipelines, processing facilities and export terminals, LNG processing facilities and transportation, and our natural gas liquids (NGLs) processing business.

Our upstream LNG production activities are located in Abu Dhabi, Angola, Australia, Indonesia, Mauritania and Senegal and Trinidad and Tobago. In 2025 our production was 12 million tonnes (Mt) of LNG from these assets, of which 5.2Mt were optimized and delivered through supply, trading and shipping (ST&S), which supplements equity production with merchant third-party volumes leading to a global long-term strategic LNG portfolio of 26.8Mtpa. In addition to the long-term equity and merchant supply portfolio, bp delivered 14.7Mtpa in 2025 of incremental merchant volumes through short and mid-term cargoes managed through the ST&S LNG business. These supplement the long-term portfolio and allow generation of short-term value when opportunities exist.

The LNG is marketed through contractual rights to access import terminal capacity in the liquid markets of Europe and UK, and relationships to market directly to end-user customers or trading entities. LNG is supplied to all major LNG demand centres for example Argentina, Bangladesh, Brazil, Caribbean, China, Croatia, Iberia and North West Europe, India, Japan, Mediterranean, Philippines, Singapore, South Korea, Taiwan, Thailand, Türkiye and the UK.

Europe

bp has interest in offshore oil and gas activities in the UK and Norway. In 2025 bp's UK production came from two key areas: the Shetland area comprising the Clair and Schiehallion fields; and the central area comprising the Andrew area, Culzean, Vorlich and ETAP fields. In Norway, production was through our equity-accounted 15.9% interest in Aker BP.

- Aker BP achieved its strongest exploration year since 2010, highlighted by three major 2025 discoveries: the Lofn and Langemann gas and condensate find near Sleipner, the large Omega Alfa oil discovery in the Yggdrasil area and the Kjøttkake oil and gas discovery in the Northern North Sea.
- In October bp agreed to sell its 32% non-operated working interest in the Culzean development in the central North Sea to Serica Energy. The sale was subject to a pre-emption period of 30 days, with each of the Culzean field partners (TotalEnergies, 49.99%, and NEO NEXT, 18.01%) having the option to acquire bp's stake on the same terms as those agreed by Serica. In November NEO NEXT exercised its preemption rights and acquired bp's working interest on the conditions agreed with Serica. The deal completed in December.
- In October bp announced it had safely started up production from the Murlach field in the UK North Sea. The two-well subsea tieback is expected to add a peak net production of around 15,000 barrels of oil equivalent per day.

North America

Our oil and gas activities in North America are located in four areas: deepwater Gulf of America, the Lower 48 states, Canada and Mexico.

bp has around 300 lease blocks in the Gulf of America and operates five production hubs.

- In April bp announced an oil discovery at the Far South prospect in the deepwater US Gulf of America. Both the initial well and a

subsequent sidetrack encountered oil in high-quality Miocene reservoirs. Preliminary data supports a potentially commercial volume of hydrocarbons.

- In August bp announced the start-up of the Argos Southwest Extension project in the Gulf of America. The project consists of three wells and a new drill centre tied back to the Argos platform and is expected to add 20,000 barrels of oil equivalent per day of gross peak annualized average production. bp is operator of Argos with 60.5% working interest, with co-owners Woodside Energy (23.9%) and Union Oil Company of California, an affiliate of Chevron U.S.A. Inc. (15.6%).
- In September bp announced it had reached a final investment decision (FID) on the Tiber-Guadalupe project in the Gulf of America. The 100% bp-owned Tiber-Guadalupe will be bp's seventh operated oil and gas production hub in the Gulf of America, featuring a new floating production platform with the capacity to produce 80,000 barrels of crude oil per day. The project includes six wells in the Tiber field and a two-well tieback from the Guadalupe field. Production is expected to start in 2030.
- In December bp was the apparent highest bidder on 51 lease blocks in the US Gulf of America Federal Lease Sale BBG1, which included 219 leases.
- In December bp successfully delivered first oil from the Atlantis Drill Center 1 expansion in the US Gulf of America. The two-well subsea tieback to the existing Atlantis platform is expected to add 15,000boe/d gross peak annualized average production.

bpx energy, bp's onshore oil and gas business in the Lower 48 states, has significant operated and non-operated activities across Louisiana and Texas producing natural gas, oil, NGLs and condensate, with primary focus on developing unconventional resources. It had a 1.8 billion boe proved reserve base at 31 December 2025, predominantly in unconventional reservoirs (tight gas, shale gas and shale oil). bpx energy's core assets span over 0.8 million net developed acres with over 2,400 operated gross wells at 31 December 2025. Daily net production averaged 466mboe/d in 2025.

bpx energy continues to operate as a separate business while remaining part of the OP&O segment. With its own governance, systems, and processes, it is structured to increase competitive performance through swift decision making and innovation, while maintaining bp's commitment to safe, reliable and compliant operations.

- In June bpx energy started up the Crossroads facility in the Permian Basin, bpx's fourth and final central delivery facility to be built, following the earlier Grand Slam, Checkmate and Bingo facilities.
- In July bpx energy took over operations from Devon Energy of certain assets in the Eagle Ford Shale following the April dissolution of their joint venture in the Blackhawk field.
- In November and December bp completed a two-phase divestment of non-controlling interests in Permian and Eagle Ford midstream assets to investor Sixth Street for a total of \$1.5 billion.

bp's onshore US crude oil and product pipelines and related transportation assets were included in the customers & products segment.

In Canada, bp is focused on pursuing offshore exploration and development opportunities and conducts trading and marketing activities across various energy commodities. We hold exploration and significant discovery licenses in offshore Newfoundland and Labrador, including an interest in the Equinor-operated Bay du Nord project. bp also holds offshore exploration licenses in the Arctic, where the moratorium has been extended until 31 December 2028.

In Mexico, bp holds interests in an exploration block in the Salina Basin with Equinor and Total, Block 1 (bp 33% operator) and an exploration block in the Sureste Basin, Block 34 (bp 42.5% operator), with Total, QPI Mexico and Hokchi Energy. Hokchi Energy is a subsidiary of Pan American Energy Group (PAEG, see below). bp holds 50% of PAEG and PAEG holds 55% of Hokchi Energy. Separate to the above holdings in Mexico, Hokchi Energy also holds an interest in two other blocks.

Formal relinquishment of Block 1 and Block 34 licences is still pending regulatory approval.

South America

bp has oil and gas activities in Brazil and Trinidad and Tobago and, through PAEG, in Argentina and Bolivia.

In Brazil bp has interests in six exploration areas across three basins:

- Petrobras as the operator of Alto de Cabo Frio Central block (bp 50%) drilled an appraisal well completed in July, as part of the appraisal plan (PAD) filed in 2023, with indication of hydrocarbon shows. The block strategy is under development and will be finalized following completion of post-well analyses, expected by end 2026.
- In June GNA II started commercial operation, a 1.7 gigawatts capacity gas fired power plant, the largest in Brazil. bp is the exclusive LNG supplier for GNA II and holds a 33.5% stake in the project alongside Siemens Energy (33.5%) and SPIC Brazil (33%).
- In August bp announced an exploration discovery at the Bumerangue prospect in the deepwater offshore Brazil. bp drilled exploration well 1-BP-13-SPS at the Bumerangue block, located in the Santos Basin, 404 kilometres (218 nautical miles) off the coast of Brazil, in a water depth of 2,372 metres. bp holds a 100% participation in the block with Pré-Sal Petr leo S.A. as the Production Sharing Contract manager. bp secured the block in December 2022 during the first cycle of the Open Acreage of Production Sharing of the Brazilian national petroleum agency (ANP). bp's initial estimate is that there are around 8 billion barrels of liquids in place – split roughly 50% oil, 50% condensate. As is normal at this stage, there is a wide range of uncertainty around this estimate. bp is now putting plans in place for an appraisal programme which is expected to start around the end of the year. This will provide data from locations across the reservoir, to enable us to describe the fluid characteristics and resource potential.

PAEG, a joint venture that is owned by bp (50%) and BC E&P Uruguay S.A. (50%), has activities mainly in Argentina and as noted above, Mexico, and is also present in Bolivia.

In Trinidad and Tobago bp holds interests in exploration and production licences and production-sharing contracts (PSCs) covering 2.1 million acres offshore the east and north-east coast. Facilities include 12 offshore platforms, 3 subsea tiebacks and 2 onshore processing facilities. Production comprises gas and associated liquids.

bp also holds interests in the Atlantic LNG facility. The total gross capacity of the LNG facility is approximately 12Mtpa, with three trains in operation. bp's shareholding averages 43% across the companies which own the LNG trains comprising the LNG facility. Upon expiration of the Train 4 contract on 1 May 2027, and completion of full restructuring bp's shareholding will increase to 45%.

- In March FID was taken on the Ginger project which will become bpTT's fourth subsea project and will include four subsea wells and subsea trees tied back to bpTT's existing Mahogany B platform. First gas from the project is expected in 2027.
- In May bp announced first gas from the Mento project. Mento is a 50:50 joint venture between EOG Resources Trinidad Ltd (EOG) and bpTT, with EOG as the operator. The development features a 12-slot attended facility that is located in acreage jointly licensed by bpTT and EOG off Trinidad's south-east coast.
- In November bp announced that it had safely completed the Cypre seven-well drilling programme in Trinidad, the second phase of the Cypre project, following delivery of first gas in April 2025. Cypre is bpTT's third subsea development. It comprises seven wells tied back into bpTT's existing Juniper platform.
- bpTT and EOG are also currently working on the Coconut gas development under a similar joint venture arrangement. Construction is in progress with start-up expected in 2027.
- The seismic processing activity over the joint Manakin-Cocuina field was successfully completed in September 2024. bp is operator of the Manakin block which was discovered in 2000. bp and NGC also hold an exploration and production licence for the development of the Cocuina gas discovery, which is the Venezuelan portion of the

cross-border Manakin-Cocuina gas field. Activity ceased in April 2025 with the revocation of its specific OFAC license. In February 2026 General Licences 48, 49 and 50 were issued by OFAC which authorized contractors and certain companies including bp plc and its subsidiaries to progress with oil and gas projects in Venezuela. bp is therefore authorized to progress with the development of the Manakin-Cocuina project subject to the conditions contained in the General Licences.

Seismic processing activity was completed and interpretation of results underway on deepwater blocks Blocks 25a, 25b and 27 in Trinidad and Tobago. These blocks are a 50:50 joint venture between bp and Shell, with bp operating Blocks 25a and 25b, and Shell operating Block 27.

Africa

bp's oil and gas activities in Africa are located in Angola, Namibia, Egypt, Libya, Mauritania and Senegal.

In Angola, bp and Eni each own a 50% interest in the Azule Energy (Azule) joint venture. Azule is Angola's largest independent equity producer of oil and gas, holding stakes in 18 licences, as well as an interest in the Angola LNG plant.

- In July Azule, operator of Block 15/06 in Angola, together with its partners, announced the successful start-up of the Agogo Integrated West Hub Project, which aims to fully develop the Agogo and Ndungu fields in Block 15/06.
- In July Azule, operator of Block 1/14, and its partners announced a gas discovery at the Gajajeira-01 exploration well, located offshore in the Lower Congo Basin, Angola. Initial assessments suggest gas volumes in place could exceed 1 trillion cubic feet, with up to 100 million barrels of associated condensate.
- In October Rhino Resources, operator of the Petroleum Exploration Licence 85 in the Orange Basin offshore Namibia, partnering with Azule, announced a discovery at the Volans 1-X well. The well found 26 metres of net pay in rich-gas condensate bearing reservoirs with excellent quality petrophysical properties and a high condensate to gas ratio. This discovery builds on the announcement in April of a discovery in the Capricornus 1-X exploration well in the same license block.
- In December Azule announced the signing of a Sale and Purchase Agreement (SPA) with a consortium of Etablissements Maurel & Prom S.A. (M&P) and BW Energy (BWE) for the sale of Azule's participating interest in offshore Blocks 14 and 14K located in the Lower Congo Basin. Azule holds a 20% interest in Block 14 and a 10% interest in Block 14K. The offshore blocks have been producing since 1999. Net working interest production to Azule from both the blocks combined was 9600 barrels of oil per day in 2024. Completion of the transaction is expected to occur mid-2026 and is subject to customary adjustments and approvals by the partners and Angolan authorities.

In Egypt, bp holds an investment in Nile Delta. Through its joint ventures with Egyptian Natural Gas Holding Company (EGAS), Egyptian General Petroleum Corporation (EGPC), International Egyptian Oil Company (IEOC), Eni, the Pharaonic Petroleum Company (PhPC), ADNOC, and through collaboration with Belayim Petroleum Company (Petrobel), bp and its partners now produce more than 60% of Egypt's total gas supply. In addition, bp owns interest in other exploration projects.

- In February bp successfully completed the drilling activity at the El King-2 exploration well in the North King Mariout Offshore Concession as part of its West Nile Delta (WND) drilling campaign
- Also in February bp announced the Raven Infills project in the West Nile Delta (WND) had started production ahead of schedule. bp, the operator, holds an 82.75% stake in the project, while Harbour Energy owns the remaining 17.25%.
- In March bp announced successful completion of the El Fayoum-5 gas discovery well in the North Alexandria Offshore Concession. It is planned to be tied-back to bp's operated WND Gas Development.
- In September bp announced the signing of a memorandum of understanding (MoU) to evaluate opportunities for a five-well programme at water depths ranging from 300 to 1,500 metres in the

Mediterranean Sea, offshore Egypt. Drilling operations are expected to start in 2026.

- In January 2026 bp was awarded two offshore exploration concessions in Egypt: North-East El Alamein Offshore and West El Hammad Offshore, advancing our exploration portfolio and long-term growth ambitions. The North-East El Alamein Offshore Concession (bp 100% equity) covers 3,336km² near bp's West Nile Delta assets. The West El Hammad Offshore Concession (Eni 75% operator, bp 25%) covers 1,894km² in the East Nile Delta, also near existing infrastructure.

In Libya, bp partners with the Libyan Investment Authority (LIA) and Eni (operator) in an exploration and production-sharing agreement (EPSA) to explore acreage in the onshore Ghadames and offshore Sirt basins (bp 42.5%).

Exploration operations under the EPSA resumed in 2023, following the period of force majeure between 2012 and 2022.

In Mauritania and Senegal, bp retains the exploitation licences in the respective C8 and Saint Louis Offshore Profond blocks pertinent to the Greater Tortue Ahmeyim (GTA) Unit cross-border development (bp 56.3%).

- In April bp announced that it had safely loaded the first cargo of LNG for export from GTA.

Asia

bp has activities in Abu Dhabi, Azerbaijan, China, India, Indonesia, Iraq, Kuwait and Oman.

In China, we have a 30% equity stake in the Guangdong LNG regasification terminal and trunkline project (GDLNG) with a total storage capacity of 640,000 cubic metres. bp also has 0.6Mtpa of regasification capacity at GDLNG for up to 12 years starting from the beginning of 2021. bp imports LNG from our global portfolio and delivers regasified natural gas via the terminal to power plant and city gas customers in Guangdong province under long-term sales contracts.

In May bp announced it had entered into a long-term LNG sale and purchase agreement with Zhejiang Energy. Under the agreement, bp will provide Zhejiang Energy with up to 1 million tonnes per annum of LNG for over 10 years on a delivered ex-ship (DES) basis from bp's diverse portfolio of LNG sources.

In Azerbaijan, bp operates two production-sharing agreements (PSAs)★, Azeri-Chirag-Gunashli (ACG) (bp 30.37%) and Shah Deniz (SD) (bp 29.99%) and also holds a number of other exploration and development licenses.

- In March bp announced it has agreed for Apollo-managed funds to purchase a 25% non-controlling stake in BP Pipelines (TANAP) Limited, the bp subsidiary that holds a 12% share in the Trans Anatolian Natural Gas Pipeline (TANAP) that carries natural gas from Azerbaijan across Türkiye, for consideration of approximately \$1.0 billion. bp remains the controlling shareholder of BP Pipelines (TANAP) Limited. A similar deal on purchase by Apollo of a 20% non-controlling interest in BP Pipelines TAP Limited was completed in 2024.
- In June bp and its partners, announced the FID for the new Shah Deniz Compression project, the next stage of development of the giant Shah Deniz gas field in the Azerbaijan sector of the Caspian Sea.
- In June bp, State Oil Company of the Azerbaijan Republic (SOCAR) and TPAO signed agreements enabling TPAO to join the PSA for the Shafag-Asiman offshore block in the Azerbaijan sector of the Caspian Sea. Following completion, bp and SOCAR each holds 35%, while TPAO will hold 30% participating interest in the PSA.
- In June bp announced it had signed fully termed agreements with SOCAR to acquire 35% participating interests and become the operator of each of the Karabagh development block and the Ashrafi-Dan Ulduzu-Aypara (ADUA) exploration area in the Azerbaijan sector of the Caspian Sea.
- In December the development programme for the Karabagh field in the Caspian Sea, offshore Azerbaijan, was approved by the management committee (joint venture) and subsequently by SOCAR

as the State representative. Seismic acquisition commenced thereafter.

Naftiran Intertrade Co Ltd (NICO), a subsidiary of the National Iranian Oil Company, and LUKOIL Overseas Shah Deniz Limited, a subsidiary of PJSC LUKOIL, hold a 10% and 19.99% participating interest respectively in the Shah Deniz PSA. For information on the compliance of this project with the EU, UK and US trade sanctions, see International trade sanctions on [page 358](#).

bp holds a 30.1% interest in and operates the Baku-Tbilisi-Ceyhan (BTC) oil pipeline. The 1,768-kilometre pipeline transports oil from the ACG oilfield and condensate from the Shah Deniz gas and condensate field in the Caspian Sea, along with other third-party oil, to the eastern Mediterranean port of Ceyhan. The pipeline has a capacity of 1mmboe/d, with an average throughput in 2025 of 565mboe/d.

bp as operator of Azerbaijan International Operating Company and the Georgian Pipeline Company for the Georgian section also operates the Western Route Export Pipeline (WREP) that transports ACG oil to Supsa on the Black Sea coast of Georgia. Exports through the pipeline have been suspended since May 2022 (with occasional short-term exports driven by operational needs) due to lack of nominations from the shipper group. In current market conditions WREP serves as a contingency export route for ACG crude oil.

bp holds a 29.99% interest in and operates certain parts of the 693-kilometre South Caucasus Pipeline (SCP). The pipeline takes gas from the Shah Deniz field in Azerbaijan through Georgia to the Turkish border and has a capacity of 440mboe/d (including expansion), with average throughput in 2025 of 392mboe/d.

bp also holds a 12% interest in the Trans Anatolian Natural Gas Pipeline (TANAP). The pipeline takes Shah Deniz gas from the Turkish border and transports it to Eskisehir in Türkiye and to the Greek border where it connects with the Trans Adriatic Pipeline (TAP). The current capacity of TANAP is 275mboe/d and the average throughput in 2025 was 260mboe/d.

bp has a 20% interest in Trans Adriatic Pipeline (TAP), which takes gas through Greece and Albania into Italy. The current capacity of TAP is 167mboe/d and the total average throughput in 2025 was 173mboe/d.

In Oman, bp operates Block 61 in which bp holds 40% interest. bp also has a 50% interest in Block 77 operated by Eni.

In Abu Dhabi, bp holds a 10% interest in the ADNOC Onshore concession and 10% shareholding in the shipping company NGSCO and 10% in Ruwais LNG. ADNOC LNG supplied approximately 5Mt of LNG (0.7bcfe/d regasified) in 2025. bp's interest in the ADNOC Onshore concession expires at the end of 2054.

- In June bp acquired a 10% interest in ADNOC's planned LNG project in Al Ruwais Industrial City, Abu Dhabi, joining ADNOC Gas (60% stake), Mitsui & Co, Shell and TotalEnergies (also 10% each). Ruwais LNG is planned to have two liquefaction trains with a total annual capacity of 9.6Mt per annum.

In February 2026 bp and the Kuwait Oil Company signed a two-year extension of the enhanced technical service agreement to support production optimization of the Burgan oil field.

In Iraq, bp holds a 49% participating interest in Basra Energy Company Limited (BECL). BECL is an incorporated joint venture (IJV) company owned by bp (49%) and PetroChina (51%) and acts as Rumaila lead contractor since 2022.

In March bp received final government ratification for its contract to invest in the redevelopment of several giant oil fields in Kirkuk, in the north of Iraq. The contract between North Oil Company, North Gas Company (NGC) and bp includes the rehabilitation and redevelopment of the fields, spanning oil, gas, power and water with potential for investment in exploration. In October this contract became effective, after agreeing an initial baseline production rate.

In India, bp holds a participating interest in two oil and gas PSAs, KG D6 33.33% and NEC25 33.33%, operated by Reliance Industries Limited (RIL), and three oil and gas blocks under revenue-sharing contracts, 40% in KG-UDWHP-2018/1 and 40% in KG-UDWHP-2022/1, operated by RIL; and 30% in GS-OSHP-2022/2 operated by Oil and Natural Gas

Corporation Limited (ONGC). bp also holds a 50% stake in India Gas Solutions Private Limited, a joint venture with RIL, for the sourcing and marketing of gas in India.

- In May bp made the FID to invest in an infill wells programme at the KG D6 block located offshore India

In February bp and ONGC signed agreement under which bp will serve as the technical services provider for ONGC's Mumbai High field.

In April bp, RIL and ONGC were awarded a shallow water block GS-QSHP-2022/2 (ONGC operator 40%, RIL 30%, bp 30%) in Gujarat-Saurashtra basin, in India's Open Acreage Licensing Policy Bid Round IX.

In the Asian part of Indonesia, bp holds an interest in the Andaman II PSC exploration block (operated by Harbour Energy), located offshore North Sumatra, and in Agung I and Agung II exploration blocks offshore Indonesia. Agung I covers over 6,000km² off the coast of Bali and East Java and Agung II spans almost 8,000km² offshore South Sulawesi, West Nusa Tenggara and East Java.

Australasia

bp has activities in Australia and Eastern Indonesia.

In Australia bp is one of six participants in the North West Shelf (NWS) venture, which has been producing LNG, pipeline gas, condensate, LPG and oil since the 1980s. Five partners hold interest in the gas infrastructure (bp 16.67%) and six partners hold interest in the gas and condensate reserves (bp 15.78%). The NWS venture is one of the largest LNG export projects in the region, with four LNG trains currently in operation following retirement of one LNG train in late 2024, and also supplies domestic gas into the Western Australia market. bp's net share of the capacity of NWS LNG trains is 2.26Mt (15.78% of 14.3Mtpa gross) of LNG per year.

- In November the Greater Western Flank 4 project in the North West Shelf, offshore Australia (bp 16.67%, operator Woodside) reached FID. The project involves five subsea tieback wells with start-up targeted for 2028.

bp is one of four participants in Browse LNG Joint Venture, operated by Woodside (bp 44.33%). The project is aimed at developing natural gas resources located in the offshore Browse basin.

bp has a 50% interest in the WA-541-P exploration title in Western Australia's offshore Northern Carnarvon basin. The joint venture, operated by Santos, is working towards the drilling of two commitment wells.

bp also has a 100% interest in the WA-551-P exploration title adjacent to WA-541-P and is currently carrying out prospect maturation activities.

In Papua Barat, Eastern Indonesia, bp operates the Tangguh LNG plant (bp 40.22%). The plant consists of three trains with total production capacity of 11.4Mtpa. The Tangguh asset comprises 30 production wells, four offshore platforms, three LNG processing trains, and two LNG loading facilities. Tangguh supplies LNG to customers in Indonesia, Mexico, China, South Korea, Taiwan and Japan through a combination of long, medium and spot contracts.

- In August a consortium of bp (16.09%), its Tangguh partners (23.91%), operator EnQuest (40%), and Agra (20%) secured the right to explore the Gaea and Gaea II cover onshore and offshore gas blocks near our Tangguh LNG facility with the signing of government-backed contracts

Oil and natural gas Resource progression

bp manages its hydrocarbon resources in three major categories: prospect inventory, contingent resources and reserves. When a discovery is made, volumes usually transfer from the prospect inventory to the contingent resources category. The contingent resources move through various sub-categories as their technical and commercial maturity increases through appraisal activity.

At the point of final investment decision, most proved reserves will be categorized as proved undeveloped (PUD). Volumes will subsequently be recategorized from PUD to proved developed (PD) as a consequence of development activity. When part of a well's proved reserves depends on a later phase of activity, only that portion of proved reserves associated with existing, available facilities and infrastructure moves to PD. The first PD bookings will typically occur at the point of first oil or gas production. Major development projects typically take one to five years from the time of initial booking of PUD to the start of production. Changes to proved reserves bookings may be made due to analysis of new or existing data concerning production, reservoir performance, commercial factors and additional reservoir development activity.

Volumes can also be added or removed from our portfolio through acquisition or divestment of properties and projects. When we dispose of an interest in a property or project, the volumes associated with our adopted plan of development for which we have a final investment decision will be removed from our proved reserves upon completion of the transaction. When we acquire an interest in a property or project, the volumes associated with the existing development and any committed projects will be added to our proved reserves if bp has made a final investment decision and they satisfy the SEC's criteria for attribution of proved status. Following the acquisition, additional volumes may be progressed to proved reserves from non-proved reserves or contingent resources.

Non-proved reserves and contingent resources in a field will only be recategorized as proved reserves when all the criteria for attribution of proved status have been met and the volumes are included in the business plan and scheduled for development, typically within five years. bp will only book proved reserves where development is scheduled to commence after more than five years if these proved reserves satisfy the SEC's criteria for attribution of proved status and bp management has reasonable certainty that these proved reserves will be produced.

At the end of 2025 bp had no proved undeveloped reserves held for more than five years in our onshore US developments.

Over the past five years, bp has annually progressed a five-year average of 20% (19% for 2024 five-year average) of our group proved undeveloped reserves (including the impact of disposals and price acceleration effects in PSAs) to proved developed reserves. This equates to a turnover time of five years.

Proved reserves as estimated at the end of 2025 meet bp's criteria for project sanctioning and SEC tests for proved reserves. We have not halted or changed our commitment to proceed with any material project to which proved undeveloped reserves have been attributed.

In 2025 we progressed 481mmboe of proved undeveloped reserves (412mmboe for our subsidiaries* alone) to proved developed reserves through ongoing investment in our subsidiaries' and equity-accounted entities' development activities. Total development expenditure, excluding midstream activities, was \$13,336 million in 2025 (\$8,387 million for subsidiaries and \$4,949 million for equity-accounted entities). Of the \$8,387 million of total development expenditure for our subsidiaries, approximately \$4,900 million was used for development activity to progress proved undeveloped reserves to proved developed. Of the \$4,949 million development expenditure for our equity-accounted entities, approximately \$1,800 million was used for development activity to progress proved undeveloped reserves to proved developed. The major areas with progressed volumes in 2025 were the US, Azerbaijan, Trinidad and Tobago, Southern Cone and Middle East.

Revisions of previous estimates for proved undeveloped reserves are due to changes relating to field performance, well results, revisions to future activity plans (including alignment with our investment criteria and changes to the macroeconomic climate) or changes in commercial conditions including price impacts. The net revisions to previous estimates across both our subsidiaries and our equity-accounted entities include net positive revisions driven by revisions to activity plans, revisions due to well results and revisions driven by price, and net negative revisions driven by field performance. The net revisions to previous estimates across only our subsidiaries include net positive revisions driven by revisions to activity plans, revisions due to well results and revisions driven by price, and net negative revisions driven by field performance. In each case, none of these factors resulted in revisions that were material to the group as a whole. The following tables describe the changes to our proved undeveloped reserves position through the year for our subsidiaries and equity-accounted entities, and for our subsidiaries alone.

	volumes in mmmboe ^a
Subsidiaries and equity-accounted entities	
	Group
Proved undeveloped reserves at 1 January 2025	2,387
Revisions of previous estimates	380
Price	78
Revision of future activity plans	409
Field performance	(119)
Well results	12
Improved recovery	20
Discoveries and extensions	125
Purchases	59
Sales	(42)
Total in year proved undeveloped reserves changes	542
Proved developed reserves reclassified as undeveloped	77
Progressed to proved developed reserves by development activities (e.g. drilling/completion)	(481)
Proved undeveloped reserves at 31 December 2025	2,525
Subsidiaries only	
	volumes in mmmboe ^a
Proved undeveloped reserves at 1 January 2025	1,875
Revisions of previous estimates	418
Price	88
Revision of future activity plans	416
Field performance	(107)
Well results	22
Improved recovery	15
Discoveries and extensions	66
Purchases	59
Sales	(41)
Total in year proved undeveloped reserves changes	518
Proved developed reserves reclassified as undeveloped	75
Progressed to proved developed reserves by development activities (e.g. drilling/completion)	(412)
Proved undeveloped reserves at 31 December 2025	2,055

a Because of rounding, some totals may not agree exactly with the sum of their component parts.

bp bases its proved reserves estimates on the requirement of reasonable certainty, with rigorous technical and commercial assessments based on conventional industry practice and regulatory requirements. bp only applies technologies that have been field-tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. bp applies high-resolution seismic data for the identification of reservoir extent and fluid contacts only where there is an overwhelming track record of success in its local application. In certain cases bp uses numerical simulation as part of a holistic assessment of recovery factor for its fields, where these simulations have been field-tested and have been demonstrated to provide

reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. In certain deepwater fields bp has booked proved reserves before production flow tests are conducted, in part because of the significant safety, cost and environmental implications of conducting these tests. The industry has made substantial technological improvements in understanding, measuring and delineating reservoir properties without the need for flow tests. To determine reasonable certainty of commercial recovery, bp employs a general method of reserves assessment that relies on the integration of three types of data:

- Well data used to assess the local characteristics and conditions of reservoirs and fluids.
- Field-scale seismic data to allow the interpolation and extrapolation of these characteristics outside the immediate area of the local well control.
- Data from relevant analogous fields.

Well data includes appraisal wells or sidetrack holes, full logging suites, core data and fluid samples. bp considers the integration of this data in certain cases to be superior to a flow test in providing understanding of overall reservoir performance. The collection of data from logs, cores, wireline formation testers, pressures and fluid samples calibrated to each other and to the seismic data can allow reservoir properties to be determined over a greater volume than the localized volume of investigation associated with a short-term flow test. There is a strong track record of proved reserves recorded using these methods, validated by actual production levels.

Governance

bp's centrally controlled process for proved reserves estimation approval forms part of a holistic and integrated system of internal control. It consists of the following elements:

- Accountabilities of certain officers of the group to ensure that there is review and approval of proved reserves bookings independent of the operating business, and that there are effective controls in the approval process and verification that the proved reserves estimates and the related financial impacts are reported in a timely manner.
- Capital allocation processes, whereby delegated authority is exercised to commit to capital projects that are consistent with the delivery of the group's business plan. A formal review process exists to ensure that both technical and commercial criteria are met prior to the commitment of capital to projects.
- Internal audit, whose role is to consider whether the group's system of internal control is adequately designed and operating effectively to respond appropriately to the risks that are significant to bp.
- Approval hierarchy, whereby proved reserves changes above certain threshold volumes require immediate review and all proved reserves require annual central authorization and have scheduled periodic reviews. The frequency of periodic reviews ensures that 100% of the bp proved reserves base undergoes central review every three years.

bp's vice president of reserves is the individual primarily responsible for overseeing the preparation of the reserves estimate. He has more than 30 years of diversified industry experience in reserves estimation with the past five years managing the governance and compliance. He is a past chairman of the Society of Petroleum Engineers (Russia & Caspian).

No specific portion of compensation bonuses for senior management is directly related to proved reserves targets. Additions to proved reserves is one of several indicators by which the performance of the gas & low carbon energy and oil production & operations segments is assessed by the remuneration committee for the purposes of determining compensation bonuses for the executive directors. Other indicators include a number of financial and operational measures.

bp's variable pay programme for the other senior managers in the gas & low carbon energy and oil production & operations segments is based on individual performance contracts. Individual performance contracts are based on agreed items from the business performance plan, one of which, if chosen, could relate to proved reserves.

Compliance

International Financial Reporting Standards (IFRS) do not provide specific guidance on reserves disclosures. bp estimates proved reserves in accordance with SEC Rule 4-10 (a) of Regulation S-X and relevant Compliance and Disclosure Interpretations (C&DI) and Staff Accounting Bulletins as issued by the SEC staff.

By their nature, there is always risk involved in the ultimate development and production of proved reserves including, but not limited to: final regulatory approval; the installation of new or additional infrastructure, as well as changes in oil and gas prices; changes in operating and development costs; and the continued availability of additional development capital. All the group's proved reserves held in subsidiaries and equity-accounted entities are estimated by the group's petroleum engineers, or by independent petroleum engineering consulting firms and then assured by the group's petroleum engineers.

Netherland, Sewell & Associates (NSAI), an independent petroleum engineering consulting firm, has estimated the net proved crude oil, condensate, natural gas liquids (NGLs) and natural gas reserves, as of 31 December 2025, of certain properties owned by bp in the US Lower 48. The properties evaluated by NSAI account for 100% of bp's net proved reserves in the US Lower 48 as of 31 December 2025. The net proved reserves estimates prepared by NSAI were prepared in accordance with the reserves definitions of Rule 4-10(a)(1)-(32) of Regulation S-X. All reserves estimates involve some degree of uncertainty. bp has filed NSAI's independent report on its reserves estimates as an exhibit to this *Annual Report and Form 20-F 2025* filed with the SEC.

Our proved reserves are associated with both concessions (tax and royalty arrangements) and agreements where the group is exposed to the upstream risks and rewards of ownership, but where our entitlement to the hydrocarbons is calculated using a more complex formula, such as with PSAs. In a concession, the consortium of which we are a part is entitled to the proved reserves that can be produced over the licence period, which may be the life of the field. In a PSA, we are entitled to recover volumes that equate to costs incurred to develop and produce the proved reserves, and an agreed share of the remaining volumes or the economic equivalent. As part of our entitlement is driven by the monetary amount of costs to be recovered, price fluctuations will have an impact on both production volumes and reserves.

We disclose our share of proved reserves held in equity-accounted entities (joint ventures★ and associates★), although we do not control these entities or the assets held by such entities.

bp's estimated net proved reserves and proved reserves replacement

94% of our total proved reserves of subsidiaries at 31 December 2025 were held through joint operations★ (94% in 2024), and 22% of the proved reserves were held through such joint operations where we were not the operator (23% in 2024).

Estimated net proved reserves of crude oil at 31 December 2025^{abc}

million barrels			
	Developed	Undeveloped	Total
UK	56	41	97
US	599	443	1,042
Rest of North America	—	—	—
South America ^d	1	4	6
Africa	2	—	2
Rest of Asia	691	298	989
Australasia	6	3	8
Subsidiaries	1,354	788	2,143
Equity-accounted entities	566	299	865
Total	1,920	1,088	3,008

Estimated net proved reserves of natural gas liquids at 31 December 2025^{ab}

million barrels			
	Developed	Undeveloped	Total
UK	1	—	1
US	204	212	415
Rest of North America	—	—	—
South America	—	—	—
Africa	—	—	—
Rest of Asia	—	—	—
Australasia	1	—	1
Subsidiaries	206	212	417
Equity-accounted entities	17	5	22
Total	222	217	439

Estimated net proved reserves of liquids^{d★}

million barrels			
	Developed	Undeveloped	Total
Subsidiaries	1,560	1,000	2,560
Equity-accounted entities	582	304	887
Total	2,143	1,304	3,447

Estimated net proved reserves of natural gas at 31 December 2025^{ab}

billion cubic feet			
	Developed	Undeveloped	Total
UK	76	12	88
US	3,009	3,881	6,890
Rest of North America	—	—	—
South America ^e	413	358	771
Africa	123	—	123
Rest of Asia	2,660	1,368	4,028
Australasia	947	498	1,445
Subsidiaries	7,227	6,117	13,344
Equity-accounted entities	1,610	962	2,572
Total	8,837	7,079	15,916

Estimated net proved reserves on an oil equivalent basis

million barrels of oil equivalent			
	Developed	Undeveloped	Total
Subsidiaries	2,806	2,055	4,861
Equity-accounted entities	860	470	1,330
Total	3,666	2,525	6,191

- a Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently, and include non-controlling interests in consolidated operations. We disclose our share of reserves held in joint ventures and associates that are accounted for by the equity method, although we do not control these entities or the assets held by such entities.
- b The 2025 marker prices used were Brent \$69.512/bbl (2024 \$81.171/bbl and 2023 \$83.27/bbl) and Henry Hub \$3.409/mmBtu (2024 \$2.065/mmBtu and 2023 \$2.58/mmBtu).
- c Includes condensate.
- d Includes 1.7 million barrels of liquids in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
- e Includes 231 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

Because of rounding, some totals may not agree exactly with the sum of their component parts.

Proved reserves replacement

Total hydrocarbon proved reserves at 31 December 2025, on an oil equivalent basis including equity-accounted entities, decreased by 1% compared with 31 December 2024 (0.2% decrease for subsidiaries and 3% decrease for equity-accounted entities). Natural gas increased by 8% (10% increase for subsidiaries and 3% decrease for equity-accounted entities).

There was a net increase from acquisitions and disposals of 27mmboe within our US and North Sea subsidiaries.

The proved reserves replacement ratio★ is the extent to which production is replaced by proved reserves additions. This ratio is expressed in oil equivalent terms and includes changes resulting from revisions to previous estimates, improved recovery, and extensions and discoveries. For 2025, the proved reserves replacement ratio excluding acquisitions and disposals was 90% (50% in 2024 and 47% in 2023) for subsidiaries and equity-accounted entities, 95% for subsidiaries alone and 69% for equity-accounted entities alone. There was a net increase (126mmbob) of reserves due to higher gas prices, primarily in our US subsidiaries, partly offset by a decrease in reserves in some of our PSAs in Angola.

In 2025 net additions to the group's proved reserves (excluding production, sales and purchases of reserves-in-place) amounted to 780mmbob (679mmbob for subsidiaries and 101mmbob for equity-accounted entities), through revisions to previous estimates including price, improved recovery from, and extensions to, existing fields, and discoveries of new fields. The majority of subsidiary additions were through revisions to previous estimates and extensions to existing fields and discoveries of new fields, where they represented a mixture of proved developed and proved undeveloped reserves. The principal proved reserves additions in our subsidiaries by region were in the US, Trinidad and the Middle East. The principal reserves additions in our equity-accounted entities were in Iraq, Angola and Norway.

In January 2024 it was reported that the Oslo District Court had determined that certain development permits granted by the Norwegian government during 2023 were invalid. This includes development permits for two fields in which Aker bp has an interest. The court's decision is not final and could be appealed. If bp's equity-accounted share of the reserves attributable to these two fields is removed from the calculation of bp's 2025 proved reserves ratio, that ratio would remain the same. Removal of the same reserves from bp's 2025 reporting would impact proved hydrocarbon reserves for the group, proved undeveloped reserves and estimated net proved reserves on an oil equivalent basis, amongst other reported measures, both for equity-accounted entities and group.

24% of our proved reserves are associated with PSAs. The countries in which we produced under PSAs in 2025 were Angola, Azerbaijan, Egypt, India, Indonesia, Mexico and Oman, and includes the technical service contract (TSC)★ governing our investment in the Rumaila field in Iraq that functions as a PSA.

The group holds no licences in our PSAs or TSCs due to expire within the next three years that would have a significant impact on bp's reserves or production, including undeveloped acreage.

For further information on our reserves see [page 248](#).

bp's net production by country – crude oil^a and natural gas liquids

	Crude oil			Natural gas liquids		
	thousand barrels per day			thousand barrels per day		
	bp net share of production ^b			bp net share of production ^b		
	2025	2024	2023	2025	2024	2023
Subsidiaries						
UK	78	70	74	4	4	5
Total Europe	78	70	74	4	4	5
Lower 48 onshore ^c	108	86	69	87	84	66
Gulf of America deepwater	291	290	266	24	23	22
Total US	399	376	335	111	107	88
Total North America	399	376	335	111	107	88
Trinidad and Tobago	5	4	4	6	4	4
Total South America	5	4	4	6	4	4
Egypt ^d	7	19	28	–	1	1
Algeria ^c	–	–	1	–	–	1
Mauritania	1	–	–	–	–	–
Total Africa	8	19	29	–	1	2
Abu Dhabi	208	202	197	–	–	–
Azerbaijan	66	66	70	–	–	–
India	6	6	4	–	–	–
Oman	22	23	22	–	–	–
Total Rest of Asia	302	297	293	–	–	–
Total Asia	302	297	293	–	–	–
Australia	6	7	8	1	2	2
Eastern Indonesia	2	2	2	–	–	–
Total Australasia	8	9	10	1	2	2
Total subsidiaries	800	775	745	123	117	100
Equity-accounted entities (bp share)						
Argentina	51	52	51	1	1	1
Mexico	4	3	5	–	–	–
Bolivia	1	1	1	–	–	–
Egypt ^d	3	–	–	2	2	2
Norway	55	58	60	2	2	3
Iraq	79	69	62	–	–	–
Angola	75	82	82	3	4	4
Total equity-accounted entities	268	266	261	8	9	9
Total subsidiaries and equity-accounted entities ^e	1,069	1,041	1,006	131	126	109

a Includes condensate.

b Production excludes royalties due to others whether payable in cash or in kind where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

c In 2024 bp disposed of certain Lower 48 onshore interests in the US. In 2023 bp disposed of its interests in Algeria.

d In 2024 bp disposed of certain interests in Egypt to form Arcius Energy.

e Includes 2 net mboe/d of NGLs from processing plants in which bp has an interest (2024 2mboe/d and 2023 2mboe/d).

Because of rounding, some totals may not agree exactly with the sum of their component parts.

bp's net production by country – natural gas

	million cubic feet per day		
	bp net share of production ^a		
	2025	2024	2023
Subsidiaries			
UK	203	197	247
Total Europe	203	197	247
Lower 48 onshore ^b	1,573	1,530	1,338
Gulf of America deepwater	177	160	149
Total US	1,751	1,690	1,486
Total North America	1,751	1,690	1,486
Trinidad and Tobago ^b	1,045	1,145	1,191
Total South America	1,045	1,145	1,191
Egypt ^c	353	904	1,220
Mauritania ^d	53	–	–
Senegal ^d	48	–	–
Algeria ^b	–	–	16
Total Africa	453	904	1,236
Azerbaijan	731	748	714
India	275	303	283
Oman	590	604	582
Total Rest of Asia	1,597	1,655	1,578
Total Asia	1,597	1,655	1,578
Australia	227	276	301
Eastern Indonesia	572	606	473
Total Australasia	799	882	774
Total subsidiaries ^e	5,847	6,474	6,512
Equity-accounted entities (bp share)			
Argentina	246	267	247
Bolivia	37	33	50
Mexico	1	1	2
Egypt ^c	165	9	–
Norway	54	55	58
Angola	99	76	74
Total equity-accounted entities ^e	603	440	432
Total subsidiaries and equity-accounted entities	6,450	6,914	6,944

a Production excludes royalties due to others whether payable in cash or in kind where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

b In 2024 bp disposed of certain interests in Trinidad and Tobago. In 2023 bp disposed of its interests in Algeria and certain Lower 48 onshore interests in the US.

c In 2024 bp disposed of certain interests in Egypt to form Arcius Energy.

d In 2025 the Greater Tortue Ahmeyim LNG project in Mauritania and Senegal has begun flowing gas.

e Natural gas production volumes exclude gas consumed in operations within the lease boundaries of the producing field, but the related reserves are included in the group's reserves.

Because of rounding, some totals may not agree exactly with the sum of their component parts.

The following tables provide additional data and disclosures in relation to our oil and gas operations.

Average sales price per unit of production (realizations ★)^a

	\$ per unit of production								
	Europe		North America		South America	Africa	Asia	Australasia	Total group average
	UK	Rest of Europe	US	Rest of North America					
Subsidiaries									
2025									
Crude oil ^b	69.20	–	63.79	–	70.05	64.50	70.53	63.87	66.92
Natural gas liquids	38.80	–	20.74	–	36.08	–	–	48.71	22.35
Gas	12.76	–	2.63	–	5.20	4.14	7.01	9.36	5.61
2024									
Crude oil ^b	80.81	–	74.73	–	81.89	75.21	81.28	70.21	77.77
Natural gas liquids	43.45	–	20.09	–	20.46	–	–	49.25	21.25
Gas	11.65	–	1.49	–	3.42	4.68	6.83	8.95	4.91
2023									
Crude oil ^b	82.99	–	75.28	–	84.36	76.30	83.86	68.27	79.37
Natural gas liquids	46.52	–	19.26	–	30.76	44.41	–	33.47	23.79
Gas	16.71	–	2.08	–	3.58	4.82	7.72	8.89	5.60
Equity-accounted entities^c									
2025									
Crude oil ^b	–	68.90	–	–	62.47	67.07	61.82	–	64.90
Natural gas liquids	–	–	–	–	25.50	49.02	–	–	36.90
Gas	–	11.99	–	–	3.69	–	–	–	4.98
2024									
Crude oil ^b	–	80.10	–	–	79.21	78.60	73.86	–	77.84
Natural gas liquids	–	–	–	–	27.84	–	–	–	27.84
Gas	–	10.83	–	–	3.38	–	–	–	4.54
2023									
Crude oil ^b	–	81.61	–	–	75.49	80.21	75.21	–	78.33
Natural gas liquids	–	–	–	–	30.95	42.89	–	–	36.70
Gas	–	12.80	–	–	3.66	–	–	–	5.15

Average production cost per unit of production^d

	\$ per unit of production								
	Europe		North America		South America	Africa	Asia	Australasia	Total group average
	UK	Rest of Europe	US	Rest of North America					
Subsidiaries									
2025	12.82	–	8.61	–	4.45	11.19	2.68	1.85	6.28
2024	13.74	–	9.33	–	5.27	3.57	2.89	1.78	6.17
2023	10.69	–	9.61	–	4.53	2.52	2.81	2.09	5.78
Equity-accounted entities									
2025	–	7.31	–	–	20.07	18.42	22.51	–	17.64
2024	–	6.16	–	–	20.40	18.30	22.88	–	17.37
2023	–	6.22	–	–	17.87	15.46	16.41	–	14.38

a Units of production are barrels for liquids and thousands of cubic feet for gas. Realizations include transfers between businesses.

b Includes condensate.

c In certain countries it is common for equity-accounted entities' agreements to include pricing clauses that require selling a significant portion of the entitled production to local governments or markets at discounted prices.

d Units of production are barrels for liquids and thousands of cubic feet for gas. Amounts do not include ad valorem and severance taxes.

Additional information for customers & products

Reconciliation of customers & products RC profit before interest and tax to underlying RC profit before interest and tax to adjusted EBITDA★ by business

	\$ million		
	2025	2024	2023
RC profit (loss) before interest and tax for customers & products ^a	4,100	(1,043)	4,230
Less: Adjusting items gains (charges) ^a	(1,172)	(3,560)	(2,183)
Underlying RC profit before interest and tax for customers & products	5,272	2,517	6,413
By business:			
customers – convenience & mobility	3,764	2,584	2,644
Castrol – included in customers	971	831	730
products – refining & trading	1,508	(67)	3,769
Add back: Depreciation, depletion and amortization	4,145	3,957	3,548
By business:			
customers – convenience & mobility	2,443	2,135	1,736
Castrol – included in customers	179	176	167
products – refining & trading	1,702	1,822	1,812
Adjusted EBITDA for customers & products	9,417	6,474	9,961
By business:			
customers – convenience & mobility	6,207	4,719	4,380
Castrol – included in customers	1,150	1,007	897
products – refining & trading	3,210	1,755	5,581

a 2024 has been restated for material items to reflect the move of our Archaea Energy business from the customers & products segment to the gas & low carbon energy segment.

Sales volume

	thousand barrels per day		
	2025	2024	2023
Marketing sales ^a	2,696	2,714	2,718
Trading/supply sales ^b	494	373	358
Total refined product sales	3,190	3,087	3,076
Crude oil ^c	72	86	102
Total	3,262	3,173	3,178

- a Marketing sales include branded and unbranded sales of refined fuel products and lubricants to business-to-business and business-to-consumer customers, including service station dealers, jobbers, airlines, small and large resellers such as supermarkets, and the military.
- b Trading/supply sales are fuel sales to large unbranded resellers and other oil companies.
- c Crude oil sales relate to third-party transactions executed primarily by supply, trading and shipping. In addition, reported crude oil sales in 2025 includes 37 thousand barrels per day (2024 52 thousand barrels per day and 2023 68 thousand barrels per day) relating to volumes sold directly by the gas & low carbon energy and oil production & operations segments.

In the table above, volumes of crude oil and refined product trading/supply sales are presented on a basis consistent with income statement presentation. These figures do not correspond to actual volumes of physically traded energy products and are not intended for use in assessing emissions volumes or carbon intensity. Marketing volumes shown represent physically delivered transactions regardless of income statement presentation of such transactions.

Retail sites^a

	Number of bp-branded retail sites		
	2025	2024	2023
US	8,750	8,500	8,200
Europe	7,150	7,750	8,050
Rest of world	5,150	4,950	4,850
Total	21,050	21,200	21,100

a Reported to the nearest 50. Includes sites operated by dealers, jobbers, franchisees or brand licensees or joint venture (JV) partners, under the bp brand. These may move to and from the bp brand as their fuel supply agreement or brand licence agreement expires and is renegotiated in the normal course of business. Retail sites are primarily branded bp, ARCO, Amoco, Aral, Thorntons and TravelCenters of America, and also include sites in India through our Jio-bp JV.

Refinery throughputs^{abcde}

	thousand barrels per day		
	2025	2024	2023
US	635	612	662
Europe	805	782	749
Total	1,440	1,394	1,411
			%
Refining availability★	96.3	94.3	96.1

- a This does not include bp's interest in Pan American Energy Group.
- b Refinery throughputs reflect crude oil and other feedstock volumes.
- c On 28 February 2023, bp completed the sale of its 50% interest in the bp-Husky Toledo refinery in Ohio, US to Cenovus Energy, its partner in the facility.
- d On 1 December 2024, bp completed the sale of its 50% ownership in the SAPREF refinery to the South African state-owned entity Central Energy Fund SOC Ltd.
- e On 6 February 2025 bp announced its intention to market its Ruhr Oel GmbH – BP Gelsenkirchen operation in Germany for potential sale, including its refinery in Gelsenkirchen and DHC Solvent Chemie GmbH in Mülheim an der Ruhr.

Refinery capacity

The following table^a summarizes bp's average daily crude distillation capacities as at 31 December 2025.

	Country	Refinery	Crude distillation capacities ^b thousand barrels per day
US			
US North West	US	Cherry Point	251
US Mid West		Whiting	440
			691
Europe			
North West Europe	Germany	Gelsenkirchen ^c	265
		Lingen	97
	Netherlands	Rotterdam	394
Mediterranean	Spain	Castellón	110
			866
Total capacity at 31 December 2025			1,557

a This does not include bp's interest in Pan American Energy Group.

b Crude distillation capacity is gross rated capacity, which is defined as the highest average sustained unit rate for a consecutive 30-day period under normal operational conditions.

c On 6 February 2025 bp announced its intention to market its Ruhr Oel GmbH – BP Gelsenkirchen operation in Germany for potential sale, including its refinery in Gelsenkirchen and DHC Solvent Chemie GmbH in Mülheim an der Ruhr.

Environmental expenditure

	\$ million		
	2025	2024	2023
Operating expenditure	435	575	524
Capital expenditure	443	393	329
Clean-ups	16	20	23
Additions to environmental remediation provision	325	254	228
Increase (decrease) in decommissioning provision	528	942	920

Operating and capital expenditure on the prevention, control, treatment or elimination of air and water emissions and solid waste is often not incurred as a separately identifiable transaction. Instead, it forms part of a larger transaction that includes, for example, normal operations and maintenance expenditure. The figures for environmental operating and capital expenditure in the table are therefore estimates, based on the definitions and guidelines of the American Petroleum Institute.

Environmental operating expenditure of \$435 million in 2025 (2024 \$575 million) showed an overall decrease of 24%, largely due to decreased expenditure in BP Products North America.

Environmental capital expenditure of \$443 million in 2025 (2024 \$393 million) showed an overall increase of 13%, largely due to increased expenditure for BP Products North America.

Clean-up costs were \$16 million in 2025 (2024 \$20 million), representing oil spill clean-up costs and other associated remediation and disposal costs.

In addition to operating and capital expenditure, we also establish provisions for future environmental remediation work. Expenditure against such provisions normally occurs in subsequent periods and is not included in environmental operating expenditure reported for such periods.

Provisions for environmental remediation are made when a clean-up is probable and the amount of the obligation can be reliably estimated. Generally, this coincides with the commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites.

The extent and cost of future environmental restoration, remediation and abatement programmes are inherently difficult to estimate. They often depend on the extent of contamination, and the associated impact and timing of the corrective actions required, technological feasibility and bp's share of liability. Though the costs of future programmes could be significant and may be material to the results of operations in the period in which they are recognized, it is not expected that such costs will be material to the group's overall results of operations or financial position. For further information, see **Note 1 – Significant judgements and estimates: provisions**.

Additions to our environmental remediation provision reflect new liabilities and scope/cost reassessments of the remediation plans of a number of our sites, primarily in the US. The charge for environmental remediation provisions in 2025 arising from new and acquired sites was \$4 million (2024 \$24 million and 2023 \$37 million).

In addition, we make provisions on installation of our oil and gas producing assets and related pipelines to meet the cost of eventual decommissioning. On installation of an oil or natural gas production facility, a provision is established that represents the discounted value of the expected future cost of decommissioning the asset.

In 2025 the net increase in the decommissioning provision was primarily due to recognition of additional provisions from new infrastructure and changes in cost estimate assumptions.

We undertake periodic reviews of existing provisions. These reviews take account of revised cost assumptions, changes in decommissioning requirements and any technological developments.

Provisions for environmental remediation and decommissioning are usually established on a discounted basis, as required by IAS 37 'Provisions, Contingent Liabilities and Contingent Assets'.

Further details of decommissioning and environmental provisions appear in Financial statements – **Note 23**.

Regulation of the group's business

Our businesses and operations are subject to the laws and regulations applicable in each country, state or other regional or local area in which they occur. These cover virtually all aspects of bp's activities and include matters such as the acquisition of rights to develop and operate projects, production rates, royalties, environmental, health and safety protection, fuel specifications and transportation, trading, pricing, anti-trust, export, taxes, and foreign exchange.

Oil and gas contractual and regulatory framework

The terms and conditions of the leases, licences and contracts under which our upstream oil and gas interests are held vary from country to country. These leases, licences and contracts are generally granted by or entered into with a government entity or state-owned or controlled company and are sometimes entered into with private property owners. Arrangements with governmental or state entities usually take the form of licences or production-sharing agreements (PSAs)★, although arrangements with private entities and US government entities are usually by lease.

Licences (or concessions) give the holder the right to explore for, develop and produce a commercial discovery. Under a licence, the holder bears the risk of exploration, development and production activities and provides the financing for these operations. In principle, the licence holder is entitled to all production, minus any royalties that are payable in kind. A licence holder is generally required to pay production taxes or royalties, which may be in cash or in kind.

In certain countries, separate licences are required for exploration and production activities, and in some cases production licences are limited to only a portion of the area covered by the original exploration licence.

PSAs entered into with a government entity or state-owned or state-controlled company generally require bp (alone or with other contracting companies) to provide all the financing and bear the risk of exploration and production activities in exchange for a share of the production remaining after royalties, if any. Less typically, bp may explore for, develop and produce hydrocarbons under a service agreement with the host entity in exchange for reimbursement of costs and/or a fee paid in cash rather than production.

bp frequently conducts its exploration and production activities in joint arrangements or co-ownership arrangements with other international oil companies, state-owned or -controlled companies and/or private companies. Conventionally, all costs, benefits, rights, obligations, liabilities and risks incurred in carrying out joint arrangement or co-ownership operations under a lease, licence or PSA are shared among the joint arrangement or co-owning parties according to agreed ownership interests which are set out in a joint operating agreement. To the extent that any liabilities arise, whether to governments or third parties, or between the joint arrangement parties or co-owners themselves, each joint arrangement party or co-owner will generally be liable under the terms of a joint operating agreement to meet these in proportion to its ownership interest. Any agreed allocation of liability amongst the joint arrangement parties is, however, often different to the position under the relevant licence, lease or PSA, which may provide for joint and several liability of the joint arrangement parties including for decommissioning obligations. In many upstream operations, a party (known as the operator) will be appointed (pursuant to a joint operating agreement) to carry out day-to-day operations on behalf of the joint arrangement or co-ownership. The operator is typically one of the joint arrangement parties or a co-owner and will carry out its duties either through its own staff, or by contracting out various elements to third-party contractors or service providers. bp acts as operator on behalf of joint arrangements and co-ownerships in a number of countries.

Frequently, work (including drilling and related activities) will be contracted out to third-party service providers. The relevant contract will specify the work, the remuneration, and typically the risk allocation between the parties. Depending on the service to be provided, the

contract may also contain provisions allocating risks and liabilities associated with pollution and environmental damage, damage to a well or hydrocarbon reservoirs and for claims from third parties or other losses. The allocation of those risks varies among contracts and is determined through negotiation between the parties.

In general, bp incurs income tax on income generated from production activities (whether under a licence or PSA). In addition, depending on the area, bp's production activities may be subject to a range of other taxes, levies and assessments, including special petroleum taxes and revenue taxes. The taxes imposed on oil and gas production profits and activities may be substantially higher than those imposed on other activities, for example in Egypt, the UK, the US and the United Arab Emirates.

Low carbon energy – renewables contractual and regulatory framework

The majority of our renewable assets are held indirectly through interests in incorporated joint ventures or special purpose entities (in either case, a Project Company). The renewables contractual and regulatory framework and the rights granted in relation to a renewable asset significantly vary from country to country. In some countries, the regulatory framework is still under development or subject to significant change as the renewables industry evolves.

In general terms the rights to a renewable asset are usually held by a Project Company through a package of assets that together form the renewable project owned by such Project Company, including:

- one or more leases, easements or licences over land or seabed granted by a public or private individual or entity that grant the Project Company rights to develop, build and operate the renewable asset in such areas of land or seabed;
- one or more generation licences that grant the Project Company the right to produce and sell the electricity to the market;
- an interconnection agreement that grants the Project Company the right to connect the power project into the grid;
- an offtake agreement which, depending on the country's electricity market, is entered into with a utility company, a corporate buyer or a public entity; and
- potentially, a subsidy mechanism in the form of a feed in tariff, contract for difference, hedging mechanism or renewable energy certificate to support the development of the project.

The risk allocation between the developer/generator and the host government or private entity has not been standardized in the industry. However, in general terms the Project Company bears the risk of the development, construction and operation of the renewable energy project and secures the financing for these operations and receives any profit from the revenue generated through the offtake agreement and/or subsidy mechanism (if available).

Greenhouse gas regulation

In December 2015, nearly 200 nations at the United Nations climate change conference in Paris (COP21) agreed to the Paris Agreement which aims to hold the increase in the global average temperature to well below 2°C above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5°C above pre-industrial levels. Signatories aim to reach global peaking of greenhouse gas (GHG) emissions as soon as possible and to undertake rapid reductions thereafter, so as to achieve a balance between human caused emissions and removals by sinks of GHGs in the second half of this century. The Paris Agreement commits all signatories to submit Nationally Determined Contributions (NDCs) (i.e. pledges or plans of climate action) and pursue domestic measures aimed at achieving the objectives of their NDCs. Signatories are required to submit revised NDCs every five years, and the revised NDCs are expected to be more ambitious with each revision. The first global stocktake of progress was published by the United Nations in September 2023 and further assessments will occur every five years. The UAE conference (COP28) in Dubai, which took place in November and December 2023, marked the conclusion and outcome of this first stocktake and reached a consensus which includes calls for an acceleration of efforts towards the phase-down of unabated coal power and to transition away from

fossil fuels in energy systems. The 2024 Baku conference (COP 29) included agreements in relation to finance and carbon markets. The 2025 Belém conference (COP30) included agreement to triple adaptation finance by 2035, and emphasized accelerating the shift to renewable energy sources, and ensuring a just transition.

More stringent national and regional measures relating to the transition to a lower carbon economy, such as the UK's 2050 net zero carbon emissions commitment, can be expected in the future. These measures could increase bp's production costs for certain products, increase compliance and litigation costs, increase demand for competing energy alternatives or products with lower-carbon intensity, and affect the sales and specifications of many of bp's products. Further, such measures could lead to constraints on production and supply and access to new reserves, particularly due to the long-term nature of many of bp's projects.

Certain current and announced GHG measures and developments potentially affecting bp's businesses in various markets in which bp operates are summarized below. For information on steps that bp is taking in relation to climate change issues and for details of bp's GHG reporting, see [page 37](#).

United States

In the US, bp's operations are affected by the regulation of GHGs in a number of ways. The federal Clean Air Act (CAA) and its various amendments regulate air emissions, permitting, fuel specifications and other aspects of our production, refining, distribution and marketing activities.

GHG Reporting Rule

The federal GHG Mandatory Reporting Rule requires operators of certain facilities and producers and importers/exporters of petroleum products to file annual GHG emissions reports with EPA quantifying direct GHG emissions from affected facilities, as well as the GHG emissions that would result from the release or combustion of the petroleum products imported, exported or produced. In addition, several states have their own GHG reporting rules.

Our US businesses are subject to GHG and other environmental requirements and regulatory uncertainty, including that the current or any future US administration could revise or revoke current or prior administration programmes, as well as the possibility of increased expenditures in having to comply with numerous diverse and non-uniform regulatory initiatives at the state and local levels. In September 2025, the United States Environmental Protection Agency (US EPA) proposed regulations that would revoke or suspend GHG reporting requirements for the oil and gas sector for 10 years.

US Inflation Reduction Act

The 2022 US Inflation Reduction Act (IRA) included a significant package of largely supply-side measures supporting low carbon energy sources and decarbonization technologies in the US. In 2023, bp applied for various DOE and FAA grants related to certain of bp's low carbon energy and decarbonization projects. In 2024 DOE and FAA notified bp of its grant awards and bp and its co-applicants executed award agreements with the DOE. On 20 January 2025, the Trump Administration issued an Executive Order directing agencies to pause the disbursement of IRA funding for review. This Order is subject to legal challenges that have resulted in the effective suspension of implementation pending judicial resolution.

Methane

In 2024 the EPA promulgated the "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review." These regulations focused on methane and volatile organic compound emissions from oil and gas production at new and existing facilities and include significant requirements in the areas of fugitive emissions monitoring and repair, flaring, emission event reporting, process controller and pump emissions, and storage vessels. In March 2025, the EPA announced reconsideration of the 2024 regulations, and, in December 2025, finalized the Interim Final Rule extending many of the original compliance deadlines in the 2024 regulations.

Separate from the above, the IRA required EPA to collect an annual Waste Emissions Charge (WEC) on methane emissions from oil and natural gas facilities that exceed specific levels of emissions and methane intensity. In November 2024, EPA promulgated regulations to implement the WEC provisions of the IRA, but those regulations were disapproved by the US Congress in March 2025 and are no longer in place.

Climate Resilience Funds

Several US states, including New York and Vermont, have enacted laws seeking recovery from historical GHG emitters to create climate resilience funds to address climate change impacts by financing infrastructure upgrades, disaster preparation, and other resilience projects. Other states, including New Jersey, California, Maryland and Massachusetts, are considering similar legislation. The extent and cost of such future environmental climate fund programmes are difficult to estimate at this time.

Electricity

Other EPA GHG and environmental regulations affect electricity generation practices and prices and have an impact on the market for fuels used to generate electricity and on renewable energy installations. These regulations are in flux due to changes in approach between presidential administrations, as well as lawsuits challenging those regulations.

The 2022 Supreme Court decision in *West Virginia v. EPA* limited EPA's regulatory authority to require electricity 'generation shifting' (e.g. from coal to natural gas or renewable sources). In response to the *West Virginia v. EPA* decision, in April 2024 EPA promulgated new carbon pollution standards for coal and gas-fired power plants. The regulations significantly tighten emissions limits for those plants and will require some plants to install carbon capture technology. In 2025 EPA proposed repealing those regulations.

Renewable Fuel Standard

EPA's Renewable Fuel Standard (RFS) regulations require transportation fuel sold in the US to contain a minimum volume of renewable fuels. In 2023, EPA announced a final rule establishing biofuel volume requirements and associated percentage standards (renewable volume obligations or RVOs) for cellulosic biofuel, biomass-based diesel, advanced biofuel, and total renewable fuel for 2023-2025, which was remanded to EPA and the wildlife agencies for further explanation. EPA is delayed in promulgating RVOs for 2026, but in a deadline lawsuit challenging the agency's delay, EPA stated its intention to finalize the regulations in the first quarter of 2026.

State Low Carbon Fuel Standards

A number of states, municipalities and regional organizations continue to advance climate initiatives that affect our US operations. For example, California, Oregon, and Washington impose carbon-intensity reduction requirements on transportation fuels sold in those states. In November 2024, California updated its Low Carbon Fuel Standard (LCFS) to achieve a 30% reduction in carbon intensity by 2030 and a 90% reduction in carbon intensity by 2045. In 2024 New Mexico became the latest US state to enact LCFS legislation, with regulations likely to take effect in 2026.

Mobile Source Emissions

US fuel markets are affected by EPA and National Highway Traffic Safety Administration (NHTSA) regulation of light, medium and heavy-duty vehicle emissions (both fuel economy and tailpipe standards) as well as for non-road engines and vehicles and certain large GHG stationary emission sources. In August 2025, EPA issued a proposed rescission of all federal GHG emission standards and the Endangerment Finding that provides the legal justification for such GHG standards for light-, medium- and heavy-duty vehicles. EPA has not yet finalized the proposed rescissions and legal challenges to rescinding the 2009 Endangerment Finding are expected. In December 2025, NHTSA proposed to reduce the stringency of fuel economy standards for light-duty vehicles. Relatedly, in July 2025, the US Congress eliminated civil penalties for non-compliance with corporate average fuel economy standards.

Light-duty and Medium Duty Vehicles

In March 2024, EPA promulgated a final rule entitled "Multi-Pollutant Emissions Standards for Model Year 2027 and Later Light-Duty and Medium-Duty Vehicles," which significantly tightens emissions standards for light- and medium-duty vehicles for model year (MY) 2027 and beyond and imposes new warranty, durability, and certification requirements, including for electric vehicles. The regulations are intended to spur emissions reductions technology on hydrocarbon-powered vehicles and to encourage the transition to electric vehicles. The regulations will phase in over MY 2027-2032. In March 2025, EPA announced that it would reconsider the regulations.

Heavy-Duty Vehicles

In 2022, EPA promulgated a final rule entitled "Control of Air Pollution from New Motor Vehicles: Heavy Duty Engine and Vehicle Standards," which established new emission standards for oxides of nitrogen (NOx) and other pollutants for highway heavy-duty engines. In March 2025, EPA announced that it would re-evaluate that final rule.

California Mobile Sources

The CAA authorizes the state of California to set its own separate vehicle emissions regulations, stricter than those at the federal level. Under CAA Section 209, California can apply to EPA for a waiver of federal pre-emption, and EPA is to grant this waiver absent certain disqualifying conditions. Under CAA Section 177, other states can adopt California standards or follow federal standards but cannot set their own. In May 2025, the US Congress passed resolutions under the Congressional Review Act (CRA) rescinding EPA waivers covering California's Advanced Clean Cars (ACC) II, Advanced Clean Trucks (ACT), and Heavy-Duty Low NOx Omnibus (Omnibus) regulations, which set emissions standards and sales mandates for zero-emission vehicles (ZEVs) in the state. California and other states have sued to challenge these CRA rescissions, and California has offered manufacturers alternative paths for certification of new vehicles in the state - including continued compliance with the regulations subject to CRA disapproval, compliance with superseded California standards, or compliance with EPA standards and certification requirements. Meanwhile, EPA and other parties have contested whether California can fall back on pre-existing standards or else require certification within the state for current and future model years.

In October 2025, a federal district court issued a preliminary injunction barring California from attempting to enforce the Clean Truck Partnership - a 2023 agreement between California and the heavy-duty vehicle and engine manufacturers under which the manufacturers agreed to comply with California regulations in exchange for more lead time and other measures. Claims challenging California's continued enforcement of ACC II, ACT and Omnibus remain pending in the case.

California Advanced Clean Cars Program

California's ACC regulations were originally enacted in 2012 for MY 2015 to 2025. The ACC program is a package of state regulations that set emissions standards for criteria pollutants, GHG emission standards for light-duty vehicles, and a ZEV sales mandate. In 2019, EPA and NHTSA jointly promulgated the "Safer Affordable Fuel-Efficient Vehicles Rule Part One: One National Program (SAFE-1)," which effectively disallowed the ACC program. In 2021, EPA revoked SAFE-1, and the ACC program went back into force. In response to a legal challenge, the US Court of Appeals for the DC Circuit upheld EPA's decision to restore the California waiver. That decision was appealed to the Supreme Court, which did not review the waiver itself but held that fuel producers had standing to challenge the waiver. That litigation is now stayed as EPA again reconsiders the waiver decision. In 2022, California finalized the next generation of its GHG and ZEV standards ACC II sets annual ZEV and plug-in hybrid vehicle (PHEV) sales requirements from MY 2026 to 2035 and increasingly more stringent emission standards to ensure automakers gradually phase out new sales of internal combustion engine vehicles.

In 2023 California filed a CAA Section 209 waiver of federal pre-emption application with EPA. In December 2024, EPA granted California's waiver under ACC II that requires that by MY 2035, all new light-duty vehicles sold in California must be ZEVs or PHEVs. As noted above, in

May 2025, Congress passed the CRA resolution rescinding the ACC II waiver, which California and other states have challenged.

California Advanced Clean Trucks Program

In 2023, EPA granted California's request for a waiver of federal preemption covering, in part, ACT regulations, which mandate increasing quantities of ZEV sales for medium- and heavy-duty vehicles in the state. As noted above, in May 2025, the US Congress passed a resolution under the CRA that purports to void that waiver. Legal challenges to the CRA resolution, as well as legal challenges to continuing efforts to enforce the ACT Program, have been filed and are pending.

EPA Proposal to Rescind Endangerment Finding

In 2025 EPA proposed to rescind the 2009 Endangerment Finding, which forms the statutory basis for GHG emissions regulations for motor vehicles and engines under the Clean Air Act, including the Biden Administration electric vehicle mandates. If finalized, the proposal would remove all GHG standards for light-, medium- and heavy-duty vehicles and heavy-duty engines. EPA indicated it will solicit public comment on the proposal.

These and other initiatives regarding GHG emissions create significant regulatory uncertainty and may have a significant effect on the production, sale and profitability of many of bp's products in the US.

European Union

The EU has adopted a goal of achieving climate neutrality by 2050 as part of the European Green Deal and, subsequently, a 55% GHG reduction target by 2030 and a 90% target by 2040, both compared to 1990 levels. To achieve the 2030 target, EU member states and Parliament adopted most measures proposed as part of the so-called 'Fit for 55' package. These include: revisions of the EU Emissions Trading Scheme (EU ETS) and a newly created Carbon Border Adjustment Mechanism (CBAM); the Renewable Energy Directive (RED) - including an obligation on transport fuel suppliers to increase the share of renewables of their fuel supply; a sustainable aviation fuel (SAF) blending mandate from 2025; and CO₂ targets for the sales of new vehicles which are expected to accelerate the decarbonization of the transport sector and impact fuel demand despite certain flexibilities for vehicle manufacturers currently under discussion. We expect changes to some of these laws as part of planned reviews and to bring them in line with the recently agreed 2040 GHG reduction target.

Pending full implementation and ongoing and future revisions of these laws, this would inter alia lead to higher shares of renewables across all sectors (including transport), higher cost to supply fuels due to a cap-and-trade system for the road transport and buildings sector starting in 2028, a continuously reduced number of GHG emission allowances and associated free allocation under the EU ETS, and a continued decline of fuel demand from new cars and trucks linked to CO₂ targets for vehicle manufacturers. The EU also adopted measures that may impact the ability to import certain crude oils and natural gas into the region.

Some EU member states have adopted national targets above and beyond current EU climate goals, such as Germany, with a climate neutrality target by 2045.

United Kingdom

In November 2024, the UK government announced a nationally determined contribution target to reduce all greenhouse gas emissions by at least 81% by 2035 compared to 1990 levels.

The UK Emissions Trading System (UK ETS) launched on 1 January 2021 following the end of the Brexit transition period and the UK's participation in the EU ETS. It seeks to provide a carbon pricing mechanism as a tool for helping achieve the UK's net zero target and covers the same GHGs and sectors as the EU ETS. bp's North Sea operations are subject to the UK ETS.

In July 2023, the UK government published a response to a 2022 consultation on proposed changes to the UK ETS rules. That response included decisions to expand the scope of the scheme to include domestic maritime transport from 2026, waste incineration and energy

from waste from 2028 and process emissions from carbon dioxide venting from the upstream oil and gas sector from 2025.

In November 2025, the UK government and the UK ETS Authority published their combined response to the December 2023 Free Allocation Review and the December 2024 Carbon Leakage consultations. In relation to data and benchmarking, the UK ETS Authority decided that operators can choose to have their activity data for either 2020 only, or 2020 and 2021, excluded from determining their historical activity level for the 2027-30 allocation period. Current benchmarks for 2027 are retained, with the intention of adopting updated EU benchmark values from 2028-30. In relation to carbon leakage, the UK ETS Authority decided that: (i) The current list of sectors subject to carbon leakage is retained; (ii) It will not introduce the tiering of free allocations of UK ETS allowances for sectors at risk of carbon leakage based on the carbon leakage exposure factor or cross-sectoral correction factor; (iii) It will not bring forward the phase out of free allocations for sectors not at risk of carbon leakage; (iv) No additional benchmarking methodologies will be introduced in 2027, which would have introduced conditions on the provision of free allocation to installations with exceptional access to decarbonisation technologies. Their introduction may be reconsidered for future allocation periods; and (v) It will gradually phase out free allocations for sectors covered by the UK Carbon Border Adjustment Mechanism (UK CBAM) beginning in 2027, with an indicative phase out trajectory of nine years.

In December 2025, the UK ETS published the response to its December 2023 Future Markets Policy consultation. The response indicates that the UK ETS Authority will retain and inflation-proof the auction reserve price to maintain its real value, implementing an inflation-based increase since its introduction in 2026, and increasing the value yearly by inflation from 2027. It will retain the existing design and operation of the cost containment mechanism and retain its discretion. It will also discount the implementation of a quantity-triggered supply adjustment mechanism for a standalone UK ETS.

In December 2025, UK government also published a response to the UK ETS Authority's consultation to extend the UK ETS beyond 2030. The response confirmed it will be extended into a Phase II from 2031, which will run for 10 years from 1 January 2031 to 31 December 2040, and banking of allowances will be permitted between Phase I and Phase II.

Other countries and regions

China is operating emissions trading pilot programmes in a number of cities and provinces. One of bp's subsidiaries in China is participating in these programmes. In February 2021 China introduced a national emissions trading market (National ETS). The National ETS is intended to be an essential tool for China to fulfil its commitment to reach peak emissions by 2030 and carbon neutrality by 2060. On 9 September 2024, the Ministry for Ecology and Environment of China (the MEE) released a draft work plan to expand the sectoral coverage of the National ETS. Currently covering only the power sector, the plan proposes to extend the National ETS to include the cement, steel, and aluminium industries. In March 2025, the MEE officially expanded the sectoral coverage of the National ETS to include the cement, steel, and aluminium industries. The expansion would bring an additional approximately 1,500 companies into the National ETS. For now, the National ETS participants are limited to the key emission entities identified by each provincial-level government authority based on the standard set out by the MEE. bp is not participating in the National ETS.

In October 2021, as part of its '1+N' climate policy framework, China issued working guidance setting out specific targets and measures for achieving peak carbon emissions and carbon neutrality, and an action plan which sets out the main objectives for the next decade to achieve peak carbon emissions by 2030. The working guidance is the '1' (i.e. a long-term approach to combating climate change), while 'N' are various policies starting with the action plan. In June 2022, 17 government authorities jointly released the National Climate Change Adaptation Strategy 2035 making overall plans to prepare the country to adapt to climate change from the present to 2035.

China's domestic voluntary carbon mechanism called the China Certified Emission Reduction (CCER) programme has been suspended since 2017. In 2023, significant progress towards relaunching the CCER

has been made by relevant authorities, including the promulgation of a regulation on CCER trading for trial implementation and the publication of methodologies that will be used to quantify net emission reductions or removals for four types of projects (forestation, solar thermal power, offshore wind power generation and mangrove revegetation). CCER programme was relaunched on 22 January 2024 and the first CCER project after the relaunch was registered on 3 December 2024. On 3 January 2025, two new CCER methodologies were released – for issuing carbon credits to projects utilizing coal mine gas and energy efficient highway tunnel lighting. First batch of new CCERs was issued in March 2025 and more CCER methodologies were released in 2025.

On 5 January 2024, China’s State Council approved an interim regulation for the national emissions trading scheme. The final version was issued on 4 February 2024 which has provisions on defining the scale of the national carbon market, determining allocation of emissions allowances and data quality supervision.

Other environmental regulation

In addition to the GHG regulations referred to above, climate change programmes and regulation of unconventional oil and gas extraction under a number of environmental laws may have a significant effect on the production, sale and profitability of many of bp’s products.

Environmental laws also require bp to remediate and restore areas affected by the release of hazardous substances or hydrocarbons associated with our operations or properties. These laws may apply to sites that bp currently owns or operates, sites that it previously owned or operated, or sites used for the disposal of its and other parties’ waste. See Financial statements – **Note 23** for information on provisions for environmental restoration and remediation.

A number of pending or anticipated governmental proceedings against certain bp group companies under environmental laws could result in monetary or other sanctions. Group companies are also subject to environmental claims for personal injury and property damage alleging the release of, or exposure to, hazardous substances. The costs associated with future environmental remediation obligations, governmental proceedings and claims could be significant and may be material to the results of operations in the period in which they are recognized. We cannot accurately predict the effects of future developments, such as stricter environmental laws and regulations or enforcement policies, or future events at our facilities on the group, and there can be no assurance that material liabilities and costs will not be incurred in the future. For a discussion of the group’s environmental expenditure, see **page 352** and for a discussion of legal proceedings, see **page 236**.

Significant health, safety and environmental legislation and regulation affecting our businesses and profitability, in addition to those referred to above, include the following:

United States

- The Clean Water Act regulates wastewater and other effluent discharges from bp’s facilities, and bp is required to obtain discharge permits, install control equipment and implement operational controls and preventative measures.
- The Resource Conservation and Recovery Act (RCRA) regulates the generation, storage, transportation and disposal of wastes associated with our operations and can require corrective action at locations where such wastes have been disposed of or released. bp has incurred, or is likely to incur, liability under RCRA or similar state laws in connection with sites bp operates or previously operated.
- The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) can, in certain circumstances, impose the entire cost of investigation and remediation on a party who owned or operated a site contaminated with a hazardous substance, or who arranged for disposal of a hazardous substance at a site. bp has incurred, or is likely to incur, liability under CERCLA or similar state laws, including costs attributed to insolvent or unidentified parties. bp is also subject to claims for remediation costs and natural resource damages under CERCLA and other federal and state laws. CERCLA also requires reporting on the releases of certain quantities of listed hazardous substances to designated government agencies.

In April 2024, EPA listed PFOA and PFOS (types of perfluoroalkyl substances (PFAS) used in fire-fighting foam and many consumer products) as hazardous substances under CERCLA. This listing may impact remediation costs and result in additional reporting and other environmental obligations. Several states have passed legislation limiting the use of PFAS in fire-fighting foam, and other states may do so in the future.

- The Emergency Planning and Community Right-to-Know Act requires reporting on the storage, use and releases of certain quantities of listed extremely hazardous substances to designated government agencies.
- The Toxic Substances Control Act regulates bp’s manufacture, import, export, sale and use of chemical substances and products. In addition, EPA has revised processes and procedures for prioritization of existing chemicals for risk evaluation, assessment and management. Agency actions and announcements are monitored regularly to identify developments with potential impacts on chemical substances important to bp products and operations.
- The Occupational Safety and Health Act imposes workplace safety and health requirements on bp operations along with significant process safety management obligations, requiring continuous evaluation and improvement of operational practices to enhance safety and reduce workplace emissions at gas processing, refining and other regulated facilities.
- The Oil Pollution Act 1990 imposes operational requirements, liability standards and other obligations governing the transportation of petroleum products in US waters. States may impose additional obligations. Alaska, West Coast and certain East Coast states impose additional requirements and stricter liability standards.
- The Outer Continental Shelf Land Act, the Mineral Leasing Act and other statutes give the Department of Interior (DOI) and the Bureau of Land Management authority to regulate operations and air emissions, including equipment and testing, at offshore and onshore operations on federal lands subject to DOI authority.
- The Endangered Species Act (ESA) and Marine Mammal Protection Act protect certain species’ habitats from adverse human impacts by restricting operations or development at certain times and in certain places. In 2020, the US Fish and Wildlife Service (FWS) published regulatory definitions impacting habitat designations under the ESA, but in 2022 the Biden administration rescinded those definitions. The Biden administration rescission of those definitions could expand the geographic areas subject to habitat protections. In November 2025, the FWS proposed to reinstate the 2020 version of the habitat designation regulations.

European Union

- The Industrial Emissions Directive (IED) 2010 provides the framework for granting permits for major industrial sites. Revised IED entered into force in August 2024, strengthening the application of Best Available Techniques (BATs) and introducing stricter emission limit values and binding environmental performance levels, among other changes. It will impact bp refineries across Europe.
- The EU Registration, Evaluation Authorization and Restriction of Chemicals (REACH) Regulation 2006 requires registration of chemical substances manufactured in or imported into the EU, together with the submission of relevant hazard and risk data. REACH affects our manufacturing or trading/import operations in the EU. bp maintains compliance by checking whether imports are covered by the registrations of non-EU suppliers’ representatives, preparing and submitting registration dossiers to cover new manufactured and imported substances, and updating previously submitted registrations as required.
- The Water Framework Directive (WFD) published in 2000 aims to protect the quantity and quality of ground and surface waters of the EU member states. The transposition into national laws is still ongoing and planned to be finalized by 2027. Future proceedings on the determination of pollutants/priority substances as well as environmental quality standards in line with the WFD may require additional compliance efforts and increased costs for managing freshwater withdrawals and discharges from bp’s EU operations.

- The Corporate Sustainability Reporting Directive (CSRD) entered into force on 5 January 2023 introducing new requirements for certain EU and non-EU companies, to include disclosures related to climate, the environment and wider sustainability issues. The CSRD also expands to in-scope entities the requirements introduced by the EU Taxonomy Regulation, to identify environmentally sustainable activities and then disclose metrics related to capital and operating expenditure and turnover associated with those activities. Under the 2025 Omnibus simplification package, the application of CSRD reporting requirements has been delayed by two years for many in-scope companies, with reporting expected to begin in 2027 for FY2026.
- The Corporate Sustainability Due Diligence Directive (CSDDD) entered into force in July 2024 but has undergone targeted amendments as part of the Omnibus package. It still requires certain EU and non-EU companies to conduct due diligence on human rights and environmental risks but no longer includes the obligation to adopt a climate transition plan. In-scope companies are expected to comply in July 2029 for FY2028.

United Kingdom

- Following the UK's exit from the European Union, operative EU laws were retained in UK law by the European Union (Withdrawal) Act 2018 (EUWA). In June 2023, the Retained EU Law (Revocation and Reform) Act 2023 received Royal Assent. From 1 January 2024, retained EU law is now termed "assimilated law," and the Act removed the principle of EU law supremacy and direct effect. The Act allows for significant changes to the status, operation and content of retained EU law, including through amendments to the EUWA. This may mean that over time there will be amendments to and deviations from retained EU law including in respect of environmental matters.
- Since the end of the transition period on 31 December 2020, there has been a parallel UK REACH regime which applies in Great Britain only, with EU REACH continuing to apply in Northern Ireland. UK REACH contains equivalent requirements to EU REACH, although future developments and potential divergences are uncertain.
- The Environment Act 2021 comprises various key parts including governance, waste and resource efficiency, air quality and environmental recall, water, nature and biodiversity and conservation covenants. The governance parts include a comprehensive framework for legally binding environmental improvement targets; to establish a framework for future policy statements on environmental principles to protect the environment by making environmental considerations a key part of policy development process across government; and to establish the Office for Environmental Protection, an independent public body to have oversight of environmental matters. The UK government's first suite of environmental targets became law in January 2023, but these have not had a material impact on bp.

Other countries and regions

Regulations governing the discharge of treated water have also been developed in countries outside the US and EU, including in Trinidad and Tobago where bp commissioned a new wastewater treatment plant in 2020 to meet consent levels agreed with the regulators to apply relevant water discharge rules.

The Abidjan Convention, together with its Additional Protocols, sets environmental quality standards for the discharge of chemicals to the marine environment. Mauritania and Senegal are both signatories to the Abidjan Convention. bp's offshore facilities have implemented water management systems which are designed to meet the environmental quality standards for their gas operations in Mauritania and Senegal.

The Convention for the Protection of the Marine Environment of the North-East Atlantic (OSPAR) aims to protect the marine environment of the North-East Atlantic. The OSPAR 2012 recommendation and guideline for the implementation of a risk-based approach to the management of produced water discharges from offshore installations in the North Sea supports a key goal of working towards eliminating harmful discharges. In 2020 the International Association of Oil and Gas Producers issued a report 'Oil And Gas Risk Based Assessment of Offshore Produced Water Discharges' which presents industry good practice and aims to broaden the understanding and acceptance of Risk Based Assessment (RBA)

techniques internationally and improve consistency in the application of assumptions, levels of conservatism, and selection of risk endpoints.

At OSPAR's Offshore Industry Committee (OIC) meeting in March 2024, the Committee agreed changes to OSPAR's List of Substances/Preparations Used and Discharged Offshore which are Considered to Pose Little or No Risk to the Environment (PLONOR). This includes two inorganic substances, calcium bromide and sodium bromide which are used in Completion fluid formulations. Further work is progressing on the harmonisation of OSPAR's approach to offshore chemicals and the REACH Regulation, now focused on the potential impact of adjustments to the current Harmonised Mandatory Control System (HCMS) for regulators and industry. OIC also agreed the report on the implementation of OSPAR Recommendation 2006/3 on Environmental Goals for the Discharge by the Offshore Industry of Chemicals that Are, or Which Contain Substances Identified as Candidates for Substitution – Technical and Safety Obstacles.

Environmental maritime regulations

bp's shipping operations are subject to extensive national and international regulations governing operations, training, pollution prevention, liability, and insurance. These include:

- Liability and spill prevention and planning requirements governing, among others, tankers, barges, and offshore facilities are imposed by OPA in US waters. OPA also mandates a levy on imported and domestically produced oil to fund oil spill responses. Some states, including Alaska, Washington, Oregon and California, impose additional liability for oil spills. Outside US territorial waters, bp shipping tankers are subject to international pollution prevention, liability, spill response and preparedness regulations developed through the UN's International Maritime Organization (IMO), including the International Convention on Civil Liability for Oil Pollution Damage, the International Convention for the Prevention of Pollution from Ships (MARPOL), the International Convention on Oil Pollution, Preparedness, Response and Co-operation, and the International Convention on Civil Liability for Bunker Oil Pollution Damage. In April 2010, a Protocol was adopted to address issues that have inhibited ratification of the International Convention on Liability and Compensation for Damage in Connection with the Carriage of Hazardous and Noxious Substances by Sea 1996 (HNS Convention). As at 31 December 2025, the HNS Convention had not entered into force.
- A global sulphur cap of 0.5% applies to marine fuel under MARPOL with a stricter 0.1% cap in environmentally sensitive areas. In order to comply, ships either need to consume low sulphur marine fuels, operate on alternative low sulphur fuels such as LNG or implement approved abatement technology to enable them to meet the low sulphur emissions requirements while continuing to use higher sulphur fuel. Certain regional and local authorities also enforce sulphur caps outside of the MARPOL framework.
- From 2023 all vessels over 400 gross tonnage became subject to IMO requirements as to energy efficiency design (EEXI) and the carbon intensity of operations (CII).
- Under EU legislation, maritime transport has been brought into the scope of the EU ETS from 2024, applicable to all vessels of 5,000 gross tonnage and above calling at EU ports regardless of a vessel's flag.
- Under the Fuel EU Maritime Regulation, from 2025 ship owners are required to reduce the GHG intensity of their fuel use gradually over time, initially by 2%, increasing to 6% by 2030 and 80% by 2050.
- From 2025 tankers calling at California's major ports must comply with emission reduction and reporting requirements set by the California Air Resources Board (CARB), aimed at limiting emission of pollutants including oxides of nitrogen (Nox) and diesel particulate matter.

To meet its financial responsibility requirements, bp shipping maintains marine oil pollution liability insurance in respect of its operated ships to a maximum limit of \$1 billion for each occurrence through mutual insurance associations (P&I Clubs), although there can be no assurance that a spill would necessarily be adequately covered by insurance or that liabilities would not exceed insurance recoveries.

International trade sanctions

During the period covered by this report, non-US subsidiaries, or other non-US entities of bp, conducted limited activities in, or with persons from, certain countries identified by the US Department of State as State Sponsors of Terrorism or otherwise subject to US, EU and UK sanctions (Sanctioned Countries). In 2025 sanctions restrictions were insignificant to the group's financial condition and results of operations. bp monitors its activities with Sanctioned Countries, persons from Sanctioned Countries and individuals and companies subject to US, EU and UK sanctions and seeks to comply with applicable sanctions laws and regulations.

bp has a 29.99% interest in and operates the Shah Deniz field in Azerbaijan (Shah Deniz), has a 29.99% interest in and performs some operations for a related gas pipeline entity, South Caucasus Pipeline Company Limited (SCPC), and has a 23.99% non-operating interest in a related gas marketing entity, Azerbaijan Gas Supply Company Limited (AGSC). Naftiran Intertrade Co. Limited and NICO SPV Limited (collectively, NICO) have a 10% non-operating interest in each of Shah Deniz and SCPC and an 8% non-operating interest in AGSC. LUKOIL Overseas Shah Deniz Limited and LUKOIL Overseas Shah Deniz Midstream Limited (collectively, LUKOIL Shah Deniz) have a 19.99% non-operating interest in each of Shah Deniz and SCPC and a 15.99% non-operating interest in AGSC.

Shah Deniz, SCPC and AGSC continue in operation as they were excluded from the application of US Iran sanctions as they fall within the exception for certain natural gas projects under Section 603 of the Iran Threat Reduction and Syria Human Rights Act of 2012 (ITRA). Shah Deniz was excluded from the main operative provisions of the EU sanctions regulations following the snap-back of the EU Iran sanctions in September 2025. In September and October 2025, the UK issued two general licences permitting UK persons to conduct activities relating to Shah Deniz, SCPC and AGSC that would otherwise be prohibited by UK Iran and Russia sanctions respectively.

On 3 December 2018 bp entered into an agreement with, among others, SOCAR and NICO pursuant to which SOCAR pays to BP Exploration (Shah Deniz) Limited (BPXSD), as the Shah Deniz operator, compensation for NICO's waiver of its right to lift its share of Shah Deniz condensate. Such amounts are used to cover cash calls to NICO in respect of operating costs due from NICO to BPXSD. On 20 November 2025, a similar arrangement was entered into among bp, SOCAR and LUKOIL Shah Deniz. In November 2025, OFAC issued a licence in relation to these arrangements which is subject to further renewal before its expiry in April 2026.

In 2025 international sanctions against Syria were significantly lifted. bp terminated all sales of crude oil and petroleum products into Syria following the imposition in 2011 of further US and EU sanctions against Syria at the time, though bp continues to supply aviation fuel to non-governmental Syrian resellers outside of Syria.

bp has a joint arrangement in Cuba which imports, manufactures, markets and sells lubricants.

Since 2014, the US and the EU have imposed sanctions on certain sectors of the Russian economy (energy, finance and defence/military) and on certain individuals and entities, including Rosneft. These sectoral sanctions include restrictions on certain oil and gas activities in Russia including the provision of financial assistance, technical assistance, goods and services.

In response to Russia's military action in Ukraine in 2022, the US, EU, UK and many other countries have imposed broad economic and trade sanctions. The scope of these sanctions includes restrictions on dealing with designated individuals and entities (including Rosneft and Lukoil as of 2025); restrictions on the Russian financial sector; blocking economic activity in certain areas of Ukraine not controlled by the Ukrainian government; prohibitions in relation to investment in Russia; prohibitions and restrictions relating to Russian origin oil and oil products; prohibitions and restrictions relating to Russian origin iron and steel products, prohibitions and restrictions relating to Russian origin metals, prohibitions and restrictions on the provision of certain legal advisory services, prohibitions and restrictions in relation to transportation, including shipping and aircraft; trade controls limiting

the purchase and import of a wide range of goods from Russia, and export controls limiting the export of a wide range of goods and technical assistance to Russia.

In response, Russia has implemented counter-sanctions including restrictions on the divestment from Russian assets by foreign investors and restrictions on the payments of dividends to certain foreign shareholders, including those based in the UK, requiring such dividends to be paid in roubles into restricted bank accounts and a requirement for approval of the Russian government for transfers from any such bank accounts out of Russia.

The bp group does not source any materials directly from Russia. In 2022 bp discontinued sales of our products to customers in Russia. Such sales were not material to the bp group. As a result, outside of our shareholding in Rosneft and related businesses in Russia, direct impacts due to exposure to Russia have not been material and are not expected to be material in the future. bp continues to monitor Russia related sanctions and other international restrictions for any impacts on our businesses and the exit of our shareholding in Rosneft.

bp maintains bank accounts and has registered and paid required fees to maintain registrations of patents and trademarks in certain Sanctioned Countries.

bp has equity interests in non-operated joint arrangements with air fuel sellers, resellers, and fuel delivery services around the world. From time to time, the joint arrangement operator or other partners may sell or deliver fuel to airlines from Sanctioned Countries or flights to Sanctioned Countries, without bp's involvement.

bp has no control over the activities non-controlled associates may undertake in Sanctioned Countries or with persons from Sanctioned Countries.

Disclosure pursuant to ITRA Section 219

To our knowledge, none of bp's activities, transactions or dealings are required to be disclosed pursuant to ITRA Section 219, with the following possible exceptions.

In 2025 payments in relation to tax with an aggregate US dollar equivalent value of approximately \$3,000 were made from a bp trust account held with Tadvin Co. to Iranian public entities on behalf of BP Iran. No gross revenues or net profits are attributable to BP Iran's activities.

During 2025 the International Bank of Yemen (IBY) was sanctioned by the US. bp holds two bank accounts at IBY which were used to support historical operations in Yemen. Both accounts were dormant prior to the time IBY was sanctioned, became blocked accounts from that time and remain blocked as at the date of this report. Together, the accounts hold around \$60,000. In 2025, bp did not operate in Yemen and no gross revenues or net profits are attributable to any bp activities in Yemen.

Material contracts

On 4 April 2016 the district court approved the Consent Decree among BP Exploration & Production Inc., BP Corporation North America Inc., BP p.l.c., the United States and the states of Alabama, Florida, Louisiana, Mississippi and Texas (the Gulf states) which fully and finally resolved any and all natural resource damages (NRD) claims of the United States, the Gulf states, and their respective natural resource trustees and all Clean Water Act (CWA) penalty claims, and certain other claims of the United States and the Gulf states.

Concurrently, the definitive Settlement Agreement that bp entered into with the Gulf states (Settlement Agreement) with respect to State claims for economic, property and other losses became effective.

bp has filed the Consent Decree and the Settlement Agreement as exhibits to its *Annual Report and Form 20-F 2020* filed with the SEC. For further details of the Consent Decree and the Settlement Agreement, see Legal proceedings in *bp Annual Report and Form 20-F 2015*.

Property, plant and equipment

bp has freehold and leasehold interests in real estate and other tangible assets in numerous countries, but no individual property is significant to the group as a whole. For more on the significant subsidiaries★ of the group at 31 December 2025 and the group percentage of ordinary share capital see Financial statements – **Note 37**. For information on significant joint ventures★ and associates★ of the group see Financial statements – **Note 16** and **17**.

Related party transactions

Transactions between the group and its significant joint ventures and associates are summarized in Financial statements – **Note 16 and 17**. In the ordinary course of its business, the group enters into transactions with various organizations with which some of its directors or executive officers are associated. Except as described in this report, the group did not have any material transactions or transactions of an unusual nature with, and did not make loans to, related parties in the period commencing 1 January 2025 to 13 February 2026.

Corporate governance practices

In the US, bp ADSs are listed on the New York Stock Exchange (NYSE). The significant differences between bp's corporate governance practices as a UK company and those required by NYSE listing standards for US companies are listed as follows:

Independence

As set out on **page 77**, bp has adopted separate terms of reference for the board and each of its committees as part of its corporate governance framework. The terms of reference for the board and each of its committees are reviewed periodically. The board and audit committee terms of reference were last updated with effect from 1 January 2025, while the other three principal committees were last updated with effect from 25 July 2024. The terms of reference reflect the UK Corporate Governance Code approach to corporate governance. As such, the way in which bp makes determinations of directors' independence differs from the NYSE approach.

bp's corporate governance framework requires that all non-executive directors (NEDs) be determined by the board to be 'independent in character and judgement and free from any business or other relationship which could materially interfere with the exercise of their judgement'. The bp board has determined that, in its judgement, all of the NEDs are independent. In doing so, however, the board did not explicitly take into consideration the independence requirements outlined in the NYSE's listing standards.

Committees

bp has a number of board committees that are broadly comparable in purpose and composition to those required by NYSE rules for domestic US companies. For instance, bp has a remuneration (rather than a compensation) committee. bp also has an audit committee, which NYSE rules require for both US companies and foreign private issuers. These committees are composed solely of NEDs whom the board has determined to be independent, in the manner described above.

Each committee operates under its own terms of reference together with a set of terms applicable to all the committees (see the board committee reports on **pages 82-125** and **bp.com/governance**).

Under US securities law and the listing standards of the NYSE, bp is required to have an audit committee that satisfies the requirements of Rule 10A-3 under the Exchange Act and Section 303A.06 of the NYSE Listed Company Manual. bp's audit committee complies with these requirements. The bp audit committee does not have direct responsibility for the appointment, reappointment or removal of the independent auditors. Instead, it follows the UK Companies Act 2006 and the UK Corporate Governance Code by making recommendations to the board on these matters for it to put forward for shareholder approval at the AGM.

One of the NYSE's additional requirements for the audit committee states that at least one member of the audit committee is to have 'accounting or related financial management expertise'. The board determined that Tushar Morzaria possesses such expertise and also

possesses the financial and audit committee experience set forth in both the UK Corporate Governance Code and the SEC rules (see audit committee report on **page 84**). Mr Morzaria is the audit committee financial expert as defined in Item 16A of Form 20-F.

Summary of terms of reference for audit committee and remuneration committee

The audit committee's full terms of reference are available on our website at **bp.com/governance**. A summary of the committee's key responsibilities is provided below:

- Monitor and critically assess bp's financial statements and financial information, including the integrity of the financial reporting and related processes, context in which statements are made, compliance with relevant legal and regulatory requirements and financial reporting standards, including the Task Force on Climate-related Financial Disclosures (TCFD).
- Assess the going concern assumption and the longer-term viability statement as to bp's ability to continue to operate and meet its liabilities.
- Review and challenge the application and appropriateness of significant accounting policies and financial reporting estimates and judgements.
- Evaluate the risk to quality and effectiveness of the financial reporting process and, where requested by the board, advise whether the Annual Report and Accounts are fair, balanced and understandable.
- Review the affordability of distributions to shareholders.
- Oversee the appointment, remuneration, independence and performance of the external auditor and the integrity of the audit process as a whole, including the engagement of the external auditor to supply non-audit services to bp.
- Review the effectiveness of the internal audit function, bp's internal financial controls and its systems of internal control and risk management.
- Monitor the principal risks allocated to the committee by the board and review the mitigations proposed by management in respect of risks associated with bp internal financial controls and reporting responsibilities and such emerging risks that may fall within scope.
- Review the systems in place to enable those who work for bp to raise concerns about improprieties in financial reporting or other issues, and for those matters to be investigated.

The remuneration committee's full terms of reference are available on our website at **bp.com/governance**. A summary of the committee's key responsibilities is provided below:

- Recommend to the board the remuneration principles for the executive directors while considering remuneration and related policies for the employees below the board and leadership team.
- Set and approve the terms of appointment, fees and benefits for the chair of the board in accordance with the policy.
- Set and approve the terms of engagement, remuneration, benefits and termination of employment for the executive directors, leadership team, chief internal auditor, head of ethics and compliance and the company secretary in accordance with the policy.
- Prepare the annual remuneration report to shareholders to outline policy implementation.
- Approve the principles of any equity plan that requires shareholder approval.
- Ensure termination terms and payments to executive directors and the leadership team are appropriate and fair.
- Receive and consider regular updates on workforce views and engagement initiatives related to remuneration, insights and data from pay ratios and potential pay gaps as appropriate.
- Maintain appropriate dialogue with shareholders on remuneration matters.

Shareholder approval of equity compensation plans

The NYSE rules for US companies require that shareholders must be given the opportunity to vote on all equity-compensation plans and material revisions to those plans. bp complies with UK requirements that are similar to the NYSE rules. The board, however, does not explicitly take into consideration the NYSE's detailed definition of what are considered 'material revisions'.

Item 16J insider trading policy

The board has approved a share dealing policy governing the acquisition, sale and other dispositions of the company's securities by employees, contractors, officers and members of the board of the company.

The bp share dealing policy is included in this Form 20-F as Exhibit 11.2.

Code of ethics

The company has adopted a code of ethics for its chief executive officer, chief financial officer, group controller, and SVP internal audit whose roles are equivalent to the SEC roles as required by the provisions of Section 406 of the Sarbanes-Oxley Act of 2002 and the rules issued by the SEC. There have been no waivers from the code of ethics relating to any officers. A copy of the code of ethics can be found at bp.com/codeofethics.

The NYSE rules require that US companies adopt and disclose a code of business conduct and ethics for directors, officers and employees. bp has adopted a code of conduct, which applies to all employees, officers and members of the board. This was updated and published in January 2023, with certain elements further updated and published in October 2025. In addition, bp has adopted a code of ethics as described above for the chief executive officer, chief financial officer, group controller, and SVP internal audit as required by the SEC. bp considers that these codes and policies address the matters specified in the NYSE rules for US companies. During 2021 the board adopted a diversity, equity and inclusion policy, which requires it to encourage a diverse and inclusive working environment in the boardroom. The policy was most recently reviewed by the board in 2024, and amendments were made to reflect regulatory changes and market practice. The updated policy was then approved with effect from 1 January 2025.

Controls and procedures

Evaluation of disclosure controls and procedures

The company maintains 'disclosure controls and procedures', as such term is defined in Exchange Act Rule 13a-15(e), that are designed to ensure that information required to be disclosed in reports the company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms, and that such information is accumulated and communicated to management, including the company's group chief executive and chief financial officer, as appropriate, to allow timely decisions regarding required disclosure.

In designing and evaluating our disclosure controls and procedures, our management, including the group chief executive and chief financial officer, recognize that any controls and procedures, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the disclosure controls and procedures are met. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud within the company, if any, have been detected. Further, in the design and evaluation of our disclosure controls and procedures our management necessarily was required to apply its judgement in evaluating the costs and benefits of possible control and procedure design options. Also, we have investments in unconsolidated entities. As we do not control these entities, our disclosure controls and procedures with respect to such entities are necessarily substantially more limited than those we maintain with respect to our consolidated subsidiaries★. Because of the inherent limitations in a cost-effective control system, misstatements due to

error or fraud may occur and not be detected. The company's disclosure controls and procedures have been designed to meet, and management believes that they meet, reasonable assurance standards.

The company's management, with the participation of the company's interim group chief executive and chief financial officer, has evaluated the effectiveness of the company's disclosure controls and procedures pursuant to Exchange Act Rule 13a-15(b) as of the end of the period covered by this annual report. Based on that evaluation, the interim group chief executive and chief financial officer have concluded that the company's disclosure controls and procedures were effective at a reasonable assurance level.

Management's report on internal control over financial reporting

Management of bp is responsible for establishing and maintaining adequate internal control over financial reporting. bp's internal control over financial reporting is a process designed under the supervision of the principal executive and financial officers to provide reasonable assurance regarding the reliability of financial reporting and the preparation of bp's financial statements for external reporting purposes in accordance with IFRS.

As of the end of the 2025 fiscal year, management conducted an assessment of the effectiveness of internal control over financial reporting in accordance with the criteria in the Internal Control Integrated Framework issued in 2013 by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management has determined that bp's internal control over financial reporting as of 31 December 2025 was effective.

The company's internal control over financial reporting includes policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets; provide reasonable assurances that transactions are recorded as necessary to permit preparation of financial statements in accordance with IFRS and that receipts and expenditures are being made only in accordance with authorizations of management and the directors of bp; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of bp's assets that could have a material effect on our financial statements. bp's internal control over financial reporting as of 31 December 2025 has been audited by Deloitte LLP, an independent registered public accounting firm, as stated in their report appearing on [page 154](#) of *bp Annual Report and Form 20-F 2025*.

Changes in internal control over financial reporting

There were no changes in the group's internal control over financial reporting that occurred during the period covered by the Form 20-F that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

Cyber security

Governance

The board oversees bp's internal control and risk management framework. The board is supported by the safety and sustainability committee which oversees cyber security risk and received reports from bp's chief information security officer (CISO) on cyber security incidents at every committee meeting in 2025, including information on bp's response to incidents. This allows an ongoing assessment by the committee of the effectiveness of bp's overall cyber security programme. A session is held once a year to review bp's roadmap and progress for addressing cyber security risk. Read more in the safety and sustainability committee report on [page 82](#).

At management level, assessment and management of material risks from cyber security threats is led by bp's executive vice president of technology, a member of bp's leadership team with deep experience in bp's engineering and operations functions, with support from bp's CISO, who has over 20 years of experience in the information technology industry. bp's digital safety operational risk committee brings together additional senior members of bp's digital leadership team to assist in ensuring that cyber security risks across bp are

identified, understood, accurately quantified and are managed in accordance with bp's internal controls framework.

Risk management and strategy

bp has implemented a threat-focused strategy to assess cyber security risks and protect against, detect, respond to, and recover from cyber attacks. bp maintains internal teams focused on cyber security intelligence and emergency response to monitor the external threat landscape and the threats to bp's IT and operational technology infrastructure. bp partners with third-party specialists to augment its in-house capabilities as necessary. bp has a defined protocol for cyber incident notification based on severity and bp's internal cyber security teams brief the CISO, technology EVP, other senior leadership and relevant board and management committees about incidents on an as needed basis.

Cyber security risk management is integrated into bp's overall risk management process. bp's entities are required to identify, assess and report key risks, including cyber security risks, to relevant members of senior leadership. bp maintains additional procedures to manage cyber security risks related to third-party service providers, including conducting information security assessments for certain providers, providing relevant trainings for bp employees, and maintaining information security requirements for suppliers.

Our business strategy, results of operations and financial condition have not been materially affected by risks from cyber security threats, including as a result of previously identified cyber security incidents. For more information on our cyber security related risks, see Risk Factors on [page 67](#).

Principal accountant's fees and services

The audit committee has established policies and procedures for the engagement of the independent registered public accounting firm, Deloitte LLP, to render audit and certain assurance services. The policy provides for pre-approval by the audit committee of specifically defined audit, audit-related, non-audit and other services that are not prohibited by regulatory or other professional requirements. Deloitte is engaged for these services when its expertise and experience of bp are important. Most of this work is of an audit nature. The audit committee, CFO and group controller monitor overall compliance with bp's policy on audit-related and non-audit services, including whether the necessary pre-approvals have been obtained. The committee regularly reviews the policy, including in 2025, when it was updated to include clarification regarding bp's employment of current and former employees or partners of the auditor.

Under the policy, pre-approval is given for specific services within the following categories: i) audit-related services, such as those required by law or where the auditor is best placed to undertake such work on similar terms, ii) non-audit services required by law, such as reporting required by a regulatory authority, and iii) other services, such as additional assurance or updates on applicable law and accounting standards. bp operates a two-tier system for audit and non-audit services. For audit-related services, the audit committee has a pre-approved aggregate level, within which specific work may be approved by management. Non-audit services are pre-approved for management to authorize per individual engagement, but above a defined level must be approved by the chair of the audit committee or the full committee. The audit committee has delegated to the chair of the audit committee authority to approve permitted services provided that any decisions are reported to the committee at its next scheduled meeting. Any proposed service not included in the approved service list must be approved in advance of commencing the engagement by the audit committee chair or the full audit committee, depending on the level of fee payable.

The audit committee evaluates the performance of the auditor each year. The audit fees payable to Deloitte are reviewed by the committee in the context of other global companies for cost-effectiveness. The committee keeps under review the scope and results of audit work and the independence and objectivity of the auditor. External regulation and bp policy requires the auditor to rotate its lead audit partner every five years. See Financial statements – [Note 36](#) and the audit committee

report on [page 84](#) for details of fees for services provided by the auditor.

Additional Directors' report disclosures

This section of *bp Annual Report and Form 20-F 2025* forms part of the Directors' report. Certain information has been included in the Strategic report that would otherwise be required to be disclosed in the Directors' report, as noted below.

Indemnity provisions

In accordance with bp's Articles of Association, on appointment each director is granted an indemnity from the company in respect of liabilities incurred as a result of their office, to the extent permitted by law. These indemnities were in force throughout the financial year and at the date of this report. In respect of those liabilities for which directors may not be indemnified, the company maintained a directors' and officers' liability insurance policy throughout 2025. During the year, a review of the terms and scope of the policy was undertaken as part of the annual renewal. Although a director's defence costs may be met, neither the company's indemnity nor insurance provides cover in the event that the director is proved to have acted fraudulently or dishonestly. One of the group's subsidiaries★ is a trustee of the UK pension scheme. Each director of that subsidiary is granted an indemnity from the company in respect of liabilities incurred as a result of such a subsidiary's activities as a trustee of the pension scheme, to the extent permitted by law. These indemnities were in force throughout the financial year and as at the date of this report.

Financial risk management objectives and policies

The disclosures in relation to financial risk management objectives and policies, including the policy for hedging, are included in *How we manage risk* on [page 67](#), *Liquidity and capital resources* on [page 338](#) and *Financial statements – Notes 29 and 30*.

Exposure to price risk, credit risk, liquidity risk and cash flow risk

The disclosures in relation to exposure to price risk, credit risk, liquidity risk and cash flow risk are included in *Financial statements – Notes 29 and 30*.

Important events since the end of the financial year

Disclosures of the particulars of the important events affecting bp which have occurred since the end of the financial year are included in the Strategic report as well as in other places in the Directors' report.

Likely future developments in the business

An indication of the likely future developments in the business of the company is included in the Strategic report.

Research and development

Indications of our activities in the field of research and development are provided throughout the Strategic report and the Directors' report. See also [pages 12 and 189](#) for our expenditure on research and development.

Branches

As a global group our interests and activities are held or operated through subsidiaries, branches, joint arrangements★ or associates★ established in – and subject to the laws and regulations of – many different jurisdictions.

Employees

Disclosures in respect of how the directors have engaged with employees and had regard to their interests are included in *Our stakeholders and Key decisions* on [pages 79, 80 and 81](#).

The disclosures concerning policies in relation to the employment of disabled persons and employee involvement are included in *Sustainability – our people* on [page 57](#).

Employee share schemes

Certain shares held as a result of participation in some employee share plans carry voting rights. Voting rights in respect of such shares are exercisable via a nominee. Dividend waivers are in place in respect of unallocated shares held in employee share plan trusts.

Suppliers, customers and others

Disclosures in respect of how the directors have engaged with suppliers, customers and others in business relationships with the company are included in Our stakeholders on **pages 80-81**.

Change of control provisions

On 5 October 2015, the United States lodged with the district court in MDL 2179 a proposed Consent Decree between the United States, the Gulf states, BP Exploration & Production Inc., BP Corporation North America Inc. and BP p.l.c., to fully and finally resolve any and all natural resource damages claims of the United States, the Gulf states and their respective natural resource trustees and all Clean Water Act penalty claims, and certain other claims of the United States and the Gulf states. Concurrently, bp entered into a definitive Settlement Agreement with the five Gulf states (Settlement Agreement) with respect to state claims for economic, property and other losses. On 4 April 2016, the district court approved the Consent Decree, at which time the Consent Decree and Settlement Agreement became effective. The federal government and the Gulf states may jointly elect to accelerate the payments under the Consent Decree in the event of a change of control or insolvency of BP p.l.c., and the Gulf states individually have similar acceleration rights under the Settlement Agreement. For further details of the Consent Decree and the Settlement Agreement, see Legal proceedings in bp Annual Report and Form 20-F 2015.

Political donations, expenditure and contributions

Disclosures in relation to political donations, expenditure and contributions are included on **page 58**.

Greenhouse gas emissions, energy consumption and energy efficiency

Disclosures in relation to greenhouse gas emissions, energy consumption and energy efficiency are included in Sustainability on **pages 39-40**.

Disclosures required under UK Listing Rule 6.6.1R

The information required to be disclosed by UK Listing Rule 6.6.1R can be located as set out below:

Information required	Page
(1) Amount of interest capitalized	189
(2), (3)	Not applicable
(4), (5) Waiver of director emoluments	Not applicable
(6) - (10)	Not applicable
(11), (12) Dividend waivers	362
(13)	Not applicable

Cautionary statement

In order to utilize the 'safe harbor' provisions of the United States Private Securities Litigation Reform Act of 1995 (the 'PSLRA') and the general doctrine of cautionary statements, bp is providing the following cautionary statement.

This document contains certain forecasts, projections and forward-looking statements that is, statements related to future, not past, events and circumstances - with respect to the financial condition, results of operations and businesses of bp and certain of the plans and objectives of bp with respect to these items. These statements may generally, but not always, be identified by the use of words such as 'will',

'expects', 'is expected to', 'aims', 'should', 'may', 'objective', 'is likely to', 'intends', 'believes', 'anticipates', 'plans', 'we see' or similar expressions. In particular, among other statements, (i) certain statements in the Chair's letter (**page 4**), Interim chief executive officer's letter (**page 5**), the Strategic report (inside front cover and **pages 1-71**), Additional disclosures (**pages 334-363**) and Shareholder information (**pages 364-374**), including but not limited to statements under the headings 'Energy Outlook', 'Our strategy', 'Consistency with the Paris goals', 'Our business model', 'Our financial frame', '2026 guidance' 'Outlook for 2026', 'Our investment process' and '2026 shareholder calendar' and including but not limited to statements regarding: plans and expectations relating to business, financial performance, results of operations, cash flow and allocation of capital expenditure; plans and expectations regarding bp's financial frame (including annual dividend increases, net debt, credit rating, capital expenditures and distribution of operating cash flow as dividends and share buybacks), balance sheet, working capital, operating cash flow, return on average capital employed (ROACE), liquidity, capital discipline, cost base, future shareholder distributions, amount, timing or use of payments related to divestments and other proceeds (including expectations and plans relating to the Castrol divestment and allocation of the expected proceeds), future dividend payments and progress towards our cost saving targets; plans and expectations regarding share buybacks, allocation and use of excess cash; plans and expectations regarding bp's 2026 guidance (including with respect to reported and underlying upstream production, growth of bp's customers businesses, products refining margins and refinery turnaround activity); plans and expectations regarding total capital expenditure, depreciation, depletion and amortization, divestments and other proceeds, Gulf of America oil spill payments, other businesses & corporate underlying annual charge, and the effective tax rate and the underlying effective tax rate; plans and expectations regarding bp's engagement plans and programs and their impact on bp's results of operations and financial position; plans and expectations regarding bp's four primary targets (including adjusted free cash flow growth, net debt, structural cost reduction and ROACE) and reporting of bp's progress towards those targets; assumptions regarding interest rates and broader macroeconomic conditions; plans and expectations relating to bp's investor proposition including those to grow shareholder value and simplify and strengthen bp; plans and expectations relating to bp's investment process, strategy and capital investment, including future capital investment allocation, expected IRR, access to capital and the restructuring of certain investments; plans and expectations relating to bp's intra-group funding and liquidity arrangements; plans and expectations relating to bp's ability to meet contractual obligations; expectations regarding inflation, price volatility, refining margins and price assumptions; plans and expectations relating to risk, including risk management processes and climate-related risks; plans, expectations and projections regarding bp's oil and gas business, including related investment plans and their impact on production and cash flow, oil and gas prices, operational emissions, oil and gas production targets, and future divestments; plans and expectations regarding bp's customers and products business, including investment plans and growth in aviation, biofuels and refineries; plans and expectations regarding bp's low carbon energy business, including the growth and decarbonization of the offshore wind and hydrogen and CCS businesses; plans and expectations regarding bp's ST&S business, including relating to electrification of the energy systems and decarbonization of electricity; plans and expectations related to the energy transition (including scenario analysis), investments in transition businesses, reduction of operational carbon intensity, climate change, sustainability (including bp's sustainability aims), greenhouse gas emissions, management, decarbonization, net zero ambition and aims, and related laws and regulations; plans and expectations regarding bp's focus on biodiversity and water use, including bp's freshwater use, bp's freshwater management approach, bp's ability to address water-related business risk and bp's freshwater withdrawal in stressed catchments; plans and expectations regarding projects, joint ventures, partnerships, agreements and memoranda of understanding with governments, commercial entities and other third party partners (including, but not limited to, the Gelsenkirchen refinery, the Green Canyon Block 584, the Tiber-Guadalupe project, the Atlantis Drill Center 1 expansion project, the NZT and NEP projects, the Ginger project, the KGD6 infills wells

project, the Shah Deniz Compression, the Atlantis Major Facility Expansion, the Kirkuk redevelopment project, the Juniper Wells, the Greater Western Flank 4 project, the Argos Southwest Extension project, the Murlach project, the Etlas joint venture, Lightsource bp., the Alto de Cabo Frio Central block, the Bumerangue project, the Atlantic LNG facility, the Agogo Integrated West Hub Project, offshore Blocks 1/14, 14 and 14K in the Lower Congo Basin, the five-well programme in the Mediterranean Sea, the agreement between State Oil Company of the Azerbaijan Republic and bp and subsequently approved development plans in regard to the Karabagh field, the agreement between bp and ONGC in relation to Mumbai High field and the Browse LNG Joint Venture); expectations regarding contingent liabilities, legal and trial proceedings, court decisions, potential investigations and civil actions by regulators, government entities and/or other entities or parties, and the timing and potential impact of such proceedings, settlement agreements relating to such proceedings and bp's intentions in respect thereof; plans and expectations regarding relationships with governments, customers, partners, suppliers, communities and key stakeholders; plans and expectations regarding upstream production and downstream performance and returns; plans and expectations regarding bp's external audit tender process; plans and expectations regarding the appointment and succession plans of bp's directors; plans and expectations regarding bp's long-term viability, including ability to continue in operation and meet liabilities; expectations regarding bp's refining assets, including their useful economic lives and depreciation; expectations regarding the impact of emissions costs on bp's oil and gas CGU carrying values; expectations regarding the impact of the energy transition on the recoverable amount of property, plant and equipment and goodwill in the oil and gas industry; expectations regarding the timing of production of bp's reserves and resources; expectations regarding the impact of the German tax legislation on bp's tax obligations; plans and expectations regarding the adoption and impact of the amendments to IFRS and related elections; plans and expectations regarding employee share plans, funded defined benefit plans and other post-employment benefits; expectations regarding impact of international trade sanctions; plans and expectations regarding operations and safety; expectations regarding the structure of energy demand; plans and expectations regarding the competitiveness and value of bp's refineries; plans and expectations relating to bp's research and development spend and outcomes; expectations related to changes laws, regulations and policies; and plans and expectations regarding bp's shareholder calendar.

By their nature, forward-looking statements involve risk and uncertainty because they relate to events and depend on circumstances that will or may occur in the future and are outside the control of bp.

Actual results or outcomes may differ materially from those expressed in such statements, depending on a variety of factors, including: the extent and duration of the impact of current market conditions including the volatility of oil prices, the effects of bp's plan to exit its shareholding in Rosneft and other investments in Russia, overall global economic and business conditions impacting bp's business and demand for bp's products as well as the specific factors identified in the discussions accompanying such forward-looking statements; changes in consumer preferences and societal expectations; the pace of development and adoption of alternative energy solutions; developments in policy, law, regulation, technology and markets, including societal and investor sentiment related to the issue of climate change; the receipt of relevant third party and/or regulatory approvals including ongoing approvals required for the continued developments of approved projects; the timing and level of maintenance and/or turnaround activity; the timing and volume of refinery additions and outages; the timing of bringing new fields onstream; the timing, quantum and nature of certain acquisitions and divestments; future levels of industry product supply, demand and pricing, including supply growth in North America and continued base oil and additive supply shortages; OPEC+ quota restrictions; PSA and TSC effects; operational and safety problems; potential lapses in product quality; economic and financial market conditions generally or in various countries and regions; political stability and economic growth in relevant areas of the world; changes in laws and governmental regulations and policies, including related to climate change; changes in social attitudes and

customer preferences; regulatory or legal actions including the types of enforcement action pursued and the nature of remedies sought or imposed; the actions of prosecutors, regulatory authorities and courts; delays in the processes for resolving claims; amounts ultimately payable and timing of payments relating to the Gulf of America oil spill; exchange rate fluctuations; development and use of new technology; recruitment and retention of a skilled workforce; the success or otherwise of partnering; the actions of competitors, trading partners, contractors, subcontractors, creditors, rating agencies and others; bp's access to future credit resources; business disruption and crisis management; the impact on bp's reputation of ethical misconduct and non-compliance with regulatory obligations; trading losses; major uninsured losses; the possibility that international sanctions or other steps taken by governmental or any other relevant persons may impact bp's ability to sell its interests in Rosneft, or the price for which bp could sell such interests; the actions of contractors; natural disasters and adverse weather conditions; changes in public expectations and other changes to business conditions; wars and acts of terrorism; cyber-attacks or sabotage; and those factors discussed elsewhere in this report including under Risk factors (page 62). In addition to factors set forth elsewhere in this report, those set out above are important factors, although not exhaustive, that may cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements.

Cautionary note to US investors – This document contains references to non-proved reserves and production outlooks based on non-proved reserves that the SEC's rules prohibit us from including in our filings with the SEC. U.S. investors are urged to consider closely the disclosures in our Form 20-F, SEC File No. 1-06262. This form is available on our website at www.bp.com. You can also obtain this form from the SEC's website at www.sec.gov.

Statements regarding competitive position

Statements referring to bp's competitive position are based on the company's belief and, in some cases, rely on a range of sources, including investment analysts' reports, independent market studies and bp's internal assessments of the relevant market based on publicly available information about the financial results and performance of market participants.

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Share prices and listings

Markets and market prices

The primary market for the company's ordinary shares (trading symbol 'BP'), 8% cumulative first preference shares (trading symbol 'BP.A') and 9% cumulative second preference shares (trading symbol 'BP.B') is the London Stock Exchange (LSE). The company's ordinary shares are a constituent element of the Financial Times Stock Exchange 100 Index.

In the US, the company's securities are listed and traded on the New York Stock Exchange (NYSE) in the form of American Depositary Shares (ADSs) (trading symbol 'BP'), for which JPMorgan Chase Bank, N.A. is the depositary (the Depositary) and transfer agent. The Depositary's principal office is 270 Park Avenue, Floor 8, New York, NY, 10017, US. Each ADS represents six ordinary shares. ADSs are evidenced by American depositary receipts (ADRs), which may be issued in either certificated or book entry form.

The company delisted from the Frankfurt Stock Exchange on 23 April 2025.

On 13 February 2026, 697,484,895 ADSs (equivalent to approximately 4,184,909,371 ordinary shares or some 26.65% of the total issued share capital, excluding shares held in treasury) were outstanding and were held by approximately 55,047 ADS holders. Of these, about 54,410 had registered addresses in the US at that date. One of the registered holders of ADSs represents approximately 1,278,868 underlying holders.

On 13 February 2026, there were approximately 186,939 ordinary shareholders. Of these shareholders, around 1,449 had registered addresses in the US and held a total of some 3,534,557 ordinary shares. On 13 February 2026, there were approximately 1,029 preference shareholders. Of these shareholders, around 14 had registered addresses in the US and held a total of some 2,773 preference shares.

Since a number of the ordinary shares and ADSs were held by brokers and other nominees, the number of holders in the US may not be representative of the number of beneficial holders or their respective country of residence.

Dividends

The company's current policy is to pay interim dividends on a quarterly basis on its ordinary shares.

Our policy is also to announce dividends for ordinary shares in US dollars and state an equivalent sterling dividend. Dividends on the company's ordinary shares will be paid in sterling and on the company's ADSs in US dollars. The rate of exchange used to determine the sterling amount equivalent is the average of the market exchange rates in London over three business days in advance of the sterling equivalent announcement date. The directors may choose to declare dividends in any currency provided that a sterling equivalent is announced. It is not the company's intention to change its current policy of announcing dividends on ordinary shares in US dollars.

Information regarding dividends announced and paid by the company on ordinary shares and preference shares is provided in the consolidated Financial statements – **Note 10**.

A Scrip Dividend Programme (Scrip Programme) was approved by shareholders in 2010 and was renewed for a further three years at the 2024 AGM. It enabled the company's ordinary shareholders and ADS holders to elect to receive dividends by way of new fully paid ordinary shares (or ADSs in the case of ADS holders) instead of cash. The operation of the Scrip Programme is always subject to the directors' decision to make the Scrip Programme offer available in respect of any particular dividend.

The company announced on 29 October 2019 and as part of all subsequent quarterly results announcements made since, that the board had suspended the Scrip Programme in respect of those quarterly dividends. The company does not expect to offer a scrip election for the foreseeable future. Ordinary shareholders and ADS holders (subject to certain exceptions) may be able to participate in dividend reinvestment plans. Any decisions with respect to future dividends will be made by the board of BP p.l.c. following the end of each quarter.

Future dividends will be dependent on future earnings, the financial condition of the group, the Risk factors set out on **page 67** and other matters that may affect the business of the group set out in Our strategy on **page 8** and in Liquidity and capital resources on **page 338**.

The quarterly dividend which is expected to be paid on 27 March 2026 in respect of the fourth quarter 2025 is 8.320 cents per ordinary share (\$0.49920 per American Depositary Share (ADS)). The corresponding amount in sterling will be announced on 17 March 2026.

The following table shows dividends announced and paid by the company per ADS for the past five years.

Dividends per ADS ^a		March	June	September	December	Total
2021	UK pence	22.61	22.27	23.72	24.63	92.23
	US cents	31.50	31.50	32.76	32.76	128.52
2022	UK pence	24.96	26.13	31.01	29.64	111.74
	US cents	32.76	32.76	36.04	36.04	137.60
2023	UK pence	33.30	31.85	34.39	34.42	133.97
	US cents	39.66	39.66	43.62	43.62	166.56
2024	UK pence	34.15	34.10	36.30	37.78	142.33
	US cents	43.62	43.62	48.00	48.00	183.24
2025	UK pence	37.06	35.40	37.17	37.44	147.07
	US cents	48.00	48.00	49.92	49.92	195.84

^a Dividends announced and paid by the company on ordinary and preference shares are provided in the consolidated Financial statements – Note 10.

There are no UK foreign exchange controls or other restrictions on the import or export of capital by, or on the payment of dividends to, non-resident holders of BP p.l.c. shares, or that materially affect the conduct of BP p.l.c.'s operations, other than restrictions applicable to certain countries and persons subject to UN, US, UK, or EU economic sanctions, to the extent these restrictions can be complied with in law.

Shareholder taxation information

This section describes the material US federal income tax and UK taxation consequences of owning ordinary shares or ADSs to a US holder who holds the ordinary shares or ADSs as capital assets for tax purposes. This section does not discuss tax consequences arising under the Medicare contribution tax on net investment income or the alternative minimum tax. It also does not apply inter alia to members of special classes of holders some of which may be subject to other rules, including: tax-exempt entities, life insurance companies, dealers in securities, traders in securities that elect a mark-to-market method of accounting for securities holdings, holders that, actually or constructively, hold 10% or more of the company's shares (as measured by voting power or value), holders that hold the shares or ADSs as part of a straddle or a hedging or conversion transaction, holders that purchase or sell the shares or ADSs as part of a wash sale for US federal income tax purposes, or holders whose functional currency is not the US dollar. In addition, if a partnership holds the shares or ADSs, the US federal income tax treatment of a partner will generally depend on the status of the partner and the tax treatment of the partnership and may not be described fully below.

A US holder is any beneficial owner of ordinary shares or ADSs that is for US federal income tax purposes (1) a citizen or resident of the US, (2) a US domestic corporation, (3) an estate whose income is subject to US federal income taxation regardless of its source, or (4) a trust if a US court can exercise primary supervision over the trust's administration and one or more US persons are authorized to control all substantial decisions of the trust.

This section is based on the tax laws of the United States, including the Internal Revenue Code of 1986, as amended, its legislative history, existing and proposed US Treasury regulations thereunder, published rulings and court decisions, and the taxation laws of the UK, all as currently in effect, as well as the income tax convention between the US and the UK that entered into force on 31 March 2003 (the Treaty). These laws are subject to change, possibly on a retroactive basis. This section further assumes that each obligation under the terms of the deposit

agreement relating to bp ADSs and any related agreement will be performed in accordance with its terms.

For purposes of the Treaty and the estate and gift tax convention between the US and the UK that entered into force on 11 November 1979 (the Estate Tax Convention) and for US federal income tax and UK taxation purposes, a holder of ADRs evidencing ADSs will be treated as the owner of the company's ordinary shares represented by those ADRs. Exchanges of ordinary shares for ADRs and ADRs for ordinary shares generally will not be subject to US federal income tax or to UK taxation other than stamp duty or stamp duty reserve tax, as described below.

Investors should consult their own tax advisor regarding the US federal, state and local, UK and other tax consequences of owning and disposing of ordinary shares and ADSs in their particular circumstances, and in particular whether they are eligible for the benefits of the Treaty in respect of their investment in the shares or ADSs.

Taxation of dividends

UK taxation

Under current UK taxation law, no withholding tax will be deducted from dividends paid by the company, including dividends paid to US holders. A US holder that is a company resident for tax purposes in the UK or trading in the UK through a permanent establishment generally will not be taxable in the UK on a dividend it receives from the company. A US holder who is an individual resident for tax purposes in the UK is subject to UK tax on dividends received from the company, including dividends paid but reinvested under any dividend reinvestment plan for ordinary shareholders, that are in excess of the annual dividend allowance. However, if the shareholder's dividend income is covered by their personal allowance of £12,570 (for 2025/26) after taking into account other sources of income, no UK tax will be payable on their dividend income.

For 2025/26 the dividend allowance is £500 which means there is no UK tax due on the first £500 of dividends received. Dividends above this level are subject to tax at 8.75% for basic tax payers, 33.75% for higher rate tax payers and 39.35% for additional rate tax payers.

Although the first £500 of dividend income is not subject to UK income tax, it does not reduce the total income for tax purposes. Dividends within the dividend allowance still count towards basic or higher rate bands, and may therefore affect the rate of tax paid on dividends received in excess of the £500 allowance. For instance, if an individual has an annual gross salary of £55,000 and also receives a dividend of £12,000 they will be subject to the following scenario. The individual's personal allowance and the basic rate tax band will be used up by the gross salary. The remaining part of the salary and the whole of the dividend will be subject to tax at the higher rate, although the dividend allowance will reduce the amount of dividend subject to tax. The dividend of £12,000 will be reduced by the dividend allowance of £500 leaving taxable dividend income of £11,500. The dividend will be taxed at 33.75% so that the total tax payable on the dividends is £3,881.

An individual US holder should inform HM Revenue & Customs each year for which that US holder receives dividends chargeable to UK tax. If a US holder needs to report to HMRC and already files a self-assessment tax return in the UK, the US holder should include the dividend income in that return and submit it by the deadline. If the US holder does not file a self-assessment return, the US holder should inform HM Revenue & Customs by 5 October. How the income is reported and taxed will depend on the size of the dividend income for that tax year. If the US holder received dividend income up to £10,000, the US holder can inform HM Revenue & Customs by either asking to update his or her tax code or contacting the helpline. If the US holder's dividend income is over £10,000, he or she will need to fill out a self-assessment tax return. For this, the US holder will need to register for self-assessment by 5 October. A US holder will not need to report his or her dividend income to HM Revenue & Customs if the amount is within his or her dividend allowance for that tax year.

US federal income taxation

A US holder is subject to US federal income taxation on the gross amount of any dividend paid by the company (including dividends paid but reinvested under the Global Invest Direct (GID) Dividend Reinvestment Plan for ADS holders) out of its current or accumulated earnings and profits (as determined for US federal income tax purposes). Dividends paid to a non-corporate US holder that constitute qualified dividend income will be taxable to the holder at a preferential rate, provided that the holder has a holding period in the ordinary shares or ADSs of more than 60 days during the 121-day period beginning 60 days before the ex-dividend date and meets other holding period requirements. Dividends paid by the company with respect to the ordinary shares or ADSs will generally be qualified dividend income.

For US federal income tax purposes, a dividend must be included in income when the US holder, in the case of ordinary shares, or the Depository, in the case of ADSs, actually or constructively receives the dividend and will not be eligible for the dividends-received deduction generally allowed to US corporations in respect of dividends received from other US corporations. US ADS holders should consult their own tax advisor regarding the US tax treatment of the dividend fee in respect of dividends. Dividends will generally be income from sources outside the US and generally will be 'passive category income' for purposes of computing a US holder's foreign tax credit limitation.

As noted above in UK taxation, a US holder will not be subject to UK withholding tax. Accordingly, the receipt of a dividend will not entitle the US holder to a foreign tax credit.

The amount of the dividend distribution on the ordinary shares that is paid in pounds sterling will be the US dollar value of the pounds sterling payments made, determined at the spot pounds sterling/US dollar rate on the date the dividend is distributed, regardless of whether the payment is, in fact, converted into US dollars. Generally, any gain or loss resulting from currency exchange fluctuations during the period from the date the pounds sterling dividend payment is distributed to the date the payment is converted into US dollars will be treated as ordinary income or loss and will not be eligible for the preferential tax rate on qualified dividend income. The gain or loss generally will be income or loss from sources within the US for foreign tax credit limitation purposes.

Distributions in excess of the company's earnings and profits, as determined for US federal income tax purposes, will be treated as a return of capital to the extent of the US holder's basis in the ordinary shares or ADSs and thereafter as capital gain, subject to taxation as described in 'Taxation of capital gains – US federal income taxation' section below.

In addition, the taxation of dividends may be subject to the rules for passive foreign investment companies (PFIC), described below under 'Taxation of capital gains – US federal income taxation'. Distributions made by a PFIC do not constitute qualified dividend income and are not eligible for the preferential tax rate applicable to such income.

Taxation of capital gains

UK taxation

A US holder may be liable for both UK and US tax in respect of a gain on the disposal of ordinary shares or ADSs if the US holder is (1) resident for tax purposes in the UK at the date of disposal, (2) person who (a) has left the UK; (b) was resident in the UK for four out of the seven years before the year of departure; (c) acquired the shares before leaving the UK; (d) sold the shares while not resident in the UK; and (e) returns to the UK within a period not exceeding five complete tax years after departure, (3) a US domestic corporation resident in the UK by reason of its business being managed or controlled in the UK, or (4) a citizen of the US that carries on a trade or profession or vocation in the UK through a branch or agency or a corporation that carries on a trade, profession or vocation in the UK, through a permanent establishment, and that has used, held, or acquired the ordinary shares or ADSs for the purposes of such trade, profession or vocation of such branch, agency or permanent establishment.

Under the Treaty, capital gains on dispositions of ordinary shares or ADSs generally will be subject to tax only in the jurisdiction of residence

of the relevant holder as determined under both the laws of the UK and the US and as required by the terms of the Treaty.

Under the Treaty, individuals who are residents of either the UK or the US and who have been residents of the other jurisdiction (the US or the UK, as the case may be) at any time during the six years immediately preceding the relevant disposal of ordinary shares or ADSs may be subject to tax with respect to capital gains arising from a disposition of ordinary shares or ADSs of the company not only in the jurisdiction of which the holder is resident at the time of the disposition but also in the other jurisdiction.

The UK Capital Gains Tax rate is dependent on the level of an individual's taxable income. For 2025/26, where total taxable income and gains after all allowable deductions are less than the upper limit of the basic rate income tax band of £37,700 (for 2025/26), the rate of Capital Gains Tax will be 18%. For gains (and any parts of gains) above that limit the rate will be 24%.

An individual may be entitled to a capital gains tax free allowance, depending on that individual's circumstances (in particular, election for the remittance basis of taxation). For individuals who are entitled to the allowance for 2025/26, this has been set at £3,000. Corporation tax on chargeable gains is levied at 25% for companies from 1 April 2023.

US federal income taxation

A US holder who sells or otherwise disposes of ordinary shares or ADSs will recognize a capital gain or loss for US federal income tax purposes equal to the difference between the US dollar value of the amount realized on the disposition and the US holder's tax basis, determined in US dollars, in the ordinary shares or ADSs. Any such capital gain or loss generally will be long-term gain or loss, subject to tax at a preferential rate for a non-corporate US holder, if the US holder's holding period for such ordinary shares or ADSs exceeds one year. The tax basis of shares acquired through reinvested dividends under the GID Dividend Reinvestment Plan for ADS holders is equal to the fair market value of the stock on the investment date. The holding period for shares acquired under the plan begins the day after the applicable investment date.

Gain or loss from the sale or other disposition of ordinary shares or ADSs will generally be income or loss from sources within the US for foreign tax credit limitation purposes. The deductibility of capital losses is subject to limitations.

We do not believe that ordinary shares or ADSs will be treated as stock of a passive foreign investment company (PFIC) for US federal income tax purposes, but this conclusion is a factual determination that is made annually and thus is subject to change. If we are treated as a PFIC, unless a US holder elects to be taxed annually on a mark-to-market basis with respect to ordinary shares or ADSs, any gain realized on the sale or other disposition of ordinary shares or ADSs would in general not be treated as capital gain. Instead, a US holder would be treated as if he or she had realized such gain ratably over the holding period for ordinary shares or ADSs and would be taxed at the highest tax rate in effect for each such year to which the gain was allocated, in addition to which an interest charge in respect of the tax attributable to each such year would apply. Certain 'excess distributions' would be similarly treated if we were treated as a PFIC.

Additional tax considerations

Scrip Programme

Until the publication of the 2019 third quarter results, the company had an optional Scrip Programme, wherein holders of bp ordinary shares or ADSs could elect to receive any dividends in the form of new fully paid ordinary shares or ADSs of the company instead of cash. Please consult your tax advisor for the consequences to you.

UK inheritance tax

The Estate Tax Convention applies to UK inheritance tax. ADSs held by an individual who is domiciled for the purposes of the Estate Tax Convention in the US and is for the purposes of the Estate Tax Convention a national of the US and not a national of the UK will not be subject to UK inheritance tax on the individual's death or on transfer during the individual's lifetime unless, among other things, the ADSs are

part of the business property of a permanent establishment situated in the UK or a fixed base used for the performance of independent personal services. In the exceptional case where ADSs are subject to both inheritance tax and US federal gift or estate tax, the Estate Tax Convention generally provides for tax payable in the US to be credited against tax payable in the UK or for tax paid in the UK to be credited against tax payable in the US, based on priority rules set forth in the Estate Tax Convention.

UK stamp duty and stamp duty reserve tax

The statements below relate to what is understood to be the current practice of HM Revenue & Customs in the UK under existing law.

Provided that any instrument of transfer is not executed in the UK and remains at all times outside the UK and the transfer does not relate to any matter or thing done or to be done in the UK, no UK stamp duty is payable on the acquisition or transfer of ADSs. Neither will an agreement to transfer ADSs in the form of ADRs give rise to a liability to stamp duty reserve tax.

Purchases of ordinary shares, as opposed to ADSs, through the CREST system of paperless share transfers will be subject to stamp duty reserve tax at 0.5%. The charge will arise as soon as there is an agreement for the transfer of the shares (or, in the case of a conditional agreement, when the condition is fulfilled). The stamp duty reserve tax will apply to agreements to transfer ordinary shares even if the agreement is made outside the UK between two non-residents. Purchases of ordinary shares outside the CREST system are subject either to stamp duty at a rate of £5 per £1,000 (or part, unless the stamp duty is less than £5, when no stamp duty is charged), or stamp duty reserve tax at 0.5%. Stamp duty and stamp duty reserve tax are generally the liability of the purchaser.

A subsequent transfer of ordinary shares to the Depository's nominee will give rise to further stamp duty at the rate of £1.50 per £100 (or part) or stamp duty reserve tax at the rate of 1.5% of the value of the ordinary shares at the time of the transfer. For ADR holders electing to receive ADSs instead of cash, after the 2012 first quarter dividend payment, HM Revenue & Customs no longer seeks to impose 1.5% stamp duty reserve tax on issues of UK shares and securities to non-EU clearance services and depository receipt systems.

Major shareholders

The disclosure of certain major and significant shareholdings in the share capital of the company is governed by the Companies Act 2006, the UK Financial Conduct Authority's Disclosure Guidance and Transparency Rules (DTR) and the US Securities Exchange Act of 1934.

Register of members holding bp ordinary shares as at 31 December 2025

Range of holdings	Number of ordinary shareholders	Percentage of total ordinary shareholders	Percentage of total ordinary share capital excluding shares held in treasury
1-200	50,785	27.06	0.02
201-1,000	60,165	32.05	0.21
1,001-10,000	67,106	35.75	1.35
10,001-100,000	8,482	4.52	1.13
100,001-1,000,000	648	0.35	1.54
Over 1,000,000 ^a	522	0.28	95.76
Totals	187,708	100	100

^a Includes JPMorgan Chase Bank, N.A. holding 26.40% of the total ordinary issued share capital (excluding shares held in treasury) as the approved depository for ADSs, a breakdown of which is shown in the table below.

Register of holders of American depositary shares (ADSs) as at 31 December 2025^a

Range of holdings	Number of ADS holders	Percentage of total ADS holders	Percentage of total ADSs
1-200	33,191	58.98	0.26
201-1,000	15,026	26.70	1.04
1,001-10,000	7,774	13.81	2.86
10,001-100,000	277	0.49	0.66
100,001-1,000,000	3	0.01	0.08
Over 1,000,000 ^b	2	0.00	95.10
Totals	56,273	100	100

a One ADS represents six 25 cent ordinary shares.

b One holder of ADSs represents 1,278,163 approx. underlying shareholders.

As at 31 December 2025 there were also 1,038 preference shareholders. Preference shareholders represented 0.54% and ordinary shareholders represented 99.46% of the total issued nominal share capital of the company (excluding shares held in treasury) as at that date.

As at 13 February 2026, the 8% preference shares and 9% preference shares in issue comprised only 0.31% and 0.23% respectively of the company's total issued nominal share capital (excluding shares held in treasury) the rest being ordinary shares.

Substantial shareholders

The following table shows holdings of 3% or more voting rights in ordinary shares of 25 cents in BP p.l.c. as per the most recent notification of each respective holder to bp under DTR 5. The percentage of voting rights detailed below was calculated as at the date of the relevant disclosures.

	As at 31 December 2025		As at 13 February 2026	
	Number of voting rights	Percentage of capital	Number of voting rights	Percentage of capital
BlackRock, Inc.	1,504,412,502	7.37	1,504,412,502	7.37
Elliott Investment Management, L.P.	806,743,232	5.00	806,743,232	5.00
Norges Bank ^a	641,036,583	3.99	641,036,583	3.99

a In the last three financial years and up to the date of this report, BP p.l.c. received six notifications from Norges Bank relating to changes in its voting rights holdings, as follows: (1) the percentage of voting rights exceeding 3% on 9 February 2023; (2) exceeding 4% on 12 September 2024; (3) falling below 4% on 20 September 2024; (4) exceeding 4% again on 23 September 2024; (5) falling below 4% on 11 April 2025; and (6) falling below 3% on 2 January 2026.

There are no current disclosable interests in holdings of 3% or more voting rights in 8% cumulative first preference shares of £1 each and 9% cumulative second preference shares of £1 each.

Largest registered shareholders

Under the US Securities Exchange Act of 1934 bp is aware of the following interests as at 13 February 2026.

Ordinary shares of \$0.25 in BP p.l.c.:

Holder	Holding of ordinary shares	Percentage of ordinary share capital excluding shares held in treasury
JPMorgan Chase Bank N.A., depositary for ADSs, through its nominee Guaranty Nominees Limited	4,184,909,371	26.65
BlackRock, Inc.	1,429,585,141	9.11
Vanguard Group Holdings	840,449,006	5.35
Norges Bank Investment Management (NBIM)	460,072,521	2.93

8% cumulative first preference shares of £1 each in BP p.l.c.:

Holder	Holding of 8% cumulative first preference shares	Percentage of class
Hargreaves Lansdown Asset Management Limited	1,384,537	19.14
Interactive Investor Share Dealing Services	1,114,005	15.40
Halifax Share Dealing Services	625,928	8.65
Barclays, Plc.	547,371	7.57
Canaccord Genuity Group Inc.	532,260	7.36
AJ Bell Securities, Ltd.	482,911	6.68
Ameriprise Financials, Inc.	287,500	3.97
HSBC Holdings Plc	247,915	3.43

9% cumulative second preference shares of £1 each in BP p.l.c.:

Holder	Holding of 9% cumulative second preference shares	Percentage of class
Hargreaves Lansdown Asset Management Limited	941,599	17.20
Interactive Investor Share Dealing Services	695,214	12.70
AJ Bell Securities, Ltd	640,890	11.71
Canaccord Genuity Group Inc.	359,000	6.56
J. Safra Sarasin Group	345,500	6.31
Halifax Share Dealing Services	337,325	6.16
Ameriprise Financial, Inc.	250,000	4.57
Barclays, PLC.	188,886	3.45
HSBC Holdings Plc	172,325	3.15
Charles Stanley Group Plc	165,697	3.03

The company's major shareholders' voting rights may differ to their total interest and can be found under the 'Substantial shareholders' heading above where voting rights are over 3%.

Annual general meeting (AGM)

The 2026 AGM is scheduled to be held on Thursday 23 April 2026 at 11:00am BST. A separate notice convening the meeting is distributed to shareholders, which includes an explanation of the items of business to be considered at the meeting.

All resolutions for which notice has been given will be decided on a poll. Deloitte LLP have expressed their willingness to continue in office as auditors and a resolution for their reappointment is included in the *Notice of bp Annual General Meeting 2026*.

Memorandum and Articles of Association

The following summarizes certain provisions of the company's Memorandum and Articles of Association and applicable English law. This summary is qualified in its entirety by reference to the UK Companies Act 2006 (the Act) and the company's Memorandum and Articles of Association. The Memorandum and Articles of Association are available online at bp.com/usefuldocs.

The company's Articles of Association may be amended by a special resolution at a general meeting of the shareholders. At the AGM held on 21 May 2018 shareholders voted to adopt new Articles of Association to reflect developments in market practice and to provide clarification and additional flexibility where necessary or appropriate.

Objects and purposes

BP p.l.c. is a public company limited by shares and registered in England and Wales with the registered number 102498. The provisions regulating the operations of the company, known as its 'objects', were historically stated in a company's memorandum. The Act abolished the need to have object provisions and so at the AGM held on 15 April 2010 shareholders approved the removal of its objects clause together with all other provisions of its Memorandum that, by virtue of the Act, are treated as forming part of the company's Articles of Association.

Directors and secretary

The business and affairs of the company shall be managed by the directors. The company's Articles of Association provide that any person may be appointed by the existing directors or by the shareholders in a general meeting either as a replacement for another director or as an additional director. Any person appointed by the directors will hold office only until the next general meeting, notice of which is first given after their appointment and will then be eligible for re-election by the shareholders. A director may be removed by the company as provided for by applicable law and shall vacate office in certain circumstances as set out in the Articles of Association. In addition, the company may, by special resolution, remove a director before the expiration of his/her period of office and, subject to the Articles of Association, may by ordinary resolution appoint another person to be a director instead. There is no requirement for a director to retire on reaching any age.

The Articles of Association place a general prohibition on a director voting in respect of any contract or arrangement in which the director has a material interest other than by virtue of such director's interest in shares in the company. However, in the absence of some other material interest not indicated below, a director is entitled to vote and to be counted in a quorum for the purpose of any vote relating to a resolution concerning the following matters:

- The giving of security or indemnity with respect to any money lent or obligation taken by the director at the request or benefit of the company or any of its subsidiary undertakings.
- The giving of security or indemnity to a third party with respect to any debt or obligation of the company or any of its subsidiary undertakings for which the director has assumed responsibility.
- Any proposal in which the director is interested, concerning the underwriting of company securities or debentures or the giving of any security to a third party for a debt or obligation of the company or any of its subsidiary undertakings.
- Any proposal concerning any other company in which the director is interested, directly or indirectly (whether as an officer or shareholder or otherwise), provided that the director and persons connected with such director are not the holder or holders of 1% or more of the voting interest in the shares of such company.
- Any proposal concerning the purchase or maintenance of any insurance policy under which the director may benefit.
- Any proposal concerning the giving to the director of any other indemnity which is on substantially the same terms as indemnities given or to be given to all of the other directors or to the funding by the company of his expenditure on defending proceedings or the doing by the company of anything to enable the director to avoid incurring such expenditure where all other directors have been given or are to be given substantially the same arrangements.
- Any proposal concerning an arrangement for the benefit of the employees and directors or former employees and former directors of the company or any of its subsidiary undertakings, including but without being limited to a retirement benefits scheme and an employees' share scheme, which does not accord to any director any privilege or advantage not generally accorded to the employees or former employees to whom the arrangement relates.

The Act requires a director of a company who is in any way interested in a contract or proposed contract with the company to declare the nature of the director's interest at a meeting of the directors of the company. The definition of 'interest' includes the interests of spouses, children,

companies and trusts. The Act also requires that a director must avoid a situation where a director has, or could have, a direct or indirect interest that conflicts, or possibly may conflict, with the company's interests. The Act allows directors of public companies to authorize such conflicts where appropriate, if a company's Articles of Association so permit. The company's Articles of Association permit the authorization of such conflicts. The directors may exercise all the powers of the company to borrow money, except that the amount remaining undischarged of all moneys borrowed by the company shall not, without approval of the shareholders, exceed two times the amount paid up on the share capital plus the aggregate of the amount of the capital and revenue reserves of the company and its subsidiary undertakings incorporated in the UK. Variation of the borrowing power of the board may only be affected by amending the Articles of Association.

Remuneration of non-executive directors shall be determined in the aggregate by resolution of the shareholders. Remuneration of executive directors is determined by the remuneration committee. This committee is made up of non-executive directors only. There is no requirement of share ownership for a director's qualification.

The Articles of Association provide entitlement to the directors' pensions and death and disability benefits to the directors' relations and dependants respectively.

The circumstances in which a director's office will automatically terminate include, among others: when a director ceases to hold an executive office of the company and the directors resolve that they should cease to be a director; if a medical practitioner provides an opinion that a director has become incapable of acting as a director and may remain so incapable for more than a further three months and the directors resolve that they should cease to be a director; and if all of the other directors vote in favour of a resolution stating that the person should cease to be a director.

The company secretary has express powers to delegate any of the powers or discretions conferred on him or her.

Dividend rights; other rights to share in company profits; capital calls

Shareholders of the company may, by resolution, declare dividends but no such dividend may be declared in excess of the amount recommended by the directors. The directors may also pay interim dividends without obtaining shareholder approval. No dividend may be paid other than out of profits available for distribution, as determined under IFRS and the Act. Dividends on ordinary shares are payable only after payment of dividends on bp preference shares. Any dividend unclaimed after a period of 10 years from the date of declaration of such dividend shall be forfeited and reverts to bp. If the company exercises its right to forfeit shares and sells shares belonging to an untraced shareholder, then any entitlement to claim dividends or other monies unclaimed in respect of those shares will be for a period of 12 months after the sale. The company may take such steps as the directors decide are appropriate in the circumstances to trace the member entitled and the sale may be made at such time and on such terms as the directors may decide.

The directors have the power to declare and pay dividends in any currency provided that a sterling equivalent is announced. It is not the company's intention to change its current policy of paying dividends in US dollars. At the company's AGM held on 15 April 2010, shareholders approved the introduction of a Scrip Dividend Programme (Scrip Programme) and to include provisions in the Articles of Association to enable the company to operate the Scrip Programme. The Scrip Programme was renewed at the company's AGM held on 25 April 2024 for a further three years. The Scrip Programme enables ordinary shareholders and bp ADS holders to elect to receive new fully paid ordinary shares (or bp ADSs in the case of bp ADS holders) instead of cash. The operation of the Scrip Programme is always subject to the directors' decision to make the scrip offer available in respect of any particular dividend. Should the directors decide not to offer the scrip in respect of any particular dividend, cash will automatically be paid instead. The directors may determine in relation to any scrip dividend plan or programme how the costs of the programme will be met, the minimum number of ordinary shares required in order to be able to

participate in the programme and any arrangements to deal with legal and practical difficulties in any particular territory.

Apart from shareholders' rights to share in bp's profits by dividend (if any is declared or announced), the Articles of Association provide that the directors may set aside:

- A special reserve fund out of the balance of profits each year to make up any deficit of cumulative dividend on the bp preference shares.
- A general reserve out of the balance of profits each year, which shall be applicable for any purpose to which the profits of the company may properly be applied. This may include capitalization of such sum, pursuant to an ordinary shareholders' resolution, and distribution to shareholders as if it were distributed by way of a dividend on the ordinary shares or in paying up in full unissued ordinary shares for allotment and distribution as bonus shares.

Any such sums so deposited may be distributed in accordance with the manner of distribution of dividends as described above.

Holders of shares are not subject to calls on capital by the company, provided that the amounts required to be paid on issue have been paid off. All shares are fully paid.

Share transfers and share certificates

The directors may permit transfers to be effected other than by an instrument in writing. Share certificates will not be required to be issued by the company if they are not required by law.

The company may charge an administrative fee in the event that a shareholder wishes to replace two or more certificates representing shares with a single certificate or wishes to surrender a single certificate and replace it with two or more certificates. All certificates are sent at the member's risk.

Voting rights

The Articles of Association of the company provide that voting on resolutions at a shareholders' meeting will be decided on a poll other than resolutions of a procedural nature, which may be decided on a show of hands. If voting is on a poll, every shareholder who is present in person or by proxy has one vote for every ordinary share held and two votes for every £5 in nominal amount of bp preference shares held. If voting is on a show of hands, each shareholder who is present at the meeting in person or whose duly appointed proxy is present in person will have one vote, regardless of the number of shares held, unless a poll is requested.

Shareholders do not have cumulative voting rights.

For the purposes of determining which persons are entitled to attend or vote at a shareholders' meeting and how many votes such persons may cast, the company may specify in the notice of the meeting a time, not more than 48 hours before the time of the meeting, by which a person who holds shares in registered form must be entered on the company's register of members in order to have the right to attend or vote at the meeting or to appoint a proxy to do so.

Holders on record of ordinary shares may appoint a proxy, including a beneficial owner of those shares, to attend, speak and vote on their behalf at any shareholders' meeting, provided that a duly completed proxy form is received not less than 48 hours (or such shorter time as the directors may determine) before the time of the meeting or adjourned meeting or, where the poll is to be taken after the date of the meeting, not less than 24 hours (or such shorter time as the directors may determine) before the time of the poll.

Record holders of bp ADSs are also entitled to attend, speak and vote at any shareholders' meeting of the company by the appointment by the approved depository, JPMorgan Chase Bank N.A., of them as proxies in respect of the ordinary shares represented by their ADSs. Each such proxy may also appoint a proxy. Alternatively, holders of bp ADSs are entitled to vote by supplying their voting instructions to the Depository, who will vote the ordinary shares represented by their ADSs in accordance with their instructions.

Proxies may be delivered electronically.

Corporations who are members of the company may appoint one or more persons to act as their representative or representatives at any shareholders' meeting provided that the company may require a corporate representative to produce a certified copy of the resolution appointing them before they are permitted to exercise their powers.

Matters are transacted at shareholders' meetings by the proposing and passing of resolutions, of which there are two types: ordinary or special.

An ordinary resolution requires the affirmative vote of a majority of the votes cast at a meeting at which there is a quorum. A special resolution requires the affirmative vote of not less than three quarters of the votes cast at a meeting at which there is a quorum. Any AGM requires 21 clear days' notice. The notice period for any other general meeting is 14 clear days subject to the company obtaining annual shareholder approval, failing which, a 21 clear day notice period will apply.

Liquidation rights; redemption provisions

In the event of a liquidation of bp, after payment of all liabilities and applicable deductions under UK laws and subject to the payment of secured creditors, the holders of bp preference shares would be entitled to the sum of (1) the capital paid up on such shares plus, (2) accrued and unpaid dividends and (3) a premium equal to the higher of (a) 10% of the capital paid up on the bp preference shares and (b) the excess of the average market price over par value of such shares on the London Stock Exchange during the previous six months. The remaining assets (if any) would be divided pro rata among the holders of ordinary shares.

Without prejudice to any special rights previously conferred on the holders of any class of shares, bp may issue any share with such preferred, deferred or other special rights, or subject to such restrictions as the shareholders by resolution determine (or, in the absence of any such resolutions, by determination of the directors), and may issue shares that are to be or may be redeemed.

Variation of rights

The rights attached to any class of shares may be varied with the consent in writing of holders of 75% of the shares of that class or on the adoption of a special resolution passed at a separate meeting of the holders of the shares of that class. At every such separate meeting, all of the provisions of the Articles of Association relating to proceedings at a general meeting apply, except that the quorum with respect to a meeting to change the rights attached to the preference shares is 10% or more of the shares of that class, and the quorum to change the rights attached to the ordinary shares is one third or more of the shares of that class.

Shareholders' meetings and notices

Shareholders must provide bp with a postal or electronic address in the UK to be entitled to receive notice of shareholders' meetings. Holders of bp ADSs are entitled to receive notices under the terms of the deposit agreement relating to bp ADSs. The substance and timing of notices are described above under the heading 'Voting rights'.

Under the Act, the AGM of shareholders must be held once every year, within each six-month period beginning with the day following the company's accounting reference date. All general meetings shall be held at a time and place determined by the directors. If any shareholders' meeting is adjourned for lack of quorum, notice of the time and place of the adjourned meeting may be given in any lawful manner, including electronically. Powers exist for action to be taken either before or at the meeting by authorized officers to ensure its orderly conduct and safety of those attending.

The directors have power to convene a general meeting which is a hybrid meeting, that is to provide facilities for shareholders to attend a meeting which is being held at a physical place by electronic means as well (but not to convene a purely electronic meeting).

The provisions of the Articles of Association in relation to satellite meetings permit facilities being provided by electronic means to allow those persons at each place to participate in the meeting.

Limitations on voting and shareholding

There are no limitations, either under the laws of the UK or under the company's Articles of Association, restricting the right of non-resident or foreign owners to hold or vote bp ordinary or preference shares in the company other than limitations that would generally apply to all of the shareholders and limitations applicable to certain countries and persons subject to EU economic sanctions or those sanctions adopted by the UK government which implement resolutions of the Security Council of the United Nations.

Disclosure of interests in shares

The Act permits a public company to give notice to any person whom the company believes to be or, at any time during the three years prior to the issue of the notice, to have been interested in its voting shares requiring them to disclose certain information with respect to those interests. Failure to supply the information required may lead to disenfranchisement of the relevant shares and a prohibition on their transfer and receipt of dividends and other payments in respect of those shares and any new shares in the company issued in respect of those shares. In this context the term 'interest' is widely defined and will generally include an interest of any kind whatsoever in voting shares, including any interest of a holder of bp ADSs.

Called-up share capital

Details of the allotted, called-up and fully-paid share capital at 31 December 2025 are set out in Financial statements – **Note 31**. In accordance with institutional investor guidelines, the company deems it appropriate to grant authority to the directors to allot shares and other securities and to disapply pre-emption rights by way of shareholders' resolutions at each AGM in place of authority granted by virtue of the company's Articles of Association. At the AGM on 17 April 2025, authorization was given to the directors to allot shares in the company and to grant rights to subscribe for, or to convert any security into, shares in the company up to an aggregate nominal amount as set out in the *Notice of Annual General Meeting 2025*. These authorities were given for the period until the next AGM in 2026 or 17 July 2026, whichever is the earlier. These authorities are renewed annually at the AGM.

Company records and service of notice

In relation to notices not covered by the Act, the reference to notice by advertisement in a national newspaper also includes advertisements via other means such as a public announcement.

Purchases of equity securities by the issuer and affiliated purchasers

During the 2025 financial year the company repurchased 835,648,878 ordinary shares with a nominal value of \$0.25 each for a total consideration of \$4,479,471,803 (including transaction costs), for the purpose of returning capital to shareholders and to offset the expected dilution from the vesting of awards under employee share schemes. The shares repurchased in 2025 represented 5.35% of the company's issued share capital, excluding shares held in treasury, on 31 December 2025. Of the shares repurchased in 2025, shares purchased under the 2024 AGM authority represented 3.27%, and shares purchased under the 2025 AGM authority represented 2.07% of bp's issued share capital, excluding shares held in treasury, on 31 December 2025. A further 74,395,880 ordinary shares were repurchased between the end of the financial year and 13 February 2026 at a cost of \$450,225,900 (including transaction costs) representing 0.48% of the company's issued share capital, excluding shares held in treasury, on 31 December 2025. Of the ordinary shares repurchased in 2025 and in 2026 up to 13 February under the share buyback programme, 176,152,257 were cancelled and 733,892,501 were transferred into treasury.

Authorization for the company to make market purchases (as defined in section 693(4) of the Companies Act 2006) of ordinary shares with a nominal value of \$0.25 each in the company was renewed at the company's 2025 AGM covering the period until the date of the company's 2026 AGM or 17 July 2026, whichever is earlier. The maximum number of ordinary shares to be purchased under this authority will not exceed 1,600,606,341 ordinary shares. The shares purchased may be cancelled or held in treasury.

The following table provides details of ordinary share purchases made (1) under the share buyback programmes and (2) by the Employee Share Ownership Plans (ESOPs) and other purchases of ordinary shares and ADSs made to satisfy the requirements of certain employee share-based payment plans.

	Total number of shares purchased ^a	Average price paid per share \$	Number of shares purchased by ESOPs or for certain employee share-based plans ^b	Number of shares purchased under buyback programmes ^c	Maximum approximate dollar value of shares yet to be purchased under the programmes \$ million
2025					
January 7 - January 31	132,132,317	5.25	1,200,000	130,932,317	N/A
February 3 - February 11	45,219,940	5.30	–	45,219,940	N/A
March 6 - March 31	165,553,368	5.56	68,000	165,485,368	N/A
April 1 - April 29	170,261,000	4.88	–	170,261,000	N/A
May 21 - May 30	11,533,500	4.88	–	11,533,500	N/A
June 2 - June 30	33,297,000	5.08	–	33,297,000	N/A
July 1 - July 31	88,997,107	5.32	–	88,997,107	N/A
August 1 - August 29	25,601,600	5.60	–	25,601,600	N/A
September 1 - September 30	22,955,250	5.80	–	22,955,250	N/A
October 1 - October 31	86,032,971	5.73	–	86,032,971	N/A
November 3 - November 28	30,171,877	6.03	–	30,171,877	N/A
December 1 - December 22	25,160,948	5.98	–	25,160,948	N/A
2026					
January 7 - January 30	54,782,912	5.92	–	54,782,912	N/A
February 2 - February 13	37,278,988	6.31	17,666,020	19,612,968	N/A

a All share purchases were of ordinary shares of \$0.25 each and/or ADSs (each representing six ordinary shares) and were on/open market transactions.

b Transactions represent the purchases of ordinary shares and ADSs made to satisfy requirements of certain employee share-based payment plans.

c Share repurchases from 1 January to 7 February 2025 were made under a share buyback programme announced on 29 October 2024 for a period up to and including 7 February 2025. On 3 March 2025 the company announced a programme covering a period up to and including 25 April 2025. On 29 April 2025 the company announced a programme covering a period up to and including 1 August 2025. On 5 August 2025 the company announced a programme covering a period up to and including 31 October 2025. On 4 November 2025 the company announced a programme covering a period up to and including 6 February 2026.

Fees and charges payable by ADS holders

The Depository collects fees for delivery and surrender of ADSs directly from investors depositing shares or surrendering ADSs for the purpose of withdrawal or from intermediaries acting for them. The Depository collects fees for making distributions to investors by deducting those fees from the amounts distributed or by selling a portion of the distributable property to pay the fees.

The charges of the Depository payable by investors are as follows:

Type of service	Depository actions	Fee
Depositing or substituting the underlying shares	Issuance of ADSs against the deposit of shares, including deposits and issuances in respect of: <ul style="list-style-type: none"> • Share distributions, stock splits, rights, merger. • Exchange of securities or other transactions or event or other distribution affecting the ADSs or deposited securities. 	\$5.00 per 100 ADSs (or portion thereof) evidenced by the new ADSs delivered.
Selling or exercising rights	Distribution or sale of securities, the fee being an amount equal to the fee for the execution and delivery of ADSs that would have been charged as a result of the deposit of such securities.	\$5.00 per 100 ADSs (or portion thereof).
Withdrawing an underlying share	Acceptance of ADSs surrendered for withdrawal of deposited securities.	\$5.00 for each 100 ADSs (or portion thereof) evidenced by the ADSs surrendered.
Expenses of the Depository	Expenses incurred on behalf of holders in connection with: <ul style="list-style-type: none"> • Stock transfer or other taxes and governmental charges. • Delivery by cable, telex, electronic and facsimile transmission. • Transfer or registration fees, if applicable, for the registration of transfers of underlying shares. • Expenses of the Depository in connection with the conversion of foreign currency into US dollars (which are paid out of such foreign currency). 	Expenses payable are subject to agreement between the company and the Depository by billing holders or by deducting charges from one or more cash dividends or other cash distributions.
Dividend fees	ADS holders who receive a cash dividend are charged a fee which bp uses to offset the costs associated with administering the ADS programme.	The Deposit Agreement provides that a fee of \$0.05 or less per ADS can be charged. The current fee is \$0.02 per bp ADS per calendar year (equivalent to \$0.005 per bp ADS per quarter per cash distribution).
Global Invest Direct (GID) Plan	New investors and existing ADS holders can buy, sell or reinvest dividends into further bp ADSs by enrolling in bp's GID Plan, sponsored and administered by the Depository.	Cost per transaction is \$2.00 for recurring, \$2.00 for one-time automatic investments, and \$5.00 for investment made by check. Dividend reinvestment is 5% of the dividend amount up to a maximum of \$5.00. Purchase trading commission is \$0.12 per share.

Fees and payments made by the Depository to the issuer

The Depository has agreed to reimburse certain company expenses related to the company's ADS programme and incurred by the company in connection with the ADS programme arising during the year ended 31 December 2025. The Depository reimbursed to the company, or paid amounts on the company's behalf to third parties, or waived its fees and expenses, of \$15,033,009.99 for the year ended 31 December 2025.

The table below sets out the types of expenses that the Depository has agreed to reimburse and the fees it has agreed to waive for standard costs associated with the administration of the ADS programme relating to the year ended 31 December 2025.

Category of expense reimbursed, waived or paid directly to third parties	Amount reimbursed, waived or paid directly to third parties for the year ended 31 December 2025 \$
Fees for delivery and surrender of bp ADSs	1,788,953.72
Dividend fees ^a	13,244,056.27
Waived fees	—
Total	15,033,009.99

^a Dividend fees are charged to ADS holders who receive a cash distribution, which bp uses to offset the costs associated with administering the ADS programme.

Under certain circumstances, including removal of the Depository or termination of the ADS programme by the company, the company is required to repay the Depository certain amounts reimbursed and/or expenses paid to or on behalf of the company during the 12-month period prior to notice of removal or termination.

Documents on display

The *bp Annual Report and Form 20-F 2025* is available online at bp.com/annualreport. To obtain a hard copy of bp's complete audited financial statements, free of charge, UK-based shareholders should contact bp Distribution Services by calling +44 (0) 800 037 2172 or by emailing bpdistinctionservices@bp.com. If based in the US or Canada, shareholders should contact Equiniti by calling 1 888 301 2505 or by emailing bpreports@equiniti.com

The company is subject to the information requirements of the US Securities Exchange Act of 1934 applicable to foreign private issuers. In accordance with these requirements, the company files its *Annual Report and Form 20-F* and other related documents with the SEC. The SEC maintains an internet site at sec.gov that contains reports and other information regarding issuers, including bp, that file electronically with the SEC. bp's SEC filings are also available at bp.com/sec. bp discloses in this report (see Corporate governance practices (Form 20-F Item 16G) on [page 359](#) significant ways (if any) in which its corporate governance practices differ from those mandated for US companies under NYSE listing standards.

Shareholding administration

If you have any queries about the administration of shareholdings, such as change of address, change of ownership, dividend payment options or to change the way you receive your company documents (such as the *bp Annual Report and Form 20-F* and *Notice of bp Annual General Meeting*) please contact the bp Registrar or the bp ADS Depositary.

Holders of American Depositary Receipts may request to inspect the books of the Depositary and the listing of receipt holders by contacting the bp ADS Depositary.

Ordinary and preference shareholders

The bp Registrar, MUFG Corporate Markets
Central Square,
29 Wellington Street,
Leeds, LS1 4DL

Freephone in the UK 0800 701107
From outside the UK +44 (0)371 277 1014

bp share centre mybpshares.com

ADS holders

Computershare Trust Company, N.A.
PO Box 43304, Providence, RI 02940-3304

Toll-free in the US +1 877 638 5672
From outside the US +1 651 306 4383

2026 shareholder calendar^a

27 Mar 2026	Fourth quarter interim dividend payment for 2025
23 Apr 2026	Annual general meeting
28 April 2026	First quarter results announced
15 May 2026	Record date (to be eligible for the first quarter interim dividend)
26 June 2026	First quarter interim dividend payment for 2025 and 8% and 9% preference shares record date
31 Jul 2026	8% and 9% preference shares dividend payment
04 Aug 2026	Second quarter results announced
14 Aug 2026	Record date (to be eligible for the second quarter interim dividend)
18 Sep 2026	Second quarter interim dividend payment for 2025
27 Oct 2026	Third quarter results announced
6 Nov 2026	Record date (to be eligible for the third quarter interim dividend)
18 Dec 2026	Third quarter interim dividend payment for 2025

^a All future dates are provisional and may be subject to change. For the full calendar see bp.com/financialcalendar.

Glossary

Abbreviations

ADR

American depositary receipt.

ADS

American depositary share. 1 ADS = 6 ordinary shares.

Barrel (bbl)

159 litres, 42 US gallons.

bcf

Billion cubic feet.

bcfe

Billion cubic feet equivalent.

boe

Barrels of oil equivalent.

CAGR

Compound annual growth rate.

EJ/yr

Exajoules per year.

EVP

Executive vice president.

FPSO

Floating production, storage and offloading.

GAAP

Generally accepted accounting practice.

Gas

Natural gas.

gCO₂e/MJ

Grams of carbon dioxide equivalent per megajoule of energy.

GHG

Greenhouse gas.

GRI

Global Reporting Initiative.

GtCO₂

Gigatonnes of carbon dioxide.

GW

Gigawatt.

GWh

Gigawatt hour.

HSSE

Health, safety, security and environment.

IFRS

International Financial Reporting Standards.

kb/d

Thousand barrels per day.

KPIs

Key performance indicators.

kt

Thousand tonnes.

LNG

Liquefied natural gas.

LPG

Liquefied petroleum gas.

mb/d

Thousand barrels per day.

Mbbl

Million barrels.

mboe/d

Thousand barrels of oil equivalent per day.

mmb/d

Million barrels per day.

mmboe/d

Million barrels of oil equivalent per day.

mmBtu

Million British thermal units.

mmcf/d

Million cubic feet per day.

Mt

Million tonnes.

MtCO₂e

Million tonnes of CO₂ equivalent.

Mtpa

Million tonnes per annum.

MW

Megawatt.

MWe

Megawatt electrical.

MWp

Megawatt peak.

NGLs

Natural gas liquids.

PSA

Production-sharing agreement.

PTA

Purified terephthalic acid.

RC

Replacement cost.

SEC

The United States Securities and Exchange Commission.

TWh

Terawatt hour.

SVP

Senior vice president.

scfm

Standard cubic feet per minute.

Definitions

Unless the context indicates otherwise, the definitions for the following glossary terms are given below.

Non-IFRS measures are sometimes referred to as alternative performance measures.

CA100+ resolution glossary

CA100+ resolution

The CA100+ resolution means the special resolution requisitioned by Climate Action 100+ and passed at bp's 2019 Annual General Meeting, the text of which is set out below.

Special resolution: Climate Action 100+ shareholder resolution on climate change disclosures.

That in order to promote the long-term success of the company, given the recognized risks and opportunities associated with climate change, we as shareholders direct the company to include in its strategic report and/or other corporate reports, as appropriate, for the year ending 2019 onwards, a description of its strategy which the board considers, in good faith, to be consistent with the goals of Articles 2.1(a)(1) and 4.1(2) of the Paris Agreement (3) (the Paris goals), as well as:

(1) Capital expenditure: how the company evaluates the consistency of each new material capex investment, including in the exploration, acquisition or development of oil and gas resources and reserves and other energy sources and technologies, with (a) the Paris goals and separately (b) a range of other outcomes relevant to its strategy.

(2) Metrics and targets: the company's principal metrics and relevant targets or goals over the short, medium and/or long term, consistent with the Paris goals, together with disclosure of:

- a The anticipated levels of investment in (i) oil and gas resources and reserves; and (ii) other energy sources and technologies.
- b The company's targets to promote reductions in its operational greenhouse gas emissions, to be reviewed in line with changing protocols and other relevant factors.
- c The estimated carbon intensity of the company's energy products and progress on carbon intensity over time.
- d Any linkage between the above targets and executive remuneration.

(3) Progress reporting: an annual review of progress against (1) and (2) above.

Such disclosure and reporting to include the criteria and summaries of the methodology and core assumptions used, and to omit commercially confidential or competitively sensitive information and be prepared at reasonable cost; and provided that nothing in this resolution shall limit the company's powers to set and vary its strategy, or associated targets or metrics, or to take any action which it believes in good faith, would best promote the long-term success of the company.

The Paris goals

- (1) Article 2.1(a) of the Paris Agreement states the goal of 'Holding the increase in the global average temperature to well-below-2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels, recognizing that this would significantly reduce the risks and impacts of climate change'.
- (2) Article 4.1 of the Paris Agreement: In order to achieve the long-term temperature goal set out in Article 2, parties aim to reach global peaking of greenhouse gas emissions as soon as possible, recognizing that peaking will take longer for developing country parties, and to undertake rapid reductions thereafter in accordance with best available science, so as to achieve a balance between anthropogenic emissions by sources and removals by sinks of greenhouse gases in the second half of this century, on the basis of equity, and in the context of sustainable development and efforts to eradicate poverty.

- (3) U.N. Framework Convention on Climate Change Conference of Parties, Twenty-First Session, Adoption of the Paris Agreement, U.N. Doc. FCCC/CP/2015/L.9/Rev.1 (Dec. 12, 2015).

New material capex investment

For the purposes of the 2024 evaluation discussed on **pages 20-23**, 'new material capex investment' means a decision taken by the resource commitment meeting (RCM) in 2024 to incur inorganic or organic investments greater than \$250 million that relate to a new project or asset, extending an existing project or asset, or acquiring or increasing a share in a project, asset or entity.

For the purposes of evaluating material capex investments for consistency with the Paris goals, two quantitative tests were applied, see **page 22**.

Operational carbon intensity (CI)

The annual average operational GHG emissions (TeCO₂e/unit), divided by the relevant unit of output:

Per thousand barrels of oil equivalent in upstream.

- Per utilized equivalent distillation capacity in refining.
- per thousand tonnes of petrochemicals production.

Net zero aims and ambition glossary

Average carbon intensity of sold energy products

The rate of GHG emissions per unit of energy delivered (in grams CO₂e/MJ) estimated in respect of sold energy products★. GHG emissions are estimated on a lifecycle basis covering use, production, and distribution of sold energy products.

Energy products

For the purposes of our 2025 disclosures relating to net zero sales★ we consider an energy product to be one that is emissive or provides energy in its end use case. For further information on products included in bp's 2025 net zero sales aim reporting see the *bp Basis of Reporting 2025*, bp.com/basisofreporting.

Methane intensity

Methane intensity refers to the amount of methane emissions from bp's operated upstream oil and gas assets as a percentage of the total gas that goes to market from those operations. Our methodology is aligned with the Oil and Gas Climate Initiative (OGCI) methodology.

Net zero

References to global net zero in the phrase, 'to help the world get to net zero', means achieving '...a balance between anthropogenic emissions by sources and removals by sinks of greenhouse gases...on the basis of equity, and in the context of sustainable development and efforts to eradicate poverty', as set out in Article 4(1) of the Paris Agreement.

References to net zero for bp in the context of our ambition and net zero operations and net zero sales aims mean achieving a balance between (a) the relevant Scope 1 and 2 emissions (for net zero operations) and product lifecycle emissions (for net zero sales) and (b) the aggregate of applicable deductions from qualifying activities such as sinks under our methodology at the applicable time.

Net zero★ operations

bp's aim to reach net zero operational greenhouse gas (CO₂ and methane) emissions by 2050 or sooner, on a gross operational control basis, in accordance with bp's net zero operations aim, which relates to our reported Scope 1 and 2 emissions. Any interim target or aim in respect of bp's net zero operations aim is defined in terms of absolute reductions relative to the baseline year of 2019.

Net zero sales

bp's aim to reach net zero for the carbon intensity of sold energy products★. Any interim target or aim in respect of bp's net zero sales aim is defined in terms of reductions in the carbon intensity of the energy products we sell (in grams CO₂e/MJ) relative to the baseline year of 2019.

Sold energy products

For the purposes of bp's net zero sales aim, sold energy products represent sales by a bp group subsidiary, joint operation or bp equity accounted entity (EAE). For further information see the bp Basis of Reporting 2025 [bp.com/basisofreporting](https://www.bp.com/basisofreporting).

Adjusted EBIDA

Adjusted EBIDA is a non-IFRS measure. This metric, as applicable to the directors' remuneration performance measure, requires a calculation of profit or loss for the period, adjusting for finance costs and net finance (income) or expense relating to pensions and other post-employment benefits and taxation, inventory holding gains or losses before tax, net adjusting items★ before interest and tax, and taxation on an underlying RC basis, and adding back depreciation, depletion and amortization (pre-tax) and exploration expenditure written-off (net of adjusting items, pre-tax). The nearest equivalent measure on an IFRS basis is profit or loss for the period.

Adjusted EBIDA per share compound annual growth rate (CAGR)

Adjusted EBIDA per share is a non-IFRS measure. This metric, as applicable to the directors' remuneration performance measure, is calculated based on the shares in issue at period end.

Adjusted EBITDA

Adjusted EBITDA is a non-IFRS measure presented for bp's operating segments and the group. Adjusted EBITDA for bp's operating segments is defined as replacement cost (RC) profit before interest and tax, excluding net adjusting items before interest and tax, and adding back depreciation, depletion and amortization and exploration write-offs (net of adjusting items). Adjusted EBITDA by business is a further analysis of adjusted EBITDA for the customers & products businesses. bp believes it is helpful to disclose adjusted EBITDA by operating segment and by business because it reflects how the segments measure underlying business delivery. The nearest equivalent measure on an IFRS basis for the segment is RC profit or loss before interest and tax, which is bp's measure of profit or loss that is required to be disclosed for each operating segment under IFRS. A reconciliation to IFRS information is provided on [pages 350 and 388](#).

Adjusted EBITDA for the group is defined as profit or loss for the period, adjusting for finance costs and net finance (income) or expense relating to pensions and other post-employment benefits and taxation, inventory holding gains or losses before tax, net adjusting items before interest and tax, and adding back depreciation, depletion and amortization (pre-tax) and exploration expenditure written-off (net of adjusting items, pre-tax). The nearest equivalent measure on an IFRS basis for the group is profit or loss for the period. A reconciliation to IFRS information is provided on [page 387](#).

Adjusted free cash flow

Non-IFRS measure. It is defined as adjusted operating cash flow★ (see below) less total cash capital expenditure★.

bp believes the measure provides useful information to investors. Adjusted free cash flow enables investors to measure our progress on delivering growth and improving our performance. The nearest IFRS measures are net cash provided by (used in) operating activities and total cash capital expenditure. A reconciliation of net cash provided by (used in) operating cash flow to adjusted free cash flow is provided on [page 387](#).

We are unable to present reconciliations of forward-looking information for adjusted free cash flow to net cash provided by operating activities, because without unreasonable efforts, we are unable to forecast accurately certain adjusting items required to present a meaningful comparable IFRS forward-looking financial measure. These items include inventory holding gains or losses, fair value accounting effects and other adjusting items, that are difficult to predict in advance in order to include in an IFRS estimate.

Adjusted free cash flow compound annual growth rate (CAGR)

Non-IFRS measure. Adjusted free cash flow compound annual growth is the annualized growth rate of adjusted free cash flow (defined above).

bp believes adjusted free cash flow CAGR is useful information to investors to compare with adjusted free cash flow on a price adjusted basis CAGR. The nearest IFRS measures to calculate adjusted free cash flow CAGR are net cash provided by (used in) operating activities and total cash capital expenditure.

Adjusted free cash flow compound annual growth rate (CAGR) (primary target)

Non-IFRS measure. Our primary target adjusted free cash flow CAGR is on a price adjusted basis and is the annualized growth rate of adjusted free cash flow (defined above), assuming a hypothetical price environment of \$70/bbl Brent, \$4/mmBtu Henry Hub, and \$10.3/bbl refining indicator margin (all 2024 real) and assumptions about the impact of these marker prices on underlying replacement cost profit before tax.

bp believes adjusted free cash flow on a price adjusted basis compound annual growth rate helps investors to measure our progress on delivering growth and improving our performance on a normalized price environment basis. The nearest IFRS measures to calculate adjusted free cash flow CAGR are net cash provided by (used in) operating activities and total capital expenditure.

We are unable to present reconciliations of forward-looking information for adjusted free cash flow to net cash provided by operating activities, because without unreasonable efforts, we are unable to forecast accurately certain adjusting items required to present a meaningful comparable IFRS forward-looking financial measure. These items include inventory holding gains or losses, fair value accounting effects and other adjusting items, that are difficult to predict in advance in order to include in an IFRS estimate.

Adjusted operating cash flow

Non-IFRS measure. It is defined as net cash provided by (used in) operating activities as presented in the group cash flow statement, excluding movements in inventories and other current and non-current assets and liabilities as presented in the group cash flow statement, adjusted for inventory holding gains/losses, fair value accounting effects (FVAEs) relating to subsidiaries and other adjusting items relating to the non-cash movement of US emissions obligations carried as a provision that will be settled by allowances held as inventory. When used in the context of a segment or subset of businesses rather than the group, the terms refer to the segment or business' estimated share thereof.

bp believes the measure provides useful information to investors. Adjusted operating cash flow enables investors to measure our progress on delivering growth and improving our performance. The nearest IFRS measure is net cash provided by (used in) operating activities.

We are unable to present reconciliations of forward-looking information for adjusted operating cash flow to net cash provided by operating activities, because without unreasonable efforts, we are unable to forecast accurately certain adjusting items required to present a meaningful comparable IFRS forward-looking financial measure. These items include inventory holding gains or losses, FVAEs and other adjusting items, that are difficult to predict in advance in order to include in an IFRS estimate.

Adjusted operating expenditure

Non IFRS measure and a subset of production and manufacturing expenses plus distribution and administration expenses. It represents the majority of the remaining expenses in these line items but excludes certain costs that are variable, primarily with volumes (such as freight costs). Other variable costs are included in purchases in the income statement. Management believes that adjusted operating expenditure is a performance measure that provides investors with useful information regarding the company's financial performance because it considers these expenses to be the principal operating and overhead expenses that are most directly under their control although they also

include certain adjusting items★, foreign exchange and commodity price effects. The nearest IFRS measures are production and manufacturing expenses and distributions and administration expenses. A reconciliation of production and manufacturing expense plus distribution and administration expenses to adjusted operating expenditure is provided on [page 386](#).

Adjusting items

Adjusting items are items that bp discloses separately because it considers such disclosures to be meaningful and relevant to investors. They are items that management considers to be important to period-on-period analysis of the group's results and are disclosed in order to enable investors to better understand and evaluate the group's reported financial performance. Adjusting items include gains and losses on the sale of businesses and fixed assets, impairments, environmental and related provisions and charges, restructuring, integration and rationalization costs, fair value accounting effects, costs relating to the Gulf of America oil spill and other items. Adjusting items within equity-accounted earnings are reported net of incremental income tax reported by the equity-accounted entity. Adjusting items are used as a reconciling adjustment to derive underlying RC profit or loss and related underlying measures which are non-IFRS measures. An analysis of adjusting items by segment and type is shown on [page 336](#).

Associate

An entity over which the group has significant influence and that is neither a subsidiary nor a joint arrangement of the group. Significant influence is the power to participate in the financial and operating policy decisions of the investee but is not control or joint control over those policies.

Blue hydrogen

Hydrogen made from natural gas or coal in combination with carbon capture and storage (CCS).

Capital employed

Non-IFRS measure. It is defined as total equity plus finance debt.

Capital expenditure

Total cash capital expenditure as stated in the group cash flow statement. Capital expenditure for the operating segments, gas & low carbon energy businesses and customers & products businesses is presented on the same basis.

Commodity trading contracts

bp participates in regional and global commodity trading markets in order to manage, transact and hedge the crude oil, refined products and natural gas that the group either produces or consumes in its manufacturing operations. The range of contracts the group enters into in its commodity trading operations is described below. Using these contracts, in combination with rights to access storage and transportation capacity, allows the group to access advantageous pricing differences between locations, time periods and grades.

Exchange-traded commodity derivatives

Contracts that are typically in the form of futures and options traded on a recognized exchange, such as Nymex and ICE. Such contracts are traded in standard specifications for the main marker crude oils, such as Brent and West Texas Intermediate; the main product grades, such as gasoline and gasoil; and for natural gas and power. Gains and losses, otherwise referred to as variation margin, are generally settled on a daily basis with the relevant exchange. These contracts are used for the trading and risk management of crude oil, refined products, and natural gas and power. Realized and unrealized gains and losses on exchange-traded commodity derivatives are included in sales and other operating revenues for accounting purposes.

Over-the-counter (OTC) contracts

Contracts that are typically in the form of forwards, swaps and options. Some of these contracts are traded bilaterally between counterparties or through brokers, others may be cleared by a central clearing counterparty. These contracts can be used both for trading and risk management activities. Realized and unrealized gains and losses on OTC contracts are included in sales and other operating revenues for

accounting purposes. Many grades of crude oil bought and sold use standard contracts including US domestic light sweet crude oil, commonly referred to as West Texas Intermediate, and a standard North Sea crude blend – Brent, Forties, Oseberg and Ekofisk (BFOE). Forward contracts are used in connection with the purchase of crude oil supplies for refineries and for marketing and sales of the group's oil production and refined products. The contracts typically contain standard delivery and settlement terms. These transactions call for physical delivery of oil with consequent operational and price risk. However, various means exist and are used from time to time, to settle obligations under the contracts in cash rather than through physical delivery. Physically settled BFOE contracts delivered by cargo additionally specify a standard volume and tolerance.

Gas and power OTC markets are highly developed in North America and the UK, where commodities can be bought and sold for delivery in future periods. These contracts are negotiated between two parties to purchase and sell gas and power at a specified price, with delivery and settlement at a future date. Typically, the contracts specify delivery terms for the underlying commodity. Some of these transactions are not settled physically as they can be net settled by transacting offsetting sale or purchase contracts for the same location and delivery period. The contracts contain standard terms such as delivery point, pricing mechanism, settlement terms and specification of the commodity. Typically, volume, price and term (e.g. daily, monthly and balance of month) are the main variable contract terms.

Swaps are typically contractual obligations to exchange cash flows between two parties. A typical swap transaction usually references a floating price and a fixed price with the net difference of the cash flows being settled. Options give the holder the right, but not the obligation, to buy or sell crude, oil products, natural gas or power at a specified price on or before a specific future date. Amounts under these derivative financial instruments are settled at expiry. Typically, netting agreements are used to limit credit exposure and support liquidity.

Spot and term contracts

Spot contracts are contracts to purchase or sell a commodity at the market price prevailing on or around the delivery date when title to the inventory is taken. Term contracts are contracts to purchase or sell a commodity at regular intervals over an agreed term. Though spot and term contracts may have a standard form, there is no offsetting mechanism in place. As such, these transactions result in physical delivery with operational and price risk. Spot and term contracts typically relate to purchases of crude for a refinery, products for marketing, or third-party natural gas, or sales of the group's oil production, oil products or gas production to third parties. For accounting purposes, spot and term sales are included in sales and other operating revenues when title passes. Similarly, spot and term purchases are included in purchases for accounting purposes.

Consolidation adjustment – UPII

Unrealized profit in inventory arising on inter-segment transactions.

Convenience gross margin

Non-IFRS measure. Convenience gross margin is calculated as RC profit before interest and tax for the customers & products segment, excluding RC profit before interest and tax for the refining & trading business (a non-IFRS measure), and adjusting items★ (as defined above) for the convenience & mobility business to derive underlying RC profit before interest and tax for the convenience & mobility business; subtracting underlying RC profit before interest and tax for the *Castrol* business; adding back depreciation, depletion and amortization, production and manufacturing, distribution and administration expenses for convenience & mobility (excluding *Castrol*); subtracting earnings from equity-accounted entities in the convenience & mobility business (excluding *Castrol*) and gross margin for the retail fuels, EV charging, aviation, B2B and midstream businesses. bp believes it is helpful because this measure may help investors to understand and evaluate, in the same way as management, our progress against our strategic objectives of convenience growth. The nearest IFRS measure is RC profit before interest and tax for the customers & products segment.

Convenience gross margin growth (%)

Non-IFRS measure. See convenience gross margin definition. Convenience gross margin growth at constant foreign exchange is a non-IFRS measure. This metric, as applicable to the directors' remuneration performance measure, requires a calculation of the comparative convenience margin (\$ million) at current period foreign exchange rates (constant foreign exchange) and compares the current period value with the restated comparative period value, which results in the growth % at constant foreign exchange rates. The nearest IFRS measure to convenience gross margin is RC profit before interest and tax for the customer & products segment.

Developed renewables to final investment decision (FID)

Total generating capacity for assets developed to FID by all entities where bp has an equity share (proportionate to equity share). If asset is subsequently sold bp will continue to record capacity as developed to FID. If bp equity share increases developed capacity to FID will increase proportionately to share increase for any assets where bp held equity at the point of FID.

Divestment proceeds

Disposal proceeds as per the group cash flow statement.

Dividend yield

Sum of the four quarterly dividends announced in respect of the year as a percentage of the year-end share price.

Downstream

Downstream is the customers & products segment. It comprises our customer-focused businesses, which include convenience and retail fuels, EV charging, as well as *Castrol*, aviation, B2B, midstream and bp bioenergy. It also comprises our products businesses which include refining and oil trading.

Dutch Title Transfer Facility

The TTF (Title Transfer Facility) is the virtual trading point for natural gas in the Netherlands. It is commonly used as a benchmark hub for gas prices in Europe.

Electric vehicle charge points / EV charge points

Defined as the number of connectors on a charging device, operated by either bp or a bp joint venture, as adjusted to be reflective of bp's accounting share of joint arrangements.

Excess cash

Non-IFRS measure. It refers to the net of sources and uses of cash. Sources of cash include net cash provided by operating activities, cash provided from investing activities and cash receipts relating to transactions involving non-controlling interests. Uses of cash include lease liability payments, payments on perpetual hybrid bonds, dividends paid, cash capital expenditure, the cash cost of share buybacks to offset the dilution from vesting of awards under employee share schemes, cash payments relating to transactions involving non-controlling interests and currency translation differences relating to cash and cash equivalents as presented on the condensed group cash flow statement.

Fair value accounting effects

Non-IFRS adjustments to our IFRS profit (loss). They reflect the difference between the way bp manages the economic exposure and internally measures performance of certain activities and the way those activities are measured under IFRS. Fair value accounting effects are included within adjusting items. They relate to certain of the group's commodity, interest rate and currency risk exposures as detailed below. Other than as noted below, the fair value accounting effects described are reported in both the gas & low carbon energy and customer & products segments.

bp uses derivative instruments to manage the economic exposure relating to inventories above normal operating requirements of crude oil, natural gas and petroleum products. Under IFRS, these inventories are recorded at historical cost. The related derivative instruments, however, are required to be recorded at fair value with gains and losses recognized in the income statement. This is because hedge accounting

is either not permitted or not followed, principally due to the impracticality of effectiveness-testing requirements. Therefore, measurement differences in relation to recognition of gains and losses occur. Gains and losses on these inventories, other than net realizable value provisions, are not recognized until the commodity is sold in a subsequent accounting period. Gains and losses on the related derivative commodity contracts are recognized in the income statement, from the time the derivative commodity contract is entered into, on a fair value basis using forward prices consistent with the contract maturity.

bp enters into physical commodity contracts to meet certain business requirements, such as the purchase of crude for a refinery or the sale of bp's gas production. Under IFRS these physical contracts are treated as derivatives and are required to be fair valued when they are managed as part of a larger portfolio of similar transactions. Gains and losses arising are recognized in the income statement from the time the derivative commodity contract is entered into.

IFRS require that inventory held for trading is recorded at its fair value using period-end spot prices, whereas any related derivative commodity instruments are required to be recorded at values based on forward prices consistent with the contract maturity. Depending on market conditions, these forward prices can be either higher or lower than spot prices, resulting in measurement differences.

bp enters into contracts for pipelines and other transportation, storage capacity, oil and gas processing, liquefied natural gas (LNG) and certain gas and power contracts that, under IFRS, are recorded on an accruals basis. These contracts are risk-managed using a variety of derivative instruments that are fair valued under IFRS. This results in measurement differences in relation to recognition of gains and losses.

The way that bp manages the economic exposures described above, and measures performance internally, differs from the way these activities are measured under IFRS. bp calculates this difference for consolidated entities by comparing the IFRS result with management's internal measure of performance. We believe that disclosing management's estimate of this difference provides useful information for investors because it enables investors to see the economic effect of these activities as a whole.

These include:

- Under management's internal measure of performance the inventory, transportation and capacity contracts in question are valued based on fair value using relevant forward prices prevailing at the end of the period.
- Fair value accounting effects also include changes in the fair value of the near-term portions of LNG contracts that fall within bp's risk management framework. LNG contracts are not considered derivatives, because there is insufficient market liquidity, and they are therefore accrual accounted under IFRS. However, oil and natural gas derivative financial instruments used to risk manage the near-term portions of the LNG contracts are fair valued under IFRS. The fair value accounting effect, which is reported in the gas and low carbon energy segment, represents the change in value of LNG contracts that are being risk managed and which is reflected in the underlying result, but not in reported earnings. Management believes that this gives a better representation of performance in each period.

Furthermore, the fair values of derivative instruments used to risk manage certain other oil, gas, power and other contracts, are deferred to match with the underlying exposure. The commodity contracts for business requirements are accounted for on an accruals basis.

In addition, fair value accounting effects include changes in the fair value of derivatives entered into by the group to manage currency exposure and interest rate risks relating to hybrid bonds to their respective first call periods. The hybrid bonds which are classified as equity instruments and were recorded in the balance sheet at their issuance date at their USD equivalent issued value. Under IFRS these equity instruments are not remeasured from period to period, and do not qualify for application of hedge accounting. The derivative instruments relating to the hybrid bonds, however, are required to be

recorded at fair value with mark to market gains and losses recognized in the income statement. Therefore, measurement differences in relation to the recognition of gains and losses occur. The fair value accounting effect, which is reported in the other businesses & corporate segment, eliminates the fair value gains and losses of these derivative financial instruments that are recognized in the income statement. We believe that this gives a better representation of performance, by more appropriately reflecting the economic effect of these risk management activities, in each period.

Finance debt ratio

Finance debt ratio is defined as the ratio of finance debt to the total of finance debt plus total equity.

Gearing

See net debt and gearing below.

Gearing including leases

See net debt including leases and gearing including leases below.

Green hydrogen

Hydrogen produced by electrolysis of water using renewable power.

Hydrocarbons

Liquids and natural gas. Natural gas is converted to oil equivalent at 5.8 billion cubic feet = 1 million barrels.

Inorganic capital expenditure

A subset of capital expenditure on a cash basis and a non-IFRS measure. Inorganic capital expenditure comprises consideration in business combinations and certain other significant investments made by the group. It is reported on a cash basis. bp believes that this measure provides useful information as it allows investors to understand how bp's management invests funds in projects which expand the group's activities through acquisition. The nearest equivalent measure on an IFRS basis is capital expenditure on a cash basis. Further information and a reconciliation to IFRS information is provided on [page 335](#).

Inventory holding gains and losses

Inventory holding gains and losses are non-IFRS adjustments to our IFRS profit (loss) and represent:

- The difference between the cost of sales calculated using the replacement cost of inventory and the cost of sales calculated on the first-in first-out (FIFO) method after adjusting for any changes in provisions where the net realizable value of the inventory is lower than its cost. Under the FIFO method, which we use for IFRS reporting of inventories other than for trading inventories, the cost of inventory charged to the income statement is based on its historical cost of purchase or manufacture, rather than its replacement cost. In volatile energy markets, this can have a significant distorting effect on reported income. The amounts disclosed as inventory holding gains and losses represent the difference between the charge to the income statement for inventory on a FIFO basis (after adjusting for any related movements in net realizable value provisions) and the charge that would have arisen based on the replacement cost of inventory. For this purpose, the replacement cost of inventory is calculated using data from each operation's production and manufacturing system, either on a monthly basis, or separately for each transaction where the system allows this approach.
- An adjustment relating to certain trading inventories that are not price risk managed which relate to a minimum inventory volume that is required to be held to maintain underlying business activities. This adjustment represents the movement in fair value of the inventories due to prices, on a grade-by-grade basis, during the period. This is calculated from each operation's inventory management system on a monthly basis using the discrete monthly movement in market prices for these inventories.

The amounts disclosed are not separately reflected in the financial statements as a gain or loss. No adjustment is made in respect of the cost of inventories held as part of a trading position and certain other

temporary inventory positions that are price risk-managed. See Replacement cost (RC) profit or loss definition below.

Joint arrangement

An arrangement in which two or more parties have joint control.

Joint control

Contractually agreed sharing of control over an arrangement, which exists only when decisions about the relevant activities require the unanimous consent of the parties sharing control.

Joint operation

A joint arrangement whereby the parties that have joint control of the arrangement have rights to the assets, and obligations for the liabilities, relating to the arrangement.

Joint venture

A joint arrangement whereby the parties that have joint control of the arrangement have rights to the net assets of the arrangement.

Liquids

Comprises crude oil, condensate and natural gas liquids. For the oil production & operations segment, it also includes bitumen.

LNG portfolio

LNG portfolio refers to bp group's LNG equity production plus additional long-term merchant LNG volumes.

LNG train

An LNG train is a processing facility used to liquefy and purify natural gas in the formation of LNG.

Major projects

Have a bp net investment of at least \$250 million, or are considered to be of strategic importance to bp or of a high degree of complexity.

Modified free cash flow

A non-IFRS measure. It is defined as operating cash flow less: (1) net cash used in investing activities as presented in the group cash flow statement; and (2) lease liability payments included in financing activities and adjusting for receipts relating to transactions involving non-controlling interests reported within financing activities in the group cash flow statement and movements in lease creditor.

Net debt and gearing

Non-IFRS measures. Net debt is calculated as finance debt, as shown in the balance sheet, plus the fair value of associated derivative financial instruments that are used to hedge foreign currency exchange and interest rate risks relating to finance debt, for which hedge accounting is applied, less cash and cash equivalents. Net debt does not include accrued interest, which is reported within other receivables and other payables on the balance sheet and for which the associated cash flows are presented as operating cash flows in the group cash flow statement. Gearing is defined as the ratio of net debt to the total of net debt plus total equity. bp believes these measures provide useful information to investors. Net debt enables investors to see the economic effect of finance debt, related hedges and cash and cash equivalents in total. Gearing enables investors to see how significant net debt is relative to total equity. The derivatives are reported on the balance sheet within the headings 'Derivative financial instruments'. See Financial statements – [Note 27](#) for information on finance debt, which is the nearest equivalent measure to net debt on an IFRS basis. The nearest equivalent IFRS measure to gearing on an IFRS basis is finance debt ratio.

We are unable to present reconciliations of forward-looking information for net debt or gearing to finance debt and total equity, because without unreasonable efforts, we are unable to forecast accurately certain adjusting items required to present a meaningful comparable IFRS forward-looking financial measure. These items include fair value asset (liability) of hedges related to finance debt and cash and cash equivalents, that are difficult to predict in advance in order to include in an IFRS estimate.

Net debt including leases and gearing including leases

Non-IFRS measure. Net debt including leases is calculated as net debt plus lease liabilities, less the net amount of partner receivables and payables relating to leases entered into on behalf of joint operations. Gearing including leases is defined as the ratio of net debt including leases to the total of net debt including leases plus total equity. bp believes these measures provide useful information to investors as they enable investors to understand the impact of the group's lease portfolio on net debt and gearing. See Financial statements – **Note 27** for information on finance debt, which is the nearest equivalent measure to net debt including leases on an IFRS basis. The nearest equivalent IFRS measure to gearing including leases on an IFRS basis is finance debt ratio. A reconciliation to IFRS information is provided on **page 337**.

Operating cash flow

Net cash provided by (used in) operating activities as stated in the group cash flow statement. When used in the context of a segment rather than the group, the terms refer to the segment's share thereof.

Operating management system (OMS)

bp's OMS helps us manage risks in our operating activities by setting out bp's principles for good operating practice. It brings together bp requirements on health, safety, security, the environment, social responsibility and operational reliability, as well as related issues, such as maintenance, contractor relations and organizational learning, into a common management system.

Organic capital expenditure

Non-IFRS measure. Organic capital expenditure comprises capital expenditure on a cash basis less inorganic capital expenditure. bp believes that this measure provides useful information as it allows investors to understand how bp's management invests funds in developing and maintaining the group's assets. The nearest equivalent measure on an IFRS basis is capital expenditure on a cash basis. An analysis of organic capital expenditure by segment and region, and a reconciliation to IFRS information is provided on **page 335**.

We are unable to present reconciliations of forward-looking information for organic capital expenditure to total cash capital expenditure, because without unreasonable efforts, we are unable to forecast accurately the adjusting item, inorganic capital expenditure, that is difficult to predict in advance in order to derive the nearest IFRS estimate.

Plant reliability

This metric, as applicable to the directors' remuneration performance measure, see Upstream / hydrocarbon plant reliability.

Production-sharing agreement/contract (PSA/PSC)

An arrangement through which an oil and gas company bears the risks and costs of exploration, development and production. In return, if exploration is successful, the oil company receives entitlement to variable physical volumes of hydrocarbons, representing recovery of the costs incurred and a stipulated share of the production remaining after such cost recovery.

Proved reserves replacement ratio

The extent to which the year's production has been replaced by proved reserves added to our reserve base. The ratio is expressed in oil-equivalent terms and includes changes resulting from discoveries, improved recovery and extensions and revisions to previous estimates, but excludes changes resulting from acquisitions and disposals.

Realizations

Realizations are the result of dividing revenue generated from hydrocarbon sales, excluding revenue generated from purchases made for resale and royalty volumes, by revenue generating hydrocarbon production volumes. Revenue generating hydrocarbon production reflects the bp share of production as adjusted for any production which does not generate revenue. Adjustments may include losses due to shrinkage, amounts consumed during processing, and contractual or regulatory host committed volumes such as royalties. For the gas & low

carbon energy and oil production & operations segments, realizations include transfers between businesses.

Refining availability

Represents Solomon Associates' operational availability for bp-operated refineries, which is defined as the percentage of the year that a unit is available for processing after subtracting the annualized time lost due to turnaround activity and all mechanical, process and regulatory downtime.

Refining indicator margin (RIM)

A simple indicator of the weighted average of bp's crude slate and product yield as deemed representative for each refinery. Actual margins realized by bp may vary due to a variety of factors, including the actual mix of a crude and product for a given quarter.

Refining marker margin (RMM)

The average of regional indicator margins weighted for bp's crude refining capacity in each region. Each regional marker margin is based on product yields and a marker crude oil deemed appropriate for the region. The regional indicator margins may not be representative of the margins achieved by bp in any period because of bp's particular refinery configurations and crude and product slate.

Renewable natural gas (RNG)

RNG is a pipeline-quality, lower carbon fuel that is interchangeable with traditional natural gas. It is a form of biogas and a product of decomposing organic material at sites including landfills, farms and wastewater treatment facilities.

Renewables pipeline

Renewable projects satisfying the criteria below until the point they can be considered developed to FID:

Site-based projects that have obtained land exclusivity rights, or for power purchase agreement based projects an offer has been made to the counterparty, or for auction projects pre-qualification criteria have been met, or for acquisition projects post a binding offer has been accepted.

Replacement cost (RC) profit or loss/RC profit or loss attributable to bp shareholders

Reflects the replacement cost of inventories sold in the period and is calculated as profit or loss attributable to bp shareholders, adjusting for inventory holding gains and losses (net of tax). RC profit or loss for the group is not a recognized IFRS measure. bp believes this measure is useful to illustrate to investors the fact that crude oil and product prices can vary significantly from period to period and that the impact on our reported result under IFRS can be significant. Inventory holding gains and losses vary from period to period due to changes in prices as well as changes in underlying inventory levels. In order for investors to understand the operating performance of the group excluding the impact of price changes on the replacement of inventories, and to make comparisons of operating performance between reporting periods, bp's management believes it is helpful to disclose this measure. The nearest equivalent measure on an IFRS basis is profit or loss attributable to bp shareholders. See Financial statements – **Note 5**. A reconciliation to IFRS information is provided on **page 24**.

Reported recordable injury frequency

Reported recordable injury frequency measures the number of reported work-related employee and contractor incidents that result in a fatality or injury per 200,000 hours worked. This represents reported incidents occurring within bp's operational HSSE reporting boundary. That boundary includes bp's own operated facilities and certain other locations or situations.

Retail fuel volumes

Retail fuel volumes are fuel volumes sold from bp branded retail sites and includes gasoline, diesel, LPG sales and other fuel sales (e.g. ad blue sold at the pump). Does not include fuels volume for equity accounted entities.

Retail sites

Retail sites include sites operated by dealers, jobbers, franchisees or brand licensees or joint venture (JV) partners, under the bp brand. These may move to and from the bp brand as their fuel supply agreement or brand licence agreement expires and are renegotiated in the normal course of business.

Retail sites are primarily branded *BP*, *Arco*, *Amoco*, *Aral*, *Thorntons*, and *TravelCenters of America* and also includes sites in India through our *Jio-bp JV*.

Return on average capital employed (ROACE)

Non-IFRS measure. ROACE is defined as underlying replacement cost profit, which is defined as profit or loss attributable to bp shareholders adjusted for inventory holding gains and losses, adjusting items and related taxation on inventory holding gains and losses and adjusting items total taxation, after adding back non-controlling interest and interest expense net of tax, divided by the average of the beginning and ending balances of total equity plus finance debt, excluding cash and cash equivalents and goodwill as presented on the group balance sheet over the periods presented. Interest expense before tax is finance costs as presented on the group income statement, excluding lease interest, the unwinding of the discount on provisions and other payables and other adjusting items reported in finance costs. bp believes it is helpful to disclose the ROACE because this measure gives an indication of the company's capital efficiency. The nearest IFRS measures of the numerator and denominator are profit or loss for the period attributable to bp shareholders and total equity respectively. The reconciliation of the numerator and denominator is provided on [page 385](#).

We are unable to present forward-looking information of the nearest IFRS measures of the numerator and denominator for ROACE, because without unreasonable efforts, we are unable to forecast accurately certain adjusting items required to calculate a meaningful comparable IFRS forward-looking financial measure. These items include inventory holding gains or losses and interest net of tax, that are difficult to predict in advance in order to include in an IFRS estimate.

Return on average capital employed (ROACE) on a price adjusted basis

Non-IFRS measure. ROACE on a price adjusted basis is adjusted ROACE (defined above), calculated assuming a hypothetical price environment of \$70/bbl Brent, \$4/mmBtu Henry Hub, and a \$10.3/bbl refining indicator margin (all 2024 real) and assumptions about the impact of these marker prices on underlying replacement cost profit before tax.

bp believes ROACE on a price adjusted basis helps investors to assess the company's capital efficiency and underlying performance on a normalized price environment basis. The nearest IFRS measures of the numerator and denominator are profit or loss for the period attributable to bp shareholders and total equity respectively.

Strategic convenience sites

Strategic convenience sites are retail sites, within the bp portfolio, which sell bp-supplied vehicle energy (e.g. *BP*, *Aral*, *Arco*, *Amoco*, *Thorntons*, *bp pulse*, *TravelCenters of America* and *PETRO*) and either carry one of the strategic convenience brands (e.g. *M&S*, *Rewe to Go*) or a differentiated bp-controlled convenience offer. To be considered a strategic convenience site, the convenience offer should have a demonstrable level of differentiation in the market in which it operates. Strategic convenience site count includes sites under a pilot phase.

Structural cost reduction

Non-IFRS measure. It is calculated as decreases in underlying operating expenditure ★ (as defined below) as a result of operational efficiencies, divestments, workforce reductions and other cost saving measures that are expected to be sustainable compared with 2023 levels. The total change between periods in underlying operating expenditure will reflect both structural cost reductions and other changes in spend, including market factors, such as inflation and foreign exchange impacts, as well as changes in activity levels and costs associated with new operations. Estimates of cumulative annual structural cost reduction may be revised depending on whether cost reductions realized in prior periods are determined to be sustainable compared

with 2023 levels. Structural cost reductions are stewarded internally to support management's oversight of spending over time.

bp believes this performance measure is useful in demonstrating how management drives cost discipline across the entire organization, simplifying our processes and portfolio and streamlining the way we work. The nearest IFRS measures are production and manufacturing expenses and distributions and administration expenses. A reconciliation of production and manufacturing expenses plus distribution and administration expenses to underlying operating expenditure is provided on [page 386](#).

We are unable to present forward-looking information of the nearest IFRS measures, because without unreasonable efforts, we are unable to forecast accurately certain adjusting items required to calculate a meaningful comparable IFRS forward-looking financial measure.

Subsidiary

An entity that is controlled by the bp group. Control of an investee exists when an investor is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee.

Technical service contract (TSC)

Technical service contract is an arrangement through which an oil and gas company bears the risks and costs of exploration, development and production. In return, the oil and gas company receives entitlement to variable physical volumes of hydrocarbons, representing recovery of the costs incurred and a profit margin which reflects incremental production added to the oilfield.

Tier 1 and tier 2 process safety events

Tier 1 events are losses of primary containment from a process of greatest consequence – such as causing harm to a member of the workforce, damage to equipment from a fire or explosion, a community impact or exceeding defined quantities. Tier 2 events are those of lesser consequence. These represent reported incidents occurring within bp's operational HSE reporting boundary. That boundary includes bp's own operated facilities and certain other locations or situations.

Tight oil and gas

Natural oil and gas reservoirs locked in hard sandstone rocks with low permeability, making the underground formation extremely tight.

Transition businesses

Business activities (including development, production/manufacture/generation and marketing, distribution and trading) associated with products and services that support energy transition, including in the areas of biogas, biofuels, EV charging, renewable power generation, hydrogen and carbon capture.

Transition Scenario Catalogue

A catalogue of third-party transition scenarios, compiled by bp to support TCFD transition resilience analysis and to help inform impairment sensitivity analysis. This catalogue takes as its start point data from the most recent (at the time of preparation) World Business Council for Sustainable Development (WBCSD) Energy Climate Scenario Catalogue Version 3.0, published May 2024, which we have updated for amended IEA, NGFS and UN PRI IPR data where these source providers have since published updated scenarios for key transition variables or have 'retired' older scenarios. For further details see [page 53](#).

UK National Balancing Point

A virtual trading location for sale, purchase and exchange of UK natural gas. It is the pricing and delivery point for the Intercontinental Exchange natural gas futures contract.

Ultra-fast charging

Electric vehicle charging of greater than or equal to 150kW.

Unconventionals

Resources found in geographic accumulations over a large area, that usually present additional challenges to development such as low permeability or high viscosity. Examples include shale gas and oil,

coalbed methane, gas hydrates and natural bitumen deposits. These typically require specialized extraction technology such as hydraulic fracturing or steam injection.

Underlying effective tax rate (ETR)

Non-IFRS measure. The underlying ETR is calculated by dividing taxation on an underlying replacement cost (RC) basis by underlying RC profit or loss before tax. Taxation on an underlying RC basis for the group is calculated as taxation as stated on the group income statement adjusted for taxation on inventory holding gains and losses and adjusting items total taxation. Information on underlying RC profit or loss is provided below. Taxation on an underlying RC basis presented for the operating segments is calculated through an allocation of taxation on an underlying RC basis to each segment. bp believes it is helpful to disclose the underlying ETR because this measure may help investors to understand and evaluate, in the same manner as management, the underlying trends in bp's operational performance on a comparable basis, period on period. Taxation on an underlying RC basis and underlying ETR are non-IFRS measures. The nearest equivalent measure on an IFRS basis is the ETR on profit or loss for the period.

We are unable to present reconciliations of forward-looking information for underlying ETR to ETR on profit or loss for the period, because without unreasonable efforts, we are unable to forecast accurately certain adjusting items required to present a meaningful comparable IFRS forward-looking financial measure. These items include the taxation on inventory holding gains and losses and adjusting items, that are difficult to predict in advance in order to include in an IFRS estimate. A reconciliation to IFRS information is provided on [page 384](#).

Underlying operating expenditure

Non-IFRS measure. A subset of production and manufacturing expenses plus distribution and administration expenses and excludes costs that are classified as adjusting items. It represents the majority of the remaining expenses in these line items but excludes certain costs that are variable, primarily with volumes (such as freight costs). Other variable costs are included in purchases in the income statement. Management believes that underlying operating expenditure is a performance measure that provides investors with useful information regarding the company's financial performance because it considers these expenses to be the principal operating and overhead expenses that are most directly under their control although they also include certain foreign exchange and commodity price effects. The nearest IFRS measures are production and manufacturing expenses and distributions and administration expenses. A reconciliation of production and manufacturing expense plus distribution and administration expenses to underlying operating expenditure is provided on [page 386](#).

Underlying production

Production after adjusting for acquisitions and divestments and entitlement impacts in our production-sharing agreements (PSAs). 2024 underlying production, when compared with 2023, is production after adjusting for acquisitions and divestments, curtailments, and entitlement impacts in our production-sharing agreements/contracts and technical service contract.

Underlying replacement cost (RC) profit or loss / underlying RC profit or loss attributable to bp shareholders

Non-IFRS measure. RC profit or loss ★ (as defined above) after excluding net adjusting items and related taxation. See [page 336](#) for additional information on the adjusting items that are used to arrive at underlying RC profit or loss in order to enable a full understanding of the items and their financial impact. Underlying RC profit or loss before interest and tax for the operating segments or customers & products businesses is calculated as RC profit or loss (as defined above) including profit or loss attributable to non-controlling interests before interest and tax for the operating segments and excluding net adjusting items for the respective operating segment or business.

bp believes that underlying RC profit or loss is a useful measure for investors because it is a measure closely tracked by management to evaluate bp's operating performance and to make financial, strategic

and operating decisions and because it may help investors to understand and evaluate, in the same manner as management, the underlying trends in bp's operational performance on a comparable basis, period on period, by adjusting for the effects of these adjusting items.

The nearest equivalent measure on an IFRS basis for the group is profit or loss attributable to bp shareholders. The nearest equivalent measure on an IFRS basis for segments and businesses is RC profit or loss before interest and taxation. A reconciliation to IFRS information is provided on [page 24](#) for the group and [pages 28-36](#) for the segments.

Underlying RC profit or loss per share and underlying RC profit or loss per ADS

Non-IFRS measures. Earnings per share is defined in [Note 11](#). Underlying RC profit or loss per ordinary share is calculated using the same denominator as earnings per share as defined in the consolidated financial statements. The numerator used is underlying RC profit or loss attributable to bp shareholders rather than profit or loss attributable to bp shareholders. Underlying RC profit or loss per ADS is calculated as outlined above for underlying RC profit or loss per share except the denominator is adjusted to reflect one ADS equivalent to six ordinary shares. bp believes it is helpful to disclose the underlying RC profit or loss per ordinary share and per ADS because these measures may help investors to understand and evaluate, in the same manner as management, the underlying trends in bp's operational performance on a comparable basis, period on period. The nearest equivalent measure on an IFRS basis is basic earnings per share based on profit or loss for the period attributable to bp shareholders. A reconciliation to IFRS information is provided on [page 384](#).

Upstream

Upstream includes oil and natural gas field development and production within the gas & low carbon energy and oil production & operations segments. References to upstream exclude Rosneft.

Upstream / hydrocarbon plant reliability

bp-operated upstream plant reliability is calculated taking 100% less the ratio of total unplanned plant deferrals divided by installed production capacity, excluding non-operated assets and bpx energy. Unplanned plant deferrals are associated with the topside plant and where applicable the subsea equipment (excluding wells and reservoirs). Unplanned plant deferrals include breakdowns, which does not include Gulf of America weather-related downtime.

Upstream unit production costs

Upstream unit production costs are calculated as production costs divided by units of production. Production costs do not include ad valorem and severance taxes. Units of production are barrels for liquids and thousands of cubic feet for gas. Amounts disclosed are for bp subsidiaries only and do not include bp's share of equity-accounted entities.

West Texas Intermediate (WTI)

A light sweet crude oil, priced at Cushing, Oklahoma, which serves as a benchmark price for purchases of oil in the US.

Working capital

Movements in inventories and other current and non-current assets and liabilities as stated in the group cash flow statement.

Trade marks

Trade marks of the bp group appear throughout this report. They include:

Amoco, Aral, Aral pulse, BP, bp pulse, Castrol, Gigahub, PETRO, TA, Thorntons, epic goods and earnify

Trade marks:

REWE to Go – a registered trade mark of REWE

Non-IFRS measures reconciliations

Reconciliation of basic earnings per ordinary share to underlying RC profit★ per ordinary share★

	Per ordinary share - cents		
	2025	2024	2023
Profit (loss) for the year attributable to bp shareholders	0.35	2.38	87.78
Inventory holding (gains) losses★, before tax	8.67	2.98	7.12
Taxation charge (credit) on inventory holding gains and losses	(2.15)	(0.73)	(1.69)
	6.87	4.63	93.21
Net (favourable) adverse impact of adjusting items★, before tax	37.76	56.95	(6.58)
Taxation charge (credit) on adjusting items	3.39	(7.18)	(6.94)
Underlying RC profit for the year	48.02	54.40	79.69

Reconciliation of basic earnings per ADS to underlying RC profit per ADS★

	Per ADS - dollars		
	2025	2024	2023
Profit (loss) for the year attributable to bp shareholders	0.02	0.14	5.27
Inventory holding (gains) losses, before tax	0.52	0.18	0.43
Taxation charge (credit) on inventory holding gains and losses	(0.13)	(0.04)	(0.11)
	0.41	0.28	5.59
Net (favourable) adverse impact of adjusting items, before tax	2.27	3.42	(0.40)
Taxation charge (credit) on adjusting items	0.20	(0.44)	(0.41)
Underlying RC profit for the year	2.88	3.26	4.78

Reconciliation of effective tax rate (ETR) to underlying ETR★

Taxation (charge) credit

	\$ million		
	2025	2024	2023
Taxation on profit or loss before taxation for the year	(6,451)	(5,553)	(7,869)
Adjusted for taxation on inventory holding gains and losses	334	119	292
Adjusted for adjusting items total taxation	(528)	1,179	1,204
Taxation on an underlying RC basis	(6,257)	(6,851)	(9,365)

Effective tax rate

	%		
	2025	2024	2023
ETR on profit or loss before taxation for the year	83	82	33
Adjusted for inventory holding gains and losses	(8)	(4)	–
Adjusted for adjusting items total taxation	(33)	(37)	6
Underlying ETR	42	41	39

Return on average capital employed (ROACE) ★

	\$ million	
	2025	2024
Profit for the year attributable to bp shareholders	55	381
Inventory holding (gains) losses, before tax	1,351	488
Taxation charge (credit) on inventory holding gains and losses	(334)	(119)
Adjusting items, before tax	5,885	9,344
Taxation charge (credit) on adjusting items	528	(1,179)
Underlying RC profit	7,485	8,915
Interest expense ^a	3,339	3,113
Taxation on interest expense	(539)	(404)
Non-controlling interests (NCI)	1,240	848
	11,525	12,472
Total equity	74,000	78,318
Finance debt	57,958	59,547
Capital employed	131,958	137,865
Less: Goodwill ^b	13,056	14,888
Cash and cash equivalents	36,556	39,204
	82,346	83,773
Average capital employed excluding goodwill and cash and cash equivalents	83,059	87,859
Profit for the year attributable to bp shareholders divided by total equity	0.1%	0.5%
ROACE	13.9%	14.2%
ROACE on a price adjusted basis^c		
Underlying RC profit	7,485	8,915
Interest expense ^a	3,339	3,113
Taxation on interest expense	(539)	(404)
Non-controlling interests (NCI)	1,240	848
	11,525	12,472
Price adjustments ^d	(109)	(2,016)
	11,416	10,456
Average capital employed excluding goodwill and cash and cash equivalents	83,059	87,859
ROACE on a price adjusted basis (%)	13.7%	11.9%

a Finance costs, as reported in the Group income statement, were \$5,106 million (2024 \$4,683 million). Interest expense is finance costs excluding lease interest of \$672 million (2024 \$441 million), unwinding of discount on provisions and other payables of \$1,147 million (2024 \$1,013 million) and other adjusting items related to finance costs \$52 million gain (2024 \$116 million expense).

b 2025 includes the amount of goodwill classified as held for sale at 31 December 2025.

c This does not form part of bp's Annual Report and Form 20-F as filed with the SEC.

d This is on a price adjusted basis that assumes a hypothetical price environment of \$70/bbl Brent, \$4/mmBtu Henry Hub, and \$10.3/bbl refining indicator margin (all 2024 real) and assumptions about the impact of these marker prices on underlying replacement cost profit before tax.

Underlying operating expenditure ★ reconciliation

		\$ million	\$ million
	2025	2024	2023
From group income statement			
Production and manufacturing expenses	25,646	26,584	25,044
Distribution and administration expenses	17,494	16,417	16,772
	43,140	43,001	41,816
Less certain variable costs:			
Transportation and shipping costs ^a	10,456	10,516	9,650
Environmental costs ^a	5,713	3,987	4,271
Marketing and distribution costs	1,692	1,882	2,430
Commission, storage and handling costs	1,594	1,519	1,633
Other variable costs and non-cash costs	1,819	1,495	743
Certain variable costs	21,274	19,399	18,727
Adjusted operating expenditure ★	21,866	23,602	23,089
Less certain adjusting items ★:			
Gulf of America oil spill	31	51	57
Environmental and related provisions	656	181	647
Restructuring, integration and rationalization costs	520	222	(37)
Fair value accounting effects – derivative instruments relating to the hybrid bonds	(1,157)	221	(630)
Other certain adjusting items	(71)	601	419
Certain adjusting items	(21)	1,276	456
Underlying operating expenditure	21,887	22,326	22,633
Underlying operating expenditure reduction relative to 2023	(439)	(307)	
Increase/(decrease) in underlying operating expenditure due to inflation, exchange, portfolio changes and organic growth	1,572	443	
Structural cost reduction ★	(2,011)	(750)	

a Comparative periods have been restated for a reclassification in costs from transportation and shipping to environmental.

Adjusted free cash flow^a★

	2025	2024
Net cash provided by operating activities (operating cash flow)	24,493	27,297
Less: Total cash capital expenditure★	(14,533)	(16,237)
Net cash provided by operating activities less total cash capital expenditure	9,960	11,060
Net cash provided by operating activities less total cash capital expenditure compound annual growth (%)	(10)%	
Adjusted free cash flow on a price adjusted basis★		
Net cash provided by operating activities	24,493	27,297
Adjusted working capital:		
Working capital★ as stated in the group cash flow statement	(4,820)	3,975
Adjusted for inventory holding gains (losses)	(1,351)	(488)
Adjusted for fair value accounting effects★ relating to subsidiaries	2,298	(2,018)
Other adjusting items	975	(661)
Working capital release (build) after adjusting for net inventory holding gains (losses), fair value accounting effects and other adjusting items	(2,898)	808
Adjusted operating cash flow★	27,391	26,489
Less: Total cash capital expenditure	(14,533)	(16,237)
Adjusted free cash flow	12,858	10,252
Price adjustments ^b	(109)	(2,016)
Adjusted free cash flow on a price adjusted basis	12,749	8,236
Adjusted free cash flow on a price adjusted basis compound annual growth (%)	55%	

a This does not form part of bp's Annual Report on Form 20-F as filed with the SEC.

b This is on a price adjusted basis that assumes a hypothetical price environment of \$70/bbl Brent, \$4/mmBtu Henry Hub, and \$10.3/bbl refining indicator margin (all 2024 real) and assumptions about the impact of these marker prices on underlying replacement cost profit before tax.

Adjusted EBITDA★

	\$ million		
	2025	2024	2023
Profit (loss) for the period	1,295	1,229	15,880
Finance costs	5,106	4,683	3,840
Net finance (income) expense relating to pensions and other post-employment benefits	(210)	(168)	(241)
Taxation	6,451	5,553	7,869
Profit before interest and tax	12,642	11,297	27,348
Inventory holding (gains) losses, before tax	1,351	488	1,236
	13,993	11,785	28,584
Net (favourable) adverse impact of adjusting items, before interest and tax	5,457	8,839	(1,548)
	19,450	20,624	27,036
Add back: Depreciation, depletion and amortization	17,822	16,622	15,928
Exploration expenditure written off	343	766	746
Adjusted EBITDA	37,615	38,012	43,710

Reconciliation of RC profit before interest and tax for gas & low carbon energy and oil production & operations to adjusted EBITDA

	\$ million		
	2025	2024	2023
gas & low carbon energy			
RC profit before interest and tax ^a	1,330	3,052	14,080
Less: Net favourable (adverse) impact of adjusting items ^a	(4,037)	(3,751)	5,358
Underlying RC profit before interest and tax	5,367	6,803	8,722
Add back: Depreciation, depletion and amortization	4,969	4,835	5,680
Exploration expenditure written off	30	222	362
Adjusted EBITDA	10,366	11,860	14,764
oil production & operations			
RC profit before interest and tax	8,558	10,789	11,191
Less: Net favourable (adverse) impact of adjusting items	(856)	(1,148)	(1,590)
Underlying RC profit before interest and tax	9,414	11,937	12,781
Add back: Depreciation, depletion and amortization	7,719	6,797	5,692
Exploration expenditure written off	313	544	384
Adjusted EBITDA	17,446	19,278	18,857

a 2024 has been restated for material items to reflect the move of our Archaea Energy business from the customers & products segment to the gas & low carbon energy segment.

The Directors' report on [pages 72-90, 91](#) (in respect of the remuneration committee), [126-128](#), [241-268](#) and [334-388](#) was approved by the board and signed on its behalf by Ben J. S. Mathews, company secretary on 6 March 2026.

BP p.l.c.

Registered in England and Wales No. 102498

Signatures

The registrant hereby certifies that it meets all of the requirements for filing on Form 20-F and that it has duly caused and authorized the undersigned to sign this annual report on its behalf.

BP p.l.c.
(Registrant)

/s/ Ben J. S. Mathews
Company secretary
6 March 2026

Cross reference to Form 20-F

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Information about this report

This document constitutes the Annual Report and Accounts in accordance with UK requirements and the Annual Report on Form 20-F in accordance with the US Securities Exchange Act of 1934, for BP p.l.c. for the year ended 31 December 2025. A cross reference to Form 20-F requirements is included on [page 390](#).

This document contains the Strategic report on the inside front cover and [pages 1-71](#) and the Directors' report on [pages 72-90, 91](#) (in part only), [126-128, 241-268](#) and [334-388](#). The Strategic report and the Directors' report together include the management report required by DTR 4.1 of the UK Financial Conduct Authority's Disclosure Guidance and Transparency Rules. The Directors' remuneration report is on [pages 91-125](#). The consolidated financial statements of the group are on [pages 129-240](#) and the corresponding reports of the auditor are on [pages 130-154](#). The parent company financial statements of BP p.l.c. are on [pages 269-333](#).

The Directors' statements (comprising the Statement of directors' responsibilities; Risk management and internal control; Longer-term viability; Going concern; and Fair, balanced and understandable), the independent auditor's report on the annual report and accounts to the members of BP p.l.c., the parent company financial statements of BP p.l.c. and corresponding auditor's report do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

bp Annual Report and Form 20-F 2025 may be downloaded from bp.com/annualreport. No material on the bp website, other than the items identified as *bp Annual Report and Form 20-F 2025*, forms any part of this document. References in this document to other documents on the bp website, such as *bp Energy Outlook 2025*, and *bp Sustainability Report* are included as an aid to their location and are not incorporated by reference into this document.

BP p.l.c. is the parent company of the bp group of companies. The company was incorporated in 1909 in England and Wales and changed its name to BP p.l.c. in 2001. Where we refer to the company, we mean BP p.l.c. The company and each of its subsidiaries★ are separate legal entities. Unless otherwise stated or the context otherwise requires, the term "BP" or "bp" and terms such as "we", "us" and "our" are used in this report for convenience to refer to one or more of the members of the bp group instead of identifying a particular entity or entities. Information in this document reflects 100% of the assets and operations of the company and its subsidiaries that were consolidated at the date or for the periods indicated, including non-controlling interests.

The company's primary share listing is the London Stock Exchange. In the US, the company's securities are traded on the New York Stock Exchange (NYSE) in the form of ADSs (see [page 365](#) for more details).

The term 'shareholder' in this report means, unless the context otherwise requires, investors in the equity capital of BP p.l.c., both direct and indirect. As the company's shares, in the form of ADSs, are listed on the NYSE, an Annual Report on Form 20-F is filed with the SEC. Ordinary shares are ordinary fully paid shares in BP p.l.c. of 25 cents each. Preference shares are cumulative first preference shares and cumulative second preference shares in BP p.l.c. of £1 each.

Registered office and our worldwide headquarters: BP p.l.c.	Our agent in the US: BP America Inc.
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Tel +44 (0)20 7496 4000	Tel +1 281 366 2000
Registered in England and Wales No. 102498. London Stock Exchange symbol 'BP.'	

Exhibits

The following documents are filed in the Securities and Exchange Commission (SEC) EDGAR system, as part of this Annual Report on Form 20-F, and can be viewed on the SEC's website.

Exhibit 1	Memorandum and Articles of Association of BP p.l.c.****†
Exhibit 2	Description of rights of each class of securities registered under Section 12 of the Securities Exchange Act of 1934†
Exhibit 4.1	The BP Executive Directors' Incentive Plan****†
Exhibit 4.4	Director's Service Agreement for K Thomson****†
Exhibit 4.8	Director's Service Agreement for C Howlett
Exhibit 4.10	The BP Share Award Plan 2025†
Exhibit 8	Subsidiaries (included as Note 37 to the Financial Statements)
Exhibit 11.1	Code of Ethics**†
Exhibit 11.2	Insider trading policy and procedure****†
Exhibit 12	Rule 13a – 14(a) Certifications†
Exhibit 13	Rule 13a – 14(b) Certifications#†
Exhibit 15.1	Consent of Netherland, Sewell & Associates†
Exhibit 15.2	Report of Netherland, Sewell & Associates†
Exhibit 15.3	Consent Decree***†
Exhibit 15.4	Gulf states Settlement Agreement***†
Exhibit 15.5	Consent of Deloitte LLP†
Exhibit 17	Guaranteed Securities†
Exhibit 97	Executive Compensation Clawback Policy****†
Exhibit 101	Inline XBRL data files
Exhibit 104	Cover page interactive data file (formatted as Inline XBRL and contained in Exhibit 101)

* Incorporated by reference to the company's Annual Report on Form 20-F for the year ended 31 December 2009.

** Incorporated by reference to the company's Annual Report on Form 20-F for the year ended 31 December 2015.

*** Incorporated by reference to the company's Annual Report on Form 20-F for the year ended 31 December 2023.

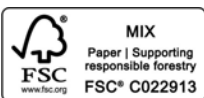
**** Incorporated by reference to the company's Annual Report on Form 20-F for the year ended 31 December 2024.

Furnished only.

† Included only in the annual report filed in the Securities and Exchange Commission EDGAR system.

The total amount of long-term securities of BP p.l.c. and its subsidiaries under any one instrument does not exceed 10% of their total assets on a consolidated basis.

The company agrees to furnish copies of any or all such instruments to the SEC on request.



This report is printed on Arena White Smooth paper and board. Forest Stewardship Council® (FSC®) certified paper sourced from well-managed forests and other controlled sources. The paper is Elemental Chlorine Free (ECF) and Acid Free. Printed in the UK by Pureprint Group, CarbonNeutral®, ISO 14001 and FSC® certified.



bp's corporate reporting suite includes information about our financial and operating performance, sustainability performance and global energy trends and projections.

[bp.com](https://www.bp.com)

bp Annual Report and Form 20-F 2025

Details of our financial and operating performance in print and online.

[bp.com/annualreport](https://www.bp.com/annualreport)

bp Sustainability Report 2025

Details of our sustainability performance with additional information online.

[bp.com/sustainability](https://www.bp.com/sustainability)

bp Energy Outlook 2025

Provides our projections of future energy trends and factors that could affect them out to 2040.

[bp.com/energyoutlook](https://www.bp.com/energyoutlook)

Group databook 2021-2025

Five-year financial and operating data in PDF and Excel format.

[bp.com/financial-disclosure](https://www.bp.com/financial-disclosure)

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