

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 Master netting arrangements	Cash collateral (received) pledged	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.

Cash outflows for derivative financial instruments at 31 December	2025			2024		
	Derivative assets	Derivative liabilities	Total	Derivative assets	Derivative liabilities	Total
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	\$ million	mmBtu
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

Employee costs	\$ million		
	2025	2024	2023
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

Average number of employees ^c	2025			2024			2023		
	US	Non-US	Total	US	Non-US	Total	US	Non-US	Total
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

Fees	\$ million		
	2025	2024	2023
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	4,351	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
Accumulated depreciation	–	5,084	–	–	12,655	8,962	9,947	–	36,648
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	2025	Total
		UK	Rest of Europe	US	Rest of North America						
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
										2025
										Total
Europe		North America		South America	Africa	Asia	Australasia			
UK	Rest of Europe	US	Rest of North America							
Total liquids^{a,b}										
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							Total	
	Europe		North America		South America	Africa	Asia		Australasia
	UK	Rest of Europe	US	Rest of North America					
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	One percentage point 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.

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.

bp Annual Report and Form 20-F 2025

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, Itapagipe, 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, Lvdilianshengguoji, 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

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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

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