Consolidated financial statements of the bp group

Notes on financial statements

Supplementary information on oil and natural gas (unaudited)

Parent company financial statements of BP p.l.c.

Consolidated financial statements of the bp group

Independent auditor's report to the members of BP p.l.c.

Report on the audit of the financial statements

1. Opinion

In our opinion:

- The financial statements of BP p.l.c. (the 'parent company' or 'bp') and its subsidiaries (the 'group' or 'bp') give a true and fair view of the state of the group's and of the parent company's affairs as at 31 December 2023 and of the group's profit for the year then ended.
- The group financial statements have been properly prepared in accordance with United Kingdom adopted international accounting standards and International Financial Reporting Standards (IFRSs) as issued by the International Accounting Standards Board (IASB) and as adopted by the European Union (EU).
- The parent company financial statements have been properly prepared in accordance with United Kingdom accounting standards (United Kingdom generally accepted accounting practice), including FRS 101 'Reduced Disclosure Framework'.
- The financial statements have been prepared in accordance with the requirements of the Companies Act 2006.

We have audited the financial statements of BP p.l.c which comprise the:

- group and parent company income statements
- group and parent company statements of comprehensive income
- group and parent company statements of changes in equity
- group and parent company balance sheets
- group cash flow statement
- group related Notes 1 to 38 to the financial statements, including a summary of material accounting policy information and
- parent company related Notes 1 to 14 to the financial statements, including a summary of material accounting policy information.

The financial reporting framework that has been applied in the preparation of the group financial statements is applicable law, United Kingdom adopted international accounting standards and IFRSs as issued by the IASB and as adopted by the EU. The financial reporting framework that has been applied in the preparation of the parent company financial statements is applicable law and United Kingdom accounting standards, including FRS 101 'Reduced Disclosure Framework' (United Kingdom generally accepted accounting practice).

2. Basis for opinion

We conducted our audit in accordance with International Standards on Auditing (UK) (ISAs (UK)) and applicable law. Our responsibilities under those standards are further described in the auditor's responsibilities for the audit of the financial statements section of our report.

We are independent of the group and the parent company in accordance with the ethical requirements that are relevant to our audit of the financial statements in the UK, including the Financial Reporting Council's (the 'FRC's') Ethical Standard as applied to listed public interest entities, and we have fulfilled our other ethical responsibilities in accordance with these requirements. The non-audit services provided to the group and parent company for the year are disclosed in Note 36 to the financial statements. We confirm that we have not provided any non-audit services prohibited by the FRC's Ethical Standard to the group or the parent company.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

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3. Summary of our audit approach

Key audit matters	The key audit matters that we identified in the current year were: • potential impact of climate change and the energy transition • impairment of upstream oil and gas property, plant and equipment (PP&E) assets • decommissioning provisions • accounting for complex transactions executed to deliver against the wider group strategy • valuation of commodity financial derivatives, where fraud risks may arise in revenue recognition, and • management override of controls. We have not included a key audit matter in respect of 'IT controls relating to financial systems' as there have been no new significant issues arising from our testing of financial systems. We also revisited the key audit matter of accounting for complex transactions and valuation of commodity financial derivatives identified in the prior year and concluded that given the evolving nature of these risks in the business and our response thereto, it would be appropriate to identify them as two separate key audit matters. All other key audit matters are consistent with those we identified in the prior year and the developments in fact patterns of these previously identified key audit matters are explained in the respective sections below.
Materiality	The materiality that we used for the group financial statements was $1,000 million (2022 $1,250 million) which was determined based on profit before tax and underlying replacement cost profit before interest and tax. In the prior year we determined materiality using profit before tax adjusted for the exceptional charges of $25.5 billion associated with the decision to exit bp's shareholding in Rosneft and underlying replacement cost profit before interest and tax.
Scoping	Our scope covered 189 consolidation units (cons units). Of these, 138 were full-scope audits and the remaining 51 were subject to specific procedures on certain account balances by component audit teams or the group audit team. These covered 70% of group revenue, 75% of PP&E and 71% of profit before tax. The remaining 743 cons units were subject to other procedures, including performing analytical reviews, making inquiries of management and evaluating and testing management's group-wide controls.

4. Conclusions relating to going concern

In auditing the financial statements, we have concluded that the directors' use of the going concern basis of accounting in the preparation of the financial statements is appropriate.

Our evaluation of the directors' assessment of the group's and parent company's ability to continue to adopt the going concern basis of accounting included:

- considering whether material uncertainties exist that could cast significant doubt on the entity's ability to continue as a going concern for at least 12 months after the date of approval of the financial statements
- assessing the financing facilities including the nature of the facilities, repayment terms and covenants
- assessing whether the impact of potential margin calls in respect of derivative exchange contracts used to risk manage the physical portfolio has been appropriately considered given price volatility
- assessing management's identified potential mitigating actions and the appropriateness of the inclusion of these in the going concern assessment
- testing the clerical accuracy of the going concern model
- assessing the historical accuracy of forecasts prepared by management
- performing our independent sensitivity analysis and
- assessing the disclosures made within the financial statements.

Based on our assessment, we concluded that the assumptions used by management were reasonable overall and the disclosures made within the financial statements were appropriate.

Based on the work we have performed, we have not identified any material uncertainties relating to events or conditions that, individually or collectively, may cast significant doubt on the group's and parent company's ability to continue as a going concern for a period of at least twelve months from when the financial statements are authorised for issue.

In relation to the reporting on how the group has applied the UK Corporate Governance Code, we have nothing material to add or draw attention to in relation to the directors' statement in the financial statements about whether the directors considered it appropriate to adopt the going concern basis of accounting.

Our responsibilities and the responsibilities of the directors with respect to going concern are described in the relevant sections of this report.

5. Key audit matters

Key audit matters are those matters that, in our professional judgement, were of most significance in our audit of the financial statements of the current year and include the most significant assessed risks of material misstatement (whether or not due to fraud) that we identified. These matters included those which had the greatest effect on the overall audit strategy, the allocation of resources in the audit and directing the efforts of the engagement team.

Throughout the course of our audit, we identify risks of material misstatement ('risks'). We consider both the likelihood of a risk and the potential magnitude of a misstatement in making the assessment. Certain risks are classified as 'significant' or 'higher' depending on their severity. The category of the risk determines the level of evidence we seek in providing assurance that the associated financial statement item is not materially misstated.

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The matters described below were addressed in the context of our audit of the financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

5.1 Potential impact of climate change and the energy transition (impacting PP&E, goodwill, intangible assets, investments in joint ventures and provisions) – Notes 1, 4, 12, 14, 15, 16 and 33	
Key audit matter description	Climate change impacts bp's business in a number of ways as set out in the strategic report on pages 1-80 of the Annual Report and Note 1 of the financial statements on page 169. It represents a strategic challenge and a key focus of management. The related risks that we have assessed for our audit are as follows: • Forecast assumptions used in assessing the value-in-use of oil and gas PP&E assets within bp's balance sheet for impairment testing, particularly oil and gas price assumptions and their interrelationship with forecast emissions costs, may not appropriately reflect changes in supply and demand due to climate change and the energy transition (see 'Impairment of upstream oil and gas PP&E assets' below). • The timing of expected future decommissioning expenditures in respect of oil and gas assets may need to be brought forward with a resulting increase in the present value of the associated liabilities due to the impact of climate change. In addition, there is an exposure to decommissioning obligations that may revert back to bp in respect of assets transferred to third parties through historical divestments. The risk of exposure is increased due to the impacts of climate change which have heightened long term financial resilience concerns for many industry participants. Furthermore, provisions for decommissioning refining assets, not generally recognised on the basis that the potential obligations cannot be measured given their indeterminate settlement dates, might need to be recognised if reductions in demand due to climate change curtail their operational lives (see 'Decommissioning provisions' below). • The recoverability of certain of the group's $4.3 billion total exploration and appraisal (E&A) assets capitalised as at 31 December 2023 (2022 $4.2 billion) is potentially exposed to climate change and the global energy transition risk factors (see Note 15). This is because a greater number of E&A projects may not proceed as a consequence of the energy transition leading to lower forecast future oil and gas prices, bp's intention to reduce its hydrocarbon production (by around 25% by 2030 relative to 2019 – see page 171). The determination of whether and when E&A costs should be written off, impaired, or retained on the balance sheet as E&A assets, remains complex and continues to require significant management judgement. • The carrying value of bp's refining assets within PP&E may no longer be recoverable, due to changes in supply and demand which arise as a consequence of climate change and the energy transition. Management identified impairment indicators in respect of the Gelsenkirchen refinery during the year and, as a result, an impairment test was performed to assess the recoverability of the refinery carrying value. As disclosed in Note 4 to the accounts on page 192, management has recorded an impairment charge of $1.3 billion in respect of the Gelsenkirchen refinery in Germany, primarily driven by changes in economic assumptions. • bp's intention to reduce its hydrocarbon production (by around 25% by 2030 relative to 2019 – see page 171) and the group's wider strategy includes potentially disposing of certain higher emissions intensity upstream oil assets and others. As a consequence, for certain assets and investments judgement is required in the determination of the recoverable amount as to whether it should consider the estimated disposal proceeds from a third party, as a key input. Management recorded $0.1 billion of pre-tax impairment charges in 2023 for such potential disposals but recorded $2.9 billion of such charges in 2022. There is a continuing risk that management judgements taken to determine whether impairment charges are required based on bp's view of whether transactions are likely to proceed or not, and bp's strategic appetite regarding the value of disposal consideration that would be accepted, are not reasonable. • The carrying value of the group's investments in low carbon energy assets may no longer be recoverable due to an increase in the low carbon energy discount rate (the renewable power assets discount rate) as well as increased project development costs, which have been impacted by higher inflation and activity levels within the sector (as a result of the energy transition). These factors are adversely impacting the value of low carbon energy projects, impacting investment decisions. As a result, impairment tests (which include judgements in relation to the fair value of land and sea bed leases, capital and operating cost assumptions and forecast yield and power price assumptions) were performed to assess the recoverability of the group's low carbon energy assets, resulting in an impairment recognised by equity accounted entities of $1.3 billion, as disclosed in Note 16 to the accounts on page 208. • The useful economic lives of the group's refining assets may be shortened as society moves towards 'net zero' emissions targets and bp seeks to achieve its net zero ambition, such that the depreciation charge is materially understated. Of the total refining assets carried in the balance sheet, all but an immaterial residual value relating primarily to land and buildings will be fully depreciated by 2050. As disclosed in Note 1 to the accounts on page 171, management has concluded that demand for refined products is expected to remain sufficient for the existing refineries to continue operating for the duration of their remaining useful lives and hence no changes to the useful economic lives of its refinery assets were required.

	• The total goodwill balance as at 31 December 2023 is $12.5 billion, of which $7.0 billion relates to upstream oil and gas assets. The carrying values of goodwill may no longer be recoverable as a consequence of climate change and therefore may need to be impaired. For oil production & operations (OP&O), goodwill is allocated to CGUs in aggregate at the segment level and for gas & low carbon energy (G&LCE) goodwill is allocated to the hydrocarbon CGUs within the segment. The most significant assumption in the goodwill impairment tests affected by climate change relates to future oil and gas prices (see 'Impairment of upstream oil and gas PP&E assets' below). Given the significant level of headroom in the goodwill impairment tests, management identified no other assumption that could lead to a material misstatement of goodwill due to the energy transition and other climate change factors. Disclosures in relation to sensitivities for goodwill are included within Note 14 on page 205. The customers & products (C&P) segment has a goodwill balance of $5.4 billion, of which the most significant element is $2.7 billion relating to the Castrol business. Notwithstanding the expected global transition to electric vehicles which may reduce demand for Lubricants, due to the substantial headroom in the most recent impairment test (as described in Note 14), management has assessed as remote the likelihood that the recoverable amount of goodwill is less than its carrying value. • Climate change-related litigation brought against bp, as disclosed in Note 33 to the financial statements, may lead to an outflow of funds requiring provision. The above considerations were a significant focus of management during the period which led to this being a matter that we communicated to the audit committee, and which had a significant effect on the overall audit strategy. We therefore identified this as a key audit matter.
How the scope of our audit responded to the key audit matter	**Overall response** We held discussions with management, with our climate change specialists and within the group engagement team to identify the areas where we felt climate change could have a potential impact on the financial statements. We also continued to utilise a climate change steering committee comprising a group of senior partners and specialists with specific climate change and technical audit and accounting expertise within Deloitte to provide an independent challenge to our key decisions and conclusions with respect to this area. **Audit procedures** The audit response related to two of the audit risks identified is set out under the key audit matters for 'Impairment of upstream oil and gas PP&E assets' on pages 143-145 and 'Decommissioning provisions' on pages 146-147. Other procedures are as follows: In respect of the recoverability of E&A assets capitalised as at 31 December 2023: • We tested the relevant controls within the group's E&A write-off and impairment assessment processes. • We challenged and evaluated management's key E&A judgements with regards to the impairment criteria of IFRS 6. Where impairment indicators were identified, we corroborated key judgements with internal and external evidence for assets that remained on the balance sheet. This included analysing evidence of future E&A plans, budgets and capital allocation decisions, assessing management's key accounting judgement papers, reading meeting minutes and assessing licence documentation and evidence of active dialogue with partners and regulators including negotiations to renew licences or modify key terms. We considered the impact of potential changes in supply and demand on the group's refining portfolio and reviewed internal and external market studies of future supply and demand. In relation to the Gelsenkirchen refinery impairment test, we assessed the valuation methodology, tested the integrity and mechanical accuracy of the impairment model and assessed the appropriateness of key assumptions and inputs, notably forecast refining margins and energy input costs, challenging and evaluating management's assumptions by reference to third party data where available. We also evaluated management's ability to forecast future cash flows and margins by comparing actual results to historical forecasts and tested management's internal controls over the impairment test and related inputs. We challenged management's analysis that identified the specific assets that are likely to be disposed of by bp as part of its strategy. Where relevant, we challenged bp's asset impairment assessments based on their estimated disposal proceeds and whether transactions are judged likely to proceed or not. We obtained evidence of any negotiations with third parties, considered bp's strategic intent in this context and challenged management's assessment of the recoverable amounts for material transactions. We also tested relevant controls which covered both the recoverable amounts determined and the likelihood of transaction completion. In respect of the impairment tests performed on certain offshore wind asset low carbon energy investments, we tested the result by: • Testing the relevant controls over these low carbon energy impairment tests including controls over key assumptions and the discount rate • Assessing the low carbon energy discount rate with input from our valuation specialists • Challenging and evaluating the key assumptions within the impairment tests. This included the fair value of land and sea bed leases, capital and operating cost assumptions, and forecast yield and power price assumptions impacting the fair value of the development project and • Testing the mechanical accuracy of the impairment models.

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	We challenged management's assertion that no changes are required to the assessed useful economic lives of refining assets as a consequence of climate change factors. In doing this, we obtained third party reports assessing future refined petroleum product demand for those countries which are included in our group full audit scope for the C&P segment. In particular, we considered the forecasts as set out in the IEA World Energy Outlook 2023 which shows that demand for refined petroleum products is expected to remain sufficient for at least the current remaining useful economic lives of the refineries such that current depreciation rates are appropriate, including under the Announced Pledges Scenario which is associated with a temperature rise of 1.7 °C in 2100 (with a 50% probability). We performed procedures to satisfy ourselves that, other than future oil and gas price assumptions, there were no other assumptions in management's oil and gas goodwill impairment tests to which reasonably possible changes due to the energy transition and other climate change factors could cause goodwill to be materially misstated. We obtained evidence which supported management's conclusion that goodwill relating to the C&P segment activities is not impaired due to climate change or other factors. With regard to climate change litigation, we designed procedures specifically to respond to the risks that provisions could be understated or that contingent liability disclosures may be omitted or be inaccurate including: • Holding discussions with the group general counsel and other senior bp lawyers regarding climate change matters • Conducting a search for climate change litigation and claims brought against the group • Making written inquiries of, and holding discussions with, external legal counsel advising bp in relation to climate change litigation and • Assessing the contingent liability disclosures in the annual report on pages 241-243. We read the other information included in the Annual Report and considered (a) whether there was any material inconsistency between the other information and the financial statements; or (b) whether there was any material inconsistency between the other information and our understanding of the business based on audit evidence obtained and conclusions reached in the audit.
Key observations	Key observations in relation to oil and gas price assumptions used in oil and gas PP&E asset impairment tests, and the impact of climate change on decommissioning provisions are set out in the relevant key audit matter below. We concluded that the key E&A assessments had been appropriately determined and the judgements management had made were appropriately supported. We did not identify any additional impairments or write-offs from the work we performed. We also confirmed management's view that they did not consider that the progression of any of their E&A assets would be inconsistent with bp's current strategy and management's capital frame and capital allocation intentions in light of climate change and the energy transition. We are satisfied: • with the results of our procedures relating to the carrying value of refining assets and that the impairments recorded are reasonable • that management's planned disposal related asset impairment assessments are reasonable and we did not identify any additional material impairments • with the results of the low carbon energy impairment tests. The discount rate used by management was within the range that we would have expected. • with the results of our procedures relating to the assessment of the useful economic lives of refining assets and therefore depreciation charges, based on the market studies we read • with the sensitivity analysis disclosures around the energy transition and other climate change factors performed in respect of the goodwill balances; and that the group's goodwill balances are not materially misstated • with management's assertion that no provision should currently be made in respect of climate change litigation. Based on the audit evidence obtained both from internal and external legal counsel, we concluded that management's disclosure of the contingent liabilities in respect of these matters is appropriate and • that management's other disclosures in the Annual Report relating to climate change are consistent with the financial statements and our understanding of the business. Whilst many of bp's oil and gas properties and refining assets are long term in nature, by 2050, the remaining carrying value of assets currently being depreciated will be immaterial, this date being the target set by the majority of governments with 'net zero' emissions targets and also by bp, being Aim 1 of the 'Getting to net zero' strategy set out on page 48. At current rates of depreciation, depletion and amortisation (DD&A), the average remaining depreciable life of the upstream oil and gas PP&E (within the OP&O and G&LCE segments) is six years and the refining assets (within the C&P segment) is twelve years.

5.2 Impairment of upstream oil and gas property, plant and equipment (PP&E) assets – Notes 1, 4 and 12 to the financial statements	
Key audit matter description	The group balance sheet as at 31 December 2023 includes PP&E of $105 billion (2022 $106 billion), of which $62 billion (2022 $68 billion) is oil and gas properties. Management's best estimate of oil and gas price assumptions for value-in-use impairment tests were revised in 2023 as set out in Note 1 on page 177. Brent oil price and Henry Hub assumption revisions during 2023 were not significant. Management has also revised bp's 'best estimate' discount rate assumptions for value-in-use impairment tests in 2023, as set out in Note 1 on page 177. bp's post-tax nominal weighted average cost of capital, being the starting point for setting discount rates used for impairment testing for oil and gas assets, has increased to 8% (2022 7%), reflecting the impact of observable increases in risk free rates on bp's weighted average cost of capital. Given the significance of the discount rate assumption revisions during 2023, alongside certain CGU specific new indicators, management has tested all oil and gas CGUs for impairment and/or impairment reversal during the year. Management recorded $3.6 billion (2022 $2.2 billion) of pre-tax oil and gas CGU impairment charges, principally due to the discount rate revisions detailed above, price revisions, increase in certain capital expenditure forecasts, operating expenditure forecasts and certain reserves write downs. Further information has been provided in Note 1 on page 177 and Note 4 on page 191. We identified three key management estimates in management's determination of the level of impairment charge and/or impairment reversal. These are: **Oil and gas prices** - bp's oil and gas price assumptions have a significant impact on many CGU impairment assessments performed across the OP&O and G&LCE segments and are inherently uncertain. The estimation of future prices is subject to increased uncertainty given climate change, the global energy transition, macro-economic factors and disruption in global supply due to ongoing geo-political conflicts. There is a risk that management do not forecast reasonable 'best estimate' oil and gas price forecasts when assessing CGUs for impairment charge and/or impairment reversal, leading to material misstatements. These price assumptions are highly judgmental and are pervasive inputs to bp's oil and gas CGU valuation. There is also a risk that management's oil and gas price related disclosures are not reasonable. bp's oil and gas price assumptions for value-in use impairment assessments are aligned with bp's investment appraisal assumptions, except that potential future emissions costs that could be borne by bp are included in investment appraisals as bp costs without assuming incremental revenue. As described in Note 1 on page 170, emissions costs forecasts interrelate with bp's oil and gas prices, because bp's price assumptions for value-in-use estimates represent 'net producer prices', i.e., net of any further emissions costs that may be enacted in the future. Management's judgement is that the potential impact of such further emissions costs being borne by producers including bp is not expected to have a material impact on bp's oil and gas CGU carrying values as costs would effectively be borne by oil and gas end users via overall higher commodity prices. There is a risk that management's judgement is not reasonable. **Discount rates** – Given the long timeframes involved, certain CGU impairment assessments are sensitive to the discount rate applied. Discount rates should reflect the return required by the market and the risks inherent in the cash flows being discounted. There is a risk that management does not assume reasonable discount rates, adjusted as applicable for country risks and relevant tax rates, leading to material misstatements. Determining a reasonable discount rate is highly judgmental and, consistent with price assumptions above, the discount rate assumption is also a pervasive input across bp's oil and gas CGU valuations, before adjustments for asset specific risks and tax rates. **Reserves and resources estimates** – A key input to certain CGU impairment assessments is the oil and gas production forecast, which is based on underlying reserves estimates and field specific development assumptions. Certain CGU production forecasts include specific risk adjusted resource volumes, in addition to proven and/or probable reserves estimates, that are inherently less certain than reserves; and assumptions related to these volumes can be particularly judgemental. There is a risk that material misstatements could arise from unreasonable production forecasts for individually material CGUs and/or from the aggregation of systematic flaws in bp's reserves and resources estimation policies across the OP&O and G&LCE segments. We identified certain individual CGUs with a total carrying value of $18 billion (2022 $17 billion) which we determined would be most at risk of material impairment charges as a result of a reasonably possible change in the oil and gas price assumptions. This population includes $5 billion of previously impaired assets which are also at risk of material impairment reversal resulting from potential oil and gas price assumption changes. We identified that a subset of these CGUs was also individually materially sensitive to the discount rate assumption. Accordingly, we identified these as significant audit risks. We also identified CGUs with a further $2 billion (2022 $13 billion) of combined carrying value which were less sensitive. We identified these as a higher audit risk as they would be potentially at risk, in aggregate, to a material impairment by a reasonably possible change in some or all of the key assumptions. No impairment reversals are available for these CGUs. Further information regarding these sensitivities is given in Note 1 on page 178. Impairment charge and/or impairment reversal assessments of upstream oil and gas PP&E assets remain a key audit matter because recoverable values are reliant on forecasts that are inherently judgemental and complex for management to estimate, and the magnitude of the potential misstatement risk is material to the group.

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How the scope of our audit responded to the key audit matter	We tested relevant internal controls over the estimation of oil and gas prices, discount rates, and reserve and resources estimates, as well as key internal controls over the performance of the impairment charge and/or impairment reversal assessments where we identified audit risks. In addition, we conducted the following substantive procedures. **Oil and gas prices** • We independently developed a reasonable range of forecasts based on external data obtained, against which we compared management's oil and gas price assumptions in order to challenge whether they are reasonable. • In developing this range, we obtained a variety of reputable and reliable third party forecasts, peer information and other relevant market data. • In challenging management's price assumptions, we considered the extent to which they and each of the forecast pricing scenarios obtained from third parties reflect the impact of lower oil and gas demand due to climate change and the energy transition. • The 2015 Conference of the Parties (CoP) 21 Paris Agreement goals of 'holding the increase in the global average temperature to well below 2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels' was reaffirmed at CoP 28 in Dubai during December 2023. We specifically analysed third party forecasts stated, or interpreted by us, as being consistent with scenarios achieving the Paris 'well below 2°C goal' and/or '1.5°C ambition' and evaluated whether they presented contradictory audit evidence. • We challenged and evaluated management's judgement, described in Note 1 on page 170, that the potential impact of further emission costs being borne by producers including bp is not expected to have a material impact on bp's oil and gas CGU carrying values. We obtained evidence supporting that oil and gas price forecasts included in our reasonable range are forecast on a 'net producer prices' basis, (i.e., net of potential future emissions costs that are assumed to be borne by oil and gas end users), consistent with the basis of bp's value-in-use price assumptions. • We assessed management's disclosures in Note 1, including the sensitivity of forecast revenue cash inflows to lower oil and gas prices and how climate change and the energy transition, potential future emissions costs and/or reduced demand scenarios may impact bp to a greater extent than currently anticipated in bp's value-in-use estimates for oil and gas CGUs. **Discount rates** • We independently evaluated bp's discount rates used in impairment tests with input from our valuation specialists, against relevant third party market and peer data. • When performing procedures over specific assets, we assessed whether specific country risks and tax adjustments were reasonably reflected in bp's discount rates. • We challenged and evaluated management's disclosures in Note 1, including in relation to the sensitivity of discount rate assumptions. **Reserves and resources estimates** With the assistance of our oil and gas reserves specialists we: • assessed bp's reserves and resources estimation methods and policies for reasonableness • assessed how these policies had been applied to a sample of bp's reserves and resources estimates which included those that we judged to represent the greatest risk of material misstatement • read and evaluated a sample of reports provided by management's external reserves experts and assessed the scope of work and findings of these third parties • assessed the competence, capabilities and objectivity of bp's internal and external reserve experts, through understanding their relevant professional qualifications and experience • assessed whether management's production forecasts are consistent overall with bp's strategy, including the group's expectation to reduce its hydrocarbon production (by around 25% by 2030 relative to 2019 - see page 171) • compared the production forecasts used in the impairment tests with management's approved reserves and resources estimates and • performed a retrospective assessment in order to assess management's ability to accurately estimates reserves and resources and to check for indications of estimation bias over time.

Key observations	**Oil and gas prices** For the purpose of PP&E impairment tests, management is required under IAS 36 to apply its current 'best estimate' of future oil and gas prices. We determined that bp's 'best estimate' assumptions are reasonable when compared against a range of third party forecasts and peer information that we identified as being appropriate for this purpose. In forming this view, we included each forecaster's 'base case', 'central case' or 'most likely' estimate. We further observed that, as well as publishing a 'base case', 'central case' or 'most likely' estimate, certain third party price forecasters (including the IEA and the WBCSD Catalogue from April 2023) published other price forecasts including some that were stated as, or were interpreted by us as being, Paris 'well below 2°C goal' or Paris '1.5°C ambition' scenarios. We observed that none of those third party forecasters described their 'Paris consistent' scenarios as their 'base case', 'central case' or 'most likely' estimate. Management notes on page 170 that they consider their 'best estimate' prices to be in line with a range of transition paths consistent with the Paris climate goal of limiting global warming to well below 2°C as well as the ambition to limit global warming to no greater than 1.5°C. We observed that for oil, whilst being within the lower half of our range of 'best estimate' forecasts described above, bp's Brent price assumptions were overall within the higher half of our range of Paris 'well below 2°C goal' and '1.5°C ambition' scenarios. For Henry Hub gas, management's updated gas price assumptions until 2050 sit towards the middle of our range. The positioning of bp's revised oil and gas forecasts within the range is broadly consistent with bp's positioning in the prior period range. We also noted certain other reputable third party sources that set out or implied even higher prices under both Paris 'well below 2°C goal' and '1.5°C ambition' scenarios, highlighting the large inherent uncertainty regarding 'Paris consistent' pathways and the very wide range of potential price forecasts. Accordingly, we consider management's statement as set out above to be reasonable. By inquiry and analysis, we confirmed that the third party oil and gas price forecasts used to develop our independent range are on a net producer price basis. Accordingly, we are satisfied management's judgement is reasonable that the potential impact of further emission costs being borne by bp is not expected to have a material impact on the group's oil and gas CGU carrying values. We reviewed the disclosures included in Note 1 to the accounts in respect of oil and gas price assumptions, including the sensitivity analysis presented therein. We observed that management's downside sensitivity, in which oil and gas prices are lower than the 'best estimate' in all future periods, is broadly in the middle of our range of third party Paris 'well below 2°C goal' and Paris '1.5°C ambition' scenarios between 2025 and 2030 and thereafter close to the bottom of the range for both Brent oil and Henry Hub gas. **Discount rates** bp's post-tax nominal 8% weighted average cost of capital, being the starting point for setting discount rates used for impairment testing for oil and gas assets, was within the independent range calculated by our valuation specialists. We were also satisfied with the calculation of country risk premia. Accordingly, we are satisfied with the discount rates used in the impairment charge and impairment reversal testing. **Reserves and resources** We assessed the production forecasts used in the oil and gas CGU valuations that we tested to be reasonable and appropriately risked where applicable, for the purposes of management's impairment tests. We observed that in aggregate, management's production forecasts, as utilised in year end oil and gas CGU impairment testing, are aligned with bp's target to reduce hydrocarbon production by 25% of 2019 levels by 2030.

5.3 Decommissioning provisions - Note 1 and 23	
Key audit matter description	A decommissioning provision of $12.4 billion is recorded in the financial statements as at 31 December 2023 (2022 $12.3 billion). The estimation of decommissioning provisions is a highly judgemental area as it involves a number of key estimates related to the cost and timing of decommissioning, in particular inflation and discount rate assumptions. Given management expects upstream hydrocarbon production to be around 25% lower by 2030 relative to 2019 as stated on page 171, consistency of that expectation with the timing of decommissioning expenditure and underlying cost assumptions remains a key consideration. Consistent with prior years, management estimates that the average rate of forecast inflation applicable to the substantial majority of bp's decommissioning cost estimates is 1.5%, which is 0.5% lower than its estimated long term general inflation rate of 2%. The extent to which average future decommissioning cost inflation will differ from the general inflation rate depends on industry demand and supply of rigs and other relevant services at the time future decommissioning occurs, which in turn will be influenced by future oil and gas demand, and increasingly by structural changes in the industry supply chain driven by the energy transition, which are uncertain. With the impact of inflation on relevant costs now better understood and able to be factored into cost estimates, and general inflationary pressures easing in some areas during 2023, we considered this judgement to be a higher rather than a significant audit risk for 2023. The estimated undiscounted cost of the obligations and the timing of future payment are set out in Note 1 on page 184. Economic factors, future activities and the legislative environments that bp operates in are used to inform cost estimates, whereas the timing of decommissioning activities is dependent on cessation of production (CoP) dates, which are sensitive to changes in bp's price forecasts as price estimates determine economic cut off of oil and gas reserve estimates. bp increased its discount rate used in calculating its decommissioning provisions from 3.5% as at 31 December 2022 to 4.0% as at 31 December 2023. The increase was primarily driven by the increased US treasury bond rates. Additionally, bp is exposed to decommissioning obligations that could revert back to the group in respect of historical divestments to third parties. Judgement is required to assess the potential risk of reversion and if applicable, the estimated exposure, for each historically divested asset. The risk of reversion could be elevated by the potential impact of the energy transition, in particular the potential for lower oil and gas prices in the longer term which could result in financial resilience concerns for some industry participants. The risk further increased following a US legal judgement in 2020 which required a specific provision and increased the likelihood of decommissioning liabilities reverting to former owners as part of a bankruptcy proceeding. Provisions for decommissioning refining assets, not generally recognised on the basis that the potential obligations cannot be measured given their indeterminate settlement dates, might need to be recognised if reductions in demand due to climate change curtail their operational lives. As disclosed in Note 1 on page 184 management concluded that, although obligations may arise if refineries cease manufacturing operations, they would only be recognised at the point when sufficient information became available to determine potential settlement dates. Accordingly, other than where a decision has been made to cease refining operations, no triggers for assessing the need to record a decommissioning provision have been identified.
How the scope of our audit responded to the key audit matter	**Long term inflation rate** • We tested the control related to the determination of the decommissioning specific inflation rate assumption. • We tested how management derived the decommissioning specific inflation rate assumption of 1.5%, and the evidence on which it is based, by gaining an understanding of the process used by management, testing management's calculations of the assumption, and evaluating the evidence relevant to management's assumption, both supporting and contradictory. • As the 1.5% decommissioning specific inflation rate assumption is determined by making an adjustment to management's 2.0% general long term inflation rate assumption, we evaluated the general long term inflation rate assumption used of 2.0%, comparing it against latest external market data. • We made inquiries and evaluated the competence, capabilities and objectivity of management's decommissioning experts who derived the decommissioning specific inflation rate. • We inspected analyst forecasts and reports in respect of the future decommissioning market and related costs for evidence of supporting and contradictory evidence, with particular focus on the future rig market. • We particularly considered the expectation that demand for oil and gas products and related activities will decrease, primarily in response to climate change and energy transition effects pivoting future energy industry investment and development activity towards renewable sources. We challenged and evaluated management's assessment of the impact this will have on the decommissioning market and related inflation assumption. • We analysed historical trends of rig market rates against oil prices and historical inflation to challenge management's assumption that the decommissioning inflation assumption does not inflate at the same rate as general inflation.

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	Cost and timing estimates • We tested the controls over the year end decommissioning cost and timing assumptions used within management's decommissioning provision estimate. • We assessed the completeness and accuracy of the assets subject to decommissioning, including understanding the process to establish whether a legal or constructive obligation existed. • We evaluated changes in key cost assumptions including rig rates, vessel rates, well plug and abandonment duration and non-productive time assumptions. • We challenged whether the impact of inflation experienced in 2023 was appropriately considered and reflected where relevant within bp's cost assumptions. • We assessed the reasonableness of key cost assumptions with reference to internal and appropriate third party data. • We assessed changes in assumptions for the estimated date of decommissioning and evaluated whether CoP dates used for decommissioning estimation are aligned with CoP assumptions in other areas, including PP&E impairment testing and oil and gas reserve estimation. • We assessed the accuracy of bp's disclosure of the estimated undiscounted cost of its obligations and the timing of future decommissioning payments. **Discount rates** • We tested the control related to the determination of the discount rate assumption. • We assessed the reasonableness of management's methodology for determining the discount rate and recalculated the discount rate with reference to independent third party data, most notably US treasury bond yields. **Reversion risk** • We obtained an understanding of bp's decommissioning reversion risk assessment process and tested relevant internal controls including those controls over the completeness and accuracy of the previously divested asset data. • We challenged and evaluated management's key judgements related to the decommissioning reversion risk and conclusions as to whether any additional provision should be recognised, or specific contingent liability disclosure made. We assessed the relevant internal and external evidence used in forming this judgement, including the financial health of the counterparty or counterparties in the ownership chain for the divested assets and the existence of any other pertinent factors which could indicate a higher probability of decommissioning obligations reverting to bp. **Potential decommissioning of refinery assets** • We challenged and evaluated management's analysis which supported the judgement that no decommissioning provisions should be recognised in respect of refineries where there is ongoing activity and management has no current intention to cease these activities. • We have reviewed analysis undertaken by management, as well as third party studies, of forecast demand for refined products in regions served by bp's refineries. Furthermore, we read external profitability benchmarking which supported a conclusion that the group's remaining refineries would likely remain operational for longer than many of their regional competitors, in the event of refining capacity reductions. • We also met with refinery management to understand the potential plans under consideration for refineries in the future and obtained evidence that management is developing plans for the existing refinery sites remaining in the portfolio which would be compatible with net zero emissions, for instance through the production of alternative low carbon and sustainable fuels.
Key observations	We concluded that the assumed inflation rate of 1.5% remains reasonable as a long-term inflation rate for decommissioning liabilities. We accept as reasonable that the high level of general inflation experienced in 2023 does not require a change to bp's long term average inflation assumption. With respect to the extent to which average future decommissioning cost inflation will differ from the general inflation rate, which is influenced by the demand and supply of rigs and other relevant services at the time future decommissioning occurs, we concluded that market forecasts support the assertion that demand for rigs will not increase in the long term as a result of the impact of the energy transition and therefore that inflation of rig costs will be limited. We concluded that the cost and timing assumptions used in the decommissioning provision calculation were reasonable and the assumptions are appropriately supported by industry data. The disclosure included on page 184 with respect to the estimated undiscounted cost of bp's decommissioning obligations and the timing of future decommissioning payments are consistent with these conclusions. Based on our audit procedures, we consider bp's increased 4.0% discount rate to be reasonable. No material additional decommissioning provisions have been made in respect of historical divestments where bp are exposed to decommissioning reversion risk as a result of the potential future bankruptcy of the current asset owner. Based on our review and challenge of management's assessment, we consider this judgement to be reasonable. We also consider the contingent liability disclosure to be reasonable. In respect of the group's refining assets, taking into consideration both the IEA demand forecasts and management's strategic plans for the group's refineries, including developing production of low carbon and sustainable fuels, we are satisfied that it is not currently possible for management to determine closure dates for the remaining operational refineries or estimate reliably a settlement date for any decommissioning obligations prior to a decision being made to cease refining operations. Accordingly, we have not identified any triggers that would require a decommissioning provision to be recorded.

5.4 Accounting for complex transactions executed to deliver against the wider group strategy - Notes 1, 20, 22, 29 and 30 to the financial statements

<table>
<tr><td>Key audit matter description</td><td>
To support the overall group strategy, which includes achieving bp's group 'net zero' target, bp is increasingly entering into long term arrangements that include gas and renewable power offtake/supply contracts in existing and new markets whilst providing solutions to bp’s customers through offering lower carbon hydrocarbons. Given the nature of these transactions, we direct significant audit effort towards challenging management’s adopted accounting treatment and/or valuation estimates.
In previous years, such activity was primarily carried out within the trading and shipping (T&S) function. However, such activity can also originate outside of T&S, across segments, functions and/or geographies but in close collaboration with T&S.
These transactions may be complex and have sustainability, legal, tax or financial reporting outcomes which are new for the group and may be executed in reference to, or in conjunction with, existing arrangements. Determining the appropriate accounting treatment for these transactions can require a high degree of management judgement.
Determining the appropriate accounting treatment for these complex transactions:
Based on our risk assessment and understanding of the underlying business rationale of such transactions, we generally consider that complexity arises where the arrangements exhibit one or more of the following indicators:

Offtake/sale-purchase agreements where the group is the only key customer/supplier;
The counterparty or the arrangement depends on the group to provide a significant level of financing;
The group controls exclusive rights, licenses, technology, know-how etc. without which the counterparty cannot conduct its operations or the arrangement cannot be fulfilled;
The arrangement exposes the group to returns/losses which are disproportionate to those which its economic interest would suggest;
Contractual arrangements entered into in contemplation of each other; or
The transaction or arrangement directly impacts key performance indicators, in particular, finance debt.

The presence of any one or a combination of these indicators does not make a transaction or arrangement inherently complex but are factors we consider in our assessment of the risk arising from the transaction.
Accounting for such transactions can be complex and can involve significant judgement, as a feature of these transactions is that they often include multiple elements that will have a material impact on the presentation and disclosure in the financial statements and on key performance measures, including in particular the classification of liabilities as finance debt. Accordingly, we have identified a significant audit risk around the accounting for such transactions.
</td></tr>
<tr><td>How the scope of our audit responded to the key audit matter</td><td>
For complex accounting transactions identified during the year we:

Tested controls related to the accounting for complex transactions.
Developed an understanding of the commercial rationale of the transactions through discussions with management and reading transaction documents and executed agreements.
For transactions exhibiting certain of the above indicators, performed a detailed accounting analysis leveraging the expertise of technical accounting specialists with experience in commodities markets.

For complex transactions which were identified during the prior years and that continue through 2023, we have refreshed our assessment in 2023 taking account of any amendments to the contracts. We assessed whether the conclusions reached previously remain appropriate and in accordance with relevant accounting standards.
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<tr><td>Key observations</td><td>
As the group’s activities continue to evolve, in pursuit of its long and medium term strategy, we noted complex accounting transactions primarily emerging from its transitional activities, such as gas, power and renewables.
For complex accounting transactions identified during the period, we concluded that the accounting applied by management was compliant with IFRS.
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5.5 Valuation of commodity financial derivatives, where fraud risks may arise in revenue recognition - Notes 1, 29 and 30 to the financial statements	
Key audit matter description	bp's trading and shipping (T&S) function is responsible for globally trading and risk managing the group's owned as well as third party production. To discharge this responsibility, T&S regularly executes commodity contracts, physically settled or otherwise, which are accounted for as a derivative and fair valued under IFRS 9. These contracts, therefore, result in unrealised gains/losses that are recognised on account of fair value movements in the associated derivative assets and liabilities. Determining the fair value of derivative assets and liabilities can be complex and subjective, particularly where the valuation is dependent on significant inputs which are not observable and are classified as level 3 in the fair value hierarchy set out in IFRS 13. This degree of subjectivity also makes such fair value estimates liable to potential fraud by management incorporating bias in the inputs used in determining fair values. Given the significant judgements, sensitivity to management assumptions, and the absolute value associated with these positions, we have identified a significant risk in respect of certain financial instruments where the valuation is dependent on significant unobservable inputs. Fair value measurements associated with unrealised commodity contracts are also impacted by the macroeconomic sentiment and outlook. In 2023, commodity markets remained relatively volatile due to continuing uncertainty resulting from the planned energy transition, macro-economic factors such as inflation and interest rates, and disruptions in global supply due to geopolitical conflicts. In response to the volatility observed, we focused our audit efforts on the valuation of all commodity derivatives and designed procedures specifically to test for management bias. As at 31 December 2023, the group's total level 3 derivative financial assets were $9.2 billion (2022 $8.8 billion) and level 3 derivative financial liabilities were $7.1 billion (2022 $7.0 billion).
How the scope of our audit responded to the key audit matter	In response to the above, we analysed the population of these instruments to assess the level of unobservability of the inputs used in their valuation and then further disaggregated the population into different risk populations which in turn drove the nature, timing and extent of our audit procedures. To address the complexities associated with auditing the valuation of instruments dependent on significant unobservable inputs, we included valuation specialists with significant quantitative and modelling expertise to assist in performing our audit procedures. Our valuation audit included the following control and substantive procedures: • We tested the group's valuation controls including: – the model certification control, which is designed to review a model's theoretical soundness and the appropriateness of its valuation methodology; and – the independent price verification control, which is designed to review the appropriateness of valuation inputs that are not observable and are significant to the financial instrument's valuation. • We performed valuation testing procedures at interim and year-end balance sheet dates, including: – comparing management's input assumptions against the expected assumptions of other market participants and observable market data; – evaluating management's valuation methodologies against standard valuation practice and analysing whether a consistent framework is applied across the business period over period; and – engaging our valuation specialists to challenge models, develop fair value estimates and evaluate consistency in management's modelling and input assumptions throughout the year.
Key observations	Based on the evaluation of the results of the procedures noted above, we concluded that management's valuations relating to commodity derivatives were appropriate. We did not identify any indications of inappropriate misrepresentation of revenue recognition in the transactions, valuation estimates or accounting entries that we tested.

5.6 Management override of controls (potentially impacting all financial statement accounts)	
Key audit matter description	We conducted an assessment of the fraud risks arising from management override of controls by considering potential areas where the group's financial statements could be manipulated. In performing this assessment, we considered pressures or incentives to achieve certain IFRS or non-IFRS measures due to the remuneration arrangements of people in Financial Reporting Oversight Roles (FRORs), including management and senior executives, as well as other incentives which could exist in light of bp's share buyback commitments communicated to its shareholders. Our considerations included the potential for: • inappropriate accounting estimates and judgements • the posting of fictitious or fraudulent journal entries or • inappropriate accounting for significant transactions that are outside the normal course of business for the entity. Management has implemented a number of new journal controls in 2021, 2022 and 2023 to address deficiencies identified during prior period audits. During the year we identified deficiencies in these new controls but mitigating controls to address the risk associated with the deficiencies were also identified. These included analytical reviews, controls over closing balances, period-end analytical review controls and certain automated business controls. This had a significant bearing again this year on the allocation of audit resources and has been discussed with the audit committee throughout the year. Accordingly, we identified this as a key audit matter.

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How the scope of our audit responded to the key audit matter	We tested the mitigating controls to respond to the risk of fraudulent journal entries. In addition, we: made inquiries of individuals involved in the financial reporting process about inappropriate or unusual activity relating to the processing of journal entries and other adjustments; identified and tested relevant entity-level controls, in particular those related to the bp Code of Conduct, whistleblowing (bp OpenTalk) and controls monitoring financial reporting processes and financial results; used our data analytics tools to select for testing journal entries and other adjustments made at the end of a reporting period or otherwise having characteristics associated with common fraud schemes; and tested journal entries and other adjustments recorded in the general ledger throughout the period, with a particular focus on adjustments that occur late in the financial close process. We assessed accounting estimates for bias and evaluated whether the circumstances producing the bias, if any, represent a risk of material misstatement due to fraud. A number of the most significant estimates are covered by the other Key Audit Matters set out above. This assessment included: evaluating whether the judgements and decisions made by management in making the accounting estimates included in the financial statements, even if they are individually reasonable, indicate a possible bias on the part of bp's management that may represent a risk of material misstatement due to fraud; and performing a retrospective analysis of management judgements and assumptions related to significant accounting estimates reflected in the financial statements of the prior year. We considered whether there were any significant transactions that are outside the normal course of business, or that otherwise appear to be unusual due to their nature, timing or size. The risks and responses to the revenue recognition risks within the trading and shipping function are set out on page 149.
Key observations	Our testing of the mitigating controls indicated that they were operating effectively. Our substantive testing of journal entries and other adjustments, selected through the use of our data analytics tools, did not identify any inappropriate items. We did not identify evidence of overall bias or any significant transactions that are outside the normal course of business for which the business rationale (or the lack thereof) of the transaction suggested that it may have been entered into to engage in fraudulent financial reporting or to conceal misappropriation of assets.

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6. Our application of materiality

6.1 Materiality

We define materiality as the magnitude of misstatement in the financial statements that makes it probable that the economic decisions of a reasonably knowledgeable person would be changed or influenced. We use materiality both in planning the scope of our audit work and in evaluating the results of our work.

Based on our professional judgement, we determined materiality for the financial statements as a whole as follows:

	Group financial statements	Parent company financial statements
Materiality	In 2023 we set materiality for both the group and parent company at $1,000 million. In 2022 we used a materiality of $1,250 million for the group and parent company. Group and parent company planning materiality for 2022 was $1,000 million and our audit scoping and audit testing was conducted using this planning materiality.	
Basis for determining materiality	Consistent with the prior year we concluded that it is appropriate to use profit before tax as a materiality benchmark; however unlike last year where there were exceptional charges associated with the decision to exit bp's shareholding in Rosneft, no adjustment in respect of exceptional items was made in the current year. For both the current and prior years, we also used underlying replacement cost profit before interest and tax as a benchmark for determining materiality. Materiality was determined to be $1,000 million, which is 4.2% of profit before tax and 3.7% of underlying replacement cost profit before tax. In 2022, we determined materiality to be $1,250 million, which represented 3.1% of normalized profit before tax and 2.7% of underlying replacement cost profit before tax.	We determined materiality for our audit of the standalone parent using 0.8% (2022 1.1%) of net assets.
Rationale for the benchmark applied	We conducted an assessment of which line items are the most important to investors and analysts by reading analyst reports and bp's communications to shareholders and lenders, as well as the communications of peer companies. Profit before tax is the benchmark ordinarily considered by us when auditing listed entities. It provides comparability against companies across all sectors but has limitations when auditing companies whose earnings are strongly correlated to commodity prices, which can be volatile from one period to the next, and therefore may not be representative of the volume of transactions and the overall size of the business in the year. This resulted in us selecting profit before tax and underlying replacement cost profit before interest and tax as the most appropriate benchmarks. We further note that the non-IFRS measure underlying replacement cost profit before interest and tax is one of the key metrics communicated by management in bp's results announcements and therefore is considered to be an appropriate benchmark.	The materiality determined for the standalone parent company is based on net assets as the company is non--trading and operates primarily as a holding company; we believe the net asset position is the most appropriate benchmark to use.

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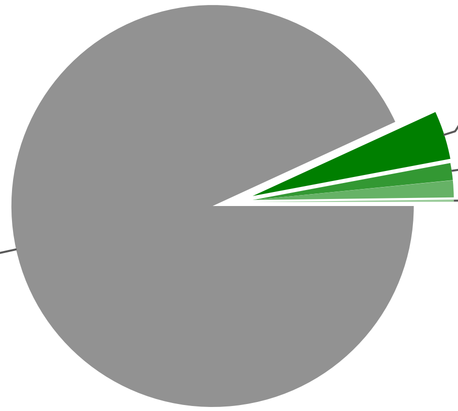

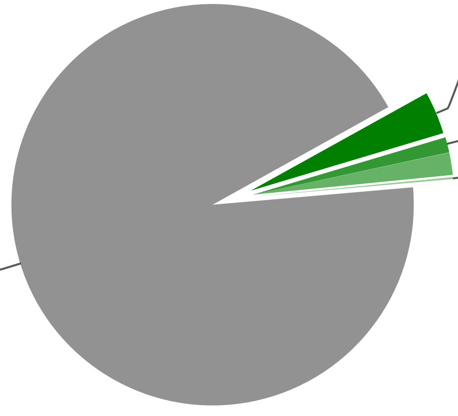

6.2 Performance materiality

We set performance materiality at a level lower than materiality to reduce the probability that, in aggregate, uncorrected and undetected misstatements exceed the materiality for the financial statements as a whole.

	Group financial statements	Parent company financial statements
Performance materiality	Group and parent company performance materiality was set at 65% of materiality for the 2023 audit (2022 65% of materiality).	
Basis and rationale for determining performance materiality	Consistent with the prior year, performance materiality of 65% reflects the overall quality of the control environment, the magnitude of misstatements identified in the current and prior years, as well as the fact that management is generally willing to correct any such misstatements.	

6.3 Error reporting threshold

We agreed with the audit committee that we would report to the committee all audit differences in excess of $50 million (2022 $50 million), as well as differences below that threshold that, in our view, warranted reporting on qualitative grounds. We also report to the audit committee on disclosure matters that we identified when assessing the overall presentation of the financial statements.

7. An overview of the scope of our audit

7.1 Identification and scoping of components

As a result of the highly disaggregated nature of the group, with operations in over 60 countries through approximately 930 cons units, a significant portion of our audit planning effort was ensuring that the scope of our work is appropriate in addressing the identified risks of material misstatement.

The factors that we considered when assessing the scope of the bp audit, and the level of work to be performed at the cons units that are in scope for group reporting purposes, included the following:

- The financial significance of an operating unit (which will typically include multiple cons units) to bp's revenue and profit before tax, or PP&E, including consideration of the financial significance of specific account balances or transactions.
- The significance of specific risks relating to an operating unit, history of unusual or complex transactions, identification of significant audit issues or the potential for, or a history of, material misstatements.

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- The effectiveness of the control environment and monitoring activities, including entity-level controls.
- The findings, observations and audit differences that we noted as a result of our 2022 audit engagement.
- Our audit approach was generally to place reliance on management's controls over financial reporting.

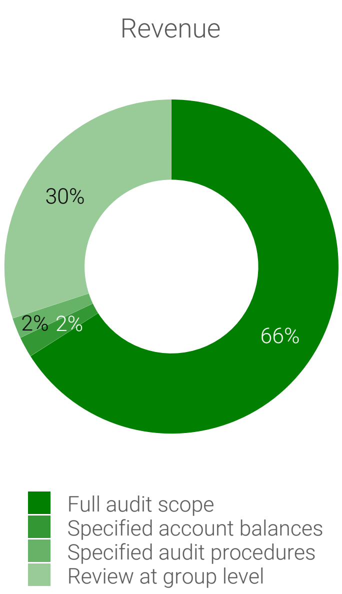
To ensure we were able to obtain sufficient, appropriate audit evidence for the purposes of our audit of the financial statements, we performed full scope audit procedures for 138 reporting cons units (2022 152) which were selected based on their size or risk characteristics. There are certain cons units which have fallen out of scope due to disposals, asset impairments and non-recurring one off transactions which were in scope in the prior year. Our full-scope audits are in the UK, US, Australia, Azerbaijan and Germany.

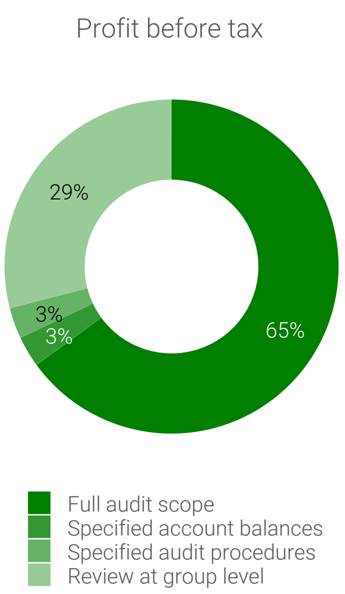
In addition, component teams performed audit procedures on specified account balances in 24 cons units (2022 19) also covering Trinidad and Tobago, Mauritania & Senegal, Indonesia, Egypt, India and UAE. The group engagement team performed audit procedures on specified account balances to component materiality, with certain additional specific procedures performed by component teams, covering an additional 27 cons units (2022 33).

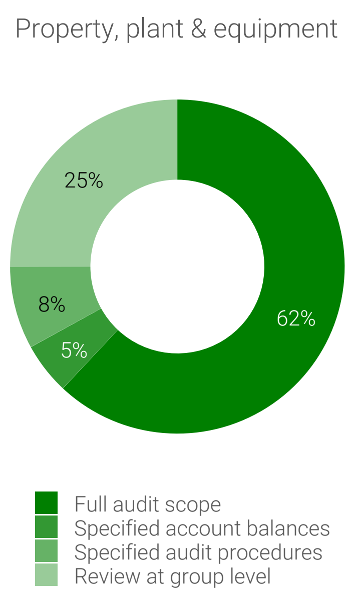
The remaining cons units are not significant individually and include many small, low risk components and balances. On average, they each represent 0.04% of group revenue (2022 0.03%), 0.03% of property, plant and equipment (2022 0.03%) and 0.04% of profit before tax (2022 0.04%).

In our assessment of the residual balances not covered by the above procedures, we have considered the risk that there could be a material misstatement within the large number of geographically dispersed businesses, in particular within the C&P segment. This assessment included use of our analytic tools to interrogate data, preparation of trend analysis and comparison of business performance to market benchmark prices. We also tested management's group-wide controls across a range of locations and segments. We concluded that through this additional risk assessment, we have reduced the audit risk of such a misstatement arising to a sufficiently low level.

Our audit coverage of 'Property, plant and equipment', 'Sales and other operating revenue' and 'Profit before tax' is materially the same as in the prior year.







7.2 Our consideration of the control environment

Our audit approach was generally to place reliance on management's relevant controls over all business cycles affecting in scope financial statement line items. We tested a sample of these controls through a combination of tests of inquiry, observation, inspection and re-performance.

In limited situations where we were not able to take a controls reliance approach due to controls being deficient and there not being sufficient mitigating or alternative controls we could rely on instead, we adopted a non-controls reliance approach. All control deficiencies which we considered to be significant were communicated to the audit committee. All other deficiencies were communicated to management. For all deficiencies identified we considered the impact and updated our audit plan accordingly.

The group's financial systems environment is complex, with 140 separate IT systems scoped (including 23 systems acquired by bp through recent acquisitions) as being relevant to the audit for the following key locations (UK, US, Germany, Azerbaijan and Australia) as well as other minor locations. These systems are all directly or indirectly relevant to the entity's financial reporting process.

We planned to rely on the General IT Controls ('GITCs') associated with these systems, and having tested controls over access security, change management, data centre operations and network operations, were able to do so.

7.3 Working with other auditors

The group audit team are responsible for the scope and direction of the audit process and provide direct oversight, review, and coordination of our component audit teams. We interacted regularly with the component Deloitte teams during each stage of the audit and reviewed key working papers. We maintained continuous and open dialogue with our component teams in addition to holding formal meetings quarterly to ensure that we were fully aware of their progress and results of their procedures.

Consistent with prior year, the senior statutory auditor and other group audit partners and staff conducted visits to meet with the component teams responsible for all of the full scope locations during the year as well as Egypt, Indonesia and Trinidad and Tobago. These visits included attending planning meetings, discussing the audit approach including the risk assessments and any issues arising from the component team's work, meetings with local management, and reviewing key audit working papers on higher and significant-risk areas to drive a consistent and high-quality audit. In addition, a global audit planning meeting was held in London for three days in July led by the senior statutory auditor and involving the group audit team, partners and staff from all full scope component teams, audit teams responsible for testing at key Global Business Services (GBS) locations and senior management from bp.

Following the group's decision to exit Rosneft in February 2022, Rosneft is no longer classified as a reportable segment and the investment was fully impaired in that year. Accordingly, Rosneft was no longer a significant component in scope of the group audit and we therefore did not require reporting from Rosneft's auditor. The group audit team audited the Rosneft investment valuation and other Rosneft related judgements including the decision not to recognise dividends.

8. Other information

The other information comprises the information included in the annual report, other than the financial statements and our auditor's report thereon. The directors are responsible for the other information contained within the annual report.

Our opinion on the financial statements does not cover the other information and, except to the extent otherwise explicitly stated in our report, we do not express any form of assurance conclusion thereon.

Our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the course of the audit, or otherwise appears to be materially misstated.

If we identify such material inconsistencies or apparent material misstatements, we are required to determine whether this gives rise to a material misstatement in the financial statements themselves. If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact.

We have nothing to report in this regard.

9. Responsibilities of directors

As explained more fully in the directors' responsibilities statement, the directors are responsible for the preparation of the financial statements and for being satisfied that they give a true and fair view, and for such internal control as the directors determine is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, the directors are responsible for assessing the group's and the parent company's ability to continue as a going concern, disclosing as applicable matters related to going concern and using the going concern basis of accounting unless the directors either intend to liquidate the group or the parent company or to cease operations, or have no realistic alternative but to do so.

10. Auditor's responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with ISAs (UK) will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

A further description of our responsibilities for the audit of the financial statements is located on the FRC's website at: frc.org.uk/auditorsresponsibilities. This description forms part of our auditor's report.

11. Extent to which the audit was considered capable of detecting irregularities, including fraud

Irregularities, including fraud, are instances of non-compliance with laws and regulations. We design procedures in line with our responsibilities, outlined above, to detect material misstatements in respect of irregularities, including fraud. The extent to which our procedures are capable of detecting irregularities, including fraud is detailed below.

11.1 Identifying and assessing potential risks related to irregularities

In identifying and assessing risks of material misstatement in respect of irregularities, including fraud and non-compliance with laws and regulations, we considered the following:

- our meetings throughout the year with the Group Head of Ethics and Compliance and reviews of bp's internal ethics and compliance reporting summaries, including those concerning investigations.
- enquiries of management, internal audit, and the audit committee, including obtaining and reviewing supporting documentation, concerning the group's policies and procedures relating to:
  - identifying, evaluating and complying with laws and regulations and whether they were aware of any instances of non-compliance
  - detecting and responding to the risks of fraud and whether they have knowledge of any actual, suspected or alleged fraud and
  - the internal controls established to mitigate risks related to fraud or non-compliance with laws and regulations.
- review of the terms of reference of the Fraud Governance Board set up by management to support the creation and delivery of the Group Fraud Risk Strategy, periodically monitor the threat outlook and review the risk appetite.
- review of the Fraud Governance Board's meeting minutes and its fraud risk assessment.
- enquiries of those charged with governance with regards to the facts and circumstances related to the resignation of the former Chief Executive Officer and the related investigation undertaken by the Board, and the impact of this on the Board's assessment of risk of non-compliance with laws and regulations.
- the group's remuneration policies, key drivers for remuneration and bonus levels and

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- discussions among the engagement team regarding how and where fraud might occur in the financial statements and any potential indicators of fraud. The engagement team includes audit partners and staff who have extensive experience of working with companies in the same sectors as bp operates, and this experience was relevant to the discussion about where fraud risks may arise. The discussions also involved fraud specialists who advised the engagement team of fraud schemes that had arisen in similar sectors and industries, and they participated in the initial fraud risk assessment discussions.

In common with all audits under ISAs (UK), we are also required to perform specific procedures to respond to the risk of management override.

We also obtained an understanding of the legal and regulatory frameworks that the group operates in, focusing on provisions of those laws and regulations that had a direct effect on the determination of material amounts and disclosures in the financial statements. The key laws and regulations we considered in this context included the UK Companies Act, UK Corporate Governance Code, United Kingdom adopted international accounting standards and IFRSs as issued by the IASB and as adopted by the EU, FRS 101, US Securities Exchange Act 1934 and relevant SEC regulations, as well as laws and regulations prevailing in each country in which we identified a full-scope component.

In addition, we considered provisions of other laws and regulations that do not have a direct effect on the financial statements but compliance with which may be fundamental to the group's ability to operate or to avoid a material penalty. These included the group's operating licences and environmental regulations.

11.2 Audit response to risks identified

As a result of performing the above, we did not identify any key audit matters related to the potential risk of non-compliance with laws and regulations. We did identify two key audit matters relating to fraud risks, as described above, being the valuation of commodity financial derivatives, and management override of controls. The key audit matters section of our report explains the matters in more detail and also describes the specific procedures we performed in response to those key audit matters.

In addition to the above, procedures to respond to risks identified included the following:

- reviewing the financial statement disclosures and testing to supporting documentation to assess compliance with provisions of relevant laws and regulations described as having a direct effect on the financial statements
- enquiring of management, the audit committee and in-house legal counsel concerning actual and potential litigation and claims
- obtaining confirmations from external legal counsel concerning open litigation and claims
- performing analytical procedures to identify any unusual or unexpected relationships that may indicate risks of material misstatement due to fraud and
- reading minutes of meetings of those charged with governance, reviewing internal audit reports and reviewing correspondence with HMRC and the IRS.

We also communicated relevant identified laws and regulations and potential fraud risks to all engagement team members including internal specialists and significant component audit teams and remained alert to any indications of fraud or non-compliance with laws and regulations throughout the audit.

Report on other legal and regulatory requirements

12. Opinions on other matters prescribed by the Companies Act 2006

In our opinion the part of the directors' remuneration report to be audited has been properly prepared in accordance with the Companies Act 2006.

In our opinion, based on the work undertaken in the course of the audit:

- The information given in the strategic report and the directors' report for the financial year for which the financial statements are prepared is consistent with the financial statements.
- The strategic report and the directors' report have been prepared in accordance with applicable legal requirements.

In the light of the knowledge and understanding of the group and the parent company and their environment obtained in the course of the audit, we have not identified any material misstatements in the strategic report or the directors' report.

13. Corporate Governance Statement

The Listing Rules require us to review the directors' statement in relation to going concern, longer-term viability and that part of the Corporate Governance Statement relating to the group's compliance with the provisions of the UK Corporate Governance Code specified for our review.

Based on the work undertaken as part of our audit, we have concluded that each of the following elements of the Corporate Governance Statement is materially consistent with the financial statements and our knowledge obtained during the audit:

- the directors' statement with regards to the appropriateness of adopting the going concern basis of accounting and any material uncertainties identified set out on page 135
- the directors' explanation as to its assessment of the group's prospects, the period this assessment covers and why the period is appropriate set out on page 135
- the directors' statement on fair, balanced and understandable set out on page 135
- the board's confirmation that it has carried out a robust assessment of the emerging and principal risks set out on page 134
- the section of the annual report that describes the review of effectiveness of risk management and internal control systems set out on page 134 and
- the section describing the work of the audit committee set out on pages 98-102.

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

14. Matters on which we are required to report by exception

14.1 Adequacy of explanations received and accounting records

Under the Companies Act 2006 we are required to report to you if, in our opinion:

- we have not received all the information and explanations we require for our audit or
- adequate accounting records have not been kept by the parent company, or returns adequate for our audit have not been received from branches not visited by us or
- the parent company financial statements are not in agreement with the accounting records and returns.

We have nothing to report in respect of these matters.

14.2 Directors' remuneration

Under the Companies Act 2006 we are also required to report if in our opinion certain disclosures of directors' remuneration have not been made or the part of the directors' remuneration report to be audited is not in agreement with the accounting records and returns.

We have nothing to report in respect of these matters.

15. Other matters which we are required to address

15.1 Auditor tenure

The board appointed Deloitte as the company's auditor with effect from 29 March 2018 to fill the vacancy arising from the resignation of the previous auditor. On 27 April 2023, shareholders resolved at the annual general meeting to reappoint Deloitte as auditor from the conclusion of the meeting until the conclusion of the annual general meeting to be held in 2024 and authorized the directors to set the audit fees.

The first accounting period we audited was the 12 month period ended 31 December 2018. The period of total uninterrupted engagement including previous renewals and reappointments of the firm is 6 years, covering the years ending 31 December 2018 to 31 December 2023.

15.2 Consistency of the audit report with the additional report to the audit committee

Our audit opinion is consistent with the additional report to the audit committee we are required to provide in accordance with ISAs (UK).

16. Use of our report

This report is made solely to the company's members, as a body, in accordance with Chapter 3 of Part 16 of the Companies Act 2006. Our audit work has been undertaken so that we might state to the company's members those matters we are required to state to them in an auditor's report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the company and the company's members as a body, for our audit work, for this report, or for the opinions we have formed.

In due course, as required by the Financial Conduct Authority (FCA) Disclosure Guidance and Transparency Rule (DTR) 4.1.15R – DTR 4.1.18R, these financial statements will form part of the Electronic Format Annual Financial Report filed on the National Storage Mechanism of the FCA in accordance with DTR 4.1.15R – DTR 4.1.18R. This auditor's report provides no assurance over whether the Electronic Format Annual Financial Report has been prepared in compliance with DTR 4.1.15R – DTR 4.1.18R.

Judith Tacon FCA (Senior statutory auditor)
For and on behalf of Deloitte LLP
Statutory Auditor
London, United Kingdom
8 March 2024

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Report of Independent Registered Public Accounting Firm

To the shareholders and board of directors of BP p.l.c.

Opinion on the financial statements

We have audited the accompanying consolidated group balance sheets of BP p.l.c. and subsidiaries (together 'bp' or 'the group') as at 31 December 2023 and 2022, the related consolidated group income statements, group statements of comprehensive income, group statements of changes in equity and group cash flow statements, for each of the three years in the period ended 31 December 2023, and the related notes (collectively referred to as the 'financial statements'). In our opinion, the financial statements present fairly, in all material respects, the financial position of the group as at 31 December 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended 31 December 2023, in accordance with United Kingdom adopted international accounting standards and International Financial Reporting Standards (IFRSs) as issued by the International Accounting Standards Board (IASB) and as adopted by the European Union (EU).

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), bp's internal control over financial reporting as of 31 December 2023, based on criteria established in the UK Financial Reporting Council's Guidance on Risk Management, Internal Control and Related Financial and Business reporting relating to internal control over financial reporting and our report dated 8 March 2024 expressed an unqualified opinion on bp's internal control over financial reporting.

Basis for opinion

These financial statements are the responsibility of bp's management. Our responsibility is to express an opinion on bp's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to bp in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current-period audit of the financial statements that were communicated or required to be communicated to the audit committee and that (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

1. Impairment of upstream oil and gas property, plant and equipment (PP&E) assets – Notes 1, 4 and 12 to the financial statements

Critical Audit Matter Description

The group balance sheet as at 31 December 2023 includes PP&E, of which $62 billion is oil and gas properties.

Management's best estimate of oil and gas price assumptions for value-in-use impairment tests were revised in 2023 as set out in Note 1 on page 177. Brent oil price and Henry Hub assumption revisions during 2023 were not significant. Management has also revised bp's 'best estimate' discount rate assumptions for value-in-use impairment tests in 2023, as set out in Note 1 on page 177. bp's post-tax nominal weighted average cost of capital, being the starting point for setting discount rates used for impairment testing for oil and gas assets, has increased to 8%, reflecting the impact of observable increases in risk free rates on bp's weighted average cost of capital.

Given the significance of the discount rate assumption revisions during 2023, alongside certain CGU specific new indicators, management has tested all oil and gas CGUs for impairment and/or impairment reversal during the year. Management recorded $3.6 billion of pre-tax oil and gas CGU impairment charges, principally due to the discount rate revisions detailed above, price revisions, increase in certain capital expenditure forecasts, operating expenditure forecasts and certain reserves write downs. Further information has been provided in Note 1 on page 177 and Note 4 on page 191.

We identified three key management estimates in management's determination of the level of impairment charge and/or impairment reversal. These are:

Oil and gas prices - bp's oil and gas price assumptions have a significant impact on many CGU impairment assessments performed across the OP&O and G&LCE segments and are inherently uncertain. The estimation of future prices is subject to increased uncertainty given climate change, the global energy transition, macro-economic factors and disruption in global supply due to ongoing geo-political conflicts. There is a risk that management do not forecast reasonable 'best estimate' oil and gas price forecasts when assessing CGUs for impairment charge and/or impairment reversal, leading to material misstatements. These price assumptions are highly judgmental and are pervasive inputs to bp's oil and gas CGU valuations. There is also a risk that management's oil and gas price related disclosures are not reasonable.

Discount rates - Given the long timeframes involved, certain CGU impairment assessments are sensitive to the discount rate applied. Discount rates should reflect the return required by the market and the risks inherent in the cash flows being discounted. There is a risk that management does not assume reasonable discount rates, adjusted as applicable for country risks and relevant tax rates, leading to material misstatements. Determining a reasonable discount rate is highly judgmental and, consistent with price assumptions above, the discount rate assumption is also a pervasive input across bp's oil and gas CGU valuations, before adjustments for asset specific risks and tax rates.

Reserves and resources estimates - A key input to certain CGU impairment assessments is the oil and gas production forecast, which is based on underlying reserves estimates and field specific development assumptions. Certain CGU production forecasts include specific risk adjusted resource volumes, in addition to proven and/or probable reserves estimates, that are inherently less certain than reserves; and assumptions related to these volumes can be particularly judgemental. There is a risk that material misstatements could arise from unreasonable production forecasts for individually material CGUs and/or from the aggregation of systematic flaws in bp's reserves and resources estimation policies across the OP&O and G&LCE segments.

We identified certain individual CGUs which we determined would be most at risk of material impairment charges as a result of a reasonably possible change in the oil and gas price assumptions. This population includes previously impaired assets which are also at risk of material impairment reversal resulting from potential oil and gas price assumption changes. We identified that a subset of these CGUs was also individually materially sensitive to the discount rate assumption.

We also identified CGUs which were less sensitive as they would be potentially at risk, in aggregate, to a material impairment by a reasonably possible change in some or all of the key assumptions. No impairment reversals are available for these CGUs. Further information regarding these sensitivities is given in Note 1 on page 178.

Impairment charge and/or impairment reversal assessments of upstream oil and gas PP&E assets remain a critical audit matter because recoverable values are reliant on forecasts that are inherently judgemental and complex for management to estimate, and the magnitude of the potential misstatement risk is material to the group.

How the Critical Audit Matter was addressed in the Audit

We tested relevant internal controls over the estimation of oil and gas prices, discount rates, and reserve and resources estimates, as well as key internal controls over the performance of the impairment charge and/or impairment reversal assessments where we identified audit risks. In addition, we conducted the following substantive procedures.

Oil and gas prices

- We independently developed a reasonable range of forecasts based on external data obtained, against which we compared management's oil and gas price assumptions in order to challenge whether they are reasonable.
- In developing this range, we obtained a variety of reputable and reliable third party forecasts, peer information and other relevant market data.
- In challenging management's price assumptions, we considered the extent to which they and each of the forecast pricing scenarios obtained from third parties reflect the impact of lower oil and gas demand due to climate change and the energy transition.
- The 2015 Conference of the Parties (CoP) 21 Paris Agreement goals of 'holding the increase in the global average temperature to well below 2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels' was reaffirmed at CoP 28 in Dubai during December 2023. We specifically analysed third party forecasts stated, or interpreted by us, as being consistent with scenarios achieving the Paris 'well below 2°C goal' and/or '1.5°C ambition' and evaluated whether they presented contradictory audit evidence.
- We assessed management's disclosures in Notes 1, including the sensitivity of forecast revenue cash inflows to lower oil and gas prices and how climate change and the energy transition, potential future emissions costs and/or reduced demand scenarios may impact bp to a greater extent than currently anticipated in bp's value-in-use estimates for oil and gas CGUs.

Discount rates

- We independently evaluated bp's discount rates used in impairment tests with input from our valuation specialists, against relevant third party market and peer data.
- When performing procedures over specific assets, we assessed whether specific country risks and tax adjustments were reasonably reflected in bp's discount rates.
- We challenged and evaluated management's disclosures in Notes 1, including in relation to the sensitivity of discount rate assumptions.

Reserves and resources estimates

With the assistance of our oil and gas reserves specialists we:

- assessed bp's reserves and resources estimation methods and policies for reasonableness
- assessed how these policies had been applied to a sample of bp's reserves and resources estimates
- read and evaluated a sample of reports provided by management's external reserves experts and assessed the scope of work and findings of these third parties
- assessed the competence, capabilities and objectivity of bp's internal and external reserve experts, through understanding their relevant professional qualifications and experience
- assessed whether management's production forecasts are consistent overall with bp's strategy, including the group's expectation to reduce its hydrocarbon production (by around 25% by 2030 relative to 2019 - see page 171)
- compared the production forecasts used in the impairment tests with management's approved reserves and resources estimates and
- performed a retrospective assessment in order to assess management's ability to accurately estimate reserves and resources and to check for indications of estimation bias over time.

2. Decommissioning provisions – Notes 1 and 23

Critical Audit Matter Description

A decommissioning provision of $12.4 billion is recorded in the financial statements as at 31 December 2023. The estimation of decommissioning provisions is a highly judgemental area as it involves a number of key estimates related to the cost and timing of decommissioning, in particular inflation and discount rate assumptions. Given management expects upstream hydrocarbon production to be around 25% lower by 2030 relative to 2019 as stated on page 171, consistency of that expectation with the timing of decommissioning expenditure and underlying cost assumptions remains a key consideration.

Consistent with prior years, management estimates that the average rate of forecast inflation applicable to the substantial majority of bp's decommissioning cost estimates is 1.5%, which is 0.5% lower than its estimated long term general inflation rate of 2%.

The estimated undiscounted cost of the obligations and the timing of future payment are set out in Note 1 on page 184. Economic factors, future activities and the legislative environments that bp operates in are used to inform cost estimates, whereas the timing of decommissioning activities is dependent on cessation of production (CoP) dates, which are sensitive to changes in bp's price forecasts as price estimates determine economic cut off of oil and gas reserve estimates.

bp increased its discount rate used in calculating its decommissioning provisions from 3.5% as at 31 December 2022 to 4.0% as at 31 December 2023. The increase was primarily driven by the increased US treasury bond rates.

Provisions for decommissioning refining assets, not generally recognised on the basis that the potential obligations cannot be measured given their indeterminate settlement dates, might need to be recognised if reductions in demand due to climate change curtail their operational lives. As disclosed in Note 1 on page 184 management concluded that, although obligations may arise if refineries cease manufacturing operations, they would only be recognised at the point when sufficient information became available to determine potential settlement dates. Accordingly, other than where a decision has been made to cease refining operations, no triggers for assessing the need to record a decommissioning provision have been identified.

How the Critical Audit Matter was addressed in the Audit

Long term Inflation rate

- We tested the control related to the determination of the decommissioning specific inflation rate assumption.
- We tested how management derived the decommissioning specific inflation rate assumption of 1.5%, and the evidence on which it is based, by gaining an understanding of the process used by management, testing management's calculations of the assumption, and evaluating the evidence relevant to management's assumption, both supporting and contradictory.
- As the 1.5% decommissioning specific inflation rate assumption is determined by making an adjustment to management's 2.0% general long term inflation rate assumption, we evaluated the general long term inflation rate assumption used of 2.0%, comparing it against latest external market data.
- We made inquiries and evaluated the competence, capabilities and objectivity, of management's decommissioning experts who derived the decommissioning specific inflation rate.
- We inspected analyst forecasts and reports in respect of the future decommissioning market and related costs for evidence of supporting and contradictory evidence, with particular focus on the future rig market.
- We particularly considered the expectation that demand for oil and gas products and related activities will decrease, primarily in response to climate change and energy transition effects pivoting future energy industry investment and development activity towards renewable sources. We challenged and evaluated management's assessment of the impact this will have on the decommissioning market and related inflation assumption.
- We analysed historical trends of rig market rates against oil prices and historical inflation to challenge management's assumption that the decommissioning inflation assumption does not inflate at the same rate as general inflation.

Cost and timing estimates

- We tested the controls over the year end decommissioning cost and timing assumptions used within management's decommissioning provision estimate.
- We assessed the completeness and accuracy of the assets subject to decommissioning, including understanding the process to establish whether a legal or constructive obligation existed.
- We evaluated changes in key cost assumptions including rig rates, vessel rates, well plug and abandonment duration and non-productive time assumptions.
- We challenged whether the impact of inflation experienced in 2023 was appropriately considered and reflected where relevant within bp's cost assumptions.
- We assessed the reasonableness of key cost assumptions with reference to internal and appropriate third party data.
- We assessed changes in assumptions for the estimated date of decommissioning and evaluated whether CoP dates used for decommissioning estimation are aligned with CoP assumptions in other areas, including PP&E impairment testing and oil and gas reserve estimation.
- We assessed the accuracy of bp's disclosure of the estimated undiscounted cost of its obligations and the timing of future decommissioning payments.

Discount rates

- We tested the control related to the determination of the discount rate assumption.
- We assessed the reasonableness of management's methodology for determining the discount rate and recalculated the discount rate with reference to independent third party data, most notably US treasury bond yields.

Potential decommissioning of refinery assets

- We challenged and evaluated management's analysis which supported the judgement that no decommissioning provisions should be recognised in respect of refineries where there is ongoing activity and management has no current intention to cease these activities.
- We have reviewed analysis undertaken by management, as well as third party studies, of forecast demand for refined products in regions served by bp's refineries. Furthermore, we read external profitability benchmarking which supported a conclusion that the group's remaining refineries would likely remain operational for longer than many of their regional competitors, in the event of refining capacity reductions.
- We also met with refinery management to understand the potential plans under consideration for refineries in the future and obtained evidence that management is developing plans for the existing refinery sites remaining in the portfolio which would be compatible with net zero emissions, for instance through the production of alternative low carbon and sustainable fuels.

3. Accounting for complex transactions executed to deliver against the wider group strategy - Notes 1, 20, 22, 29 and 30 to the financial statements

Critical Audit Matter Description

To support the overall group strategy, which includes achieving bp's 'net zero' target, bp is increasingly entering into long term arrangements that include gas and renewable power offtake/supply contracts in existing and new markets whilst providing solutions to bp's customers through offering lower carbon hydrocarbons. Given the nature of these transactions, we direct significant audit effort towards challenging management's adopted accounting treatment and/or valuation estimates.

In previous years, such activity was primarily carried out within the trading and shipping (T&S) function. However, such activity can also originate outside of T&S, across segments, functions and/or geographies but in close collaboration with T&S.

These transactions may be complex and have sustainability, legal, tax or financial reporting outcomes which are new for the group and may be executed in reference to, or in conjunction with, existing arrangements. Determining the appropriate accounting treatment for these transactions can require a high degree of management judgement.

Determining the appropriate accounting treatment for these complex transactions:

Based on our risk assessment and understanding of the underlying business rationale of such transactions, we generally consider that complexity arises where the arrangements exhibit one or more of the following indicators:

- Offtake/sale-purchase agreements where the group is the only key customer/supplier;
- The counterparty or the arrangement depends on the group to provide a significant level of financing;
- The group controls exclusive rights, licenses, technology, know-how etc. without which the counterparty cannot conduct its operations or the arrangement cannot be fulfilled;
- The arrangement exposes the group to returns/losses which are disproportionate to those which its economic interest would suggest;
- Contractual arrangements entered into in contemplation of each other; or
- The transaction or arrangement directly impacts key performance indicators, in particular, finance debt.

The presence of any one or a combination of these indicators does not make a transaction or arrangement inherently complex but are factors we consider in our assessment of the risk arising from the transaction.

Accounting for such transactions can be complex and can involve significant judgement, as a feature of these transactions is that they often include multiple elements that will have a material impact on the presentation and disclosure in the financial statements, including in particular the classification of liabilities as finance debt.

How the Critical Audit Matter was addressed in the Audit

For complex accounting transactions identified during the year, we:

- Tested controls related to the accounting for complex transactions.
- Developed an understanding of the commercial rationale of the transactions through discussions with management and reading transaction documents and executed agreements.
- For transactions exhibiting certain of the above indicators, performed a detailed accounting analysis leveraging the expertise of technical accounting specialists with experience in commodities markets.

4. Valuation of commodity financial derivatives, where fraud risks may arise in revenue recognition - Notes 1, 29 and 30 to the financial statements

Critical Audit Matter Description

bp's trading and shipping (T&S) function is responsible for globally trading and risk managing the group's owned as well as third party production. To discharge this responsibility, T&S regularly executes commodity contracts, physically settled or otherwise, which are accounted for as a derivative and fair valued under IFRS 9. These contracts, therefore, result in unrealised gains/losses that are recognised on account of fair value movements in the associated derivative assets and liabilities.

Determining the fair value of derivative assets and liabilities can be complex and subjective, particularly where the valuation is dependent on significant inputs which are not observable and are classified as level 3 in the fair value hierarchy set out in IFRS 13. This degree of subjectivity also makes such fair value estimates prone to potential fraud by management incorporating bias in the inputs used in determining fair values. Given the significant judgements, sensitivity to management assumptions, and the absolute value associated with these positions, we have identified a risk in respect of certain financial instruments where the valuation is dependent on significant unobservable inputs.

Fair value measurements associated with unrealised commodity contracts are also impacted by the macroeconomic sentiment and outlook. In 2023, commodity markets remained relatively volatile due to continuing uncertainty resulting from the planned energy transition, macro-economic factors such as inflation and interest rates, and disruptions in global supply due to geopolitical conflicts. In response to the volatility observed, we focused our audit efforts on the valuation of all commodity derivatives and designed procedures specifically to test for management bias.

As at 31 December 2023, the group's total level 3 derivative financial assets were $9.2 billion and level 3 derivative financial liabilities were $7.1 billion.

How the Critical Audit Matter was addressed in the Audit

In response to the above, we analysed the population of these instruments to assess the level of unobservability of the inputs used in their valuation and then further disaggregated the population into different risk populations which in turn drove the nature, timing and extent of our audit procedures.

To address the complexities associated with auditing the valuation of instruments dependent on significant unobservable inputs, we included valuation specialists with significant quantitative and modelling expertise to assist in performing our audit procedures. Our valuation audit included the following control and substantive procedures:

- We tested the group's valuation controls including:
  - the model certification control, which is designed to review a model's theoretical soundness and the appropriateness of its valuation methodology; and
  - the independent price verification control, which is designed to review the appropriateness of valuation inputs that are not observable and are significant to the financial instrument's valuation.
- We performed valuation testing procedures at interim and year-end balance sheet dates, including:
  - comparing management's input assumptions against the expected assumptions of other market participants and observable market data;
  - evaluating management's valuation methodologies against standard valuation practice and analysing whether a consistent framework is applied across the business period over period; and
  - engaging our valuation specialists to challenge models, develop fair value estimates and evaluate consistency in management's modelling and input assumptions throughout the year.

5. Impairment of E&A assets, investments in joint ventures and refinery PP&E as a consequence, among other things, of climate change and the energy transition – Notes 1, 4, 15 and 16

Critical Audit Matter Description

Intangible Assets

The recoverability of certain of the group's $4.3 billion total exploration and appraisal (E&A) assets capitalised as at 31 December 2023 is potentially exposed to climate change and the global energy transition risk factors (see Note 15). This is because a greater number of E&A projects may not proceed as a consequence of the energy transition leading to lower forecast future oil and gas prices, and bp's intention to reduce its hydrocarbon production (by around 25% by 2030 relative to 2019 – see page 171). The determination of whether and when E&A costs should be written off, impaired, or retained on the balance sheet as E&A assets, remains complex and continues to require significant management judgement.

PP&E and Investment in joint ventures

The carrying value of bp's refining assets within PP&E may no longer be recoverable, due to changes in supply and demand which arise as a consequence of climate change and the energy transition. Management identified impairment indicators in respect of the Gelsenkirchen refinery during the year and as a result, an impairment test was performed to assess the recoverability of the refinery carrying value. As disclosed in Note 4 to the accounts on page 192, management has recorded an impairment charge of $1.3 billion in respect of the Gelsenkirchen refinery in Germany, primarily driven by changes in economic assumptions.

There is also a risk that the carrying value of the group's investments in low carbon energy assets may no longer be recoverable due to an increase in the low carbon energy discount rate (the renewable power assets discount rate) as well as increased project development costs, which have been impacted by higher inflation and activity levels within the sector (as a result of the energy transition). These factors are adversely impacting the value of low carbon energy projects, impacting investment decisions. As a result, impairment tests(which include judgements in relation to the fair value of land and sea bed leases, capital and operating cost assumptions and forecast yield and power price assumptions) were performed to assess the recoverability of the group's low carbon energy assets, resulting in an impairment recognised by equity accounted entities of $1.3 billion, as disclosed in Note 16 to the accounts on page 208.

How the Critical Audit Matter Was Addressed in the Audit

A climate change steering committee comprising a group of senior partners and specialists with specific climate change and technical audit and accounting expertise within Deloitte was utilised to provide an independent challenge to our key decisions and conclusions with respect to this area.

Intangible Assets

In respect of the recoverability of E&A assets capitalised as at 31 December 2023:

- We tested the relevant controls within the group's E&A write-off and impairment assessment processes.
- We challenged and evaluated management's key E&A judgements with regards to the impairment criteria of IFRS 6. Where impairment indicators were identified we corroborated key judgements with internal and external evidence for assets that remained on the balance sheet. This included analysing evidence of future E&A plans, budgets and capital allocation decisions, assessing management's key accounting judgement papers, reading meeting minutes and assessing licence documentation and evidence of active dialogue with partners and regulators including negotiations to renew licences or modify key terms.

PP&E and Investment in joint ventures

We considered the impact of potential changes in supply and demand on the group's refining portfolio and assessed internal and external market studies of future supply and demand. In relation to the Gelsenkirchen refinery impairment test, we assessed the valuation methodology, tested the integrity and mechanical accuracy of the impairment model and assessed the appropriateness of key assumptions and inputs, notably forecast refining margins and energy input costs, challenging and evaluating management's assumptions by reference to third party data where available. We also evaluated management's ability to forecast future cash flows and margins by comparing actual results to historical forecasts and tested management's internal controls over the impairment test and related inputs.

In respect of the impairment tests performed on certain offshore wind asset low carbon energy investments, we tested the result by:

- Testing the relevant controls over these low carbon energy impairment tests including controls over key assumptions and the discount rate
- Assessing the low carbon energy discount rate with input from our valuation specialists
- Challenging and evaluating the key assumptions within the impairment tests. This included the fair value of land and sea bed leases, capital and operating cost assumptions and forecast yield and power price assumptions impacting the fair value of the development project, and
- Testing the mechanical accuracy of the impairment models.

/s/ Deloitte LLP

London
United Kingdom
8 March 2024

We have served as bp's auditor since 2018.

Report of Independent Registered Public Accounting Firm

To the shareholders and board of directors of BP p.l.c.

Opinion on internal control over financial reporting

We have audited the internal control over financial reporting of BP p.l.c. and its subsidiaries (the group) as of 31 December 2023, based on the criteria established in the UK Financial Reporting Council's Guidance on Risk Management, Internal Control and Related Financial and Business Reporting relating to internal control over financial reporting (UK FRC Guidance). In our opinion, the group maintained, in all material respects, effective internal control over financial reporting as of 31 December 2023, based on the criteria established in the UK FRC Guidance.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as at and for the year ended 31 December 2023, of the group and our report dated 8 March 2024 expressed an unqualified opinion on those financial statements.

As described in management's report on internal control over financial reporting, management excluded from its assessment the internal control over financial reporting at 'TravelCenters of America Inc.' (TCA) which was acquired on 15 May 2023. TCA's financial statements constitute 2.1% and 1.5% of net and total assets, respectively, 2.8% of 'Sales and other operating revenues', and 4% of 'profit (loss) for the year' of the consolidated financial statement amounts as of and for the year ended 31 December 2023. Accordingly, our audit did not include the internal control over financial reporting at TCA.

Basis for opinion

The Group's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's report on internal control over financial reporting. Our responsibility is to express an opinion on the group's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the group in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and limitations of internal control over financial reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Deloitte LLP
London, United Kingdom
8 March 2024

1. **The maintenance and integrity of the BP p.l.c. web site is the responsibility of BP p.l.c.; the work carried out by the auditors does not involve consideration of these matters and, accordingly, the auditors accept no responsibility for any changes that may have occurred to the financial statements since they were initially presented on the web site.**
2. **Legislation in the United Kingdom governing the preparation and dissemination of financial statements may differ from legislation in other jurisdictions.**

Group income statement

For the year ended 31 December				$ million
	Note	**2023**	2022	2021
Sales and other operating revenues	6	**210,130**	241,392	157,739
Earnings from joint ventures – after interest and tax	16	**67**	1,128	543
Earnings from associates – after interest and tax	17	**831**	1,402	3,456
Interest and other income	7	**1,635**	1,103	581
Gains on sale of businesses and fixed assets	4	**369**	3,866	1,876
Total revenues and other income		**213,032**	248,891	164,195
Purchases	19	**119,307**	141,043	92,923
Production and manufacturing expenses		**25,044**	28,610	25,843
Production and similar taxes	5	**1,779**	2,325	1,308
Depreciation, depletion and amortization	5	**15,928**	14,318	14,805
Net impairment and losses on sale of businesses and fixed assets	4	**5,857**	30,522	(1,121)
Exploration expense	8	**997**	585	424
Distribution and administration expenses		**16,772**	13,449	11,931
Profit (loss) before interest and taxation		**27,348**	18,039	18,082
Finance costs	7	**3,840**	2,703	2,857
Net finance (income) expense relating to pensions and other post-retirement benefits	24	**(241)**	(69)	(2)
Profit (loss) before taxation		**23,749**	15,405	15,227
Taxation	9	**7,869**	16,762	6,740
Profit (loss) for the year		**15,880**	(1,357)	8,487
Attributable to				
bp shareholders		**15,239**	(2,487)	7,565
Non-controlling interests		**641**	1,130	922
		15,880	(1,357)	8,487
Earnings per share				
Profit (loss) for the year attributable to bp shareholders				
Per ordinary share (cents)				
Basic	11	**87.78**	(13.10)	37.57
Diluted	11	**85.85**	(13.10)	37.33
Per ADS (dollars)				
Basic	11	**5.27**	(0.79)	2.25
Diluted	11	**5.15**	(0.79)	2.24

Group statement of comprehensive income[a]

For the year ended 31 December				$ million
	Note	2023	2022	2021
Profit (loss) for the year		**15,880**	(1,357)	8,487
Other comprehensive income				
Items that may be reclassified subsequently to profit or loss				
Currency translation differences		**585**	(3,786)	(921)
Exchange (gains) losses on translation of foreign operations reclassified to gain or loss on sale of businesses and fixed assets		**(2)**	10,759	36
Cash flow hedges marked to market	30	**1,065**	(825)	(430)
Cash flow hedges reclassified to the income statement	30	**(428)**	1,502	255
Costs of hedging marked to market	30	**(67)**	61	(105)
Costs of hedging reclassified to the income statement	30	**(11)**	25	21
Share of items relating to equity-accounted entities, net of tax	16, 17	**(192)**	402	44
Income tax relating to items that may be reclassified	9	**(10)**	(334)	65
		940	7,804	(1,035)
Items that will not be reclassified to profit or loss				
Remeasurements of the net pension and other post-retirement benefit liability or asset	24	**(2,262)**	340	4,416
Remeasurements of equity investments		**51**	—	—
Cash flow hedges that will subsequently be transferred to the balance sheet	30	**15**	(4)	1
Income tax relating to items that will not be reclassified	9	**745**	68	(1,317)
		(1,451)	404	3,100
Other comprehensive income		**(511)**	8,208	2,065
Total comprehensive income		**15,369**	6,851	10,552
Attributable to				
bp shareholders		**14,702**	5,782	9,654
Non-controlling interests		**667**	1,069	898
		15,369	6,851	10,552

[a] See Note 32 for further information.

Group statement of changes in equity[a]

$ million

	Share capital and capital reserves	Treasury shares	Foreign currency translation reserve	Fair value reserves	Profit and loss account	bp shareholders' equity	Non-controlling interests: Hybrid bonds	Non-controlling interests: Other interest	Total equity
At 1 January 2023	**47,873**	**(12,153)**	**(2,643)**	**(256)**	**34,732**	**67,553**	**13,390**	**2,047**	**82,990**
Profit for the year	**–**	**–**	**–**	**–**	**15,239**	**15,239**	**586**	**55**	**15,880**
Other comprehensive income	**–**	**–**	**728**	**431**	**(1,696)**	**(537)**	**–**	**26**	**(511)**
Total comprehensive income	**–**	**–**	**728**	**431**	**13,543**	**14,702**	**586**	**81**	**15,369**
Dividends[b]	**–**	**–**	**–**	**–**	**(4,831)**	**(4,831)**	**–**	**(403)**	**(5,234)**
Cash flow hedges transferred to the balance sheet, net of tax	**–**	**–**	**–**	**(1)**	**–**	**(1)**	**–**	**–**	**(1)**
Repurchase of ordinary share capital	**–**	**–**	**–**	**–**	**(8,167)**	**(8,167)**	**–**	**–**	**(8,167)**
Share-based payments, net of tax	**140**	**830**	**–**	**–**	**(301)**	**669**	**–**	**–**	**669**
Share of equity-accounted entities' changes in equity, net of tax	**–**	**–**	**–**	**–**	**1**	**1**	**–**	**–**	**1**
Issue of perpetual hybrid bonds	**–**	**–**	**–**	**–**	**(1)**	**(1)**	**176**	**–**	**175**
Payments on perpetual hybrid bonds	**–**	**–**	**(5)**	**–**	**–**	**(5)**	**(586)**	**–**	**(591)**
Transactions involving non-controlling interests, net of tax	**–**	**–**	**–**	**–**	**363**	**363**	**–**	**(81)**	**282**
At 31 December 2023	**48,013**	**(11,323)**	**(1,920)**	**174**	**35,339**	**70,283**	**13,566**	**1,644**	**85,493**
At 1 January 2022	46,871	(12,624)	(9,572)	(1,027)	51,815	75,463	13,041	1,935	90,439
Profit for the year	–	–	–	–	(2,487)	(2,487)	519	611	(1,357)
Other comprehensive income	–	–	6,914	770	585	8,269	–	(61)	8,208
Total comprehensive income	–	–	6,914	770	(1,902)	5,782	519	550	6,851
Dividends[b]	–	–	–	–	(4,365)	(4,365)	–	(294)	(4,659)
Cash flow hedges transferred to the balance sheet, net of tax	–	–	–	1	–	1	–	–	1
Issue of ordinary share capital	820	–	–	–	–	820	–	–	820
Repurchase of ordinary share capital	–	–	–	–	(10,493)	(10,493)	–	–	(10,493)
Share-based payments, net of tax	182	471	–	–	194	847	–	–	847
Issue of perpetual hybrid bonds	–	–	–	–	(4)	(4)	374	–	370
Payments on perpetual hybrid bonds	–	–	15	–	–	15	(544)	–	(529)
Transactions involving non-controlling interests, net of tax	–	–	–	–	(513)	(513)	–	(144)	(657)
At 31 December 2022	47,873	(12,153)	(2,643)	(256)	34,732	67,553	13,390	2,047	82,990
At 1 January 2021	46,701	(13,224)	(8,719)	(808)	47,300	71,250	12,076	2,242	85,568
Profit for the year	–	–	–	–	7,565	7,565	507	415	8,487
Other comprehensive income	–	–	(846)	(209)	3,144	2,089	–	(24)	2,065
Total comprehensive income	–	–	(846)	(209)	10,709	9,654	507	391	10,552
Dividends[b]	–	–	–	–	(4,316)	(4,316)	–	(311)	(4,627)
Cash flow hedges transferred to the balance sheet, net of tax	–	–	–	(10)	–	(10)	–	–	(10)
Repurchase of ordinary share capital	–	–	–	–	(3,151)	(3,151)	–	–	(3,151)
Share-based payments, net of tax	170	600	–	–	(138)	632	–	–	632
Share of equity-accounted entities' changes in equity, net of tax	–	–	–	–	556	556	–	–	556
Issue of perpetual hybrid bonds	–	–	–	–	(26)	(26)	950	–	924
Payments on perpetual hybrid bonds	–	–	(7)	–	–	(7)	(492)	–	(499)
Transactions involving non-controlling interests, net of tax	–	–	–	–	881	881	–	(387)	494
At 31 December 2021	46,871	(12,624)	(9,572)	(1,027)	51,815	75,463	13,041	1,935	90,439

[a] See Note 32 for further information.
[b] See Note 10 for further information.

Group balance sheet

At 31 December	Note	2023	2022
			$ million
Non-current assets			
Property, plant and equipment	12	**104,719**	106,044
Goodwill	14	**12,472**	11,960
Intangible assets	15	**9,991**	10,200
Investments in joint ventures	16	**12,435**	12,400
Investments in associates	17	**7,814**	8,201
Other investments	18	**2,189**	2,670
Fixed assets		**149,620**	151,475
Loans		**1,942**	1,271
Trade and other receivables	20	**1,767**	1,092
Derivative financial instruments	30	**9,980**	12,841
Prepayments		**623**	576
Deferred tax assets	9	**4,268**	3,908
Defined benefit pension plan surpluses	24	**7,948**	9,269
		176,148	180,432
Current assets			
Loans		**240**	315
Inventories	19	**22,819**	28,081
Trade and other receivables	20	**31,123**	34,010
Derivative financial instruments	30	**12,583**	11,554
Prepayments		**2,520**	2,092
Current tax receivable		**837**	621
Other investments	18	**843**	578
Cash and cash equivalents	25	**33,030**	29,195
		103,995	106,446
Assets classified as held for sale	2	**151**	1,242
		104,146	107,688
Total assets		**280,294**	288,120
Current liabilities			
Trade and other payables	22	**61,155**	63,984
Derivative financial instruments	30	**5,250**	12,618
Accruals		**6,527**	6,398
Lease liabilities	28	**2,650**	2,102
Finance debt	26	**3,284**	3,198
Current tax payable		**2,732**	4,065
Provisions	23	**4,418**	6,332
		86,016	98,697
Liabilities directly associated with assets classified as held for sale	2	**62**	321
		86,078	99,018
Non-current liabilities			
Other payables	22	**10,076**	10,387
Derivative financial instruments	30	**10,402**	13,537
Accruals		**1,310**	1,233
Lease liabilities	28	**8,471**	6,447
Finance debt	26	**48,670**	43,746
Deferred tax liabilities	9	**9,617**	10,526
Provisions	23	**14,721**	14,992
Defined benefit pension plan and other post-retirement benefit plan deficits	24	**5,456**	5,244
		108,723	106,112
Total liabilities		**194,801**	205,130
Net assets		**85,493**	82,990
Equity			
bp shareholders' equity	32	**70,283**	67,553
Non-controlling interests	32	**15,210**	15,437
Total equity	32	**85,493**	82,990

Helge Lund Chair
Murray Auchincloss Chief executive officer
8 March 2024

Group cash flow statement

For the year ended 31 December				$ million
	Note	2023	2022	2021
Operating activities				
Profit (loss) before taxation		**23,749**	15,405	15,227
Adjustments to reconcile profit before taxation to net cash provided by operating activities				
Exploration expenditure written off	8	**746**	385	167
Depreciation, depletion and amortization	5	**15,928**	14,318	14,805
Impairment and (gain) loss on sale of businesses and fixed assets	4	**5,488**	26,656	(2,997)
Earnings from joint ventures and associates		**(898)**	(2,530)	(3,999)
Dividends received from joint ventures and associates		**2,092**	1,700	1,842
Interest receivable		**(1,265)**	(444)	(235)
Interest received		**1,119**	414	320
Finance costs	7	**3,840**	2,703	2,857
Interest paid		**(2,950)**	(2,208)	(2,474)
Net finance expense relating to pensions and other post-retirement benefits	24	**(241)**	(69)	(2)
Share-based payments		**616**	795	627
Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans	24	**(193)**	(257)	(655)
Net charge for provisions, less payments		**(2,481)**	440	2,934
(Increase) decrease in inventories		**5,634**	(5,492)	(7,458)
(Increase) decrease in other current and non-current assets		**4,620**	(18,584)	(13,263)
Increase (decrease) in other current and non-current liabilities		**(13,592)**	17,806	20,095
Income taxes paid		**(10,173)**	(10,106)	(4,179)
Net cash provided by operating activities		**32,039**	40,932	23,612
Investing activities				
Expenditure on property, plant and equipment, intangible and other assets		**(14,285)**	(12,069)	(10,887)
Acquisitions, net of cash acquired	3	**(799)**	(3,530)	(186)
Investment in joint ventures		**(1,039)**	(600)	(1,440)
Investment in associates		**(130)**	(131)	(335)
Total cash capital expenditure		**(16,253)**	(16,330)	(12,848)
Proceeds from disposals of fixed assets	4	**133**	709	1,145
Proceeds from disposals of businesses, net of cash disposed	4	**1,193**	1,841	5,812
Proceeds from loan repayments		**55**	67	197
Net cash used in investing activities		**(14,872)**	(13,713)	(5,694)
Financing activities				
Repurchase of shares		**(7,918)**	(9,996)	(3,151)
Lease liability payments		**(2,560)**	(1,961)	(2,082)
Proceeds from long-term financing		**7,568**	2,013	6,987
Repayments of long-term financing		**(3,902)**	(11,697)	(16,804)
Net increase (decrease) in short-term debt		**(861)**	(1,392)	1,077
Issue of perpetual hybrid bonds		**175**	370	924
Payments relating to perpetual hybrid bonds		**(1,008)**	(708)	(538)
Payments relating to transactions involving non-controlling interests (other)		**(187)**	(9)	(560)
Receipts relating to transactions involving non-controlling interests (other)		**546**	11	683
Dividends paid				
bp shareholders	10	**(4,809)**	(4,358)	(4,304)
Non-controlling interests		**(403)**	(294)	(311)
Net cash provided by (used in) financing activities		**(13,359)**	(28,021)	(18,079)
Currency translation differences relating to cash and cash equivalents		**27**	(684)	(269)
Increase (decrease) in cash and cash equivalents		**3,835**	(1,486)	(430)
Cash and cash equivalents at beginning of year		**29,195**	30,681	31,111
Cash and cash equivalents at end of year		**33,030**	29,195	30,681

Notes on financial statements

1. Material accounting policy information, significant judgements, estimates and assumptions

Authorization of financial statements and statement of compliance with International Financial Reporting Standards

The consolidated financial statements of BP p.l.c and its subsidiaries (collectively referred to as bp or the group) were approved and signed by the chief executive officer and chairman on 8 March 2024 having been duly authorized to do so by the board of directors. BP p.l.c. is a public limited company incorporated and domiciled in England and Wales. The consolidated financial statements have been prepared in accordance with United Kingdom adopted international accounting standards and International Financial Reporting Standards (IFRSs) as issued by the International Accounting Standards Board (IASB) and as adopted by the European Union (EU) and in accordance with the provisions of the UK Companies Act 2006 as applicable to companies reporting under international accounting standards. IFRS as adopted by the UK does not differ from IFRS as adopted by the EU. IFRS as adopted by the UK and EU differs in certain respects from IFRS as issued by the IASB. The differences have no impact on the group's consolidated financial statements for the years presented. The material accounting policy information and accounting judgements, estimates and assumptions of the group are set out below.

Basis of preparation

The consolidated financial statements have been prepared on a going concern basis and in accordance with IFRS and IFRS Interpretations Committee (IFRIC) interpretations issued and effective for the year ended 31 December 2023. The accounting policies that follow have been consistently applied to all years presented, except where otherwise indicated.

The consolidated financial statements are presented in US dollars and all values are rounded to the nearest million dollars ($ million), except where otherwise indicated.

Material accounting policy information: use of judgements, estimates and assumptions

Inherent in the application of many of the accounting policies used in preparing the consolidated financial statements is the need for bp management to make judgements, estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities, and the reported amounts of revenues and expenses. Actual outcomes could differ from the estimates and assumptions used. The accounting judgements and estimates that have a significant impact on the results of the group are set out in boxed text below, and should be read in conjunction with the information provided in the Notes on financial statements.

The areas requiring the most significant judgement and estimation in the preparation of the consolidated financial statements are: accounting for the investments in Rosneft and Aker BP; exploration and appraisal intangible assets; the recoverability of asset carrying values, including the estimation of reserves; supplier financing arrangements; derivative financial instruments; provisions and contingencies; pensions and other post-retirement benefits; and taxation. Judgements and estimates, not all of which are significant, made in assessing the impact of the current economic and geopolitical environment, and climate change and the transition to a lower carbon economy on the consolidated financial statements are also set out in boxed text below. Where an estimate has a significant risk of resulting in a material adjustment to the carrying amounts of assets and liabilities within the next financial year this is specifically noted within the boxed text.

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 consolidated financial statements. These may have significant impacts on the currently reported amounts of the group's assets and liabilities discussed below and on similar assets and liabilities that may be recognized in the future. The group's assumptions for investment appraisal (see page 30) form part of an investment decision-making framework for currently unsanctioned future capital expenditure on property, plant and equipment, and intangibles including exploration and appraisal assets, that is designed to support the effective and resilient implementation of bp's strategy. The price assumptions used for investment appraisal include oil and gas price assumptions, which are producer prices and are therefore net of any future carbon prices that the purchaser may be required to pay, and an assumption of a single carbon emissions cost imposed on the producer in respect of operational greenhouse gas (GHG) emissions (carbon dioxide and methane) in order to incentivize engineering solutions to mitigate GHG emissions on projects. The group's oil and gas price assumptions for value-in-use impairment testing are aligned with those investment appraisal assumptions. The assumptions for future carbon emissions costs in value-in-use impairment testing differ from the investment appraisal assumptions and are described below.

Management has also not identified any off-balance sheet commodity purchase obligations to be onerous contracts as result of the transition to a lower carbon economy at 31 December 2023.

Impairment of property, plant and equipment and goodwill

The energy transition is likely to impact the future prices of commodities such as oil and natural gas which in turn may affect the recoverable amount of property, plant and equipment and goodwill in the oil and gas industry. Management's best estimate of oil and natural gas price assumptions for value-in-use impairment testing were revised during 2023. Prices are disclosed in real 2022 terms. The near term Brent oil assumption was held constant at $70 per barrel to reflect near-term supply constraints before declining after 2030 to $50 per barrel by 2050 continuing to reflect the assumption that as the energy system decarbonizes, falling oil demand will cause oil prices to decline. The price assumptions for Henry Hub gas up to 2050 were held constant at $4.00 per mmBtu reflecting an assumption that declining domestic demand in the US is offset by higher LNG exports. 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 consistent with the temperature goal of the Paris climate change agreement, of holding the increase in the global average temperature to well below 2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels.

As noted above, the group's investment appraisal process includes a carbon emissions price series for the investment economics which is applied to bp's anticipated share of bp's forecast of the investment assets' scope 1 and 2 GHG emissions where they exceed defined thresholds, and is assumed to apply whether or not bp is the asset operator. However, for value-in-use impairment testing on bp's existing cash generating units (CGUs), consistent with all other relevant cash flows estimated, bp is required to reflect management's best estimate of any expected applicable carbon emission costs payable by bp, including where bp is not the operator, in the future for each jurisdiction in which the group has interests. This requires management's best estimate of how future changes to relevant carbon emission cost policies and/or legislation are likely to affect the future cash flows of the group's applicable CGUs, whether currently enacted or not. Future potential carbon pricing and/or costs of carbon emissions allowances are included in the value-in-use calculations to the extent management has sufficient information to make such an estimate. Currently this results in limited application of carbon price assumptions in value-in-use impairment tests given that carbon pricing legislation in most impacted jurisdictions where the group has interests is not in place and there is not sufficient information available as to the relevant policy makers' future intentions regarding carbon pricing to support an estimate. A key input into the determination of impairment is the assumption, aligned with bp's aim to reach net zero greenhouse gas emissions by 2050 or sooner, that the current recognized portfolio of oil and gas properties and refining assets will have an immaterial carrying value by 2050.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Where we consider that the outcome of a value-in-use impairment test could be significantly affected by a carbon price in place in any jurisdiction, this is incorporated into the value-in use impairment testing cash flows. The most significant instances where a carbon price has been incorporated in the 2023 value-in-use impairment tests is for the UK North Sea and the Gelsenkirchen refinery. The assumptions for UK North Sea were £45/tCO_2e in 2024 gradually increasing to £201/tCO_2e in 2050. The assumption applied for the Gelsenkirchen refinery was an average of approximately €72/tCO_2e.

However, as bp's forecast future prices are producer prices, the group considers it reasonable to assume that if, in addition to the costs already in place, further scope 1 and 2 emission costs were partially to be borne directly by oil and gas producers including bp in future and the prevalence of such costs were to become widespread, the gross oil and gas prices realized by producers would be correspondingly higher over the long term, resulting in no expected overall materially negative impacts on the group's net cash flows. See significant judgements and estimates: recoverability of asset carrying values for further information including sensitivity analysis in relation to reasonably possible changes in the price assumptions and carbon costs.

Production assumptions within upstream property, plant and equipment and goodwill value-in-use impairment tests reflect management's current best estimate of future production of the existing upstream portfolio. The group sees the expected reduction in upstream hydrocarbon production by around 25% by 2030 from its 2019 baseline (see page 13) being achieved through future active management, including divestments, and high-grading of the portfolio. Changes in upstream production since 2019 will be included in the best estimate to the extent the divestments have been announced or completed however, as the specific future changes to the remainder of the portfolio are not yet known, the current best estimate used for accounting purposes does not include the full extent of the expected upstream production reduction. See significant judgements and estimates: recoverability of asset carrying values and Note 14 for sensitivity analyses in relation to reasonably possible changes in production for upstream oil and gas properties and goodwill respectively.

Impairment charges were recognized on certain upstream oil and gas properties partly as a result of price and discount rate changes. See Note 4 for further information.

For the customers & products segment, though the energy transition may impact demand for certain refined products in the future, management anticipates sufficiently robust demand for the remainder of each refinery's useful life.

Management will continue to review price assumptions as the energy transition progresses and this may result in impairment charges or reversals in the future.

Exploration and appraisal intangible assets

The energy transition may affect the future development or viability of exploration prospects. The recoverability of the group's exploration and appraisal intangible assets was considered during 2023. No significant write-offs were identified. These assets will continue to be assessed as the energy transition progresses. See significant judgement: exploration and appraisal intangible assets and Note 8 for further information.

Property, plant and equipment – depreciation and expected useful lives

The energy transition may curtail the expected useful lives of oil and gas industry assets thereby accelerating depreciation charges. However, a significant majority of bp's existing upstream oil and natural gas properties are likely to have immaterial carrying values within the next 12 years and, as outlined in bp's strategy, oil and natural gas production will remain an important part of bp's business activities over that period. The significant majority of refining assets, recognized on the group's balance sheet at 31 December 2023 that are subject to depreciation, will be depreciated within the next 12 years; demand for refined products is expected to remain sufficient to support the remaining useful lives of existing assets. Therefore, management does not expect the useful lives of bp's reported property, plant and equipment to change and do not consider this to be a significant accounting judgement or estimate. Significant capital expenditure is still required for ongoing projects as well as renewal and/or replacement of aged assets and therefore the useful lives of future capital expenditure may be different. See material accounting policy: property, plant and equipment for more information.

Provisions: decommissioning

The energy transition may bring forward the decommissioning of oil and gas industry assets thereby increasing the present value of associated decommissioning provisions. The majority of bp's existing upstream oil and gas properties are expected to start decommissioning within the next two decades. The group's expectation to reduce its upstream hydrocarbon production by around 25% by 2030 from its 2019 baseline (see page 13) is expected to be achieved through future active management, including divestments, and high-grading of the portfolio. Any resulting increases or decreases to the weighted average timing of decommissioning will be driven by the profile of assets held in the revised portfolio. Currently, the expected timing of decommissioning expenditures for the upstream oil and gas assets in the group's portfolio has not materially been brought forward. Management does not expect a reasonably possible change of two years in the expected timing of all decommissioning to have a material effect on the upstream decommissioning provisions, assuming cost assumptions remain unchanged.

Decommissioning cost estimates are based on the known regulatory and external environment. These cost estimates may change in the future, including as a result of the transition to a lower carbon economy. For refineries, decommissioning provisions are generally not recognized as the associated obligations have indeterminate settlement dates, typically driven by the cessation of manufacturing. Management does not expect manufacturing to cease at refineries within a determinate period of time, as existing property, plant and equipment is expected to be renewed or replaced. Management will continue to review facts and circumstances to assess if decommissioning provisions need to be recognized. Decommissioning provisions relating to refineries at 31 December 2023 are not material. See significant judgements and estimates: provisions for further information.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Judgements and estimates made in assessing the impact of the geopolitical and economic environment

In preparing the consolidated financial statements, the following areas involving judgement and estimates were identified as most relevant with regards to the impact of the current geopolitical and economic environment.

Oil and gas price assumptions

Oil and gas price assumptions applied in value-in-use impairment testing have been updated to reflect the current outlook on Brent oil supply constraints and an assumption that declining domestic natural gas demand in the US is offset by higher LNG exports. See significant judgements and estimates: recoverability of asset carrying values for further information.

Discount rate assumptions

The discount rates used for impairment testing and provisions were reassessed during the year in light of changing economic and geopolitical outlooks. The nominal discount rate applied to provisions was increased during the year to reflect higher US Treasury yields. The principal impact of this rate increase was a $0.9 billion decrease in the decommissioning provision with an associated decrease in the carrying amount of property, plant and equipment of $0.7 billion and a pre-tax credit to the income statement of $0.2 billion. Impairment discount rates were also increased from those reported in 2022. See significant judgements and estimates: recoverability of asset carrying values and provisions for further information.

Pensions and other post-retirement benefits

The volatility in the financial markets during 2023 impacted the assumptions used for determining the fair value of plan assets and the present value of defined benefit obligations in the group's defined benefit pension plans. See significant estimate: pensions and other post-retirement benefits and Note 24 for further information.

Basis of consolidation

The group financial statements consolidate the financial statements of BP p.l.c. and its subsidiaries drawn up to 31 December each year. Subsidiaries are consolidated from the date of their acquisition, being the date on which the group obtains control, including when control is obtained via potential voting rights, and continue to be consolidated until the date that control ceases.

The financial statements of subsidiaries are prepared for the same reporting year as the parent company, using consistent accounting policies. Intra-group balances and transactions, including unrealized profits arising from intra-group transactions, have been eliminated. Unrealized losses are eliminated unless the transaction provides evidence of an impairment of the asset transferred.

Non-controlling interests represent the equity in subsidiaries that is not attributable, directly or indirectly, to bp shareholders. Included within non-controlling interests are perpetual subordinated hybrid securities issued by subsidiaries and for which the group has the unconditional right to avoid transferring cash or another financial asset to the holders. Profit or loss attributable to bp shareholders is adjusted to reflect the coupon/interest related to these hybrid securities whether or not such distribution has been deferred.

Interests in other entities

Business combinations and goodwill

Business combinations are accounted for using the acquisition method. The identifiable assets acquired and liabilities assumed are recognized at their fair values at the acquisition date.

Goodwill is initially measured as the excess of the aggregate of the consideration transferred, the amount recognized for any non-controlling interest and the acquisition-date fair values of any previously held interest in the acquiree over the fair value of the identifiable assets acquired and liabilities assumed at the acquisition date. The amount recognized for any non-controlling interest is measured at the present ownership's proportionate share in the recognized amounts of the acquiree's identifiable net assets. At the acquisition date, any goodwill acquired is allocated to each of the cash-generating units, or groups of cash-generating units, expected to benefit from the combination's synergies. Following initial recognition, goodwill is measured at cost less any accumulated impairment losses. Goodwill arising on business combinations prior to 1 January 2003 is stated at the previous carrying amount under UK generally accepted accounting practice, less subsequent impairments.

Goodwill may arise upon investments in joint ventures and associates, being the surplus of the cost of investment over the group's share of the net fair value of the identifiable assets and liabilities. Any such goodwill is recorded within the corresponding investment in joint ventures and associates.

Goodwill may also arise upon acquisition of interests in joint operations that meet the definition of a business. The amount of goodwill separately recognized is the excess of the consideration transferred over the group's share of the net fair value of the identifiable assets and liabilities.

Interests in joint arrangements

The results, assets and liabilities of joint ventures are incorporated in these consolidated financial statements using the equity method of accounting as described below.

Certain of the group's activities, particularly in the oil production & operations and gas & low carbon energy segments, are conducted through joint operations. bp recognizes, on a line-by-line basis in the consolidated financial statements, its share of the assets, liabilities and expenses of these joint operations incurred jointly with the other partners, along with the group's revenue from the sale of its share of the output and any liabilities and expenses that the group has incurred in relation to the joint operation.

For joint arrangements in a separate entity, judgement may be required as to whether the arrangement should be classified as a joint venture or if the legal form, contractual arrangements or other facts and circumstances indicate that the group has rights to the assets and obligations for the liabilities of the arrangement, rather than rights to the net assets, and therefore should be classified as a joint operation. No such judgement made by the group is considered significant.

Interests in associates

The results, assets and liabilities of associates are incorporated in these consolidated financial statements using the equity method of accounting as described below.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Significant judgement: investment in Aker BP

Judgement is required in assessing the level of control or influence over another entity in which the group holds an interest. For bp, the judgement that the group has significant influence over Aker BP, a Norwegian oil and gas company, is significant.

As a consequence of this judgement, bp uses the equity method of accounting for its investment and bp's share of Aker BP's oil and natural gas reserves is included in the group's estimated net proved reserves of equity-accounted entities. If significant influence was not present, the investment would be accounted for as an investment in an equity instrument measured at fair value as described under 'Financial assets' below and no share of Aker BP's oil and natural gas reserves would be reported.

Significant influence is defined in IFRS as the power to participate in the financial and operating policy decisions of the investee but is not control or joint control of those decisions. Significant influence is presumed when an entity owns 20% or more of the voting power of the investee. Significant influence is presumed not to be present when an entity owns less than 20% of the voting power of the investee.

bp owned 15.9% of the voting shares at 31 December 2023. bp’s group chief executive officer, Murray Auchincloss, has been a member of the Aker BP board since 2017. bp’s other nominated director, group chief financial officer, Kate Thomson, has been a member of the Aker BP board since formation of that company in 2016. She is also a member of the Aker BP board’s Audit and Risk Committee. bp also holds the voting rights at general meetings of shareholders conferred by its stake in Aker BP. bp's management considers, therefore, that the group continues to have significant influence at 31 December 2023.

Significant judgements and estimate: investment in Rosneft

Since the first quarter 2022, bp accounts for its interest in Rosneft and its other businesses with Rosneft within Russia, as financial assets measured at fair value within ‘Other investments’. bp is not able to sell its Rosneft shares on the Moscow Stock Exchange and is unable to ascribe probabilities to possible outcomes of any exit process. It is considered by management that any measure of fair value, other than nil, would be subject to such high measurement uncertainty, considering the sanctions and restrictions implemented by Russia on Russian assets held by foreign investors, that no estimate would provide useful information even if it were accompanied by a description of the estimate made in producing it and an explanation of the uncertainties that affect the estimate. Accordingly, it is not currently possible to estimate any carrying value other than zero when determining the measurement of the interest in Rosneft and the other businesses with Rosneft within Russia as at 31 December 2023. Events or outcomes within the next financial year, that are different to those outlined above, could materially change the fair value of the investment.

Russia has imposed restrictions on the payments of dividends to certain foreign shareholders, including those based in the UK, requiring such dividends to be paid in roubles into restricted bank accounts and a requirement for approval of the Russian government for transfers from any such bank accounts out of Russia. Given the restrictions applicable to such accounts, management has made the significant judgement that the criteria for recognizing any dividend income from Rosneft and its other businesses with Rosneft within Russia, for the years to 31 December 2022 and 31 December 2023 have not been met.

The equity method of accounting

Under the equity method, an investment is carried on the balance sheet at cost plus post-acquisition changes in the group’s share of net assets of the entity, less distributions received and less any impairment in value of the investment. Loans advanced to equity-accounted entities that have the characteristics of equity financing are also included in the investment on the group balance sheet. The group income statement reflects the group’s share of the results after tax of the equity-accounted entity, adjusted to account for depreciation, amortization and any impairment of the equity-accounted entity’s assets based on their fair values at the date of acquisition. The group statement of comprehensive income includes the group’s share of the equity-accounted entity’s other comprehensive income. The group’s share of amounts recognized directly in equity by an equity-accounted entity is recognized in the group’s statement of changes in equity.

Financial statements of equity-accounted entities are typically prepared for the same reporting year as the group. Where material differences arise in the accounting policies used by the equity-accounted entity and those used by bp, adjustments are made to those financial statements to bring the accounting policies used into line with those of the group. Unrealized gains on transactions, apart from those that meet the definition of a derivative, between the group and its equity-accounted entities are eliminated to the extent of the group’s interest in the equity-accounted entity. This includes unrealized gains arising on contribution of a business on formation of an equity-accounted entity.

Segmental reporting

The group’s operating segments are established on the basis of those components of the group that are evaluated regularly by the chief executive officer, bp’s chief operating decision maker, in deciding how to allocate resources and in assessing performance.

The accounting policies of the operating segments are the same as the group’s accounting policies described in this note, except that IFRS requires that the measure of profit or loss disclosed for each operating segment is the measure that is provided regularly to the chief operating decision maker. For bp, this measure of profit or loss is replacement cost profit before interest and tax which reflects the replacement cost of inventories sold in the period and is arrived at by excluding inventory holding gains and losses from profit before interest and tax. Replacement cost profit for the group is not a recognized measure under IFRS.

For further information see Note 5.

Foreign currency translation

In individual subsidiaries, joint ventures and associates, transactions in foreign currencies are initially recorded in the functional currency of those entities at the spot exchange rate on the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are retranslated into the functional currency at the spot exchange rate on the balance sheet date. Any resulting exchange differences are included in the income statement, unless hedge accounting is applied. Non-monetary items, other than those measured at fair value, are not retranslated subsequent to initial recognition.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

In the consolidated financial statements, the assets and liabilities of non-US dollar functional currency subsidiaries, joint ventures, associates, and related goodwill, are translated into US dollars at the spot exchange rate on the balance sheet date. The results and cash flows of non-US dollar functional currency subsidiaries, joint ventures and associates are translated into US dollars using average rates of exchange. In the consolidated financial statements, exchange adjustments arising when the opening net assets and the profits for the year retained by non-US dollar functional currency subsidiaries, joint ventures and associates are translated into US dollars are recognized in a separate component of equity and reported in other comprehensive income. Exchange gains and losses arising on long-term intra-group foreign currency borrowings used to finance the group's non-US dollar investments are also reported in other comprehensive income if the borrowings form part of the net investment in the subsidiary, joint venture or associate. On disposal or for certain partial disposals of a non-US dollar functional currency subsidiary, joint venture or associate, the related accumulated exchange gains and losses recognized in equity are reclassified from equity to the income statement.

Non-current assets held for sale

Non-current assets and disposal groups classified as held for sale are measured at the lower of carrying amount and fair value less costs to sell.

Significant non-current assets and disposal groups are classified as held for sale if their carrying amounts will be recovered through a sale transaction rather than through continuing use. This condition is regarded as met only when the sale is highly probable and the asset or disposal group is available for immediate sale in its present condition subject only to terms that are usual and customary for sales of such assets. Management must be committed to the sale, which should be expected to qualify for recognition as a completed sale within one year from the date of classification as held for sale, and actions required to complete the plan of sale should indicate that it is unlikely that significant changes to the plan will be made or that the plan will be withdrawn.

Property, plant and equipment and intangible assets are not depreciated or amortized, and equity accounting of associates and joint ventures is ceased once classified as held for sale.

Intangible assets

Intangible assets, other than goodwill, include expenditure on the exploration for and evaluation of oil and natural gas resources, biogas rights agreements, digital assets, patents, licences and trademarks and are stated at the amount initially recognized, less accumulated amortization and accumulated impairment losses.

Intangible assets are carried initially at cost unless acquired as part of a business combination. Any such asset is measured at fair value at the date of the business combination and is recognized separately from goodwill if the asset is separable or arises from contractual or other legal rights.

Intangible assets with a finite life, other than capitalized exploration and appraisal costs as described below, are amortized on a straight-line basis over their expected useful lives. For patents, licences and trademarks, expected useful life is the shorter of the duration of the legal agreement and economic useful life, and can range from three to fifteen years. The expected useful life of biogas rights agreements is the shorter of the duration of the legal agreement and economic useful life and can be up to 50 years. Digital asset costs generally have a useful life of three to five years.

The expected useful lives of assets and the amortization method are reviewed on an annual basis and, if necessary, changes in useful lives or the amortization method are accounted for prospectively.

Oil and natural gas exploration and appraisal expenditure

Oil and natural gas exploration and appraisal expenditure is accounted for using the principles of the successful efforts method of accounting as described below.

Licence and property acquisition costs

Exploration licence and leasehold property acquisition costs are capitalized within intangible assets and are reviewed at each reporting date to confirm that there is no indication that the carrying amount exceeds the recoverable amount. This review includes confirming that exploration drilling is still under way or planned or that it has been determined, or work is under way to determine, that the discovery is economically viable based on a range of technical and commercial considerations, and sufficient progress is being made on establishing development plans and timing. If no future activity is planned, the remaining balance of the licence and property acquisition costs is written off. Lower value licences are pooled and amortized on a straight-line basis over the estimated period of exploration. Upon internal approval for development and recognition of proved or sanctioned probable reserves of oil and natural gas, the relevant expenditure is transferred to property, plant and equipment.

Exploration and appraisal expenditure

Geological and geophysical exploration costs are recognized as an expense as incurred. Costs directly associated with an exploration well are initially capitalized as an intangible asset until the drilling of the well is complete and the results have been evaluated. These costs include employee remuneration, materials and fuel used, rig costs and payments made to contractors. If potentially commercial quantities of hydrocarbons are not found, the exploration well costs are written off. If hydrocarbons are found and, subject to further appraisal activity, are likely to be capable of commercial development, the costs continue to be carried as an asset. If it is determined that development will not occur, that is, the efforts are not successful, then the costs are expensed.

Costs directly associated with appraisal activity undertaken to determine the size, characteristics and commercial potential of a reservoir following the initial discovery of hydrocarbons, including the costs of appraisal wells where hydrocarbons were not found, are initially capitalized as an intangible asset. Upon internal approval for development and recognition of proved or sanctioned probable reserves, the relevant expenditure is transferred to property, plant and equipment. If development is not approved and no further activity is expected to occur, then the costs are expensed.

The determination of whether potentially economic oil and natural gas reserves have been discovered by an exploration well is usually made within one year of well completion, but can take longer, depending on the complexity of the geological structure. Exploration wells that discover potentially economic quantities of oil and natural gas and are in areas where major capital expenditure (e.g. an offshore platform or a pipeline) would be required before production could begin, and where the economic viability of that major capital expenditure depends on the successful completion of further exploration or appraisal work in the area, remain capitalized on the balance sheet as long as such work is under way or firmly planned.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Significant judgement: exploration and appraisal intangible assets

Judgement is required to determine whether it is appropriate to continue to carry costs associated with exploration wells and exploratory-type stratigraphic test wells on the balance sheet. This includes costs relating to exploration licences or leasehold property acquisitions. It is not unusual to have such costs remaining suspended on the balance sheet for several years while additional appraisal drilling and seismic work on the potential oil and natural gas field is performed or while the optimum development plans and timing are established. The costs are carried based on the current regulatory and political environment or any known changes to that environment. All such carried costs are subject to regular technical, commercial and management review on at least an annual basis to confirm the continued intent to develop, or otherwise extract value from, the discovery. Where this is no longer the case, the costs are immediately expensed.

The carrying amount of capitalized costs are included in Note 8.

Property, plant and equipment

Property, plant and equipment owned by the group is stated at cost, less accumulated depreciation and accumulated impairment losses. The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into the location and condition necessary for it to be capable of operating in the manner intended by management, the initial estimate of any decommissioning obligation, if applicable, and, for assets that necessarily take a substantial period of time to get ready for their intended use, directly attributable general or specific finance costs. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset.

Expenditure on major maintenance refits or repairs comprises the cost of replacement assets or parts of assets, inspection costs and overhaul costs. Where an asset or part of an asset that was separately depreciated is replaced and it is probable that future economic benefits associated with the item will flow to the group, the expenditure is capitalized and the carrying amount of the replaced asset is derecognized. Inspection costs associated with major maintenance programmes are capitalized and amortized over the period to the next inspection. Overhaul costs for major maintenance programmes, and all other maintenance costs are expensed as incurred.

Expenditure on the construction, installation and completion of infrastructure facilities such as platforms, pipelines and the drilling of development wells, including service and unsuccessful development or delineation wells, is capitalized within property, plant and equipment and is depreciated from the commencement of production.

Oil and natural gas properties, including certain related pipelines, are depreciated using a unit-of-production method. The cost of producing wells is amortized over proved developed reserves. Licence acquisition, common facilities and future decommissioning costs are amortized over total proved reserves. The unit-of-production rate for the depreciation of common facilities takes into account expenditures incurred to date, together with estimated future capital expenditure expected to be incurred relating to as yet undeveloped reserves expected to be processed through these common facilities. Information on the carrying amounts of the group's oil and natural gas properties, together with the amounts recognized in the income statement as depreciation, depletion and amortization is contained in Note 12 and Note 5 respectively.

Estimates of oil and natural gas reserves determined in accordance with US Securities and Exchange Commission (SEC) regulations, including the application of prices using 12-month historical price data in assessing the commerciality of technical volumes, are typically used to calculate depreciation, depletion and amortization charges for the group's oil and gas properties. Therefore, where this approach is adopted, charges are not dependent on management forecasts of future oil and gas prices.

However, for certain oil and natural gas assets, the use of reserves determined in accordance with SEC regulations would result in a charge that is not reflective of the pattern in which the future economic benefits are expected to be consumed. In these limited instances other approaches are applied to determine the reserves base used to calculate depreciation, depletion and amortization, including the use of management's best estimate of price assumptions as disclosed in Significant judgements and estimates: recoverability of asset carrying values, to determine the commerciality of technical proved reserves.

The impact of changes in estimated proved reserves is dealt with prospectively by amortizing the remaining carrying value of the asset over the expected future production.

The estimation of oil and natural gas reserves and bp's process to manage reserves bookings is described in Supplementary information on oil and natural gas on page 247, which is unaudited. Details on bp's proved reserves and production compliance and governance processes are provided on page 346. The 2023 movements in proved reserves are reflected in the tables showing movements in oil and natural gas reserves by region in Supplementary information on oil and natural gas (unaudited) on page 247.

Other property, plant and equipment is depreciated on a straight-line basis over its expected useful life. The typical useful lives of the group's other property, plant and equipment on initial recognition are as follows:

Land improvements	15 to 25 years
Buildings	20 to 50 years
Refineries	20 to 30 years
Pipelines	10 to 50 years
Service stations	15 years
Office equipment	3 to 10 years
Fixtures and fittings	5 to 15 years

The expected useful lives and depreciation method of property, plant and equipment are reviewed on an annual basis and, if necessary, changes in useful lives or the depreciation method are accounted for prospectively. An item of property, plant and equipment is derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the item) is included in the income statement in the period in which the item is derecognized.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Impairment of property, plant and equipment, intangible assets, goodwill, and equity-accounted entities

The group assesses assets or groups of assets, called cash-generating units (CGUs), for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset or CGU may not be recoverable; for example, changes in the group's business plans, plans to dispose rather than retain assets, changes in the group's assumptions about discount rates, commodity prices, low plant utilization, evidence of physical damage or, for oil and gas assets, significant downward revisions of estimated reserves or increases in estimated future development expenditure or decommissioning costs. If any such indication of impairment exists, the group makes an estimate of the asset's or CGU's recoverable amount. Individual assets are grouped into CGUs for impairment assessment purposes at the lowest level at which there are identifiable cash inflows that are largely independent of the cash inflows of other groups of assets. A CGU's recoverable amount is the higher of its fair value less costs of disposal and its value in use. If it is probable that the value of the CGU will be primarily recovered through a disposal transaction, the expected disposal proceeds are considered in determining the recoverable amount. Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down to its recoverable amount.

The business segment plans, which are approved on an annual basis by senior management, are the primary source of information for the determination of value in use. They contain forecasts for oil and natural gas production, power generation, refinery throughputs, sales volumes for various types of refined products (e.g. gasoline and lubricants), revenues, costs and capital expenditure. Carbon taxes and costs of emissions allowances are included in estimates of future cash flows, where applicable, based on the regulatory environment in each jurisdiction in which the group operates. As an initial step in the preparation of these plans, various assumptions regarding market conditions, such as oil prices, natural gas prices, power prices, refining margins, refined product margins and cost inflation rates are set by senior management. These assumptions take account of existing prices, global supply-demand equilibrium for oil and natural gas, other macroeconomic factors and historical trends and variability. In assessing value in use, the estimated future cash flows are adjusted for the risks specific to the asset group to the extent that they are not already reflected in the discount rate and are discounted to their present value typically using a pre-tax discount rate that reflects current market assessments of the time value of money.

Fair value less costs of disposal is the price that would be received to sell the asset in an orderly transaction between market participants and does not reflect the effects of factors that may be specific to the group and not applicable to entities in general. Fair value may be determined by reference to agreed or expected sales proceeds, recent market transactions for similar assets or using discounted cash flow analyses. Where discounted cash flow analyses are used to calculate fair value less costs of disposal, estimates are made about the assumptions market participants would use when pricing the asset, CGU or group of CGUs containing goodwill and the test is performed on a post-tax basis.

An assessment is made at each reporting date as to whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. If such an indication exists, the recoverable amount is estimated. A previously recognized impairment loss is reversed only if there has been a change in the estimates used to determine the asset's or CGU's recoverable amount since the last impairment loss was recognized. If that is the case, the carrying amount of the asset or CGU is increased to the lower of its recoverable amount and the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the asset or CGU in prior years. Impairment reversals are recognized in profit or loss. After a reversal, the depreciation charge is adjusted in future periods to allocate the asset's or CGU's revised carrying amount, less any residual value, on a systematic basis over its remaining useful life.

Goodwill is reviewed for impairment annually or more frequently if events or changes in circumstances indicate the recoverable amount of the group of CGUs to which the goodwill relates should be assessed. In assessing whether goodwill has been impaired, the carrying amount of the group of CGUs to which goodwill has been allocated is compared with its recoverable amount. Where the recoverable amount of the group of CGUs is less than the carrying amount (including goodwill), an impairment loss is recognized. An impairment loss recognized for goodwill is not reversed in a subsequent period.

The group assesses investments in equity-accounted entities for impairment whenever there is objective evidence that the investment is impaired, after recognizing its share of any losses of the equity-accounted entity itself. If any such objective evidence of impairment exists, the carrying amount of the investment is compared with its recoverable amount, being the higher of its fair value less costs of disposal and value in use. If the carrying amount exceeds the recoverable amount, the investment is written down to its recoverable amount.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Significant judgements and estimates: recoverability of asset carrying values

Determination as to whether, and by how much, an asset, CGU, or group of CGUs containing goodwill is impaired involves management estimates on highly uncertain matters such as the effects of inflation and deflation on operating expenses, discount rates, capital expenditure, carbon pricing (where applicable), production profiles, reserves and resources, and future commodity prices, including the outlook for global or regional market supply-and-demand conditions for crude oil, natural gas, power and refined products. Judgement is required when determining the appropriate grouping of assets into a CGU or the appropriate grouping of CGUs for impairment testing purposes. For example, individual oil and gas properties may form separate CGUs whilst certain oil and gas properties with shared infrastructure may be grouped together to form a single CGU. Alternative groupings of assets or CGUs may result in a different outcome from impairment testing. See Note 14 for details on how these groupings have been determined in relation to the impairment testing of goodwill.

As described above, the recoverable amount of an asset is the higher of its value in use and its fair value less costs of disposal. Fair value less costs of disposal may be determined based on expected sales proceeds or similar recent market transaction data.

Details of impairment charges and reversals recognized in the income statement are provided in Note 4 and details on the carrying amounts of assets are shown in Note 12, Note 14 and Note 15.

The estimates for assumptions made in impairment tests in 2023 relating to discount rates and oil and gas properties are discussed below. Changes in the economic environment including as a result of the energy transition or other facts and circumstances may necessitate revisions to these assumptions and could result in a material change to the carrying values of the group's assets within the next financial year.

Discount rates

For discounted cash flow calculations, future cash flows are adjusted for risks specific to the CGU. Value-in-use calculations are typically discounted using a pre-tax discount rate based upon the cost of funding the group derived from an established model, adjusted to a pre-tax basis and incorporating a market participant capital structure and country risk premiums. Fair value less costs of disposal discounted cash flow calculations use a post-tax discount rate.

The discount rates applied in impairment tests are reassessed each year and, in 2023, the post-tax discount rate was 8% (2022 7%) 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 4% was reflected in the post-tax discount rate (2022 1% to 2%). 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 20% (2022 7% to 18%) 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 in 2023 (including those in equity accounted entities), where the risk profile of expected cash flows supports a lower rate, tests were performed using a post-tax WACC-based discount rate of 6.5%. For assets tested in 2022, the tests were performed on a fair value less costs of disposal basis using a post-tax cost of equity-based discount rate of 6%.

Oil and natural gas properties

For oil and natural gas properties in the oil production & operations and gas & low carbon energy segments, expected future cash flows are estimated using management's best estimate of future oil and natural gas prices, production and reserves and certain resources volumes. Forecast cash flows include the impact of all approved emission reduction projects. The estimated future level of production in all impairment tests is based on assumptions about future commodity prices, production and development costs, field decline rates, current fiscal regimes and other factors.

In 2023, the group identified oil and gas properties in these segments with carrying amounts totalling $18,374 million (2022 $11,652 million) where the headroom, based on the most recent impairment test performed in the year on those assets, was less than or equal to 20% of the carrying value. A change in the discount rate, reserves, resources or the oil and gas price assumptions in the next financial year may result in a recoverable amount of one or more of these assets above or below the current carrying amount and therefore there is a risk of impairment reversals or charges in that period. Management considers that reasonably possible changes in the discount rate or forecast revenue, arising from a change in oil and natural gas prices and/or production could result in a material change in their carrying amounts within the next financial year, see Sensitivity analyses, below.

The recoverability of intangible exploration and appraisal expenditure is covered under Oil and natural gas exploration, appraisal and development expenditure above.

Oil and natural gas prices

The price assumptions used for value-in-use impairment testing are based on those used for investment appraisal. bp's carbon emissions cost assumptions and their interrelationship with oil and gas prices are described in 'Judgements and estimates made in assessing the impact of climate change and the transition to a lower carbon economy' on page 170. The investment appraisal price assumptions are 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 are 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 (in real 2022 terms) for the near term Brent oil assumption was held constant at $70 per barrel to reflect near term supply constraints before declining after 2030 to $50 per barrel by 2050 continuing to reflect the assumption that as the energy system decarbonizes, falling oil demand will cause oil prices to decline. The price assumptions for Henry Hub gas up to 2050 were held constant at $4.00 per mmBtu reflecting an assumption that declining domestic demand in the US is offset by higher LNG exports. These price assumptions are derived from the central case investment appraisal assumptions, adjusted where applicable to reflect short-term market conditions (see page 30). A summary of the group's revised price assumptions for Brent oil and Henry Hub gas, applied in 2023 and 2022, in real 2022 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 consistent with the temperature goal of the Paris climate change agreement, of holding the increase in the global average temperature to well below 2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels. However, they do not correspond to any specific Paris-consistent scenario. An inflation rate of 2% (2022 2%) is applied to determine the price assumptions in nominal terms.

The majority of bp's reserves and resources that support the carrying value of the group's existing oil and gas properties are expected to be produced over the next 12 years.

The recoverability of deferred tax assets is also affected by the group's oil and natural gas price assumptions as these could impact the estimate of future taxable profits. See Note 9 for further information.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

2023 price assumptions	2024	2025	2030	2040	2050
Brent oil ($/bbl)	70	70	70	63	50
Henry Hub gas ($/mmBtu)	4.00	4.00	4.00	4.00	4.00

2022 price assumptions	2023	2025	2030	2040	2050
Brent oil ($/bbl)	78	71	71	59	46
Henry Hub gas ($/mmBtu)	4.08	4.08	4.08	3.57	3.57

Global oil production increased by 2.2% in 2023. Strong US tight oil supply and non-OPEC+ supply more than offset OPEC+ pledged additional output reductions. Global oil demand continued its recovery, increasing by 2.4% in 2023. Chinese demand growth was unexpectedly strong making up 75% of total oil demand growth, with the rest coming from other non-OECD countries. Brent dropped by nearly $20 per barrel in 2023 as oil markets recovered from the shocks in 2022 and supply/demand was balanced. bp's long term view is for a more stable market in 2024 as the price responsiveness of shale activity, OPEC+ discipline and ample spare capacity limits the scope for large movements, even with the political tensions in the Middle East. bp's long-term assumption for oil prices is lower than the 2023 price average, based on the judgement that, in the long term, oil demand is likely to fall so that the price levels needed to encourage sufficient investment to meet declining global oil demand is also lower.

US gas prices in 2023 decreased around 60% compared to 2022, to $2.5 per mmbtu. Prices fell as gas production growth outpaced demand. Milder than normal winter weather and an extended outage at Freeport LNG left US gas storage stocks well above historic average levels at the end of winter 2022/2023. Henry Hub prices fell during the summer which incentivized coal-to-gas switching in the power sector, and hot weather in the third-quarter helped the market avoid storage containment issues. Meanwhile gas production continued to grow, reaching record levels by the end of 2023 despite a 20% decrease in gas rigs over the first half of the year. Growth was supported by strong associated gas production as well as pipeline de-bottlenecking. Finally, mild weather in the fourth-quarter further loosened balances and storage stocks exited the year 13% above five-year average levels. The level of US gas prices in 2023 is below bp's long term price assumption based on the judgment of the price level required to incentivize new production.

Oil and natural gas reserves

In addition to oil and natural gas prices, significant technical and commercial assessments are required to determine the group's estimated oil and natural gas reserves. Reserves estimates are regularly reviewed and updated. Factors such as the availability of geological and engineering data, reservoir performance data, acquisition and divestment activity and drilling of new wells all impact on the determination of the group's estimates of its oil and natural gas reserves. bp bases its reserves estimates on the requirement of reasonable certainty with rigorous technical and commercial assessments based on conventional industry practice and regulatory requirements.

Reserves assumptions for value-in-use tests reflect the reserves and resources that management currently intend to develop. The recoverable amount of oil and gas properties is determined using a combination of inputs including reserves, resources and production volumes. Risk factors may be applied to reserves and resources which do not meet the criteria to be treated as proved or probable.

Sensitivity analyses

Management considers discount rates, oil and natural gas prices and production to be the key sources of estimation uncertainty in determining the recoverable amount of upstream oil and gas assets. The sensitivity analyses below, in addition to covering the key sources of estimation uncertainty, also indicate how the energy transition, potential future carbon emissions costs for operational GHG emissions and/or reduced demand for oil and gas may further impact forecast revenue cash inflows to a greater extent than currently anticipated in the group's value-in-use estimates for oil and gas CGUs, if carbon emissions costs were to be implemented as a deduction against revenue cash flows. The analyses therefore represent a net revenue sensitivity.

A change in net revenue from upstream oil and gas properties can arise either due to changes in oil and natural gas prices, carbon emissions costs/ carbon prices, changes in oil and natural gas production, or a combination of these.

Management tested the impact of changes in net revenue cash flows in value-in-use impairment testing under the following sensitivity analyses: an increase in net revenues of 8% in all years up to 2040, and 25% in all remaining years to 2050; and a decrease in net revenues of 20% in all years up to 2030, 35% in all subsequent years to 2040 and 50% in all remaining years to 2050.

Net revenue reductions of this magnitude in isolation could indicatively lead to a reduction in the carrying amount of bp's currently held upstream oil and gas properties in the range of $16-17 billion which is approximately 23-24% of the net book value of property, plant and equipment as at 31 December 2023. If this net revenue reduction was due to reductions in prices in isolation, it reflects an indicative decrease in the carrying amount of using price assumptions for Brent oil trending broadly towards the bottom of the range of prices associated with the World Business Council for Sustainable Development (WBCSD) 'family' of scenarios considered to be consistent with limiting global average temperature to 1.5°C above pre-industrial levels. This 'family' of scenarios is also used in bp's TCFD scenario analysis (see page 55).

Net revenue increases of this magnitude in isolation could indicatively lead to an increase in the carrying amount of bp's currently held upstream oil and gas properties in the range of $2-3 billion which is approximately 3-4% of the net book value of property, plant and equipment as at 31 December 2023. This potential increase in the carrying amount would arise due to reversals of previously recognized impairments and represents approximately one third of the total impairment reversal capacity available at 31 December 2023. If this net revenue increase was due to increases in prices in isolation, it reflects an indicative increase in the carrying amount of using price assumptions for Brent oil trending broadly towards the top end until 2040, and then towards the mean average at 2050, of the range of prices associated with the WBCSD 'family' of scenarios considered to be consistent with limiting global average temperature to 1.5°C above pre-industrial levels. This 'family' of scenarios is also used in bp's TCFD scenario analysis.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

These sensitivity analyses do not, however, represent management's best estimate of any impairment charges or reversals that might be recognized as they do not fully incorporate consequential changes that may arise, such as changes in costs and business plans and phasing of development. For example, costs across the industry are more likely to decrease as oil and natural gas prices fall. The analyses also assume the impact of increases in carbon price on operational GHG emissions are fully absorbed as a decrease in net revenue (and vice versa) rather than reflecting how carbon prices or other carbon emissions costs may ultimately be incorporated by the market. The above sensitivity analyses therefore do not reflect a linear relationship between net revenue and value that can be extrapolated. The interdependency of these inputs and factors plus the diverse characteristics of the group's upstream oil and gas properties limits the practicability of estimating the probability or extent to which the overall recoverable amount is impacted by changes to the price assumptions or production volumes.

Management also tested the impact of a one percentage point change in the discount rate used for value-in-use impairment testing of upstream oil and gas properties. This level of change reflects past experience of a reasonable change in rate that could arise within the next financial year. If the discount rate was one percentage point higher across all tests performed, the net impairment loss recognized in 2023 would have been approximately $0.8 billion higher. If the discount rate was one percentage point lower, the net impairment loss recognized would have been approximately $0.9 billion lower.

Goodwill

Irrespective of whether there is any indication of impairment, bp is required to test annually for impairment of goodwill acquired in business combinations. The group carries goodwill of $12.5 billion on its balance sheet (2022 $12.0 billion), principally relating to the Atlantic Richfield, Burmah Castrol, Devon Energy and Reliance transactions. Of this, $7.0 billion relates to goodwill in the oil production & operations and gas & low carbon energy segments (2022 $7.2 billion), for which oil and gas price and production assumptions are key sources of estimation uncertainty. Sensitivities and additional information relating to impairment testing of goodwill in these segments are provided in Note 14.

Inventories

Inventories, other than inventories held for short-term trading purposes, are stated at the lower of cost and net realizable value. Cost is typically determined by the first-in first-out method and comprises direct purchase costs, cost of production, transportation and manufacturing expenses. Net realizable value is determined by reference to prices existing at the balance sheet date, adjusted where the sale of inventories after the reporting period gives evidence about their net realizable value at the end of the period.

Inventories held for short-term trading purposes are stated at fair value less costs to sell and any changes in fair value are recognized in the income statement.

Supplies are valued at the lower of cost on a weighted-average basis and net realizable value.

Leases

Agreements that convey the right to control the use of an identified asset for a period of time in exchange for consideration are accounted for as leases. The right to control is conveyed if bp has both the right to obtain substantially all of the economic benefits from, and the right to direct the use of, the identified asset throughout the period of use. An asset is identified if it is explicitly or implicitly specified by the agreement and any substitution rights held by the lessor over the asset are not considered substantive.

Agreements that convey the right to control the use of an intangible asset including rights to explore for or use hydrocarbons are not accounted for as leases. See material accounting policy information: intangible assets.

A lease liability is recognized on the balance sheet on the lease commencement date at the present value of future lease payments over the lease term. The discount rate applied is the rate implicit in the lease if readily determinable, otherwise an incremental borrowing rate is used. For the majority of the leases in the group, there is not sufficient information available to readily determine the rate implicit in the lease, and therefore the incremental borrowing rate is used. The incremental borrowing rate is determined based on factors such as the group's cost of borrowing, lessee legal entity credit risk, currency and lease term. The lease term is the non-cancellable period of a lease together with any periods covered by an extension option that bp is reasonably certain to exercise, or periods covered by a termination option that bp is reasonably certain not to exercise. The future lease payments included in the present value calculation are any fixed payments, payments that vary depending on an index or rate, payments due for the reasonably certain exercise of options and expected residual value guarantee payments. Repayments of principal are presented as financing cash flows and payments of interest are presented as operating cash flows.

Payments that vary based on factors other than an index or a rate such as usage, sales volumes or revenues are not included in the present value calculation and are recognized in the income statement and presented as operating cash flows. The lease liability is recognized on an amortized cost basis with interest expense recognized in the income statement over the lease term, except for where capitalized as exploration, appraisal or development expenditure.

The right-of-use asset is recognized on the balance sheet as property, plant and equipment at a value equivalent to the initial measurement of the lease liability adjusted for lease prepayments, lease incentives, initial direct costs and any restoration obligations. The right-of-use asset is depreciated typically on a straight-line basis over the lease term. The depreciation charge is recognized in the income statement except for where capitalized as exploration, appraisal or development expenditure. Right-of-use assets are assessed for impairment in line with the accounting policy for impairment of property, plant and equipment, intangible assets and goodwill.

Agreements may include both lease and non-lease components. Payments for lease and non-lease components are allocated on a relative stand-alone selling price basis except for leases of retail service stations where the group has elected not to separate non-lease payments from the calculation of the lease liability and right-of-use asset.

If the lease term at commencement of the agreement is less than 12 months, a lease liability and right-of-use asset are not recognized, and a lease expense is recognized in the income statement on a straight-line basis.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

If a significant event or change in circumstances, within the control of bp, arises that affects the reasonably certain lease term or there are changes to the lease payments, the present value of the lease liability is remeasured using the revised term and payments, with the right-of-use asset adjusted by an equivalent amount.

Modifications to a lease agreement beyond the original terms and conditions are accounted for as a re-measurement of the lease liability with a corresponding adjustment to the right-of-use asset. Any gain or loss on modification is recognized in the income statement. Modifications that increase the scope of the lease at a price commensurate with the stand-alone selling price are accounted for as a separate new lease.

The group recognizes the full lease liability, rather than its working interest share, for leases entered into on behalf of a joint operation if the group has the primary responsibility for making the lease payments. This may be the case if for example bp, as operator of the joint operation, is the sole signatory to the lease agreement. In such cases, bp's working interest share of the right-of-use asset is recognized if it is jointly controlled by the group and the other joint operators, and a receivable is recognized for the share of the asset transferred to the other joint operators. If bp is a non-operator, a payable to the operator is recognized if they have the primary responsibility for making the lease payments and bp has joint control over the right-of-use asset, otherwise no balances are recognized.

Financial assets

Financial assets are recognized initially at fair value, normally being the transaction price. In the case of financial assets not measured at fair value through profit or loss, directly attributable transaction costs are also included. The subsequent measurement of financial assets depends on their classification, as set out below. The group derecognizes financial assets when the contractual rights to the cash flows expire or the rights to receive cash flows have been transferred to a third party and either substantially all of the risks and rewards of the asset have been transferred, or substantially all the risks and rewards of the asset have neither been retained nor transferred but control of the asset has been transferred. This includes the derecognition of receivables for which discounting arrangements are entered into.

The group classifies its financial asset debt instruments as measured at amortized cost, fair value through other comprehensive income or fair value through profit or loss. The classification depends on the business model for managing the financial assets and the contractual cash flow characteristics of the financial asset.

Financial assets measured at amortized cost

Financial assets are classified as measured at amortized cost when they are held in a business model the objective of which is to collect contractual cash flows and the contractual cash flows represent solely payments of principal and interest. Such assets are carried at amortized cost using the effective interest method if the time value of money is significant. Gains and losses are recognized in profit or loss when the assets are derecognized or impaired and when interest income is recognized using the effective interest method. This category of financial assets includes trade and other receivables.

Financial assets measured at fair value through other comprehensive income

Financial assets are classified as measured at fair value through other comprehensive income when they are held in a business model the objective of which is both to collect contractual cash flows and sell the financial assets, and the contractual cash flows represent solely payments of principal and interest.

Financial assets measured at fair value through profit or loss

Financial assets are classified as measured at fair value through profit or loss when the asset does not meet the criteria to be measured at amortized cost or fair value through other comprehensive income. Such assets are carried on the balance sheet at fair value with gains or losses recognized in the income statement. Derivatives, other than those designated as effective hedging instruments, are included in this category.

Investments in equity instruments

Investments in equity instruments are subsequently measured at fair value through profit or loss unless an election is made on an instrument-by-instrument basis to recognize fair value gains and losses in other comprehensive income.

Derivatives designated as hedging instruments in an effective hedge

Derivatives designated as hedging instruments in an effective hedge are carried on the balance sheet at fair value. The treatment of gains and losses arising from revaluation is described below in the accounting policy for derivative financial instruments and hedging activities.

Cash equivalents

Cash equivalents are held for the purpose of meeting short-term cash commitments and are short-term highly liquid investments that are readily convertible to known amounts of cash, are subject to insignificant risk of changes in value and generally have a maturity of three months or less from the date of acquisition. Cash equivalents are classified as financial assets measured at amortized cost or, in the case of certain money market funds, fair value through profit or loss.

Impairment of financial assets measured at amortized cost

The group assesses on a forward-looking basis the expected credit losses associated with financial assets measured at amortized cost at each balance sheet date. Expected credit losses are measured based on the maximum contractual period over which the group is exposed to credit risk. As lifetime expected credit losses are recognized for trade receivables and the tenor of substantially all other in-scope financial assets is less than 12 months there is no significant difference between the measurement of 12-month and lifetime expected credit losses for the group. The measurement of expected credit losses is a function of the probability of default, loss given default and exposure at default. The expected credit loss is estimated as the difference between the asset's carrying amount and the present value of the future cash flows the group expects to receive discounted at the financial asset's original effective interest rate. The carrying amount of the asset is adjusted, with the amount of the impairment gain or loss recognized in the income statement.

A financial asset or group of financial assets classified as measured at amortized cost is considered to be credit-impaired if there is reasonable and supportable evidence that one or more events that have a detrimental impact on the estimated future cash flows of the financial asset (or group of financial assets) have occurred. Financial assets are written off where the group has no reasonable expectation of recovering amounts due.

Equity instruments

Instruments are classified as either financial liabilities or as equity in accordance with the substance of the contractual arrangements. Instruments that cannot be settled in the group's own equity instruments and that include no contractual obligation to deliver cash or another financial asset or to exchange financial assets or financial liabilities with another entity that are potentially unfavourable are classified as equity. Equity instruments issued by the group are recognized at the proceeds received, net of directly attributable issue costs.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Financial liabilities

Financial liabilities are recognized when the group becomes party to the contractual provisions of the instrument. The group derecognizes financial liabilities when the obligation specified in the contract is discharged, cancelled or expired. The measurement of financial liabilities depends on their classification, as follows:

Financial liabilities measured at fair value through profit or loss

Financial liabilities that meet the definition of held for trading are classified as measured at fair value through profit or loss. Such liabilities are carried on the balance sheet at fair value with gains or losses recognized in the income statement. Derivatives, other than those designated as effective hedging instruments, are included in this category.

Derivatives designated as hedging instruments in an effective hedge

Derivatives designated as hedging instruments in an effective hedge are carried on the balance sheet at fair value. The treatment of gains and losses arising from revaluation is described below in the accounting policy for derivative financial instruments and hedging activities.

Financial liabilities measured at amortized cost

All other financial liabilities are initially recognized at fair value, net of directly attributable transaction costs. For interest-bearing loans and borrowings this is typically equivalent to the fair value of the proceeds received, net of issue costs associated with the borrowing.

After initial recognition, other financial liabilities are subsequently measured at amortized cost using the effective interest method. Amortized cost is calculated by taking into account any issue costs and any discount or premium on settlement. Gains and losses arising on the repurchase, settlement or cancellation of liabilities are recognized in interest and other income and finance costs respectively.

This category of financial liabilities includes trade and other payables and finance debt.

Significant judgement: supplier financing arrangements

The group's trade payables include some supplier arrangements that utilize letter of credit facilities. Judgement is required to assess the payables subject to these arrangements to determine whether they should continue to be classified as trade payables and give rise to operating cash flows or finance debt and financing cash flows. The criteria used in making this assessment include the payment terms for the amount due relative to terms commonly seen in the markets in which bp operates and whether the arrangements significantly change the nature of the liability. Liabilities subject to these arrangements with payment terms of up to approximately 60 days are generally considered to be trade payables and give rise to operating cash flows. At 31 December 2023, trade payables subject to these arrangements and this significant judgement included $10 billion (2022 $9.5 billion) payable to the providers of the letters of credit. See Note 29 - Liquidity risk for further information.

Financial guarantees

The group issues financial guarantee contracts to make specified payments to reimburse holders for losses incurred if certain associates, joint ventures or third-party entities fail to make payments when due in accordance with the original or modified terms of a debt instrument such as a loan. The liability for a financial guarantee contract is initially measured at fair value and subsequently measured at the higher of the contract's estimated expected credit loss and the amount initially recognized less, where appropriate, cumulative amortization.

Derivative financial instruments and hedging activities

The group uses derivative financial instruments to manage certain exposures to fluctuations in foreign currency exchange rates, interest rates and commodity prices, as well as for trading purposes. These derivative financial instruments are recognized initially at fair value on the date on which a derivative contract is entered into and subsequently remeasured at fair value. Derivatives are carried as assets when the fair value is positive and as liabilities when the fair value is negative.

Contracts to buy or sell a non-financial item (for example, oil, oil products, gas or power) that can be settled net in cash, with the exception of contracts that were entered into and continue to be held for the purpose of the receipt or delivery of a non-financial item in accordance with the group's expected purchase, sale or usage requirements, are accounted for as financial instruments. Gains or losses arising from changes in the fair value of derivatives that are not designated as effective hedging instruments are recognized in the income statement.

If, at inception of a contract, the valuation cannot be supported by observable market data, any gain or loss determined by the valuation methodology is not recognized in the income statement but is deferred on the balance sheet and is commonly known as a 'day-one gain or loss'. This deferred gain or loss is recognized in the income statement over the life of the contract until substantially all the remaining contractual cash flows can be valued using observable market data at which point any remaining deferred gain or loss is recognized in the income statement. Changes in valuation subsequent to the initial valuation at inception of a contract are recognized immediately in the income statement.

For the purpose of hedge accounting, hedges are classified as:

- Fair value hedges when hedging exposure to changes in the fair value of a recognized asset or liability.
- Cash flow hedges when hedging exposure to variability in cash flows that is attributable to either a particular risk associated with a recognized asset or liability or a highly probable forecast transaction.

Hedge relationships are formally designated and documented at inception, together with the risk management objective and strategy for undertaking the hedge. The documentation includes identification of the hedging instrument, the hedged item or transaction, the nature of the risk being hedged, the existence at inception of an economic relationship and subsequent measurement of the hedging instrument's effectiveness in offsetting the exposure to changes in the hedged item's fair value or cash flows attributable to the hedged risk, the hedge ratio and sources of hedge ineffectiveness. Hedges meeting the criteria for hedge accounting are accounted for as follows:

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Fair value hedges

The change in fair value of a hedging derivative is recognized in profit or loss. The change in the fair value of the hedged item attributable to the risk being hedged is recorded as part of the carrying value of the hedged item and is also recognized in profit or loss, where it offsets. The group applies fair value hedge accounting when hedging interest rate risk and certain currency risks on fixed rate finance debt.

Fair value hedge accounting is discontinued only when the hedging relationship or a part thereof ceases to meet the qualifying criteria. This includes when the risk management objective changes or when the hedging instrument is sold, terminated or exercised. The accumulated adjustment to the carrying amount of a hedged item at such time is then amortized prospectively to profit or loss as finance interest expense over the hedged item's remaining period to maturity.

Cash flow hedges

The effective portion of the gain or loss on a cash flow hedging instrument is reported in other comprehensive income, while the ineffective portion is recognized in profit or loss. Amounts reported in other comprehensive income are reclassified to the income statement when the hedged transaction affects profit or loss.

Where the hedged item is a highly probable forecast transaction that results in the recognition of a non-financial asset or liability, such as a forecast foreign currency transaction for the purchase of property, plant and equipment, the amounts recognized within other comprehensive income are transferred to the initial carrying amount of the non-financial asset or liability. Where the hedged item is an equity investment, the amounts recognized in other comprehensive income remain in the separate component of equity until the hedged cash flows affect profit or loss or when accounting under the equity method is discontinued. Where the hedged item is recognized directly in profit or loss, the amounts recognized in other comprehensive income are reclassified to production and manufacturing expenses or sales and other operating revenues as appropriate.

Cash flow hedge accounting is discontinued only when the hedging relationship or a part thereof ceases to meet the qualifying criteria. This includes when the designated hedged forecast transaction or part thereof is no longer considered to be highly probable to occur, or when the hedging instrument is sold, terminated or exercised without replacement or rollover. When cash flow hedge accounting is discontinued amounts previously recognized within other comprehensive income remain in equity until the forecast transaction occurs and are reclassified to profit or loss or transferred to the initial carrying amount of a non-financial asset or liability as above. If the forecast transaction is no longer expected to occur, amounts previously recognized within other comprehensive income will be immediately reclassified to profit or loss.

Costs of hedging

The foreign currency basis spread of cross-currency interest rate swaps are excluded from hedge designations and accounted for as costs of hedging. Changes in fair value of the foreign currency basis spread are recognized in other comprehensive income to the extent that they relate to the hedged item.

For time-period related hedged items, the amount recognized in other comprehensive income is amortized to profit or loss on a straight line basis over the term of the hedging relationship.

Fair value measurement

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. The group categorizes assets and liabilities measured at fair value into one of three levels depending on the ability to observe inputs employed in their measurement. Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Level 2 inputs are inputs that are observable, either directly or indirectly, other than quoted prices included within level 1 for the asset or liability. Level 3 inputs are unobservable inputs for the asset or liability reflecting significant modifications to observable related market data or bp's assumptions about pricing by market participants.

Significant estimate and judgement: derivative financial instruments

In some cases the fair values of derivatives are estimated using internal models due to the absence of quoted prices or other observable, market-corroborated data. This primarily applies to the group's longer-term derivative contracts. The majority of these contracts are valued using models with inputs that include price curves for each of the different products that are built up from available active market pricing data (including volatility and correlation) and modelled using the maximum available external information. Additionally, where limited data exists for certain products, prices are determined using historical and long-term pricing relationships. The use of alternative assumptions or valuation methodologies may result in significantly different values for these derivatives. A reasonably possible change in the price assumptions used in the models relating to index price would not have a material impact on net assets and the Group income statement primarily as a result of offsetting movements between derivative assets and liabilities.

In some cases, judgement is required to determine whether contracts to buy or sell commodities meet the definition of a derivative or to determine appropriate presentation and classification of transactions in certain cases. In particular, contracts to buy and sell LNG are not considered to meet the definition as they are not considered capable of being net settled due to a lack of liquidity in the LNG market and the inability or lack of history of net settlement and are accounted for on an accruals basis, rather than as a derivative. Under IFRS, bp fair values the derivative financial instruments used to risk-manage the LNG contracts themselves, resulting in a measurement mismatch.

For more information, including the carrying amounts of level 3 derivatives, see Note 30.

Offsetting of financial assets and liabilities

Financial assets and liabilities are presented gross in the balance sheet unless both of the following criteria are met: the group currently has a legally enforceable right to set off the recognized amounts; and the group intends to either settle on a net basis or realize the asset and settle the liability simultaneously. A right of set off is the group's legal right to settle an amount payable to a creditor by applying against it an amount receivable from the same counterparty. The relevant legal jurisdiction and laws applicable to the relationships between the parties are considered when assessing whether a current legally enforceable right to set off exists.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Provisions and contingencies

Provisions are recognized when the group has a present legal or constructive obligation as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. Where appropriate, the future cash flow estimates are adjusted to reflect risks specific to the liability.

If the effect of the time value of money is material, provisions are determined by discounting the expected future cash flows at a pre-tax risk-free rate that reflects current market assessments of the time value of money. Where discounting is used, the increase in the provision due to the passage of time is recognized within finance costs. Provisions are discounted using a nominal discount rate of 4% (2022 3.5%) .

Provisions are split between amounts expected to be settled within 12 months of the balance sheet date (current) and amounts expected to be settled later (non-current).

Contingent liabilities are possible obligations whose existence will only be confirmed by future events not wholly within the control of the group, or present obligations where it is not probable that an outflow of resources will be required or the amount of the obligation cannot be measured with sufficient reliability. Contingent liabilities are not recognized in the consolidated financial statements but are disclosed, if material, unless the possibility of an outflow of economic resources is considered remote.

Decommissioning

Liabilities for decommissioning costs are recognized when the group has an obligation to plug and abandon a well, dismantle and remove a facility or an item of plant and to restore the site on which it is located, and when a reliable estimate of that liability can be made. Where an obligation exists for a new facility or item of plant, such as oil and natural gas production or transportation facilities, this liability will be recognized on construction or installation. Similarly, where an obligation exists for a well, this liability is recognized when it is drilled. An obligation for decommissioning may also crystallize during the period of operation of a well, facility or item of plant through a change in legislation or through a decision to terminate operations; an obligation may also arise in cases where an asset has been sold but the subsequent owner is no longer able to fulfil its decommissioning obligations, for example due to bankruptcy. The amount recognized is the present value of the estimated future expenditure determined in accordance with local conditions and requirements. The provision for the costs of decommissioning wells, production facilities and pipelines at the end of their economic lives is estimated using existing technology, at future prices, depending on the expected timing of the activity, and discounted using a nominal discount rate.

An amount equivalent to the decommissioning provision is recognized as part of the corresponding intangible asset (in the case of an exploration or appraisal well) or property, plant and equipment. The decommissioning portion of the property, plant and equipment is subsequently depreciated at the same rate as the rest of the asset. Other than the unwinding of discount on or utilization of the provision, any change in the present value of the estimated expenditure is reflected as an adjustment to the provision and the corresponding asset where that asset is generating or is expected to generate future economic benefits.

Environmental expenditures and liabilities

Environmental expenditures that are required in order for the group to obtain future economic benefits from its assets are capitalized as part of those assets. Expenditures that relate to an existing condition caused by past operations that do not contribute to future earnings are expensed.

Liabilities for environmental costs are recognized when a clean-up is probable and the associated costs can be reliably estimated. Generally, the timing of recognition of these provisions coincides with the commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites.

The amount recognized is the best estimate of the expenditure required to settle the obligation. Provisions for environmental liabilities have been estimated using existing technology, at future prices and discounted using a nominal discount rate.

Emissions

Liabilities for emissions are recognized when the cumulative volumes of gases emitted by the group at the end of the reporting period exceed the allowances granted free of charge held for own use or a set baseline for emissions. The provision is measured at the best estimate of the expenditure required to settle the present obligation at the balance sheet date. It is based on the excess of actual emissions over the free allowances held or set baseline in tonnes (or other appropriate quantity) and is valued at the actual cost of any allowances that have been purchased and held for own use on a first-in-first-out (FIFO) basis, and, if insufficient allowances are held, for the remaining requirement on the basis of the spot market price of allowances at the balance sheet date. The majority of these provisions are typically settled within 12 months of the balance sheet date however certain schemes may have longer compliance periods. The cost of allowances purchased to cover a shortfall is recognized separately on the balance sheet as an intangible asset unless the emission allowances acquired or generated by the group are risk-managed by the trading and shipping function, then they are recognized on the balance sheet as inventory.

Restructuring provisions

Restructuring provisions are recognized where a detailed formal plan exists, and a valid expectation of risk of redundancy has been made to those affected but where the specific outcomes remain uncertain. Where formal redundancy offers have been made, the obligations for those amounts are reported as payables and, if not, as provisions if unpaid at the year-end.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Significant judgements and estimates: provisions

The group holds provisions for the future decommissioning of oil and natural gas production facilities and pipelines at the end of their economic lives. The largest decommissioning obligations facing bp relate to the plugging and abandonment of wells and the removal and disposal of oil and natural gas platforms and pipelines around the world. Most of these decommissioning events are many years in the future and the precise requirements that will have to be met when the removal event occurs are uncertain. Decommissioning technologies and costs are constantly changing, as are political, environmental, safety and public expectations. The timing and amounts of future cash flows are subject to significant uncertainty and estimation is required in determining the amounts of provisions to be recognized. Any changes in the expected future costs are reflected in both the provision and, where still recognized, the asset.

If oil and natural gas production facilities and pipelines are sold to third parties, judgement is required to assess whether the new owner will be unable to meet their decommissioning obligations, whether bp would then be responsible for decommissioning, and if so the extent of that responsibility. This typically requires assessment of the local legal requirements and the financial standing of the owner. If the standing deteriorates significantly, for example, bankruptcy of the owner, a provision may be required. The group has assessed that $0.6 billion of decommissioning provisions should be recognized as at 31 December 2023 (2022 $0.8 billion) for assets previously sold to third parties where the sale transferred the decommissioning obligation to the new owner. See Note 33 for further information.

Decommissioning provisions associated with downstream refineries are generally not recognized, as the potential obligations cannot be measured, given their indeterminate settlement dates. Obligations may arise if refineries cease manufacturing operations and any such obligations would be recognized in the period when sufficient information becomes available to determine potential settlement dates. See Note 33 for further information.

The group performs periodic reviews of its downstream refineries for any changes in facts and circumstances including those relating to the energy transition, that might require the recognition of a decommissioning provision. Portfolio strength and flexibility are such that the point of cessation of manufacturing at the group's operating refineries is not yet expected within a determinate time period, as existing property plant and equipment is expected to be renewed or replaced.

The provision for environmental liabilities is estimated based on current legal and constructive requirements, technology, price levels and expected plans for remediation. Actual costs and cash outflows can differ from current estimates because of changes in laws and regulations, public expectations, prices, discovery and analysis of site conditions and changes in clean-up technology.

The timing and amount of future expenditures relating to decommissioning and environmental liabilities are reviewed annually. The interest rate used in discounting the cash flows is reviewed quarterly. The nominal interest rate used to determine the balance sheet obligations at the end of 2023 was 4% (2022 3.5%), which was based on long-dated US government bonds. The weighted average period over which decommissioning and environmental costs are generally expected to be incurred is estimated to be approximately 17 years (2022 17 years) and 6 years (2022 6 years) respectively. Costs at future prices are typically determined by applying an inflation rate of 1.5% (2022 1.5%) to decommissioning costs and 2% (2022 2%) for all other provisions. A lower rate is typically applied to decommissioning as certain costs are expected to remain fixed at current or past prices.

The estimated phasing of undiscounted cash flows in real terms for upstream decommissioning is approximately $5.5 billion (2022 $5.6 billion) within the next 10 years, $5.8 billion (2022 $5.3 billion) in 10 to 20 years and the remainder of approximately $6.6 billion (2022 $6.0 billion) after 20 years. The timing and amount of decommissioning cash flows are inherently uncertain and therefore the phasing is management's current best estimate but may not be what will ultimately occur.

Further information about the group's provisions is provided in Note 23. Changes in assumptions in relation to the group's provisions could result in a material change in their carrying amounts within the next financial year. A 1.0 percentage point increase in the nominal discount rate applied could decrease the group's provision balances by approximately $1.6 billion (2022 $1.8 billion). The pre-tax impact on the group income statement would be a credit of approximately $0.4 billion (2022 $0.5 billion). This level of change reflects past experience of a reasonable change in rate that could arise within the next financial year.

The discounting impact on the group's decommissioning provisions for oil and gas properties in the oil productions & operations and gas & low carbon energy segments of a two-year change in the timing of expected future decommissioning expenditures is approximately $0.6 billion (2022 $0.5 billion). Management currently does not consider a change of greater than two years to be reasonably possible in the next financial year and therefore the timing of upstream decommissioning expenditure is not a key source of estimation uncertainty.

If all expected future decommissioning expenditures were 10% higher, then these decommissioning provisions would increase by approximately $1.1 billion (2022 $1.2 billion) and a pre-tax charge of approximately $0.2 billion (2022 $0.3 billion) would be recognized. A one percentage point increase in the inflation rate applied to upstream decommissioning costs to determine the nominal cash flows could increase the decommissioning provision by approximately $1.9 billion (2022 $2.0 billion) with a pre-tax charge of approximately $0.5 billion (2022 $0.5 billion).

As described in Note 33, the group is subject to claims and actions for which no provisions have been recognized. The facts and circumstances relating to particular cases are evaluated regularly in determining whether a provision relating to a specific litigation should be recognized or revised. Accordingly, significant management judgement relating to provisions and contingent liabilities is required, since the outcome of litigation is difficult to predict.

Employee benefits

Wages, salaries, bonuses, social security contributions, paid annual leave and sick leave are accrued in the period in which the associated services are rendered by employees of the group. Deferred bonus arrangements that have a vesting date more than 12 months after the balance sheet date are valued on an actuarial basis using the projected unit credit method and amortized on a straight-line basis over the service period until the award vests. The material accounting policy information for pensions and other post-retirement benefits are described below.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Pensions and other post-retirement benefits

The cost of providing benefits under the group's defined benefit plans is determined separately for each plan using the projected unit credit method, which attributes entitlement to benefits to the current period to determine current service cost and to the current and prior periods to determine the present value of the defined benefit obligation. Past service costs, resulting from either a plan amendment or a curtailment (a reduction in future obligations as a result of a material reduction in the plan membership), are recognized immediately when the company becomes committed to a change.

Net interest expense relating to pensions and other post-retirement 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-retirement benefits

Accounting for defined benefit pensions and other post-retirement benefits involves making significant estimates when measuring the group's pension plan surpluses and deficits. These estimates require assumptions to be made about many uncertainties.

Pensions and other post-retirement benefit assumptions are reviewed by management at the end of each year. These assumptions are used to determine the projected benefit obligation at the year end and hence the surpluses and deficits recorded on the group's balance sheet and pension and other post-retirement benefit expense for the following year.

The assumptions that are the most significant to the amounts reported are the discount rate, inflation rate and mortality levels. Assumptions about these variables are based on the environment in each country. The assumptions used vary from year to year, with resultant effects on future net income and net assets. Changes to some of these assumptions, in particular the discount rate and inflation rate, could result in material changes to the carrying amounts of the group's pension and other post-retirement benefit obligations within the next financial year, in particular for the UK, US and Eurozone plans. Any differences between these assumptions and the actual outcome will also affect future net income and net assets.

The values ascribed to these assumptions and a sensitivity analysis of the impact of changes in the assumptions on the benefit expense and obligation used are provided in Note 24.

Income taxes

Income tax expense represents the sum of current tax and deferred tax.

Income tax is recognized in the income statement, except to the extent that it relates to items recognized in other comprehensive income or directly in equity, in which case the related tax is recognized in other comprehensive income or directly in equity.

Current tax is based on the taxable profit for the period. Taxable profit differs from net profit as reported in the income statement because it is determined in accordance with the rules established by the applicable taxation authorities. It therefore excludes items of income or expense that are taxable or deductible in other periods as well as items that are never taxable or deductible. The group's liability for current tax is calculated using tax rates and laws that have been enacted or substantively enacted by the balance sheet date.

Deferred tax is provided, using the liability method, on temporary differences at the balance sheet date between the tax bases of assets and liabilities and their carrying amounts for financial reporting purposes. Deferred tax liabilities are recognized for all taxable temporary differences except:

- Where the deferred tax liability arises on the initial recognition of goodwill.
- Where the deferred tax liability arises on the initial recognition of an asset or liability in a transaction that is not a business combination, at the time of the transaction, affects neither accounting profit nor taxable profit or loss and, at the time of the transaction, does not give rise to equal taxable and deductible temporary differences.
- In respect of taxable temporary differences associated with investments in subsidiaries and associates and interests in joint arrangements, where the group is able to control the timing of the reversal of the temporary differences and it is probable that the temporary differences will not reverse in the foreseeable future.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Deferred tax assets are recognized for deductible temporary differences, carry-forward of unused tax credits and unused tax losses, to the extent that it is probable that taxable profit will be available against which the deductible temporary differences and the carry-forward of unused tax credits and unused tax losses can be utilized, except where the deferred tax asset relating to the deductible temporary difference arises from the initial recognition of an asset or liability in a transaction that is not a business combination, at the time of the transaction, affects neither accounting profit nor taxable profit or loss and, at the time of the transaction, does not give rise to equal taxable and deductive temporary differences.

In respect of deductible temporary differences associated with investments in subsidiaries and associates and interests in joint arrangements, deferred tax assets are recognized only to the extent that it is probable that the temporary differences will reverse in the foreseeable future and taxable profit will be available against which the temporary differences can be utilized.

The carrying amount of deferred tax assets is reviewed at each balance sheet date and reduced to the extent that it is no longer probable or increased to the extent that it is probable that sufficient taxable profit will be available to allow all or part of the deferred tax asset to be utilized.

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply in the period when the asset is realized or the liability is settled, based on tax rates (and tax laws) that have been enacted or substantively enacted at the balance sheet date. Deferred tax assets and liabilities are not discounted.

Deferred tax assets and liabilities are offset only when there is a legally enforceable right to set off current tax assets against current tax liabilities and when the deferred tax assets and liabilities relate to income taxes levied by the same taxation authority on either the same taxable entity or different taxable entities where there is an intention to settle the current tax assets and liabilities on a net basis or to realize the assets and settle the liabilities simultaneously.

Where tax treatments are uncertain, if it is considered probable that a taxation authority will accept the group's proposed tax treatment, income taxes are recognized consistent with the group's income tax filings. If it is not considered probable, the uncertainty is reflected within the carrying amount of the applicable tax asset or liability using either the most likely amount or an expected value, depending on which method better predicts the resolution of the uncertainty.

The computation of the group's income tax expense and liability involves the interpretation of applicable tax laws and regulations in many jurisdictions throughout the world. The resolution of tax positions taken by the group, through negotiations with relevant tax authorities or through litigation, can take several years to complete and in some cases it is difficult to predict the ultimate outcome. Therefore, judgement is required to determine whether provisions for income taxes are required and, if so, estimation is required of the amounts that could be payable.

In addition, the group has carry-forward tax losses and tax credits in certain taxing jurisdictions that are available to offset against future taxable profit. However, deferred tax assets are recognized only to the extent that it is probable that taxable profit will be available against which the unused tax losses or tax credits can be utilized. Management judgement is exercised in assessing whether this is the case and estimates are required to be made of the amount of future taxable profits that will be available. Such judgements are inherently impacted by estimates affecting future taxable profits such as oil and natural gas prices and decommissioning expenditure, see 'Significant judgements and estimates: recoverability of asset carrying values and provisions'.

In May 2023, the IASB issued International Tax Reform – Pillar Two Model Rules - Amendments to IAS 12 Income Taxes to clarify the application of IAS 12 to tax legislation enacted or substantively enacted to implement Pillar Two of the Organisation for Economic Co-operation and Development's Base Erosion and Profit Shifting project, which aims to address the tax challenges arising from the digitalisation of the economy. The amendments include a mandatory temporary exception from accounting for deferred tax on such tax law. In July 2023, the UK government enacted legislation to implement the Pillar Two rules. The legislation is effective for bp from 1 January 2024 and includes an income inclusion rule and a domestic minimum tax, which together are designed to ensure a minimum effective tax rate of 15% in each country in which the group operates. Similar legislation is being enacted by other governments around the world. In line with the amendments to IAS 12, the exception from accounting for deferred tax for the Pillar Two rules has been applied and there are no impacts on the consolidated financial statements for 2023. Based on an assessment of historic data and forecasts for the year ending 31 December 2024, the Group does not expect a material exposure to Pillar Two income taxes for the year ending 31 December 2024.

Significant judgement and estimate: taxation

The value of deferred tax assets and liabilities is an area involving inherent uncertainty and estimation and balances are therefore subject to risk of material change as a result of underlying assumptions and judgements used, in particular the forecast of future profitability used to determine the recoverability of deferred tax, for example future oil and gas prices, see 'Significant judgement and estimates - Recoverability of asset carrying values'. It is impracticable to disclose the extent of the possible effects of profitability assumptions on the group's deferred tax assets. It is reasonably possible that to the extent that actual outcomes differ from management's estimates, material income tax charges or credits, and material changes in current and deferred tax assets or liabilities, may arise within the next financial year and in future periods.
Judgement is required when determining whether a particular tax is an income tax or another type of tax (for example, a production tax). The attributes of the tax, including whether it is calculated on profits or another measure such as production or revenues, the extent of deductibility of costs and the interaction with existing income taxes, are considered in determining the classification of the tax. Accounting for deferred tax is applied to income taxes as described above but is not applied to other types of taxes; rather such taxes are recognized in the income statement in accordance with the applicable accounting policy such as Provisions and contingencies.

This judgement is considered significant only in relation to the group's taxes payable under the fiscal terms of bp's onshore concession in Abu Dhabi. These are principally reported as income taxes rather than as production taxes.

For more information see Note 9 and Note 33.

Customs duties and sales taxes

Customs duties and sales taxes that are passed on or charged to customers are excluded from revenues and expenses. Assets and liabilities are recognized net of the amount of customs duties or sales tax except:

- Customs duties or sales taxes incurred on the purchase of goods and services which are not recoverable from the taxation authority are recognized as part of the cost of acquisition of the asset.
- Receivables and payables are stated with the amount of customs duty or sales tax included.

The net amount of sales tax recoverable from, or payable to, the taxation authority is included within receivables or payables in the balance sheet.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Own equity instruments – treasury shares

The group’s holdings in its own equity instruments are shown as deductions from shareholders’ equity. Treasury shares represent bp shares repurchased and available for specific and limited purposes. For accounting purposes, shares held in Employee Share Ownership Plans (ESOPs) to meet the future requirements of the employee share-based payment plans are treated in the same manner as treasury shares and are, therefore, included in the consolidated financial statements as treasury shares. The cost of treasury shares subsequently sold or reissued is calculated on a weighted-average basis. Consideration, if any, received for the sale of such shares is also recognized in equity. No gain or loss is recognized in the income statement on the purchase, sale, issue or cancellation of equity shares. Shares repurchased under the share buy-back programme which are immediately cancelled are not shown as treasury shares, but are shown as a deduction from the profit and loss account reserve in the group statement of changes in equity.

Revenue and other income

Revenue from contracts with customers is recognized when or as the group satisfies a performance obligation by transferring control of a promised good or service to a customer. The transfer of control of oil, natural gas, natural gas liquids, LNG, petroleum and chemical products, and other items usually coincides with title passing to the customer and the customer taking physical possession. The group principally satisfies its performance obligations at a point in time; the amounts of revenue recognized relating to performance obligations satisfied over time are not significant.

When, or as, a performance obligation is satisfied, the group recognizes as revenue the amount of the transaction price that is allocated to that performance obligation. The transaction price is the amount of consideration to which the group expects to be entitled. The transaction price is allocated to the performance obligations in the contract based on standalone selling prices of the goods or services promised.

Contracts for the sale of commodities are typically priced by reference to quoted prices. Revenue from term commodity contracts is recognized based on the contractual pricing provisions for each delivery. Certain of these contracts have pricing terms based on prices at a point in time after delivery has been made. Revenue from such contracts is initially recognized based on relevant prices at the time of delivery and subsequently adjusted as appropriate. All revenue from these contracts, both that recognized at the time of delivery and that from post-delivery price adjustments, is disclosed as revenue from contracts with customers.

Sales and purchase of commodities accounted for under IFRS 15 are presented on a gross basis in Revenue from contracts with customers and Purchases respectively. Physically settled derivatives which represent trading or optimization activities are presented net alongside financially settled derivative contracts in Other operating revenues within Sales and other operating income. Certain physically settled sale and purchase derivative contracts which are not part of trading and optimization activities are presented gross within Other operating revenues and Purchases respectively. Changes in the fair value of derivative assets and liabilities prior to physical delivery are also classified as other operating revenues.

Physical exchanges with counterparties in the same line of business in order to facilitate sales to customers are reported net, as are sales and purchases made with a common counterparty, as part of an arrangement similar to a physical exchange.

Where the group acts as agent on behalf of a third party to procure or market energy commodities, any associated fee income is recognized but no purchase or sale is recorded.

Interest income is recognized as the interest accrues (using the effective interest rate, that is, the rate that exactly discounts estimated future cash receipts through the expected life of the financial instrument to the net carrying amount of the financial asset).

Dividend income from investments is recognized when the shareholders’ right to receive the payment is established.

Contract asset and contract liability balances are included within amounts presented for trade receivables and other payables respectively.

Finance costs

Finance costs directly attributable to the acquisition, construction or production of qualifying assets, which are assets that necessarily take a substantial period of time to get ready for their intended use, are added to the cost of those assets until such time as the assets are substantially ready for their intended use. All other finance costs are recognized in the income statement in the period in which they are incurred.

Updates to material accounting policy information

Impact of new International Financial Reporting Standards

There are no new or amended standards or interpretations adopted from 1 January 2023 onwards, including the amendments to IAS 12 'Income Taxes' as described on page 186 and IFRS 17 'Insurance Contracts,' that have a significant impact on the consolidated financial statements for 2023. Further, there are no new or amended standards not yet adopted that are expected to have a material impact.

2. Non-current assets held for sale

The carrying amount of assets classified as held for sale at 31 December 2023 is $151 million (2022 $1,242 million), with associated liabilities of $62 million (2022 $321 million).

customers & products

On 16 November 2023, bp entered into an agreement to sell its Türkiye ground fuels business to Petrol Ofisi. This includes the group's interest in three joint venture terminals in Türkiye. Completion of the sale is subject to regulatory approvals. The carrying amount of assets classified as held for sale at 31 December 2023 is $151 million, with associated liabilities of $62 million. Cumulative foreign exchange losses within reserves of approximately $850 million are expected to be recycled to the group income statement at completion.

Transactions that have been classified as held for sale during 2023, but were completed by 31 December 2023, are described below.

gas & low carbon energy

The assets held for sale balance at 31 December 2022 included assets of $511 million and associated liabilities of $48 million relating to the agreement to sell bp's upstream business in Algeria to Eni. The transaction closed on 28 February 2023.

customers & products

In addition, at 31 December 2022 assets of $731 million and associated liabilities of $273 million were classified as held for sale relating to the sale of bp's 50% interest in the bp-Husky Toledo refinery in Ohio US, to Cenovus Energy, its partner in the facility. The sale completed on 28 February 2023.

The total assets and liabilities held for sale at 31 December 2023 and 2022, which for 2023 are all in the customers & products segments and for 2022 in the gas & low carbon energy and customers & products segments, are set out in the table below.

		$ million
	2023	2022
Property, plant and equipment	**49**	693
Goodwill	**—**	58
Intangible assets	**3**	—
Loans	**1**	—
Inventories	**—**	255
Cash	**—**	35
Trade and other receivables	**98**	201
Assets classified as held for sale	**151**	1,242
Trade and other payables	**(1)**	(256)
Lease liabilities	**(40)**	(14)
Provisions	**(10)**	(36)
Deferred tax liabilities	**—**	(15)
Defined benefit pension plan and other post-retirement benefit plan deficits	**(11)**	—
Liabilities directly associated with assets classified as held for sale	**(62)**	(321)

3. Business combinations and other significant transactions

Business combinations

2023

The group undertook a number of business combinations during 2023. Total consideration paid in cash amounted to $1,282 million (2022 $3,671 million), offset by cash acquired of $484 million (2022 $141 million).

The fair value of the net assets (including goodwill) recognized from business combinations in the full year, inclusive of measurement period adjustments for business combinations in previous periods, was $1,228 million (2022 $4,121 million). This principally related to the acquisition of TravelCenters of America.

2022

Archaea Energy

On 28 December 2022, bp acquired 100% of the issued common stock of Archaea Energy Inc. a leading producer of renewable natural gas (RNG) in the US, that was listed on the New York Stock Exchange.

The total cash consideration for the transaction, all paid at completion, was $3,137 million.

The transaction was accounted for as a business combination using the acquisition method. As the transaction completed shortly prior to the end of the reporting period, the acquisition-date fair values of the assets and liabilities acquired reported in 2022 were provisional. The final and provisional fair values of the identifiable assets and liabilities acquired, as at the date of acquisition are shown in the table below. The measurement period adjustments between the provisional and final values were recognized in 2023 as the impact on the comparative period was not material. The intangible assets recognized are primarily the biogas rights agreements Archaea Energy has with landfill owners. The goodwill recognized reflects the part of the project development pipeline that did not qualify for separate recognition at the acquisition date and goodwill arising from recognition of deferred tax liabilities on fair value uplifts. The goodwill balance is not expected to be deductible for tax purposes.

The transaction included a step acquisition of the Mavrix LLC joint venture, which bp and Archaea Energy each held a 50% interest in prior to this transaction. The final fair value of bp's interest in Mavrix LLC immediately before the acquisition date was $303 million and the gain recognized in 'Interest and other income', initially in 2022 and revised in 2023, as a result of remeasuring this interest to fair value was $196 million.

		$ million
	Provisional	**Final**
Assets		
Property plant and equipment	**885**	**929**
Goodwill	**409**	**707**
Intangible assets	**3,475**	**3,178**
Investments in equity-accounted entities	**917**	**883**
Inventory	**42**	**31**
Trade and other receivables	**67**	**47**
Cash and cash equivalents	**107**	**96**
Liabilities		
Trade and other payables	**(1,032)**	**(1,145)**
Finance debt	**(1,044)**	**(1,044)**
Deferred tax liabilities	**(293)**	**(214)**
Provisions	**(16)**	**(21)**
Non-controlling interest	**(7)**	**(7)**
Total consideration	**3,510**	**3,440**
Of which:		
Cash	**3,137**	**3,137**
Fair value of previously held interest in Mavrix LLC	**373**	**303**

4. Disposals and impairment

The following amounts were recognized in the income statement in respect of disposals and impairments.

			$ million
	2023	2022	2021
Gains on sale of businesses and fixed assets			
gas & low carbon energy	**19**	45	1,034
oil production & operations	**297**	3,446	869
customers & products	**44**	374	(52)
other businesses & corporate	**9**	1	25
	369	3,866	1,876

			$ million
	2023	2022	2021
Losses on sale of businesses and fixed assets, and closures			
gas & low carbon energy	**9**	—	1
oil production & operations	**5**	921	86
customers & products	**143**	177	142
other businesses & corporate	**(1)**	11,083	1
	156	12,181	230
Impairment losses			
gas & low carbon energy	**2,213**	745	834
oil production & operations	**1,840**	4,480	1,617
customers & products	**1,614**	1,874	962
other businesses & corporate	**80**	13,536	63
	5,747	20,635	3,476
Impairment reversals			
gas & low carbon energy	**(1)**	(1,333)	(2,338)
oil production & operations	**(26)**	(893)	(2,479)
customers & products	**—**	(68)	(7)
other businesses & corporate	**(19)**	—	(3)
	(46)	(2,294)	(4,827)
Impairment and losses on sale of businesses and fixed assets, and closures	**5,857**	30,522	(1,121)

Disposals

Disposal proceeds and principal gains and losses on disposals by segment are described below.

			$ million
	2023	2022	2021
Proceeds from disposals of fixed assets	**133**	709	1,145
Proceeds from disposals of businesses, net of cash disposed	**1,193**	1,841	5,812
	1,326	2,550	6,957
By business			
gas & low carbon energy	**536**	22	2,425
oil production & operations	**333**	1,935	3,022
customers & products	**436**	592	1,050
other businesses & corporate	**21**	1	460
	1,326	2,550	6,957

Proceeds from disposals of businesses in 2023 includes $477 million relating to the sale of the upstream business in Algeria to Eni and $351 million relating to the disposal of the bp-Husky Toledo refinery to Cenovus Energy. At 31 December 2023, deferred consideration relating to disposals amounted to $141 million receivable within one year (2022 $191 million and 2021 $205 million) and $217 million receivable after one year (2022 $194 million and 2021 $823 million). The amounts of deferred consideration are reported within Trade and other receivables in Other receivables in the group balance sheet. In addition, contingent consideration receivable relating to disposals amounted to $1,694 million at 31 December 2023 (2022 $1,896 million and 2021 $1,917 million). The contingent consideration at 31 December 2023 relates to the prior period disposals of our Alaskan business and certain assets in the North Sea and the disposal of our 50% interest in the Sunrise oil sands project in Canada. These amounts of contingent consideration are reported within Other investments on the group balance sheet - see Note 18 for further information.

Gains and losses on sale of businesses and fixed assets, and closures

gas & low carbon energy

In 2021 gains on disposal of businesses and fixed assets were principally related to a $1,031 million gain on disposal of a 20% participating interest in Block 61 in Oman.

4. Disposals and impairment – continued

oil production & operations

In 2023 gains principally related to prior period disposals in the US and Canada.

In 2022 gains principally related to a gain of $1,932 million arising from the contribution of bp's Angolan business to Azule Energy, a gain of $904 million related to the deemed disposal of 12% of the group's interest in Aker BP, an associate of bp, following completion of Aker BP's acquisition of Lundin Energy, and $349 million in relation to the disposal of the group's interest in the Rumaila field in Iraq to Basra Energy Company, an associate of bp.

Losses included $479 million of accumulated exchange losses previously charged to equity and taken to the income statement as a result of the decision to exit bp's other businesses with Rosneft within Russia.

In 2021 gains principally resulted from adjustments to disposals in prior periods. Gains include $171 million from the disposal of a 2.1% interest in Aker BP in the North Sea, $100 million from the disposal of certain exploration assets in Brazil, and $502 million fair value movements in relation to deferred and contingent consideration in relation to prior disposals in Alaska and the North Sea.

customers & products

In 2022, gains principally relate to a gain of $268 million arising from the divestment of our Swiss retail assets.

other businesses and corporate

In 2022 the losses on disposal of businesses and fixed assets was $11,082 million in respect of the decision to exit our holding in Rosneft which resulted in the reclassification to the income statement of $10,372 million of accumulated exchange losses, a cash flow hedge reserve of $651 million relating to the original acquisition of Rosneft shares and bp's cumulative share of Rosneft's other comprehensive income of $59 million which were all previously charged to equity.

Summarized financial information relating to the sale of businesses is shown in the table below.

The principal transactions categorized as a business disposal in 2023 were the sale of the upstream business in Algeria to Eni and the disposal of the bp-Husky Toledo refinery to Cenovus Energy.

The principal transactions categorized as a business disposal in 2022 were the formation of Azule Energy, the formation of Basra Energy Company and the sale of our 50% interest in the Sunrise oil sands project in Canada.

The principal transaction categorized as a business disposal in 2021 was the sale of a 20% participating interest from bp’s 60% participating interest in Block 61 in Oman.

			$ million
	2023	2022	2021
Non-current assets	**1,145**	3,681	1,620
Current assets	**557**	2,972	69
Non-current liabilities	**(60)**	(1,869)	(287)
Current liabilities	**(454)**	(1,074)	(3)
Total carrying amount of net assets disposed	**1,188**	3,710	1,399
Recycling of foreign exchange on disposal	**—**	(26)	35
Costs on disposal	**57**	488	(5)
	1,245	4,172	1,429
Gains (losses) on sale of businesses	**158**	6,219	1,632
Total consideration	**1,403**	10,391	3,061
Non-cash consideration	**(51)**	(8,999)	(108)
Consideration received (receivable)	**(159)**	449	2,859
Proceeds from the sale of businesses, net of cash disposed[a]	**1,193**	1,841	5,812

[a] Proceeds are stated net of cash and cash equivalents disposed of $33 million (2022 $318 million and 2021 $2 million).

Impairments

Impairment losses and impairment reversals in each segment are described below. For information on significant estimates and judgements made in relation to impairments see Impairment of property, plant and equipment, intangibles, goodwill and equity-accounted entities within Note 1. See also Note 12, and Note 15 for further information on impairments by asset category.

gas & low carbon energy

The 2023 impairment loss of $2,213 million primarily relates to losses incurred in respect of certain assets in Mauritania & Senegal ($1,434 million) and principally arose as a result of increased forecast future expenditure. A further $565 million relates to producing assets in Trinidad and arose as a result of changes to the group's oil and gas price and discount rate assumptions and activity phasing. The recoverable amount of all CGUs for which impairment charges or reversals were recognized in 2023 in total, based on their value in use, is $4,811 million.

The 2022 impairment loss of $745 million primarily relates to losses incurred in respect of certain assets in Mauritania & Senegal ($729 million) and principally arose as a result of increased forecast future expenditure. The 2022 impairment reversal of $1,333 million primarily relates to the Trinidad CGU ($1,331 million) and principally arose as a result of changes to the group's oil and gas price assumptions. The recoverable amount of all CGUs for which impairment charges or reversals were recognized in 2022 in total, based on their value in use, is $9,609 million.

4. Disposals and impairment – continued

The 2021 impairment loss of $834 million primarily relates to losses incurred in respect of certain assets in Mauritania & Senegal ($819 million) and principally arose as a result of increased forecast future expenditure. The 2021 impairment reversal of $2,338 million primarily relates to reversals in respect of producing assets in the KGD6 CGU in India ($1,229 million) and the Trinidad CGU ($600 million) and principally arose as a result of changes to the group's oil and gas price assumptions and re-assessment of reserves. The recoverable amount of all CGUs for which impairment charges or reversals were recognized in 2021 in total, based on their value in use, is $17,330 million.

oil production & operations

Impairment losses and reversals in all years relate primarily to producing assets and, in 2022, equity accounted investments.

The 2023 impairment loss of $1,840 million primarily arose as a result of changes to the group's oil and gas price and discount rate assumptions, activity phasing and disposal decisions in relation to certain assets in North Sea ($852 million) and in bpx energy ($802 million). The recoverable amount of all CGUs for which impairment charges or reversals were recognized in 2023 in total, based on their value in use, is $14,072 million.

The 2022 impairment loss of $4,480 million primarily relates to impairment of the Pan American Energy Group S.L. joint venture as a result of expected portfolio changes ($2,900 million) and the decision to exit bp's other businesses with Rosneft within Russia ($1,043 million). The 2022 impairment reversal of $893 million principally relates to changes in price and reserves assumptions in the North Sea ($643 million). The recoverable amount of all CGUs for which impairment charges or reversals were recognized in 2022 in total, based on their value in use, is $7,831 million.

The 2021 impairment loss of $1,617 million principally relates to the decision to exit the Sunrise oil sands project in Canada ($1,109 million). The 2021 impairment reversals of $2,479 million principally arose as a result of changes to the group’s oil and gas price assumptions and re-assessment of reserves. They include amounts in BPX Energy ($1,356 million) and the North Sea ($950 million). The principal CGU on which a significant impairment reversal was recognized was $982 million for Hawkville in BPX Energy. The recoverable amount of all CGUs for which impairment charges or reversals were recognized in 2021, based on their value in use, is $16,586 million.

customers & products

The 2023 impairment loss of $1,614 million primarily relates to strategy implementation and changes to economic assumptions in the products business including an impairment of the Gelsenkirchen refinery in Germany ($1,336 million). The recoverable amounts of the CGUs were based on value-in-use calculations. The recoverable amount of all CGUs for which impairment charges or reversals were recognized in 2023 in total, based on their value in use, is $327 million.

The 2022 impairment loss of $1,874 million primarily relates to changes in economic assumptions in the products business including an impairment of the Gelsenkirchen refinery in Germany ($1,366 million), and announced portfolio changes. The recoverable amounts of the CGUs were based on value-in-use calculations. The recoverable amount of all CGUs for which impairment charges or reversals were recognized in 2022 in total, based on their value in use, is $1,648 million.

2021 impairment loss of $962 million principally relates to announced portfolio changes in the products business ($595 million).

Other businesses and corporate

The 2022 impairment loss of $13,536 million arises primarily a result of bp's decision to exit its shareholding in Rosneft ($13,479 million, including $528 million which relates to estimated earnings in the first two months of the year prior to the loss of significant influence). The recoverable amount of the CGU which comprises Rosneft is estimated to be $nil.

Impairment losses totalling $63 million were recognized in 2021.

5. Segmental analysis

The group's organizational structure reflects the various activities in which bp is engaged as well as how performance and resource allocation is evaluated by the chief operating decision maker. At 31 December 2023, bp has three reportable segments: Gas & low carbon energy, Oil production & operations, and Customers & products. Each are managed separately, with decisions taken for the segment as a whole, and represent a single operating segment that does not result from aggregating two or more segments.

Gas & low carbon energy comprises regions with upstream businesses that predominantly produce natural gas, gas marketing and trading activities and the group's solar, wind and hydrogen businesses.

Oil production & operations comprises regions with upstream activities that predominantly produce crude oil.

Customers & products comprises the group's customer-focused businesses, which includes convenience and retail fuels, EV charging, as well as Castrol, aviation and B2B and midstream. It also includes our products businesses, refining & oil trading, as well as our bioenergy businesses.

Other businesses and corporate also comprises the group's shipping and treasury functions, and corporate activities worldwide.

The accounting policies of the operating segments are the same as the group's accounting policies described in Note 1. However, IFRS requires that the measure of profit or loss disclosed for each operating segment is the measure that is provided regularly to the chief operating decision maker for the purposes of performance assessment and resource allocation. For bp, this measure of profit or loss is replacement cost profit or loss before interest and tax which reflects the replacement cost of supplies by excluding from profit or loss before interest and tax inventory holding gains and losses[a]. Replacement cost profit or loss before interest and tax for the group is not a recognized measure under IFRS.

Sales between segments are made at prices that approximate market prices, taking into account the volumes involved. Segment revenues and segment results include transactions between business segments. These transactions and any unrealized profits and losses are eliminated on consolidation, unless unrealized losses provide evidence of an impairment of the asset transferred. Sales to external customers by region are based on the location of the group subsidiary which made the sale. The UK region includes the UK-based international activities of customers & products.

All surpluses and deficits recognized on the group balance sheet in respect of pension and other post-retirement benefit plans are allocated to Other businesses and corporate. However, the periodic expense relating to these plans is allocated to the operating segments based upon the business in which the employees work.

Certain financial information is provided separately for the US as this is an individually material country for bp, and for the UK as this is bp's country of domicile.

[a] Inventory holding gains and losses represent:

- the difference between the cost of sales calculated using the replacement cost of inventory and the cost of sales calculated on the first-in first-out (FIFO) method after adjusting for any changes in provisions where the net realizable value of the inventory is lower than its cost. Under the FIFO method, which we use for IFRS reporting of inventories other than for trading inventories, the cost of inventory charged to the income statement is based on its historical cost of purchase or manufacture, rather than its replacement cost. In volatile energy markets, this can have a significant distorting effect on reported income. The amounts disclosed as inventory holding gains and losses represent the difference between the charge to the income statement for inventory on a FIFO basis (after adjusting for any related movements in net realizable value provisions) and the charge that would have arisen based on the replacement cost of inventory. For this purpose, the replacement cost of inventory is calculated using data from each operation's production and manufacturing system, either on a monthly basis, or separately for each transaction where the system allows this approach.
- an adjustment relating to certain trading inventories that are not price risk managed which relate to a minimum inventory volume that is required to be held to maintain underlying business activities. This adjustment represents the movement in fair value of the inventories due to prices, on a grade-by-grade basis, during the period. This is calculated from each operation's inventory management system on a monthly basis using the discrete monthly movement in market prices for these inventories.

The amounts disclosed are not separately reflected in the financial statements as a gain or loss. No adjustment is made in respect of the cost of inventories held as part of a trading position and certain other temporary inventory positions that are price risk-managed.

5. Segmental analysis – continued

						$ million
						2023
By business	gas & low carbon energy	oil production & operations	customers & products	other businesses & corporate	Consolidation adjustment and eliminations	Total group
Segment revenues						
Sales and other operating revenues	50,297	24,904	160,215	2,657	(27,943)	210,130
Less: sales and other operating revenues between segments	(1,808)	(23,708)	(367)	(2,060)	27,943	—
Third party sales and other operating revenues	48,489	1,196	159,848	597	—	210,130
Earnings from joint ventures and associates – after interest and tax	(677)	1,164	427	(16)	—	898
Segment results						
Replacement cost profit (loss) before interest and taxation	14,080	11,191	4,230	(903)	(14)	28,584
Inventory holding gains (losses)[a]	1	—	(1,237)	—	—	(1,236)
Profit (loss) before interest and taxation	14,081	11,191	2,993	(903)	(14)	27,348
Finance costs						(3,840)
Net finance income relating to pensions and other post-retirement benefits						241
Profit before taxation						23,749
Other income statement items						
Depreciation, depletion and amortization						
US	96	3,554	1,883	85	—	5,618
Non-US	5,584	2,138	1,665	923	—	10,310
Charges for provisions, net of write-back of unused provisions, including change in discount rate	139	35	2,007	152	—	2,333
Segment assets						
Investments in joint ventures and associates	4,173	10,721	5,327	28	—	20,249
Additions to non-current assets[b]	4,859	7,384	9,383	1,075	—	22,701

[a] See explanation of inventory holding gains and losses on page 193.
[b] Includes additions to property, plant and equipment; goodwill; intangible assets; investments in joint ventures; and investments in associates.

5. Segmental analysis – continued

						$ million
						2022
By business	gas & low carbon energy	oil production & operations	customers & products	other businesses & corporate	Consolidation adjustment and eliminations	Total group
Segment revenues						
Sales and other operating revenues	56,255	33,193	188,623	2,299	(38,978)	241,392
Less: sales and other operating revenues between segments	(5,913)	(30,294)	(1,418)	(1,353)	38,978	—
Third party sales and other operating revenues	50,342	2,899	187,205	946	—	241,392
Earnings from joint ventures and associates – after interest and tax	148	1,609	248	525	—	2,530
Segment results						
Replacement cost profit (loss) before interest and taxation	14,696	19,721	8,869	(26,737)	139	16,688
Inventory holding gains (losses)[a]	(8)	(7)	1,366	—	—	1,351
Profit (loss) before interest and taxation	14,688	19,714	10,235	(26,737)	139	18,039
Finance costs						(2,703)
Net finance income relating to pensions and other post-retirement benefits						69
Profit before taxation						15,405
Other income statement items						
Depreciation, depletion and amortization						
US	75	3,141	1,328	80	—	4,624
Non-US	4,933	2,423	1,542	796	—	9,694
Charges for provisions, net of write-back of unused provisions, including change in discount rate	(234)	213	3,955	143	—	4,077
Segment assets						
Investments in joint ventures and associates	5,299	11,370	3,875	57	—	20,601
Additions to non-current assets[b]	4,439	15,098	9,541	1,047	—	30,125

[a] See explanation of inventory holding gains and losses on page 193.
[b] Includes additions to property, plant and equipment; goodwill; intangible assets; investments in joint ventures; and investments in associates.

5. Segmental analysis – continued

						$ million
						2021
By business	gas & low carbon energy	oil production & operations	customers & products	other businesses & corporate	Consolidation adjustment and eliminations	Total group
Segment revenues						
Sales and other operating revenues	30,840	24,519	130,095	1,724	(29,439)	157,739
Less: sales and other operating revenues between segments	(4,563)	(22,408)	(1,226)	(1,242)	29,439	—
Third party sales and other operating revenues	26,277	2,111	128,869	482	—	157,739
Earnings from joint ventures and associates – after interest and tax	426	576	385	2,612	—	3,999
Segment results						
Replacement cost profit (loss) before interest and taxation	2,133	10,501	2,208	(348)	(67)	14,427
Inventory holding gains (losses)[a]	33	8	3,355	—	—	3,655
Profit (loss) before interest and taxation	2,166	10,509	5,563	(89)	(67)	18,082
Finance costs						(2,857)
Net finance income relating to pensions and other post-retirement benefits						2
Profit before taxation						15,227
Other income statement items						
Depreciation, depletion and amortization						
US	80	3,174	1,349	94	—	4,697
Non-US	4,384	3,354	1,651	719	—	10,108
Charges for provisions, net of write-back of unused provisions, including change in discount rate	173	7	3,063	477	—	3,720
Segment assets						
Investments in joint ventures and associates	5,224	8,044	3,291	14,424	—	30,983
Additions to non-current assets[b]	4,963	6,090	3,940	1,007	—	16,000

[a] See explanation of inventory holding gains and losses on page 193.
[b] Includes additions to property, plant and equipment; goodwill; intangible assets; investments in joint ventures; and investments in associates.

			$ million
			2023
By geographical area	**US**	**Non-US**	**Total**
Revenues			
Third party sales and other operating revenues[a]	**60,577**	**149,553**	**210,130**
Other income statement items			
Production and similar taxes	**136**	**1,643**	**1,779**
Non-current assets			
Non-current assets[b c]	**64,238**	**83,816**	**148,054**

[a] Non-US region includes UK $39,975 million
[b] Non-US region includes UK $23,949 million
[c] Includes property, plant and equipment; goodwill; intangible assets; investments in joint ventures; investments in associates; and non-current prepayments.

			$ million
			2022
By geographical area	US	Non-US	Total
Revenues			
Third party sales and other operating revenues[a]	71,118	170,274	241,392
Other income statement items			
Production and similar taxes	194	2,131	2,325
Non-current assets			
Non-current assets[b c]	60,237	89,144	149,381

[a] Non-US region includes UK $36,541 million.
[b] Non-US region includes UK $24,813 million.
[c] Includes property, plant and equipment; goodwill; intangible assets; investments in joint ventures; investments in associates; and non-current prepayments.

5. Segmental analysis – continued

By geographical area	US	Non-US	$ million 2021 Total
Revenues			
Third party sales and other operating revenues[a]	53,748	103,991	157,739
Other income statement items			
Production and similar taxes	108	1,200	1,308
Non-current assets			
Non-current assets[b c]	54,395	108,793	163,188

[a] Non-US region includes UK $11,248 million.
[b] Non-US region includes UK $19,530 million.
[c] Includes property, plant and equipment; goodwill; intangible assets; investments in joint ventures; investments in associates; and non-current prepayments.

6. Sales and other operating revenues

	2023	2022	$ million 2021
Crude oil	**2,413**	6,309	5,483
Oil products	**128,969**	149,854	101,418
Natural gas, LNG and NGLs	**29,541**	41,770	24,378
Non-oil products and other revenues from contracts with customers	**10,298**	7,896	6,082
Revenue from contracts with customers	**171,221**	205,829	137,361
Other operating revenues[a]	**38,909**	35,563	20,378
Total sales and other operating revenues	**210,130**	241,392	157,739

[a] Principally relates to commodity derivative transactions including sales of bp own production in trading books.

An analysis of third-party sales and other operating revenues by segment and region is provided in Note 5.

The group's sales to customers of crude oil and oil products were substantially all made by the customers & products segment. The group's sales to customers of natural gas, LNG and NGLs were made by the gas & low carbon energy segment. A significant majority of the group's sales of non-oil products and other revenues from contracts with customers were made by the customers & products segment.

7. Income statement analysis

	2023	2022	$ million 2021
Interest and other income			
Interest income from			
Financial assets measured at amortized cost	**1,034**	371	221
Financial assets measured at fair value through profit or loss	**215**	59	5
Other income	**386**	673	355
	1,635	1,103	581
Currency exchange losses charged to the income statement[a]	**74**	160	345
Expenditure on research and development	**298**	274	266
Costs relating to the Gulf of Mexico oil spill (pre-interest and tax)[b]	**57**	84	70
Finance costs			
Interest expense on lease liabilities	**363**	245	288
Interest expense on other liabilities measured at amortized cost[c]	**3,115**	2,070	1,820
Capitalized at 4.88% (2022 3.56% and 2021 2.63%)[d]	**(514)**	(464)	(287)
Finance debt risk management activities[e]	**(35)**	43	145
Unwinding of discount on provisions	**504**	369	391
Unwinding of discount on other payables measured at amortized cost	**407**	440	500
	3,840	2,703	2,857

[a] Excludes exchange gains and losses arising on financial instruments measured at fair value through profit or loss.
[b] Included within production and manufacturing expenses.
[c] 2023 includes a loss of $49 million (2022 gain of $37 million and 2021 loss of $195 million) associated with the buyback of finance debt.
[d] Tax relief on capitalized interest is approximately $130 million (2022 $108 million and 2021 $66 million).
[e] Relates to temporary valuation differences associated with the group's interest rate and foreign currency exchange risk management of finance debt.

8. Exploration for and evaluation of oil and natural gas resources

The following financial information represents the amounts included within the group totals relating to activity associated with the exploration for and evaluation of oil and natural gas resources. All such activity is recorded within the gas & low carbon energy and oil production & operations segments.

For information on significant judgements made in relation to oil and natural gas accounting see Intangible assets in Note 1.

			$ million
	2023	2022	2021
Exploration and evaluation costs			
Exploration expenditure written off	**746**	385	167
Other exploration costs	**251**	200	257
Exploration expense for the year	**997**	585	424
Impairment losses	**20**	2	1
Intangible assets – exploration and appraisal expenditure[a]	**4,328**	4,213	4,289
Liabilities	**109**	88	98
Net assets	**4,219**	4,125	4,191
Cash used in operating activities	**251**	200	257
Cash used in investing activities	**1,039**	909	369

a Amount capitalized at 31 December 2023, 2022 and 2021 relates to assets in various regions. The largest of these is approximately $600 million capitalized in the Middle East region (2022 approximately $600 million and 2021 approximately $700 million and capitalized in the Middle East region).

9. Taxation

Tax on profit

			$ million
	2023	2022	2021
Current tax			
Charge for the year	**9,048**	12,523	4,808
Adjustment in respect of prior years	**(373)**	145	138
	8,675	12,668	4,946
Deferred tax			
Origination and reversal of temporary differences in the current year[a]	**(238)**	4,768	3,366
Adjustment in respect of prior years[b]	**(568)**	(674)	(1,572)
	(806)	4,094	1,794
Tax charge on profit	**7,869**	16,762	6,740

a 2022 includes a charge of $1,834 million in respect of the impact of the UK Energy Profits Levy on existing temporary differences unwinding over the period 1 January 2023 to 31 March 2028.

b The adjustment in respect of prior years reflects the reassessment of the deferred tax balances for prior periods in light of changes in facts and circumstances during the year, including changes to price assumptions and profit forecasts. 2023 also includes a credit of $232 million in respect of a revision to the deferred tax impact of the UK Energy Profits Levy.

In 2023, the total tax credit recognized within other comprehensive income was $735 million (2022 $266 million charge and 2021 $1,252 million charge). In 2023 and 2021 this primarily comprises the deferred tax impact of the remeasurements of the net pension and other post-retirement benefit liability or asset. In 2022 this primarily comprises a release of deferred withholding tax on other comprehensive income movements relating to Rosneft. See Note 32 for further information.

The total tax charge recognized directly in equity was $56 million (2022 $214 million credit and 2021 $170 million charge). This mainly relates to transactions involving non-controlling interests.

9. Taxation – continued

Reconciliation of the effective tax rate

The following table provides a reconciliation of the group weighted average statutory corporate income tax rate to the effective tax rate of the group on profit or loss before taxation. For 2022 the items presented in the reconciliation are affected by the impacts of Rosneft. In order to provide a more meaningful analysis of the effective tax rate for 2022, the table also presents a separate reconciliation for the group excluding the impacts of Rosneft, and for the impacts of Rosneft in isolation.

					$ million
	2023	2022 excluding impact of Rosneft	2022 impact of Rosneft[a]	2022	2021
Profit (loss) before taxation	**23,749**	40,925	(25,520)	15,405	15,227
Tax charge (credit) on profit or loss[b]	**7,869**	17,823	(1,061)	16,762	6,740
Effective tax rate	**33%**	44%	4%	109%	44%

					%
Tax rate computed at the weighted average statutory rate[c]	**34**	42	20	77	54
Increase (decrease) resulting from					
Tax reported in equity-accounted entities[d]	**(2)**	(1)	–	(4)	(3)
Adjustments in respect of prior years	**(4)**	(1)	–	(3)	(9)
Deferred tax not recognized	**2**	(1)	–	(2)	8
Tax incentives for investment	**–**	–	–	(1)	(1)
Disposal impacts[e]	**–**	(3)	–	(8)	(4)
Foreign exchange	**–**	1	–	3	1
Items not deductible for tax purposes	**2**	2	–	5	1
Impact of bp's decision to exit its shareholding in Rosneft	**–**	–	(16)	27	–
Tax rate change effect of UK Energy Profits Levy[f]	**–**	4	–	12	–
Other	**1**	1	–	3	(3)
Effective tax rate	**33**	44	4	109	44

a Includes the impact of bp's decision to exit its shareholding in Rosneft and its other businesses with Rosneft in Russia.
b The tax credit regarding the impact of Rosneft relates to the release of deferred withholding tax on unremitted earnings.
c Calculated based on the statutory corporate income tax rate applicable in the countries in which the group operates, weighted by the profits and losses before tax in the respective countries. 2023 and 2022 include the impact of the UK Energy Profits Levy.
d Includes withholding tax in respect of distributions from equity-accounted entities.
e 2022 primarily relates to the contribution of bp's Angolan business to Azule Energy and 2021 primarily relates to the divestment of a 20% stake in Oman Block 61.
f 2022 comprises the deferred tax impact of the UK Energy Profits Levy on existing temporary differences.

Deferred tax

		$ million
Analysis of movements during the year in the net deferred tax liability	2023	2022
At 1 January	**6,618**	2,370
Exchange adjustments[a]	**134**	(334)
Charge (credit) for the year in the income statement	**(806)**	4,094
Charge (credit) for the year in other comprehensive income	**(735)**	272
Charge (credit) for the year in equity	**56**	(214)
Acquisitions and disposals[b]	**82**	430
At 31 December	**5,349**	6,618

a Primarily relates to the foreign currency retranslation effect on the deferred tax liability on pension plan surpluses in the UK.
b 2022 primarily relates to the Archaea Energy acquisition and the contribution of bp's Angolan business to Azule Energy.

9. Taxation – continued

The following table provides an analysis of deferred tax in the income statement and the balance sheet by category of temporary difference:

					$ million
	Income statement			Balance sheet	
	2023	2022	2021	**2023**	2022
Deferred tax liability					
Depreciation	**(1,552)**	1,863	899	**17,392**	18,025
Pension plan surpluses[a]	**133**	42	105	**2,568**	3,022
Derivative financial instruments	**12**	(21)	(33)	**12**	—
Other taxable temporary differences[b]	**10**	(992)	180	**1,020**	1,000
	(1,397)	892	1,151	**20,992**	22,047
Deferred tax asset					
Depreciation	**(166)**	(309)	(846)	**(2,141)**	(1,974)
Lease liabilities	**(176)**	(8)	(43)	**(1,785)**	(1,047)
Pension plan and other post-retirement benefit plan deficits	**(60)**	47	119	**(755)**	(647)
Decommissioning, environmental and other provisions	**563**	770	(744)	**(6,042)**	(6,653)
Derivative financial instruments	**(14)**	(6)	(9)	**(136)**	(282)
Tax credits	**(67)**	1,578	1,282	**(893)**	(779)
Loss carry forward	**296**	1,536	1,064	**(2,467)**	(2,669)
Other deductible temporary differences[c]	**215**	(406)	(180)	**(1,424)**	(1,378)
	591	3,202	643	**(15,643)**	(15,429)
Net deferred tax charge (credit) and net deferred tax liability	**(806)**	4,094	1,794	**5,349**	6,618
Of which – deferred tax liabilities				**9,617**	10,526
– deferred tax assets				**4,268**	3,908

a In November 2023 the UK Government announced a reduction in the authorised surplus payments charge applicable to defined benefit pension schemes from 35% to 25%. The legislation has not yet been enacted or substantively enacted, but is expected to be effective from 6 April 2024. The change is expected to reduce the deferred tax liability on pension plan surpluses by around $0.7 billion with the related gain recognised in other comprehensive income when the legislation is substantively enacted.

b The 2022 income statement includes amounts relating to deferred withholding tax on unremitted earnings of Rosneft. The 2023 and 2022 balance sheet amounts do not include any temporary differences that are individually significant in their nature.

c The 2023 and 2022 balance sheet amounts do not include any temporary differences that are individually significant in their nature.

Of the $4,268 million of deferred tax assets recognized on the group balance sheet at 31 December 2023 (2022 $3,908 million), $2,336 million (2022 $2,779 million) relates to entities that have suffered a loss in either the current or preceding period. For 2023, this mainly includes $1,003 million in Germany, $672 million in Mauritania and $500 million in Senegal (2022 mainly included $1,333 million in the UK, $505 million in Mauritania and $370 million in Senegal). For 2023 these amounts are supported by forecasts consistent with bp's future oil and gas price assumptions (see Note 1 for further information) and for Germany, forecast profits associated with the customers & products businesses, that indicate sufficient future taxable profits will be available to utilize such assets within any applicable expiry period.

A summary of temporary differences, unused tax credits and unused tax losses for which deferred tax has not been recognized is shown in the table below.

		$ billion
At 31 December	**2023**	2022
Unused US state tax losses[a]	**2.1**	2.1
Unused tax losses – other jurisdictions[b]	**5.6**	5.4
Unused tax credits	**31.3**	28.6
of which – arising in the UK[c]	**27.3**	24.6
– arising in the US[d]	**4.0**	4.0
Deductible temporary differences[e]	**20.7**	22.7
Taxable temporary differences associated with investments in subsidiaries and equity-accounted entities	**0.7**	0.7

a For 2023 the majority of these losses expire in the period 2024-2043 with applicable tax rates ranging from 3% to 9%.

b 2023 and 2022 mainly relate to the UK, Brazil and Canada. The majority of the unused tax losses have no fixed expiry date.

c The UK unused tax credits arise predominantly in overseas branches of UK entities based in jurisdictions with higher statutory corporate income tax rates than the UK. No deferred tax asset has been recognized on these tax credits as they are unlikely to have value in the future; UK taxes on these overseas branches are largely mitigated by double tax relief in respect of overseas tax. These tax credits have no fixed expiry date.

d The US unused tax credits predominantly comprise foreign tax credits. No deferred tax asset has been recognized on these tax credits as they are unlikely to have value in the future. For 2023 these tax credits expire in the period 2025-2033.

e 2023 and 2022 mainly comprise fixed asset temporary differences in overseas branches of UK entities. Substantially all of the temporary differences have no expiry date.

			$ million
Impact of previously unrecognized deferred tax or write-down of deferred tax assets on tax charge	**2023**	2022	2021
Current tax benefit relating to the utilization of previously unrecognized deferred tax assets	**360**	492	331
Deferred tax benefit arising from the reversal of a previous write-down of deferred tax assets	**3**	—	773
Deferred tax benefit relating to the recognition of previously unrecognized deferred tax assets	**332**	792	820
Deferred tax expense arising from the write-down of a previously recognized deferred tax asset	**54**	—	29

10. Dividends

The quarterly dividend which is expected to be paid on 28 March 2024 in respect of the fourth quarter 2023 is 7.270 cents per ordinary share ($0.43620 per American Depositary Share (ADS)). The corresponding amount in sterling will be announced on 12 March 2024.

	Pence per share			Cents per share			$ million		
	2023	2022	2021	2023	2022	2021	2023	2022	2021
Dividends announced and paid in cash									
Preference shares							1	1	2
Ordinary shares									
March	5.5507	4.1595	3.7684	6.610	5.460	5.250	1,183	1,068	1,063
June	5.3089	4.3556	3.7118	6.610	5.460	5.250	1,152	1,061	1,062
September	5.7320	5.1684	3.9529	7.270	6.006	5.460	1,249	1,140	1,100
December	5.7367	4.9402	4.1045	7.270	6.006	5.460	1,224	1,088	1,077
	22.3283	18.6237	15.5376	27.760	22.932	21.420	4,809	4,358	4,304
Dividend announced, paid in March 2024				7.270			1,222		

The amount of unclaimed dividends recognized as a liability in other payables at 31 December 2023 is $91 million (2022 $69 million).

The board decided not to offer a scrip dividend alternative in respect of any dividends announced since the third quarter 2019, including the fourth quarter 2023 dividend expected to be paid on 28 March 2024.

The financial statements for the year ended 31 December 2023 do not reflect the dividend announced on 6 February 2024 and which is expected to be paid on 28 March 2024; this will be treated as an appropriation of profit in the year ending 31 December 2024.

11. Earnings per share

			Cents per share
Per ordinary share	2023	2022	2021
Basic earnings per share	87.78	(13.10)	37.57
Diluted earnings per share	85.85	(13.10)	37.33

			Dollars per share
Per American Depositary Share (ADS)[a]	2023	2022	2021
Basic earnings per share	5.27	(0.79)	2.25
Diluted earnings per share	5.15	(0.79)	2.24

[a] One ADS is equivalent to six ordinary shares.

Basic earnings per ordinary share amounts are calculated by dividing the profit for the year attributable to bp ordinary shareholders by the weighted average number of ordinary shares outstanding during the year.

The weighted average number of shares outstanding includes certain shares that will be issuable in the future under employee share-based payment plans and excludes treasury shares, which includes shares held by the Employee Share Ownership Plan trusts (ESOPs).

For the diluted earnings per share calculation, the weighted average number of shares outstanding during the year is adjusted for the average number of shares that are potentially issuable in connection with employee share-based payment plans. If the inclusion of potentially issuable shares would decrease loss per share, the potentially issuable shares are excluded from the weighted average number of shares outstanding used to calculate diluted earnings per share.

			$ million
	2023	2022	2021
Profit (loss) attributable to bp shareholders	15,239	(2,487)	7,565
Less: dividend requirements on preference shares	1	1	2
Profit (loss) for the year attributable to bp ordinary shareholders	15,238	(2,488)	7,563

			Shares thousand
	2023	2022	2021
Basic weighted average number of ordinary shares[a]	17,360,288	18,987,936	20,128,862
Potential dilutive effect of ordinary shares issuable under employee share-based payment plans	389,790	—	131,526
Weighted average number of ordinary shares outstanding used to calculate diluted earnings per share	17,750,078	18,987,936	20,260,388

			Shares thousand
	2023	2022	2021
Basic weighted average number of ordinary shares – ADS equivalent	2,893,381	3,164,656	3,354,810
Potential dilutive effect of ordinary shares (ADS equivalent) issuable under employee share-based payment plans	64,965	—	21,921
Weighted average number of ordinary shares (ADS equivalent) outstanding used to calculate diluted earnings per share	2,958,346	3,164,656	3,376,731

[a] Excludes treasury shares. See Note 31 for further information.

11. Earnings per share – continued

The number of ordinary shares outstanding at 31 December 2023, excluding treasury shares, and including certain shares that will be issuable in the future under employee share-based payment plans was 16,824,651,796 (2022 17,974,112,648). Between 31 December 2023 and 16 February 2024, the latest practicable date before the completion of these financial statements, there was a net decrease of 21,406,501 of ordinary shares primarily as a result of share issues in relation to employee share-based payment plans partially offset by share buy backs. For additional information on share buy backs see Note 31.

Employee share-based payment plans

The group operates share and share option plans for directors and certain employees to obtain ordinary shares and ADSs in the company. Information on these plans for directors is shown in the Directors remuneration report on pages 105-132.

The following table shows the number of shares potentially issuable under equity-settled employee share option plans, including the number of options outstanding, the number of options exercisable at the end of each year, and the corresponding weighted average exercise prices. The dilutive effect of these plans at 31 December is also shown.

Share options	2023		2022	
	Number of options[a b] thousand	Weighted average exercise price $	Number of options[a b] thousand	Weighted average exercise price $
Outstanding	**545,044**	**4.04**	564,079	4.00
Exercisable	**905**	**3.31**	342	4.99
Dilutive effect	**166,581**	**n/a**	83,204	n/a

[a] Numbers of options shown are ordinary share equivalents (one ADS is equivalent to six ordinary shares).
[b] At 31 December 2023 the quoted market price of one bp ordinary share was £4.66 (2022 £4.75).

In addition, the group operates a number of equity-settled employee share plans under which share units are granted to the group's senior leaders and certain other employees. These plans typically have a three-year performance or restricted period during which the units accrue net notional dividends which are treated as having been reinvested. Leaving employment will normally preclude the conversion of units into shares, but special arrangements apply for participants that leave for qualifying reasons. The number of shares that are expected to vest each year under employee share plans are shown in the table below. The dilutive effect of the employee share plans at 31 December is also shown.

Share plans	2023	2022
Vesting	Number of shares[a] thousand	Number of shares[a] thousand
Within one year	**226,190**	167,672
1 to 2 years	**257,511**	192,734
2 to 3 years	**114,500**	226,027
3 to 4 years	**1,176**	2,595
Over 4 years	**308**	173
	599,685	589,201
Dilutive effect	**284,908**	244,886

[a] Numbers of shares shown are ordinary share equivalents (one ADS is equivalent to six ordinary shares).

There has been a net decrease of 109,230,677 in the number of potential ordinary shares relating to employee share-based payment plans between 31 December 2023 and 16 February 2024.

12. Property, plant and equipment (PP&E)

$ million

	Land and land improvements	Buildings	Oil and gas properties[a c]	Plant, machinery and equipment	Fittings, fixtures and office equipment[c]	Transportation	Oil depots, storage tanks and service stations	Total
Cost - owned PP&E								
At 1 January 2023	**3,513**	**950**	**179,028**	**44,662**	**2,202**	**3,076**	**10,089**	**243,520**
Exchange adjustments	**112**	**2**	**—**	**294**	**31**	**2**	**342**	**783**
Additions	**134**	**48**	**8,252**	**2,921**	**221**	**80**	**1,126**	**12,782**
Acquisitions	**206**	**—**	**—**	**27**	**12**	**48**	**1,060**	**1,353**
Transfers from intangible assets	**—**	**—**	**171**	**—**	**—**	**—**	**—**	**171**
Reclassified as assets held for sale	**(7)**	**—**	**—**	**(3)**	**(3)**	**(1)**	**(74)**	**(88)**
Deletions and disposals	**(34)**	**(8)**	**(2,105)**	**(517)**	**(173)**	**(247)**	**(319)**	**(3,403)**
At 31 December 2023	**3,924**	**992**	**185,346**	**47,384**	**2,290**	**2,958**	**12,224**	**255,118**
Depreciation - owned PP&E								
At 1 January 2023	**700**	**501**	**111,434**	**22,903**	**1,671**	**2,431**	**5,819**	**145,459**
Exchange adjustments	**14**	**3**	**—**	**200**	**18**	**2**	**206**	**443**
Charge for the year	**45**	**30**	**10,468**	**1,519**	**163**	**85**	**629**	**12,939**
Impairment losses	**108**	**22**	**3,628**	**1,467**	**—**	**10**	**58**	**5,293**
Impairment reversals	**—**	**—**	**(18)**	**—**	**—**	**(9)**	**—**	**(27)**
Reclassified as assets held for sale	**(1)**	**—**	**—**	**(2)**	**(1)**	**(1)**	**(74)**	**(79)**
Deletions and disposals	**(28)**	**(3)**	**(2,070)**	**(416)**	**(167)**	**(226)**	**(275)**	**(3,185)**
At 31 December 2023	**838**	**553**	**123,442**	**25,671**	**1,684**	**2,292**	**6,363**	**160,843**
Owned PP&E - net book amount at 31 December 2023	**3,086**	**439**	**61,904**	**21,713**	**606**	**666**	**5,861**	**94,275**
Right-of-use assets - net book amount at 31 December 2023[b]	**—**	**1,243**	**53**	**916**	**4**	**2,463**	**5,765**	**10,444**
Total PP&E - net book amount at 31 December 2023	**3,086**	**1,682**	**61,957**	**22,629**	**610**	**3,129**	**11,626**	**104,719**
Cost - owned PP&E								
At 1 January 2022[c]	3,713	1,245	208,778	44,037	2,213	3,033	10,241	273,260
Exchange adjustments	(184)	(30)	—	(599)	(83)	(14)	(590)	(1,500)
Additions	51	31	6,221	2,188	252	42	993	9,778
Acquisitions	1	40	—	998	—	37	3	1,079
Transfers from intangible assets	—	—	357	—	—	—	—	357
Reclassified as assets held for sale	(49)	—	(4,351)	(1,408)	—	—	—	(5,808)
Deletions and disposals	(19)	(336)	(31,977)	(554)	(180)	(22)	(558)	(33,646)
At 31 December 2022	3,513	950	179,028	44,662	2,202	3,076	10,089	243,520
Depreciation - owned PP&E								
At 1 January 2022[c]	706	654	135,294	21,841	1,774	2,388	5,783	168,440
Exchange adjustments	(26)	(21)	—	(299)	(61)	(11)	(354)	(772)
Charge for the year	47	26	9,770	1,457	135	72	501	12,008
Impairment losses	6	14	1,251	1,487	—	4	336	3,098
Impairment reversals	—	—	(2,221)	(65)	—	(5)	—	(2,291)
Reclassified as assets held for sale	(18)	—	(3,972)	(1,164)	—	—	—	(5,154)
Deletions and disposals	(15)	(172)	(28,688)	(354)	(177)	(17)	(447)	(29,870)
At 31 December 2022	700	501	111,434	22,903	1,671	2,431	5,819	145,459
Owned PP&E - net book amount at 31 December 2022	2,813	449	67,594	21,759	531	645	4,270	98,061
Right-of-use assets - net book amount at 31 December 2022[b]	—	1,157	17	926	7	2,333	3,543	7,983
Total PP&E - net book amount at 31 December 2022	2,813	1,606	67,611	22,685	538	2,978	7,813	106,044
Assets under construction included above								
At 31 December 2023								**13,390**
At 31 December 2022								22,313
Depreciation charge for the year on right-of-use assets								
2023		**196**	**16**	**558**	**5**	**1,055**	**783**	**2,613**
2022		190	18	321	10	853	577	1,969

a For information on significant estimates and judgements made in relation to the estimation of oil and natural reserves see Property, plant and equipment within Note 1.

b $661 million (2022 $560 million) of drilling rig right-of-use assets and $2,337 million (2022 $2,208 million) of shipping vessel right-of-use assets are included in Plant, machinery and equipment and Transportation respectively.

c An amendment has been made to prior year balances to correctly present offsetting movements in oil and gas properties (an increase of $744 million) and fittings, fixtures and office equipment (a decrease of $18 million) cost and depreciation. The amendment has no impact on reported profit or net book amounts of PPE.

13. Capital commitments

Authorized future capital expenditure for property, plant and equipment (excluding right-of-use assets) by group companies for which contracts had been signed at 31 December 2023 amounted to $10,354 million (2022 $9,381 million, 2021 $8,208 million). bp has contracted capital commitments amounting to $1,580 million (2022 $1,764 million, 2021 $1,075 million) in relation to joint ventures and $105 million (2022 $18 million, 2021 $126 million) in relation to associates.

14. Goodwill and impairment review of goodwill

		$ million
	2023	2022
Cost		
At 1 January	**12,577**	12,991
Exchange adjustments	**184**	(367)
Acquisitions and other additions	**415**	573
Reclassified as assets held for sale	**—**	(58)
Deletions and disposals	**—**	(562)
At 31 December	**13,176**	12,577
Impairment losses		
At 1 January	**617**	618
Exchange adjustments	**2**	(1)
Impairment losses for the year	**85**	—
At 31 December	**704**	617
Net book amount at 31 December	**12,472**	11,960
Net book amount at 1 January	**11,960**	12,373

Impairment review of goodwill

		$ million
Goodwill at 31 December	**2023**	2022
gas & low carbon energy	**2,095**	2,232
oil production & operations	**4,925**	4,925
customers & products	**5,431**	4,740
other businesses & corporate	**21**	63
	12,472	11,960

Goodwill acquired through business combinations has been allocated to groups of cash-generating units (CGUs) that are expected to benefit from the synergies of the acquisition. For oil production & operations goodwill is allocated to CGUs in aggregate at the segment level, for gas & low carbon energy goodwill is allocated to the hydrocarbon CGUs within the segment. For customers and products, goodwill has been allocated to Castrol, US Fuels, European Fuels, Archaea and Other.

For information on significant estimates and judgements made in relation to impairments see Impairment of property, plant and equipment, intangible assets and goodwill in Note 1.

gas & low carbon energy and oil production & operations

		$ million		$ million
	gas & low carbon energy		**oil production & operations**	
	2023	2022	**2023**	2022
Goodwill	**2,095**	2,232	**4,925**	4,925
Excess of recoverable amount over carrying amount	**5,886**	12,971	**18,854**	36,045

The table above shows the carrying amount of goodwill for the segments at the period end and the excess of the recoverable amount, based on a pre-tax value-in-use calculation, over the carrying amount (headroom) at the date of the most recent test. The decrease in headroom for both segments relates to movements due to the impacts of updates to price and discount rate assumptions.

No material impairment of the goodwill balances in either gas & low carbon energy or oil production & operations was recognized during 2023 (2022 $nil).

14. Goodwill and impairment review of goodwill – continued

The value in use for relevant CGUs in both gas & low carbon energy and oil production & operations is based on the cash flows expected to be generated by the projected production profiles up to the expected dates of cessation of production of each field, based on appropriately risked estimates of reserves and resources. Midstream and supply and trading activities and equity-accounted entities are generally not included in the impairment reviews of goodwill, as they do not represent part of the grouping of CGUs to which the goodwill balances relate and which are used to monitor the goodwill balances for internal management purposes. Where such activities form part of wider CGUs to which goodwill relates they are reflected in the test. As the production profile and related cash flows can be estimated from bp's past experience, management believes that the cash flows generated over the estimated life of field is the appropriate basis upon which to assess goodwill and individual assets for impairment in both gas & low carbon energy and oil & production operations. The estimated date of cessation of production depends on the interaction of a number of variables, such as the recoverable quantities of hydrocarbons, the production profile of the hydrocarbons, the cost of the development of the infrastructure necessary to recover the hydrocarbons, production costs, the contractual duration of the production concession and the selling price of the hydrocarbons produced. As each field has specific reservoir characteristics and economic circumstances, the cash flows of each field are computed using appropriate individual economic models and key assumptions agreed by bp management.

Estimated production volumes and cash flows up to the date of cessation of production on a field-by-field basis, including operating and capital expenditure, are derived from the business segment plans. The production profiles used are consistent with the reserve and resource volumes approved as part of bp's centrally controlled process for the estimation of proved and probable reserves and total resources.

The average production for the purposes of goodwill impairment testing in the gas & low carbon energy segment over the next 15 years is 185 mmboe per year (2022 191 mmboe per year) and in the oil production and operations segment is 402 mmboe per year (2022 346 mmboe per year). Production assumptions used for the goodwill impairment tests in both gas & low carbon energy and oil production & operations reflect management's best estimate of future production of the existing portfolio at the time of the calculation. The group's expectation to reduce upstream hydrocarbon production by around 25% by 2030 from its 2019 baseline is expected to be achieved through future active management, including divestments, and high-grading of the portfolio. Changes in upstream production since 2019 will be included in the best estimates however as the specific future changes to the portfolio are not yet known, these best estimates do not include the full extent of the expected upstream production reductions.

The weighted average pre-tax discount rate used in the review for the oil production & operations segment is 17%, and 11% for the gas & low carbon energy segment (2022 16% for the oil production & operations segment and 10% for the gas & low carbon energy segment).

The most recent reviews for impairment for the oil production & operations and gas & low carbon energy segments were carried out in the fourth quarter. The key assumptions used in the value-in-use calculations are oil and natural gas prices, production volumes and the discount rate. The value-in-use calculations have been prepared for the purposes of determining whether the goodwill balances were impaired. Estimated future cash flows were prepared on the basis of certain assumptions prevailing at the time of the tests. The actual outcomes may differ from the assumptions made. For example, reserves and resources estimates and production forecasts are subject to revision as further technical information becomes available and economic conditions change. Due to economic developments, regulatory change and emissions reduction activity arising from climate concern and other factors, future commodity prices and other assumptions may differ from the forecasts used in the calculations.

Sensitivities to different variables have been estimated using certain simplifying assumptions. For example, lower oil and gas price or production sensitivities do not fully reflect the specific impacts for each contractual arrangement and will not capture all favourable impacts that may arise from cost deflation or savings. A detailed calculation in either segment at any given price or production profile may, therefore, produce a different result.

It is estimated that a 22% (2022 27%) reduction in revenue throughout each year of the remaining life of those assets, either as a result of adverse price or production conditions or a combination of each, would cause the recoverable amount to be equal to the carrying amount of goodwill and related net non-current assets of the oil production and operations segment. For gas & low carbon energy an 15% (2022 18%) reduction would have the same result.

It is estimated that no reasonably possible change in the discount rate would cause the recoverable amount to be equal to the carrying amount of goodwill and related net non-current assets of either segment.

customers & products

												$ million
						2023						2022
	Castrol	**US Fuels**	**European Fuels**	**Archaea**	**Other**	**Total**	Castrol	US Fuels	European Fuels	Archaea	Other	Total
Goodwill	**2,672**	**792**	**839**	**707**	**421**	**5,431**	2,524	606	815	409	386	4,740

Cash flows for each CGU are derived from the business segment plans, which cover a period of up to five years, except for Archaea where a business plan to 2035 is in place following the recent acquisition. To determine the value in use for each of the cash-generating units, cash flows for a period of 10 years (12 years for Archaea), are discounted and aggregated with a terminal value. It is estimated that no reasonably possible change in the key assumptions used in the US Fuels, European Fuels and Archaea goodwill impairment assessments would cause the recoverable amount to be equal to the carrying amount of goodwill and related net non-current assets.

Castrol

The key assumptions to which the calculation of value in use for the Castrol unit is most sensitive are operating unit margins, sales volumes, and discount rate. Operating margin and sales volumes assumptions used in the detailed impairment review of goodwill calculation are consistent with the assumptions used in the Castrol unit's business plan. A pre-tax discount rate of 9% (2022 8%) is applied in the test. No reasonably possible change in any of these key assumptions would cause the unit's recoverable amount to be equal to the carrying amount of goodwill and related net non-current assets. Cash flows beyond the plan period are extrapolated using a nominal 3.4% (2022 3.4%) growth rate.

15. Intangible assets

								$ million
				2023				2022
	Exploration and appraisal expenditure[a]	Biogas rights agreements	Other intangibles	Total	Exploration and appraisal expenditure[a]	Biogas rights agreements	Other intangibles	Total
Cost								
At 1 January	**12,571**	**3,398**	**6,817**	**22,786**	14,311	—	6,152	20,463
Exchange adjustments	**—**	**—**	**144**	**144**	—	—	(216)	(216)
Acquisitions[b]	**—**	**—**	**130**	**130**	—	3,398	194	3,592
Remeasurements of acquisition accounting[b]	**—**	**(394)**	**—**	**(394)**	—	—	—	—
Additions	**1,058**	**23**	**799**	**1,880**	894	—	831	1,725
Transfers to property, plant and equipment	**(171)**	**—**	**—**	**(171)**	(357)	—	—	(357)
Reclassified as assets held for sale	**—**	**—**	**(6)**	**(6)**	(9)	—	(7)	(16)
Deletions and disposals	**(383)**	**(38)**	**(767)**	**(1,188)**	(2,268)	—	(137)	(2,405)
At 31 December	**13,075**	**2,989**	**7,117**	**23,181**	12,571	3,398	6,817	22,786
Amortization								
At 1 January	**8,358**	**—**	**4,228**	**12,586**	10,022	—	3,990	14,012
Exchange adjustments	**—**	**—**	**79**	**79**	—	—	(128)	(128)
Exploration expenditure written off	**746**	**—**	**—**	**746**	385	—	—	385
Charge for the year	**—**	**106**	**642**	**748**	—	—	491	491
Impairment losses	**20**	**—**	**77**	**97**	2	—	21	23
Impairment reversals	**—**	**—**	**—**	**—**	—	—	(3)	(3)
Reclassified as assets held for sale	**—**	**—**	**(3)**	**(3)**	(9)	—	(7)	(16)
Deletions and disposals	**(377)**	**(1)**	**(685)**	**(1,063)**	(2,042)	—	(136)	(2,178)
At 31 December	**8,747**	**105**	**4,338**	**13,190**	8,358	—	4,228	12,586
Net book amount at 31 December	**4,328**	**2,884**	**2,779**	**9,991**	4,213	3,398	2,589	10,200
Net book amount at 1 January	**4,213**	**3,398**	**2,589**	**10,200**	4,289	—	2,162	6,451

a For further information see Intangible assets within Note 1 and Note 8.
b Primarily relates to the acquisition of Archaea Energy Inc. See Note 3 for further information.

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.

					$ million
			Income statement		Balance sheet
			Earnings from joint ventures - after interest and tax		Investments in joint ventures
	2023	2022	2021	**2023**	2022
Azule Energy	**700**	540	—	**5,066**	5,264
Pan American Energy Group	**—**	538	(217)	**—**	2,000
Other joint ventures[a]	**(633)**	50	760	**7,369**	5,136
	67	1,128	543	**12,435**	12,400

a 2023 includes Pan American Energy Group as no longer considered material to the group post 2022 impairment.

The joint venture that is material to the group at 31 December 2023 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.

Following the 2022 impairment of bp's investment in PAEG, this is no longer considered material to the group for 2023 and is now included with Other joint ventures.

The following table provides summarized financial information relating to Azule Energy for 2023 and 2022 and Pan American Energy Group for 2022 and 2021. This information is presented on a 100% basis and reflects adjustments made by bp to Azule Energy and Pan American Energy Group's own results in applying the equity method of accounting. bp adjusts Azule Energy Holdings Limited and Pan American Energy Group's results for the accounting required under IFRS relating to bp's purchase of its interests in Azule Energy Holdings Limited and Pan American Energy Group S.L..

The operational and financial information is based on preliminary operational and financial results of Azule Energy Holdings Limited for 2023 and 2022 and Pan American Energy Group S.L. for 2022 and 2021. Actual results may differ from these amounts - immaterial adjustments to the 2022 numbers for Azule Energy Holdings Limited have been included in the 2023 numbers and adjustments to the 2021 numbers for Pan America Energy Group S.L. have been included in the 2022 numbers.

16. Investments in joint ventures – continued

				$ million
				Gross amount
	2023		2022	2021
	Azule Energy	Azule Energy	PAEG	PAEG
Sales and other operating revenues	**5,164**	2,274	6,408	4,394
Profit (loss) before interest and taxation	**2,146**	1,460	1,560	806
Finance costs	**400**	218	376	262
Profit (loss) before taxation[a]	**1,746**	1,242	1,184	544
Taxation[b]	**346**	162	108	978
Profit (loss) for the year	**1,400**	1,080	1,076	(434)
Other comprehensive income	**—**	—	—	—
Total comprehensive income	**1,400**	1,080	1,076	(434)
Non-current assets	**18,788**	22,218	14,598	
Current assets[c]	**3,928**	4,132	3,054	
Total assets	**22,716**	26,350	17,652	
Current liabilities[d]	**2,510**	2,594	1,996	
Non-current liabilities[e]	**10,074**	13,228	5,856	
Total liabilities	**12,584**	15,822	7,852	
Net assets	**10,132**	10,528	9,800	
Less: non-controlling interests	**—**	—	—	
	10,132	10,528	9,800	

[a] Azule Energy includes depreciation and amortisation of $2,768 million (2022 $1,145 million), interest income of $nil (2022 $11 million) and interest expense of $407 million (2022 $218 million). For 2022 and 2021 PAEG includes depreciation and amortisation of $1,039 million and $930 million respectively, interest income of $29 million and $19 million respectively and interest expense of $375 million and $262 million respectively.
[b] PAEG 2021 net income expense includes a deferred tax charge of $415 million related to a change in the income tax rate.
[c] Azule Energy includes cash and cash equivalents of $603 million (2022 $1,031 million). PAEG includes cash and cash equivalents of $1,012 million for 2022.
[d] Azule Energy includes current financial liabilities of $2,409 million (2022 $2,077 million). PAEG includes current financial liabilities of $751 million for 2022.
[e] Azule Energy includes non-current financial liabilities of $4,735 million (2022 $4,700 million). PAEG includes non-current financial liabilities of $2,151 million for 2022.

The group received dividends of $708 million from Azule Energy Holdings Limited in 2023 (2022 $500 million).

The group received dividends of $35 million and $nil from Pan American Energy Group S.L in 2022 and 2021 respectively.

The following table provides aggregated summarized financial information relating to the group's share of joint ventures.

										$ million
										bp share
			2023				2022			2021
	Azule Energy	Other	Total	Azule Energy	PAEG	Other	Total	PAEG	Other	Total
Sales and other operating revenues	**2,582**	**13,705**	**16,287**	1,137	3,204	9,770	14,111	2,197	9,048	11,245
Profit (loss) before interest and taxation	**1,073**	**8**	**1,081**	730	780	255	1,765	403	927	1,330
Finance costs	**200**	**421**	**621**	109	188	137	434	131	58	189
Profit (loss) before taxation	**873**	**(413)**	**460**	621	592	118	1,331	272	869	1,141
Taxation	**173**	**219**	**392**	81	54	67	202	489	107	596
Non-controlling interest	**—**	**1**	**1**	—	—	1	1	—	2	2
Profit (loss) for the year	**700**	**(633)**	**67**	540	538	50	1,128	(217)	760	543
Other comprehensive income	**—**	**45**	**45**	—	—	50	50	—	5	5
Total comprehensive income	**700**	**(588)**	**112**	540	538	100	1,178	(217)	765	548
Non-current assets	**9,394**	**16,505**	**25,899**	11,109	7,299	7,775	26,183			
Current assets	**1,964**	**4,387**	**6,351**	2,066	1,527	2,778	6,371			
Total assets	**11,358**	**20,892**	**32,250**	13,175	8,826	10,553	32,554			
Current liabilities	**1,255**	**2,992**	**4,247**	1,297	998	1,713	4,008			
Non-current liabilities	**5,037**	**7,505**	**12,542**	6,614	2,928	3,687	13,229			
Total liabilities	**6,292**	**10,497**	**16,789**	7,911	3,926	5,400	17,237			
Net assets	**5,066**	**10,395**	**15,461**	5,264	4,900	5,153	15,317			
Less: non-controlling interests	**—**	**(15)**	**(15)**	—	—	(13)	(13)			
	5,066	**10,380**	**15,446**	5,264	4,900	5,140	15,304			
Group investment in joint ventures										
Group share of net assets (as above)	**5,066**	**10,380**	**15,446**	5,264	4,900	5,140	15,304			
Cumulative impairment charge	**—**	**(3,007)**	**(3,007)**	—	(2,900)	—	(2,900)			
Loans made by group companies to joint ventures	**—**	**(4)**	**(4)**	—	—	(4)	(4)			
	5,066	**7,369**	**12,435**	5,264	2,000	5,136	12,400			

16. Investments in joint ventures – continued

Transactions between the group and its joint ventures are summarized below.

$ million

Sales to joint ventures	2023		2022		2021	
Product	**Sales**	**Amount receivable at 31 December**	Sales	Amount receivable at 31 December	Sales	Amount receivable at 31 December
LNG, crude oil and oil products, natural gas	**3,585**	**501**	4,212	316	3,923	292

Purchases from joint ventures	2023		2022		2021	
Product	**Purchases**	**Amount payable at 31 December**	Purchases	Amount payable at 31 December	Purchases	Amount payable at 31 December
LNG, crude oil and oil products, natural gas, refinery operating costs, plant processing fees	**3,328**	**427**	1,893	574	716	93

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 2023 relate to heating oil, gasoline, diesel and lubricant product transactions with Mobene and Ocwen Energy. The majority of purchases from joint ventures in 2023 relate to crude oil and oil products transactions with Azule Energy.

The bp investment in Pan American Energy Group S.L. joint venture had an impairment charge in 2022 of $2,900 million as a result of expected portfolio changes.

bp's share of net impairment charges recognized by joint ventures in 2023 was $1,285 million (2022 $256 million charge and 2021 reversals of $214 million) of which $1,152 million charge (2022 $276 million and 2021 $nil) was in the gas and low carbon energy segment and $133 million charge (2022 $20 million reversals and 2021 reversals of $214 million) was in the oil production & operations segment. The 2023 charges in the gas and low carbon energy segment principally relate to the group's US offshore wind investments. The project assets were measured at fair value less costs of disposal following the rejection in October 2023 of requests to renegotiate the power purchase agreements associated with three wind farms off the coast of New York (Empire Wind 1 and 2, Beacon Wind 1) and the announcement in January 2024 that bp and Equinor will restructure those investments. Subject to approvals, bp will assume full ownership of the Beacon projects and Equinor the Empire projects.

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 2023. The associate which was material to the Group at 31 December 2021 was Rosneft. At 31 December 2021 bp classified its investment in Rosneft as an associate because, in management's judgement, bp had significant influence over Rosneft. On 27 February 2022, bp announced it would exit its shareholding in Rosneft and bp's two nominated Rosneft directors both stepped down from Rosneft's board. As a result, the significant judgement on significant influence over Rosneft was reassessed. Since the first quarter 2022, bp accounts for its interest in Rosneft and its other businesses with Rosneft within Russia, as financial assets measured at fair value within 'Other investments'. For further information see Note 1 *Significant judgements and estimate: investment in Rosneft*.

$ million

	Income statement			Balance sheet	
	Earnings from associates - after interest and tax			Investments in associates	
	2023	2022	2021	**2023**	2022
Rosneft	**—**	528	2,694	**—**	—
Other associates	**831**	874	762	**7,814**	8,201
	831	1,402	3,456	**7,814**	8,201

The group recognized dividends, net of withholding tax, of $nil from Rosneft in 2023 (2022 $nil and 2021 $640 million).

17. Investments in associates – continued

The following table provides summarized financial information relating to Rosneft for 2021. This information is presented on a 100% basis and reflects adjustments made by bp to Rosneft's own results in applying the equity method of accounting. bp adjusted Rosneft's results for the accounting required under IFRS relating to bp's purchase of its interest in Rosneft and the amortization of the deferred gain relating to the disposal of bp's interest in TNK-BP.

	$ million
	Gross amount
	2021
Sales and other operating revenues	118,755
Profit before interest and taxation	18,537
Finance costs	1,357
Profit (loss) before taxation	17,180
Taxation	3,209
Non-controlling interests	1,743
Profit (loss) for the year	12,228
Other comprehensive income	54
Total comprehensive income	12,282

Summarized financial information for the group's share of associates is shown below.

					$ million
					bp share
	2023	2022			2021
	Total	Total	Rosneft	Other	Total
Sales and other operating revenues	**11,396**	14,841	26,163	10,005	36,168
Profit before interest and taxation	**2,279**	3,053	4,084	1,602	5,686
Finance costs	**41**	73	299	73	372
Profit (loss) before taxation	**2,238**	2,980	3,785	1,529	5,314
Taxation	**1,407**	1,498	707	767	1,474
Non-controlling interests	**—**	80	384	—	384
Profit (loss) for the year	**831**	1,402	2,694	762	3,456
Other comprehensive income	**(237)**	352	12	27	39
Total comprehensive income	**594**	1,754	2,706	789	3,495
Non-current assets	**11,483**	11,993			
Current assets	**3,776**	3,368			
Total assets	**15,259**	15,361			
Current liabilities	**3,003**	2,936			
Non-current liabilities	**4,473**	4,255			
Total liabilities	**7,476**	7,191			
Net assets	**7,783**	8,170			
Less: non-controlling interests	**—**	—			
	7,783	8,170			
Group investment in associates					
Group share of net assets (as above)	**7,783**	8,170			
Loans made by group companies to associates	**31**	31			
	7,814	8,201			

17. Investments in associates – continued

Transactions between the group and its associates are summarized below.

						$ million
Sales to associates		2023		2022		2021
Product	Sales	Amount receivable at 31 December	Sales	Amount receivable at 31 December	Sales	Amount receivable at 31 December
LNG, crude oil and oil products, natural gas	1,009	368	1,042	417	852	201

						$ million
Purchases from associates		2023		2022		2021
Product	Purchases	Amount payable at 31 December	Purchases	Amount payable at 31 December	Purchases	Amount payable at 31 December
Crude oil and oil products, natural gas, transportation tariff	5,473	2,607	6,199	2,086	7,683	2,072

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 2023 and 2022 relate to crude oil and oil products transactions with Aker BP. The majority of purchases from associates in 2021 relate to crude oil and oil products transactions with Rosneft. Sales to associates are related to various entities.

bp has commitments amounting to $8,615 million (2022 $8,488 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 2023 was $nil (2022 $nil).

18. Other investments

				$ million
		2023		2022
	Current	Non-current	Current	Non-current
Equity investments[a]	—	1,177	—	1,040
Contingent consideration	754	939	364	1,522
Other	89	73	214	108
	843	2,189	578	2,670

a The majority of equity investments are unlisted.

Contingent consideration relates to amounts arising on disposals which are financial assets classified as measured at fair value through profit or loss. The fair value is determined using an estimate of discounted future cash flows that are expected to be received and is considered a level 3 valuation under the fair value hierarchy. Future cash flows are estimated based on inputs including oil and natural gas prices, production volumes and operating costs related to the disposed operations. The discount rate used is based on a risk-free rate adjusted for asset-specific risks. The contingent consideration principally relates to the disposal of our Alaskan business.

19. Inventories

		$ million
	2023	2022
Crude oil	3,227	3,608
Natural gas	410	825
Emissions allowances	464	436
Refined petroleum and petrochemical products	7,413	7,920
	11,514	12,789
Trading inventories	9,850	14,004
	21,364	26,793
Supplies	1,455	1,288
	22,819	28,081
Cost of inventories expensed in the income statement	119,307	141,043

The inventory valuation at 31 December 2023 is stated net of a provision of $497 million (2022 $483 million) to write down inventories to their net realizable value, of which $310 million (2022 $195 million) relates to hydrocarbon inventories. The net charge to the income statement in the year in respect of inventory net realizable value provisions was $87 million (2022 $199 million charge), of which $112 million charge (2022 $137 million charge) 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
		2023		2022
	Current	Non-current	Current	Non-current
Financial assets				
Trade receivables	**25,175**	**652**	28,229	12
Amounts receivable from joint ventures and associates	**843**	**26**	654	79
Other receivables	**3,936**	**722**	3,953	608
	29,954	**1,400**	32,836	699
Non-financial assets				
Sales taxes and production taxes	**1,028**	**355**	1,037	379
Other receivables	**141**	**12**	137	14
	1,169	**367**	1,174	393
	31,123	**1,767**	34,010	1,092

In both 2023 and 2022 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
		2023		2022		2021
	Trade and other receivables	Fixed asset investments	Trade and other receivables	Fixed asset investments	Trade and other receivables	Fixed asset investments
At 1 January	**636**	**3,050**	584	169	555	186
Charged to costs and expenses	**866**	**176**	143	17,471	136	3
Charged to other accounts[a]	**1**	**(1)**	(8)	(27)	(11)	—
Deductions	**(79)**	**(42)**	(83)	(41)	(96)	(20)
Reclassifications	**—**	**—**	—	(14,522)	—	—
At 31 December	**1,424**	**3,183**	636	3,050	584	169

[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 $1,301 million (2022 $513 million, 2021 $456 million) relating to receivables that were credit-impaired at the end of the year and $123 million (2022 $123 million, 2021 $128 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. The amount charged to costs and expenses in 2022 principally relates to bp's investments in Rosneft and Pan American Energy Group S.L.. Amounts related to bp's investments in Rosneft and other businesses with Rosneft within Russia were reclassified in 2022 following bp's loss of significant influence.

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
		2023		2022
	Current	Non-current	Current	Non-current
Financial liabilities				
Trade payables	**42,406**	**—**	47,210	—
Amounts payable to joint ventures and associates	**3,034**	**—**	2,660	—
Payables for capital expenditure and acquisitions	**3,063**	**305**	2,579	446
Payables related to the Gulf of Mexico oil spill	**1,130**	**7,602**	1,213	8,350
Other payables	**7,313**	**663**	5,995	1,133
	56,946	**8,570**	59,657	9,929
Non-financial liabilities				
Sales taxes, customs duties, production taxes and social security	**2,264**	**134**	2,361	124
Other payables	**1,945**	**1,372**	1,966	334
	4,209	**1,506**	4,327	458
	61,155	**10,076**	63,984	10,387

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 Mexico oil spill, are predominantly interest free. See Note 29 (c) for further information.

Payables related to the Gulf of Mexico 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 Mexico oil spill for these elements of the agreements are $3,782 million payable over 9 years, $2,098 million payable over 10 years and $2,812 million payable over 9 years respectively at 31 December 2023. Reported within net cash provided by operating activities in the group cash flow statement is a net cash outflow of $1,280 million (2022 outflow of $1,370 million, 2021 outflow of $1,484 million) related to the Gulf of Mexico 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 Mexico oil spill at 31 December 2023 also include amounts payable for settled economic loss and property damage claims which are payable over a period of up to four years.

23. Provisions

						$ million
	Decommissioning	Environmental	Litigation and claims	Emissions	Other	Total
At 1 January 2023	**12,343**	**1,721**	**779**	**5,062**	**1,419**	**21,324**
Exchange adjustments	**129**	**6**	**—**	**29**	**25**	**189**
Acquisitions	**5**	**33**	**2**	**—**	**—**	**40**
New and increase in existing provisions[a]	**915**	**228**	**147**	**2,347**	**718**	**4,355**
Write-back of unused provisions[a]	**(3)**	**(51)**	**(15)**	**(710)**	**(261)**	**(1,040)**
Unwinding of discount[b]	**418**	**55**	**19**	**—**	**12**	**504**
Change in discount rate	**(921)**	**(41)**	**(23)**	**—**	**(6)**	**(991)**
Utilization	**(70)**	**(307)**	**(173)**	**(3,703)**	**(491)**	**(4,744)**
Reclassified to other payables	**(444)**	**(29)**	**—**	**—**	**—**	**(473)**
Reclassified as liabilities directly associated with assets held for sale	**—**	**(1)**	**(9)**	**—**	**—**	**(10)**
Deletions	**—**	**—**	**—**	**—**	**(15)**	**(15)**
At 31 December 2023	**12,372**	**1,614**	**727**	**3,025**	**1,401**	**19,139**
Of which – current	**637**	**371**	**111**	**2,807**	**492**	**4,418**
– non-current	**11,735**	**1,243**	**616**	**218**	**909**	**14,721**

[a] Recognized in the Group income statement, other than changes in decommissioning provisions related to owned assets.
[b] Recognized in the Group income statement.

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 Mexico oil spill

The group has recognized certain assets, payables and provisions and incurs certain residual costs relating to the Gulf of Mexico oil spill that occurred in 2010. For further information see Notes 7, 22, 29, 33. The litigation and claims provision presented in the table above includes the latest estimate for the remaining costs associated with the Gulf of Mexico oil spill. The amounts payable may differ from the amount provided and the timing of payments is uncertain.

24. Pensions and other post-retirement 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-retirement benefits in Note 1.

The pension obligation in the UK consists primarily of a 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. This plan was closed to new joiners in 2010 and was closed to future accrual on 30 June 2021.

Employees in the UK are eligible for membership of a defined contribution plan.

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. During 2023 the committee was composed of six 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-retirement healthcare to eligible retired employees and their dependants (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.

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 2023 the aggregate level of contributions was $42 million (2022 $74 million and 2021 $274 million). The aggregate level of contributions in 2024 is expected to be approximately $150 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 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 2023 formal actuarial valuation. No contractually committed funding was due at 31 December 2023. The closure of the defined benefit plan to future accrual reduces the need for funding and the plan's expected future funding volatility.

The surplus relating to the primary UK 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 2023 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 2023.

The obligation and cost of providing pensions and other post-retirement benefits is assessed annually using the projected unit credit method. The date of the most recent actuarial review was 31 December 2023. The UK 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 pension plan was as at 31 December 2020; the 31 December 2023 valuation is currently underway. A valuation of the US plan and largest Eurozone plans are carried out annually.

24. Pensions and other post-retirement 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[a]	**2023**	2022	2021	**2023**	2022	2021	**2023**	2022	2021
Discount rate for plan liabilities	**4.8**	5.0	1.8	**5.0**	5.2	2.7	**3.6**	4.2	1.3
Rate of increase for pensions in payment	**2.8**	2.9	3.2	**—**	—	—	**2.1**	1.8	1.4
Rate of increase in deferred pensions	**2.8**	2.9	3.2	**—**	—	—	**0.7**	0.6	0.4
Inflation for plan liabilities	**3.0**	3.1	3.3	**2.0**	2.0	2.1	**2.4**	2.1	1.6

									%
			UK			US			Eurozone
Financial assumptions used to determine benefit expense	**2023**	2022	2021	**2023**	2022	2021	**2023**	2022	2021
Discount rate for plan service cost[b]	**N/A**	N/A	1.5	**5.2**	2.8	2.4	**4.3**	1.7	1.4
Discount rate for plan other finance expense[c]	**5.0**	1.8	1.7	**5.2**	2.7	2.2	**4.2**	1.3	1.0
Inflation for plan service cost[b]	**N/A**	N/A	2.8	**2.0**	2.1	1.7	**2.1**	1.6	1.5

[a] Salary growth has not been a material financial assumption for the Group following the closure of the primary pension plan to future accrual in 2021.

[b] UK discount rate and inflation rate assumptions are not significant in determining the benefit expense following the closure of the primary UK plan to future accrual in 2021. Rates for the remaining small worldwide plan administered/reported through the UK are 5.0% (2022 2.5%) and 1.9% (2022 2.2%) respectively.

[c] The discount rate for plan other finance expense in 2021 was 1.4% for the primary UK plan for the period before the plan closed to future accrual on 30th June 2021 and 1.9% thereafter.

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:

									Years
Mortality assumptions			UK			US			Eurozone
	2023	2022	2021	**2023**	2022	2021	**2023**	2022	2021
Life expectancy at age 60 for a male currently aged 60	**27.4**	26.9	26.9	**25.0**	25.0	24.9	**26.1**	26.0	25.8
Life expectancy at age 60 for a male currently aged 40	**29.2**	28.5	28.4	**26.7**	26.6	26.6	**28.6**	28.5	28.3
Life expectancy at age 60 for a female currently aged 60	**29.2**	28.8	28.9	**28.1**	28.0	27.9	**29.3**	29.3	29.1
Life expectancy at age 60 for a female currently aged 40	**30.6**	30.6	30.5	**29.6**	29.5	29.4	**31.6**	31.4	31.2

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 plan as it matures is to invest in assets whose value changes in the same way as the plan liabilities, in order to reduce the level of funding risk. To move towards this objective, the UK plan uses a liability driven investment (LDI) approach for part of the portfolio, investing primarily in government bonds to achieve this matching effect for 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.

For the primary UK pension plan there is an agreement with the trustee to increase the proportion of assets with liability matching characteristics over time primarily by reducing the proportion of plan assets held as equities and increasing the proportion held as bonds. There is a similar agreement in place for the primary US plan. During 2023, the asset allocation policy of the UK plan switched 2% of plan assets from equities to bonds (2022 2%). The US asset allocation policy remained consistent.

The current asset allocation policy for the major plans at 31 December 2023 was as follows:

	UK	**US**
Asset category	**%**	**%**
Total equity (including private equity)	**8**	**19**
Bonds/cash (including LDI)	**85**	**81**
Property/real estate	**7**	**—**

24. Pensions and other post-retirement benefits – continued

The amounts invested under the LDI programme by the primary UK pension plan as at 31 December 2023 were $6,215 million (2022 $3,981 million) of government-issued nominal bonds and $13,177 million (2022 $11,945 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 216.

					$ million
	UK[a]	US[b]	Eurozone	Other	Total
Fair value of pension plan assets					
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**
At 31 December 2022					
Listed equities – developed markets	1,252	127	299	213	1,891
– emerging markets	117	17	48	71	253
Private equity[c]	2,715	1,126	—	2	3,843
Government issued nominal bonds[d]	4,039	1,370	682	263	6,354
Government issued index-linked bonds[d]	11,945	—	79	—	12,024
Corporate bonds[d]	6,317	2,569	563	146	9,595
Property[e]	2,297	—	89	18	2,404
Cash	567	175	61	116	919
Other[f]	1,088	33	56	357	1,534
Debt (repurchase agreements) used to fund liability driven investments	(5,290)	—	—	—	(5,290)
	25,047	5,417	1,877	1,186	33,527
At 31 December 2021					
Listed equities – developed markets	2,964	340	473	290	4,067
– emerging markets	252	45	67	76	440
Private equity[c]	3,233	1,537	—	3	4,773
Government issued nominal bonds[d]	7,491	2,606	974	432	11,503
Government issued index-linked bonds[d]	24,516	—	100	—	24,616
Corporate bonds[d]	10,128	2,475	689	498	13,790
Property[e]	2,714	—	110	22	2,846
Cash	1,136	116	54	69	1,375
Other	1,133	54	70	22	1,279
Debt (repurchase agreements) used to fund liability driven investments	(10,723)	—	—	—	(10,723)
	42,844	7,173	2,537	1,412	53,966

[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 insurance policies arising from annuity buy-in in Canada amounting to $374 million.

24. Pensions and other post-retirement benefits – continued

					$ 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)
Movements in benefit obligation during the year					
Benefit obligation at 1 January	17,480	5,880	4,799	1,343	29,502
Exchange adjustments	1,056	—	215	30	1,301
Operating charge relating to defined benefit plans	48	156	52	22	278
Interest cost	869	297	194	66	1,426
Contributions by plan participants	6	—	2	5	13
Benefit payments (funded plans)[c]	(1,071)	(262)	(79)	(81)	(1,493)
Benefit payments (unfunded plans)[c]	(8)	(166)	(230)	(25)	(429)
Reclassified as assets held for sale	—	—	—	(14)	(14)
Remeasurements	1,199	(68)	584	25	1,740
Benefit obligation at 31 December[a d]	19,579	5,837	5,537	1,371	32,324
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	25,047	5,417	1,877	1,186	33,527
Exchange adjustments	1,462	—	81	39	1,582
Interest income on plan assets[a e]	1,259	274	78	56	1,667
Contributions by plan participants	6	—	2	5	13
Contributions by employers (funded plans)	20	—	11	11	42
Benefit payments (funded plans)[c]	(1,071)	(262)	(79)	(81)	(1,493)
Remeasurements[e]	(677)	45	82	28	(522)
Fair value of plan assets at 31 December[f]	26,046	5,474	2,052	1,244	34,816
Surplus (deficit) at 31 December	6,467	(363)	(3,485)	(127)	2,492
Represented by					
Asset recognized	6,631	1,133	120	64	7,948
Liability recognized	(164)	(1,496)	(3,605)	(191)	(5,456)
	6,467	(363)	(3,485)	(127)	2,492
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	6,631	1,133	104	29	7,897
Unfunded	(164)	(1,496)	(3,589)	(156)	(5,405)
	6,467	(363)	(3,485)	(127)	2,492
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(19,415)	(4,341)	(1,948)	(1,215)	(26,919)
Unfunded	(164)	(1,496)	(3,589)	(156)	(5,405)
	(19,579)	(5,837)	(5,537)	(1,371)	(32,324)

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-retirement benefit plans are included in the benefit obligation. Following the closure of the primary UK pension plan to future accrual, 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.

c The benefit payments amount shown above comprises $1,858 million benefits and $10 million settlements, plus $54 million of plan expenses incurred in the administration of the benefit.

d The benefit obligation for the US is made up of $4,527 million for pension liabilities and $1,310 million for other post-retirement benefit liabilities (which are unfunded and are primarily retiree medical liabilities). The benefit obligation for the Eurozone includes $3,393 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 214.

24. Pensions and other post-retirement benefits – continued

					$ million
					2022
	UK	US	Eurozone	Other	Total
Analysis of the amount charged to profit or loss					
Current service cost[a]	41	219	87	25	372
Past service cost[b]	23	–	(1)	(21)	1
Settlement[b]	(8)	–	–	(4)	(12)
Operating charge (credit) relating to defined benefit plans	56	219	86	–	361
Payments to defined contribution plans	110	132	6	36	284
Total operating charge (credit)	166	351	92	36	645
Interest income on plan assets[a]	(694)	(189)	(34)	(44)	(961)
Interest on plan liabilities	529	217	85	61	892
Other finance (income) expense	(165)	28	51	17	(69)
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets	(12,955)	(1,581)	(507)	(151)	(15,194)
Change in financial assumptions underlying the present value of the plan liabilities	11,531	2,195	1,903	221	15,850
Change in demographic assumptions underlying the present value of the plan liabilities	47	–	(14)	(15)	18
Experience gains and losses arising on the plan liabilities	(146)	(15)	(159)	(14)	(334)
Remeasurements recognized in other comprehensive income	(1,523)	599	1,223	41	340
Movements in benefit obligation during the year					
Benefit obligation at 1 January	32,834	8,273	7,108	1,652	49,867
Exchange adjustments	(3,224)	–	(443)	(68)	(3,735)
Operating charge relating to defined benefit plans	56	219	86	–	361
Interest cost	529	217	85	61	892
Contributions by plan participants	9	–	2	4	15
Benefit payments (funded plans)[c]	(1,211)	(364)	(78)	(79)	(1,732)
Benefit payments (unfunded plans)[c]	(7)	(285)	(229)	(23)	(544)
Reclassified as assets held for sale	–	–	–	(12)	(12)
Disposals	(74)	–	(2)	–	(76)
Remeasurements	(11,432)	(2,180)	(1,730)	(192)	(15,534)
Benefit obligation at 31 December[a d]	17,480	5,880	4,799	1,343	29,502
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	42,844	7,173	2,537	1,412	53,966
Exchange adjustments	(4,258)	–	(156)	(52)	(4,466)
Interest income on plan assets[a e]	694	189	34	44	961
Contributions by plan participants	9	–	2	4	15
Contributions by employers (funded plans)	10	–	45	19	74
Benefit payments (funded plans)[c]	(1,211)	(364)	(78)	(79)	(1,732)
Reclassified as assets held for sale	–	–	–	(11)	(11)
Disposals	(86)	–	–	–	(86)
Remeasurements[e]	(12,955)	(1,581)	(507)	(151)	(15,194)
Fair value of plan assets at 31 December[f]	25,047	5,417	1,877	1,186	33,527
Surplus (deficit) at 31 December	7,567	(463)	(2,922)	(157)	4,025
Represented by					
Asset recognized	7,716	1,227	256	70	9,269
Liability recognized	(149)	(1,690)	(3,178)	(227)	(5,244)
	7,567	(463)	(2,922)	(157)	4,025
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	7,716	1,227	238	39	9,220
Unfunded	(149)	(1,690)	(3,160)	(196)	(5,195)
	7,567	(463)	(2,922)	(157)	4,025
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(17,331)	(4,190)	(1,639)	(1,147)	(24,307)
Unfunded	(149)	(1,690)	(3,160)	(196)	(5,195)
	(17,480)	(5,880)	(4,799)	(1,343)	(29,502)

[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-retirement benefit plans are included in the benefit obligation. Following the closure of the primary UK pension plan to future accrual, current service cost in the UK consists of $30 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 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. Settlements reflect costs associated with buyouts in Canada and in certain other small worldwide plans administered and reported through the UK.

[c] The benefit payments amount shown above comprises $2,217 million benefits and $8 million settlements, plus $51 million of plan expenses incurred in the administration of the benefit.

[d] The benefit obligation for the US is made up of $4,411 million for pension liabilities and $1,469 million for other post-retirement benefit liabilities (which are unfunded and are primarily retiree medical liabilities). The benefit obligation for the Eurozone includes $2,992 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 214.

24. Pensions and other post-retirement benefits – continued

					$ million
					2021
	UK	US	Eurozone	Other	Total
Analysis of the amount charged to profit or loss					
Current service cost[a]	154	246	105	31	536
Past service cost[b]	(302)	—	(27)	2	(327)
Settlement[b]	—	—	(4)	(1)	(5)
Operating charge (credit) relating to defined benefit plans	(148)	246	74	32	204
Payments to defined contribution plans	76	136	7	36	255
Total operating charge (credit)	(72)	382	81	68	459
Interest income on plan assets[a]	(684)	(150)	(30)	(40)	(904)
Interest on plan liabilities	559	209	78	56	902
Other finance (income) expense	(125)	59	48	16	(2)
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets	2,440	749	12	25	3,226
Change in financial assumptions underlying the present value of the plan liabilities	(100)	777	233	97	1,007
Change in demographic assumptions underlying the present value of the plan liabilities	66	(41)	(15)	1	11
Experience gains and losses arising on the plan liabilities	7	173	(11)	3	172
Remeasurements recognized in other comprehensive income	2,413	1,658	219	126	4,416

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-retirement benefit plans are included in the benefit obligation.
b The past service credit in the UK represents curtailment gains arising from the closure of the primary pension plan in the UK to future accrual. For active members of that plan on 30 June 2021, benefits payable are now linked to salary as at that date. Past service credits and settlements in the Eurozone include $18 million of curtailments and settlements due to restructuring initiatives. Remaining past service cost and 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 2023 for the group's pensions and other post-retirement benefit expense would have had the effects shown in the tables below. The effects shown for the expense in 2024 comprise the total of current service cost and net finance income or expense.

						$ million
						One percentage point
	UK		**US**		**Eurozone**	
	Increase	**Decrease**	**Increase**	**Decrease**	**Increase**	**Decrease**
Discount rate[a]						
Effect on expense in 2024	**(197)**	**173**	**(40)**	**46**	**(8)**	**4**
Effect on obligation at 31 December 2023	**(2,259)**	**2,811**	**(449)**	**651**	**(608)**	**737**
Inflation rate[b]						
Effect on expense in 2024	**89**	**(83)**	**7**	**(6)**	**34**	**(29)**
Effect on obligation at 31 December 2023	**1,872**	**(1,738)**	**41**	**(35)**	**582**	**(503)**

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 2024	**28**	**4**	**10**
Effect on obligation at 31 December 2023	**577**	**64**	**216**

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 2023 are as follows:

					$ million
Estimated future benefit payments	**UK**	**US**	**Eurozone**	**Other**	**Total**
2024	**1,169**	**474**	**332**	**88**	**2,063**
2025	**1,113**	**469**	**326**	**84**	**1,992**
2026	**1,126**	**456**	**318**	**85**	**1,985**
2027	**1,146**	**458**	**313**	**86**	**2,003**
2028	**1,159**	**441**	**308**	**86**	**1,994**
2029 - 2033	**5,958**	**2,204**	**1,454**	**440**	**10,056**
					Years
Weighted average duration	**12.9**	**9.3**	**12.9**	**11.4**	

25. Cash and cash equivalents

		$ million
	2023	2022
Cash	**16,683**	15,008
Triparty repos and term bank deposits	**9,788**	7,971
Other cash equivalents	**6,559**	6,216
	33,030	29,195

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 2023 includes $5,282 million (2022 $5,866 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 $7,174 million (2022 $5,822 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
			2023			2022
	Current	**Non-current**	**Total**	Current	Non-current	Total
Borrowings	**3,284**	**48,670**	**51,954**	3,198	43,746	46,944

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 $2,688 million (2022 $2,297 million) and issued commercial paper of $456 million (2022 $725 million). Finance debt does not include accrued interest of $495 million (2022 $409 million), which is reported within other payables. As part of actively managing its debt portfolio, during the year the group bought back $1.7 billion equivalent of finance debt consisting entirely of euro bonds (2022 $7.4 billion US dollar bonds). Derivatives associated with non-US dollar debt bought back were also terminated. 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**
						2023
US dollar	**4**	**13**	**33,511**	**8**	**18,134**	**51,645**
Other currencies	**6**	**7**	**205**	**10**	**104**	**309**
			33,716		**18,238**	**51,954**
						2022
US dollar	3	14	28,651	6	18,105	46,756
Other currencies	6	8	188	—	—	188
			28,839		18,105	46,944

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 2023, 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
		2023		2022
	Fair value	**Carrying amount**	Fair value	Carrying amount
Short-term borrowings	**596**	**596**	901	901
Long-term borrowings	**48,199**	**51,358**	41,689	46,043
Total finance debt	**48,795**	**51,954**	42,590	46,944

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 2023, gearing was 19.7% (2022 20.5%).

		$ million
At 31 December	**2023**	2022
Finance debt	**51,954**	46,944
Less: fair value asset (liability) of hedges related to finance debt[a]	**(1,988)**	(3,673)
	53,942	50,617
Less: cash and cash equivalents	**33,030**	29,195
Net debt	**20,912**	21,422
Total equity	**85,493**	82,990
Gearing	**19.7%**	20.5%

a Derivative financial instruments entered into for the purpose of managing interest rate and foreign currency exchange risk associated with net debt with a fair value liability position of $73 million (2022 liability of $91 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.

An analysis of changes in liabilities arising from financing activities is provided below.

					$ million
	Finance debt	**Currency swaps**[a]	**Lease liabilities**	**Net partner payable for leases entered into on behalf of joint operations**	**Total liabilities arising from financing activities**
At 1 January 2023	**46,944**	**5,312**	**8,549**	**42**	**60,847**
Exchange adjustments	**33**	**—**	**132**	**1**	**166**
Net financing cash flow	**3,040**	**(213)**	**(2,560)**	**(22)**	**245**
Fair value (gains) losses	**1,389**	**(2,065)**	**—**	**—**	**(676)**
New and remeasured leases/joint operations payables	**—**	**—**	**4,956**	**10**	**4,966**
Other movements[b]	**548**	**(56)**	**44**	**(1)**	**535**
At 31 December 2023	**51,954**	**2,978**	**11,121**	**30**	**66,083**
At 1 January 2022	61,176	481	8,611	250	70,518
Exchange adjustments	(164)	—	(260)	1	(423)
Net financing cash flow	(10,855)	(192)	(1,961)	(29)	(13,037)
Fair value (gains) losses	(3,694)	5,023	—	—	1,329
New and remeasured leases/joint operations payables	—	—	2,367	21	2,388
Other movements[c]	481	—	(208)	(201)	72
At 31 December 2022	46,944	5,312	8,549	42	60,847

a Currency swaps include cross currency interest rate swaps.
b 2023 other movements in finance debt include $545 million acquired with TravelCenters of America.
c 2022 other movements in finance debt include $1,044 million acquired with Archaea Energy Inc. and a non-cash reduction in balances related to the Alaska divestment. Other movements in the net partner payable for leases entered into on behalf of joint operations primarily represent transfers to amounts held for sale.

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 $746 million (2022 $497 million) at the balance sheet date for shares repurchased between the end of the reporting period and 6 February 2024. $7,918 million (2022 $9,996 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 7 years (2022 7 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
	2023	2022
Undiscounted lease liability cash flows due:		
Within 1 year	**3,038**	2,348
1 to 2 years	**2,177**	1,728
2 to 3 years	**1,386**	1,232
3 to 4 years	**1,139**	740
4 to 5 years	**947**	632
5 to 10 years	**3,045**	1,909
Over 10 years	**1,348**	1,275
	13,080	9,864
Impact of discounting	**(1,959)**	(1,315)
Lease liabilities at 31 December	**11,121**	8,549
Of which – current	**2,650**	2,102
– non-current	**8,471**	6,447

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 2023 is $5,507 million (2022 $5,360 million). The majority of this future commitment relates to the floating LNG vessel to service the Greater Tortue Ahmeyim project from 2025.

		$ million
	2023	2022
Total cash outflow for amounts included in lease liabilities[a]	**2,904**	2,200
Expense for variable payments not included in the lease liability[a]	**27**	27
Short-term lease expense[a]	**657**	482
Additions to right-of-use assets in the period	**5,015**	2,451

[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 2023	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**	**3,006**	**–**	**3,032**
Loans		**1,725**	**457**	**–**	**2,182**
Trade and other receivables	20	**31,354**	**–**	**–**	**31,354**
Derivative financial instruments	30	**–**	**22,444**	**119**	**22,563**
Cash and cash equivalents	25	**27,804**	**5,226**	**–**	**33,030**
Financial liabilities					
Trade and other payables	22	**(65,516)**	**–**	**–**	**(65,516)**
Derivative financial instruments	30	**–**	**(13,545)**	**(2,107)**	**(15,652)**
Accruals		**(7,837)**	**–**	**–**	**(7,837)**
Lease liabilities	28	**(11,121)**	**–**	**–**	**(11,121)**
Finance debt	26	**(51,954)**	**–**	**–**	**(51,954)**
		(75,519)	**17,588**	**(1,988)**	**(59,919)**

29. Financial instruments and financial risk factors – continued

At 31 December 2022	Note	Measured at amortized cost	Mandatorily measured at fair value through profit or loss	Derivative hedging instruments	Total carrying amount
					$ million
Financial assets					
Other investments	18	26	3,222	—	3,248
Loans		1,245	341	—	1,586
Trade and other receivables	20	33,535	—	—	33,535
Derivative financial instruments	30	—	24,395	—	24,395
Cash and cash equivalents	25	25,611	3,584	—	29,195
Financial liabilities					
Trade and other payables	22	(69,586)	—	—	(69,586)
Derivative financial instruments	30	—	(22,481)	(3,674)	(26,155)
Accruals		(7,631)	—	—	(7,631)
Lease liabilities	28	(8,549)	—	—	(8,549)
Finance debt	26	(46,944)	—	—	(46,944)
		(72,293)	9,061	(3,674)	(66,906)

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 $11 million (2022 net loss of $238 million and 2021 net gain of $627 million). Dividend income of $18 million (2022 $14 million and 2021 $11 million) from investments in equity instruments classified as measured at fair value through profit or loss is presented within other income.

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 EVP trading and shipping and SVPs treasury, tax, accounting reporting control and planning & performance management. 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 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 trading and shipping business and are also underpinned by the compliance, control and risk management infrastructure common to the activities of bp's 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 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 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 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 trading positions in liquid periods 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. Trading activity occurring in liquid periods is subject to value-at-risk and other limits for each trading

29. Financial instruments and financial risk factors – continued

activity and the aggregate of all trading activity. The calculation of potential changes in value within the liquid 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 trading positions in liquid periods at 31 December 2023 was $26 million (2022 $63 million) whereas the average value-at-risk measure for the period was $49 million (2022 $89 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 outside of liquid periods 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 2023, the total foreign currency borrowings not swapped into US dollars amounted to $309 million (2022 $188 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.

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 2023 the most significant open contracts in place were for USD equivalent amounts of $296 million sterling and $22 million Euro (2022 $5 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 2023 was 35% of total finance debt outstanding (2022 39%). The weighted average interest rate on finance debt at 31 December 2023 was 5% (2022 4%) and the weighted average maturity of fixed rate debt was thirteen years (2022 fourteen 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 (see Note 26). If the interest rates applicable to these floating rate instruments were to have changed by one percentage point on 1 January 2024, it is estimated that the group's finance costs for 2024 would change by approximately $182 million (2022 $181 million).

Prior to June 2023, the main benchmark interest rate to which bp was exposed was 3 month USD LIBOR, primarily in relation to finance debt and derivative contracts. During 2023, bp's internal working group for IBOR reform continued to monitor market developments and managed the transition to alternative benchmark rates. Publication of USD LIBOR tenors, including 3 month USD LIBOR, ceased from 30 June 2023.

Finance debt exposed to IBOR benchmark rates was renegotiated with relevant counterparties and transitioned to reference alternative risk free benchmarks. Amendments to finance debt terms arising were limited only to changes necessary to ensure economic equivalence with the former interest benchmarks, for example credit spread adjustments to the contractual interest rates.

Derivatives that previously referenced USD LIBOR also transitioned to referencing the Secured Overnight Financing Rate (SOFR) via the International Swaps and Derivatives Association (ISDA) fallback protocol. The derivatives comprise relevant derivative contracts hedging finance debt and hybrid bonds. In October 2020 the ISDA published its fallback protocol containing clauses to amend derivative contracts on the cessation of LIBOR should an entity and its counterparties adhere to the protocol. The protocol's pricing mechanism is at fair market value and bp has signed up to the protocol as this removes transition uncertainty for any interest rate and cross-currency interest rate swap contracts of the group. New contracts are being executed based on the new risk free rates. As at 31 December 2023, bp has no remaining contractual exposure to interest rate benchmark reform.

(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 2023 was $1,655 million (2022 $1,704 million) in respect of liabilities of joint ventures and associates and $598 million (2022 $680 million) in respect of liabilities of other third parties. An amount of $201 million (2022 $267 million) is recorded as a liability at 31 December 2023 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.

29. Financial instruments and financial risk factors – continued

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 2023, the group had in place credit enhancements designed to mitigate approximately $12.0 billion (2022 $12.6 billion) of credit risk of which approximately $10.7 billion (2022 $10.3 billion) related to assets in the scope of IFRS 9's impairment requirements. Credit enhancements include standby and documentary letters of credit, bank guarantees, insurance and liens which are typically taken out with financial institutions who have investment grade credit ratings, or are liens over assets held by the counterparty of the related receivables. 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.

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	**2023**	2022
AAA to AA-	**7 %**	9 %
A+ to A-	**59 %**	49 %
BBB+ to BBB-	**15 %**	15 %
BB+ to BB-	**7 %**	11 %
B+ to B-	**4 %**	12 %
CCC+ and below	**8 %**	4 %

Movements in the impairment provision for trade and other receivables are shown in Note 21.

29. Financial instruments and financial risk factors – continued

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
				Related amounts not set off in the balance sheet		
At 31 December 2023	Gross amounts of recognized financial assets (liabilities)	Amounts set off	Net amounts presented on the balance sheet	Master netting arrangements	Cash collateral (received) pledged	Net amount
Derivative assets	**25,188**	**(2,625)**	**22,563**	**(3,436)**	**(1,245)**	**17,882**
Derivative liabilities	**(18,277)**	**2,625**	**(15,652)**	**3,436**	**263**	**(11,953)**
Trade and other receivables	**17,867**	**(7,789)**	**10,078**	**(1,141)**	**(633)**	**8,304**
Trade and other payables	**(16,284)**	**7,789**	**(8,495)**	**1,141**	**44**	**(7,310)**
At 31 December 2022						
Derivative assets	33,199	(8,804)	24,395	(3,988)	(918)	19,489
Derivative liabilities	(34,918)	8,804	(26,114)	3,988	436	(21,690)
Trade and other receivables	17,947	(8,381)	9,566	(1,325)	(224)	8,017
Trade and other payables	(20,671)	8,381	(12,290)	1,325	61	(10,904)

(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 of 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 letter of credit (LC) 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 $13,180 million (2022 $12,730 million), allowing LCs to be issued for a maximum 24-month duration. There were also uncommitted secured LC facilities in place at 31 December 2023 for $3,515 million (2022 $3,800 million), which are secured against inventories or receivables when utilized. The facilities are held with over 28 international banks. The uncommitted LC facilities can only be terminated by either party giving a stipulated termination notice to the other.

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 2023, $9,955 million (2022 $9,520 million) of the group's trade payables subject to these 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 settlement periods were shorter.

Standard & Poor's Ratings long-term credit rating for bp is A- (positive) and Moody's Investors Service rating is A2 (positive) and the Fitch Ratings' long-term credit rating is A+ (stable).

During 2023, $6 billion (2022 $2 billion) of long-term taxable bonds were issued with terms ranging from seven to 15 years. In addition the group drew down on perpetual hybrid capital instruments with a US dollar equivalent value of $0.2 billion (2022 $0.4 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 $33.0 billion at 31 December 2023 (2022 $29.2 billion), primarily invested with highly rated banks or money market funds and readily accessible at immediate and short notice. At 31 December 2023, the group had substantial amounts of undrawn borrowing facilities available, consisting of an undrawn committed $8.0 billion (2022 $8.0 billion) credit facility and $4.0 billion (2022 $4.0 billion) of standby facilities. As at 31 December 2023 $0.2 billion of the credit facility was available for one year and $7.8 billion was available for 2 years. As at 31 December 2023 $0.1 billion of the standby facilities were available for three years and $3.9 billion were available for four years. The facilities are with 27 international banks and borrowings under them would be at pre-agreed rates.

For further information on the group's sources and uses of cash see Liquidity and capital resources on page 340.

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.

								$ million
				2023				2022
	Trade and other payables[a]	Accruals	Finance debt	Interest on finance debt	Trade and other payables[a]	Accruals	Finance debt	Interest on finance debt[b]
Within one year	**56,852**	**6,527**	**3,054**	**2,394**	59,618	6,398	2,978	2,013
1 to 2 years	**1,876**	**329**	**3,820**	**2,151**	1,625	230	2,811	1,848
2 to 3 years	**1,158**	**147**	**4,767**	**1,907**	1,378	207	4,066	1,684
3 to 4 years	**1,178**	**135**	**5,367**	**1,666**	1,192	110	5,077	1,452
4 to 5 years	**1,141**	**121**	**5,778**	**1,396**	1,188	114	5,773	1,204
5 to 10 years	**5,028**	**382**	**12,939**	**4,894**	6,109	348	13,621	3,680
Over 10 years	**136**	**196**	**14,586**	**6,890**	772	224	13,135	6,968
	67,369	**7,837**	**50,311**	**21,298**	71,882	7,631	47,461	18,849

a 2023 includes $10,662 million (2022 $11,884 million) in relation to the Gulf of Mexico oil spill, of which $9,520 million (2022 $10,660 million) matures in greater than one year.
b Comparative amounts for interest on finance debt have been amended to align with current year presentation. The amendment has increased cash outflows by $3,022 million.

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 $24,120 million at 31 December 2023 (2022 $23,970 million) to be received on the same day as the related cash outflows.

		$ million
Cash outflows for derivative financial instruments at 31 December	2023	2022
Within one year	**2,071**	1,492
1 to 2 years	**1,718**	2,531
2 to 3 years	**5,136**	2,053
3 to 4 years	**3,077**	5,575
4 to 5 years	**1,743**	3,584
5 to 10 years	**6,708**	7,627
Over 10 years	**4,092**	2,772
	24,545	25,634

For further information on our derivative financial instruments, see Note 30.

30. Derivative financial instruments

In the normal 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 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
		2023		2022
	Fair value asset	**Fair value liability**	Fair value asset	Fair value liability
Derivatives held for trading[a]				
Currency derivatives	**478**	**(1,511)**	634	(2,346)
Oil price derivatives	**1,859**	**(1,139)**	2,753	(1,961)
Natural gas price derivatives	**14,750**	**(6,708)**	15,437	(12,129)
Power price derivatives	**5,355**	**(4,187)**	5,527	(6,004)
Other derivatives	**2**	**—**	44	—
	22,444	**(13,545)**	24,395	(22,440)
Embedded derivatives				
Other embedded derivatives	**—**	**—**	—	(41)
	—	**—**	—	(41)
Cash flow hedges				
Currency forwards	**—**	**(1)**	—	—
	—	**(1)**	—	—
Fair value hedges				
Currency swaps	**119**	**(2,102)**	—	(3,670)
Interest rate swaps	**—**	**(4)**	—	(4)
	119	**(2,106)**	—	(3,674)
	22,563	**(15,652)**	24,395	(26,155)
Of which – current	**12,583**	**(5,250)**	11,554	(12,618)
– non-current	**9,980**	**(10,402)**	12,841	(13,537)

[a] Includes embedded derivatives for which the critical terms are matched by standalone derivatives that are also classified as held for trading.

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
							2023
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Currency derivatives	**95**	**31**	**38**	**33**	**28**	**253**	**478**
Oil price derivatives	**1,423**	**206**	**81**	**52**	**41**	**56**	**1,859**
Natural gas price derivatives	**8,705**	**1,412**	**625**	**458**	**426**	**3,124**	**14,750**
Power price derivatives	**2,339**	**961**	**513**	**360**	**250**	**932**	**5,355**
Other derivatives	**—**	**—**	**—**	**—**	**—**	**2**	**2**
	12,562	**2,610**	**1,257**	**903**	**745**	**4,367**	**22,444**

							$ million
							2022
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	536	14	10	10	9	55	634
Oil price derivatives	1,971	445	150	63	35	89	2,753
Natural gas price derivatives	7,157	3,740	749	442	316	3,033	15,437
Power price derivatives	1,848	1,317	623	376	291	1,072	5,527
Other derivatives	42	—	—	—	—	2	44
	11,554	5,516	1,532	891	651	4,251	24,395

30. Derivative financial instruments – continued

Derivative liabilities held for trading have the following fair values and maturities.

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
							$ million
							2023
Currency derivatives	**(341)**	**(3)**	**(405)**	**(166)**	**(7)**	**(589)**	**(1,511)**
Oil price derivatives	**(1,047)**	**(61)**	**(14)**	**(4)**	**(1)**	**(12)**	**(1,139)**
Natural gas price derivatives	**(2,126)**	**(796)**	**(473)**	**(348)**	**(293)**	**(2,672)**	**(6,708)**
Power price derivatives	**(1,692)**	**(666)**	**(413)**	**(306)**	**(227)**	**(883)**	**(4,187)**
	(5,206)	**(1,526)**	**(1,305)**	**(824)**	**(528)**	**(4,156)**	**(13,545)**

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
							$ million
							2022
Currency derivatives	(587)	(95)	(3)	(629)	(319)	(713)	(2,346)
Oil price derivatives	(1,615)	(318)	(23)	(4)	(1)	—	(1,961)
Natural gas price derivatives	(7,255)	(1,157)	(539)	(328)	(214)	(2,636)	(12,129)
Power price derivatives	(2,924)	(1,002)	(506)	(335)	(273)	(964)	(6,004)
	(12,381)	(2,572)	(1,071)	(1,296)	(807)	(4,313)	(22,440)

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.

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
							$ million
							2023
Fair value of derivative assets							
Level 1	**98**	**41**	**11**	**1**	**—**	**—**	**151**
Level 2	**12,802**	**1,857**	**557**	**236**	**124**	**130**	**15,706**
Level 3	**1,765**	**1,063**	**784**	**699**	**638**	**4,263**	**9,212**
	14,665	**2,961**	**1,352**	**936**	**762**	**4,393**	**25,069**
Less: netting by counterparty	**(2,103)**	**(351)**	**(95)**	**(33)**	**(17)**	**(26)**	**(2,625)**
	12,562	**2,610**	**1,257**	**903**	**745**	**4,367**	**22,444**
Fair value of derivative liabilities							
Level 1	**(70)**	**(44)**	**(11)**	**(1)**	**—**	**—**	**(126)**
Level 2	**(6,051)**	**(1,127)**	**(844)**	**(365)**	**(93)**	**(500)**	**(8,980)**
Level 3	**(1,188)**	**(706)**	**(545)**	**(491)**	**(452)**	**(3,682)**	**(7,064)**
	(7,309)	**(1,877)**	**(1,400)**	**(857)**	**(545)**	**(4,182)**	**(16,170)**
Less: netting by counterparty	**2,103**	**351**	**95**	**33**	**17**	**26**	**2,625**
	(5,206)	**(1,526)**	**(1,305)**	**(824)**	**(528)**	**(4,156)**	**(13,545)**
Net fair value	**7,356**	**1,084**	**(48)**	**79**	**217**	**211**	**8,899**

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
							$ million
							2022
Fair value of derivative assets							
Level 1	207	17	19	4	—	—	247
Level 2	17,161	5,628	935	289	77	65	24,155
Level 3	1,525	1,014	783	659	601	4,215	8,797
	18,893	6,659	1,737	952	678	4,280	33,199
Less: netting by counterparty	(7,339)	(1,143)	(205)	(61)	(27)	(29)	(8,804)
	11,554	5,516	1,532	891	651	4,251	24,395
Fair value of derivative liabilities							
Level 1	(281)	(20)	(22)	(7)	—	—	(330)
Level 2	(18,116)	(2,901)	(702)	(915)	(437)	(805)	(23,876)
Level 3	(1,323)	(794)	(552)	(435)	(397)	(3,537)	(7,038)
	(19,720)	(3,715)	(1,276)	(1,357)	(834)	(4,342)	(31,244)
Less: netting by counterparty	7,339	1,143	205	61	27	29	8,804
	(12,381)	(2,572)	(1,071)	(1,296)	(807)	(4,313)	(22,440)
Net fair value	(827)	2,944	461	(405)	(156)	(62)	1,955

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 2023	**28**	**905**	**(524)**	**61**	**44**	**514**
Gains (losses) recognized in the income statement	**79**	**19**	**379**	**161**	**29**	**667**
Settlements	**13**	**(320)**	**86**	**(3)**	**(71)**	**(295)**
Transfers out of level 3	**(13)**	**(5)**	**(61)**	**—**	**—**	**(79)**
Net fair value of contracts at 31 December 2023	**107**	**599**	**(120)**	**219**	**2**	**807**
Deferred day-one gains (losses)						**1,341**
Derivative asset (liability)						**2,148**

						$ million
	Oil price	Natural gas price	Power price	Currency	Other	Total
Fair value contracts at 1 January 2022	199	534	40	(154)	10	629
Gains (losses) recognized in the income statement	17	508	334	215	34	1,108
Purchases[a]	—	(4)	(889)	—	—	(893)
Settlements	(73)	(210)	(32)	—	—	(315)
Transfers out of level 3	(115)	77	23	—	—	(15)
Net fair value of contracts at 31 December 2022	28	905	(524)	61	44	514
Deferred day-one gains (losses)						1,245
Derivative asset (liability)						1,759

[a] Primarily relates to the acquisition of EDF Energy Services.

The amount recognized in the income statement for the year relating to level 3 held-for-trading derivatives still held at 31 December 2023 was a $631 million gain (2022 $1,223 million gain related to derivatives still held at 31 December 2022).

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 $19,786 million (2022 $7,829 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 recognised in the financial statements when associated cargoes are lifted. The embedded value in these contracts is not recognised and is subject to underlying commodity price volatility, as observed during 2022 and 2023. bp realised significant profits in 2023 as LNG cargoes were delivered. 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 year ended 31 December 2023, there were material gains recognized on the associated derivative positions due to the movement in the underlying commodity prices. For the year ended 31 December 2022, there were no material gains or losses recorded on the associated derivative positions. For additional information, details of management's internal measure of performance are given in the Group Performance Report on page 35 and on page 338.

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 $632 million (2022 $1,280 million net loss and 2021 $775 million net loss). 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 2023, 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.

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.

30. Derivative financial instruments – continued

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 2023			
Cash flow hedges			
Foreign exchange risk			
Highly probable forecast capital expenditure	**1**	**(1)**	**—**
Commodity price risk			
Highly probable forecast sales	**1,065**	**(1,065)**	**—**
At 31 December 2022			
Cash flow hedges			
Foreign exchange risk			
Highly probable forecast capital expenditure	—	—	—
Commodity price risk			
Highly probable forecast sales	(825)	825	—

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		
At 31 December 2023	$ million	$ million	$ million	mmBtu
Cash flow hedges				
Foreign exchange risk				
Highly probable forecast capital expenditure	**–**	**(1)**	**318**	
Commodity price risk				
Highly probable forecast sales	**–**	**–**		**(392)**
At 31 December 2022				
Cash flow hedges				
Foreign exchange risk				
Highly probable forecast capital expenditure	–	–	5	
Commodity price risk				
Highly probable forecast sales	–	–		(469)

All hedging instruments are presented within derivative financial instruments on the group balance sheet.

All of the nominal amount of hedging instruments at 31 December 2023 and 2022 relating to highly probable forecast capital expenditure matures within 12 months of the relevant balance sheet date. All of the nominal amount of hedging instruments at 31 December 2023 relating to highly probable forecast sales matures within 12 months (2022 349 mmBtu within 12 months and 120 mmBtu within one to two years) of the relevant balance sheet date.

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			
	2023		2022	
At 31 December	**Forecast capital expenditure**	**Forecast sales**	Forecast capital expenditure	Forecast sales
Sterling/US dollar	**1.27**		1.25	
Euro/US dollar	**1.11**		–	
Henry Hub $/mmBtu		**4.02**		4.03

Fair value hedges

At 31 December 2023, 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, Swiss franc, Canadian 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.

bp's fair value hedge accounting relationships have been directly affected by interest rate benchmark reform. Prior to 2023, the group's swaps which reference interest rates were primarily exposed to 3 month USD LIBOR. During 2023, all the swaps that previously referenced USD LIBOR transitioned to referencing SOFR through activation of the ISDA fallback clauses. The transition was enacted on an 'economically equivalent' basis. No other changes were made to the terms of swap contracts upon transition to SOFR. The hedge relationships were not discontinued and SOFR is now assessed as the hedged interest rate benchmark risk. The interest rate benchmark reform did not change the risk management strategy for fair value hedges. New derivative hedging instruments are being executed based on the new risk free rates.

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
At 31 December 2023	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)
Fair value hedges			
Interest rate risk on finance debt	**–**	**–**	**–**
Interest rate and foreign currency risk on finance debt	**(1,417)**	**1,356**	**61**
At 31 December 2022			
Fair value hedges			
Interest rate risk on finance debt	26	(27)	1
Interest rate and foreign currency risk on finance debt	3,519	(3,495)	(24)

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		Nominal amounts of hedging instruments
At 31 December 2023	Assets	Liabilities	
Fair value hedges			
Interest rate risk on finance debt	**–**	**(4)**	**387**
Interest rate and foreign currency risk on finance debt	**119**	**(2,102)**	**16,862**
At 31 December 2022			
Fair value hedges			
Interest rate risk on finance debt	–	(4)	368
Interest rate and foreign currency risk on finance debt	–	(3,670)	17,032

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.

30. Derivative financial instruments – continued

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
At 31 December 2023	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	5-10 years	Over 10 years	Total
Fair value hedges								
Interest rate risk on finance debt	**239**	**—**	**148**	**—**	**—**	**—**	**—**	**387**
Interest rate and foreign currency risk on finance debt	**1,857**	**1,716**	**1,933**	**1,441**	**1,741**	**4,164**	**4,010**	**16,862**
At 31 December 2022								
Fair value hedges								
Interest rate risk on finance debt	—	216	—	152	—	—	—	368
Interest rate and foreign currency risk on finance debt	1,307	2,238	1,971	2,244	1,845	4,869	2,558	17,032

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		2023		2022
	Interest rate swaps	Cross-currency interest rate swaps	Interest rate swaps	Cross-currency interest rate swaps
Interest rate	**3.49 %**	**7.35 %**	2.48 %	6.23 %
Sterling/US dollar		**1.27**		1.36
Euro/US dollar		**1.13**		1.13
Canadian dollar/US dollar		**0.78**		0.78

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		
At 31 December 2023	Liabilities	Assets	Liabilities	Discontinued hedges
Fair value hedges				
Interest rate risk on finance debt	**(426)**	**4**	**—**	**(237)**
Interest rate and foreign currency risk on finance debt	**(16,834)**	**1,512**	**—**	**—**
At 31 December 2022				
Fair value hedges				
Interest rate risk on finance debt	(422)	4	—	(337)
Interest rate and foreign currency risk on finance debt	(17,003)	2,312	—	—

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	Purchase of equity	Interest rate and foreign currency risk on finance debt	Total
At 1 January 2023	**—**	**(108)**	**—**	**(104)**	**(212)**
Recognized in other comprehensive income					
Cash flow hedges marked to market	**15**	**1,065**	**—**	**—**	**1,080**
Cash flow hedges reclassified to the income statement - hedged item affected profit or loss	**—**	**(428)**	**—**	**—**	**(428)**
Costs of hedging marked to market	**—**	**—**	**—**	**(67)**	**(67)**
Costs of hedging reclassified to the income statement	**—**	**—**	**—**	**(11)**	**(11)**
	15	**637**	**—**	**(78)**	**574**
Cash flow hedges transferred to the balance sheet	**(1)**	**—**	**—**	**—**	**(1)**
At 31 December 2023	**14**	**529**	**—**	**(182)**	**361**

					$ million
	Cash flow hedge reserve			Costs of hedging reserve	
	Highly probable forecast capital expenditure	Highly probable forecast sales	Purchase of equity[a]	Interest rate and foreign currency risk on finance debt	Total
At 1 January 2022	3	(134)	(651)	(190)	(972)
Recognized in other comprehensive income					
Cash flow hedges marked to market	(4)	(825)	—	—	(829)
Cash flow hedges reclassified to the income statement - hedged item affected profit or loss	—	851	651	—	1,502
Costs of hedging marked to market	—	—	—	61	61
Costs of hedging reclassified to the income statement	—	—	—	25	25
	(4)	26	651	86	759
Cash flow hedges transferred to the balance sheet	1	—	—	—	1
At 31 December 2022	—	(108)	—	(104)	(212)

[a] Relates to the acquisition of an 18.5% interest in Rosneft in 2013.

Substantially all of the cash flow hedge reserve balances at 31 December 2023 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.

In 2022 all of the cash flow hedge reserve related to the purchase of equity was reclassified to the income statement following bp's decision to exit its shareholding in Rosneft. The amount reclassified is presented in net impairment and losses on sale of businesses and fixed assets in the 2022 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:

	2023		2022		2021	
Issued	Shares thousand	$ million	Shares thousand	$ million	Shares thousand	$ million
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	19,097,783	4,774	20,778,082	5,194	21,449,782	5,362
Issue of new shares for employee share-based payment plans	66,000	17	55,000	14	35,001	9
Issue of new shares – other[b]	—	—	165,105	41	—	—
Repurchase of ordinary share capital	(1,262,983)	(316)	(1,900,404)	(475)	(706,701)	(177)
At 31 December	17,900,800	4,475	19,097,783	4,774	20,778,082	5,194
		4,496		4,795		5,215

[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.

[b] 165 million new ordinary shares were issued in April 2022 as non-cash consideration for the acquisition of the public units of BP Midstream Partners LP.

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 2023 the company repurchased 1,263 million ordinary shares for a total consideration of $7,918 million, including transaction costs of $43 million. All shares purchased were for cancellation. The repurchased shares represented 7.1% of ordinary share capital. A further 156 million ordinary shares were repurchased between the end of the reporting period and 16 February 2024, the latest practicable date before the completion of these financial statements, for a total cost of $922 million of which $746 million has been accrued at 31 December 2023. The number of shares in issue is reduced when shares are repurchased.

Treasury shares[a]

	2023		2022		2021	
	Shares thousand	Nominal value $ million	Shares thousand	Nominal value $ million	Shares thousand	Nominal value $ million
At 1 January	1,124,927	281	1,137,457	283	1,187,650	296
Purchases for settlement of employee share plans	24,688	6	14,150	4	1,432	—
Issue of new shares for employee share-based payment plans	71,039	19	55,000	14	35,096	9
Shares re-issued for employee share-based payment plans	(143,575)	(35)	(81,680)	(20)	(86,721)	(22)
At 31 December	1,077,079	271	1,124,927	281	1,137,457	283
Of which – shares held in treasury by bp	726,339	183	940,571	235	1,037,201	259
– shares held in ESOP trusts	350,704	88	184,356	46	100,256	24
– shares held by bp's US share plan administrator[b]	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 4.9% (2022 5.0% and 2021 5.2%) of the called-up ordinary share capital of the company.

During 2023, the movement in shares held in treasury by bp represented 1.1% (2022 less than 0.5% and 2021 less than 0.3%) of the ordinary share capital of the company.

32. Capital and reserves

	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-retirement 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**
At 1 January 2022	5,215	12,745	1,705	27,206	46,871
Profit (loss) for the year	–	–	–	–	–
Items that may be reclassified subsequently to profit or loss					
Currency translation differences (including reclassifications)[b]	–	–	–	–	–
Cash flow hedges and costs of hedging (including reclassifications)[c]	–	–	–	–	–
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-retirement benefit liability or asset	–	–	–	–	–
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	–	–	–	–	–
Issue of ordinary share capital	41	779	–	–	820
Repurchases of ordinary share capital	(475)	–	475	–	–
Share-based payments, net of tax[a]	14	168	–	–	182
Issue of perpetual hybrid bonds	–	–	–	–	–
Payments on perpetual hybrid bonds	–	–	–	–	–
Transactions involving non-controlling interests, net of tax	–	–	–	–	–
At 31 December 2022	4,795	13,692	2,180	27,206	47,873

[a] Movements in treasury shares relate to employee share-based payment plans.
[b] Following bp's decision to exit its shareholding in Rosneft on 27 February 2022, $10,372 million was reclassified to the income statement.
[c] Following bp's decision to exit its shareholding in Rosneft on 27 February 2022 $651 million was reclassified to the income statement.

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
(12,624)	(9,572)	–	(851)	(176)	(1,027)	51,815	75,463	13,041	1,935	90,439
–	–	–	–	–	–	(2,487)	(2,487)	519	611	(1,357)
–	6,914	–	–	–	–	–	6,914	–	(61)	6,853
–	–	–	671	103	774	–	774	–	–	774
–	–	–	–	–	–	402	402	–	–	402
–	–	–	–	–	–	(225)	(225)	–	–	(225)
–	–	–	–	–	–	408	408	–	–	408
–	–	–	(4)	–	(4)	–	(4)	–	–	(4)
–	6,914	–	667	103	770	(1,902)	5,782	519	550	6,851
–	–	–	–	–	–	(4,365)	(4,365)	–	(294)	(4,659)
–	–	–	1	–	1	–	1	–	–	1
–	–	–	–	–	–	–	820	–	–	820
–	–	–	–	–	–	(10,493)	(10,493)	–	–	(10,493)
471	–	–	–	–	–	194	847	–	–	847
–	–	–	–	–	–	(4)	(4)	374	–	370
–	15	–	–	–	–	–	15	(544)	–	(529)
–	–	–	–	–	–	(513)	(513)	–	(144)	(657)
(12,153)	(2,643)	–	(183)	(73)	(256)	34,732	67,553	13,390	2,047	82,990

32. Capital and reserves – continued

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Total share capital and capital reserves
At 1 January 2021	5,383	12,584	1,528	27,206	46,701
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	—	—	—	—	—
Other	—	—	—	—	—
Items that will not be reclassified to profit or loss					
Remeasurements of the net pension and other post-retirement benefit liability or asset	—	—	—	—	—
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	(177)	—	177	—	—
Share-based payments, net of tax[a]	9	161	—	—	170
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[b]	—	—	—	—	—
At 31 December 2021	5,215	12,745	1,705	27,206	46,871

[a] Movements in treasury shares relate to employee share-based payment plans.

[b] Principally relates to the sale of 49% interest in a controlled affiliate holding certain refined product and crude logistics assets onshore US and the buy-out of the non-controlling interest in the Thorntons fuels and convenience retail business. .

32. Capital and reserves – continued

$ million

Treasury shares	Foreign currency translation reserve	Cash flow hedges	Costs of hedging	Total fair value reserves	Profit and loss account	bp shareholders' equity	Non-controlling interests: Hybrid bonds	Non-controlling interests: Other interest	Total equity
(13,224)	(8,719)	(708)	(100)	(808)	47,300	71,250	12,076	2,242	85,568
—	—	—	—	—	7,565	7,565	507	415	8,487
—	(846)	—	—	—	—	(846)	—	(24)	(870)
—	—	(134)	(76)	(210)	—	(210)	—	—	(210)
—	—	—	—	—	44	44	—	—	44
—	—	—	—	—	1	1	—	—	1
—	—	—	—	—	3,099	3,099	—	—	3,099
—	—	1	—	1	—	1	—	—	1
—	(846)	(133)	(76)	(209)	10,709	9,654	507	391	10,552
—	—	—	—	—	(4,316)	(4,316)	—	(311)	(4,627)
—	—	(10)	—	(10)	—	(10)	—	—	(10)
—	—	—	—	—	(3,151)	(3,151)	—	—	(3,151)
600	—	—	—	—	(138)	632	—	—	632
—	—	—	—	—	556	556	—	—	556
—	—	—	—	—	(26)	(26)	950	—	924
—	(7)	—	—	—	—	(7)	(492)	—	(499)
—	—	—	—	—	881	881	—	(387)	494
(12,624)	(9,572)	(851)	(176)	(1,027)	51,815	75,463	13,041	1,935	90,439

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 fair value of the consideration given in excess of the nominal value of the ordinary shares issued in an acquisition made by the issue of shares.

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 issued by BP Capital Markets p.l.c., a group subsidiary, on 17 June 2020 in euro, sterling and US dollars for a US dollar equivalent amount of $11.9 billion. The hybrid bonds include redemption options exercisable at the group's discretion from June 2025 to March 2030 (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 September 2025 to June 2030 at rates of 3.25% to 4.875% and reset to rates determined by the contractual terms of each instrument on certain dates thereafter. The contractual terms of the hybrid bonds allow the group to defer coupon payments and the repayment of principal indefinitely, however their terms and conditions stipulate that any deferred payments must be made in the event of an announcement of an ordinary share or parity equity dividend distribution or certain share repurchases or redemptions. Payments made to and profit attributed to these hybrid bond holders in the year totalled $477 million (2022 $468 million and 2021 $499 million) and $473 million (2022 $468 million and 2021 $497 million) respectively. The accumulated non-controlling interest at the end of the year was $12,066 million (2022 $12,066 million). On 26 February BP Capital Markets p.l.c. issued a further $1.3 billion of US dollar perpetual subordinated hybrid bonds with a coupon fixed for an initial period up to 2034 of 6.45%. On 26 February BP Capital Markets p.l.c. announced its intent to voluntarily buy back up to $1.3 billion of the non-call 2025 4.375% US dollar hybrid bonds issued in 2020. Taken together these transactions are not expected to have a significant impact on net debt or gearing.

Non-controlling interests also includes perpetual subordinated hybrid securities issued during 2023, 2022 and 2021 by a group subsidiary. The proceeds from these issuances were specifically earmarked to fund the forward purchase and leaseback of an under-construction floating, production, storage, and offloading vessel (FPSO) to be used on one of the group's major projects. The contractual terms of these instruments allow the group to defer interest payments and repayment of principal indefinitely however their terms and conditions stipulate that the group must purchase them on the occurrence of certain events, all within the group's control, including the declaration or payment of a BP p.l.c. distribution after mid-May 2026. Payments made to and profit attributed to these hybrid security holders in the year totalled $114 million (2022 $61 million) and $113 million (2022 $51 million) respectively. The accumulated non-controlling interest at the end of the year was $1,500 million (2022 $1,324 million).

As the group has the unconditional right to avoid transferring cash or another financial asset in relation to these hybrid bonds and securities, they are classified as equity instruments and reported within non-controlling interests in the consolidated financial statements.

32. Capital and reserves – continued

The pre-tax amounts of each component of other comprehensive income, and the related amounts of tax, are shown in the table below.

			$ 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-retirement 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)**

			$ million
			2022
	Pre-tax	Tax	Net of tax
Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including reclassifications)	6,973	(120)	6,853
Cash flow hedges (including reclassifications)	677	(6)	671
Costs of hedging (including reclassifications)	86	17	103
Share of items relating to equity-accounted entities, net of tax	402	—	402
Other	—	(225)	(225)
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension and other post-retirement benefit liability or asset	340	68	408
Cash flow hedges that will subsequently be transferred to the balance sheet	(4)	—	(4)
Other comprehensive income	8,474	(266)	8,208

			$ million
			2021
	Pre-tax	Tax	Net of tax
Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including reclassifications)	(885)	15	(870)
Cash flow hedges (including reclassifications)	(175)	41	(134)
Costs of hedging (including reclassifications)	(84)	8	(76)
Share of items relating to equity-accounted entities, net of tax	44	—	44
Other	—	1	1
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension and other post-retirement benefit liability or asset	4,416	(1,317)	3,099
Cash flow hedges that will subsequently be transferred to the balance sheet	1	—	1
Other comprehensive income	3,317	(1,252)	2,065

33. Contingent liabilities and legal proceedings

Contingent liabilities

There were contingent liabilities at 31 December 2023 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.

33. Contingent liabilities and legal proceedings – continued

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 $16 billion (2022 $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 Mexico 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

Introduction

BP Exploration & Production Inc. (BPXP) was lease operator of Mississippi Canyon, Block 252 in the Gulf of Mexico, 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 are discussed below.

Medical Benefits Class Action Settlement

In 2012 the Medical Benefits Class Action Settlement (Medical Settlement) was entered into with the plaintiffs steering committee. It includes an exclusive remedy provision regarding class members pursuing exposure-based personal injury claims for later-manifested physical conditions (LMPCs). As of 31 December 2023, there were 60 pending lawsuits brought by class members claiming LMPCs.

Other civil complaints – personal injury

The vast majority of post-explosion clean-up, medical monitoring and personal injury claims from individuals that either opted out of the Medical Settlement and/or were excluded from that settlement have been dismissed (including more than 600 cases in which the courts granted BPXP's motions for summary judgment). As of 31 December 2023, 88 cases remained pending in the district courts and around 100 appeals filed to the Fifth Circuit in cases where the district courts have granted summary judgment in favour of bp also remain pending.

Non-US government lawsuits

Two class actions are pending in Mexican Federal District Courts against various bp group entities including BPXP and BP America Production Company by separate plaintiff classes. Although the two actions are separate, both broadly seek penalties, damages and compensation for alleged environmental, health and economic harm in Mexico as a result of the Incident. One of the actions also seeks an order requiring the bp defendants to repair alleged damage to the Gulf of Mexico.

bp has answered the complaints in both actions by seeking dismissal on various grounds including that no oil reached Mexican waters or land and there was no economic or environmental harm in Mexico.

These legal actions remain at a relatively early stage and while it is not possible to predict the outcome, bp believes that it has valid defences, and it intends to defend such actions vigorously.

33. Contingent liabilities and legal proceedings – continued

Other legal proceedings

FERC and CFTC matters

Following an investigation by the US Federal Energy Regulatory Commission (FERC) and the US Commodity Futures Trading Commission (CFTC) of several bp entities, the Administrative Law Judge of the FERC ruled on 13 August 2015 that bp manipulated the market by selling next-day, fixed price natural gas at Houston Ship Channel in 2008 in order to suppress the Gas Daily index and benefit its financial position. In 2016, the FERC issued an Order affirming that decision and directing bp to pay a civil penalty of $20.16 million and to disgorge $207,169 in unjust profits. Following an appeal by bp to the US Court of Appeals, the Fifth Circuit issued an opinion upholding the FERC's manipulation finding on a few trades. The Fifth Circuit also found that the FERC did not have jurisdiction over most of the transactions identified as being violations. In July 2023, bp and FERC reached a settlement agreement that reduced the civil penalty to $10.75 million and fully resolved all claims by the FERC related to the matter.

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 over 20 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. Over the last several years, defendants removed each lawsuit to federal court and the removals were contested by plaintiffs, eventually resulting in multiple decisions by several Circuit Court of Appeals rejecting defendants' attempts to have the cases moved to federal court. In 2023, the US Supreme Court declined to review the various Circuit Court of Appeals decisions. Accordingly, the cases will proceed in the various state courts. Due to these jurisdictional challenges, the lawsuits all remain at relatively early stages. 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 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. Defendants' petition for writ of certiorari to the US Supreme Court seeking review of the US Fifth Circuit's Riverwood decision was denied in early 2023. There is a small subset of the removed cases in which the defendants continue to contest jurisdiction and await a final ruling from the Fifth Circuit on a related "federal officer" removal jurisdiction theory.

Following remand, the state court in the other lead case of Cameron Parish v. Auster et al., in which bp was the principal defendant, had established a November 2023 trial date. Before trial commenced during the fourth quarter 2023, bp entered into a settlement agreement and release with the plaintiffs in respect of all claims arising within Cameron Parish. The terms of the settlement agreement and release are confidential and bp does not expect those terms to have a significant effect on the company's financial position or profitability.

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.

All of the other remanded cases remain at early stages in the litigation. 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
	2023	2022	2021
Total for all directors			
Emoluments	**8**	8	9
Amounts received under incentive schemes[a]	**6**	13	4
Total	**14**	21	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.

Further information

Full details of individual directors' remuneration are given in the Directors' remuneration report on page 105.

Remuneration of directors and senior management

			$ million
	2023	2022	2021
Total for all senior management and non-executive directors			
Short-term employee benefits	**31**	31	30
Pensions and other post-retirement benefits	**—**	—	1
Share-based payments[a]	**12**	31	32
Termination benefits	**—**	—	—
Total	**43**	62	63

[a] 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, see pages 86-87 for further information.

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-retirement benefits

The amounts represent the estimated cost to the group of providing pensions and other post-retirement 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 2023 to 16 February 2024.

35. Employee costs and numbers

Employee costs	2023	2022	2021
			$ million
Wages and salaries[a]	**7,835**	7,486	6,934
Social security costs	**943**	720	733
Share-based payments[b]	**1,131**	1,034	733
Pension and other post-retirement benefit costs	**370**	576	457
	10,279	9,816	8,857

			2023			2022			2021
Average number of employees[c]	US	Non-US	Total	US	Non-US	Total	US	Non-US	Total
gas & low carbon energy	**900**	**3,700**	**4,600**	700	3,400	4,100	400	3,400	3,800
oil production & operations	**3,100**	**5,500**	**8,600**	3,000	5,700	8,700	3,100	6,000	9,100
customers & products[d]	**19,500**	**36,300**	**55,800**	8,000	35,700	43,700	6,200	35,800	42,000
other businesses and corporate	**1,400**	**9,000**	**10,400**	1,300	8,500	9,800	1,400	7,700	9,100
	24,900	**54,500**	**79,400**	13,000	53,300	66,300	11,100	52,900	64,000

a Includes termination costs of $96 million (2022 $27 million and 2021 $74 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 33,800 (2022 23,300 and 2021 21,300) service station staff.

36. Auditor’s remuneration

Fees	2023	2022	2021
			$ million
The audit of the company annual accounts[a]	**38**	36	37
The audit of accounts of subsidiaries of the company	**15**	15	15
Total audit	**53**	51	52
Audit-related assurance services[b]	**4**	4	5
Total audit and audit-related assurance services	**57**	55	57
Non-audit and other assurance services	**3**	—	—
Services relating to bp pension plans	**1**	1	1
	61	56	58

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.

2023 includes $0.2 million of additional fees for 2022. 2022 includes $0.3 million of additional fees for 2021. 2021 includes $1.0 million of additional fees for 2020. 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 2023 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.

Under SEC regulations, the remuneration of the auditor of $61 million (2022 $56 million and 2021 $58 million) is required to be presented as follows: audit $53 million (2022 $51 million and 2021 $52 million); other audit-related $4 million (2022 $4 million and 2021 $5 million); tax $nil (2022 $nil and 2021 $nil); and all other fees $4 million (2022 $1 million and 2021 $1 million).

37. Subsidiaries, joint arrangements and associates[a]

The more important subsidiaries, joint arrangements and associates of the group at 31 December 2023 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 14 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
*Burmah Castrol PLC	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
Egypt			
BP Exploration (Delta) 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
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	%	Country of incorporation	Principal activities
Angola			
Azule Energy Holdings Limited	50	England & Wales	Exploration and production

[a] There were no important associates in the group at 31 December 2023.

38. Events after the reporting period

On 14 February 2024 bp announced that it had agreed to form a new joint venture in Egypt with ADNOC (bp 51%, ADNOC 49%). As part of the agreement bp will contribute its interests in three non-operated development concessions as well as exploration agreements in Egypt, and ADNOC will make a proportionate cash contribution. Formation of the joint venture and completion of these transactions is subject to regulatory approval. From 14 February 2024 the associated carrying values of these interests have been determined to meet the criteria to be classified as assets held for sale under IFRS 5 Non-current Assets Held for Sale and Discontinued Operations. The carrying value of fixed assets associated with these interests at 31 December 2023 was $1.4 billion. The impacts are expected to be reflected in the group's first quarter 2024 interim financial statements.

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 342-350.

[a] See Note 1 - Investment in Rosneft.

Oil and natural gas exploration and production activities

									$ 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	41,351	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 Mexico 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, 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

	Europe		North America		South America	Africa	Asia	Australasia	Total
2023	UK	Rest of Europe	US	Rest of North America					
Equity-accounted entities (bp share)									
Capitalized costs at 31 December[a] [b]									
Gross capitalized costs									
Proved properties	–	4,432	–	–	12,530	8,590	9,947	–	35,499
Unproved properties	–	652	–	–	125	372	–	–	1,149
	–	5,084	–	–	12,655	8,962	9,947	–	36,648
Accumulated depreciation	–	2,420	–	–	6,807	1,812	1,696	–	12,735
Net capitalized costs	–	2,664	–	–	5,848	7,150	8,251	–	23,913
Costs incurred for the year ended 31 December[a c d]									
Acquisition of properties[b]									
Proved	–	–	–	–	–	–	–	–	–
Unproved	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–
Exploration and appraisal costs[c]	–	42	–	–	7	44	–	–	93
Development	–	584	–	–	687	844	942	–	3,057
Total costs	–	626	–	–	694	888	942	–	3,150
Results of operations for the year ended 31 December[a]									
Sales and other operating revenues[e]									
Third parties	–	2,159	–	–	2,070	2,550	1,716	–	8,495
Sales between businesses	–	–	–	–	–	–	–	–	–
	–	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)	–	21	–	–	257	239	8	–	525
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	2,121	1,526	–	6,229
Profit (loss) before taxation	–	1,332	–	–	315	429	190	–	2,266
Allocable taxes	–	1,124	–	–	127	173	117	–	1,541
Results of operations	–	208	–	–	188	256	73	–	725

[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, 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
										2022
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[h]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
Capitalized costs at 31 December[a b]										
Gross capitalized costs										
Proved properties	30,010	—	65,870	6	16,720	20,257	—	39,899	6,324	179,086
Unproved properties	397	—	2,976	1,875	2,507	2,535	—	1,622	659	12,571
	30,407	—	68,846	1,881	19,227	22,792	—	41,521	6,983	191,657
Accumulated depreciation	21,757	—	38,205	1,586	13,849	18,207	—	21,642	4,588	119,834
Net capitalized costs	8,650	—	30,641	295	5,378	4,585	—	19,879	2,395	71,823
Costs incurred for the year ended 31 December[a b]										
Acquisition of properties										
Proved	12	—	183	—	—	—	—	245	—	440
Unproved	—	—	37	164	2	14	—	—	—	217
	12	—	220	164	2	14	—	245	—	657
Exploration and appraisal costs[c]	39	—	288	137	235	103	—	73	17	892
Development	318	—	3,825	15	483	1,378	—	1,555	176	7,750
Total costs	369	—	4,333	316	720	1,495	—	1,873	193	9,299
Results of operations for the year ended 31 December[a]										
Sales and other operating revenues[d]										
Third parties	549	—	2,101	420	2,977	3,836	—	6,551	1,588	18,022
Sales between businesses	5,747	—	12,746	—	538	2,146	—	9,932	1,472	32,581
	6,296	—	14,847	420	3,515	5,982	—	16,483	3,060	50,603
Exploration expenditure	11	—	144	109	172	57	—	94	(2)	585
Production costs	498	—	2,102	83	327	592	—	723	107	4,432
Production taxes	1	—	194	—	513	—	—	1,544	73	2,325
Other costs (income)[e]	(210)	(47)	2,926	63	96	206	32	(44)	300	3,322
Depreciation, depletion and amortization	1,242	—	3,122	18	680	2,075	1	2,495	384	10,017
Net impairments and (gains) losses on sale of businesses and fixed assets[f]	(433)	(901)	217	(3)	1,570	(1,189)	1,523	(341)	(43)	400
	1,109	(948)	8,705	270	3,358	1,741	1,556	4,471	819	21,081
Profit (loss) before taxation[g]	5,187	948	6,142	150	157	4,241	(1,556)	12,012	2,241	29,522
Allocable taxes	4,443	—	1,409	50	1,814	886	(5)	6,651	842	16,090
Results of operations	744	948	4,733	100	(1,657)	3,355	(1,551)	5,361	1,399	13,432

[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 Mexico 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, 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 $256-million gain which is offset by corresponding charges primarily in the US region, relating to the group self-insurance programme.

[f] Russia impairments include other businesses with Rosneft, which were reported in the oil production and operation segment. The Rosneft impairment is reported in the other businesses and corporate segment.

[g] Excludes the unwinding of the discount on provisions and payables amounting to $294 million which is included in finance costs in the group income statement.

[h] An amendment has been made to correctly present offsetting movements in proved properties cost and depreciation, The amendment has no impact on reported profit or net book amounts of total proved properties.

Oil and natural gas exploration and production activities – continued

										$ million
										2022
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia[a]	Rest of Asia		
Equity-accounted entities (bp share)										
Capitalized costs at 31 December[b c]										
Gross capitalized costs										
Proved properties	—	3,739	—	—	12,000	7,927	—	8,381	—	32,047
Unproved properties	—	611	—	—	120	371	—	—	—	1,102
	—	4,350	—	—	12,120	8,298	—	8,381	—	33,149
Accumulated depreciation	—	1,800	—	—	6,356	572	—	553	—	9,281
Net capitalized costs	—	2,550	—	—	5,764	7,726	—	7,828	—	23,868
Costs incurred for the year ended 31 December[b d e]										
Acquisition of properties[c]										
Proved	—	1,224	—	—	—	—	—	—	—	1,224
Unproved	—	204	—	—	—	—	—	—	—	204
	—	1,428	—	—	—	—	—	—	—	1,428
Exploration and appraisal costs[d]	—	46	—	—	22	60	28	—	—	156
Development[f]	—	(24)	—	—	673	292	428	625	—	1,994
Total costs	—	1,450	—	—	695	352	456	625	—	3,578
Results of operations for the year ended 31 December[b]										
Sales and other operating revenues[g]										
Third parties	—	2,050	—	—	2,171	1,137	—	829	—	6,187
Sales between businesses	—	—	—	—	—	—	6,052	—	—	6,052
	—	2,050	—	—	2,171	1,137	6,052	829	—	12,239
Exploration expenditure	—	39	—	—	—	7	13	—	—	59
Production costs	—	148	—	—	628	246	411	191	—	1,624
Production taxes	—	—	—	—	397	15	4,435	—	—	4,847
Other costs (income)	—	(6)	—	—	16	152	97	20	—	279
Depreciation, depletion and amortization	—	348	—	—	462	572	535	553	—	2,470
Net impairments and losses on sale of businesses and fixed assets	—	164	—	—	—	—	—	—	—	164
	—	693	—	—	1,503	992	5,491	764	—	9,443
Profit (loss) before taxation	—	1,357	—	—	668	145	561	65	—	2,796
Allocable taxes	—	1,098	—	—	77	81	109	66	—	1,431
Results of operations	—	259	—	—	591	64	452	(1)	—	1,365

a Amounts reported for Russia in this table are bp's estimated share of the equity-accounted entities, including Rosneft's worldwide activities (of which insignificant amounts relate to outside Russia).
b 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.
c Costs of decommissioning are included in capitalized costs at 31 December but are excluded from costs incurred for the year.
d Includes exploration and appraisal drilling expenditures, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.
e 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.
f Rest of Europe development costs are negative due to a true-up of prior period spend.
g Presented net of sales tax.

Oil and natural gas exploration and production activities – continued

										$ million
										2021
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[h]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
Capitalized costs at 31 December[a b]										
Gross capitalized costs										
Proved properties	30,285	—	62,901	3,385	16,351	51,157	—	45,767	6,641	216,487
Unproved properties	363	—	2,888	2,650	2,517	3,553	—	1,690	650	14,311
	30,648	—	65,789	6,035	18,868	54,710	—	47,457	7,291	230,798
Accumulated depreciation	21,293	—	34,895	5,008	14,393	46,187	—	26,607	4,617	153,000
Net capitalized costs	9,355	—	30,894	1,027	4,475	8,523	—	20,850	2,674	77,798
Costs incurred for the year ended 31 December[a b]										
Acquisition of properties										
Proved	—	—	81	—	—	—	—	—	—	81
Unproved	—	—	18	—	—	—	—	—	—	18
	—	—	99	—	—	—	—	—	—	99
Exploration and appraisal costs[c]	28	—	138	88	90	85	—	159	18	606
Development[d]	262	—	2,541	(50)	586	1,246	—	1,849	162	6,596
Total costs	290	—	2,778	38	676	1,331	—	2,008	180	7,301
Results of operations for the year ended 31 December[a]										
Sales and other operating revenues[e]										
Third parties	182	—	1,700	384	1,330	2,934	2	2,469	994	9,995
Sales between businesses	3,204	—	9,034	1	321	2,172	—	7,064	743	22,539
	3,386	—	10,734	385	1,651	5,106	2	9,533	1,737	32,534
Exploration expenditure	76	—	78	90	29	84	—	52	15	424
Production costs	653	—	1,953	121	371	781	—	967	121	4,967
Production taxes	(35)	—	108	—	266	—	—	918	51	1,308
Other costs (income)[f]	170	(2)	2,506	35	50	121	37	(12)	139	3,044
Depreciation, depletion and amortization	1,260	—	3,153	83	524	2,897	2	2,190	332	10,441
Net impairments and (gains) losses on sale of businesses and fixed assets	(755)	(124)	(1,599)	1,075	(693)	750	—	(2,762)	(1)	(4,109)
	1,369	(126)	6,199	1,404	547	4,633	39	1,353	657	16,075
Profit (loss) before taxation[g]	2,017	126	4,535	(1,019)	1,104	473	(37)	8,180	1,080	16,459
Allocable taxes	302	1	1,127	171	696	363	—	3,055	404	6,119
Results of operations	1,715	125	3,408	(1,190)	408	110	(37)	5,125	676	10,340

[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 Mexico 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, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.
[d] Development costs in Rest of North America are negative due to a true-up of prior period spend.
[e] Presented net of transportation costs, purchases and sales taxes.
[f] Includes property taxes and other government take. The UK region includes a $213-million gain which is offset by corresponding charges primarily in the US region, relating to the group self-insurance programme.
[g] Excludes the unwinding of the discount on provisions and payables amounting to $325 million which is included in finance costs in the group income statement.
[h] An amendment has been made to correctly present offsetting movements in proved properties cost and depreciation, The amendment has no impact on reported profit or net book amounts of total proved properties.

Oil and natural gas exploration and production activities – continued

										$ million
										2021
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia[a]	Rest of Asia		
Equity-accounted entities (bp share)										
Capitalized costs at 31 December[b c]										
Gross capitalized costs										
Proved properties	–	2,507	–	–	11,287	–	24,172	–	–	37,966
Unproved properties	–	383	–	–	98	–	4,362	–	–	4,843
	–	2,890	–	–	11,385	–	28,534	–	–	42,809
Accumulated depreciation	–	1,267	–	–	5,894	–	7,389	–	–	14,550
Net capitalized costs	–	1,623	–	–	5,491	–	21,145	–	–	28,259
Costs incurred for the year ended 31 December[b d e]										
Acquisition of properties[c]										
Proved	–	–	–	–	–	–	–	–	–	–
Unproved	–	–	–	–	–	–	75	–	–	75
	–	–	–	–	–	–	75	–	–	75
Exploration and appraisal costs[d]	–	60	–	–	8	–	196	–	–	264
Development	–	430	–	–	539	–	2,677	–	–	3,646
Total costs	–	490	–	–	547	–	2,948	–	–	3,985
Results of operations for the year ended 31 December[b]										
Sales and other operating revenues[f]										
Third parties	–	1,677	–	–	1,637	–	–	–	–	3,314
Sales between businesses	–	–	–	–	–	–	17,120	–	–	17,120
	–	1,677	–	–	1,637	–	17,120	–	–	20,434
Exploration expenditure	–	105	–	–	3	–	50	–	–	158
Production costs	–	222	–	–	487	–	1,335	–	–	2,044
Production taxes	–	–	–	–	308	–	9,291	–	–	9,599
Other costs (income)	–	26	–	–	34	–	293	–	–	353
Depreciation, depletion and amortization	–	347	–	–	404	–	1,633	–	–	2,384
Net impairments and losses on sale of businesses and fixed assets	–	108	–	–	(32)	–	191	–	–	267
	–	808	–	–	1,204	–	12,793	–	–	14,805
Profit (loss) before taxation	–	869	–	–	433	–	4,327	–	–	5,629
Allocable taxes	–	599	–	–	684	–	852	–	–	2,135
Results of operations	–	270	–	–	(251)	–	3,475	–	–	3,494

[a] Amounts reported for Russia in this table include bp's share of Rosneft's worldwide activities, including insignificant amounts outside Russia.
[b] 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.
[c] Costs of decommissioning are included in capitalized costs at 31 December but are excluded from costs incurred for the year.
[d] Includes exploration and appraisal drilling expenditures, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.
[e] 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.
[f] Presented net of sales tax.

Movements in estimated net proved reserves

million barrels

Crude oil[a b]	2023								
	Europe		North America		South America	Africa	Asia	Australasia	Total
	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

million barrels

Natural gas liquids[a b]									2023
	Europe		North America		South America	Africa	Asia	Australasia	Total
	UK	Rest of Europe	US[c]	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

million barrels

Total liquids[a b]									2023
	Europe		North America		South America	Africa	Asia	Australasia	Total
	UK	Rest of Europe	US[c]	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

billion cubic feet

Natural gas[a b]	Europe		North America		South America	Africa	Asia	Australasia	Total
2023	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

million barrels of oil equivalent[c]

Total hydrocarbons[a b]									2023
	Europe		North America		South America	Africa	Asia	Australasia	Total
	UK	Rest of Europe	US[f]	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 76 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

										million barrels
Crude oil[a b]										2022
	Europe		North America		South America	Africa[c]	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	178	–	705	24	5	117	–	930	28	1,987
Undeveloped	101	–	601	167	7	14	–	449	4	1,343
	279	–	1,306	191	12	131	–	1,379	33	3,330
Changes attributable to										
Revisions of previous estimates	9	–	(11)	–	(1)	1	–	(40)	(4)	(47)
Improved recovery	2	–	(2)	–	–	4	–	–	–	5
Purchases of reserves-in-place	–	–	–	–	–	–	–	3	–	3
Discoveries and extensions	–	–	22	–	–	1	–	–	–	23
Production	(29)	–	(108)	(5)	(2)	(31)	–	(112)	(5)	(292)
Sales of reserves-in-place	–	–	(1)	(185)	–	(80)	–	(157)	(3)	(426)
	(18)	–	(100)	(191)	(3)	(105)	–	(306)	(11)	(734)
At 31 December[c]										
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
Equity-accounted entities (bp share)[d]										
At 1 January										
Developed	–	100	–	10	275	3	3,045	1	–	3,434
Undeveloped	–	21	–	12	253	–	2,540	1	–	2,826
	–	121	–	22	527	3	5,585	1	–	6,260
Changes attributable to										
Revisions of previous estimates	–	(17)	–	1	(1)	23	4	(46)	–	(37)
Improved recovery	–	1	–	–	14	25	–	–	–	40
Purchases of reserves-in-place	–	42	–	–	–	165	–	152	–	359
Discoveries and extensions	–	2	–	–	–	–	–	–	–	2
Production	–	(17)	–	(1)	(21)	(12)	(55)	(9)	–	(115)
Sales of reserves-in-place[f]	–	(25)	–	(10)	–	(3)	(5,535)	(1)	–	(5,574)
	–	(15)	–	(10)	(8)	198	(5,585)	95	–	(5,325)
At 31 December										
Developed	–	90	–	5	276	127	–	95	–	592
Undeveloped	–	16	–	7	244	74	–	1	–	342
	–	106	–	12	520	201	–	96	–	935
Total subsidiaries and equity-accounted entities (bp share)										
At 1 January										
Developed	178	100	705	34	280	119	3,045	931	28	5,421
Undeveloped	101	21	601	179	259	14	2,540	450	4	4,169
	279	121	1,306	213	539	134	5,585	1,381	33	9,590
At 31 December										
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

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 3 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.
e Includes assets held for sale in Algeria
f bp's decision to exit its Russia business, including its shareholding in Rosneft, is treated as sales of reserves in place.

Movements in estimated net proved reserves – continued

										million barrels
Natural gas liquids[a b]										2022
	Europe		North America		South America	Africa[c]	Asia		Australasia	Total
	UK	Rest of Europe	US[d]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	8	—	132	—	2	9	—	—	2	153
Undeveloped	—	—	195	—	19	1	—	—	—	215
	9	—	328	—	21	10	—	—	2	368
Changes attributable to										
Revisions of previous estimates	(1)	—	101	—	(18)	(1)	—	—	—	81
Improved recovery	—	—	16	—	—	1	—	—	—	17
Purchases of reserves-in-place	—	—	—	—	—	—	—	—	—	—
Discoveries and extensions	—	—	1	—	—	1	—	—	—	2
Production[d]	(2)	—	(28)	—	(2)	(2)	—	—	(1)	(34)
Sales of reserves-in-place	—	—	(1)	—	—	(1)	—	—	—	(1)
	(2)	—	90	—	(19)	(2)	—	—	(1)	64
At 31 December[e]										
Developed	6	—	181	—	1	6	—	—	1	196
Undeveloped	—	—	236	—	—	1	—	—	—	237
	6	—	417	—	1	7	—	—	1	432
Equity-accounted entities (bp share)[f]										
At 1 January										
Developed	—	6	—	—	2	17	100	—	—	125
Undeveloped	—	—	—	—	—	—	41	—	—	41
	—	6	—	—	2	17	140	—	—	166
Changes attributable to										
Revisions of previous estimates	—	(1)	—	—	2	7	—	—	—	8
Improved recovery	—	—	—	—	—	—	—	—	—	—
Purchases of reserves-in-place	—	2	—	—	—	20	—	—	—	21
Discoveries and extensions	—	—	—	—	—	—	—	—	—	—
Production	—	(1)	—	—	—	(1)	—	—	—	(2)
Sales of reserves-in-place[g]	—	(2)	—	—	—	(17)	(140)	—	—	(159)
	—	(2)	—	—	2	9	(140)	—	—	(132)
At 31 December										
Developed	—	4	—	—	3	17	—	—	—	23
Undeveloped	—	—	—	—	1	9	—	—	—	10
	—	4	—	—	4	26	—	—	—	34
Total subsidiaries and equity-accounted entities (bp share)										
At 1 January										
Developed	8	6	132	—	4	26	100	—	2	278
Undeveloped	—	—	195	—	19	1	41	—	—	256
	9	6	328	—	22	27	140	—	2	534
At 31 December										
Developed	6	4	181	—	4	23	—	—	1	219
Undeveloped	—	—	236	—	1	10	—	—	—	247
	6	4	417	—	5	33	—	—	1	466

[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 assets held for sale in Algeria.
[d] Excludes NGLs from processing plants in which an interest is held of 2 thousand barrels per day for equity-accounted entities.
[e] Includes 0.4 million barrels of NGL in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[f] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[g] bp's decision to exit its Russia business, including its shareholding in Rosneft, is treated as sales of reserves in place.

Movements in estimated net proved reserves – continued

Total liquids[a b]										million barrels 2022
	Europe		North America		South America	Africa[c]	Asia		Australasia	Total
	UK	Rest of Europe	US[d]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	187	–	837	24	7	125	–	930	30	2,141
Undeveloped	101	–	796	167	25	15	–	449	4	1,558
	288	–	1,634	191	32	140	–	1,379	34	3,699
Changes attributable to										
Revisions of previous estimates	8	–	89	–	(19)	–	–	(40)	(4)	34
Improved recovery	2	–	14	–	–	5	–	–	–	22
Purchases of reserves-in-place	1	–	–	–	–	–	–	3	–	3
Discoveries and extensions	–	–	23	–	–	1	–	–	–	25
Production[d]	(31)	–	(136)	(5)	(3)	(34)	–	(112)	(5)	(326)
Sales of reserves-in-place	–	–	(2)	(185)		(80)	–	(157)	(4)	(428)
	(20)	–	(11)	(191)	(22)	(107)	–	(306)	(13)	(670)
At 31 December[e]										
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
Equity-accounted entities (bp share)[f]										
At 1 January										
Developed	–	106	–	10	276	20	3,145	1	–	3,558
Undeveloped	–	21	–	12	253	–	2,581	1	–	2,867
	–	127	–	22	529	20	5,726	1	–	6,425
Changes attributable to										
Revisions of previous estimates	–	(18)	–	1	1	30	4	(46)	–	(29)
Improved recovery	–	1	–	–	14	25	–	–	–	40
Purchases of reserves-in-place	–	44	–	–	–	185	–	152	–	380
Discoveries and extensions	–	2	–	–	–	–	–	–	–	2
Production	–	(18)	–	(1)	(21)	(13)	(55)	(9)	–	(117)
Sales of reserves-in-place	–	(27)	–	(10)	–	(19)	(5,675)	(1)	–	(5,733)
	–	(17)	–	(10)	(6)	207	(5,726)	95	–	(5,457)
At 31 December										
Developed	–	94	–	5	278	144	–	95	–	616
Undeveloped	–	16	–	7	245	83	–	1	–	352
	–	110	–	12	523	227	–	96	–	968
Total subsidiaries and equity-accounted entities (bp share)										
At 1 January										
Developed	187	106	837	34	284	146	3,145	931	30	5,699
Undeveloped	101	21	796	179	278	15	2,581	450	4	4,425
	288	127	1,634	213	561	161	5,726	1,381	34	10,124
At 31 December										
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

[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 assets held for sale in Algeria.
[d] Excludes NGLs from processing plants in which an interest is held of 2 thousand barrels per day for equity-accounted entities.
[e] Also includes 3 million barrels in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[f] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[g] bp's decision to exit its Russia business, including its shareholding in Rosneft, is treated as sales of reserves in place.

Movements in estimated net proved reserves – continued

Natural gas[a b]										billion cubic feet 2022
	Europe		North America		South America	Africa[c]	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	455	—	2,401	—	1,152	1,433	—	3,266	1,584	10,291
Undeveloped	45	—	3,404	—	1,147	154	—	2,522	939	8,211
	501	—	5,805	—	2,299	1,587	—	5,788	2,523	18,502
Changes attributable to										
Revisions of previous estimates	6	—	449	—	2	180	—	(575)	(165)	(102)
Improved recovery	1	—	46	—	—	—	—	—	—	47
Purchases of reserves-in-place	2	—	—	—	—	—	—	92	—	94
Discoveries and extensions	—	—	10	—	—	87	—	21	10	128
Production[d]	(109)	—	(493)	—	(476)	(517)	—	(561)	(276)	(2,432)
Sales of reserves-in-place	—	—	(9)	—	—	(93)	—	(47)	—	(149)
	(100)	—	4	—	(474)	(344)	—	(1,069)	(431)	(2,414)
At 31 December[e]										
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
Equity-accounted entities (bp share)[f]										
At 1 January										
Developed	—	130	—	4	929	689	11,399	—	—	13,149
Undeveloped	—	11	—	4	536	133	7,279	—	—	7,964
	—	140	—	8	1,465	822	18,678	—	—	21,113
Changes attributable to										
Revisions of previous estimates	—	(7)	—	1	162	131	53	—	—	340
Improved recovery	—	—	—	—	82	—	—	—	—	82
Purchases of reserves-in-place	—	14	—	—	—	575	—	45	—	634
Discoveries and extensions	—	4	—	—	—	—	—	—	—	4
Production[d]	—	(25)	—	—	(128)	(36)	(86)	(2)	—	(277)
Sales of reserves-in-place[g]	—	(49)	—	(4)	—	(803)	(18,645)	—	—	(19,501)
	—	(64)	—	(3)	115	(133)	(18,678)	43	—	(18,719)
At 31 December										
Developed	—	72	—	3	974	534	—	43	—	1,627
Undeveloped	—	5	—	2	606	154	—	—	—	767
	—	77	—	5	1,580	689	—	43	—	2,394
Total subsidiaries and equity-accounted entities (bp share)										
At 1 January										
Developed	455	130	2,401	4	2,081	2,121	11,399	3,266	1,584	23,440
Undeveloped	45	11	3,404	4	1,683	287	7,279	2,522	939	16,174
	501	140	5,805	8	3,764	2,408	18,678	5,788	2,523	39,615
At 31 December										
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

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 assets held for sale in Algeria.
d Includes 122 billion cubic feet of natural gas consumed in operations, 86 billion cubic feet in subsidiaries, 36 billion cubic feet in equity-accounted entities.
e Includes 547 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
f Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
g bp's decision to exit our Russia business, including our shareholding in Rosneft, is treated as sales of reserves in place.

Movements in estimated net proved reserves – continued

Total hydrocarbons[a b]										million barrels of oil equivalent[c] 2022
	Europe		North America		South America	Africa[d]	Asia		Australasia	Total
	UK	Rest of Europe	US[e]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	265	–	1,251	24	206	372	–	1,494	303	3,915
Undeveloped	109	–	1,383	167	223	41	–	884	166	2,973
	374	–	2,634	191	429	414	–	2,377	469	6,889
Changes attributable to										
Revisions of previous estimates	9	–	167	–	(18)	31	–	(139)	(33)	17
Improved recovery	2	–	22	–	–	5	–	–	–	30
Purchases of reserves-in-place	1	–	–	–	–	–	–	18	–	19
Discoveries and extensions	–	–	25	–	–	16	–	4	2	47
Production[f g]	(50)	–	(221)	(5)	(85)	(123)	–	(209)	(53)	(746)
Sales of reserves-in-place	–	–	(3)	(185)	–	(96)	–	(165)	(4)	(453)
	(37)	–	(10)	(191)	(103)	(167)	–	(491)	(87)	(1,086)
At 31 December[e]										
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
Equity-accounted entities (bp share)[h]										
At 1 January										
Developed	–	128	–	11	437	139	5,110	1	–	5,825
Undeveloped	–	23	–	12	345	23	3,836	1	–	4,240
	–	151	–	23	782	162	8,946	1	–	10,065
Changes attributable to										
Revisions of previous estimates	–	(19)	–	1	29	53	13	(46)	–	30
Improved recovery	–	1	–	–	28	25	–	–	–	54
Purchases of reserves-in-place	–	46	–	–	–	284	–	159	–	489
Discoveries and extensions	–	2	–	–	–	–	–	–	–	2
Production[g]	–	(22)	–	(1)	(43)	(19)	(70)	(10)	–	(165)
Sales of reserves-in-place[i]	–	(36)	–	(10)	–	(158)	(8,890)	(1)	–	(9,095)
	–	(28)	–	(11)	14	184	(8,946)	102	–	(8,685)
At 31 December										
Developed	–	106	–	6	446	236	–	102	–	896
Undeveloped	–	17	–	7	349	110	–	1	–	485
	–	123	–	13	796	346	–	103	–	1,381
Total subsidiaries and equity-accounted entities (bp share)										
At 1 January										
Developed	265	128	1,251	35	642	511	5,110	1,494	303	9,740
Undeveloped	109	23	1,383	179	568	65	3,836	884	166	7,214
	374	151	2,634	214	1,210	576	8,946	2,379	469	16,954
At 31 December										
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

[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] Includes assets held for sale in Algeria.
[e] Includes 76 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[f] Excludes NGLs from processing plants in which an interest is held of 2 thousand barrels per day for equity-accounted entities.
[g] Includes 21 million barrels of oil equivalent of natural gas consumed in operations, 15 million barrels of oil equivalent in subsidiaries, 6 million barrels of oil equivalent in equity-accounted entities.
[h] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[i] bp's decision to exit our Russia business, including our shareholding in Rosneft, is treated as sales of reserves in place.

Movements in estimated net proved reserves – continued

Crude oil[a b]										million barrels 2021
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	162	—	697	37	8	116	—	1,100	34	2,154
Undeveloped	148	—	742	195	9	21	—	547	5	1,666
	309	—	1,438	232	16	137	—	1,647	38	3,819
Changes attributable to										
Revisions of previous estimates	—	—	(46)	(32)	(3)	32	—	(121)	(1)	(171)
Improved recovery	—	—	29	—	—	2	—	—	—	32
Purchases of reserves-in-place	—	—	—	—	—	—	—	—	—	—
Discoveries and extensions	—	—	2	—	—	—	—	5	—	7
Production	(30)	—	(113)	(9)	(2)	(41)	—	(116)	(5)	(315)
Sales of reserves-in-place	(1)	—	(5)				—	(36)	—	(41)
	(30)	—	(132)	(41)	(5)	(7)	—	(268)	(6)	(489)
At 31 December[c]										
Developed	178	—	705	24	5	117	—	930	28	1,987
Undeveloped	101	—	601	167	7	14	—	449	4	1,343
	279	—	1,306	191	12	131	—	1,379	33	3,330
Equity-accounted entities (bp share)[d]										
At 1 January										
Developed	—	112	—	5	275	2	3,123	—	—	3,517
Undeveloped	—	24	—	21	237	—	2,493	—	—	2,776
	—	136	—	26	512	3	5,615	1	—	6,293
Changes attributable to										
Revisions of previous estimates	—	9	—	(5)	(4)	1	166	1	—	168
Improved recovery	—	1	—	—	—	—	—	—	—	1
Purchases of reserves-in-place	—	—	—	—	13	—	—	—	—	13
Discoveries and extensions	—	1	—	2	25	—	238	—	—	266
Production	—	(18)	—	(1)	(19)	—	(323)	—	—	(361)
Sales of reserves-in-place	—	(9)	—	—	—	—	(111)	—	—	(119)
	—	(15)	—	(4)	15	—	(30)	1	—	(33)
At 31 December[e f]										
Developed	—	100	—	10	275	3	3,045	1	—	3,434
Undeveloped	—	21	—	12	253	—	2,540	1	—	2,826
	—	121	—	22	527	3	5,585	1	—	6,260
Total subsidiaries and equity-accounted entities (bp share)										
At 1 January										
Developed	162	112	697	42	283	119	3,123	1,100	34	5,671
Undeveloped	148	24	742	215	246	22	2,493	548	5	4,441
	309	136	1,438	258	529	140	5,615	1,648	38	10,112
At 31 December										
Developed	178	100	705	34	280	119	3,045	931	28	5,421
Undeveloped	101	21	601	179	259	14	2,540	450	4	4,169
	279	121	1,306	213	539	134	5,585	1,381	33	9,590

[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 4 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.
[e] Includes 393 million barrels of crude oil in respect of the 7.16% non-controlling interest in Rosneft, including 22 mmbbl held through bp's interests in Russia other than Rosneft.
[f] Total proved crude oil reserves held as part of our equity interest in Rosneft is 5,490 million barrels, comprising 1 million barrels in Iraq and less than 1 million barrels each in Egypt, Vietnam and Canada, and 5,487 million barrels in Russia.

Movements in estimated net proved reserves – continued

Natural gas liquids[a b]										million barrels 2021
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	7	–	115	–	2	13	–	–	2	139
Undeveloped	–	–	218	–	19	1	–	–	–	237
	7	–	333	–	21	14	–	–	2	376
Changes attributable to										
Revisions of previous estimates	5	–	(1)	–	1	(1)	–	–	–	4
Improved recovery	–	–	25	–	–	–	–	–	–	25
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	–	–	–	–	–	–
Production[c]	(2)	–	(25)	–	(1)	(3)	–	–	(1)	(32)
Sales of reserves-in-place	(1)	–	(4)	–	–	–	–	–	–	(5)
	2	–	(5)	–	–	(4)	–	–	–	(8)
At 31 December[d]										
Developed	8	–	132	–	2	9	–	–	2	153
Undeveloped	–	–	195	–	19	1	–	–	–	215
	9	–	328	–	21	10	–	–	2	368
Equity-accounted entities (bp share)[e]										
At 1 January										
Developed	–	6	–	–	2	12	108	–	–	129
Undeveloped	–	1	–	–	–	–	43	–	–	44
	–	7	–	–	2	12	151	–	–	172
Changes attributable to										
Revisions of previous estimates	–	–	–	–	–	6	(9)	–	–	(2)
Improved recovery	–	–	–	–	–	–	–	–	–	–
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	–	–	–	–	–	–
Production[d]	–	(1)	–	–	–	(1)	(1)	–	–	(4)
Sales of reserves-in-place	–	–	–	–	–	–	–	–	–	–
	–	(1)	–	–	–	5	(10)	–	–	(7)
At 31 December[f g]										
Developed	–	6	–	–	2	17	100	–	–	125
Undeveloped	–	–	–	–	–	–	41	–	–	41
	–	6	–	–	2	17	140	–	–	166
Total subsidiaries and equity-accounted entities (bp share)										
At 1 January										
Developed	7	6	115	–	4	25	108	–	2	268
Undeveloped	–	1	218	–	19	1	43	–	–	281
	7	7	333	–	23	26	151	–	2	549
At 31 December										
Developed	8	6	132	–	4	26	100	–	2	278
Undeveloped	–	–	195	–	19	1	41	–	–	256
	9	6	328	–	22	27	140	–	2	534

[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 3 thousand barrels per day for equity-accounted entities.
[d] Includes 6 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.
[f] Includes 3 million barrels of NGLs in respect of the 2.3% non-controlling interest in Rosneft.
[g] Total proved NGL reserves held as part of our equity interest in Rosneft is 140 million barrels, comprising less than 1 million barrels in Canada, and 140 million barrels in Russia.

Movements in estimated net proved reserves – continued

Total liquids[a b]										million barrels 2021
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	168	—	812	37	10	129	—	1,100	36	2,293
Undeveloped	148	—	959	195	27	22	—	547	5	1,903
	316	—	1,771	232	37	151	—	1,647	41	4,196
Changes attributable to										
Revisions of previous estimates	5	—	(47)	(32)	(2)	31	—	(121)	(1)	(167)
Improved recovery	—	—	54	—	—	2	—	—	—	57
Purchases of reserves-in-place	—	—	—	—	—	—	—	—	—	—
Discoveries and extensions	—	—	2	—	—	—	—	5	—	7
Production[c]	(32)	—	(138)	(9)	(3)	(44)	—	(116)	(5)	(348)
Sales of reserves-in-place	(1)	—	(9)	—	—	—	—	(36)	—	(46)
	(29)	—	(137)	(41)	(5)	(11)	—	(268)	(6)	(497)
At 31 December[d]										
Developed	187	—	837	24	7	125	—	930	30	2,141
Undeveloped	101	—	796	167	25	15	—	449	4	1,558
	288	—	1,634	191	32	140	—	1,379	34	3,699
Equity-accounted entities (bp share)[e]										
At 1 January										
Developed	—	118	—	5	277	15	3,231	—	—	3,645
Undeveloped	—	25	—	21	237	—	2,535	—	—	2,819
	—	143	—	26	514	15	5,766	1	—	6,465
Changes attributable to										
Revisions of previous estimates	—	10	—	(5)	(4)	7	157	1	—	166
Improved recovery	—	1	—	—	—	—	—	—	—	1
Purchases of reserves-in-place	—	—	—	—	13	—	—	—	—	13
Discoveries and extensions	—	1	—	2	25	—	238	—	—	266
Production[d]	—	(19)	—	(1)	(19)	(1)	(325)	—	—	(365)
Sales of reserves-in-place	—	(9)	—	—	—	—	(111)	—	—	(120)
	—	(16)	—	(4)	15	5	(40)	1	—	(39)
At 31 December[f g]										
Developed	—	106	—	10	276	20	3,145	1	—	3,558
Undeveloped	—	21	—	12	253	—	2,581	1	—	2,867
	—	127	—	22	529	20	5,726	1	—	6,425
Total subsidiaries and equity-accounted entities (bp share)										
At 1 January										
Developed	168	118	812	42	287	144	3,231	1,100	36	5,938
Undeveloped	148	25	959	215	265	23	2,535	548	5	4,722
	316	143	1,771	258	552	166	5,766	1,648	41	10,661
At 31 December										
Developed	187	106	837	34	284	146	3,145	931	30	5,699
Undeveloped	101	21	796	179	278	15	2,581	450	4	4,425
	288	127	1,634	213	561	161	5,726	1,381	34	10,124

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 3 thousand barrels per day for equity-accounted entities.
d Also includes 10 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.
f Includes 396 million barrels of liquids in respect of the non-controlling interest in Rosneft, including 22 mmboe held through bp's interests in Russia other than Rosneft.
g Total proved liquid reserves held as part of our equity interest in Rosneft is 5,630 million barrels, comprising 1 million barrels in Iraq, less than 1 million barrels each in Canada, Egypt and Vietnam and 5,628 million barrels in Russia.

Movements in estimated net proved reserves – continued

Natural gas[a b]										billion cubic feet 2021
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	306	–	1,921	–	1,567	1,382	–	3,883	2,058	11,118
Undeveloped	51	–	3,423	–	1,964	158	–	3,641	1,029	10,267
	358	–	5,344	–	3,531	1,541	–	7,524	3,087	21,385
Changes attributable to										
Revisions of previous estimates	254	–	717	1	(767)	537	–	(66)	(285)	390
Improved recovery	–	–	247	–	–	–	–	–	–	247
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	1	–	–	25	–	116	–	142
Production[c]	(103)	–	(445)	(1)	(465)	(516)	–	(489)	(279)	(2,297)
Sales of reserves-in-place	(7)	–	(60)	–	–	–	–	(1,298)	–	(1,365)
	143	–	461	–	(1,232)	46	–	(1,736)	(564)	(2,883)
At 31 December[d]										
Developed	455	–	2,401	–	1,152	1,433	–	3,266	1,584	10,291
Undeveloped	45	–	3,404	–	1,147	154	–	2,522	939	8,211
	501	–	5,805	–	2,299	1,587	–	5,788	2,523	18,502
Equity-accounted entities (bp share)[e]										
At 1 January										
Developed	–	141	–	2	965	600	11,373	7	–	13,088
Undeveloped	–	21	–	6	513	142	7,312	–	–	7,994
	–	162	–	8	1,478	741	18,685	7	–	21,082
Changes attributable to										
Revisions of previous estimates	–	8	–	(2)	(115)	152	422	–	–	467
Improved recovery	–	4	–	–	–	–	–	–	–	4
Purchases of reserves-in-place	–	–	–	–	3	–	–	–	–	3
Discoveries and extensions	–	1	–	1	222	–	151	–	–	375
Production[c]	–	(25)	–	–	(124)	(72)	(478)	(3)	–	(702)
Sales of reserves-in-place	–	(9)	–	–	–	–	(102)	(4)	–	(115)
	–	(22)	–	(1)	(13)	80	(7)	(7)	–	31
At 31 December[f g]										
Developed	–	130	–	4	929	689	11,399	–	–	13,149
Undeveloped	–	11	–	4	536	133	7,279	–	–	7,964
	–	140	–	8	1,465	822	18,678	–	–	21,113
Total subsidiaries and equity-accounted entities (bp share)										
At 1 January										
Developed	306	141	1,921	2	2,532	1,982	11,373	3,890	2,058	24,206
Undeveloped	51	21	3,423	6	2,477	300	7,312	3,641	1,029	18,260
	358	162	5,344	8	5,009	2,282	18,685	7,531	3,087	42,467
At 31 December										
Developed	455	130	2,401	4	2,081	2,121	11,399	3,266	1,584	23,440
Undeveloped	45	11	3,404	4	1,683	287	7,279	2,522	939	16,174
	501	140	5,805	8	3,764	2,408	18,678	5,788	2,523	39,615

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 135 billion cubic feet of natural gas consumed in operations, 83 billion cubic feet in subsidiaries, 52 billion cubic feet in equity-accounted entities.
d Includes 690 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.
f Includes 1,656 billion cubic feet of natural gas in respect of the 10.20% non-controlling interest in Rosneft including 621 billion cubic feet held through bp's interests in Russia other than Rosneft.
g Total proved gas reserves held as part of our equity interest in Rosneft is 16,233 billion cubic feet, comprising less than 1 billion cubic feet in Vietnam and Canada, 376 billion cubic feet in Egypt and 15,857 billion cubic feet in Russia.

Movements in estimated net proved reserves – continued

Total hydrocarbons[a b]									million barrels of oil equivalent[c] 2021	
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[d]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	221	–	1,143	37	280	367	–	1,770	391	4,210
Undeveloped	157	–	1,549	195	366	50	–	1,175	182	3,673
	378	–	2,692	232	646	417	–	2,945	573	7,883
Changes attributable to										
Revisions of previous estimates	49	–	77	(32)	(134)	123	–	(132)	(50)	(100)
Improved recovery	–	–	97	–	–	2	–	–	–	99
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	2	–	–	4	–	25	–	31
Production[e f]	(50)	–	(214)	(9)	(83)	(133)	–	(200)	(54)	(744)
Sales of reserves-in-place	(3)	–	(19)	–	–	–	–	(260)	–	(282)
	(4)	–	(58)	(41)	(217)	(3)	–	(567)	(104)	(994)
At 31 December[d]										
Developed	265	–	1,251	24	206	372	–	1,494	303	3,915
Undeveloped	109	–	1,383	167	223	41	–	884	166	2,973
	374	–	2,634	191	429	414	–	2,377	469	6,889
Equity-accounted entities (bp share)[g]										
At 1 January										
Developed	–	142	–	5	443	118	5,192	1	–	5,902
Undeveloped	–	29	–	22	326	25	3,796	–	–	4,198
	–	171	–	27	769	143	8,988	2	–	10,100
Changes attributable to										
Revisions of previous estimates	–	11	–	(5)	(24)	33	230	1	–	246
Improved recovery	–	1	–	–	–	–	–	–	–	1
Purchases of reserves-in-place	–	–	–	–	14	–	–	–	–	14
Discoveries and extensions	–	1	–	2	63	–	264	–	–	330
Production[f]	–	(23)	–	(1)	(41)	(14)	(407)	–	–	(486)
Sales of reserves-in-place	–	(11)	–	–	–	–	(128)	(1)	–	(139)
	–	(20)	–	(4)	12	19	(42)	–	–	(34)
At 31 December[h i]										
Developed	–	128	–	11	437	139	5,110	1	–	5,825
Undeveloped	–	23	–	12	345	23	3,836	1	–	4,240
	–	151	–	23	782	162	8,946	1	–	10,065
Total subsidiaries and equity-accounted entities (bp share)										
At 1 January										
Developed	221	142	1,143	43	724	485	5,192	1,771	391	10,112
Undeveloped	157	29	1,549	217	692	74	3,796	1,175	182	7,871
	378	171	2,692	259	1,415	560	8,988	2,946	573	17,982
At 31 December										
Developed	265	128	1,251	35	642	511	5,110	1,494	303	9,740
Undeveloped	109	23	1,383	179	568	65	3,836	884	166	7,214
	374	151	2,634	214	1,210	576	8,946	2,379	469	16,954

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 Includes 76 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
e Excludes NGLs from processing plants in which an interest is held of 3 thousand barrels per day for equity-accounted entities.
f Includes 23 million barrels of oil equivalent of natural gas consumed in operations, 14 million barrels of oil equivalent in subsidiaries, 9 million barrels of oil equivalent in equity-accounted entities.
g Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
h Includes 682 million barrels of oil equivalent in respect of the 8.09% non-controlling interest in Rosneft, including 129mmboe held through bp's interests in Russia other than Rosneft.
i Total proved reserves held as part of our equity interest in Rosneft is 8,429 million barrels of oil equivalent, comprising less than 1 million barrels of oil equivalent in Canada and Vietnam, 1 million barrels of oil equivalent in Iraq, 65 million barrels of oil equivalent in Egypt and 8,362 million barrels of oil equivalent in Russia.

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
									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.

Standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves – continued

										$ million
										2022
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
At 31 December										
Subsidiaries										
Future cash inflows[a]	34,900	—	154,500	—	16,400	9,400	—	151,500	23,600	390,300
Future production cost[b]	13,600	—	36,000	—	5,300	1,300	—	42,700	5,200	104,100
Future development cost[b]	1,100	—	12,200	—	1,400	700	—	8,800	1,900	26,100
Future taxation[c]	12,600	—	19,800	—	5,000	1,900	—	65,200	5,500	110,000
Future net cash flows	7,600	—	86,500	—	4,700	5,500	—	34,800	11,000	150,100
10% annual discount[d]	3,400	—	38,200	—	700	1,000	—	11,800	4,000	59,100
Standardized measure of discounted future net cash flows[e]	4,200	—	48,300	—	4,000	4,500	—	23,000	7,000	91,000
Equity-accounted entities (bp share)[f]										
Future cash inflows[a]	—	12,800	—	—	49,800	20,500	—	9,200	—	92,300
Future production cost[b]	—	2,100	—	—	22,000	6,300	—	4,900	—	35,300
Future development cost[b]	—	400	—	—	4,900	2,800	—	3,000	—	11,100
Future taxation[c]	—	8,100	—	—	7,100	4,300	—	400	—	19,900
Future net cash flows	—	2,200	—	—	15,800	7,100	—	900	—	26,000
10% annual discount[d]	—	400	—	—	9,300	2,200	—	200	—	12,100
Standardized measure of discounted future net cash flows[g]	—	1,800	—	—	6,500	4,900	—	700	—	13,900
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows[h]	4,200	1,800	48,300	—	10,500	9,400	—	23,700	7,000	104,900

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	(22,800)	(4,600)	(27,400)
Development costs for the current year as estimated in previous year	5,500	1,800	7,300
Extensions, discoveries and improved recovery, less related costs	1,600	900	2,500
Net changes in prices and production cost	80,800	11,100	91,900
Revisions of previous reserves estimates	(18,300)	(2,700)	(21,000)
Net change in taxation	(23,000)	1,400	(21,600)
Future development costs	(2,100)	(800)	(2,900)
Net change in purchase and sales of reserves-in-place	(4,300)	(34,800)	(39,100)
Addition of 10% annual discount	6,700	3,800	10,500
Total change in the standardized measure during the year[i]	24,100	(23,900)	200

[a] The marker prices used were Brent $101.24/bbl, Henry Hub $6.19/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 $1,216 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] No reserves are reported for Russia following bp's announcement that it will exit the country. The impact of this change is primarily included within sales of reserves-in-place.
[h] Includes future net cash flows for assets held for sale at 31 December 2022.
[i] 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

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		$ million 2021
At 31 December										
Subsidiaries										
Future cash inflows[a]	25,600	–	108,600	8,400	10,300	17,100	–	126,800	20,400	317,200
Future production cost[b]	13,400	–	33,900	3,700	4,300	4,800	–	46,100	6,400	112,600
Future development cost[b]	1,100	–	12,600	1,100	1,300	1,100	–	12,400	2,100	31,700
Future taxation[c]	4,300	–	10,100	500	1,400	2,900	–	44,100	4,100	67,400
Future net cash flows	6,800	–	52,000	3,100	3,300	8,300	–	24,200	7,800	105,500
10% annual discount[d]	2,100	–	21,600	1,700	600	1,400	–	8,300	2,900	38,600
Standardized measure of discounted future net cash flows[e]	4,700	–	30,400	1,400	2,700	6,900	–	15,900	4,900	66,900
Equity-accounted entities (bp share)[f]										
Future cash inflows[a]	–	10,500	–	–	40,100	–	370,000	–	–	420,600
Future production cost[b]	–	3,400	–	–	16,600	–	254,000	–	–	274,000
Future development cost[b]	–	400	–	–	3,900	–	24,300	–	–	28,600
Future taxation[c]	–	5,100	–	–	6,100	–	15,600	–	–	26,800
Future net cash flows	–	1,600	–	–	13,500	–	76,100	–	–	91,200
10% annual discount[d]	–	400	–	–	7,800	–	45,200	–	–	53,400
Standardized measure of discounted future net cash flows[g h]	–	1,200	–	–	5,700	–	30,900	–	–	37,800
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows[i]	4,700	1,200	30,400	1,400	8,400	6,900	30,900	15,900	4,900	104,700

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

	Subsidiaries	Equity-accounted entities (bp share)	$ million Total subsidiaries and equity-accounted entities
Sales and transfers of oil and gas produced, net of production costs	(12,200)	(7,700)	(19,900)
Development costs for the current year as estimated in previous year	5,800	3,600	9,400
Extensions, discoveries and improved recovery, less related costs	1,700	2,400	4,100
Net changes in prices and production cost	71,900	29,700	101,600
Revisions of previous reserves estimates	(8,800)	1,000	(7,800)
Net change in taxation	(17,900)	(7,200)	(25,100)
Future development costs	(3,200)	(5,300)	(8,500)
Net change in purchase and sales of reserves-in-place	(3,100)	(600)	(3,700)
Addition of 10% annual discount	3,000	2,000	5,000
Total change in the standardized measure during the year[j]	37,200	17,900	55,100

[a] The marker prices used were Brent $69.23/bbl, Henry Hub $3.61/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 $820 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] Non-controlling interests in Rosneft amounted to $2,422 million in Russia.
[h] No equity-accounted future cash flows in Africa because proved reserves are received as a result of contractual arrangements, with no associated costs.
[i] Includes future net cash flows for assets held for sale at 31 December 2021.
[j] Total change in the standardized measure during the year includes the effect of exchange rate movements. Exchange rate effects arising from the translation of our share of Rosneft changes to US dollars are included within 'Net changes in prices and production cost'.

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 2023, 2022 and 2021.

Production for the year[a b]

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia[c]	Rest of Asia		
Subsidiaries[d]										
Crude oil[e]										thousand barrels per day
2023	**74**	**—**	**335**	**—**	**4**	**29**	**—**	**289**	**10**	**741**
2022	80	—	296	15	5	83	—	307	12	797
2021	82	—	308	25	5	110	—	318	13	860
Natural gas liquids										thousand barrels per day
2023	**5**	**—**	**88**	**—**	**4**	**2**	**—**	**4**	**2**	**104**
2022	5	—	76	—	4	6	—	—	2	93
2021	5	—	70	—	4	7	—	—	2	88
Natural gas[f]										million cubic feet per day
2023	**247**	**—**	**1,486**	**—**	**1,191**	**1,236**	**—**	**1,578**	**774**	**6,512**
2022	271	—	1,291	—	1,276	1,353	—	1,485	752	6,428
2021	236	—	1,197	2	1,260	1,332	—	1,279	760	6,067
Equity-accounted entities (bp share)										
Crude oil[e]										thousand barrels per day
2023	**—**	**—**	**—**	**—**	**57**	**82**	**—**	**62**	**—**	**261**
2022	—	47	—	—	59	33	150	25	—	314
2021	—	48	—	—	55	1	887	—	—	991
Natural gas liquids										thousand barrels per day
2023	**—**	**3**	**—**	**—**	**1**	**6**	**—**	**—**	**—**	**9**
2022	—	2	—	—	1	5	—	—	—	9
2021	—	3	—	—	1	6	3	—	—	12
Natural gas[f]										million cubic feet per day
2023	**—**	**58**	**—**	**—**	**299**	**74**	**—**	**—**	**—**	**432**
2022	—	66	—	—	296	64	248	—	—	674
2021	—	66	—	—	284	77	1,423	—	—	1,849

[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] Amounts reported for Russia include bp's share of Rosneft worldwide activities, including insignificant amounts outside Russia.
[d] All of the oil and liquid production from Canada is bitumen.
[e] Crude oil includes condensate.
[f] 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 2023. 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 2023										
Oil wells[b]	– gross	**114**	**123**	**1,390**	**8**	**5,367**	**864**	**2,979**	**—**	**10,845**
	– net	**65**	**20**	**736**	**2**	**2,644**	**79**	**619**	**—**	**4,166**
Gas wells[c]	– gross	**36**	**10**	**4,681**	**—**	**1,184**	**91**	**172**	**100**	**6,274**
	– net	**8**	**2**	**2,520**	**—**	**413**	**42**	**65**	**23**	**3,073**
Oil and natural gas acreage at 31 December 2023										thousands of acres
Developed	– gross	**71**	**82**	**1,903**	**8**	**1,330**	**690**	**1,334**	**838**	**6,255**
	– net	**41**	**13**	**1,024**	**1**	**381**	**120**	**277**	**157**	**2,014**
Undeveloped[d]	– gross	**561**	**333**	**3,900**	**11,011**	**9,402**	**18,538**	**5,604**	**9,660**	**59,010**
	– net	**410**	**53**	**3,320**	**6,966**	**4,193**	**8,631**	**1,743**	**6,676**	**31,991**

[a] Because of rounding, some totals may not exactly agree with the sum of their component parts.
[b] Includes approximately 166 gross (32 net) multiple completion wells (more than one formation producing into the same well bore).
[c] Includes approximately 116 gross (94 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			Russia	Rest of Asia		
2023										
Exploratory										
Productive	**—**	**—**	**2.0**	**—**	**—**	**—**	**—**	**0.8**	**0.4**	**3.2**
Dry	**0.5**	**—**	**0.8**	**0.5**	**—**	**—**	**—**	**0.2**	**—**	**2.0**
Development										
Productive	**2.6**	**0.6**	**141.9**	**0.1**	**6.2**	**4.2**	**—**	**39.7**	**0.4**	**195.6**
Dry	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**0.4**	**—**	**0.4**
2022										
Exploratory										
Productive	—	—	0.5	1.0	1.0	0.6	—	0.5	0.3	4.0
Dry	—	—	—	1.2	0.3	0.1	—	0.8	—	2.3
Development										
Productive	0.9	1.5	137.2	0.3	71.4	2.8	—	39.0	1.4	254.5
Dry	—	—	1.1	—	0.5	0.1	—	1.1	—	2.8
2021										
Exploratory										
Productive	—	—	0.2	—	1.1	1.4	16.3	1.2	—	20.2
Dry	—	—	0.6	—	—	1.4	—	0.3	0.4	2.7
Development										
Productive	2.4	0.6	107.2	0.8	69.4	2.5	285.2	27.3	1.3	496.6
Dry	—	0.1	7.3	—	0.7	—	—	0.1	—	8.2

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

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 2023. 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 2023									
Exploratory									
Gross	–	–	–	–	–	1.0	10.0	–	11.0
Net	–	–	–	–	–	0.1	1.9	–	2.0
Development									
Gross	5.0	3.1	161.0	–	25.0	9.0	97.0	1.0	301.1
Net	3.1	0.5	118.7	–	4.6	3.1	18.9	0.4	149.3

[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	2023	2022
Dividend income		18,133	29,005
Interest and other income		6,007	2,115
Total income		24,140	31,120
Administrative and other expenses		(747)	(563)
Net impairment of fixed asset investments	2	—	3,433
Loss on termination of operations		(8)	—
Profit (loss) before interest and taxation		23,385	33,990
Interest payable to subsidiaries		(9,280)	(3,567)
Net finance income (expense) relating to pensions	4	391	165
Profit (loss) before taxation		14,496	30,588
Taxation	6	(126)	(48)
Profit (loss) for the year		14,370	30,540

Company statement of comprehensive income

For the year ended 31 December			$ million
	Note	2023	2022
Profit (loss) for the year		14,370	30,540
Other comprehensive income			
Items that may be reclassified subsequently to profit or loss			
Currency translation differences		407	(1,037)
		407	(1,037)
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension liability or asset	4	(1,877)	(1,530)
Income tax relating to items that will not be reclassified	6	513	931
		(1,364)	(599)
Other comprehensive income		(957)	(1,636)
Total comprehensive income		13,413	28,904

The parent company financial statements of BP p.l.c. on pages 275-334 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

Company balance sheet

At 31 December			$ million
	Note	2023	2022
Non-current assets			
Investments	2	**177,741**	165,483
Receivables	3	**853**	772
Defined benefit pension plan surpluses	4	**6,631**	7,716
		185,225	173,971
Current assets			
Receivables	3	**5,864**	10,646
Cash and cash equivalents		**208**	85
		6,072	10,731
Total assets		**191,297**	184,702
Current liabilities			
Payables	5	**11,707**	5,864
Net current (liabilities)/assets		**(5,635)**	4,867
Total assets less current liabilities		**179,590**	178,838
Non-current liabilities			
Payables	5	**53,583**	53,489
Deferred tax liabilities	6	**2,305**	2,692
Defined benefit pension plan deficits	4	**143**	128
		56,031	56,309
Total liabilities		**67,738**	62,173
Net assets		**123,559**	122,529
Capital and reserves[a]			
Profit and loss account			
Brought forward		**88,541**	73,324
Profit (loss) for the year		**14,370**	30,540
Other movements		**(14,718)**	(15,323)
		88,193	88,541
Called-up share capital	7	**4,496**	4,795
Share premium account		**13,815**	13,692
Other capital and reserves		**17,055**	15,501
		123,559	122,529

[a] See Statement of changes in equity on page 277 for further information.

The financial statements on pages 275-334 were approved and signed by the chief executive officer on 8 March 2024 having been duly authorized to do so by the board of directors:

Murray Auchincloss Chief executive officer

The parent company financial statements of BP p.l.c. on pages 275-334 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

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 2023	**4,795**	**13,692**	**2,180**	**26,509**	**(12,154)**	**(1,034)**	**88,541**	**122,529**
Profit (loss) for the year	**—**	**—**	**—**	**—**	**—**	**—**	**14,370**	**14,370**
Other comprehensive income	**—**	**—**	**—**	**—**	**—**	**407**	**(1,364)**	**(957)**
Total comprehensive income	**—**	**—**	**—**	**—**	**—**	**407**	**13,006**	**13,413**
Dividends	**—**	**—**	**—**	**—**	**—**	**—**	**(4,830)**	**(4,830)**
Repurchases of ordinary share capital[a]	**(316)**	**—**	**316**	**—**	**—**	**—**	**(8,167)**	**(8,167)**
Share-based payments, net of tax	**17**	**123**	**—**	**—**	**831**	**—**	**(357)**	**614**
At 31 December 2023	**4,496**	**13,815**	**2,496**	**26,509**	**(11,323)**	**(627)**	**88,193**	**123,559**
At 1 January 2022	5,215	12,745	1,705	26,509	(12,623)	3	73,324	106,878
Profit (loss) for the year	—	—	—	—	—	—	30,540	30,540
Other comprehensive income	—	—	—	—	—	(1,037)	(599)	(1,636)
Total comprehensive income	—	—	—	—	—	(1,037)	29,941	28,904
Dividends	—	—	—	—	—	—	(4,365)	(4,365)
Repurchases of ordinary share capital	(475)	—	475	—	—	—	(10,493)	(10,493)
Share-based payments, net of tax	14	168	—	—	469	—	134	785
New issue of ordinary share capital	41	779	—	—	—	—	—	820
At 31 December 2022	4,795	13,692	2,180	26,509	(12,154)	(1,034)	88,541	122,529

[a] See Note 7 for further information.

The parent company financial statements of BP p.l.c. on pages 275-334 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

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 2023 were approved and signed by the chief executive officer on 8 March 2024 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 in paragraph 38 of IAS 1 'Presentation of Financial Statements' to present comparative information in respect of paragraph 79(a)(iv) of IAS 1.

(c) the requirements of IAS 7 ‘Statement of Cash Flows’;

(d) 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;

(e) the requirements of paragraphs 17 and 18A of IAS 24 ‘Related Party Disclosures’;

(f) 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;

(g) 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;

(h) the requirements of paragraphs 45(b) and 46 to 52 of IFRS 2 'Share-based Payment';

(i) the requirements of IFRS 7 ‘Financial Instruments: Disclosures’; and

(j) 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.

In May 2023, the IASB issued International Tax Reform – Pillar Two Model Rules - Amendments to IAS 12 Income Taxes to clarify the application of IAS 12 to tax legislation enacted or substantively enacted to implement Pillar Two of the Organisation for Economic Co-operation and Development’s Base Erosion and Profit Shifting project, which aims to address the tax challenges arising from the digitalisation of the economy. The amendments include a mandatory temporary exception from accounting for deferred tax on such tax law. In July 2023, the UK government enacted legislation to implement the Pillar Two rules. The legislation is effective for bp from 1 January 2024 and includes an income inclusion rule and a domestic minimum tax, which together are designed to ensure a minimum effective tax rate of 15%. Similar legislation is being enacted by other governments around the world. In line with the amendments to IAS 12, the exception from accounting for deferred tax for the Pillar Two rules has been applied and there are no impacts on the financial statements for 2023. Based on an assessment of historic data and forecasts for the year ending 31 December 2024, the company does not expect a material exposure to Pillar Two income taxes for the year ending 31 December 2024.

There are no new IFRS standards or amended standards or interpretations adopted from 1 January 2023 onwards, including the amendments to IAS 12 'Income Taxes' described above and IFRS 17 'Insurance Contracts,' that have a significant impact on the financial statements. Further, there are no new or amended standards not yet adopted that are expected to have a material impact.

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 group are set out in boxed text below, and should be read in conjunction with the information provided in the Notes on financial statements.

The areas requiring the most significant judgement and estimation in the preparation of the 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.

The parent company financial statements of BP p.l.c. on pages 275-334 do not form part of bp’s Annual Report on Form 20-F as filed with the SEC.

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 for all subsidiaries were revised during 2023. Prices disclosed are in real 2022 terms. The near term Brent oil assumption was held constant at $70 per barrel to reflect near-term supply constraints before declining after 2030 to $50 per barrel by 2050 continuing to reflect the assumption that as the energy system decarbonizes, falling oil demand will cause oil prices to decline. The price assumptions for Henry Hub gas up to 2050 were held constant at $4.00 per mmBtu reflecting an assumption that declining domestic demand in the US is offset by higher LNG exports. 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 consistent with the temperature goal of the Paris climate change agreement, of holding the increase in the global average temperature to well below 2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels.

Judgements and estimates made in assessing the impact of the geopolitical and economic environment

In preparing the 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 137 to 246) 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 2023 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 2023 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 group's assets within the next financial year.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Discount rates

For discounted cash flow calculations, future cash flows are adjusted for risks specific to the CGU. Value-in-use calculations are typically discounted using a pre-tax discount rate based upon the cost of funding the 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 2023, the post-tax discount rate was 8% (2022 7%) 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 4% was reflected in the post-tax discount rate (2022 1% to 2%). 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 20% (2022 7% to 18%) 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 in 2023 (including those in equity accounted entities), where the risk profile of expected cash flows supports a lower rate, tests were performed using a post-tax WACC-based discount rate of 6.5%. For assets tested in 2022, the tests were performed on a fair value less costs of disposal basis using a post-tax cost of equity-based discount rate of 6%.

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 170. The investment appraisal price assumptions are 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 are 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 (in real 2022 terms) for the near term Brent oil assumption was held constant at $70 per barrel to reflect near term supply constraints before declining after 2030 to $50 per barrel by 2050 continuing to reflect the assumption that as the energy system decarbonises, falling oil demand will cause oil prices to decline. The price assumptions for Henry Hub gas up to 2050 were held constant at $4.00 per mmBtu reflecting an assumption that declining domestic demand in the US is offset by higher LNG exports. These price assumptions are derived from the central case investment appraisal assumptions, adjusted where applicable to reflect short-term market conditions (see page 30). A summary of the group's revised price assumptions for Brent oil and Henry Hub gas, applied in 2023 and 2022, in real 2022 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 consistent with the temperature goal of the Paris climate change agreement, of holding the increase in the global average temperature to well below 2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels. However, they do not correspond to any specific Paris-consistent scenario. An inflation rate of 2% (2022 2%) is applied to determine the price assumptions in nominal terms.

2023 price assumptions	**2024**	**2025**	**2030**	**2040**	**2050**
Brent oil ($/bbl)	70	70	70	63	50
Henry Hub gas ($/mmBtu)	4.00	4.00	4.00	4.00	4.00

2022 price assumptions	**2023**	**2025**	**2030**	**2040**	**2050**
Brent oil ($/bbl)	78	71	71	59	46
Henry Hub gas ($/mmBtu)	4.08	4.08	4.08	3.57	3.57

Oil and natural gas reserves

The majority of bp's reserves and resources that support the carrying value of the company's subsidiaries holding upstream oil and gas properties are expected to be produced over the next 12 years.

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.

The parent company financial statements of BP p.l.c. on pages 275-334 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

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. 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-retirement 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-retirement 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-retirement 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.

Deferred tax assets are only recognized to the extent that it is probable that they will be realized in the future.

The parent company financial statements of BP p.l.c. on pages 275-334 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

1. Material accounting policy information, significant judgements, estimates and assumptions – continued

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply in the period when the asset is realized or the liability is settled, based on tax rates (and tax laws) that have been enacted or substantively enacted at the balance sheet date. Deferred tax assets and liabilities are not discounted. See Note 6 for further details.

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. This includes the derecognition of receivables for which discounting arrangements are entered into.

Financial assets measured at amortized cost

Financial assets are classified as measured at amortized cost when they are held in a business model the objective of which is to collect contractual cash flows and the contractual cash flows represent solely payments of principal and interest. Such assets are carried at amortized cost using the effective interest method if the time value of money is significant. Gains and losses are recognized in profit or loss when the assets are derecognized or impaired and when interest income is recognized using the effective interest method. This category of financial assets includes trade and other receivables.

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.

The parent company financial statements of BP p.l.c. on pages 275-334 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

2. Investments

			$ million
	Subsidiaries[a]	Associates	
	Shares	Shares	Total
Cost			
At 1 January 2023	**169,148**	**9**	**169,157**
Additions	**12,266**	**—**	**12,266**
Disposals	**(8)**	**—**	**(8)**
At 31 December 2023	**181,406**	**9**	**181,415**
Amounts provided			
At 1 January 2023	**3,674**	**—**	**3,674**
At 31 December 2023	**3,674**	**—**	**3,674**
Cost			
At 1 January 2022	166,760	9	166,769
Additions	2,388	—	2,388
At 31 December 2022	169,148	9	169,157
Amounts provided			
At 1 January 2022	7,107	—	7,107
Additions	—	—	—
Reversals	(3,433)	—	(3,433)
At 31 December 2022	3,674	—	3,674
At 31 December 2023	**177,732**	**9**	**177,741**
At 31 December 2022	165,474	9	165,483

At 31 December 2023, the carrying amount of the company's net assets of $123.6 billion (2022 $122.5 billion) exceeded the group's market capitalisation of $102.2 billion (2022 $105.8 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. Whilst the headroom determined by these tests has reduced, which is largely related to impacts of updates to price assumptions and discount rate assumptions, no impairment was determined to be required in respect of the company's investments in subsidiaries.

The more important subsidiaries of the company at 31 December 2023 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 14.

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
Burmah Castrol PLC	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

The carrying value of the investment in BP International Limited at 31 December 2023 was $76,244 million (2022 $76,281 million).

The carrying value of the investment in BP Gamma Holdings Limited at 31 December 2023 was $10,000 million (2022 Nil).

3. Receivables

				$ million
		2023		2022
	Current	Non-current	Current	Non-current
Amounts receivable from subsidiaries	**5,862**	**853**	10,641	772
Amounts receivable from associates	**2**	**—**	3	—
Other receivables	**—**	**—**	2	—
	5,864	**853**	10,646	772

The company has current receivables of $4,161 million on Internal Funding Accounts (IFAs) receivable from BP International Limited (2022 $10,218 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.

The parent company financial statements of BP p.l.c. on pages 275-334 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

4. Pensions

The pension obligation consists primarily of a 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. The plan was closed to new joiners in 2010 and was closed to future accrual on 30 June 2021. Employees in the UK are eligible for membership of a defined contribution plan.

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 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 2023 formal actuarial valuation. No contractually committed funding was due at 31 December 2023. The closure of the defined benefit plan to future accrual reduces the need for funding and the plan's expected future funding volatility.

The surplus relating to the primary UK 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.

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 2023. The UK plans are subject to a formal actuarial valuation every 3 years. The most recent formal actuarial valuation of the main pension plan was as at 31 December 2020; the 31 December 2023 valuation is currently underway.

The material financial assumptions used for estimating 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		%
	2023	2022
Discount rate for plan liabilities	**4.8**	5.0
Rate of increase for pensions in payment	**2.8**	2.9
Rate of increase in deferred pensions	**2.8**	2.9
Inflation for plan liabilities	**3.0**	3.1

Financial assumptions used to determine benefit expense		%
	2023	2022
Discount rate for plan other finance expense	**5.0**	1.8

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
	2023	2022
Life expectancy at age 60 for a male currently aged 60	**27.4**	26.9
Life expectancy at age 60 for a male currently aged 40	**29.2**	28.5
Life expectancy at age 60 for a female currently aged 60	**29.2**	28.8
Life expectancy at age 60 for a female currently aged 40	**30.6**	30.6

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 trustee's long-term investment objective for the primary UK plan as it matures is to invest in assets whose value changes in the same way as the plan liabilities, in order to reduce the level of funding risk. To move towards this objective, the UK plan uses a liability driven investment (LDI) approach for part of the portfolio, investing primarily in government bonds to achieve this matching effect for 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.

For the primary UK pension plan there is an agreement with the trustee to increase the proportion of assets with liability matching characteristics over time primarily by reducing the proportion of plan assets held as equities and increasing the proportion held as bonds. During 2023, the asset allocation policy switched 2% of plan assets from equities to bonds (2022 2%).

4. Pensions – continued

The company's asset allocation policy for the primary plan is 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 2023 were $6,215 million (2022 $3,981 million) of government-issued nominal bonds and $13,177 million (2022 $11,945 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 286.

			$ million
		2023	2022
Fair value of pension plan assets			
Listed equities	– developed markets	862	1,252
	– emerging markets	28	117
Private equity[a]		2,022	2,715
Government issued nominal bonds[b]		6,285	4,039
Government issued index-linked bonds[b]		13,177	11,945
Corporate bonds[b]		6,144	6,317
Property[c]		2,437	2,297
Cash		453	567
Other		1,123	1,088
Debt (repurchase agreements) used to fund liability driven investments		(6,485)	(5,290)
		26,046	25,047

[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.

		$ million
	2023	2022
Analysis of the amount charged to profit or loss		
Current service cost[a]	44	41
Past service cost[b]	4	23
Settlement	–	(8)
Operating charge / (credit) relating to defined benefit plans	48	56
Payments to defined contribution plan	132	110
Total operating charge / (credit)	180	166
Interest income on plan assets[c]	(1,259)	(694)
Interest on plan liabilities	868	529
Other finance (income)	(391)	(165)
Analysis of the amount recognized in other comprehensive income		
Actual asset return less interest income on pension plan assets	(677)	(12,955)
Change in financial assumptions underlying the present value of the plan liabilities	(650)	11,528
Change in demographic assumptions underlying the present value of plan liabilities	(229)	46
Experience gains and losses arising on the plan liabilities	(321)	(149)
Remeasurements recognized in other comprehensive income	(1,877)	(1,530)

[a] The costs of managing plan investments are offset against the investment return. Following the closure of the main UK pension plan to future accrual, current service cost consists of $34 million of the costs of administering the pension plan and $10 million of current service cost from the remaining small worldwide schemes administered and reported through the UK.
[b] Past service costs predominantly represent costs associated with the removal of some member benefits in non bp p.l.c pension plans being replaced with new arrangements and reported through bp p.l.c.
[c] 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.

The parent company financial statements of BP p.l.c. on pages 275-334 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

4. Pensions – continued

		$ million
	2023	2022
Movements in benefit obligation during the year		
Benefit obligation at 1 January	**17,459**	32,800
Exchange adjustments	**1,055**	(3,220)
Operating charge relating to defined benefit plans	**48**	56
Interest cost	**868**	529
Contributions by plan participants	**6**	9
Benefit payments (funded plans)[a]	**(1,071)**	(1,211)
Benefit payments (unfunded plans)[a]	**(7)**	(5)
Disposals	**—**	(74)
Remeasurements	**1,200**	(11,425)
Benefit obligation at 31 December	**19,558**	17,459
Movements in fair value of plan assets during the year		
Fair value of plan assets at 1 January	**25,047**	42,844
Exchange adjustments	**1,462**	(4,258)
Interest income on plan assets[b]	**1,259**	694
Contributions by plan participants	**6**	9
Contributions by employers (funded plans)	**20**	10
Benefit payments (funded plans)[a]	**(1,071)**	(1,211)
Disposals	**—**	(86)
Remeasurements[b]	**(677)**	(12,955)
Fair value of plan assets at 31 December[c d]	**26,046**	25,047
Surplus at 31 December	**6,488**	7,588
Represented by		
Asset recognized	**6,631**	7,716
Liability recognized	**(143)**	(128)
	6,488	7,588
The surplus may be analysed between funded and unfunded plans as follows		
Funded	**6,631**	7,716
Unfunded	**(143)**	(128)
	6,488	7,588
The defined benefit obligation may be analysed between funded and unfunded plans as follows		
Funded	**(19,415)**	(17,331)
Unfunded	**(143)**	(128)
	(19,558)	(17,459)

a The benefit payments amount shown above comprises $1,044 million benefits (2022 $1,185 million) plus $34 million (2022 $31 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 $25,760 million of assets held in the BP Pension Fund (2022 $24,788 million) and $241 million held in the BP Global Pension Trust (2022 $202 million), as well as $35 million representing the company's share of Merchant Navy Officers Pension Fund (2022 $44 million) and $10 million of Merchant Navy Ratings Pension Fund (2022 $13 million).
d The fair value of plan assets includes borrowings related to the LDI programme as described on page 285.

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 2023 for the company's plans would have had the effects shown in the table below. The effects shown for the expense in 2024 comprise the total of current service cost and net finance income or expense.

		$ million
	One percentage point	
	Increase	**Decrease**
Discount rate[a]		
Effect on pension expense in 2024	**(197)**	**173**
Effect on pension obligation at 31 December 2023	**(2,258)**	**2,809**
Inflation rate[b]		
Effect on pension expense in 2024	**89**	**(83)**
Effect on pension obligation at 31 December 2023	**1,872**	**(1,738)**

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 2024 pension expense by $27 million and the pension obligation at 31 December 2023 by $575 million.

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4. Pensions – 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 2023 are as follows:

	$ million
Estimated future benefit payments	
2024	**1,168**
2025	**1,111**
2026	**1,124**
2027	**1,144**
2028	**1,157**
2029-2033	**5,950**
	Years
Weighted average duration	**12.9**

5. Payables

				$ million
		2023		2022
	Current	**Non-current**	Current	Non-current
Amounts payable to subsidiaries	**10,750**	**53,439**	5,230	53,358
Accruals	**747**	**11**	498	8
Other payables	**210**	**133**	136	123
	11,707	**53,583**	5,864	53,489

Included in current amounts payable to subsidiaries are interest-bearing payables with BP Finance p.l.c. and BP Gamma Holdings Limited. Prior to 2023, the company's interest bearing payables with BP Finance p.l.c. and BP International Limited were exposed to 3 month USD LIBOR. Publication of 3 month USD LIBOR ceased from 30 June 2023 however a synthetic LIBOR continues to be published. The interest-bearing payable of $5,079 million (2022 $5,069 million) with BP Finance p.l.c. has interest charged based on a 3-month USD synthetic LIBOR rate minus 0.14% 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 $5,500 million (2022 Nil) with BP Gamma Holdings Limited has interest charged based on a SOFR plus 23 basis points with a maturity date of December 2024 and repayable at two business day's notice. Though the loan with BP Gamma Holdings Limited is due in 2024, 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 (2022 $52,585 million), with interest being charged based on a 3-month USD synthetic LIBOR rate plus 75 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.

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
	2023	2022
Due within		
1 to 2 years	**129**	60
2 to 5 years	**52,747**	224
More than 5 years	**707**	53,205
	53,583	53,489

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6. Taxation

		$ million
Tax charge included in total comprehensive income	2023	2022
Deferred tax		
Origination and reversal of temporary differences in the current year	(387)	(883)
This comprises:		
Taxable temporary differences relating to pensions	(387)	(883)
Deferred tax		
Deferred tax liability		
Pensions[a]	2,305	2,692
Net deferred tax liability	2,305	2,692
Analysis of movements during the year		
At 1 January	2,692	3,575
Charge (credit) for the year in the income statement	126	48
Charge (credit) for the year in other comprehensive income	(513)	(931)
At 31 December	2,305	2,692

[a] In November 2023 the UK Government announced a reduction in the authorised surplus payments charge applicable to defined benefit pension schemes from 35% to 25%. The legislation has not yet been enacted or substantively enacted, but is expected to be effective from 6 April 2024. The change is expected to reduce the deferred tax liability on pension plan surpluses by around $0.7 billion with the related gain recognised in other comprehensive income when the legislation is substantively enacted.

At 31 December 2023, deferred tax assets of $817 million on other temporary differences; $32 million relating to pensions, $159 million relating to income losses and $626 million relating to other deductible temporary differences (2022 $909 million on other temporary differences, comprising $8 million relating to pensions; $119 million relating to income losses and $782 million relating to other deductible temporary differences) were not recognised 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 unrecognised temporary differences.

7. Called-up share capital

The allotted, called-up and fully paid share capital at 31 December was as follows:

	2023		2022	
Issued	Shares thousand	$ million	Shares thousand	$ million
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	19,097,783	4,774	20,778,082	5,194
Issue of new shares for employee share-based payment plans	66,000	17	55,000	14
Issue of new shares - other[b]	—	—	165,105	41
Repurchase of ordinary share capital	(1,262,983)	(316)	(1,900,404)	(475)
At 31 December	17,900,800	4,475	19,097,783	4,774
		4,496		4,795

[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.

[b] 165 million new ordinary shares were issued in April 2022 as non-cash consideration for the acquisition of the public units of BP Midstream Partners LP.

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 2023 the company repurchased 1,263 million ordinary shares for a total consideration of $7,918 million, including transaction costs of $43 million. All shares purchased were for cancellation. The repurchased shares represented 7.1% of ordinary share capital. A further 156 million ordinary shares were repurchased between the end of the reporting period and 16 February 2024, the latest practicable date before the completion of these financial statements, for a total cost of $922 million of which $746 million has been accrued at 31 December 2023. The number of shares in issue is reduced when shares are repurchased.

7. Called-up share capital – continued

Treasury shares[a]

	2023		2022	
	Shares thousand	Nominal value $ million	Shares thousand	Nominal value $ million
At 1 January	**1,124,927**	**281**	1,137,457	283
Purchases for settlement of employee share plans	**24,688**	**6**	14,150	4
Issue of new shares for employee share-based payment plans	**71,039**	**19**	55,000	14
Shares re-issued for employee share-based payment plans	**(143,575)**	**(35)**	(81,680)	(20)
At 31 December	**1,077,079**	**271**	1,124,927	281
Of which - shares held in treasury by bp	**726,339**	**183**	940,571	235
- shares held in ESOP trusts	**350,704**	**88**	184,356	46
- shares held by bp's US plan administrator[b]	**36**	**—**	—	—

[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 4.9% (2022 5.0%) of the called-up ordinary share capital of the company.

During 2023, the movement in shares held in treasury by bp represented less than 1.1% (2022 less than 0.5%) of the 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 fair value of the consideration given in excess of the nominal value of the ordinary shares issued in an acquisition made by the issue of shares.

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 $23,858 million (2022 $23,610 million), the distribution of which is limited by statutory or other restrictions.

The financial statements for the year ended 31 December 2023 do not reflect the dividend announced on 6 February 2024 and which is expected to be paid on 28 March 2024; this will be treated as an appropriation of profit in the year ended 31 December 2024.

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 2023, for these arrangements is $649 million (2022[a] $595 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 2023, maximum guaranteed amounts pertaining to debt and lease arrangements were $61,900 million (2022 $57,265 million). These maximum amounts are more than the actual guaranteed exposure due at the balance sheet date as well as more than remaining obligations under the guaranteed contracts.

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.

The parent company financial statements of BP p.l.c. on pages 275-334 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

9. Financial guarantees and other contingencies – continued

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 Mexico oil spill. The company has also issued uncapped guarantees for certain subsidiaries' liabilities under the Plaintiffs' Steering Committee agreement relating to the Gulf of Mexico 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.

[a] An amendment has been made to prior year comparatives for the financial guarantee maximum exposure (previously reported as $107 million).

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
Remuneration of directors	2023	2022
Total for all directors		
Emoluments	8	8
Amounts awarded under incentive schemes[a]	6	13
Total	14	21

[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. Further information is provided in the Directors' remuneration report on page 105.

Directors' remuneration costs are borne by other undertakings within the group.

12. Employee costs and numbers

		$ million
Employee costs	2023	2022
Wages and salaries	1,211	924
Social security costs	192	131
	1,403	1,055

Average number of employees	2023	2022
gas & low carbon energy	430	329
oil production & operations	168	187
customers & products	1,571	1,182
other businesses and corporate	2,076	1,893
	4,245	3,591

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. Events after the reporting period

On 14 February 2024 bp announced that it had agreed to form a new joint venture in Egypt with ADNOC (bp 51%, ADNOC 49%). As part of the agreement bp will contribute its interests in three non-operated development concessions as well as exploration agreements in Egypt, and ADNOC will make a proportionate cash contribution. Formation of the joint venture and completion of these transactions is subject to regulatory approval. From 14 February 2024 the associated carrying values of these interests have been determined to meet the criteria to be classified as assets held for sale under IFRS 5 Non-current Assets Held for Sale and Discontinued Operations. The carrying value of fixed assets associated with these interests at 31 December 2023 was $1.4 billion. The impacts are expected to be reflected in the group's first quarter 2024 interim financial statements.

The parent company financial statements of BP p.l.c. on pages 275-334 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

14. 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 2023 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		
Level 11, 307 Queen Street, Brisbane, QLD, 4000, Australia		
Onyx Insight Australia Pty Ltd	Ordinary	100.00
Level 15, 240 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		
Advance Petroleum Holdings Pty Ltd	Ordinary	100.00
Advance Petroleum Pty Ltd	Ordinary	100.00
Air Refuel Pty Ltd	Ordinary A; Ordinary B	100.00
Allgreen Pty Ltd	Ordinary	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
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
Clarisse Holdings Pty Ltd	Ordinary	100.00
Dermody Petroleum 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
Open Energi Australia Pty Ltd	Ordinary; Ordinary A	100.00
Taradadis Pty. Ltd.	Ordinary	100.00

The parent company financial statements of BP p.l.c. on pages 275-334 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

14. Related undertakings of the group – continued

West Kimberley Fuels Pty Ltd	Ordinary	100.00
Austria		
Am Belvedere 10, 1100 Wien, Austria		
CASTROL Austria GmbH	Ordinary	100.00
Castrol Österreich Lubricants 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
Bahamas		
2 Bayside Executive Park, West Bay, Nassau, Bahamas		
ARCO Trinidad Exploration and Production Company Limited	Ordinary	100.00
Barbados		
The Financial Services Centre, Bishop's Court Hill, St. Michael, Barbados		
BP (Barbados) Holding SRL	Ordinary	100.00
BP Train 2/3 Holding SRL	Ordinary	100.00
Belgium		
Langerbruggekaai 18, Gent, 9000, Belgium		
BP Iraq N.V.	Ordinary	100.00
Castrol Belgium B.V.	Ordinary	100.00
Brazil		
Avenida das Américas 3434, Bloco 7, Sala 301 a 308 (parte), Barra da Tijuca, Rio de Janeiro, 22640-102, Brazil		
BP Brasil Ltda.	Membership Interest	100.00
BP Energy do Brasil Ltda.	Ordinary	100.00
Castrol Brasil Ltda.	Ordinary	100.00
Avenida das Nações Unidas, nº 12.399, 4º 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 S.A.	Ordinary	100.00
Avenida das Nações Unidas, nº 12.399, salas 62,63 e 64, lado B, 6º andar, Edifício Landmark, São Paulo/SP, CEP 04578-000, Brazil		
BP Comercializadora 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
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
1700, 421 – 7th Avenue SW Calgary, AB T2P 4K9, Canada		
Finite Carbon Canada LTD	Ordinary	80.50
240 Fourth Avenue SW, Calgary AB T2P 2H8, Canada		
563916 Alberta Ltd.	Preference	33.33
Dome Beaufort Petroleum Limited	Ordinary	100.00
Dome Wallis (1980) Limited Partnership	Partnership interest	92.50
77 King Street West, Suite 400, Toronto, Canada		
TravelCentres Canada Corporation	Membership Interest	100.00
TravelCentres Canada Inc.	Membership Interest	100.00
TravelCentres Canada Limited Partnership	Limited Partner	100.00
900, 1959 Upper Water Street, Halifax, NS, B3J 3N2, Canada		
BP Canada Energy Development Company	Ordinary	100.00
BP Canada Energy Group ULC	Ordinary	100.00
Chile		
Av. Américo Vespucio Sur No. 100, of. 1101, Las Condes, Santiago, Chile		
Burmah Chile SpA	Ordinary	100.00

The parent company financial statements of BP p.l.c. on pages 275-334 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

14. Related undertakings of the group – continued

China		
#4047, Room 313, Floor 3, Shanshui Tower, No. 3, Guloudong Avenue, Beijing, Miyun District, China		
Beijing BP Advanced Mobility Limited	Membership Interest	100.00
1-3 / F, Unit D2,1958 Double Innovation Park, No. 220, Huashan Road, Zhongyuan District, Zhengzhou City, China		
Zhenzhou BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00
302,252, Duxin North Road, Fotang Town, Yiwu City, Zhejiang Province, China		
Jinhua BP Xiaoju New Energy Technology Co., Ltd.	Membership Interest	70.00
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
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	70.00
C2256, Zhongchuang Space,9-14/F, Building A, Baoye Center, No.31 Jianshe 1st Road, Qingshan District, Wuhan City, Hubei Province, China		
Wuhan BP Xiaoju New Energy Technology Co., Ltd.	Membership Interest	70.00
D21 Room 306, No.64, Shiji Village Section, Shiji Town, Guangzhou, Panyu District, China		
Guangzhou BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00
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	70.00
Fenglin West Road, Dongpu Street,Yuecheng District, Shaoxing City, Zhejiang Province, China		
Shaoxing BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00
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. 1, Building 29, Tang'an Community, Haihong Street, Taizhou Bay New District, Taizhou City, Zhejiang Province, China		
Taizhou BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00
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	70.00
No.0152, Room 16, 17, 18, 7/F, Unit 3, Building 4, Greenland Liansheng International, East of Xingxin North Road and north of Yingbin Road, Jinhuayuan Street, Guanshanhu District, Guiyang City, Guizhou Province, China		
GuiYang City BP Xiaoju New Energy Technology Co. Ltd.	Membership Interest	70.00
No.17-5, Second Floor 04, Sumitomo Homeland, Binhu District, Wuxi City, China		
Wuxi BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00
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
Office 6, Room 708, No. 33 Jinmeng Lane, Xiangzhou District, Zhuhai City, Guangdong Province, China		
Zhuhai BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00
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 1001, 2nd Floor, Building 1,Qinqiao Agricultural Innovation Headquarters Building, Xiash, Shiyang Town, Taishun County, Wenzhou City, Zhejiang Province, China		
Wenzhou BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00
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 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 1908, YOUYOU International Plaza, Pudong District, Shanghai, China		
BP (Shanghai) Technology Company Limited	Membership Interest	100.00

14. Related undertakings of the group – continued

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	70.00
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	70.00
Room 2103, 10 Hua Xia Road, Tianhe District, Guangzhou, PR, China		
BP (Guangzhou) Advanced Mobility Limited	Ordinary	100.00
Room 215, Building 5, No. 72, Nanxiang 2nd Road, Sciecheng, Huangpu District, 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	70.00
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	70.00
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 Technology Co., Ltd	Membership Interest	70.00
Room 2302, Unit 1, Building 20, Shengtang Supreme, Luolong District, Luoyang City, Henan Province, China		
Luoyang BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00
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	70.00
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	70.00
Room 302, No.252, Duxin North Road, Fotang Town, Yiwu City, Jinhua City, Zhejiang Province, China		
Jinhua BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00
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 Technology Co., Ltd.	Membership Interest	70.00
Room 3173, Building 1,No.39 Hongtu Road, Nancheng Street, Dongguan City, Guangdong Province, China		
Dongguan BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00
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	70.00
Room 402, 4F, Block C, Complex Building, No.30 Jiefang Road, Lixia District, Jinan City, Shandong Province, China		
Jinan BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00
Room 402-12, No.90~96 Science Avenue (even), Huangpu District, Guangzhou, China		
Guangzhou Huangpu BP Xiaoju New Energy Technology Co., Ltd.	Membership Interest	70.00
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	70.00
Room 431, No. 30, East Qilong Road, Guangzhou, China		
Guangdong Jintian Technology Co., Ltd.	Membership Interest	100.00
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 6, Ground floor, Building A, No.2 Taohong West Street, Shima Village, Junhe Street, Baiyun District, Guangzhou, China		
Guangdong Jintian New Energy Automobile Co., Ltd.	Membership Interest	100.00
Room 603, Floor 6, No. 3 Lane 2889 Jinke Road, (Shanghai) Pilot Free Trade Zone, China		
Onyx Insight Analytics Shanghai Limited	Membership Interest	100.00
Room 703, Building 32, No.258 Shengpu Road, Suzhou Industrial Park, China		
Suzhou BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00
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 Technology Co., Ltd.	Membership Interest	70.00
Room 7088-594, 7th Floor, 1558 Jiangnan Road, Ningbo High-tech Zone, Zhejiang Province, China		
Ningbo BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00
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	70.00
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

The parent company financial statements of BP p.l.c. on pages 275-334 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

14. Related undertakings of the group – continued

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	70.00
Room A018, 10th Floor, Kaifeng Building, No. 188, Fuqiang Street, Yuhua District, Shijiazhuang City, Hebei Province, China		
Shijiazhuang City BP Xiaoju New Energy Technology Co. Ltd.	Membership Interest	70.00
South of NanGang Industrial Area, and East of Hai Gang Road, Tianjin Economic Development Area, Tianjin, China		
Castrol (Tianjin) Lubricants Co., Ltd	Membership Interest	100.00
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
Unit 03A, 33rd Floor, T1 Building, IFC, No.188, Jiefang West Road, Dingwangtai Street, Changsha City, Furong District, China		
Changsha BP Xiaoju New Energy Co., Ltd.	Membership Interest	70.00
Colombia		
Calle 80 No.11-42 Oficina 901, Bogota, 110111, Colombia		
GOAM 1 C.I S. A .S	Ordinary	100.00
Castrol Colombia Ltda.	Membership Interest	100.00
Croatia		
Savska cesta 32, Zagreb, Croatia		
Air BP Croatia d.o.o.	Ordinary	100.00
Denmark		
c/o Danish Refuelling Services I/S, Hydrantvej 16, 2770 Kastrup, Denmark		
BP Aviation A/S	Ordinary	100.00
Kampmannsgade 2. 1604 København V, Denmark		
Castrol Denmark A/S	Ordinary	100.00
Orestads Boulevard 73, Kobenhavn S, 2300, Denmark		
BP Danmark A/S	Ordinary	100.00
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		
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 Dépots d'Hydrocarbures - GDH	Ordinary	100.00
SRHP	Ordinary	100.00
Gambia		
3 Kairaba Avenue, 3rd Floor Centenary, Kanifing Municipality, Serekunda West, Gambia		
BP Exploration (Gambia) Limited	Ordinary	100.00
Germany		
Alexander-von-Humboldt-Straße 1, Gelsenkirchen, 45896, Germany		
Gelsenkirchen Raffinerie Netz GmbH	Ordinary	100.00
Ruhr Oel GmbH (ROG)	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
Timmerhellstsr. 28, Mülheim/Ruhr, 45478, Germany		
DHC Solvent Chemie GmbH	Ordinary	100.00
Überseeallee 1, 20457, Hamburg, Germany		
BP Europa SE[b]	Ordinary	100.00
BP Lingen Green Hydrogen Verwaltung GmbH	Ordinary	100.00
BP Olex Fanal Mineralöl GmbH	Ordinary	100.00
Castrol Deutschland Verwaltungsgesellschaft mbH	Ordinary	100.00

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14. Related undertakings of the group – continued

Castrol Germany GmbH	Ordinary	100.00
Wittener Straße 45, 44789 Bochum, Germany		
Aral Aktiengesellschaft	Ordinary	100.00
Aral Pulse GmbH	Ordinary	100.00
B2Mobility GmbH	Ordinary	100.00
BP Fuels Deutschland GmbH	Ordinary	100.00
bp OFW Management 1 GmbH	Ordinary	100.00
bp OFW Management 2 GmbH	Ordinary	100.00
bp OFW Management 3 GmbH	Ordinary	100.00
bp OFW Management 4 GmbH	Ordinary	100.00
Trafineo Service GmbH	Ordinary	75.00
Wittener Straße 56, Bochum, Germany		
TRaBP GbR	Partnership interest	75.00
Trafineo GmbH & Co. KG	Partnership interest	75.00
Trafineo Verwaltungs-GmbH	Ordinary	75.00
Zum Ölhafen 207, 26384 Wilhelmshaven, Germany		
Nord-West Oelleitung GmbH	Ordinary	59.33
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
Guernsey		
Albert House, South Esplanade, St. Peter Port, GY1 1AW, Guernsey		
BP Pensions (Overseas) Limited[c]	Membership Interest	100.00
Jupiter Insurance Limited	Ordinary	100.00
Hong Kong		
Unit 25-150, 25/F, Two Harbour Square, 180 Wai Yip Street, Kwun Tong, 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
Iceland		
Skogarhlid 12, 105, Reykjavik, Iceland		
Air BP Iceland	Ordinary	100.00
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
Office No. 306, Regus Business Center , 3rd Floor, Abbusali St, Saligramam, Chennai, Tamil Nadu, 600093, India		
OnSight Analytics Solutions India Private Ltd.	Ordinary	100.00
Technopolis Knowledge Park, Mahakali Caves Road, Andheri (East), Mumbai 400093, India		
BP India Private Limited	Ordinary	88.51
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		
Khur Al-Zubair, pear No 1, Basra, 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

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14. Related undertakings of the group – continued

Ireland		
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
Japan		
15th Fl. Roppongi Hills Mori Tower, 10-1 Roppongi 6-chome, Minato-ku, Tokyo106-6115, Japan		
BP Japan K.K.	Ordinary	100.00
TJKK	Ordinary	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
Korea (the Republic of)		
1304(Ocean Hill Officetel), 73 gangnam-haeanro, Dolsan-eup, Yeosu-si, Jeollanam Province, Korea (the Republic of)		
West Ocean Wind Co., Ltd.	Ordinary	55.00
19th Floor, 302, Teheran-ro, Gangnam-gu, Seoul, Korea (the Republic of)		
BP Korea Limited	Ordinary	100.00
3rd Floor, 10, Baumoe-ro 21-gil, Seocho-gu, Seoul, Korea (the Republic of)		
Onyx Insight Korea Co., Ltd.	Ordinary	100.00
Level 2 (787-87, Gunnae-ri), 18 Chunghaejinnam-ro, Wando-eup, Wando County, Jeollanam Province, Korea (the Republic of)		
Chunghaejin Offshore Wind Power Co., Ltd.	Ordinary	55.00
Level 2 (LS Tower), 7 Samyul 6-gil, Hupo-myeon, Uljin County, Gyeongsangbuk Province, Korea (the Republic of)		
Ilchool Offshore Wind Power Co., Ltd.	Ordinary	55.00
Level 3, 702-ho, 61-18 Odongdo-ro, Yeosu-si, Jeollanam Province, Korea (the Republic of)		
YiSunSin Offshore Wind Co., Ltd.	Ordinary	55.00
Luxembourg		
Bâtiment B, 36 route de Longwy, L-8080 Bertrange, Luxembourg		
Aral Luxembourg S.A.	Ordinary	100.00
Aral Tankstellen Services Sarl	Ordinary	100.00
Malaysia		
Level 9, Tower 5, Avenue 7, The Horizon Bangsar South City, No. 8, Jalan Kerinchi, Kuala Lumpur, 59200, Malaysia		
Aspac Lubricants (Malaysia) Sdn. Bhd.	Membership Interest	63.03
BP Business Service Centre Asia Sdn Bhd	Ordinary	100.00
BP Castrol Lubricants (Malaysia) Sdn. Bhd.	Ordinary	63.03
BP Malaysia Holdings Sdn. Bhd.	Ordinary	70.00
Mexico		
Avenida Santa Fe 505, Col. Cruz Manca Santa Fe, Delegacion Cuajimalpa, Mexico		
BP Energía México, S. de R.L. de C.V.	Ordinary; Ordinary B	100.00
BP Estaciones y Servicios Energéticos, Sociedad Anónima de Capital Variable	Ordinary A; Ordinary B	100.00
BP Exploration Mexico, S.A. De C.V.	Ordinary A; Ordinary B	100.00
BP Servicios de Combustibles S.A. de C.V.	Ordinary	100.00
BP Servicios territoriales, S.A. de C.V.	Ordinary	100.00
Castrol Mexico, S.A. de C.V.	Ordinary A; Ordinary B	100.00
Mes Tecnologia En Servicios Y Energia, S.A. De C.V.	Ordinary A; Ordinary B	100.00
Mozambique		
Torres Rani, Avenida Marginal, Talhão 141, 6° andar, Maputo, Mozambique		
BP Mocambique Limitada	Ordinary	100.00
Netherlands		
Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, England, United Kingdom		
BP Capital Markets B.V.	Ordinary	100.00
d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands		
Actomat B.V.	Ordinary	100.00
Amoco Canada International Holdings B.V.	Ordinary	100.00
Amoco Chemicals (FSC) B.V.	Ordinary	100.00
Amoco Exploration Holdings B.V.	Ordinary	100.00

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14. Related undertakings of the group – continued

Amoco Trinidad Gas B.V.	Ordinary	100.00
BP Canada International Holdings B.V.	Ordinary	100.00
BP Commodity Supply B.V.	Ordinary	100.00
BP Egypt East Tanka B.V.	Ordinary	100.00
BP Egypt Production B.V.	Ordinary	100.00
BP Egypt Ras El Barr B.V.	Ordinary	100.00
BP Egypt West Mediterranean (Block B) B.V.	Ordinary	100.00
BP Holdings B.V.	Ordinary	100.00
BP Holdings International B.V.	Ordinary	100.00
BP Management International B.V.	Ordinary	100.00
BP Management Netherlands B.V.	Ordinary	100.00
BP Muturi Holdings B.V.	Ordinary	100.00
BP Nederland Holdings B.V.	Ordinary	100.00
BP Netherlands Upstream B.V.	Ordinary	100.00
BP Offshore Renewables Energy B.V.	Ordinary	100.00
BP Raffinaderij Rotterdam B.V.	Ordinary	100.00
BPNE International B.V.	Ordinary	100.00
Castrol B.V.	Ordinary	100.00
Castrol Holdings Europe B.V.	Ordinary	100.00
Castrol Nederland B.V.	Ordinary	100.00
Foseco Holding International B.V.	Ordinary	100.00
FreeBees B.V.	Ordinary	100.00
Vaals B.V.	Ordinary	100.00
Vaals HoldCo B.V.	Ordinary	100.00
Überseeallee 1, 20457, Hamburg, Germany		
BP Holdings Central Europe B.V.	Ordinary	100.00
New Zealand		
Ground Floor, Watercare House, 73 Remuera Road, Remuera, Auckland, 1050, New Zealand		
BP New Zealand Holdings Limited	Ordinary	100.00
BP New Zealand Share Scheme Limited	Ordinary	100.00
BP Oil New Zealand Limited	Ordinary	100.00
BP Pacific Investments Ltd	Ordinary	100.00
Castrol New Zealand Limited	Ordinary	100.00
Coro Trading NZ Limited	Ordinary	100.00
Europa Oil NZ Limited	Ordinary	100.00
Nigeria		
1, Oyinka Abayomi Drive, Ikoyi, Lagos, Nigeria		
BP Exploration (Nigeria) Limited	Ordinary	100.00
188, Awolowo Road, S. W. Ikoyi, Lagos, Nigeria		
Amoco Nigeria Exploration Company Limited	Ordinary; Preference	100.00
Amoco Nigeria Oil Company Limited	Membership Interest	100.00
Amoco Nigeria Petroleum Company Limited	Membership Interest	100.00
8/10, Broad Street, Lagos, Nigeria		
ARCO Oil Company Nigeria Unlimited	Membership Interest	100.00
Heritage Place, 13th Floor, 21 Lugard Avenue,Lagos, Ikoyi, Nigeria		
BP Global West Africa Limited	Ordinary	100.00
Norway		
Tjuvholmen allé 3, 0252 Oslo, Norway		
Air BP Norway AS	Ordinary	100.00
BP Fuels & Lubricants AS	Ordinary	100.00
BP Low Carbon Energy Norway Holding AS	Ordinary	100.00
BP Norway Offshore Wind SN2 Holdco AS	Ordinary	100.00
Oman		
PO Box 2309, Salalah, 211, Oman		
BP Global Investments Salalah & Co LLC	Membership Interest	100.00
Rock Garden Plaza – Phase 1 Building, PO Box 545, PC 118, Oman		
BP Duqm Hydrogen SPC	Ordinary	100.00

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14. Related undertakings of the group – continued

Pakistan		
D-67/1, Block # 4, Scheme # 5, Clifton, Karachi, Pakistan		
Castrol Pakistan (Private) Limited	Ordinary	100.00
Peru		
Av. Camino Real, 111 Torre B Oficina, 603 San Isidro, Lima, Peru		
Castrol Del Peru S.A.	Ordinary	100.00
Philippines		
37th Floor, LKG Tower 6801, Ayala Avenue, Makati City, Philippines		
Castrol Philippines, Inc.	Ordinary	100.00
Poland		
ul. Grzybowska 62, Warszawa, 00-844, Poland		
Castrol CEE spółka z ograniczoną odpowiedzialnością	Ordinary	100.00
ul. Pawia 9, Małopolskie, Kraków, 31-154, Poland		
BP Polska Services Sp. z o.o.	Membership Interest	100.00
Portugal		
Lagoas Park, Edificio 3, Porto Salvo, Oeiras, Portugal		
BP Portugal -Comercio de Combustiveis e Lubrificantes SA	Ordinary	100.00
Castrol Portugal, S.A.	Ordinary	100.00
Fuelplane- Sociedade Abastecedora De Aeronaves, Unipessoal, Lda	Ordinary	100.00
Sociedade de Promocao Imobiliaria Quinta do Loureiro, SA	Ordinary	100.00
Romania		
Bucharest, District 3, Boulevard Comeliu Coposu, no 6-8, Unirii View Building, Office 101, floor 1, Romania		
Castrol Lubricants RO S.R.L	Ordinary	100.00
Otopeni, 224E Calea Bucurestilor, within International Airport - Băneasa, Aurel Vlaicu - platform 2,Ilfov county, Romania		
Air BP Sales Romania S.R.L.	Ordinary	100.00
Russian Federation		
Berzarina str., 36, building1, Shchukino Municipal District, Moscow, 123060, Russian Federation		
Limited liability company Setra Lubricants	Membership Interest	100.00
Senegal		
Route de Ouakam x Corniche Ouest, Immeuble Alphadio Barry, Dakar, Senegal		
BP Oil Senegal S.A.	Ordinary	100.00
Singapore		
7 Straits View #26-01, Marina One East Tower, 018936, Singapore		
BP Asia Pacific Pte Ltd[d]	Ordinary	100.00
BP Energy Asia Pte. Limited	Ordinary	100.00
BP Exploration (Xazar) Pte. Ltd.	Ordinary	100.00
BP Maritime Services (Singapore) Pte. Limited	Ordinary	100.00
BP Singapore Pte. Limited	Ordinary	100.00
Castrol Singapore PTE. Limited	Ordinary	100.00
Slovakia		
Karadžičova 2, Bratislava, 815 32, Slovakia		
Blueprint Power Slovakia s.r.o.	Membership Interest	100.00
South Africa		
199 Oxford Road, Oxford Parks, Dunkeld, Johannesburg, GP, 2196, South Africa		
BP Southern Africa Proprietary Limited	Ordinary	74.97
Burmah Castrol South Africa (Pty) Limited	Ordinary; Ordinary A	100.00
ECM Markets SA (Pty) Ltd	Ordinary	74.97
Spain		
Atraque Punta Lucero, Explanada Punta Ceballos s/n, Ziérbena (Vizcaya), Spain		
Bahia de Bizkaia Electridad, S.L.	Ordinary	75.00
Calle Quintanadueñas, 6, (Edificio Arqborea), Madrid, 28050, Spain		
BP Energy Solutions Sociedad de Valores, S.A	Ordinary	100.00
BP Espana, S.A. Unipersonal	Ordinary A; Ordinary B; Ordinary C	100.00
BP Gas & Power Iberia, S.A	Ordinary	100.00
BP Refined Products Trading Iberia, S.L.	Ordinary	100.00
BP Solar Espana, S.A. Unipersonal	Ordinary A; Ordinary B	100.00
Castrol España, S.L. Sociedad Unipersonal	Ordinary	100.00
Markoil, S.A. Unipersonal	Ordinary	100.00

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14. Related undertakings of the group – continued

Onyx Insight Spain Sociedad Limitada	Ordinary	100.00
Polígono Industrial "El Serrallo", s/n 12100 Grao de Castellón, Castellón de la Plana, Spain		
BP Energía España, S.A. Unipersonal	Ordinary	100.00
Castellón Green Hydrogen, S.L.	Ordinary	100.00
Sweden		
Box 8107, Stockholm, 10420, Sweden		
Air BP Sweden AB	Ordinary	100.00
Hemvärnsgatan, 171 54, Solna, Sweden		
Castrol Sweden AB	Ordinary	100.00
Switzerland		
Baarerschtrasse 139, Zug, 6300, Switzerland		
Castrol Switzerland GmbH	Ordinary	100.00
Taiwan (Province of China)		
57F.-1, No. 7, Sec. 5, Xinyi Rd., Xinyi Dist., Taipei City, 11049, Taiwan (Province of China)		
BP Taiwan Marketing Limited	Ordinary	100.00
Thailand		
23rd Fl. Rajanakarn Bldg, 3 South Sathon Road, Yannawa South Sathon, Bangkok 10120, Thailand		
BP - Castrol (Thailand) Limited	Ordinary	57.59
SOFAST Limited	Ordinary (100.00%); Preference (58.99%)	63.09
39/77-78 Moo 2 Rama II Road, Tambon Bangkrachao, Amphur Muang, Samutsakorn 74000, Thailand		
BP Holdings (Thailand) Limited	Ordinary (80.10%); Preference (99.07%)	81.18
BP Oil (Thailand) Limited	Ordinary (93.64%); Preference (81.18%)	90.40
Trinidad and Tobago		
5-5A Queen's Park West, Port-of-Spain, Trinidad and Tobago		
BP Alternative Energy Trinidad and Tobago Limited	Ordinary	100.00
BP Trinidad & Tobago LNG Holdings Limited	Ordinary	100.00
BP Trinidad Processing Limited	Ordinary	100.00
Mayaro Initiative for Private Enterprise Development	Ordinary	70.00
Türkiye		
Degirmen yolu cad. No:28, Asia OfisPark K:3 Icerenkoy-Atasehir, Istanbul, 34752, Türkiye		
BP Akaryakit Ortakligi	Partnership interest	70.00
BP Dogal Gaz Ticaret Anonim Sirketi	Ordinary	100.00
BP Petrolleri Anonim Sirketi	Ordinary	100.00
Içerenköy Mah, Degirmen Yolu Cad, Mengerler Blok No: 28/1 Iç Kapi No: 12, Atasehir/Istanbul, Türkiye		
Castrol Madeni Yağlar Ticaret Anonim Şirketi	Ordinary	100.00
United Arab Emirates		
2474ResCo-work07 & 2474ResCo-work08, 24, Al Sila Tower, Abu Dhabi Global Market Square, Al Maryah Island, Abu Dhabi, United Arab Emirates		
LYTT ME LIMITED	Ordinary	100.00
8th Floor, Standard Chartered Tower, Downtown, Dubai, United Arab Emirates		
BP Middle East LLC	Ordinary	100.00
Jebel Ali Free Zone, Dubai, United Arab Emirates		
Stryde Middle East FZE	Ordinary	100.00
United Kingdom		
1 Wellheads Avenue, Dyce, Aberdeen, AB21 7PB, United Kingdom		
BP Energy Europe Limited	Ordinary	100.00
BP Exploration Company Limited	Ordinary	100.00
Britannic Strategies Limited	Ordinary	100.00
Britoil Limited	Ordinary	100.00
Burmah Castrol PLC[d]	Ordinary	100.00
10 Upper Berkeley Street, London, W1H 7PE, United Kingdom		
Horizon 38 Management Company Limited	Membership Interest	53.50
11 Black Horse Lane, Ipswich, Suffolk, IP1 2EF, United Kingdom		
Manormaker (Nominee No. 1) Limited	Ordinary	99.90
Manormaker (Nominee No. 2) Limited	Ordinary	99.90
Manormaker GP Limited	Membership Interest	99.90
The Manormaker Limited Partnership	Membership Interest	99.90

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14. Related undertakings of the group – continued

33 Cavendish Square, London, W1G 0PW, United Kingdom		
Ropemaker Exempt Unit Trust	Membership Interest	100.00
Breckland, Linford Wood, Milton Keynes, MK14 6GY, England, United Kingdom		
Ashford Truckstop Freehold Limited	Ordinary	100.00
Charge Your Car Limited	Ordinary A; Ordinary B	100.00
Chargemaster Limited	Ordinary	100.00
Elektromotive Limited	Ordinary	100.00
C/O Bdo Llp, 2 Atlantic Square, 31 York Street, Glasgow, G2 8NJ, Scotland, United Kingdom		
The Burmah Oil Company (Pakistan Trading) Limited	Ordinary	100.00
C/O Bdo Llp, 5 Temple Square, Temple Street, Liverpool, L2 5RH, United Kingdom		
Autino Holdings Limited	Ordinary	100.00
BP (Indian Agencies) Limited[d]	Ordinary	100.00
BP Exploration (Canada) Limited	Ordinary	100.00
BP Exploration (Greenland) Limited	Ordinary	100.00
BP Exploration (Madagascar) Limited	Ordinary	100.00
BP Exploration (Morocco) Limited	Ordinary	100.00
BP Exploration (Namibia) Limited	Ordinary	100.00
BP Exploration (Psi) Limited	Ordinary	100.00
BP Exploration Peru Limited	Ordinary	100.00
BP Oil Venezuela Limited	Ordinary	100.00
BP Petrochemicals India Investments Limited	Ordinary	100.00
BP Subsea Well Response (Brazil) Limited	Ordinary	100.00
Expandite Contract Services Limited	Ordinary	100.00
Exploration (Luderitz Basin) Limited	Ordinary	100.00
Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, England, United Kingdom		
Air BP Limited	Ordinary	100.00
Amoco (Fiddich) Limited	Ordinary	100.00
Amoco U.K. Petroleum Limited	Ordinary	100.00
Atlantic 2/3 UK Holdings Limited	Ordinary	100.00
Autino Limited	Ordinary	100.00
BP (Abu Dhabi) Limited	Ordinary	100.00
BP (Barbican) Limited[d]	Ordinary	100.00
BP (Gibraltar) Limited	Ordinary	100.00
BP (GTA Mauritania) Finance Limited	Ordinary	100.00
BP (GTA Senegal) Finance Limited	Ordinary	100.00
BP Absheron Limited	Ordinary	100.00
BP Advanced Mobility Limited	Ordinary	100.00
BP Africa Limited[d]	Ordinary	100.00
BP Africa Oil Limited	Ordinary	100.00
BP Agung I Limited	Ordinary	100.00
BP Agung II Limited	Ordinary	100.00
BP Alternative Energy Investments Limited	Ordinary	100.00
BP America Limited	Ordinary	100.00
BP Amoco Exploration (Faroes) Limited	Membership Interest	100.00
BP Andaman II Ltd	Ordinary	100.00
BP Asia Pacific Holdings Limited	Ordinary	100.00
BP Australia Swaps Management Limited	Ordinary	100.00
BP Benevolent Fund Trustees Limited[d]	Ordinary	100.00
BP Biofuels Brazil Investments Limited	Ordinary	100.00
BP Capital Markets p.l.c.	Ordinary	100.00
BP Car Fleet Limited[d]	Ordinary	100.00
BP Carbon Trading Limited	Ordinary	100.00
BP CCUS UK LTD	Ordinary	100.00
BP CCUS UK NEP Limited	Ordinary	100.00
BP Chemicals Limited	Ordinary	100.00
BP Continental Holdings Limited	Ordinary	100.00
BP Corporate Holdings Limited	Ordinary	100.00
BP D230 Limited	Ordinary	100.00
BP East Kalimantan CBM Limited	Ordinary	100.00

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14. Related undertakings of the group – continued

BP Eastern Mediterranean Limited	Ordinary	100.00
BP Energy Colombia Limited	Ordinary	100.00
BP Eta Holdings Limited	Ordinary	100.00
BP Exploration (Absheron) Limited	Ordinary	100.00
BP Exploration (Alpha) Limited	Ordinary	100.00
BP Exploration (Azerbaijan) Limited	Ordinary	100.00
BP Exploration (Caspian Sea) Limited	Ordinary	100.00
BP Exploration (D230) Limited	Ordinary	100.00
BP Exploration (Delta) Limited	Ordinary	100.00
BP Exploration (Epsilon) Limited	Ordinary	100.00
BP Exploration (Shafag-Asiman) Limited	Ordinary	100.00
BP Exploration (Shah Deniz) Limited	Ordinary	100.00
BP Exploration (South Atlantic) Limited	Ordinary	100.00
BP Exploration (STP) Limited	Ordinary	100.00
BP Exploration Argentina Limited	Ordinary	100.00
BP Exploration Beta Limited	Ordinary	100.00
BP Exploration China Limited	Ordinary	100.00
BP Exploration Company (Middle East) Limited	Ordinary	100.00
BP Exploration Indonesia Limited	Ordinary	100.00
BP Exploration Libya Limited	Ordinary	100.00
BP Exploration Mediterranean Limited	Ordinary	100.00
BP Exploration North Africa Limited	Ordinary	100.00
BP Exploration Operating Company Limited	Ordinary	100.00
BP Exploration Orinoco Limited	Ordinary	100.00
BP Exploration Personnel Company Limited	Ordinary	100.00
BP Express Shopping Limited	Ordinary	100.00
BP Finance p.l.c.	Ordinary	100.00
BP Gamma Holdings Limited[d]	Ordinary	100.00
BP Gas & Power Investments Limited	Ordinary	100.00
BP Gas Marketing Limited	Ordinary	100.00
BP Global Investments Limited[d]	Ordinary	100.00
BP Global Solutions Limited	Ordinary	100.00
BP Greece Limited	Ordinary	100.00
BP Holdings Canada Limited[d]	Ordinary	100.00
BP Holdings Iraq Ltd	Ordinary	100.00
BP Holdings North America Limited[d]	Ordinary; Cumulative redeemable preference	100.00
BP Hydrogen and CCS Development Company Limited	Ordinary	100.00
BP Indonesia Investment Limited	Ordinary	100.00
BP Integrated Solutions Limited	Ordinary	100.00
BP International Limited[d]	Ordinary	100.00
BP Investment Management Limited	Ordinary	100.00
BP Investments Asia Limited	Ordinary	100.00
BP Iota Holdings Limited	Ordinary	100.00
BP Iran Limited	Ordinary	100.00
BP Kappa Holdings Limited	Ordinary	100.00
BP Kuwait Limited	Ordinary	100.00
BP Lambda Holdings Limited	Ordinary	100.00
BP Low Carbon Development Company Limited	Ordinary	100.00
BP Marine Limited	Ordinary	100.00
BP Mauritania Investments Limited	Ordinary	100.00
BP Middle East Limited[d]	Ordinary	100.00
BP Mocambique Limited	Ordinary	100.00
BP New Ventures Middle East Limited	Ordinary	100.00
BP North East Offshore Wind Limited	Ordinary	100.00
BP NZT Power Holdings Limited	Ordinary	100.00
BP Oil International Limited	Ordinary	100.00
BP Oil Kent Refinery Limited	Ordinary	100.00
BP Oil Llandarcy Refinery Limited	Ordinary	100.00

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14. Related undertakings of the group – continued

BP Oil Logistics UK Limited	Ordinary	100.00
BP Oil UK Limited	Ordinary; Debentures	100.00
BP Oil Vietnam Limited	Ordinary	100.00
BP Oil Yemen Limited	Ordinary	100.00
BP Pension Escrow Limited	Ordinary	100.00
BP Pension Trustees Limited[d]	Ordinary	100.00
BP Pensions Limited[d]	Ordinary	100.00
BP Pipelines (BTC) Limited	Ordinary	100.00
BP Pipelines (SCP) Limited	Ordinary	100.00
BP Pipelines (TANAP) Limited	Ordinary	100.00
BP Pipelines TAP Limited	Ordinary	100.00
BP Poseidon Limited	Ordinary	100.00
BP Properties Limited[d]	Ordinary	100.00
BP Retail Properties Limited	Ordinary	100.00
BP Russian Investments Limited	Ordinary	100.00
BP Russian Ventures Limited	Ordinary	100.00
BP Scale Up Factory Limited	Ordinary	100.00
BP Senegal Investments Limited	Ordinary	100.00
BP Services International Limited	Ordinary	100.00
BP Shafag-Asiman Limited	Ordinary	100.00
BP Shipping Limited	Ordinary	100.00
BP South America Holdings Ltd	Ordinary	100.00
BP Subsea Well Response Limited	Ordinary	100.00
BP Technology Ventures Limited	Ordinary	100.00
BP Theta Holdings Limited	Ordinary	100.00
BP Turkey Refining Limited[d]	Ordinary	100.00
BP UK Fatima Limited	Ordinary	100.00
BP UK Retained Holdings Limited	Ordinary	100.00
BP West Aru I Limited	Ordinary	100.00
BP West Aru II Limited	Ordinary	100.00
BP West Papua I Limited	Ordinary	100.00
BP Zeta Holdings Limited	Ordinary	100.00
BP+Amoco International Limited	Ordinary	100.00
Britannic Energy Trading Limited	Ordinary	100.00
Britannic Investments Iraq Limited	Ordinary	100.00
Britannic Marketing Limited	Ordinary	100.00
Britannic Trading Limited	Ordinary	100.00
BTC Pipeline Holding Company Limited	Ordinary	100.00
BXL Plastics Limited	Ordinary; Deferred	100.00
Cadman DBP Limited	Ordinary	100.00
Castrol (U.K.) Limited	Ordinary	100.00
Castrol Holdings Americas Limited	Ordinary	100.00
Castrol Holdings International Limited	Ordinary	100.00
Castrol Offshore Limited	Ordinary	100.00
Exmoor Nominee Limited	Ordinary	51.00
Exmoor Properties GP Limited	Ordinary	51.00
Exmoor Properties PF LP	Membership Interest	51.00
Fosroc Expandite Limited	Ordinary	100.00
Fotech Group Limited	Ordinary	100.00
GTA FPSO Company Ltd	Ordinary	100.00
Guangdong Investments Limited	Ordinary	100.00
H2 Teesside Limited	Ordinary	100.00
HyGreen Teesside Limited	Ordinary	100.00
Insight Analytics Solutions Holdings Limited	Ordinary	100.00
Insight Analytics Solutions Limited	Ordinary	100.00
Iraq Petroleum Company Limited	Ordinary	100.00
Kenilworth Oil Company Limited[d]	Ordinary	100.00
Low Carbon Friends Limited	Ordinary	100.00
Lubricants UK Limited	Ordinary	100.00

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14. Related undertakings of the group – continued

Lytt Limited	Ordinary	100.00
Net Zero North Sea Storage Holdings Limited	Ordinary	100.00
Net Zero North Sea Storage Limited	Ordinary	100.00
Net Zero Teesside Power Holdings Limited	Ordinary	100.00
Net Zero Teesside Power Limited	Ordinary	100.00
Open Energi Limited	Ordinary	100.00
Open Energy Limited	Ordinary	100.00
Pearl River Delta Investments Limited	Ordinary	100.00
Ropemaker Deansgate Limited	Ordinary	100.00
Ropemaker Properties Limited	Ordinary	100.00
Shafag (Jabrayil) Solar Limited	Ordinary	100.00
Stryde Limited	Ordinary	100.00
The BP Share Plans Trustees Limited[d]	Ordinary	100.00
Viceroy Investments Limited	Ordinary	100.00
Technology Centre, Whitchurch Hill, Pangbourne, Reading, RG8 7QR, United Kingdom		
Castrol Limited	Ordinary	100.00
United States		
100 Shockoe Slip, 2nd Floor, Richmond, VA, 23219, United States		
Collegiate Clean Energy, LLC	Membership Interest	100.00
INGENCO Wholesale Power, L.L.C.	Membership Interest	100.00
112 SW 7th Street, Suite 3C, Topeka, Kansas, 66603, United States		
Flat Ridge Wind Energy, LLC	Membership Interest	100.00
1201 Hays Street Tallahassee, FL, 32301		
Landfill Energy Systems Florida LLC	Membership Interest	100.00
1833 South Morgan Road, Oklahoma City OK 73128, United States		
BPX Midstream LLC	Membership Interest	100.00
1999 Bryan St., STE 900, Dallas, TX, 75201, United States		
Acamar Energy Project, LLC	Membership Interest	100.00
Andromedae Energy Project, LLC	Membership Interest	100.00
Arche Energy Project, LLC	Membership Interest	100.00
Atria Energy Project, LLC	Membership Interest	100.00
Bellatrix Energy Project, LLC	Membership Interest	100.00
BP Solar SHH, LLC	Membership Interest	100.00
BP Solar SHP, LLC	Membership Interest	100.00
BPX Operating Company	Ordinary	100.00
Buzz Energy Project, LLC	Membership Interest	100.00
Cassiopeia Energy Project, LLC	Membership Interest	100.00
Cepheus Energy Project, LLC	Membership Interest	100.00
Cressida Energy Project, LLC	Membership Interest	100.00
Delphinus Energy Project, LLC	Membership Interest	100.00
Despina Energy Project, LLC	Membership Interest	100.00
Draconis Energy Project, LLC	Membership Interest	100.00
Elanor Energy Project, LLC	Membership Interest	100.00
Electra Energy Project, LLC	Membership Interest	100.00
Juliet Energy Project, LLC	Membership Interest	100.00
Maia Energy Project, LLC	Membership Interest	100.00
Minkar Energy Project, LLC	Membership Interest	100.00
Mira Energy Project, LLC	Membership Interest	100.00
Nashira Energy Project, LLC	Membership Interest	100.00
Nunki Energy Project LLC	Membership Interest	100.00
Peacock Energy Project, LLC	Membership Interest	100.00
Perdita Energy Project, LLC	Membership Interest	100.00
Persei Energy Project, LLC	Membership Interest	100.00
Rigel Energy Project, LLC	Membership Interest	100.00
Shaula Energy Project II, LLC	Membership Interest	100.00
Shaula Energy Project III, LLC	Membership Interest	100.00
Shaula Energy Project, LLC	Membership Interest	100.00
Spica Energy Project, LLC	Membership Interest	100.00
Subra Energy Project, LLC	Membership Interest	100.00

The parent company financial statements of BP p.l.c. on pages 275-334 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

14. Related undertakings of the group – continued

Taika Energy Project, LLC	Membership Interest	100.00
Tania Energy Project, LLC	Membership Interest	100.00
Telesto Energy Project, LLC	Membership Interest	100.00
Tesni Energy Project, LLC	Membership Interest	100.00
Thalassa Energy Project, LLC	Membership Interest	100.00
Venatici Energy Project, LLC	Membership Interest	100.00
Zibal Energy Project, LLC	Membership Interest	100.00
208 South LaSalle Street, Suite 814, Chicago, IL, 60604-1101, United States		
Dradnats, Inc.	Ordinary	100.00
2108 55th Street, Suite 105, Boulder CO 80301, United States		
Insight Analytics Solutions USA, Inc	Ordinary	100.00
211 E. 7th Street, Suite 620, Austin, TX, 78701, United States		
Gulf Coast Environmental Systems, LLC (dba Conifer Systems LLC)	Membership Interest	100.00
Toro Energy of Indiana, LLC	Membership Interest	60.00
2405 York Road, Ste 201, Lutherville Timonium, MD, 21093-2264, United States		
BP Products North America Inc.	Ordinary	100.00
251 East Ohio Street, Suite 500, Indianapolis IN 46204, United States		
AmProp Finance Company	Ordinary	100.00
BP Foundation Incorporated	Membership Interest	100.00
Standard Oil Company, Inc.	Ordinary	100.00
2595 Interstate Drive, Suite 103, Harrisburg, PA 17110, United States		
PEI Power II, LLC	Membership Interest	100.00
PEI Power LLC	Membership Interest	100.00
2626 Glenwood Avenue, Suite 550, Raleigh, NC, 27608, United States		
Big Run Power Producers, LLC	Membership Interest	100.00
2711 Centerville Road, Suite 400, Wilmington, DE, 19808, United States		
Amoco Oil Holding Company	Ordinary	100.00
Amoco Pipeline Holding Company	Ordinary	100.00
BP International Services Company	Ordinary	100.00
Finite Resources, Inc.	Ordinary	80.50
Orion Post Land Investments, LLC	Membership Interest	100.00
2900 West Road STE 500, East Lansing, MI, 48823, United States		
Canton Renewables, LLC	Membership Interest	50.00
2908 Poston Avenue, Nashville, TN 37203, United States		
CERF Shelby, LLC	Membership Interest	50.00
Tennessee Renewable Group LLC	Membership Interest	100.00
306 W. Main Street, Suite 512, Frankfort, KY, 40601, United States		
Fresh-Serve Bakeries LLC	Membership Interest	100.00
Thornton Transportation LLC	Membership Interest	100.00
334, North Senate Avenue, Indianapolis, IN, 46204-1708, United States		
BP Corporation North America Inc.	Ordinary	100.00
3800 North Central Avenue, Suite 460, Phoenix, AZ, 85012, United States		
Sargas Energy Project, LLC	Membership Interest	100.00
400 Cornerstone Drive, Suite 240, Williston VT 05495, United States		
Saturn Insurance Inc.	Ordinary	100.00
435 Devon Park Drive, Suite 700, Wayne, PA, 19087, United States		
Carbon Reduction Corporation	Ordinary	80.50
Finite Carbon Corporation	Ordinary	80.50
4400 Easton Commons Way , Suite 125, Columbus OH 43219, United States		
Baltimore Ennis Land Company, Inc.	Ordinary	100.00
Exomet, Inc.	Ordinary	100.00
The Standard Oil Company	Ordinary	100.00
45 Memorial Circle, Augusta ME 04330, United States		
BP Pipelines (North America) Inc.	Ordinary	100.00
4568 Mayfield Rd. Suite 204, Cleveland, OH, 44121, United States		
Satelytics, Inc.	Preference	89.46
7 St. Paul Street, Suite 820, Baltimore MD 21202, United States		
TA HQ LLC	Membership Interest	100.00
TA Ventures LLC	Membership Interest	100.00

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14. Related undertakings of the group – continued

TA West Greenwich LLC	Membership Interest	100.00
701 South Carson Street Suite 200, Carson City, NV, 89701, United States		
Amoco Marketing Environmental Services Company	Ordinary	100.00
80 State Street, Albany, NY, United States		
Model City Energy, LLC	Membership Interest	100.00
Modern Innovative Energy, LLC	Membership Interest	100.00
Seneca Energy II, LLC	Membership Interest	100.00
814 Thayer Avenue, Bismarck, ND, 58501-4018, United States		
The Anaconda Company	Ordinary	100.00
8585 Old Dairy Rd STE 208, Juneau, AK, 99801, United States		
Frontier Operation Services, LLC	Membership Interest	100.00
920 North King Street, 2nd Floor, Wilmington DE 19801, United States		
BPRY Caribbean Ventures LLC	Membership Interest	70.00
921 S. Orchard St. Ste G, Boise ID 83705, United States		
IGI Resources, Inc.	Ordinary	100.00
Bank of America Center, 16th Floor, 1111 East Main Street, Richmond, VA, 23219, United States		
Amoco Environmental Services Company	Ordinary; Preference	100.00
c/o Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808, United States		
AH Medora LFG, LLC	Membership Interest	100.00
AHJRLLFG, LLC	Membership Interest	100.00
AHMLFG, LLC	Membership Interest	100.00
Archaea AD, LLC	Class B Membership Interest	100.00
Archaea CCS LLC	Membership Interest	100.00
Archaea Energy II LLC	Membership Interest	100.00
Archaea Energy Marketing LLC	Membership Interest	100.00
Archaea Energy Operating LLC	Membership Interest	100.00
Archaea Energy Services LLC	Membership Interest	100.00
Archaea Holdings, LLC	Membership Interest	100.00
Archaea Infrastructure, LLC	Membership Interest	100.00
Archaea Lutum, LLC	Membership Interest	100.00
Archaea Operating LLC	Membership Interest	100.00
Archaea Real Estate Holdings LLC	Membership Interest	100.00
Archaea Ventures LLC	Membership Interest	100.00
Aria Energy East LLC	Membership Interest	100.00
Aria Energy LLC	Membership Interest	100.00
Aria Energy Operating LLC	Membership Interest	100.00
Assai Energy, LLC	Membership Interest	100.00
Aurum Renewables LLC	Class B Membership Interest	100.00
Biofuels Coyote Canyon Biogas, LLC	Membership Interest	100.00
BioFuels San Bernardino Biogas, LLC	Membership Interest	100.00
Cefari RNG OKC, LLC	Membership Interest	50.00
CES Biogas LLC	Membership Interest	100.00
Cherry Island Renewable Energy, LLC	Membership Interest	100.00
CII Methane Management III, LLC	Membership Interest	100.00
CII Methane Management IV, LLC	Membership Interest	100.00
Eagle Point RNG LLC	Membership Interest	100.00
EIF KC Landfill Gas, LLC	Membership Interest	100.00
Element Markets Renewable Natural Gas, LLC	Membership Interest	100.00
Emerald City Renewables LLC	Membership Interest	100.00
Industrial Power Generating Company, LLC	Membership Interest	100.00
INGENCO Renewable Development LLC	Membership Interest	100.00
Innovative Energy Systems, LLC	Membership Interest	100.00
Innovative/Colonie, LLC	Membership Interest	100.00
Innovative/DANC, LLC	Membership Interest	100.00
Innovative/Fulton, LLC	Membership Interest	100.00
LES Development LLC	Membership Interest	100.00
LES Manager LLC	Membership Interest	100.00
LES Operations Services LLC	Membership Interest	100.00

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14. Related undertakings of the group – continued

LES Renewable NG LLC	Membership Interest	100.00
NextGen Power Holdings LLC	Membership Interest	100.00
Petro Franchise Systems LLC	Membership Interest	100.00
RNG Moovers LLC	Class B Membership Interest	47.50
Rochelle Energy LLC	Membership Interest	100.00
South Shelby RNG, LLC	Membership Interest	50.00
TA Franchise Systems LLC	Membership Interest	100.00
TA Operating LLC	Membership Interest	100.00
TA Operating Montana LLC	Partnership interest	100.00
TA Ventures 2 LLC	Membership Interest	100.00
Timberline Energy, LLC	Class A Membership Interest	100.00
UGID Broad Mountain, LLC	Membership Interest	100.00
Zeus Renewables LLC	Membership Interest	100.00
Zimmerman Energy LLC	Membership Interest	100.00
Corporation Service Company 1127 Broadway Street NE, Suite 310 Salem, OR, 17110, United States		
Finley BioEnergy, LLC	Membership Interest	100.00
Corporation Trust Center, 1209 Orange Street, Wilmington, DE, 19801, United States		
AE Cedar Creek Holdings LLC	Membership Interest	100.00
AE Goshen II Holdings LLC	Membership Interest	100.00
AE Goshen II Wind Farm LLC	Membership Interest	100.00
AE Power Services LLC	Membership Interest	100.00
AE Wind PartsCo LLC	Membership Interest	100.00
Air BP Canada LLC	Membership Interest	100.00
AM/PM International Inc.	Ordinary	100.00
American Oil Company	Ordinary	100.00
Amoco (U.K.) Exploration Company, LLC	Membership Interest	100.00
Amoco Chemical (Europe) S.A.	Ordinary	100.00
Amoco Cypress Pipeline Company	Ordinary	100.00
Amoco Destin Pipeline Company	Ordinary	100.00
Amoco International Petroleum Company	Ordinary	100.00
Amoco Louisiana Fractionator Company	Ordinary	100.00
Amoco Main Pass Gathering Company	Ordinary	100.00
Amoco MB Fractionation Company	Ordinary	100.00
Amoco MBF Company	Ordinary	100.00
Amoco Netherlands Petroleum Company	Ordinary	100.00
Amoco Nigeria Petroleum Company	Ordinary	100.00
Amoco Norway Oil Company	Ordinary	100.00
Amoco Overseas Exploration Company	Ordinary	100.00
Amoco Properties Incorporated	Ordinary	100.00
Amoco Remediation Management Services Corporation	Ordinary	100.00
Amoco Research Operating Company	Ordinary	100.00
Amoco Rio Grande Pipeline Company	Ordinary	100.00
Amoco Somalia Petroleum Company	Ordinary	100.00
Amoco Sulfur Recovery Company	Ordinary	100.00
Amoco Tri-States NGL Pipeline Company	Ordinary	100.00
Amprop, Inc.	Ordinary	100.00
Anaconda Arizona, Inc.	Ordinary	100.00
Archaea Energy Inc.	Ordinary	100.00
ARCO British Limited, LLC	Membership Interest	100.00
ARCO El-Djazair Holdings Inc.	Ordinary	100.00
ARCO Environmental Remediation, L.L.C.	Membership Interest	100.00
ARCO Gaviota Company	Ordinary	100.00
ARCO Midcon LLC	Membership Interest	100.00
ARCO Unimar Holdings LLC	Membership Interest	100.00
Atlantic Richfield Company	Ordinary; Preference	100.00
Australia Resource Holdings Inc.	Ordinary	100.00
Auwahi Wind Energy Holdings LLC	Membership Interest	100.00
Blueprint Power Technologies LLC	Membership Interest	100.00

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14. Related undertakings of the group – continued

BP Alternative Energy North America Inc.	Ordinary	100.00
BP America Chemicals Company	Ordinary	100.00
BP America Foreign Investments Inc.	Ordinary	100.00
BP America Inc.	Ordinary; Ordinary B	100.00
BP America Production Company	Ordinary	100.00
BP AMI Leasing, Inc.	Ordinary	100.00
BP Argentina Exploration Company	Membership Interest	100.00
BP Argentina Holdings LLC	Membership Interest	100.00
BP Berau Ltd.	Ordinary	100.00
BP Biofuels Advanced Technology Inc.	Ordinary	100.00
BP Biofuels North America LLC	Membership Interest	100.00
BP Bomberai Ltd.	Ordinary	100.00
BP Brazil Tracking L.L.C.	Membership Interest	100.00
BP Canada Energy Marketing Corp.	Membership Interest	100.00
BP Canada Investments Inc.	Ordinary	100.00
BP Capital Markets America Inc.	Ordinary	100.00
BP Carbon Solutions LLC	Membership Interest	100.00
BP Caribbean Company	Ordinary	100.00
BP Central Atlantic Offshore Wind Holdings LLC	Membership Interest	100.00
BP Central Atlantic Offshore Wind LLC	Membership Interest	100.00
BP Central Pipelines LLC	Membership Interest	51.00
BP Chemical Remediation Holdings LLC	Membership Interest	100.00
BP China Exploration and Production Company	Ordinary	100.00
BP Company North America Inc.	Ordinary; Redeemable preference	100.00
BP Containment Response System Holdings LLC	Membership Interest	100.00
BP Egypt Company	Ordinary	100.00
BP Energy Company	Ordinary	100.00
BP Energy Holding Company LLC	Membership Interest	100.00
BP Energy Retail Company California LLC	Membership Interest	100.00
BP Energy Retail Company LLC	Membership Interest	100.00
BP Exploration & Production Inc.	Ordinary; Preference	100.00
BP Gas Supply (Angola) LLC	Membership Interest	50.00
BP Gulf of Mexico Midstream Holding LLC	Membership Interest	100.00
BP Latin America LLC	Membership Interest	100.00
BP Latin America Upstream Services Inc.	Ordinary	100.00
BP Louisiana Energy Park LLC	Membership Interest	100.00
BP Lubricants USA Inc.	Ordinary	100.00
BP Mariner Holding Company LLC	Membership Interest	100.00
BP Midstream Partners GP LLC	Membership Interest	100.00
BP Midstream Partners Holdings LLC	Membership Interest	100.00
BP Midstream Partners LP	Ordinary	100.00
BP Midwest Product Pipelines Holdings LLC	Membership Interest	51.00
BP Northwest Offshore Wind Holdings LLC	Membership Interest	100.00
BP Northwest Offshore Wind LLC	Membership Interest	100.00
BP Nutrition Inc.	Ordinary	100.00
BP Offshore Gathering Systems Inc.	Ordinary	100.00
BP Offshore Pipelines Company LLC	Membership Interest	100.00
BP Offshore Response Company LLC	Membership Interest	100.00
BP Offshore Wind America Holding Company LLC	Membership Interest	100.00
BP Offshore Wind America LLC	Membership Interest	100.00
BP Oil Pipeline Company	Ordinary	100.00
BP Oil Shipping Company, USA	Ordinary	100.00
BP One Pipeline Company LLC	Membership Interest	51.00
BP Pakistan (Badin) Inc.	Ordinary	100.00
BP Pakistan Exploration and Production, Inc.	Ordinary	100.00
BP Pipelines (Alaska) Inc.	Ordinary	100.00
BP Pulse Fleet North America Inc.	Ordinary	100.00
BP SC Holdings LLC	Membership Interest	100.00

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14. Related undertakings of the group – continued

BP Scale Up Factory North America Inc.	Ordinary	100.00
BP Solar Holding LLC	Membership Interest	100.00
BP Solar International Inc.	Ordinary	100.00
BP Southern Cone Company	Ordinary	100.00
BP Technology Ventures Inc.	Ordinary	100.00
BP Trinidad and Tobago LLC	Membership Interest	70.00
BP US Offshore Wind Energy LLC	Membership Interest	100.00
BP Wind Energy Beacon Holding LLC	Membership Interest	100.00
BP Wind Energy Empire Holding LLC	Membership Interest	100.00
BP Wind Energy North America Inc.	Ordinary	100.00
BP Wiriagar Ltd.	Ordinary	100.00
BPX (Eagle Ford) Gathering LLC	Membership Interest	75.00
BPX (Karnes) Gathering LLC	Membership Interest	100.00
BPX (Permian) Gathering LLC	Membership Interest	100.00
BPX Energy Inc.	Ordinary	100.00
BPX Gathering Holdings LLC	Membership Interest	100.00
BPX Production Company	Ordinary	100.00
Burmah Castrol Holdings Inc.	Ordinary	100.00
Casitas Pipeline Company	Ordinary	100.00
Castrol Caribbean & Central America Inc.	Ordinary	100.00
CH-Twenty, Inc.	Ordinary	100.00
Clean Eagle RNG, LLC	Membership Interest	50.00
Coastal Offshore Renewable Energy LLC	Membership Interest	100.00
Cuyama Pipeline Company	Ordinary	100.00
Elm Holdings Inc.	Ordinary	100.00
Energy Global Investments (USA) Inc.	Ordinary	100.00
Enstar LLC	Membership Interest	100.00
Flat Ridge 2 Holdings LLC	Membership Interest	100.00
Flat Ridge 2 Wind Energy LLC	Membership Interest	100.00
Flat Ridge 2 Wind Holdings LLC	Membership Interest	100.00
Flat Ridge Interconnection LLC	Membership Interest	100.00
Foseco Holding, Inc.	Membership Interest	100.00
Foseco, Inc.	Ordinary	100.00
Fowler I Holdings LLC	Membership Interest	100.00
Fowler Ridge Holdings LLC	Membership Interest	100.00
Fowler Ridge I Land Investments LLC	Membership Interest	100.00
Fowler Ridge II Holdings LLC	Membership Interest	100.00
Fowler Ridge III Wind Farm LLC	Membership Interest	100.00
Fowler Ridge Wind Farm LLC	Membership Interest	100.00
Gardena Holdings Inc.	Ordinary	100.00
Highlands Ethanol, LLC	Membership Interest	100.00
Ken-Chas Reserve Company	Ordinary	100.00
Lightning Renewables, LLC	Membership Interest	60.00
Mardi Gras Transportation System Company LLC	Membership Interest	100.00
Mavrix, LLC	Membership Interest	50.00
Mehoopany Holdings LLC	Membership Interest	100.00
Mountain City Remediation, LLC	Membership Interest	100.00
North America Funding Company	Ordinary	100.00
Orion Delaware Mountain Wind Farm LP	Membership Interest	100.00
Orion Energy Holdings, LLC	Membership Interest	100.00
Orion Energy L.L.C.	Membership Interest	100.00
Pan American Energy US LLC	Membership Interest	51.00
Remediation Management Services Company	Ordinary	100.00
Richfield Oil Corporation	Ordinary	100.00
Rolling Thunder I Power Partners, LLC	Membership Interest	100.00
Sherbino I Holdings LLC	Membership Interest	100.00
Sherbino Mesa I Land Investments LLC	Membership Interest	100.00
Southern Ridge Pipeline Holding Company	Ordinary	100.00
Stryde Inc.	Ordinary	100.00

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14. Related undertakings of the group – continued

Thorntons LLC	Membership Interest	100.00
TLK Holding Company LLC	Membership Interest	100.00
TLK Intermediate Holding Company LLC	Membership Interest	100.00
TLK Operating Company LLC	Membership Interest	100.00
Toledo Refinery Holding Company LLC	Membership Interest	100.00
Union Texas International Corporation	Ordinary	100.00
Vastar Pipeline, LLC	Membership Interest	100.00
Westlake Houston Development, LLC	Membership Interest	100.00
Whiting Clean Energy, Inc.	Membership Interest	100.00
Venezuela		
Av. Francisco de Miranda, con primera avenida de Los Palos, Grandes, Edif Cavendes, piso 9, ofi 903, Los Palos Grandes, Caracas / Miranda, Chacao / Caracas, 1060, Venezuela		
BP Petroleo y Gas, S.A.	Ordinary	100.00
Viet Nam		
9th Floor, 22-36 Nguyen Hue Street, 57-69F Dong Khoi Street, District 1, Ho Chi Minh City, Viet Nam		
Castrol BP Petco Limited Liability Company	Membership Interest	65.00
Zimbabwe		
Barking Road, Willowvale, Harare, Zimbabwe		
Castrol Zimbabwe (Private) Limited	Membership Interest	100.00

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14. Related undertakings of the group – continued

Related undertakings other than subsidiaries

Company by country of incorporation and registered office address	Ownership interest	%
Albania		
Air BP Albania Sh.A., Aeroporti Nderkombetar i Tiranes, "Nene Tereza", Post Box 2933 in Tirana, Albania		
Air BP Albania SHA	Ordinary	50.00
Argentina		
Av. Leandro N. Alem 1180, piso 11°, Buenos Aires, Argentina		
Field Services Enterprise S.A.	Ordinary	50.00
Lithos Desarollos Energeticos S.A.	Ordinary	50.00
Pan American E&P S.A.	Ordinary	50.00
Parque Eolico Del Sur S.A.	Ordinary	27.50
Terminal CP S.A.U.	Ordinary	50.00
Vientos Ombu III S.A.	Ordinary	25.00
Calle 14, No 781, Piso 2, Oficina 3, Ciudad de La Plata, Provincia de Buenos Aires, Argentina		
Barranca Sur Minera S.A.	Ordinary	50.00
Carlos María Della Paolera 265, Piso 22, Ciudad Autónoma de Buenos Aires, Argentina		
Axion Energy Argentina S.A.	Membership Interest	50.00
RSE & RCE S.A.U.	Ordinary	50.00
Florida 1, Piso 10, Buenos Aires, Argentina		
Oleoductos del Valle (Oldelval) S.A.	Ordinary	50.00
Francisco Behr 20, Barrio Pueyrredon, Comodoro Rivadavia, Provincia del Chubut, Argentina		
Manpetrol S.A.	Ordinary	50.00
Lavalle 190, piso 6 Depto L, Buenos Aires, Argentina		
Vientos Patagonicos Chubut Norte III S.A.	Ordinary	24.50
Vientos Sudamericanos Chubut Norte IV S.A.	Ordinary	24.50
O´Higgins N° 194, Rio Grande, Argentina		
Pan American Fueguina S.A.	Ordinary	50.00
Pan American Sur S.A.	Ordinary	50.00
San Martin 140, Piso 2, Buenos Aires, Argentina		
Central Dock Sud S.A.	Ordinary	50.00
Australia		
11 Lagoon Court, Samford Valley, QLD 4520, Australia		
Australasian Lubricants Manufacturing Company Pty Ltd	Ordinary A	50.00
34 Kent Road, Mascot, NSW 2020, Australia		
5B Holdings Pty Limited	Preference Series B (27.47%)	9.80
CBW Level 19, 181 William Street, Melbourne VIC 3000, Australia		
3725 Sharp Development Pty Ltd	Ordinary	49.97
433 Link Development Company Pty Ltd	Ordinary	49.97
892 Yarrawonga Development Pty Ltd	Ordinary	49.97
Goorambat Landco Pty Ltd	Ordinary	49.97
Goulburn River FinCo Pty Limited	Ordinary	49.97
Goulburn River Fund Pty Limited	Ordinary	49.97
Goulburn River HoldCo 2 Pty Limited	Ordinary	49.97
Goulburn River Trust	Units	49.97
Lightsource Asset Management Australia Pty Ltd	Ordinary	49.97
Lightsource Australia SPV 2 Pty Ltd	Ordinary	49.97
Lightsource Australia SPV 3 Pty Ltd	Ordinary	49.97
Lightsource Australia SPV 4 Pty Ltd	Ordinary	49.97
Lightsource Development Services Australia Pty Ltd	Ordinary	49.97
Lightsource Energy Markets Pty Ltd	Ordinary	49.97
Lightsource Labs Australia Pty Limited	Ordinary	49.97
Lightsource LS Labs Australia Operations Pty Ltd	Ordinary	49.97
Lightsource Renewable Energy (Australia) Pty Ltd	Ordinary	49.97
Lower Wonga Solar Farm Pty Ltd	Ordinary	49.97
LS Australia Equity HoldCo1 Pty Ltd	Ordinary	49.97
LS Australia FinCo 1 Pty Ltd	Ordinary	49.97
LS Australia FinCo 2 Pty Ltd	Ordinary	49.97
LS Australia FinCo 3 Pty Ltd	Ordinary	49.97

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14. Related undertakings of the group – continued

LS Australia HoldCo 1 Pty Ltd	Ordinary	49.97
LS Land Holdings Pty Ltd	Ordinary	49.97
Sun Spot 3 Pty Ltd	Ordinary	49.97
Wellington LandCo Pty Ltd	Ordinary	49.97
Wellington North Solar Farm Pty Ltd	Ordinary	49.97
West Mokoan Solar Farm Pty Ltd	Ordinary	49.97
West Wyalong FinCo Pty Ltd	Ordinary	49.97
West Wyalong Fund Pty Ltd	Ordinary	49.97
West Wyalong HoldCo 2 Pty Ltd	Ordinary	49.97
West Wyalong Trust	Membership Interest	49.97
Woolooga BESS FinCo Pty Limited	Ordinary	49.97
Woolooga BESS Fund Pty Limited	Ordinary	49.97
Woolooga BESS HoldCo 2 Pty Limited	Ordinary	49.97
Woolooga FinCo Pty Ltd	Ordinary	49.97
Woolooga Fund Pty Ltd	Ordinary	49.97
Woolooga HoldCo 2 Pty Ltd	Ordinary	49.97
Woolooga Trust	Membership Interest	49.97
Wunghnu Solar Farm FinCo Pty Ltd	Ordinary	49.97
Company Matters Pty Ltd, Level 12, 680 George Street, Sydney NSW 2000, Australia		
Airport Fuel Services Pty. Limited	Ordinary	20.00
Cairns Airport Refuelling Service Pty Ltd	Ordinary	33.33
Level 10, 12 Creek Street, Brisbane, QLD 4000, Australia		
Ocwen Energy Pty Ltd	Ordinary	49.50
Level 16, 80 Collins Street, South Tower, Melbourne, Victoria, 3000, Australia		
Australian Renewable Energy Hub Pty Ltd	Ordinary	48.32
Level 16, Alluvion Building, 58 Mounts Bay Road, Perth, WA, Australia		
North West Shelf Lifting Coordinator Pty Ltd	Ordinary B (100.00%)	16.67
Level 3, Unit 3, 22 Albert Road, South Melbourne VIC 3205, Australia		
Australian Terminal Operations Management Pty Ltd	Ordinary	50.00
Suite 8.02, 28 O'Connell Street, Sydney, New South Wales 2000, Australia		
XPANSIV Limited	Ordinary (18.87%); Preference Series A (26.16%)	19.86
Austria		
Am Tankhafen 4, 4020 Linz, Austria		
TLM Tanklager Management GmbH	Membership Interest	49.00
Brucknerstraße 4, 1041 Wien, Austria		
ABG Autobahn-Betriebe GmbH	Membership Interest	32.58
Innsbrucker Bundesstraße 95, 5020 Salzburg, Austria		
Salzburg Fuelling GmbH	Membership Interest	50.00
Radlpaßstraße 6, 8502 Lannach, Austria		
Erdol-Lagergesellschaft m.b.H.	Membership Interest	23.00
Trabrennstraße 6-8 3, Wien, A-1020, Austria		
Aircraft Refuelling Company GmbH	Membership Interest	33.33
Bahamas		
Trinity Place Annex, Corner of Frederick & Shirley Streets, P.O. Box N-4805, Nassau, Bahamas		
PAE E & P Bolivia Limited	Ordinary	50.00
Pan American Energy Investments Ltd.	Ordinary	50.00
Bolivia (Plurinational State of)		
Av San Martin 1700, Cuarto Anillo, Edificio Centro Empresarial Equipetrol, Piso 6, Zona Oeste, Equipetrol Norte, Santa Cruz de la Sierra, Bolivia (Plurinational State of)		
YPFB Chaco S.A.	Ordinary	50.00
Cuarto anillo, Avda. Ovidio Barbery N° 4200, Edificio Torre, e/ Jaime Román y Victor Pinto, Equipetrol Norte, Santa Cruz de la Sierra, Bolivia (Plurinational State of)		
PAE Oil & Gas Bolivia Ltda.	Ordinary	50.00
Brazil		
1675 South State Street, Suite B, Dover, Kent Country, DE, 19901 US, Brazil		
Pan American Energy Energias Renovaveis Ltda.	Ordinary	50.00
Al Santos, 74, Andar 7 Conj 72 Sala 53, Cerqueira Cesar, Sao Paulo, 01.418-000, Brazil		
Lightsource Milagres Holding 1 S.A.	Ordinary	49.97

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14. Related undertakings of the group – continued

Alameda Santos, 74, 7º andar, conjunto 72, sala 43, Cerqueira Cesar, Municipality of São Paulo, State of São Paulo - SP - CEP 01418-000, Brazil		
Lightsource Bom Lugar Holding 2 S.A.	Ordinary	49.97
Lightsource Brasil Energia Renovável Particições S.A.	Membership Interest	49.97
Alameda Santos,74, 7th floor, suite 72, room 111, Cerqueira César, Municipality of São Paulo, State of São Paulo, 01418-000, Brazil		
Lightsource Bom Lugar Holding 1 S.A.	Ordinary	49.97
Avenida Atlântica, no. 1.130, 2nd floor (part), Copacabana,RJ, Rio de Janeiro, 22021-000, Brazil		
NFX Combustíveis Marítimos Ltda.	Ordinary	50.00
Avenida Bernardino de Campos, 98, 12th Floor, Room 38, Suite A, Paraíso, Zip Code 04004-040, Sao Paulo, Brazil		
Lightsource Brasil Energia Renovável Ltda	Ordinary	49.97
Avenida das Nações Unidas, 12.399, 4º andar, cj. 41B, sala 01, São Paulo, Brazil		
Itumbiara Trading Comercio Importação e Exportação ltda.	Ordinary	50.00
Avenida das Nações Unidas, nº 12.399, 4º andar, Brooklin Paulista, São Paulo, CEP 04578-000, Brazil		
BP Bunge Bioenergia S.A.	Ordinary	50.00
Avenida Paris, 4077, Suite 3, Cascata,São Paulo State, Paulínia, 13046-061, Brazil		
Terminal de Combustiveis Paulinia S.A.	Ordinary	50.00
Cidade de Caraúbas, Estado do Rio Grande do Norte, Sítio Retiro, S/N, Estrada Caraúbas sentido Mirandas, Km 15, lado esquerdo, Zona Rural, CEP 59780-000, Brazil		
Lightsource Caraúbas Geração de Energia Ltda	Ordinary	49.97
City and State of Rio de Janeiro,at Rua Voluntários da Pátria, No. 113, 11 floor, Botafogo, 22.270-000, Brazil		
Gas Natural Acu S.A.	Ordinary	30.00
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	49.97
Estrada Mossoró sentido Jaguaruana, S/N, Km 48, lado esquerdo, Zona Rural, Sitio Aroeira Grande, Município de Baraúna/RN, CEP 59695-000, Brazil		
Lightsource Jaguar Geração de Energia Ltda	Ordinary	49.97
Estrada Municipal Itumbiara / Chacoeira Dourada, Fazenda Jandaia, Gleba B, Goiás, Itumbiara, 75516-126, Brazil		
BP Bioenergia Itumbiara S.A.	Ordinary	50.00
Estrada que liga Brejo Santo a Vila Conceição, porteira da Caatinga Grande, S/N, Zona Rural, Sitio Ludovico, Município de Brejo Santo/CE, CEP 63260-000, Brazil		
Lightsource Milagres Expansão Geração de Energia Ltda	Ordinary	49.97
Fazenda Água Amarela, S/N, Itapegipe, Minas Gerais, 38240-000, Brazil		
Itapagipe Bioenergia Ltda.	Ordinary	50.00
Fazenda Guariroba, SN, Zona Rural, Pontes Gestal, São Paulo, 15500-000, Brazil		
Guariroba Bioenergia LTDA	Ordinary	50.00
Fazenda Moema, s/n, Rural, Orindiuva, São Paulo, 15480-000, Brazil		
Bunge Açúcar e Bioenergia S.A.	Ordinary	50.00
Fazenda Recanto, Zona Rural, CEP 38.300-898, Minas Gerais, Ituiutaba, Brazil		
BP Bioenergia Ituiutaba Ltda.	Membership Interest	50.00
Fazenda Saco Dantas, S/N, Área 3 e Área 4, Praia do Açu, São João da Barra, Rio de Janeiro, 28.200-000, Brazil		
UTE GNA II Geração de Energia S.A.	Ordinary	33.50
Fazenda Santa Bárbara, S/N, Distrito de Zelândia, Santa Juliana, Minas Gerais, 38175-000, Brazil		
Santa Juliana Bioenergia Ltda.	Ordinary	50.00
Fazenda São Bento da Ressaca, S/N, Zona Rural, Frutal, Minas Gerais, 38200-000, Brazil		
Frutal Bioenergia Ltda.	Ordinary	50.00
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	49.97
Lightsource Bom Lugar IX Geração de Energia S.A.	Ordinary	49.97
Lightsource Bom Lugar V Geração de Energia S.A.	Ordinary	49.97
Lightsource Bom Lugar VI Geração de Energia S.A.	Ordinary	49.97
Lightsource Bom Lugar VII Geração de Energia S.A.	Ordinary	49.97
Lightsource Bom Lugar VIII Geração de Energia S.A.	Ordinary	49.97
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	49.97
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	49.97
Lightsource Milagres II Geração de Energia S.A	Ordinary	49.97
Lightsource Milagres III Geração de Energia S.A	Ordinary	49.97

14. Related undertakings of the group – continued

Lightsource Milagres IV Geração de Energia S.A	Ordinary	49.97
Lightsource Milagres V Geração de Energia S.A	Ordinary	49.97
No. 804, 5th floor, Glória, Rio de Janeiro, Rio de Janeiro, 22210-010, Brazil		
Gas Natural Açu Infraestrutura S.A.	Ordinary	27.91
Praça Gago Coutinho, 540 – Ed. Aeroporto Internacional de Salvador – Box Air BP, city of Salvador, State of Bahia, 41.602-065, Brazil		
Air BP Petrobahia Ltda.	Ordinary	50.00
Rod. BA 827, S/N, KM 05 Estrada do Cantinho dos Aflitos, Fazenda Divino Espirito Santo, City of Barreiras, State of Bahia, 47.819-899, Brazil		
Lightsource Rio Branco Geração de Energia Ltda	Ordinary	49.97
Rodovia Doutor Mendel Steinbruch 10.800, Distrito Industrial, Maracanau, Ceara, 61.939-906, Brazil		
Ventos De Santa Virginia Energias Renovaveis S.A.	Ordinary	50.00
Ventos De Santo Ubaldo Energias Renovaveis S.A.	Ordinary	50.00
Ventos De Santo Urbano I Energias Renovaveis S.A.	Ordinary	50.00
Ventos De Sao Romualdo Energias Renovaveis S.A.	Ordinary	50.00
Ventos De Sao Teofano Energias Renovaveis S.A.	Ordinary	50.00
VENTOS DE SAO TEONAS ENERGIAS RENOVAVEIS S.A.	Ordinary	50.00
Ventos De Sao Thomas Energias Renovaveis S.A.	Ordinary	50.00
Ventos De Sao Tilao Energias Renovaveis S.A.	Ordinary	50.00
VENTOS DE SAO VIGILIO ENERGIAS RENOVAVEIS S.A.	Ordinary	50.00
Rodovia GO 410, km 51 à esquerda, Fazenda Canadá, s/n, Zona Rural, Goiás, Edéia, 75940-000, Brazil		
BP Bioenergia Tropical S.A.	Ordinary	50.00
Rodovia GO 410, km 51 à esquerda, Fazenda Canadá, s/n, Zona Rural, Sala 01 Estado de Goiás, Edéia, 75940-000, Brazil		
Tropical Biogás Ltda	Ordinary	50.00
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	49.97
Rodovia SP - 463 Elyeser Montenegro Magalhãe, KM 186, S/N, Zona Rural,São Paulo, Ouroeste, 15685-000, Brazil		
Usina Ouroeste - Açúcar e Álcool Ltda.	Ordinary	50.00
Rodovia TO 010 KM 20, S/N, Zona Rural, Cidade de Pedro Afonso, Tocantins, 77710-000, Brazil		
Pedro Afonso Bioenergia Ltda.	Ordinary	50.00
Rua Manoel da Nóbrega n°1280, 10° andar, Sao Paulo, Sao Paulo, 04001-902, Brazil		
Pan American Energy do Brasil Ltda.	Membership Interest	50.00
Rua Principal, Fazenda Recanto, Zona Rural, Caixa Postal 01, Minas Gerais, Ituiutaba, 38.300-898, Brazil		
BP Bioenergia Campina Verde Ltda.	Membership Interest	50.00
Rua Voluntários da Pátria n. 113, 11th floor, Botafogo, City and State of Rio de Janeiro, Zip code: 22.270-000., Brazil		
Açu Trucked LNG S.A.	Membership Interest	30.00
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	49.97
Cayman Islands		
190 Elgin Avenue, George Town, KY1-9005, Cayman Islands		
Georgian Pipeline Company	Ordinary	30.37
P.O. Box 309, Ugland House, 113 South Church Street, George Town, Cayman Islands		
Azerbaijan Gas Supply Company Limited	Ordinary	23.99
Azerbaijan International Operating Company	Ordinary	30.37
BTC International Investment Co.	Membership Interest	30.10
South Caucasus Pipeline Company Limited	Membership Interest	28.83
South Caucasus Pipeline Holding Company Limited	Membership Interest	28.83
South Caucasus Pipeline Option Gas Company Limited	Ordinary	28.83
The Baku-Tbilisi-Ceyhan Pipeline Company	Membership Interest	30.10
PO Box 472, 2nd Floor, Harbour Place, 103 South Church Street, George Town, KY1-1106, Cayman Islands		
R&B Technology Holding CO., LTD	Series B Anti-Dilution (13.33%); Series B Internal Ext (40.00%); Preference Series A (78.95%); Preference Series B+ (67.21%)	27.16
Chile		
Nueva de Lyon Nº 145, piso 12, oficina 1203, Edificio Costa, Santiago de Chile, Chile		
Pan American Energy Chile Limitada	Ordinary	50.00

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14. Related undertakings of the group – continued

China		
10-11/FTime Finance Center, No.4001 Shennan Dadao, Futian Street, Futian District, Guangdong Province, Shenzhen, China		
Guangdong Dapeng LNG Company Limited	Membership Interest	30.00
11/F, Building No.2, No. 32 Lingang Road Section One, Xihang Port Street, Shuangliu District,Sichuan Province, Chengdu, China		
CNAF Air BP General Aviation Fuel Company Limited	Membership Interest	49.00
5th Floor, Guangsha Ruiming Building, No. 231 Moganshan Road, Xihu District, Hangzhou, Zhejiang Province, China		
BP Sinopec (ZheJiang) Petroleum Co., Ltd	Membership Interest	40.00
A3#608, Dongjiang Commercial Center, #599 Eerduosi Road, Free Trade Zone (Dongjiang Free Trade Zone), China		
Xin Ying Energy Marketing Co., Ltd.	Membership Interest	50.00
Fu Yong Town, Bao An county, Guangdong Province, ShenZhen Airport, China		
Shenzhen Cheng Yuan Aviation Oil Company Limited	Membership Interest	25.00
Guangdong Dapeng Liquefied Natural Gas Filling Station, Cheng Tou Corner, Xia Sha Village, Dapeng Street, Dapeng New District, Shenzhen, China		
Shenzhen Dapeng LNG Marketing Company Limited	Membership Interest	30.00
No. B933, 9-14/F Office, Building A, Baoye Center, NO.31 JIA, China		
Castrol DongFeng Lubricant Co., Ltd	Membership Interest	50.00
Room 3501, Room 3502, Room 3503, No.62, Jinsui Road, Tianhe District, Guangzhou, China		
Guangzhou Aulton New Energy Technology Co., Ltd.	Membership Interest	20.00
Room 526, No.13,Longxue Avenue middle, Nansha District, Guangzhou, China		
BP Guangzhou Development Oil Products Company Limited	Membership Interest	40.00
Room 8309, Floor 3, Yufanghailian Office Building, No. 1 Indian Ocean Road, West Coast Comprehensive Bonded Area, Qingdao, China		
BP SPG Energy Trading Co., Ltd.	Membership Interest	49.00
Room A, building B, 5th floor, no. 22 Gangkou road, Jiangmen, China		
BP Petro China Jiangmen Fuels Co., Ltd.	Membership Interest	49.00
Room B1, 11th Floor, No.22 Gang Kou Yi Road, Peng Jiang District,Guangdong Province, Jiangmen, China		
BP PetroChina Petroleum Co., Ltd	Membership Interest	49.00
Cuba		
Calle 6 No 319, esq 5ta. Ave., Miramar, Playa, La Habana, Cuba		
Castrol Cuba S.A.	Ordinary	50.00
Cyprus		
90 Archiepiskopou str, Dromolaxia – Meneou, 7020 Larnaca, Cyprus		
LCA Aviation Fuelling Systems Limited	Ordinary	35.00
Denmark		
GA Centervej 1, Billund, DK-7190, Denmark		
Billund Refuelling I/S	Membership Interest	50.00
Kastrup Lufthavn, 2770 Kastrup, Denmark		
Danish Refuelling Services I/S	Membership Interest	50.00
Danish Tankage Services I/S	Membership Interest	50.00
Københavns, Lufthavn, 2770 Kastrup, Denmark		
Braendstoflageret Kobenhavns Lufthavn I/S	Partnership interest	20.83
Egypt		
14 Kamal El Tawil ST, Zamalek, Cairo, Egypt		
Lightsource BP Hassan Allam Developments for Renewable Energy S.A.E	Ordinary	24.99
5 El Mokhayam El Daiem St, 6th Sector, Nasr City, Egypt		
El Temsah Petroleum Company "PETROTEMSAH"	Ordinary	25.00
Mediteranean Gas Co. "MEDGAS"	Ordinary	25.00
70/72 Road 200, Maadi, Cairo, Egypt		
Pharaonic Petroleum Company "PhPC"	Ordinary	25.00
85 El Nasr Road, Cairo, Egypt		
Natural Gas Vehicles Company "NGVC"	Ordinary	40.00
Al Shaheed St., Nasr City, Cairo, Egypt		
El Burg Offshore Company (EBOC)	Ordinary	20.00
Building No. 349 & 351, Third Sector of City Centre, Fifth Settlement, New Cairo, Egypt		
United Gas Derivatives Company "UGDC"	Ordinary	33.33
Street 200, Building 70-72, Maadi, Cairo, Egypt		
Damietta Petroleum Company "PETRODAMIETTA"	Ordinary	50.00
North El Burg Petroleum Company "PETRONEB"	Ordinary	25.00

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14. Related undertakings of the group – continued

France		
1 Place Gustave Eiffel, Rungis, 94150, France		
Société d'Avitaillement et de Stockage de Carburants Aviation "SASCA"	Membership Interest	40.00
1165 rue Jean-René Guilibert Gauthier de la Lauzière – CS 20583, Aix-les-Milles Cedex 02, 13290, France		
Lightsource France Development SAS	Ordinary	49.97
150 Avenue Yves Farge, Saint Pierre des Corps, 37700, France		
Depot Petrolier De Saint-Pierre Des Corps D.P.S.P.C.	Membership Interest	20.00
27 Route du Bassin Numéro 6, Gennevilliers, 92230, France		
Société de Gestion de Produits Pétroliers - SOGEPP	Ordinary	37.00
3 Rue des Vignes, Aéroport Roissy Charles de Gaulle, Tremblay en France, 93290, France		
Fuelling Aviation Service - FAS	Membership Interest	50.00
562 Avenue du Parc de l'Ile, Nanterre, 92000, France		
Entrepot petrolier de Chambery	Ordinary	32.00
65 Rue d'Italie, Colombier-Saugnieu, 69124, France		
Stockage de Carburant d’Aviation Lyon	Membership Interest	40.00
Aeroport Bale Mulhouse, Saint-Louis, 68300, France		
Stockage de Carburant d’Aviation	Membership Interest	40.00
Aeroport Toulouse-Blagnac, Blagnac, 31700, France		
Stockage de Carburant d’Aviation Toulouse	Membership Interest	40.00
Germany		
Am Borsigturm 68, Berlin, 13507, Germany		
Service4Charger Holding GmbH	Preference Series A (75.00%)	19.88
Am Stadthafen 60, 45881 Gelsenkirchen, Germany		
TransTank GmbH	Ordinary	50.00
An der Braker Bahn 22, 26122 Oldenburg, Germany		
Klaus Köhn GmbH	Ordinary	50.00
Köhn & Plambeck GmbH & Co. KG	Partnership interest	50.00
Berghausener Straße 96, 40764 Langenfeld, Germany		
AGES International GmbH & Co. KG, Langenfeld	Partnership interest	24.70
AGES Maut System GmbH & Co. KG, Langenfeld	Partnership interest	24.70
Brunnenstraße 19-21, Berlin, 10119, Germany		
Digital Charging Solutions GmbH	Membership Interest	33.33
c/o WeWork, Kemperplatz 1, Berlin, 10785, Germany		
Lightsource Development Deutschland GmbH	Ordinary	49.97
Lightsource GP GmbH	Ordinary	49.97
Lightsource LP 1 GmbH	Ordinary	49.97
Godorfer Hauptstraße 186, 50997 Köln, Germany		
Rhein-Main-Rohrleitungstransportgesellschaft mbH	Ordinary	35.00
Jenfelder Allee 80, Hamburg, 22039, Germany		
STDG Strassentransport Dispositions Gesellschaft mbH	Ordinary	50.00
Konsul-Smidt-Strasse 14, 28217 Bremen, Germany		
Etzel-Kavernenbetriebsgesellschaft mbH & Co. KG	Partnership interest	33.33
Etzel-Kavernenbetriebs-Verwaltungsgesellschaft mbH	Ordinary	33.33
Luisenstraße 5 a, 26382 Wilhelmshaven, Germany		
Ammenn GmbH	Ordinary	50.00
Kurt Ammenn GmbH & Co. KG	Partnership interest	50.00
Rheinstraße 36, 49090 Osnabrück, Germany		
Fip Verwaltungs GmbH	Ordinary	50.00
Heinrich Fip GmbH & Co. KG	Partnership interest	50.00
Saganer Straße 31, 90475 Nürnberg, Germany		
Beer Energien GmbH & Co. KG	Membership Interest	50.00
Beer GmbH	Ordinary	50.00
Spaldingstraße 64, 20097 Hamburg, Germany		
Mobene Beteiligungs GmbH & Co. KG	Partnership interest	50.00
Mobene Beteiligungs Verwaltungs GmbH	Ordinary	50.00
Mobene GmbH & Co. KG	Partnership interest	50.00
Mobene Verwaltungs-GmbH	Ordinary	50.00

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14. Related undertakings of the group – continued

Sportallee 6, 22335 Hamburg, Germany		
Dusseldorf Fuelling Services GbR	Membership Interest	33.00
Hamburg Tank Service (HTS) GbR	Partnership interest	33.00
HFS Hamburg Fuelling Services GbR	Partnership interest	50.00
LFS Langenhagen Fuelling Services GbR	Partnership interest	50.00
TFSS Turbo Fuel Services Sachsen GbR	Partnership interest	20.00
TGFH Tanklager-Gesellschaft Frankfurt-Hahn GbR	Partnership interest	50.00
TGHL Tanklager-Gesellschaft Hannover-Langenhagen GbR	Partnership interest	50.00
TGK Tanklagergesellschaft Koln-Bonn	Partnership interest	25.00
Steindamm 55, 20099 Hamburg, Germany		
GVÖ Gebinde-Verwertungsgesellschaft der Mineralölwirtschaft mbH	Ordinary	20.36
Überseeallee 1, 20457, Hamburg, Germany		
Flughafen Hannover Pipeline Verwaltungsgesellschaft mbH	Ordinary	50.00
Flughafen Hannover Pipelinegesellschaft mbH & Co. KG	Partnership interest	50.00
Wesermünder Straße 1, 27729 Hambergen, Germany		
Tecklenburg GmbH	Ordinary	50.00
Tecklenburg GmbH & Co. Energiebedarf KG	Partnership interest	50.00
Westfalendamm 166, 44141 Dortmund, Germany		
DOPARK GmbH	Ordinary	25.00
Wittener Straße 45, 44789 Bochum, Germany		
CSG Convenience Service GmbH	Ordinary	24.80
Ghana		
Number 1, Rehoboth Place, Dade Street, North Labone Estates, Accra, Greater Accra, Accra Metropolitan, P. O. BOX CT327, Ghana		
BP West Africa Supply Limited	Ordinary	50.00
Greece		
2,Vouliagmenis Ave & Papaflessa, 16777 Elliniko, Attika, Athens, Greece		
GISSCO S.A.	Ordinary	50.00
68, Vasilisis Sofias Ave., Athens, 115 28, Greece		
AI ENERGY SINGLE MEMBER P.C.	Ordinary	49.97
Akarnanika Photovoltaic Systems Single-Member Private Company	Ordinary	49.97
Clean Energy 3 S.M.S.A.	Ordinary	49.97
Clean Energy 5 S.M.S.A.	Ordinary	49.97
Enipeas Single Member S.A.	Ordinary	49.97
Green Energy Plus 4 S.M.S.A.	Ordinary	49.97
Green Energy Plus 5 S.M.S.A.	Ordinary	49.97
Green Energy Plus 6 S.M.S.A.	Ordinary	49.97
Lightsource Renewable Energy Greece Development Single Member S.A.	Ordinary	49.97
Lightsource Renewable Energy Greece Projects Single Member S.A.	Ordinary	49.97
International airport "El. Venizelos", Athens, Greece		
SAFCO SA	Ordinary	33.33
Local Community of Kyrakalis, number 0, Municipality of Grevena, 51100, Greece		
Clean Energy 1 S.M.S.A.	Ordinary	49.97
Clean Energy 2 S.M.S.A.	Ordinary	49.97
Clean Energy 4 S.M.S.A.	Ordinary	49.97
Clean Energy 6 S.M.S.A.	Ordinary	49.97
Green Energy Plus 1 S.M.S.A.	Ordinary	49.97
Green Energy Plus 2 S.M.S.A.	Ordinary	49.97
Green Energy Plus 3 S.M.S.A.	Ordinary	49.97
Green Energy Plus 7 S.M.S.A	Ordinary	49.97
Green Energy Plus 8 S.M.S.A.	Ordinary	49.97
Sun Power 1 S.M.P.C	Other	49.97
India		
1207-1212,A2, Palladium, Nr., Orchid Wood Opp. Divyabhaskar, Corporate Rd, Makarba, Ahmedabad, India		
Blu-Smart Mobility Private Limited	Preference Series A (50.61%); Preference Series A1 (19.43%); Preference Series A2 (19.20%)	20.96

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14. Related undertakings of the group – continued

3rd Floor, Maker Chambers IV, 222, Nariman Point, Mumbai, 400 021, India		
Reliance BP Mobility Limited	Ordinary	49.00
Magenta House, Plot No. D-285, MIDC, Turbhe, Navi Mumbai, India, 400705		
Magenta EV Solutions Private Limited	Preference (53.47%)	20.89
One World Center, 16th Floor, Tower 2A, Senapati Bapat Marg, Mumbai, Mumbai City MH 400013, India		
Eversource Capital Private Limited	Ordinary	24.99
Unit Nos.71 & 737th Floor, Maker Maxity, 2nd North Avenue, Bandra - Kurla Complex, Bandra (East), Mumbai 400 051, Maharashtra, India		
India Gas Solutions Private Limited	Ordinary	50.00
Indonesia		
AKR Tower 25th floor, Jalan Panjang No.5, Kebon Jeruk, Jakarta Barat, 11530, Indonesia		
PT. Aneka Petroindo Raya	Ordinary	49.90
PT. Dirgantara Petroindo Raya	Ordinary	49.90
Iraq		
Iraqi Airways HQ Building, Baghdad International Airport, Baghdad, Iraq		
United Iraqi Company for Airports and Ground Handling Services Limited (MASIL)	Ordinary	19.60
Naz City, Building J, Suite 10 Erbil, Iraq		
Mach Monument Aviation Fuelling Co. Ltd.	Ordinary	70.00
Ireland		
70 Northumberland Road, Ballsbridge, Dublin, D04 VH66, Ireland		
BLS Bulk Liquid Storage Cork Limited	Ordinary	30.00
Trinity House, Charleston Road, Ranelagh, Dublin, D06 C8X4, Ireland		
Lightsource Ireland Development Holdings Limited	Ordinary	49.97
Lightsource Ireland SPV 6 Limited	Ordinary	49.97
Lightsource Renewable Energy Ireland Limited	Ordinary	49.97
Powerverse Connect Limited	Ordinary	49.97
Ubiworx Systems Designated Activity Company	Ordinary	49.97
Israel		
3 Shenkar Street, Herzelia, Israel		
StoreDot Ltd.	Preference Series C (21.47%); Preference Series D (14.45%)	5.10
Italy		
Via Emilia 1, 20097 San Donato Milanese, Italy		
Azule Energy Angola S.p.A	Membership Interest	50.00
Via Giacomo Leopardi 7, Milano, 20123, Italy		
Belenos s.r.l.	Ordinary	32.48
Lightsource Renewable Energy Italy Development, S.r.l.	Ordinary	49.97
Lightsource Renewable Energy Italy Finco s.r.l.	Ordinary	49.97
Lightsource Renewable Energy Italy Holdings S.r.l.	Ordinary	49.97
Lightsource Renewable Energy Italy SPV 1 s.r.l.	Ordinary	49.97
Lightsource Renewable Energy Italy SPV 10 s.r.l.	Ordinary	49.97
Lightsource Renewable Energy Italy SPV 11 S.r.l	Ordinary	49.97
Lightsource Renewable Energy Italy SPV 12 S.R.L.	Ordinary	49.97
Lightsource Renewable Energy Italy SPV 13 S.R.L.	Ordinary	49.97
Lightsource Renewable Energy Italy SPV 14 S.R.L.	Ordinary	49.97
Lightsource Renewable Energy Italy SPV 15 S.R.L.	Ordinary	49.97
Lightsource Renewable Energy Italy SPV 16 S.R.L.	Ordinary	49.97
Lightsource Renewable Energy Italy SPV 17 S.R.L.	Ordinary	49.97
Lightsource Renewable Energy Italy SPV 18 S.R.L.	Ordinary	49.97
Lightsource Renewable Energy Italy SPV 19 S.R.L.	Ordinary	49.97
Lightsource Renewable Energy Italy SPV 2 s.r.l.	Ordinary	49.97
Lightsource Renewable Energy Italy SPV 20 S.R.L.	Ordinary	49.97
Lightsource Renewable Energy Italy SPV 21 S.R.L.	Ordinary	49.97
Lightsource Renewable Energy Italy SPV 22 S.R.L.	Quotas	49.97
Lightsource Renewable Energy Italy SPV 23 S.R.L.	Ordinary	49.97
Lightsource Renewable Energy Italy SPV 24 S.R.L.	Ordinary	49.97
Lightsource Renewable Energy Italy SPV 3 s.r.l.	Ordinary	49.97
Lightsource Renewable Energy Italy SPV 4 s.r.l.	Ordinary	49.97
Lightsource Renewable Energy Italy SPV 6 s.r.l.	Ordinary	49.97

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14. Related undertakings of the group – continued

Lightsource Renewable Energy Italy SPV 8 s.r.l.	Ordinary	49.97
Lightsource Renewable Energy Italy SPV 9 s.r.l.	Ordinary	49.97
Pollon s.r.l.	Ordinary	32.48
Via Sardegna, Rome, 38 00187, Italy		
Air BP Italia Spa	Ordinary	50.00
Via Venti Settembre, 69, Palermo, 90141, Italy		
EM Sicilia Green S.r.l.	Ordinary	49.97
Marsala Energie S.r.l.	Ordinary	49.97
Melilli Energie S.r.l.	Ordinary	49.97
ML Energie Rinnovabili S.r.l.	Ordinary	49.97
Viale Francesco Scaduto, 2d, Palermo, 90144, Italy		
HF Solar 1 S.r.l.	Ordinary	49.97
HF Solar 10 S.r.l.	Ordinary	49.97
HF Solar 2 S.r.l.	Ordinary	49.97
HF Solar 3 S.r.l.	Ordinary	49.97
HF Solar 4 S.r.l	Ordinary	49.97
HF Solar 5 S.r.l	Ordinary	49.97
Japan		
4-2 Otemachi 1-chome, Chiyoda-ku, Tokyo, Japan		
Ishikari Offshore Wind LLC	Ordinary	49.00
Oga Katagami Akita Offshore Wind LLC	Membership Interest	27.78
Korea (the Republic of)		
#125 DD-01, 14F, 416 Hangang-daero, Jung-gu, Seoul, Korea (the Republic of)		
SK Devco Solar Power Plant Co., Ltd.	Ordinary	49.97
#125 DD-02, 14F, 416 Hangang-daero, Jung-gu, Seoul, Korea (the Republic of)		
LS Renewable Energy Co., Ltd.	Ordinary	49.97
#125 DD-03, 14F, 416 Hangang-daero, Jung-gu, Seoul, Korea (the Republic of)		
Gangjin Solar Power Plant Co., Ltd.	Ordinary	49.97
#132, 14F, 416 Hangang-daero, Jung-gu, Seoul, Korea (the Republic of)		
Lightsource Renewable Energy Development South Korea Co., Ltd	Ordinary	49.97
109 Sideung-ro, Hwangsan-myeon, Jeonlanam-do, Korea (the Republic of)		
Haenam Solar Power Plant Co., Ltd.	Ordinary	49.97
Mauritius		
3rd Floor, Standard Chartered Tower, Bank Street, 19 Cybercity, Ebene, 72201, Mauritius		
EverSource Management Holdings	Ordinary	24.99
Mexico		
Av. Paseo de la Reforma 505 piso 32, Colonia Cuauhtémoc, Delegación Cuauhtémoc (06500), CDMX, Mexico		
EMSEP S.A. de C.V.	Ordinary	50.00
Torre A, piso 4, oficina 402, Calzada Legaria 549, Colonia 10 de Abril, Delegación Miguel Hidalgo, Ciudad de Mexico, C. P. 11250, Mexico		
Hokchi Energy S.A. de C.V.	Ordinary	50.00
Mozambique		
Praca Dos Trabalhadores, Nr 09, Distrito Urbano 1, Maputo, Mozambique		
Maputo International Airport Fuelling Services (MIAFS) Limitada	Membership Interest	50.00
Netherlands		
Anchoragelaan 6, 1118LD Luchthaven Schiphol, Netherlands		
Gezamenlijke Tankdienst Schiphol B.V.	Ordinary	50.00
Bos en Lommerplein 280, Amsterdam, 1055RW, Netherlands		
Lightsource BP Hassan Allam Holdings B.V.	Ordinary	24.99
Butaanweg 215, NL-3196 KC Vondelingenplaat, Rotterdam, Havennummer, 3045, Netherlands		
N.V. Rotterdam-Rijn-Pijpleiding Maatschappij (RRP)	Ordinary	44.40
d'Arcyweg 76, 3198 NA Europoort Rotterdam, Netherlands		
Azule Energy Angola (Block 18) B.V.	Ordinary	50.00
Gustav Mahlerplein 28, 1082MA, Amsterdam, Netherlands		
Lightsource Renewable Energy Netherlands Development B.V.	Ordinary	49.97
Lightsource Renewable Energy Netherlands Holdings B.V.	Ordinary	49.97
Zonneweide Liesvelden B.V.	Ordinary	49.97
Zonneweide LS 4 B.V.	Ordinary	49.97
Zonneweide LS 5 B.V.	Ordinary	49.97

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14. Related undertakings of the group – continued

Zonneweide LS 6 B.V.	Ordinary	49.97
Moezelweg 101, 3198LS Europoort, Rotterdam, Netherlands		
Maatschap Europoort Terminal	Partnership interest	50.00
Oude Vijfhuizerweg 6, 1118LV Luchthaven, Schiphol, Netherlands		
Aircraft Fuel Supply B.V.	Ordinary	25.00
Rijndwarsweg 3, 3198 LK Europoort, Rotterdam, Netherlands		
BP AOC Pumpstation Maatschap	Membership Interest	50.00
BP Esso AOC Maatschap	Partnership interest	22.80
BP Esso Pipeline Maatschap	Membership Interest	50.00
Maasvlakte Europoort Pipeline Maatschap	Partnership interest	50.00
Team Terminal B.V.	Ordinary	22.80
Strawinskylaan 1725, 1077XX Amsterdam, Netherlands		
Azule Energy Angola B.V.	Membership Interest	50.00
Azule Energy Angola Production B.V.	Membership Interest	50.00
Routex B.V.	Ordinary	25.00
New Zealand		
106b Bush Road, Auckland, Albany, 0632, New Zealand		
Wiri Oil Services Limited	Ordinary	27.78
247 Cameron Road, Tauranga, 3110, New Zealand		
McFall Fuel Limited	Ordinary	49.00
RMF Holdings Limited	Ordinary	49.00
399 Moray Place, Dunedin, 9016, New Zealand		
RD Petroleum Limited	Ordinary	49.00
Corporate Services New Zealand Limited, Level 5, 79 Queen Street, Auckland, 1010, New Zealand		
LSNZ Glorit Holdco Limited	Ordinary	49.97
Level 2, Harbour City Tower, 29 Brandon Street, Wellington Central, Wellington, 6011, New Zealand		
Kowhai Park I GP Limited	Ordinary	24.99
Kowhai Park I LP	Limited Partner	49.97
Kowhai Park P GP Limited	Ordinary	49.97
Kowhai Park P LP	Limited Partner	99.95
Level 3, 139 The Terrace, Wellington, 6011, New Zealand		
New Zealand Oil Services Limited	Ordinary	50.00
Level 5, 79 Queen Street, Auckland, 1010, New Zealand		
Lightsource Development Services New Zealand Limited	Ordinary	49.97
LSNZ Kowhai Park HoldCo Limited	Ordinary	49.97
Norway		
Postboks 133, Gardermoen, NO-2061, Norway		
Gardermoen Fuelling Services AS	Ordinary	33.33
Postboks 134, Gardermoen, NO-2061, Norway		
Oslo Lufthavns Tankanlegg AS	Ordinary	33.33
Postboks 36, Stjordal, NO-7501, Norway		
Flytanking AS	Ordinary	50.00
Oman		
P.O.Box 20302/211, 20302, Oman		
BP Dhofar LLC	Ordinary	49.00
Paraguay		
Av. España 1369 esquina San Rafael, Asunción, Paraguay		
Axion Energy Paraguay S.R.L.	Membership Interest	50.00
Peru		
Avenida Ricardo Rivera Navarrete n.501 / room 1602, Lima, Peru		
Air BP PBF del Peru S.A.C.	Ordinary	50.00
Poland		
Grunwaldzka 472B, Gdansk, 80-309, Poland		
Air BP Aramco Poland sp. z o. o.	Ordinary	50.00
ul. Grzybowska 2/29, 00-131, Warszawa, Poland		
Lightsource Development Polska sp. z o.o.	Ordinary	49.97
LS 1 sp. z.o.o.	Ordinary	49.97
LS 10 sp. z o.o.	Ordinary	49.97
LS 11 sp. z o.o.	Ordinary	49.97

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14. Related undertakings of the group – continued

LS 12 sp. z o.o.	Ordinary	49.97
LS 2 sp. z.o.o.	Ordinary	49.97
LS 3 sp. z.o.o.	Ordinary	49.97
LS 4 sp. z.o.o.	Ordinary	49.97
LS 5 sp. z.o.o.	Ordinary	49.97
LS 6 sp. z.o.o.	Ordinary	49.97
LS 7 sp. z.o.o.	Ordinary	49.97
LS 8 sp. z o.o.	Ordinary	49.97
LS 9 sp. z.o.o.	Ordinary	49.97
RD PV Produkcja 5 Spółka Z Ograniczona Odpowiedzialnoscia	Ordinary	49.97
Wena Projekt 2 sp. z o.o.	Ordinary	49.97
Portugal		
Grupo Operacional de Combustiveis do Aeroporto de Lisboa, Edificio 19, 1.° Sala Saba, Lisboa, Portugal		
SABA- Sociedade Abastecedora de Aeronaves, Lda	Ordinary	25.00
Lagoas Park, Edificio 3, Porto Salvo, Oeiras, Portugal		
Charging Together, Unipessoal LDA	Ordinary	50.00
Rua 31 de Agosto, nº 12, 5000 - 305 Vila Real, Portugal		
LSBPDG - Sociedade de Produção De Energia, Limitada	Ordinary	24.99
PTSunHydrogen II, LDA	Ordinary	24.99
PTSunHydrogen III, LDA	Ordinary	24.99
PTSunHydrogen IV, LDA	Ordinary	24.99
PTSUNHYDROGEN V, LDA	Ordinary	24.99
Rua Castilho, No 50, 1250-071, Lisboa, Portugal		
Coherent Modernity Lda	Ordinary	49.97
Coloursflow - Unipessoal Lda	Ordinary	49.97
Forest Constellation - Unipessoal Lda	Ordinary	49.97
Freshpanoply - Lda	Ordinary	49.97
Ignichoice Renewable Energy V, Unipessoal LDA	Ordinary	49.97
Ignidap – Energias Renováveis, Unipessoal Lda	Ordinary	49.97
PTSunHydrogen VI, LDA	Ordinary	24.99
PTSunHydrogen VII, LDA	Ordinary	24.99
PTSunHydrogen, LDA	Ordinary	24.99
Ramisun – Consultoria e Energias Renováveis, Unipessoal Lda.	Ordinary	49.97
Solid Tomorrow - Energia Unipessoal Lda	Ordinary	49.97
Suninger - Consultoria e Energias Renováveis, Unipessoal Lda	Ordinary	49.97
Tolerantdiagonal - Lda	Ordinary	49.97
Rua Júlio Dinis, n.° 247, 6.°, E-1, Edifício Mota Galiza, Parish of Lordelo do Ouro and Massarelos, Porto, 4050-324, Portugal		
Dapsun - Investimentos e Consultoria, LDA.	Ordinary	25.23
Rua Sousa Martins, nº 10, Lisboa 1050 218, Portugal		
Lightsource Development Portugal, Unipessoal Lda	Ordinary	49.97
Lightsource Renewable Energy Portugal (HoldCo), Lda.	Ordinary	49.97
Romania		
Bucureşti Sectorul 1, Bulevardul Dacia, Nr. 20, Biroul Nr. HDR20, Etaj 5, Romania		
LIGHTSOURCE DEVELOPMENT ROMANIA S.R.L.	Ordinary	49.97
Otopeni, 59 Aurel Vlaicu Street, Otopeni, Ilfov County, Romania		
Romanian Fuelling Services S.R.L.	Ordinary	50.00
Russian Federation		
629830 Yamalo-Nenetskiy Anatomy Region, city of Gubkinskiy, Russian Federation		
LLC "Kharampurneftegaz"	Membership Interest	49.00
Kosmodamianskaya nab, 52/3, Moscow, 115035, Russian Federation		
Limited Liability Company Yermak Neftegaz	Membership Interest	49.00
Pervomayskaya street, 32A, Sakha (Yakutiya) Republic, Lensk, 678144, Russian Federation		
Lensky Nefteprovod Limited Liability Company	Membership Interest	20.00
Limited Liability Company TYNGD	Membership Interest	20.00
Shabolovka street 10 building 2, 7th Floor, Room 13, Municipal District Yakimanka, Moscow, 119049, Russian Federation		
Srednelenskoye Limited Liability Company	Membership Interest	49.00
Saudi Arabia		
Industrial Area Unit No 1, Yanbu Alsenayea, 46481 - 4659, Saudi Arabia		
Arabian Production And Marketing Lubricants Company	Ordinary	50.00

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14. Related undertakings of the group – continued

P O Box 6369, Jeddah 21442, Saudi Arabia		
Peninsular Aviation Services Company Limited[e]	Ordinary	50.00
Singapore		
12 Marina Boulevard, #35-01 MBFC Tower 3, Singapore, 018982, Singapore		
BP Sinopec Marine Fuels Pte. Ltd.	Ordinary	50.00
163 Penang Road, #08-01, Winsland House II, 238463, Singapore		
Green Growth Feeder Fund Pte. Ltd	Ordinary	24.99
8 Marina Boulevard, #05-02, Marina Bay Financial Centre, 018981, Singapore		
Lightsource Singapore Renewables Holdings Private Limited	Ordinary	49.97
Lightsource Singapore Renewables Private Limited	Ordinary	49.97
8 Temasek Boulevard #31-02, Suntec City Tower 3, Singapore 038988, Singapore		
China Aviation Oil (Singapore) Corporation Ltd	Ordinary	20.17
South Africa		
1 Refinery Road, Prospecton, 4110, South Africa		
Shell and BP South African Petroleum Refineries (Pty) Ltd	Ordinary A	37.49
135 Honshu Road, Islandview, Durban, 4052, South Africa		
Blendcor (Pty) Limited	Ordinary B	37.49
199 Oxford Road, Oxford Parks, Dunkeld, Johannesburg, GP, 2196, South Africa		
Masana Petroleum Solutions (Pty) Ltd	Ordinary	37.86
Spain		
163, Paseo de la Castellana, planta baja, Madrid, 28046, Spain		
Charging Together, S.L.	Ordinary	50.00
Calle Alcala numero 63, Madrid, 28014, Spain		
ISC Greenfield 12, S.L.	Ordinary	49.97
Parque FV Borealis, S.L.	Ordinary	49.97
Parque FV Polaris, S.L.	Ordinary	49.97
Calle Américo Vespucio 5-1, planta 2, número 1, Isla de la Cartuja, 41092, Sevilla, Spain		
Guillena 400 Promotores, S.L.	Ordinary	12.27
Calle Jose Ortega y Gasset 22-24, 2nd Floor, 28006 Madrid, Spain		
Global Cotolengo, S.L.U	Ordinary	49.97
Calle José Ortega y Gasset, número 100, 5ª planta, 28006 de Madrid, Spain		
Global Aljarafe, S.L.U	Ordinary	49.97
Global Aroche, S.L.U	Ordinary	49.97
Global Atarazana, S.L.U	Ordinary	49.97
Global Baterno, S.L.U	Ordinary	49.97
Global Baza, S.L.U	Ordinary	49.97
Global Brenes, S.L.U	Ordinary	49.97
Global Tarquinia, S.L.U	Ordinary	49.97
Global Treviso, S.L.U	Ordinary	49.97
Global Valdenoches, S.L.U	Ordinary	49.97
Calle Lituania nº 10, Castellón de la Plana, Spain		
Fundación para la Eficiencia Energética de la Comunidad Valenciana	Membership Interest	33.33
Calle Ortega y Gasset, nº 100, planta quinta, Madrid, 28006, Spain		
Alejandria Power, S.L.U.	Ordinary	49.97
Caletona Servicios y Gestiones, S.L.U.	Ordinary	49.97
Castellana Power, S.L.U.	Ordinary	49.97
Inversiones Energy Madrid, S.L.U.	Ordinary	49.97
ISC Greenfield 7, S.L.	Ordinary	49.97
Khons Sun Power, S.L.U.	Ordinary	49.97
Lightsource Europe Asset Management, SL	Ordinary	49.97
Lightsource Renewable Energy Garnacha, S.L.	Ordinary	49.97
Lightsource Renewable Energy Spain Development, SL	Ordinary	49.97
Lightsource Renewable Energy Spain Holdings, SL	Ordinary	49.97
Lightsource Renewable Energy Spain SPV 1, SL	Ordinary	49.97
Lightsource Renewable Energy Trading, SL	Ordinary	49.97
Lightsource Spain O&M, SL	Ordinary	49.97
Rin Power, S.L.U.	Ordinary	49.97
Sinfonia Solar Energy Power, S.L.U.	Ordinary	49.97

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14. Related undertakings of the group – continued

Campus Empresarial Arbea - Edificio No 1, Carretera Fuencarral a Alcobendas (M-603), km 3.8, Alcobendas, Madrid, Spain		
Hokchi Iberica, S.L.	Ordinary	50.00
PAE Desarrollos Energeticos, S.L.	Ordinary	50.00
PAE Energy Holding, S.L.	Membership Interest	50.00
Pan American Energy Group, S.L.	Ordinary B	50.00
Pan American Energy Iberica, S.L.	Ordinary	50.00
Pan American Energy, S.L.	Membership Interest	50.00
Carretera de San Andréss/n, La Jurada-María Jiménez, Santa Cruz de Tenerife, Spain		
Terminales Canarios, S.L.	Ordinary	50.00
Paseo de la Castellana 278, Madrid, Spain		
Servicios Logísticos de Combustibles de Aviación, S.L	Ordinary	50.00
Paseo De La Castellana 91 4º 4 Madrid, Spain		
Gómez Narro Renovables 132 kV, A.I.E	Membership Interest	22.72
Sweden		
Box 135, 190 46 Arlanda, Sweden		
A Flygbranslehantering AB (AFAB)	Ordinary	25.00
Box 2154, Landvetter, 438 14, Sweden		
Gothenburgh Fuelling Company AB (GFC)	Ordinary	33.33
Box 22, SE 230 32 Malmö-Sturup, Sweden		
Malmo Fuelling Services AB	Ordinary	33.33
Box 7, 190 45 Arlanda, Sweden		
Stockholm Fuelling Services Aktiebolag	Ordinary	25.00
Switzerland		
Lindenstrasse 2, 6340 Baar, Switzerland		
Trans Adriatic Pipeline AG	Ordinary	20.00
Route de Pré-Bois 17, Cointrin, 1216, Switzerland		
Saraco SA	Ordinary	20.00
Zwüscheteich, Rümlang, 8153, Switzerland		
TAR - Tankanlage Ruemlang AG	Ordinary	27.32
Taiwan (Province of China)		
No. 97, 18F, Songren Rd., Xinyi Dist, Taipei City, 110050, Taiwan (Province of China)		
Hui-Meng Energy Co., Ltd.	Ordinary	49.97
Lightsource Renewable Energy Development Taiwan Limited	Ordinary	49.97
Lightsource Renewable Energy SPV 1 Taiwan Limited	Ordinary	49.97
Lightsource Renewable Energy SPV 2 Taiwan Limited	Ordinary	49.97
Lightsource Renewable Energy SPV 3 Taiwan Limited	Ordinary	49.97
Thailand		
23rd Fl. Rajanakarn Bldg, 3 South Sathon Road, Yannawa South Sathon, Bangkok 10120, Thailand		
Pacroy (Thailand) Co., Ltd.	Ordinary (100.00%); Preference (0.82%)	39.50
Trinidad and Tobago		
Princes Court, Cor. Pembroke & Keate Street, Port-of-Spain, Trinidad and Tobago		
Atlantic LNG 2/3 Company of Trinidad and Tobago Unlimited	Ordinary	42.50
Atlantic LNG Company of Trinidad and Tobago	Ordinary	39.00
Türkiye		
Degirmen yolu cad. No:28, Asia OfisPark K:3 Icerenkoy-Atasehir, Istanbul, 34752, Türkiye		
ATAS Anadolu Tasfiyehanesi Anonim Sirketi[f]	Ordinary	68.00
Kizilirmak Mahallesi, Ufuk Üniversitesi Caddesi, Farilya Business Center, No. 8, Çukurambar, Çankaya, Ankara, Türkiye		
TANAP Dogalgaz Iletim Anonim Sirketi	Ordinary C (100.00%)	12.00
Liman Mah. 60 Sk., Çekisan-Idari Bina sit. No:25 A/1, Konyaalti, Antalya, Türkiye		
Cekisan Depolama Hizmetleri Limited Sirketi	Ordinary	35.00
Yakuplu Mahallesi Genc, Osman Caddesi, No.7 Beylikdüzü, Istanbul, Türkiye		
Ambarli Depolama Hizmetleri Limited Sirketi	Ordinary	50.00
United Arab Emirates		
8th Floor, Standard Chartered Tower, Downtown, Dubai, United Arab Emirates		
Middle East Lubricants Company LLC	Ordinary	29.33
P O Box- 97, Sharjah, United Arab Emirates		
Sharjah Aviation Services Co. LLC	Ordinary B	49.00

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14. Related undertakings of the group – continued

P.O.Box 261781, Dubai, United Arab Emirates		
EMDAD Aviation Fuel Storage FZCO	Ordinary	33.33
Plot No. B003R04, Box No. 9400, Dubai, United Arab Emirates, Dubai, United Arab Emirates		
Emoil Storage Company FZCO	Ordinary	20.00
Unit GD-GB-00-15-BC-26, Level 15, Gate District Gate Building, Dubai International Financial Center, 74777, United Arab Emirates		
Basra Energy Company Limited	Ordinary	49.00
United Kingdom		
1 Wellheads Avenue, Dyce, Aberdeen, AB21 7PB, United Kingdom		
bp Aberdeen Hydrogen Energy Limited	Ordinary B	50.00
S&JD Robertson North Air Limited	Ordinary	49.00
12, Old Broad Street, London, EC2N 1AR, England, United Kingdom		
Azule Energy Holdings Limited	Ordinary	50.00
1st Floor, 282 Earls Court Road, London, SW5 9AS, United Kingdom		
Torro Ventures Ltd.	Ordinary (18.70%); Preference Series B (39.09%)	24.00
29th Floor 40 Bank Street, London, E14 5NR, United Kingdom		
Alyssum Group Limited	Membership Interest	26.23
33 Cavendish Square, London, W1G 0PW, United Kingdom		
Great Ropemaker Partnership (G.P.) Limited	Ordinary B	50.00
Great Ropemaker Property (Nominee 1) Limited	Ordinary	50.00
Great Ropemaker Property (Nominee 2) Limited	Ordinary	50.00
Great Ropemaker Property Limited	Ordinary	50.00
The Great Ropemaker Partnership	Membership Interest	50.00
33 Holborn, 7th Floor, London, EC1N 2HU, England, United Kingdom		
Lightsource Cosecha Limited	Ordinary	49.97
5-7 Alexandra Road, Hemel Hempstead, Hertfordshire, HP2 5BS, England, United Kingdom		
British Pipeline Agency Limited	Ordinary	50.00
United Kingdom Oil Pipelines Limited	Ordinary	22.00
Walton-Gatwick Pipeline Company Limited	Ordinary	42.33
West London Pipeline and Storage Limited	Ordinary	30.50
60 Sloane Avenue, London, SW3 3XB, United Kingdom		
Fly Victor Ltd	Membership Interest	26.23
6th Floor, 60 Gracechurch Street, London, EC3V 0HR, United Kingdom		
Gasrec Ltd	Ordinary A (39.50%)	36.67
713, Cavendish Avenue, Birchwood, Warrington, WA3 6DE, England, United Kingdom		
BiSN Holdings Limited	Preference Series B2 (26.00%)	5.88
7th Floor, 33 Holborn, London, EC1N 2HU, England, United Kingdom		
Burnthouse Solar Limited	Ordinary	49.97
Free Power for Schools 13 Limited	Ordinary	49.97
Free Power for Schools 14 Limited	Ordinary	49.97
Free Power for Schools 15 Limited	Ordinary	49.97
Free Power for Schools 17 Limited	Ordinary	49.97
Free Power for Schools 4 Limited	Ordinary	49.97
Free Power for Schools 5 Limited	Ordinary	49.97
Free Power for Schools 6 Limited	Ordinary	49.97
Free Power for Schools 7 Limited	Ordinary	49.97
Freetricity Central June Limited	Ordinary	49.97
Goulburn River HoldCo 1 Limited	Ordinary	49.97
Lightsource Asset Holdings (Australia) Limited	Ordinary	49.97
Lightsource Asset Holdings (Europe) Limited	Ordinary	49.97
Lightsource Asset Holdings (Spain) Limited	Ordinary	49.97
Lightsource Asset Holdings (UK) Limited	Ordinary	49.97
Lightsource Asset Holdings (USA) Limited	Ordinary	49.97
Lightsource Asset Holdings (Vendimia I) Limited	Ordinary	49.97
Lightsource Asset Holdings (Vendimia II) Limited	Ordinary	49.97
Lightsource Asset Holdings 1 Limited	Ordinary	49.97
Lightsource Asset Holdings 2 Limited	Ordinary	49.97

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14. Related undertakings of the group – continued

Lightsource Asset Holdings 3 Limited	Ordinary	49.97
Lightsource Asset Management Limited	Ordinary	49.97
Lightsource Australia FinCo Holdings Limited	Ordinary	49.97
Lightsource Bodegas 2 Limited	Ordinary	49.97
Lightsource Bodegas 3 Limited	Ordinary	49.97
Lightsource Bodegas 4 Limited	Ordinary	49.97
Lightsource Bodegas Limited	Ordinary	49.97
Lightsource BP Renewable Energy Investments Limited	Ordinary A (49.97%); Ordinary C (49.96%); Ordinary D (50.00%); Ordinary E (50.00%); Ordinary F (49.95%); Ordinary G (50.00%)	49.97
Lightsource Brazil Holdings 1 Limited	Ordinary	49.97
Lightsource Brazil Holdings 2 Limited	Ordinary	49.97
Lightsource Commercial Rooftops Limited	Ordinary	49.97
Lightsource Construction Management Limited	Ordinary	49.97
Lightsource Corinthian Limited	Ordinary	49.97
Lightsource Development Services Limited	Ordinary	49.97
Lightsource Egypt Holdings Limited	Ordinary	49.97
Lightsource Elk Hill 2 Solar Limited	Ordinary	49.97
Lightsource Elk Hill Solar 2 Holdings Limited	Ordinary	49.97
Lightsource Finance 55 Limited	Ordinary	49.97
Lightsource Finca 2 Limited	Ordinary	49.97
Lightsource Finca 3 Limited	Ordinary	49.97
Lightsource Finca Limited	Ordinary	49.97
Lightsource France Holdings UK Limited	Ordinary	49.97
Lightsource Grace 1 Limited	Ordinary	49.97
Lightsource Grace 2 Limited	Ordinary	49.97
Lightsource Grace 3 Limited	Ordinary	49.97
Lightsource Holdings 1 Limited	Ordinary	49.97
Lightsource Holdings 2 Limited	Ordinary	49.97
Lightsource Holdings 3 Limited	Ordinary	49.97
Lightsource Iberia Greenfield Holdings Limited	Ordinary	49.97
Lightsource Iberia Project Holdings Limited	Ordinary	49.97
Lightsource Impact 1 Limited	Ordinary	49.97
Lightsource Impact 2 Limited	Ordinary	49.97
Lightsource India Holdings (Mauritius) Limited	Ordinary	49.97
Lightsource India Holdings Limited	Ordinary	49.97
Lightsource India Investments (UK) Limited	Ordinary	49.97
Lightsource India Limited	Ordinary A	25.49
Lightsource India Maharashtra 1 Holdings Limited	Ordinary	49.97
Lightsource India Maharashtra 1 Limited	Ordinary	49.97
Lightsource Kingfisher Holdings Limited	Ordinary	49.97
Lightsource Labs 1 Limited	Ordinary	49.97
Lightsource Largescale Limited	Ordinary	49.97
Lightsource Manzanilla Limited	Ordinary	49.97
Lightsource Operations 1 Limited	Ordinary	49.97
Lightsource Operations 2 Limited	Ordinary	49.97
Lightsource Operations 3 Limited	Ordinary	49.97
Lightsource Operations Services Limited	Ordinary	49.97
Lightsource Poland Holdings (UK) Limited	Ordinary	49.97
Lightsource Property 1 Limited	Ordinary	49.97
Lightsource Property 2 Limited	Ordinary	49.97
Lightsource Property Investment Holdings Ltd	Ordinary	49.97
Lightsource Property Investment Management (LPIM) LLP	LLP Designated Member	49.97
Lightsource Property Investments 1 Ltd	Ordinary	49.97
Lightsource Renewable Energy (India) Limited	Ordinary	49.97
Lightsource Renewable Energy Asia Pacific Holdings Limited	Ordinary	49.97
Lightsource Renewable Energy Australia Holdings Limited	Ordinary	49.97

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14. Related undertakings of the group – continued

Lightsource Renewable Energy Greece Holdings (UK) Limited	Ordinary	49.97
Lightsource Renewable Energy Greece Holdings 2 (UK) Limited	Ordinary	49.97
Lightsource Renewable Energy Greece Projects 2 Limited	Ordinary	49.97
Lightsource Renewable Energy Holdings Limited	Ordinary	49.97
Lightsource Renewable Energy Iberia Holdings Limited	Ordinary	49.97
Lightsource Renewable Energy India Assets Limited	Ordinary	49.97
Lightsource Renewable Energy India Holdings Limited	Ordinary	49.97
Lightsource Renewable Energy India Projects Limited	Ordinary	49.97
Lightsource Renewable Energy Italy Holdings Limited	Ordinary	49.97
Lightsource Renewable Energy Limited	Ordinary	49.97
Lightsource Renewable Energy Moristel Limited	Ordinary	49.97
Lightsource Renewable Energy Netherlands Holdings Limited	Ordinary	49.97
Lightsource Renewable Energy New Zealand Holdings Limited	Ordinary	49.97
Lightsource Renewable Energy Poland Projects 1 Limited	Ordinary	49.97
Lightsource Renewable Energy Poland Projects 2 Limited	Ordinary	49.97
Lightsource Renewable Energy Portugal Holdings Limited	Ordinary	49.97
Lightsource Renewable Energy Portugal Projects 1 Limited	Ordinary	49.97
Lightsource Renewable Energy Portugal Projects 2 Limited	Ordinary	49.97
Lightsource Renewable Energy Tempranillo Limited	Ordinary	49.97
Lightsource Renewable Energy Verdejo Limited	Ordinary	49.97
Lightsource Renewable Global Development Limited	Ordinary	49.97
Lightsource Renewable Services Limited	Ordinary	49.97
Lightsource Renewable Taiwan UK Holdings Limited	Ordinary	49.97
Lightsource Renewable UK Development Limited	Ordinary	49.97
Lightsource Residential Rooftops (PPA) Limited	Ordinary	49.97
Lightsource Residential Rooftops Limited	Ordinary	49.97
Lightsource SPV 101 Limited	Ordinary	49.97
Lightsource SPV 108 Limited	Ordinary	49.97
Lightsource SPV 114 Limited	Ordinary	49.97
Lightsource SPV 116 Limited	Ordinary	49.97
Lightsource SPV 118 Limited	Ordinary	49.97
Lightsource SPV 126 Limited	Ordinary	49.97
Lightsource SPV 127 Limited	Ordinary	49.97
Lightsource SPV 128 Limited	Ordinary	49.97
Lightsource SPV 130 Limited	Ordinary	49.97
Lightsource SPV 138 Limited	Ordinary	49.97
Lightsource SPV 140 Limited	Ordinary	49.97
Lightsource SPV 145 Limited	Ordinary	49.97
Lightsource SPV 149 Limited	Ordinary	49.97
Lightsource SPV 151 Limited	Ordinary	49.97
Lightsource SPV 154 Limited	Ordinary	49.97
Lightsource SPV 162 Limited	Ordinary	49.97
Lightsource SPV 166 Limited	Ordinary	49.97
Lightsource SPV 167 Limited	Ordinary	49.97
Lightsource SPV 171 Limited	Ordinary	49.97
Lightsource SPV 176 Limited	Ordinary	49.97
Lightsource SPV 179 Limited	Ordinary	49.97
Lightsource SPV 18 Limited	Ordinary	49.97
Lightsource SPV 182 Limited	Ordinary	49.97
Lightsource SPV 183 Limited	Ordinary	49.97
Lightsource SPV 184 Limited	Ordinary	49.97
Lightsource SPV 185 Limited	Ordinary	49.97
Lightsource SPV 189 Limited	Ordinary	49.97
Lightsource SPV 19 Limited	Ordinary	49.97
Lightsource SPV 191 Limited	Ordinary	49.97
Lightsource SPV 192 Limited	Ordinary	49.97
Lightsource SPV 199 Limited	Ordinary	49.97
Lightsource SPV 201 Limited	Ordinary	49.97
Lightsource SPV 202 Limited	Ordinary	49.97

The parent company financial statements of BP p.l.c. on pages 275-334 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

14. Related undertakings of the group – continued

Lightsource SPV 203 Limited	Ordinary	49.97
Lightsource SPV 204 Limited	Ordinary	49.97
Lightsource SPV 206 Limited	Ordinary	49.97
Lightsource SPV 212 Limited	Ordinary	49.97
Lightsource SPV 213 Limited	Ordinary	49.97
Lightsource SPV 214 Limited	Ordinary	49.97
Lightsource SPV 215 Limited	Ordinary	49.97
Lightsource SPV 216 Limited	Ordinary	49.97
Lightsource SPV 217 Limited	Ordinary	49.97
Lightsource SPV 222 Limited	Ordinary	49.97
Lightsource SPV 223 Limited	Ordinary	49.97
Lightsource SPV 232 Limited	Ordinary	49.97
Lightsource SPV 233 Limited	Ordinary	49.97
Lightsource SPV 236 Limited	Ordinary	49.97
Lightsource SPV 247 Limited	Ordinary	49.97
Lightsource SPV 25 Limited	Ordinary	49.97
Lightsource SPV 258 Limited	Ordinary	49.97
Lightsource SPV 259 Limited	Ordinary	49.97
Lightsource SPV 263 Limited	Ordinary	49.97
Lightsource SPV 264 Limited	Ordinary	49.97
Lightsource SPV 286 Limited	Ordinary	49.97
Lightsource SPV 287 Limited	Ordinary	49.97
Lightsource SPV 288 Limited	Ordinary	49.97
Lightsource SPV 29 Limited	Ordinary	49.97
Lightsource SPV 35 Limited	Ordinary	49.97
Lightsource SPV 41 Limited	Ordinary	49.97
Lightsource SPV 47 Limited	Ordinary	49.97
Lightsource SPV 56 Limited	Ordinary	49.97
Lightsource SPV 60 Limited	Ordinary	49.97
Lightsource SPV 73 Limited	Ordinary	49.97
Lightsource SPV 78 Limited	Ordinary	49.97
Lightsource SPV 88 Limited	Ordinary	49.97
Lightsource SPV 91 Limited	Ordinary	49.97
Lightsource SPV 98 Limited	Ordinary	49.97
Lightsource Titan Borrower AUD Limited	Ordinary	49.97
Lightsource Titan Borrower EUR Limited	Ordinary	49.97
Lightsource Titan Borrower GBP Limited	Ordinary	49.97
Lightsource Titan Borrower USD Limited	Ordinary	49.97
Lightsource Titan Limited	Ordinary	49.97
Lightsource Trading Limited	Ordinary	49.97
Lightsource Trinidad Holdings (UK) Limited	Ordinary	49.97
Lightsource UK Property Investments 1 LP	Limited Partner	49.98
Lightsource Viking 1 Limited	Ordinary	49.97
Lightsource Viking 2 Limited	Ordinary	49.97
Lightsource Viking Limited	Ordinary	49.97
Lightsource Xenium 1 Limited	Ordinary	49.97
Lightsource Xenium 2 Limited	Ordinary	49.97
LL Property Services 2 Limited	Ordinary	49.97
LL Property Services Limited	Ordinary	49.97
Solar Photovoltaic (SPV2) Limited	Ordinary	49.97
Solar Photovoltaic (SPV3) Limited	Ordinary	49.97
Tiln Connections Ltd	Ordinary	49.97
Tuwale Power Limited	Ordinary	49.97
West Wyalong HoldCo 1 Limited	Ordinary	49.97
Woolooga BESS HoldCo 1 Limited	Ordinary	49.97
Woolooga HoldCo 1 Limited	Ordinary	49.97
Your Power No. 1 Limited	Ordinary	49.97
Your Power No. 10 Limited	Ordinary	49.97
Your Power No. 19 Limited	Ordinary	49.97

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14. Related undertakings of the group – continued

Your Power No. 2 Limited	Ordinary	49.97
Your Power No. 3 Limited	Ordinary	49.97
Your Power No. 8 Limited	Ordinary	49.97
9 Caxton House, Broad Street, Great Cambourne, Cambridge, CB23 6JN, England, United Kingdom		
Joint Inspection Group Limited	Membership Interest	14.28
C/O ERNST & YOUNG LLP, The Paragon Counterslip, Bristol, BS1 6BX, United Kingdom		
Green Biofuels Limited	Ordinary	30.00
Calshot Way Central Area, Heathrow Airport, Hounslow, Middlesex, TW6 1PY, United Kingdom		
Aviation Fuel Services Limited	Ordinary	25.00
Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, England, United Kingdom		
Azule Energy Exploration (Angola) Limited	Ordinary	50.00
Azule Energy Exploration Angola (KB) Limited	Ordinary	50.00
Azule Energy Limited	Ordinary	50.00
Mona Offshore Wind Holdings Limited	Ordinary	50.00
Mona Offshore Wind Limited	Ordinary	50.00
Morgan Offshore Wind Holdings Limited	Ordinary	50.00
Morgan Offshore Wind Limited	Ordinary	50.00
Morven Offshore Wind Holdings Limited	Ordinary	50.00
Morven Offshore Wind Limited	Ordinary	50.00
Eni House, 10 Ebury Bridge Road, London, SW1W 8PZ, England, United Kingdom		
Solenova Limited	Membership Interest	25.00
VIC CBM Limited	Ordinary	50.00
Virginia Indonesia Co. CBM Limited	Ordinary	50.00
Mclaren Building Suite, 14a Mclaren Building, 46 Priory Queensway, Birmingham, B4 7LR, United Kingdom		
Grid Edge Limited	Preferred Series A (60.00%); Preferred Series A 2 (58.68%)	25.16
Mw1 Building 557 Shoreham Road, Heathrow Airport, London, TW6 3RT, United Kingdom		
Aviation Service (Iraq) Limited	Ordinary B	40.00
Northgate House, 2nd Floor, Upper Borough Walls, Bath, BA1 1RG, England, United Kingdom		
Blue Marble Holdings Limited	Ordinary C (96.53%)	23.58
One Bartholomew Close, London, EC1A 7BL, United Kingdom		
Manchester Airport Storage and Hydrant Company Limited	Ordinary	25.00
Oxbotica Uhq 8050 Alec Issigonis Way, Oxford Business Park North, Oxford, Oxfordshire, OX4 2HW, England, United Kingdom		
Oxa Autonomy Ltd	Ordinary (1.10%); Preference Series B (17.79%); Preference Series C (22.37%)	11.26
Regus Business Centre, Cromac Square, Belfast, Northern Ireland, BT2 8LA, United Kingdom		
Lightsource Renewable Energy (NI) Limited	Ordinary	49.97
Lightsource SPV 266 (NI) Limited	Ordinary	49.97
Lightsource SPV 267 (NI) Limited	Ordinary	49.97
Lightsource SPV 268 (NI) Limited	Ordinary	49.97
Lightsource SPV 269 (NI) Limited	Ordinary	49.97
Lightsource SPV 270 (NI) Limited	Ordinary	49.97
Lightsource SPV 271 (NI) Limited	Ordinary	49.97
Lightsource SPV 272 (NI) Limited	Ordinary	49.97
Lightsource SPV 273 (NI) Limited	Ordinary	49.97
Lightsource SPV 274 (NI) Limited	Ordinary	49.97
Lightsource SPV 275 (NI) Limited	Ordinary	49.97
Lightsource SPV 276 (NI) Limited	Ordinary	49.97
Lightsource SPV 277 (NI) Limited	Ordinary	49.97
Lightsource SPV 278 (NI) Limited	Ordinary	49.97
Lightsource SPV 279 (NI) Limited	Ordinary	49.97
Lightsource SPV 280 (NI) Limited	Ordinary	49.97
Lightsource SPV 281 (NI) Limited	Ordinary	49.97
Lightsource SPV 282 (NI) Limited	Ordinary	49.97
Lightsource SPV 283 (NI) Limited	Ordinary	49.97
Lightsource SPV 284 (NI) Limited	Ordinary	49.97
Lightsource SPV 285 (NI) Limited	Ordinary	49.97

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14. Related undertakings of the group – continued

Shell Centre, London, SE1 7NA, United Kingdom		
Shell Mex and B.P. Limited	Ordinary B	40.00
SM Realisations Limited (Liquidated)	Membership Interest	40.00
The Consolidated Petroleum Company Limited	Ordinary B	50.00
The Consolidated Petroleum Supply Company Limited[g]	Ordinary	50.00
Suite 44 (C/O Best4Business Accountants), Beaufort Court, Admirals Way, London, E14 9XL, United Kingdom		
Pentland Aviation Fuelling Services Limited	Ordinary A; Ordinary B	66.67
Sustainable Workspaces, County Hall, 5th Floor, The Riverside Building, Belvedere Road,London, SE1 7PB, England, United Kingdom		
Powerverse Development Limited	Ordinary	49.97
Powerverse Investments Limited	Ordinary	49.97
Powerverse UK Limited	Ordinary	49.97
Unit 9 Armstrong Mall, Southwood Business Park, Farnborough, GU14 0NR, England, United Kingdom		
Blue Ocean Seismic Services Limited	Preference Series A (51.28%)	31.25
Windsor House, Cornwall Road, Harrogate, England, HG1 2PW, United Kingdom		
C-Capture Limited	Preference Series A (23.17%)	19.30
United States		
108 Lakeland Avenue, Dover, Kent, DE, 19901		
Azule Energy Gas Supply Services Inc.	Ordinary	50.00
15260 Pacific Palisade #204, Pacific Palisades, California, 90271, United States		
Wastefuel Global, Inc.	Series B1 (100.00%);	2.67
1560 Broadway, Suite 2090, Denver, Colorado, 80202, United States		
Cedar Creek II, LLC	Membership Interest	50.00
160 Greentree Drive, Suite 101, City of Dover, County of Kent, DE, 19901, United States		
Zubie, Inc.	Membership Interest	20.30
16192 Coastal Highway, Sussex County, Lewes, DE, 19958, United States		
Aparecida I Power Holding LLC	Membership Interest	25.00
2140 S. Dupont Highway, Camden, County of Kent, DE, 19934, United States		
Beyond Limits, Inc.	Preference Series B (100.00%); Preference Series C (20.07%)	50.54
251, Little Falls Drive, Wilmington, DE, 19808, United States		
TAI 1 LLC	Membership Interest	100.00
2710 Gateway Oaks Drive, Suite 150N Sacramento, CA, 95833-3505, United States		
East Travel Plaza LLC	Membership Interest	40.00
Petro Travel Plaza LLC	Membership Interest	40.00
2711 Centerville Road, Suite 400, Wilmington, DE, 19808, United States		
Energy Emerging Investments, LLC	Membership Interest	50.00
3410 Belle Chase Way, Suite 600, Lansing, MI, 48911, United States		
Sunshine Gas Producers, LLC	Membership Interest	50.00
3500 DuPont Highway, Dover, County of Kent, DE, 19901, United States		
RepairPal, Inc.	Preference Series A2 (30.77%); Preference Series B (71.32%); Preference Series C (34.73%)	34.11
4001 Kennet Pike, Suite 302, Wilmington, DE, 19807, United States		
AEP I HoldCo LLC	Membership Interest	24.30
501 Westlake Park Blvd, Houston, TX 77079, United States		
HPP SD Holdings, LLC	Membership Interest	20.70
8 the Green, Ste A, Dover, Kent, DE, 19901, United States		
Lutum Technology LLC	Series A Common Units	20.00
815, 14th Street SW, Suite A100, Loveland, CO 80537, United States		
Lightning eMotors, Inc.	Ordinary	25.51
850 New Burton Road, Suite 201, Dover, Delaware, 19902, United States		
SeaPort Midstream Partners, LLC	Membership Interest	49.00
920 North King Street, 2nd Floor, Wilmington DE 19801, United States		
Atlantic 1 Holdings LLC	Membership Interest	39.00
Atlantic 2/3 Holdings LLC	Membership Interest	42.50

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14. Related undertakings of the group – continued

9900 Spectrum Drive, Austin, TX 78717, United States		
Austin Elements Inc.	Ordinary	30.00
c/o Corporation Service Company, 251 Little Falls Drive, Wilmington, DE 19808, United States		
Apis Innovation Inc.	Ordinary	37.43
Astro Solar Construction Holdings, LLC	Membership Interest	49.97
Astro Solar Construction, LLC	Membership Interest	49.97
Astro Solar Holdings 1, LLC	Membership Interest	49.97
Astro Solar Holdings 2, LLC	Membership Interest	49.97
Astro Solar Manager, LLC	Membership Interest	49.97
Astro Solar Transfer Holdings, LLC	Membership Interest	49.97
Atlas RNG LLC	Membership Interest	50.00
Bass Solar Class B, LLC	Membership Interest	49.97
Bass Solar Construction, LLC	Membership Interest	49.97
Bass Solar Holdings 1, LLC	Membership Interest	49.97
Bass Solar Holdings 2, LLC	Membership Interest	49.97
Bass Solar Holdings, LLC	Class B Membership Interest	49.97
Beacon Wind Holdings LLC	Membership Interest	50.00
Beacon Wind LLC	Membership Interest	50.00
Bellflower Solar 1, LLC	Membership Interest	49.97
Big Elk Solar, LLC	Membership Interest	49.97
Bighorn Solar 1, LLC	Membership Interest	49.97
Bighorn Solar Class B, LLC	Membership Interest	49.97
Bighorn Solar Construction, LLC	Membership Interest	49.97
Bighorn Solar Holdings 1, LLC	Membership Interest	49.97
Bighorn Solar Holdings 2, LLC	Membership Interest	49.97
Bighorn Solar Holdings, LLC	Class B Membership Interest	49.97
Birch Solar 1, LLC	Membership Interest	49.97
Black Bear Alabama Solar 1, LLC	Membership Interest	25.73
Black Bear Alabama Solar Holdings 1, LLC	Membership Interest	49.97
Black Bear Alabama Solar Holdings 2, LLC	Membership Interest	49.97
Black Bear Alabama Solar Holdings, LLC	Membership Interest	25.73
Black Bear Alabama Solar Land Holdings, LLC	Membership Interest	49.97
Black Bear Alabama Solar Manager, LLC	Membership Interest	49.97
Briar Creek Solar 1, LLC	Membership Interest	49.97
Canal Road Solar, LLC	Membership Interest	49.97
Cardinal Solar Class B, LLC	Membership Interest	49.97
Cardinal Solar Construction Holdings, LLC	Membership Interest	49.97
Cardinal Solar Construction, LLC	Membership Interest	49.97
Cardinal Solar Holdings 1, LLC	Membership Interest	49.97
Cardinal Solar Holdings 2, LLC	Membership Interest	49.97
Cardinal Solar Holdings, LLC	Membership Interest	49.97
Champion Solar 1, LLC	Membership Interest	49.97
Chester Solar Energy, LLC	Membership Interest	49.97
Concord Solar Class B, LLC	Membership Interest	49.97
Concord Solar Construction Holdings, LLC	Membership Interest	49.97
Concord Solar Construction, LLC	Membership Interest	49.97
Concord Solar Holdings 1, LLC	Membership Interest	49.97
Concord Solar Holdings 2, LLC	Membership Interest	49.97
Concord Solar Holdings, LLC	Membership Interest	49.97
Continental Divide Solar I, LLC	Membership Interest	49.97
Continental Divide Solar II, LLC	Membership Interest	49.97
Continental Divide Solar Land Holdings, LLC	Membership Interest	49.97
Cottontail Solar 1, LLC	Membership Interest	49.97
Cottontail Solar 2, LLC	Membership Interest	49.97
Cottontail Solar 3, LLC	Membership Interest	49.97
Cottontail Solar 4, LLC	Membership Interest	49.97
Cottontail Solar 5, LLC	Membership Interest	49.97
Cottontail Solar 6, LLC	Membership Interest	49.97

The parent company financial statements of BP p.l.c. on pages 275-334 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

14. Related undertakings of the group – continued

Cottontail Solar 7, LLC	Membership Interest	49.97
Cottontail Solar 8, LLC	Membership Interest	49.97
Cottontail Solar 9, LLC	Membership Interest	49.97
Cottontail Solar Class B, LLC	Membership Interest	49.97
Cottontail Solar Construction Holdings, LLC	Membership Interest	49.97
Cottontail Solar Construction, LLC	Membership Interest	49.97
Cottontail Solar Holdings 1, LLC	Membership Interest	49.97
Cottontail Solar Holdings 2, LLC	Membership Interest	49.97
Cottontail Solar Holdings, LLC	Class B Membership Interest	49.97
Crawfish Solar Class B, LLC	Membership Interest	49.97
Crawfish Solar Construction Holdings, LLC	Membership Interest	49.97
Crawfish Solar Construction, LLC	Membership Interest	49.97
Crawfish Solar Holdings 1, LLC	Membership Interest	49.97
Crawfish Solar Holdings 2, LLC	Membership Interest	49.97
Crawfish Solar Holdings, LLC	Class B Membership Interest	49.97
Crawford Solar, LLC	Membership Interest	49.97
Crossvine Solar 1, LLC	Membership Interest	49.97
Crossvine Solar Holdings, LLC	Membership Interest	49.97
Driver Solar Holdings, LLC	Membership Interest	49.97
Driver Solar, LLC	Membership Interest	49.97
Eden RNG LLC	Membership Interest	50.00
Elk Hill Solar 1 Holdings, LLC	Membership Interest	49.97
Elk Hill Solar 1 Storage, LLC	Membership Interest	49.97
Elk Hill Solar 1, LLC	Membership Interest	49.97
Elk Hill Solar 2 Holdings, LLC	Membership Interest	49.97
Elk Hill Solar 2, LLC	Membership Interest	49.97
Elm Branch Solar 1, LLC	Membership Interest	49.97
Empire Offshore Wind Holdings LLC	Membership Interest	50.00
Empire Offshore Wind LLC	Membership Interest	50.00
Endurance Solar Holdings 1, LLC	Membership Interest	49.97
Endurance Solar Holdings 2, LLC	Membership Interest	49.97
Endurance Solar Holdings, LLC	Membership Interest	49.97
Endurance Solar Investor 1, LLC	Membership Interest	49.97
Endurance Solar Investor 2, LLC	Membership Interest	49.97
Endurance Solar Manager, LLC	Membership Interest	49.97
Endurance Solar Transfer Holdings, LLC	Membership Interest	49.97
Falcon Lake Storage, LLC	Membership Interest	49.97
FreeWire Technologies, Inc.	Membership Interest	22.90
Glade CD Solar Holdings, LLC	Membership Interest	49.97
Glade Solar Class B, LLC	Membership Interest	49.97
Glade Solar Construction Holdings, LLC	Membership Interest	49.97
Glade Solar Construction, LLC	Membership Interest	49.97
Glade Solar Holdings 1, LLC	Membership Interest	49.97
Glade Solar Holdings 2, LLC	Membership Interest	49.97
Glade Solar Holdings, LLC	Class B Membership Interest	49.97
Glade Solar Land Holdings, LLC	Membership Interest	49.97
Granite Hill Solar Land Holdings, LLC	Membership Interest	49.97
Granite Hill Solar, LLC	Membership Interest	49.97
Green Meadows Operations LLC	Membership Interest	50.00
Green Meadows RNG LLC	Membership Interest	50.00
Happy Solar 1, LLC	Membership Interest	49.97
Honeysuckle Solar, LLC	Membership Interest	49.97
Impact Solar 1, LLC	Membership Interest	49.97
Impact Solar Class B, LLC	Membership Interest	49.97
Impact Solar Construction, LLC	Membership Interest	49.97
Impact Solar Holdings 1, LLC	Membership Interest	49.97
Impact Solar Holdings 2, LLC	Membership Interest	49.97

The parent company financial statements of BP p.l.c. on pages 275-334 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

14. Related undertakings of the group – continued

Impact Solar Holdings, LLC	Class B Membership Interest	49.97
Inverness Solar, LLC	Membership Interest	49.97
Janus RNG LLC	Membership Interest	50.00
Johnson Corner Solar I, LLC	Membership Interest	49.97
Jones City Solar II, LLC	Membership Interest	49.97
Jones City Solar, LLC	Membership Interest	49.97
Kirkham Solar Farms I, LLC	Membership Interest	49.97
Kirkham Solar Farms II, LLC	Membership Interest	49.97
Lightsource Beacon 2, LLC	Membership Interest	49.97
Lightsource Beacon 3, LLC	Membership Interest	49.97
Lightsource Beacon Holdings, LLC	Membership Interest	49.97
Lightsource Beacon, LLC	Membership Interest	49.97
Lightsource Osprey Holdings A, LLC	Membership Interest	49.97
Lightsource Osprey Holdings B, LLC	Membership Interest	49.97
Lightsource Renewable Energy Asset Holdings 1, LLC	Membership Interest	49.97
Lightsource Renewable Energy Asset Management Holdings, LLC	Membership Interest	49.97
Lightsource Renewable Energy Asset Management, LLC	Membership Interest	49.97
Lightsource Renewable Energy Assets Holdings, LLC	Membership Interest	49.97
Lightsource Renewable Energy Austin Holdings, LLC	Membership Interest	49.97
Lightsource Renewable Energy Development, LLC	Membership Interest	49.97
Lightsource Renewable Energy Management, LLC	Membership Interest	49.97
Lightsource Renewable Energy Operations, LLC	Membership Interest	49.97
Lightsource Renewable Energy Services Holdings, LLC	Membership Interest	49.97
Lightsource Renewable Energy Services, Inc.	Ordinary	49.97
Lightsource Renewable Energy Trading, LLC	Membership Interest	49.97
Lightsource Renewable Energy US, LLC	Membership Interest	49.97
LSBP NE Development, LLC	Membership Interest	49.97
Maverick Solar Class B, LLC	Membership Interest	49.97
Maverick Solar Construction, LLC	Membership Interest	49.97
Maverick Solar Holdings 1, LLC	Membership Interest	49.97
Maverick Solar Holdings 2, LLC	Membership Interest	49.97
Maverick Solar Holdings, LLC	Class B Membership Interest	49.97
Mayapple Solar Holdings 1, LLC	Membership Interest	49.97
Mayapple Solar Holdings, LLC	Membership Interest	49.97
Mayapple Solar, LLC	Membership Interest	49.97
Merrillville Solar Holdings, LLC	Membership Interest	49.97
Merrillville Solar Land Holdings, LLC	Membership Interest	49.97
Merrillville Solar, LLC	Membership Interest	49.97
Mound Creek Storage, LLC	Membership Interest	49.97
Mountain Daisy Solar, LLC	Membership Interest	49.97
Mountain Holly Solar, LLC	Membership Interest	49.97
Mowata Solar, LLC	Membership Interest	49.97
Nikola-TA HRS 1, LLC	Membership Interest	50.00
Osprey Solar Holdings A, LLC	Membership Interest	49.97
Osprey Solar Holdings B, LLC	Membership Interest	49.97
Oxbow Solar Farm 1, LLC	Membership Interest	49.97
Oxbow Solar Land Holdings, LLC	Membership Interest	49.97
Pan RNG LLC	Membership Interest	50.00
Paper Shell Solar 1, LLC	Membership Interest	49.97
Peony Solar 1, LLC	Membership Interest	49.97
Petro Travel Plaza Holdings LLC	Membership Interest	40.00
Pikes Peak Energy Storage Holdings, LLC	Membership Interest	49.97
Pikes Peak Energy Storage, LLC	Membership Interest	49.97
Pine Burr Solar 1, LLC	Membership Interest	49.97
Pine Cone Solar 2, LLC	Membership Interest	49.97
Pine Cone Solar 3, LLC	Membership Interest	49.97
Pine Cone Solar, LLC	Membership Interest	49.97
Poplar Solar 1, LLC	Membership Interest	49.97

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14. Related undertakings of the group – continued

Prairie Ronde Solar Class B, LLC	Membership Interest	49.97
Prairie Ronde Solar Farm, LLC	Membership Interest	49.97
Prairie Ronde Solar Holdings, LLC	Membership Interest	49.97
Renewable Energy Shared Assets LLC	Membership Interest	50.00
Roscoe Solar, LLC	Membership Interest	49.97
Saturn Renewables LLC	Partnership interest	50.00
Shorebird Solar, LLC	Membership Interest	49.97
Snowdrop Solar, LLC	Membership Interest	49.97
Starr Solar Ranch 1, LLC	Membership Interest	49.97
Starr Solar Ranch LLC	Membership Interest	49.97
Sun Mountain Solar 1, LLC	Membership Interest	49.97
Sycamore Trail Land Holdings, LLC	Membership Interest	49.97
Sycamore Trail Solar, LLC	Membership Interest	49.97
Titan Partners LLC	Membership Interest	25.00
Trinity River Solar 1, LLC	Membership Interest	49.97
TX Gulf Solar 1, LLC	Membership Interest	49.97
White Trillium Solar, LLC	Membership Interest	49.97
Whitetail Solar 1, LLC	Membership Interest	49.97
Whitetail Solar 2, LLC	Membership Interest	49.97
Whitetail Solar 3, LLC	Membership Interest	49.97
Whitetail Solar 6, LLC	Membership Interest	49.97
Whitetail Solar Land Holdings, LLC	Membership Interest	49.97
Wildflower Solar I, LLC	Membership Interest	49.97
Wildflower Solar Land Holdings, LLC	Membership Interest	49.97
Corporation Trust Center, 1209 Orange Street, Wilmington, DE, 19801, United States		
Advanced Ionics, Inc.	Series A-1 (40.90%)	15.53
Ash Grove Renewable Energy, LLC	Membership Interest	50.00
Auwahi Holdings, LLC	Membership Interest	50.00
Auwahi Wind Energy LLC	Membership Interest	50.00
Caesar Oil Pipeline Company, LLC	Membership Interest	56.00
Calysta, Inc.	Preference Series D-1	36.36
CE BP Renew Co, LLC	Membership Interest	50.00
CE bp Renew Dynamic Co I, LLC	Membership Interest	40.00
CE bp Renew Dynamic Co II, LLC	Membership Interest	50.00
CE bp Renew Dynamic Co III, LLC	Membership Interest	40.00
Cedar Creek II Holdings LLC	Membership Interest	50.00
Chicap Pipe Line Company	Ordinary	28.65
Cleopatra Gas Gathering Company, LLC	Membership Interest	53.00
Drumgoon Digester Renewable Energy, LLC	Membership Interest	40.00
East Valley Development, LLC	Membership Interest	50.00
Endymion Oil Pipeline Company, LLC	Membership Interest	65.00
Fowler II Holdings LLC	Membership Interest	50.00
Fowler Ridge II Wind Farm LLC	Membership Interest	50.00
Goshen Phase II LLC	Membership Interest	50.00
KM Phoenix Holdings LLC	Membership Interest	25.00
Mars Oil Pipeline Company LLC	Partnership interest	28.50
Marshall Ridge Renewable Energy, LLC	Membership Interest	40.00
Mehoopany Wind Energy LLC	Membership Interest	50.00
Mehoopany Wind Holdings LLC	Membership Interest	50.00
Midwest Alliance For Clean Hydrogen, LLC	Membership Interest	26.20
Olympic Pipe Line Company LLC	Membership Interest	35.70
PartsTech, Inc.	Preference Series A (65.15%); Preference Series B (17.84%)	40.13
Proteus Oil Pipeline Company, LLC	Membership Interest	65.00
Tri-Cross Renewable Energy, LLC	Membership Interest	50.00
Ursa Major Marine Holdings, LLC	Membership Interest	33.33
Ursa Oil Pipeline Company LLC	Membership Interest	22.69
Van Winkle Digester Renewable Energy, LLC	Membership Interest	50.00
VF Renewable Energy, LLC	Membership Interest	40.00

The parent company financial statements of BP p.l.c. on pages 275-334 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

14. Related undertakings of the group – continued

Uruguay		
Avenida Luis Alberto de Herrera 1248, Oficina 1901, Montevideo, Uruguay		
Axuy Energy Holdings S.R.L.	Membership Interest	50.00
Axuy Energy Investments S.R.L.	Membership Interest	50.00
Colonia 810, Oficina 403, Montevideo, Uruguay		
Baplor S.A.	Ordinary	50.00
FERMULY S.A.	Ordinary	50.00
Gemalsur S.A.	Ordinary	50.00
Pan American Energy Holdings S.A.	Ordinary	50.00
Pan American Energy Uruguay S.A.	Ordinary	50.00
Dr. Luis Bonavita 1294, Oficina 2302, Montevideo, Uruguay		
BP Bunge Montevideo S.A.	Ordinary	50.00
La Cumparsita 1373, piso 4°, Montevideo, Uruguay		
Dinarel S.A.	Ordinary	20.00
Luis A de Herrera 1248, Torre II, Piso 22 (Edificio World Trade Center), Montevideo, Uruguay		
Axion Comercializacion De Combustibles Y Lubricantes S.A.	Ordinary	50.00
Zimbabwe		
Block 1 Tendeseka Office Park, Samora Machel Av/Renfrew Road, Harare, Zimbabwe		
Central African Petroleum Refineries (Pvt) Ltd	Membership Interest	20.75

[a] 1% interest held directly by BP p.l.c.
[b] 0.01% interest held directly by BP p.l.c.
[c] 99% interest held directly by BP p.l.c.
[d] 100% interest held directly by BP p.l.c.
[e] 50% interest held directly by BP p.l.c.
[f] 15% interest held directly by BP p.l.c.
[g] 5% interest held directly by BP p.l.c.

The parent company financial statements of BP p.l.c. on pages 275-334 do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

Additional disclosures

★ See glossary on **page 373**

Additional information

Capital expenditure★

	2023	2022	2021
			$ million
Capital expenditure			
Organic capital expenditure★	**14,998**	12,470	11,779
Inorganic capital expenditure[abc]★	**1,255**	3,860	1,069
	16,253	16,330	12,848
Capital expenditure by segment			
gas & low carbon energy[c]	**4,281**	4,251	4,741
oil production & operations	**6,278**	5,278	4,838
customers & products[ab]	**5,253**	6,252	2,872
other businesses & corporate	**441**	549	397
	16,253	16,330	12,848
Capital expenditure by geographical area			
US	**8,105**	8,656	4,858
Non-US	**8,148**	7,674	7,990
	16,253	16,330	12,848

[a] 2023 includes $1.1 billion in respect of the TravelCenters of America acquisition.
[b] 2022 includes $3,030 million in respect of the Archaea Energy acquisition.
[c] 2021 includes the final payment of $712 million in respect of the strategic partnership with Equinor.

Adjusting items

Adjusting items are items that bp discloses separately because it considers such disclosures to be meaningful and relevant to investors. They are items that management considers to be important to period-on-period analysis of the group's results and are disclosed in order to enable investors to better understand and evaluate the group's reported financial performance. An analysis of adjusting items is shown in the table below.

			$ million
	2023	2022	2021
gas & low carbon energy			
Gain on sale of businesses and fixed assets[a]	**19**	45	1,034
Net impairment and losses on sale of businesses and fixed assets[a]	**(2,221)**	588	1,503
Environmental and other provisions	**—**	—	—
Restructuring, integration and rationalization costs[b]	**—**	8	(33)
Fair value accounting effects[cd] ★	**8,859**	(1,811)	(7,662)
Other[e]	**(1,299)**	(197)	(237)
	5,358	(1,367)	(5,395)
oil production & operations			
Gain on sale of businesses and fixed assets[a]	**297**	3,446	869
Net impairment and losses on sale of businesses and fixed assets[a]	**(1,819)**	(4,508)	776
Environmental and other provisions[f]	**54**	518	(1,144)
Restructuring, integration and rationalization costs[b]	**(1)**	(11)	(92)
Fair value accounting effects	**—**	—	—
Other[g]	**(121)**	52	(200)
	(1,590)	(503)	209
customers & products			
Gain on sale of businesses and fixed assets[a]	**44**	374	(52)
Net impairment and losses on sale of businesses and fixed assets[a]	**(1,757)**	(1,983)	(1,097)
Environmental and other provisions	**(97)**	(101)	(111)
Restructuring, integration and rationalization costs[b]	**—**	18	(11)
Fair value accounting effects[d]	**(86)**	(309)	436
Other[h]	**(287)**	81	(209)
	(2,183)	(1,920)	(1,044)
other businesses & corporate			
Gain on sale of businesses and fixed assets[a]	**1**	1	—
Net impairment and losses on sale of businesses and fixed assets[a]	**(41)**	(17)	(59)
Environmental and other provisions[i]	**(604)**	(92)	(281)
Restructuring, integration and rationalization costs[b]	**38**	19	(113)
Fair value accounting effects[d]	**630**	(1,381)	(849)
Rosneft[j]	**—**	(24,033)	(291)
Gulf of Mexico oil spill	**(57)**	(84)	(70)
Other	**(4)**	21	(22)
	(37)	(25,566)	(1,685)
Total before interest and taxation	**1,548**	(29,356)	(7,915)
Finance costs[k]	**(405)**	(425)	(782)
Total before taxation	**1,143**	(29,781)	(8,697)
Taxation on adjusting items[l]	**972**	456	621
Taxation - tax rate change effect of UK energy profits levy[m]	**232**	(1,834)	—
Total after taxation[n]	**2,347**	(31,159)	(8,076)

[a] See Financial statements – Note 4 for further information.
[b] Restructuring charges are classified as adjusting items where they relate to an announced major group restructuring. A major group restructuring is a restructuring programme affecting more than one of the group's operating segments that is expected to result in charges of more than $1 billion over a defined period. 2022 includes release of provisions for the reinvent bp restructuring costs. 2021 includes recognized provisions for the reinvent bp restructuring costs that were formalized in 2020.
[c] Under IFRS bp marks-to-market the value of the hedges used to risk-manage LNG contracts, but not the contracts themselves, resulting in a mismatch in accounting treatment. The fair value accounting effect includes the change in value of LNG contracts that are being risk managed, and the underlying result reflects how bp risk-manages its LNG contracts.
[d] For further information, including the nature of fair value accounting effects reported in each segment, see page 377.
[e] 2023 includes $1,140 million of impairment charges recognized through equity-accounted earnings relating to our US offshore wind projects.
[f] 2022 includes a provision reversal relating to the change in discount rate on retained decommissioning provisions. 2021 includes adjustments relating to the change in discount rate on retained decommissioning provisions and the recognition of a decommissioning provision in relation to certain assets previously sold to a third party where the decommissioning obligation transferred may revert to bp due to the financial condition of the current owner.
[g] 2021 includes a $415 million charge relating to a remeasurement of deferred tax balances in our equity-accounted entity in Argentina following income tax rate changes partially offset by impairment reversals in equity-accounted entities.
[h] 2021 includes amounts arising in relation to the amendment of the timing of recognition of certain customer incentives in our customers business.
[i] 2023 primarily relates to charges related to the control, abatement, clean-up or elimination of environmental pollution and legal settlements. 2022 and 2021 primarily reflect charges due to the annual update of environmental provisions, including asbestos-related provisions for past operations, together with updates of non-Gulf of Mexico oil spill related legal provisions.
[j] For more information see Financial statements – Note 1 Significant accounting policies, judgements, estimates and assumptions – Investment in Rosneft and Note 17 – Investments in associates.
[k] Includes the unwinding of discounting effects relating to Gulf of Mexico oil spill payables, the income statement impact associated with the buyback of finance debt (see Financial statements – Note 26 for further information) and temporary valuation differences associated with the group's interest rate and foreign currency exchange risk management of finance debt.
[l] Includes certain foreign exchange effects on tax as adjusting items. These amounts represent the impact of: (i) foreign exchange on deferred tax balances arising from the conversion of local currency tax base amounts into functional currency; and (ii) taxable gains and losses from the retranslation of US dollar-denominated intra-group loans to local currency.
[m] 2023 includes a revision to the deferred tax impact of the introduction of the UK Energy Profits Levy (EPL) on temporary differences existing at 31 December 2022 that are expected to unwind over the period 1 January 2023 to 31 March 2028. 2022 includes the deferred tax impact of the introduction of the EPL. The EPL increases the headline rate of tax to 75% and applies to taxable profits from bp's North Sea business made from 1 January 2023 until 31 March 2028. On 6 March 2024 the UK government announced an extension of the EPL to 31 March 2029. This has not yet been substantively enacted.
[n] 2023 and 2022 include a $146-million charge and a $505-million charge respectively for the EU Solidarity Contribution.

★ See glossary on **page 373**

Non-IFRS information on fair value accounting effects

The impacts of fair value accounting effects, relative to management's internal measure of performance, are set out below. Further information on fair value accounting effects is provided on page 377.

			$ million
	2023	2022	2021
gas & low carbon energy			
Unrecognized (gains) losses brought forward from previous period	**(9,960)**	(8,149)	(485)
Favourable (adverse) impact relative to management's measure of performance	**8,859**	(1,811)	(7,662)
Exchange translation gains (losses) on fair value accounting effects	**(24)**	—	(2)
Unrecognized (gains) losses carried forward	**(1,125)**	(9,960)	(8,149)
customers & products			
Unrecognized (gains) losses brought forward from previous period	**79**	391	(45)
Favourable (adverse) impact relative to management's measure of performance	**(86)**	(309)	436
Exchange translation gains (losses) on fair value accounting effects	**(10)**	(3)	—
Unrecognized (gains) losses carried forward	**(17)**	79	391
other businesses & corporate			
Unrecognized (gains) losses brought forward from previous period	**(1,555)**	(174)	675
Favourable (adverse) impact relative to management's measure of performance[a]	**630**	(1,381)	(849)
Unrecognized (gains) losses carried forward	**(925)**	(1,555)	(174)
Group			
Unrecognized (gains) losses brought forward from previous period	**(11,436)**	(7,932)	145
Favourable (adverse) impact relative to management's measure of performance	**9,403**	(3,501)	(8,075)
Exchange translation gains (losses) on fair value accounting effects	**(34)**	(3)	(2)
Unrecognized (gains) losses carried forward	**(2,067)**	(11,436)	(7,932)
Favourable (adverse) impact relative to management's measure of performance – by region			
gas & low carbon energy			
US	**900**	(1,140)	(92)
Non-US	**7,959**	(671)	(7,570)
	8,859	(1,811)	(7,662)
customers & products			
US	**(18)**	3	105
Non-US	**(68)**	(312)	331
	(86)	(309)	436
other businesses & corporate			
US	**—**	—	—
Non-US	**630**	(1,381)	(849)
	630	(1,381)	(849)
	9,403	(3,501)	(8,075)
Taxation credit (charge)	**(915)**	434	862
	8,488	(3,067)	(7,213)

[a] Includes changes in the fair value of derivatives entered into by the group to manage currency exposure and interest rate risks relating to hybrid bonds to their respective first call periods. For further information see page 377.

Net debt including leases

Net debt including leases★ is shown in the table below.

At 31 December	2023	2022
		$ million
Net debt[a]★	**20,912**	21,422
Lease liabilities	**11,121**	8,549
Net partner (receivable) payable for leases entered into on behalf of joint operations★	**(131)**	19
Net debt including leases	**31,902**	29,990
Total equity	**85,493**	82,990
Gearing including leases★	**27.2%**	26.5%

[a] See Financial statements – Note 27 for a reconciliation of net debt to finance debt, which is the nearest equivalent measure to net debt on an IFRS basis.

Surplus cash flow★ components

	2023	2022	2021
			$ million
Sources:			
Net cash provided by operating activities	**32,039**	40,932	23,612
Cash provided from investing activities	**1,381**	2,617	7,154
Other[a]	**324**	360	589
	33,744	43,909	31,355
Uses:			
Lease liability payments	**(2,560)**	(1,961)	(2,082)
Payments on perpetual hybrid bonds	**(1,008)**	(708)	(538)
Dividends paid – bp shareholders	**(4,809)**	(4,358)	(4,304)
– non-controlling interests	**(403)**	(294)	(311)
Total capital expenditure★	**(16,253)**	(16,330)	(12,848)
Net repurchase of shares relating to employee share schemes	**(675)**	(500)	(500)
Payments relating to transactions involving non-controlling interests	**(187)**	(9)	(560)
Currency translation differences relating to cash and cash equivalents	**27**	(684)	(269)
	(25,868)	(24,844)	(21,412)

[a] Other includes adjustments for net operating cash received or paid which is held on behalf of third parties for medium-term deferred payment and prior periods have been adjusted accordingly. 2023 includes $517 million of proceeds from the sale of a 49% interest in a controlled affiliate holding certain midstream assets onshore US. Other proceeds for 2022 include $573 million of proceeds from the disposal of a loan note related to the Alaska divestment. The cash was received in the fourth quarter 2021, was reported as a financing cash flow and was not included in other proceeds at the time due to potential recourse from the counterparty. The proceeds were recognized as the potential recourse reduces and by end second quarter 2022 all were recognized.

★ See glossary on **page 373**

Liquidity and capital resources

Financial framework

bp has a resilient financial framework that, taken together with our strategy, creates a compelling investor proposition offering committed distributions, profitable growth and sustainable value. The framework comprises a coherent approach to capital allocation, a resilient balance sheet, a disciplined approach to investment allocation and a relentless focus on executing bp's business plan.

bp's approach to capital allocation leads to a clear set of priorities – funding our resilient dividend as the first priority, maintaining a strong investment grade credit rating, disciplined investment in our transition growth★ engines to advance our energy transition strategy and investment in oil, gas, refining and other businesses, and then returning surplus cash flow★ as share buybacks. In a period of low prices, the group has the flexibility to reduce cash costs and to reduce or defer capital investment, as appropriate.

Our shareholder distribution policy reflects these priorities for the uses of cash alongside an ongoing consideration of factors, including changes in the environment, the underlying performance of the business, the outlook for the group financial framework, and other market factors which may vary quarter to quarter.

Net debt★ at 31 December 2023 was $20.9 billion and is expected to reduce in line with the growth in operating cash flow★. As at 31 December 2023 our target of $25 billion of divestment and other proceeds between the second half of 2020 and 2025 was underpinned by agreed or completed transactions of around $18.5 billion with $17.8 billion of proceeds received.

We expect operating cash flow to cover capital expenditure★ and the dividend. Capital expenditure in 2023 was $16.3 billion, including $1.3 billion of inorganic capital expenditure★. bp expects capital expenditure of around $16 billion through 2024 and 2025 and expects a range of $14-18 billion per annum through 2030 including inorganic expenditure. bp's cash balancing point is expected to average around $40 per barrel Brent (assuming an average refining marker margin of around $11 per barrel and Henry Hub gas price at $3 per mmBtu) in 2021 real terms.

In 2023, the return on average capital employed★ was 18.1%[a] at an average of $83 per barrel. The return on average capital employed is targeted to be over 18% by 2025 at $70 per barrel in 2021 real terms, and assuming bp planning assumptions, as we continue to execute our strategy. This is supported by an expected growth on adjusted EBIDA per share compound annual growth rate★ from the second half 2019/first half 2020[b] to 2025 and subject to the same price and planning assumptions.

[a] Nearest equivalent IFRS measures of numerator and denominator are profit for the year attributable to bp shareholders and total equity respectively: Profit for the year attributable to bp shareholders divided by total equity at the end of 2023 17.8%.

[b] Adjusted to exclude Rosneft.

Dividends and other distributions to shareholders

The dividend is determined in US dollars, the economic currency of bp, and the dividend level is reviewed by the board each quarter. The quarterly dividend was increased from 6.610 to 7.270 cents per ordinary share per quarter in the second quarter of 2023.

The total dividend distributed to bp shareholders in 2023 was $4.8 billion (2022 $4.4 billion). This dividend was all paid in cash as shareholders no longer have the option to receive a scrip dividend in place of receiving cash.

Included in the distribution policy is a commitment that, subject to maintaining a strong investment grade credit rating, at least 80% of surplus cash flow on a point forward basis will be distributed to shareholders through share buybacks. In 2023 bp executed $7.9 billion of share buybacks (2022 $10.0 billion), including fees and stamp duty. Since 1 January 2024 an additional $0.9 billion shares have been repurchased up to 16 February 2024, including fees and stamp duty. Based on bp's current forecasts, at around $60 per barrel Brent and subject to the board's discretion each quarter, bp expects to have capacity for an annual increase in the dividend per ordinary share of around 4%. Based on current market conditions bp plans share buybacks of at least $14 billion through 2025. In setting the dividend and share buybacks each quarter, the board will continue to take into account factors including the cumulative level of and outlook for surplus cash flow, the cash balance point★ and the maintenance of a strong investment grade credit rating.

Financing the group's activities

The group's principal commodities, oil and gas, are priced internationally in US dollars. Group policy has generally been to minimize economic exposure to currency movements by financing operations with US dollar debt. Where debt and hybrid bonds are issued in other currencies, they are generally swapped back to US dollars using derivative contracts, or else hedged by maintaining offsetting cash positions in the same currency. Cash balances of the group are mainly held in US dollars or swapped to US dollars and holdings are well diversified to reduce concentration risk. The group is not, therefore, exposed to significant currency risk regarding its cash or borrowings. Also see Risk factors on page 77 for further information on risks associated with prices and markets and Financial statements – Note 29.

The group's finance debt at 31 December 2023 amounted to $52.0 billion (2022 $46.9 billion). Of the total finance debt, $3.3 billion is classified as short term at the end of 2023 (2022 $3.2 billion). See Financial statements – Note 26 for more information on the short-term balance. Net debt★ was $20.9 billion at the end of 2023, a decrease of $0.5 billion from the 2022 year-end position of $21.4 billion. BP p.l.c. fully and unconditionally guarantees securities issued by BP Capital Markets p.l.c. and BP Capital Markets America Inc. which are 100%-owned finance subsidiaries of BP p.l.c.

At 31 December 2023 the group held a balance of $13.6 billion (2022 $13.4 billion) issued perpetual subordinated hybrid bonds, of which $1.5 billion (2022 $1.3 billion) were issued to fund one of the group's major projects. As the group has the unconditional right to avoid transfer of cash or another financial asset in relation to these hybrid bonds, which were issued by group subsidiaries, they are classified as equity instruments and reported within non-controlling interest.

The ratio of finance debt to finance debt plus total equity at 31 December 2023 was 37.8% (2022 36.1%). Gearing was 19.7% at the end of 2023 (2022 20.5%). See Financial statements – Note 27 for finance debt, which is the nearest equivalent measure on an IFRS basis, and for further information on net debt.

Cash and cash equivalents of $33.0 billion at 31 December 2023 (2022 $29.2 billion) are included in net debt. We manage our cash position so that the group has adequate cover to respond to potential short-term market liquidity, short-term price environment volatility and expect to maintain a robust cash position.

The group also has an undrawn committed $8 billion credit facility and undrawn committed bank facilities of $4 billion (see Financial statements – Note 29 for more information).

We believe that the group's resilient balance sheet and strong investment grade credit rating will allow the group to meet its known contractual and other obligations in both the short and long term with the group having sufficient working capital, taking into account the amounts of undrawn borrowings facilities, access to capital markets, levels of cash and cash equivalents and its ongoing ability to generate cash through operations. This belief is subject to a degree of uncertainty that can be expected to increase looking out over time and, accordingly, that future outcomes cannot be guaranteed or predicted with certainty.

bp utilizes various arrangements in order to manage its working capital including discounting of receivables and, in the supply and trading business, the active management of supplier payment terms, inventory and collateral.

Standard & Poor's Ratings' long-term credit rating for BP p.l.c. is A- (positive), the Moody's Investors Service rating is A2 (positive) and the Fitch Ratings' long-term credit rating is A+ (stable).

The group's sources of funding, its access to capital markets and maintaining a strong cash position are described in Financial statements – Note 25 and Note 29. Further information on the management of liquidity risk and credit risk, and the maturity profile and fixed/floating rate characteristics of the group's debt are also provided in Financial statements – Note 26 and Note 29.

The information above contains forward-looking statements, which by their nature involve risk and uncertainty because they relate to events and depend on circumstances that will or may occur in the future and are outside the control of bp.

You are urged to read the Cautionary statement on page 361 and Risk factors on page 77, which describe the risks and uncertainties that may cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements.

Off-balance sheet arrangements

At 31 December 2023, the group's share of third-party finance debt of equity-accounted entities was $9.9 billion (2022 $8.8 billion). These amounts are not reflected in the group's debt on the balance sheet. The group has issued third-party guarantees under which amounts outstanding, incremental to amounts recognized on the balance sheet, at 31 December 2023 were $1,655 million (2022 $1,704 million) in respect of liabilities of joint ventures★ and associates★ and $598 million (2022 $680 million) in respect of liabilities of other third parties. Of these amounts, $1,609 million (2022 $1,701 million) of the joint ventures and associates guarantees relate to borrowings and, for other third-party guarantees, $527 million (2022 $557 million) relate to guarantees of borrowings.

Contractual obligations

The following table summarizes the group's capital expenditure commitments for property, plant and equipment at 31 December 2023 and the proportion of that expenditure for which contracts have been placed.

			$ million
	Payments due by period		
Capital expenditure	Less than 1 year	More than 1 year	Total
Committed	12,890	9,648	22,538
of which is contracted	6,962	3,392	10,354

Capital expenditure is considered to be committed when the project has received the appropriate level of internal management approval. For joint operations★, the net bp share is included in the amounts above.

In addition, at 31 December 2023, the group had committed to capital expenditure relating to investments in equity-accounted entities amounting to $3,120 million. Contracts were in place for $1,685 million of this total.

The following table summarizes the group's principal contractual obligations at 31 December 2023, distinguishing between those for which a liability is recognized on the balance sheet and those for which no liability is recognized. See Financial framework above for bp's approach to capital allocation and Financing the group's activities above for bp's plan and ability to generate and obtain cash in the short and long term. Also see Financial statements – Note 23 for more information on provisions, Note 24 on pensions and other post-retirement benefits, Note 26 on borrowings, Note 28 on leases, Note 29 and Note 30 on derivatives and financial instruments.

			$ million
	Payments due by period		
Expected payments by period under contractual obligations	Less than 1 year	More than 1 year	Total
Balance sheet obligations			
Borrowings[a]	5,448	66,161	71,609
Lease liabilities[b]	3,038	10,042	13,080
Decommissioning liabilities[c]	674	23,332	24,006
Environmental liabilities[c]	352	1,626	1,978
Gulf of Mexico oil spill liabilities[d]	1,142	9,520	10,662
Pensions and other post-retirement benefits[e]	577	12,686	13,263
	11,231	123,367	134,598
Off-balance sheet obligations			
Unconditional purchase obligations[f]			
Crude oil and oil products	49,754	8,953	58,707
Natural gas and LNG	13,394	52,974	66,368
Chemicals and other refinery feedstocks	540	78	618
Power	5,075	13,514	18,589
Utilities	58	417	475
Transportation	2,153	14,764	16,917
Use of facilities and services	2,816	20,894	23,710
	73,790	111,594	185,384
Total	85,021	234,961	319,982

a Expected payments include interest totalling $21,298 million (less than 1 year $2,394 million, more than 1 year $18,904 million).
b Expected payments include interest totalling $1,961 million (less than 1 year $380 million, more than 1 year $1,581 million).
c The amounts presented are undiscounted.
d The amounts presented are undiscounted. Gulf of Mexico oil spill liabilities are included in the group balance sheet, on a discounted basis, within other payables. See Financial statements – Note 22 for further information.
e Represents the expected future contributions to funded pension plans and payments by the group for unfunded pension plans and the expected future payments for other post-retirement benefits.
f Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms (such as fixed or minimum purchase volumes, timing of purchase and pricing provisions). Agreements that do not specify all significant terms, or that are not enforceable, are excluded. The amounts shown include arrangements to secure long-term access to supplies of crude oil, natural gas, feedstocks and pipeline systems. In addition, the amounts shown for 2024 include purchase commitments existing at 31 December 2023 entered into principally to meet the group's short-term manufacturing and marketing requirements. The price risk associated with these crude oil, natural gas and power contracts is discussed in Financial statements – Note 29.

Commitments for the delivery of oil and gas

We sell crude oil, natural gas and liquefied natural gas under a variety of contractual obligations. Some of these contracts specify the delivery of fixed and determinable quantities. For the period from 2024 to 2026 worldwide, we are contractually committed to deliver approximately 291 million barrels of oil, 7,586 billion cubic feet of natural gas, and 73 million tonnes of liquefied natural gas. The commitments principally relate to group subsidiaries★ based in Egypt, Singapore, Trinidad and Tobago, the UK and the US. We expect to fulfil these delivery commitments with production from our proved developed reserves and supplies from existing contracts, supplemented by market purchases as necessary.

Oil and gas disclosures for the group

Analysis by region

Our oil and gas operations are set out below by geographical area, with associated significant events for 2023. bp's percentage working interest in oil and gas assets is shown in brackets. Working interest is the cost-bearing ownership share of an oil or gas lease. Consequently, the percentages disclosed for certain agreements do not necessarily reflect the percentage interests in proved reserves, production or revenue.

In addition to exploration, development and production activities, our oil production & operations (OP&O) and gas businesses also include certain midstream and liquefied natural gas (LNG) supply activities. Midstream activities involve the management of crude oil and natural gas pipelines, processing facilities and export terminals, LNG processing facilities and transportation, and our natural gas liquids (NGLs) processing business.

Our upstream LNG activities are located in Abu Dhabi, Angola, Australia, Indonesia, and Trinidad. In 2023 our production was 8.5 million tonnes of LNG from these assets, of which 2 million tonnes were marketed through trading and shipping (T&S), which supplements equity production with merchant third party volumes leading to a global long-term strategic LNG portfolio of 23mtpa. In addition to the long-term equity and merchant supply portfolio, bp has delivered 10mtpa in 2023 of incremental merchant volumes through short and mid-term cargos managed through the T&S LNG business. These supplement the long-term portfolio and allow generation of short-term value when opportunities exist.

The LNG is marketed through contractual rights to access import terminal capacity into the liquid gas markets of Europe, and the UK, and relationships to market directly to end-user customers or trading entities. LNG is supplied to all major LNG demand centres, for example Argentina, Brazil, the Caribbean, China, Croatia, Mediterranean, Iberia and North West Europe, India, Japan, Singapore, South Korea, Taiwan, Thailand, Türkiye and the UK.

Europe

bp is active in offshore oil and gas in the UK and Norway. In 2023 bp's UK production came from two key areas: the Shetland area comprising the Clair and Schiehallion fields; and the central area comprising the Andrew area, Culzean, Vorlich and ETAP fields. In Norway, production was through our equity-accounted 15.9% interest in Aker BP.

- On 28 June the Norwegian Ministry of Petroleum and Energy approved a total of nine plans for development and operation to Aker BP (bp 15.9%), with estimated recoverable reserves to be above 700 million barrels of oil equivalent (mmboe). As per the public announcement the Norwegian government's approval of two of the developments remain subject to legal challenge in Norway.
- In September bp and its co-venturers in the Clair joint venture made the final investment decision to proceed with the construction and operation of the Shetland Crossover Pipeline, reinforcing the gas export network and supporting UK security of supply (bp 45% operator).
- In October the first of two wells for the Murlach oil and gas field in the UK North Sea were spudded, following regulatory approval of the field development plan in September (bp 80% operator).
- In October bp successfully started production from the Seagull oil and gas field in the UK North Sea. This is the first tieback to the ETAP hub in 20 years. The new field is expected to produce around 50 thousand barrels of oil equivalent (mboe) gross per day at peak production.
- During the year an impairment charge of $0.9 billion was recognized in respect of certain assets in the North Sea as a result of changes to the group's oil and gas price and discount rate assumptions and activity phasing.

North America

Our oil and gas activities in North America are located in four areas: deepwater Gulf of Mexico, the Lower 48 states, Canada and Mexico.

bp has around 280 lease blocks in the Gulf of Mexico and operates four production hubs.

- During the year bp has been awarded 36 lease blocks in the Gulf of Mexico lease sale 259, which includes 22 leases that may provide options to further enhance our resource positions at Kaskida and Tiber. bp also moved forward with progression of the Kaskida project, bp's first 20K development in the Paleogene, and progresses on concept selection for bp-operated Tiber development project in the Gulf of Mexico.
- In April bp announced start-up of the Mad Dog Phase 2 Argos platform (bp 60.5% operator). With a gross production capacity of up to 140mboe/d, Argos is bp's fifth platform in the Gulf of Mexico.
- Following a successful appraisal well in the southwest part of the Mad Dog field, bp sanctioned the Argos Southwest Expansion project to tie back into the Argos facility.
- bp was the apparent high bidder on 24 leases in the Gulf of Mexico Lease Sale 261 that took place on 20 December 2023.
- In December partners approved the expansion of the Shell-operated Great White development in the Gulf of Mexico through a phased three-well campaign (bp 33.33%).

bpx energy, bp's onshore oil and gas business in the Lower 48 states, has significant operated and non-operated activities across Louisiana and Texas producing natural gas, oil, NGLs and condensate, with primary focus on developing unconventional resources. It had a 1.6 billion boe proved reserve base at 31 December 2023, predominantly in unconventional reservoirs (tight gas★, shale gas and shale oil). bpx energy's core assets span 0.9 million net developed acres with nearly 2,000 operated gross wells at 31 December 2023. Daily net production averaged 366mboe/d in 2023.

bpx energy continues to operate as a separate business while remaining part of the OP&O segment. With its own governance, systems, and processes, it is structured to increase competitive performance through swift decision making and innovation, while maintaining bp's commitment to safe, reliable and compliant operations.

- MiQ, the non-profit global leader in methane certification, announced that it has independently audited and certified bp as the first energy major in the US to verify the methane intensity of its entire US onshore portfolio of natural gas.
- In August bpx energy successfully brought online 'Bingo', its second central processing facility in the Permian Basin. It is a low-emission, electrified facility that will enable further production growth for bpx energy in the basin (bp 100% operator).
- During the year an impairment charge of $0.8 billion was recognized as a result of changes to the group's oil and gas price and discount rate assumptions and disposal decisions.

bp's onshore US crude oil and product pipelines and related transportation assets were included in the customers & products segment in 2023.

In Canada, bp is focused on pursuing offshore exploration and development opportunities and conducts trading and marketing activities across various energy commodities. We hold exploration and significant discovery licences offshore Newfoundland and Labrador, including an interest in the Equinor-operated Bay du Nord project. bp also holds offshore exploration licences in the Arctic where the moratorium has been extended until 31 December 2028.

In Mexico, bp held interests in two exploration blocks in the Salina Basin with Equinor and Total, Block 1 (bp 33% operator) and Block 3 (bp 33%), and one exploration block in the Sureste Basin, Block 34 (bp 42.5% operator), with Total, QPI Mexico and Hokchi Energy. Hokchi Energy is a subsidiary of Pan American Energy Group (PAEG, see below) in which bp owns 50%. Separate to the above holdings in Mexico, Hokchi Energy also holds an interest in two other blocks.

- Contract termination for Block 3 was executed in April 2023.
- Formal relinquishment of Block 1 and Block 34 licences are still pending regulatory approval.

South America

bp has oil and gas activities in Argentina, Brazil and Trinidad and Tobago and, through PAEG, in Argentina and Bolivia.

In Argentina, bp and Total (operator) are partners on a 50:50 basis in two offshore exploration concessions. Total as the operator issued a relinquishment note to the regulator, which is still pending approval.

In Brazil bp has interests in seven exploration areas across three basins.

- During 2023 bp and Petrobras received an approval from the regulatory authorities for relinquishments submitted for Dois Irmãos, C-M-755, C-M-793, BC-2, BM-POT-16, S-M-1500, and Peroba blocks.

- In May the regulatory authorities approved the final relinquishment of Xerelete (BC-2) operated by Total.
- In June the contract was executed for the Bumerangue block (bp 100%), in the Santos Basin.
- In September the appraisal plan (PAD) for Alto de Cabo Frio Central block (bp 50%), in the southern portion of the Campos Basin, was filed with the regulator and is pending approval.
- In Brazil´s second Permanent Production Sharing Offer bid round in December 2023, bp successfully bid on the Tupinambá block, an area of 3,056km^2 located in the Santos Pre-Salt Basin. bp will hold 100% participation interest on the block when the contract is executed later in 2024.

PAEG, a joint venture that is owned by bp (50%) and BC E&P Uruguay S.A. (50%), has activities mainly in Argentina and as noted above Mexico, and is also present in Bolivia.

In Trinidad and Tobago bp holds interests in exploration and production licences and production-sharing contracts (PSCs)★ covering 2.5 million acres offshore of the east and north-east coast. Facilities include 16 offshore platforms and two onshore processing facilities. Production comprises gas and associated liquids.

bp also holds interests in the Atlantic LNG facility. The total gross capacity of the four LNG trains making up the facility is approximately 12 million tonnes per annum. bp's shareholding averages 40% across the three companies which own the LNG trains comprising the LNG facility. During 2023 bp sold gas to trains 2 and 3 and processed gas in train 4. Most of the LNG produced from bp gas supplied to Trains 2, 3 and 4 is sold under long-term contracts.

- Cypre, bp's third subsea gas development in Trinidad and Tobago, is expected to start drilling in 2024 with first gas expected in 2025. The project is expected to have seven wells and be tied back to the Juniper platform.
- The Joe Douglas rig continued drilling in 2023 with Mango and is progressing to Savonette and Angelin. This development will leverage existing infrastructure and contribute to sustained delivery.
- Trinidad Offshore Pipeline Replacement (TOPR) project for a 12-inch liquids pipeline that connects Mahogany B to terminal was safely integrated into the production system in 2023. Additionally, construction of the Ocelot project, which is a 6-inch liquids pipeline connecting Beachfield to terminal, is under way.
- bp was awarded three deepwater blocks off Trinidad's east coast in a bp/Shell partnership (50:50). bp is the operator of Blocks 25a & 25b and Shell is the operator of Block 27. Activity in the coming years will include seismic acquisition and interpretation and exploration wells.
- bp is operator of the Manakin block which was discovered in 1998 and is a cross-border reservoir field with the Venezuelan reservoir, Cocuina. Manakin declared commerciality in January 2018, however cross-border discussions have not progressed due to the impact of US sanctions. In October 2023 the US government eased sanctions on Venezuela's oil sector for six months.
- Since the conclusion of short-term gas supply agreements, the Atlantic Train 1 plant has not been operational. The Atlantic shareholders, bp, Shell and the National Gas Company of Trinidad & Tobago (NGC), agreed to decouple the Train from the rest of the Atlantic facility with a view to decommissioning it. The Train has been made safe and decoupling and decommissioning work scopes are being planned. On 5 December 2023 bp, Shell and NGC agreed and executed the agreements for the restructuring of the ownership and commercial framework of the Atlantic LNG.
- During the year an impairment charge of $0.6 billion was recognized as a result of changes to the group's oil and gas price and discount rate assumptions and activity phasing.

Africa

bp's oil and gas activities in Africa are located in Angola, Egypt, Libya, Mauritania and Senegal.

In Angola, bp and Eni each own 50% interest in the Azule Energy joint venture. Azule Energy is Angola's largest independent equity producer of oil and gas, holding stakes in 20 licences, as well as an interest in the Angola LNG plant.

- During the year, Azule Energy has taken the final investment decision for the Agogo Integrated West Hub Development oil project.
- In August Azule Energy signed a production-sharing agreement (PSA)★ for Block 31/21. The agreement results from the 2021/2022 Limited Offshore Licensing Round and is a significant stride towards advancing exploration in the Lower Congo Basin.
- In December Azule Energy made progress on sustaining resilient hydrocarbon production with four new exploration agreements in blocks adjacent to existing operations (46, 47, 14/23 and 18/15).

In Egypt, bp's investments in the country include West Nile Delta, Atoll and Zohr. Through its joint ventures with Egyptian Natural Gas Holding Company (EGAS), Egyptian General Petroleum Corporation (EGPC), International Egyptian Oil Company (IEOC), Eni, the Pharaonic Petroleum Company (PhPC) and through collaboration with Belayim Petroleum Company (Petrobel), bp and its partners now produce more than 70% of Egypt's total gas supply. In addition, bp owns interest in other exploration projects.

- In October bp secured an exploration block located offshore Egypt as part of the EGAS 2022 International Bid Round. The EGY-MED-E8 (East Port Said) block (bp 33%) is located in the Mediterranean Sea, approximately 50-90km from Post Said city and covering an area of approximately 2,620km^2. In addition to farming into the existing North East Hap'y Offshore Concession the block is currently in the second exploration phase with an exploration well spudded in October 2023.
- On 14 February 2024 bp announced the formation of a new joint venture in Egypt (bp 51%, ADNOC 49%) under which, subject to regulatory approvals, bp will contribute its interests in three non-operated development concessions as well as exploration agreements in Egypt, and ADNOC will make a proportionate cash contribution.

In Libya, bp partners with the Libyan Investment Authority (LIA) and Eni in an exploration and production-sharing agreement (EPSA) to explore acreage in the onshore Ghadames and offshore Sirt basins (bp 42.5%). bp wrote off all balances associated with the Libya EPSA in 2015.

- Eni's acquisition of a 42.5% interest in the bp-operated EPSA in Libya has been ratified by the Libyan authorities effective November 2022, upon which Eni became exploration operator under the EPSA. bp, LIA and Eni continue to work with the Libyan NOC towards finalizing the transfer of operatorship from bp to Eni, recommencement of petroleum operations and completion of the programme of exploration and drilling activities included in the EPSA.

In Mauritania and Senegal, bp retains the exploitation licences in the respective C8 and Saint Louis Offshore Profond blocks pertinent to the Greater Tortue Ahmeyim (GTA) Unit cross-border development. In addition, bp holds a 62% participating interest in the BirAllah gas resource exploration licence.

- The GTA project (bp 56%) continues to progress with phase 1 critical milestones including the completion of the offshore hub terminal construction and sailaway of the gas processing FPSO from China in January 2023. The floating LNG vessel reached its destination in February 2024.
- In February 2023 bp and its partners on the GTA project announced their agreement to evaluate viability of a gravity-based structure (GBS) as the basis for the GTA Phase 2 expansion project.
- In Senegal, we have exited the Cayar Offshore Profond PSA and transferred operatorship of Yakaar-Teranga gas resource to Kosmos Energy. As a result of the exit, an exploration write-off of $0.3 billion was recognized.
- In 2023 an impairment charge of $1.4 billion was recognized in respect of certain assets in the region due to increased future forecast expenditure.

Asia

bp has activities in Abu Dhabi, Azerbaijan, China, India, Indonesia, Iraq, Kuwait and Oman.

In China, we have a 30% equity stake in the Guangdong LNG regasification terminal and trunkline project (GDLNG) with a total storage capacity of 640,000 cubic metres. bp also has 0.6 million tons per annum of regasification capacity at GDLNG for up to 12 years starting from the beginning of 2021. bp imports LNG from our global portfolio and delivers

★ See glossary on **page 373**

regasified natural gas via the terminal to power plant and city gas customers in Guangdong province under long-term sales contracts.

In Azerbaijan, bp operates two PSAs, Azeri-Chirag-Gunashli (ACG) (bp 30.37%) and Shah Deniz (bp 29.99%) and also holds a number of other exploration leases.

- bp and SOCAR signed a protocol to extend the Shafag-Asiman exploration period until the end of June 2024 to allow bp and SOCAR to agree on the terms of any potential follow-on exploration activity.
- Following dry hole results in each of the three prospective areas of the Shallow Water Absheron Peninsula (SWAP) PSA, the contract area was relinquished in December 2022. The joint operating agreement was terminated on 27 December 2023.

Naftiran Intertrade Co Ltd (NICO), a subsidiary of the National Iranian Oil Company, holds a 10% interest in the Shah Deniz joint venture. For information on the exclusion of this project from EU and US trade sanctions, see International trade sanctions on page 357.

bp holds a 30.1% interest in and operates the Baku-Tbilisi-Ceyhan (BTC) oil pipeline. The 1,768-kilometre pipeline transports oil from the ACG oilfield and condensate from the Shah Deniz gas and condensate field in the Caspian Sea, along with other third-party oil, to the eastern Mediterranean port of Ceyhan. The pipeline has a capacity of 1mmboe/d, with an average throughput in 2023 of 626mboe/d.

bp (as operator of Azerbaijan International Operating Company and the Georgian Pipeline Company for the Georgian section) also operates the Western Route Export Pipeline (WREP) that transports ACG oil to Supsa on the Black Sea coast of Georgia, with an average throughput of 3mboe/d in 2023. Exports through the pipeline have been suspended since May 2022 due to a lack of nominations from the shipper group. In current market conditions WREP serves as a contingency export route for ACG crude product. In February 2023 WREP was restarted for two weeks following a temporary suspension of liftings from BTC in the wake of the Turkish earthquake on 6 February 2023.

- The Azeri Central East (ACE) project is the next stage of development of the giant ACG field in the Azerbaijan sector of the Caspian Sea. During the third quarter the ACE platform topsides unit was safely installed in the field and the first pre-drill well was spudded. This is the seventh and most automated platform installed in the giant ACG field with approximately 100mboe/d installed capacity.

bp holds a 29.99% interest in and operates certain parts of the 693-kilometre South Caucasus Pipeline. The pipeline takes gas from the Shah Deniz field in Azerbaijan through Georgia to the Turkish border and has a capacity of 440mboe/d (including expansion), with average throughput in 2023 of 370mboe/d.

bp also holds a 12% interest in the Trans Anatolian Natural Gas Pipeline (TANAP). The pipeline takes Shah Deniz gas from the Turkish border and transports it to Eskisehir in Türkiye and to the Greek border where it connects with the Trans Adriatic Pipeline (TAP). The current capacity of TANAP is 275mboe/d and the average throughput in 2023 was 285mboe/d. bp has a 20% interest in TAP, which takes gas through Greece and Albania into Italy. The current capacity of TAP is 167mboe/d and the total average throughout in 2023 was 191mboe/d. TAP and TANAP throughputs exceeded capacity during 2023 due to high flow tests taking place during the year.

- In 2023 bp and our co-venturers in the Shah Deniz Consortium have secured additional capacity in the SNAM RETE GAS, and TANAP pipelines for 2026-2028 period, which will allow the export of more Shah Deniz gas to Europe.

In Oman, bp operates Block 61, the largest tight gas development in the Middle East (bp 40%). bp also has a 50% interest in Block 77 with Eni (operator) in which an exploration well was spudded in October 2023, scheduled for completion in 2024.

In Abu Dhabi, bp holds a 10% interest in the ADNOC Onshore concession. We also have a 10% equity shareholding in ADNOC LNG and a 10% shareholding in the shipping company NGSCO. ADNOC LNG supplied approximately 5.09 million tonnes of LNG (0.7bcfe/d regasified) in 2023. Our interest in the ADNOC Onshore concession expires at the end of 2054.

- On 28 March bp, together with ADNOC, made a non-binding offer to take NewMed Energy private through an acquisition of the free float and a partial acquisition of Delek's stake, which would result in bp and ADNOC holding 50% of NewMed Energy.

A consortium of Azerbaijan's national oil company SOCAR along with bp and Israel's NewMed was awarded two licence blocks.

In 2016 bp signed an enhanced technical service agreement for south and east Kuwait conventional oilfields, which includes the Burgan field, with Kuwait Oil Company.

In India, we have a participating interest in two oil and gas PSAs (KG D6 33.33% and NEC25 33.33%), and two oil and gas blocks under a revenue sharing contract (KG-UDWHP-2018/1 40% and KG-UDWHP-2022/1 40%), all operated by Reliance Industries Limited (RIL). We also have a 50% stake in India Gas Solutions Private Limited, a joint venture with RIL, for the sourcing and marketing of gas in India.

- On 30 June bp and RIL (operator) announced commencement of production from MJ, the last of three new deepwater developments in the KG D6 block off the east coast of India. With this development, production from the three fields in KG D6 block is expected to account for around one third of India's current domestic gas production and meet approximately 15% of India's gas demand.
- In December 2023 bp and RIL were awarded the ultra deepwater block KG-UDWHP-2022/1 (RIL operator 60%, bp 40%), adjacent to block KG-UDWHP-2018/1, in India's Open Acreage Licensing Policy bid round VIII and both RIL and bp have entered into a revenue sharing contract with the government of India.

In Indonesia, bp holds an interest in the Andaman II PSC exploration block (operated by Harbour Energy), located offshore North Sumatra and in Agung I and Agung II exploration blocks offshore Indonesia. Agung I covers over 6,000km^2 off the coast of Bali and East Java and Agung II spans almost 8,000km^2 offshore South Sulawesi, West Nusa Tenggara and East Java.

In Iraq, bp holds a 49% participating interest in Basra Energy Company Limited (BECL). BECL is an incorporated joint venture (IJV) company owned by bp (49%) and PetroChina (51%) and acts as Rumaila lead contractor since 2022.

Australasia

bp has activities in Australia and Eastern Indonesia.

In Australia bp is one of seven participants in the North West Shelf (NWS) venture, which has been producing LNG, pipeline gas, condensate, LPG and oil since the 1980s. Six partners (including bp) hold an equal 16.67% interest in the gas infrastructure and an equal 15.78% interest in the gas and condensate reserves, with a seventh partner owning the remaining 5.32% of these reserves. The NWS venture is one of the largest LNG export projects in the region, with five LNG trains in operation, and supplies domestic gas into the Western Australia market. bp's net share of the capacity of NWS LNG trains 1-5 is 2.67 million tonnes (15.78% of 16.9mtpa gross) of LNG per year. This will be reduced as the first LNG train is taken offline in 2024. bp is also one of five participants in the Browse LNG venture.

- bp completed the acquisition of Shell's interest in the Browse joint venture in October 2023, which increased bp's interest from 17.33% to 44.33%. Browse is an LNG project operated by Woodside. The Browse joint venture participants continue to work to optimize the current development scheme for Browse which consists of two new built offshore FPSOs connecting back to the NWS Venture's Karratha Gas Plant via a 917km 42-inch pipeline.

bp also has a 50% interest in the WA-541 exploration title in Western Australia's offshore Northern Carnarvon basin. The joint venture, operated by Santos, is working towards the drilling of two commitment wells.

In Papua Barat, Eastern Indonesia, bp operates the Tangguh LNG plant (bp 40.22%). The Tangguh Expansion Project has been completed, adding a third LNG processing train, which has been producing LNG since September 2023, with 3.8 million tonnes of LNG per annum production capacity additional to the existing facility totalling up to 11.4 million tonnes per annum. The Tangguh asset comprises 30 production wells, four offshore platforms, three LNG processing trains, and two LNG loading facilities. Tangguh supplies LNG to customers in Indonesia, Mexico, China, South Korea, Taiwan and Japan through a combination of long, medium and spot contracts.

Oil and natural gas

Resource progression

bp manages its hydrocarbon resources in three major categories: prospect inventory, contingent resources and reserves. When a discovery is made, volumes usually transfer from the prospect inventory to the contingent resources category. The contingent resources move through various sub-categories as their technical and commercial maturity increases through appraisal activity.

At the point of final investment decision, most proved reserves will be categorized as proved undeveloped (PUD). Volumes will subsequently be recategorized from PUD to proved developed (PD) as a consequence of development activity. When part of a well's proved reserves depends on a later phase of activity, only that portion of proved reserves associated with existing, available facilities and infrastructure moves to PD. The first PD bookings will typically occur at the point of first oil or gas production. Major development projects typically take one to five years from the time of initial booking of PUD to the start of production. Changes to proved reserves bookings may be made due to analysis of new or existing data concerning production, reservoir performance, commercial factors and additional reservoir development activity.

Volumes can also be added or removed from our portfolio through acquisition or divestment of properties and projects. When we dispose of an interest in a property or project, the volumes associated with our adopted plan of development for which we have a final investment decision will be removed from our proved reserves upon completion of the transaction. When we acquire an interest in a property or project, the volumes associated with the existing development and any committed projects will be added to our proved reserves if bp has made a final investment decision and they satisfy the SEC's criteria for attribution of proved status. Following the acquisition, additional volumes may be progressed to proved reserves from non-proved reserves or contingent resources.

Non-proved reserves and contingent resources in a field will only be recategorized as proved reserves when all the criteria for attribution of proved status have been met and the volumes are included in the business plan and scheduled for development, typically within five years. bp will only book proved reserves where development is scheduled to commence after more than five years, if these proved reserves satisfy the SEC's criteria for attribution of proved status and bp management has reasonable certainty that these proved reserves will be produced.

At the end of 2023 bp had material volumes of proved undeveloped reserves held for more than five years in Azerbaijan. These are part of ongoing infrastructure-led development activities for which bp has a historical track record of completing comparable projects. We have no proved undeveloped reserves held for more than five years in our onshore US developments.

Over the past five years, bp has annually progressed a weighted average 17% (18% for 2022 five-year average) of our group proved undeveloped reserves (including the impact of disposals and price acceleration effects in PSAs) to proved developed reserves. This equates to a turnover time of six years.

Proved reserves as estimated at the end of 2023 meet bp's criteria for project sanctioning and SEC tests for proved reserves. We have not halted or changed our commitment to proceed with any material project to which proved undeveloped reserves have been attributed.

In 2023 we progressed 624mmboe of proved undeveloped reserves (542mmboe for our subsidiaries★ alone) to proved developed reserves through ongoing investment in our subsidiaries' and equity-accounted entities' development activities. Total development expenditure, excluding midstream activities, was $11,263 million in 2023 ($8,206 million for subsidiaries and $3,057 million for equity-accounted entities). Of the $8,206 million of total development expenditure for our subsidiaries, approximately $2,800 million was used for development activity to progress proved undeveloped reserves to proved developed. Of the $3,057 million development expenditure for our equity-accounted entities, approximately $1,200 million was used for development activity to progress proved undeveloped reserves to proved developed. The major areas with progressed volumes in 2023 were the US, Asia Pacific, Trinidad and Tobago and the Middle East.

Revisions of previous estimates for proved undeveloped reserves are due to changes relating to field performance, well results, revisions to future activity plans (including alignment with our investment criteria and changes to the macroeconomic climate) or changes in commercial conditions including price impacts. The net revisions to previous estimates across both our subsidiaries and our equity-accounted entities include net positive revisions driven by price and revisions to activity plans, and net negative revisions driven by field performance and well results. The net revisions to previous estimates across only our subsidiaries include net positive revisions driven by price and revisions to activity plans and net negative revisions driven by field performance and well results. In each case, none of these factors resulted in revisions that were material to the group as a whole. The following tables describe the changes to our proved undeveloped reserves position through the year for our subsidiaries and equity-accounted entities and for our subsidiaries alone.

	volumes in mmboe[a]
Subsidiaries and equity-accounted entities	Group
Proved undeveloped reserves at 1 January 2023	**2,877**
Revisions of previous estimates	**(12)**
Price	24
Revision of future activity plans	69
Field performance	(88)
Well results	(17)
Improved recovery	**108**
Discoveries and extensions	**107**
Purchases	**74**
Sales	**(10)**
Total in year proved undeveloped reserves changes	**267**
Proved developed reserves reclassified as undeveloped	**39**
Progressed to proved developed reserves by development activities (e.g. drilling/completion)	**(624)**
Proved undeveloped reserves at 31 December 2023	**2,558**

Subsidiaries only	volumes in mmboe[a]
Proved undeveloped reserves at 1 January 2023	**2,392**
Revisions of previous estimates	**(22)**
Price	16
Revision of future activity plans	51
Field performance	(87)
Well results	–
Improved recovery	**75**
Discoveries and extensions	**27**
Purchases	**61**
Sales	**(2)**
Total in year proved undeveloped reserves changes	**139**
Proved developed reserves reclassified as undeveloped	**17**
Progressed to proved developed reserves by development activities (e.g. drilling/completion)	**(542)**
Proved undeveloped reserves at 31 December 2023	**2,006**

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

bp bases its proved reserves estimates on the requirement of reasonable certainty with rigorous technical and commercial assessments based on conventional industry practice and regulatory requirements. bp only applies technologies that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. bp applies high-resolution seismic data for the identification of reservoir extent and fluid contacts only where there is an overwhelming track record of success in its local application. In certain cases bp uses numerical simulation as part of a holistic assessment of recovery factor for its fields, where these simulations have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the

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formation being evaluated or in an analogous formation. In certain deepwater fields bp has booked proved reserves before production flow tests are conducted, in part because of the significant safety, cost and environmental implications of conducting these tests. The industry has made substantial technological improvements in understanding, measuring and delineating reservoir properties without the need for flow tests. To determine reasonable certainty of commercial recovery, bp employs a general method of reserves assessment that relies on the integration of three types of data:

- Well data used to assess the local characteristics and conditions of reservoirs and fluids.
- Field scale seismic data to allow the interpolation and extrapolation of these characteristics outside the immediate area of the local well control.
- Data from relevant analogous fields.

Well data includes appraisal wells or sidetrack holes, full logging suites, core data and fluid samples. bp considers the integration of this data in certain cases to be superior to a flow test in providing understanding of overall reservoir performance. The collection of data from logs, cores, wireline formation testers, pressures and fluid samples calibrated to each other and to the seismic data can allow reservoir properties to be determined over a greater volume than the localized volume of investigation associated with a short-term flow test. There is a strong track record of proved reserves recorded using these methods, validated by actual production levels.

Governance

bp's centrally controlled process for proved reserves estimation approval forms part of a holistic and integrated system of internal control. It consists of the following elements:

- Accountabilities of certain officers of the group to ensure that there is review and approval of proved reserves bookings independent of the operating business and that there are effective controls in the approval process and verification that the proved reserves estimates and the related financial impacts are reported in a timely manner.
- Capital allocation processes, whereby delegated authority is exercised to commit to capital projects that are consistent with the delivery of the group's business plan. A formal review process exists to ensure that both technical and commercial criteria are met prior to the commitment of capital to projects.
- Internal audit, whose role is to consider whether the group's system of internal control is adequately designed and operating effectively to respond appropriately to the risks that are significant to bp.
- Approval hierarchy, whereby proved reserves changes above certain threshold volumes require immediate review and all proved reserves require annual central authorization and have scheduled periodic reviews. The frequency of periodic review ensures that 100% of the bp proved reserves base undergoes central review every three years.

bp's vice president of reserves is the individual primarily responsible for overseeing the preparation of the reserves estimate. He has more than 30 years of diversified industry experience in reserves estimation with the past four years managing the governance and compliance. He is a past Chairman of the Society of Petroleum Engineers (Russia & Caspian) and a member of the United Nations Economic Commission for Europe Expert Group on Resource Management.

No specific portion of compensation bonuses for senior management is directly related to proved reserves targets. Additions to proved reserves is one of several indicators by which the performance of the gas & low carbon and oil production & operations segments is assessed by the remuneration committee for the purposes of determining compensation bonuses for the executive directors. Other indicators include a number of financial and operational measures.

bp's variable pay programme for the other senior managers in the gas & low carbon and oil production & operations segments is based on individual performance contracts. Individual performance contracts are based on agreed items from the business performance plan, one of which, if chosen, could relate to proved reserves.

Compliance

International Financial Reporting Standards (IFRS) do not provide specific guidance on reserves disclosures. bp estimates proved reserves in accordance with SEC Rule 4-10 (a) of Regulation S-X and relevant Compliance and Disclosure Interpretations (C&DI) and Staff Accounting Bulletins as issued by the SEC staff.

By their nature, there is always risk involved in the ultimate development and production of proved reserves including, but not limited to: final regulatory approval; the installation of new or additional infrastructure, as well as changes in oil and gas prices; changes in operating and development costs; and the continued availability of additional development capital. All the group's proved reserves held in subsidiaries and equity-accounted entities are estimated by the group's petroleum engineers or by independent petroleum engineering consulting firms and then assured by the group's petroleum engineers.

Netherland, Sewell & Associates (NSAI), an independent petroleum engineering consulting firm, has estimated the net proved crude oil, condensate, natural gas liquids (NGLs) and natural gas reserves, as of 31 December 2023, of certain properties owned by bp in the US Lower 48. The properties evaluated by NSAI account for 100% of bp's net proved reserves in the US Lower 48 as of 31 December 2023. The net proved reserves estimates prepared by NSAI were prepared in accordance with the reserves definitions of Rule 4-10(a)(1)-(32) of Regulation S-X. All reserves estimates involve some degree of uncertainty. bp has filed NSAI's independent report on its reserves estimates as an exhibit to this Annual Report on Form 20-F filed with the SEC.

Our proved reserves are associated with both concessions (tax and royalty arrangements) and agreements where the group is exposed to the upstream risks and rewards of ownership, but where our entitlement to the hydrocarbons is calculated using a more complex formula, such as with PSAs. In a concession, the consortium of which we are a part is entitled to the proved reserves that can be produced over the licence period, which may be the life of the field. In a PSA, we are entitled to recover volumes that equate to costs incurred to develop and produce the proved reserves and an agreed share of the remaining volumes or the economic equivalent. As part of our entitlement is driven by the monetary amount of costs to be recovered, price fluctuations will have an impact on both production volumes and reserves.

We disclose our share of proved reserves held in equity-accounted entities (joint ventures★ and associates★), although we do not control these entities or the assets held by such entities.

bp's estimated net proved reserves and proved reserves replacement

94% of our total proved reserves of subsidiaries at 31 December 2023 were held through joint operations★ (94% in 2022), and 31% of the proved reserves were held through such joint operations where we were not the operator (34% in 2022).

Estimated net proved reserves of crude oil at 31 December 2023[abc]

			million barrels
	Developed	Undeveloped	Total
UK	**129**	**74**	**203**
US	**713**	**352**	**1,065**
Rest of North America	**—**	**—**	**—**
South America[d]	**3**	**5**	**7**
Africa	**5**	**—**	**6**
Rest of Asia	**729**	**323**	**1,052**
Australasia	**11**	**1**	**12**
Subsidiaries	**1,590**	**755**	**2,345**
Equity-accounted entities	**588**	**387**	**976**
Total	**2,179**	**1,142**	**3,321**

Estimated net proved reserves of natural gas liquids at 31 December 2023[a b]

			million barrels
	Developed	Undeveloped	Total
UK	**3**	**–**	**3**
US	**180**	**217**	**397**
Rest of North America	**–**	**–**	**–**
South America	**–**	**–**	**–**
Africa	**–**	**–**	**–**
Rest of Asia	**–**	**–**	**–**
Australasia	**1**	**–**	**1**
Subsidiaries	**184**	**217**	**401**
Equity-accounted entities	**19**	**6**	**25**
Total	**204**	**223**	**427**

Estimated net proved reserves of liquids★

			million barrels
	Developed	Undeveloped	Total
Subsidiaries	**1,775**	**971**	**2,746**
Equity-accounted entities	**608**	**393**	**1,001**
Total	**2,382**	**1,365**	**3,747**

Estimated net proved reserves of natural gas at 31 December 2023[a b]

			billion cubic feet
	Developed	Undeveloped	Total
UK	**221**	**34**	**255**
US	**2,672**	**3,229**	**5,901**
Rest of North America	**–**	**–**	**–**
South America[e]	**931**	**503**	**1,434**
Africa	**518**	**207**	**724**
Rest of Asia	**3,051**	**1,672**	**4,722**
Australasia	**1,550**	**358**	**1,907**
Subsidiaries	**8,942**	**6,003**	**14,944**
Equity-accounted entities	**1,608**	**919**	**2,527**
Total	**10,549**	**6,922**	**17,471**

Estimated net proved reserves on an oil equivalent basis

			million barrels of oil equivalent
	Developed	Undeveloped	Total
Subsidiaries	**3,316**	**2,006**	**5,323**
Equity-accounted entities	**885**	**552**	**1,437**
Total	**4,201**	**2,558**	**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, and include non-controlling interests in consolidated operations. We disclose our share of reserves held in joint ventures and associates that are accounted for by the equity method although we do not control these entities or the assets held by such entities.
[b] The 2023 marker prices used were Brent $83.27/bbl (2022 $101.24/bbl and 2021 $69.23/bbl) and Henry Hub $2.58/mmBtu (2022 $6.19/mmBtu and 2021 $3.61/mmBtu).
[c] Includes condensate.
[d] Includes 2.2 million barrels of liquids in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[e] Includes 430 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

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

Proved reserves replacement

Total hydrocarbon proved reserves at 31 December 2023, on an oil equivalent basis including equity-accounted entities, decreased by 6% compared with 31 December 2022 (8% decrease for subsidiaries and 4% increase for equity-accounted entities). Natural gas decreased by 5% (7% decrease for subsidiaries and 6% increase for equity-accounted entities).

There was a net increase from acquisitions and disposals of 31mmboe within our US and North Africa subsidiaries.

The proved reserves replacement ratio★ is the extent to which production is replaced by proved reserves additions. This ratio is expressed in oil equivalent terms and includes changes resulting from revisions to previous estimates, improved recovery, and extensions and discoveries. For 2023, the proved reserves replacement ratio excluding acquisitions and disposals was 47% (20% in 2022 and 50% in 2021) for subsidiaries and equity-accounted entities, 31% for subsidiaries alone and 136% for equity-accounted entities alone. There was a net increase (80mmboe) of reserves in some of our PSAs in Azerbaijan and the Middle East due to lower gas and oil prices, partially offset by a decrease in the US due to price.

In 2023 net additions to the group's proved reserves (excluding production, sales and purchases of reserves-in-place) amounted to 406mmboe (227mmboe for subsidiaries and 179mmboe for equity-accounted entities), through revisions to previous estimates including price, improved recovery from, and extensions to, existing fields and discoveries of new fields. The majority of subsidiary additions were through improved recovery from, and extensions to, existing fields and discoveries of new fields where they represented a mixture of proved developed and proved undeveloped reserves. The principal proved reserves additions in our subsidiaries by region were in the US and the Middle East. The principal reserves additions in our equity-accounted entities were in Aker BP and PAEG.

In January 2024 it was reported that the Oslo District Court had determined that certain development permits granted by the Norwegian government during 2023 were invalid. This includes development permits for two fields in which Aker bp has an interest. The court's decision is not final and could be appealed. If bp's equity-accounted share of the reserves attributable to these two fields is removed from the calculation of bp's 2023 proved reserves ratio, that ratio would decrease from 47% to 44%. Removal of the same reserves from bp's 2023 reporting would also impact proved hydrocarbon reserves for the group, proved undeveloped reserves and estimated net proved reserves on an oil equivalent basis amongst other reported measures both for equity-accounted entities and group.

26% of our proved reserves are associated with PSAs. The countries in which we produced under PSAs in 2023 were Algeria, Angola, Azerbaijan, Egypt, India, Indonesia, Mexico and Oman. In addition, the technical service contract (TSC)★ governing our investment in the Rumaila field in Iraq functions as a PSA.

The group holds no licences in our PSAs or TSCs due to expire within the next three years that would have a significant impact on bp's reserves or production, including undeveloped acreage.

For further information on our reserves see page 254.

bp's net production by country – crude oil[a] and natural gas liquids

						thousand barrels per day
						bp net share of production[b]
			Crude oil			Natural gas liquids
	2023	2022	2021	2023	2022	2021
Subsidiaries						
UK[c]	**74**	80	82	**5**	5	5
Total Europe	**74**	80	82	**5**	5	5
Lower 48 onshore[c]	**69**	71	69	**66**	56	48
Gulf of Mexico deepwater	**266**	225	239	**22**	19	22
Total US	**335**	296	308	**88**	76	70
Canada[cd]	**–**	15	25	**–**	–	–
Total Rest of North America	**–**	15	25	**–**	–	–
Total North America	**335**	311	333	**88**	76	70
Trinidad and Tobago	**4**	5	5	**4**	4	4
Total South America	**4**	5	5	**4**	4	4
Angola[c]	**–**	49	80	**–**	–	–
Egypt	**28**	28	23	**1**	–	–
Algeria[c]	**1**	5	6	**1**	6	7
Total Africa	**29**	83	110	**2**	6	7
Abu Dhabi	**197**	195	171	**–**	–	–
Azerbaijan	**70**	73	77	**–**	–	–
Iraq[c]	**–**	15	43	**–**	–	–
India	**–**	–	–	**4**	–	–
Oman[c]	**22**	24	26	**–**	–	–
Total Rest of Asia	**289**	307	318	**4**	–	–
Total Asia	**289**	307	318	**4**	–	–
Australia[c]	**8**	11	11	**2**	2	2
Eastern Indonesia	**2**	1	2	**–**	–	–
Total Australasia	**10**	12	13	**2**	2	2
Total subsidiaries	**741**	797	860	**104**	93	88
Equity-accounted entities (bp share)						
Rosneft[e] (Russia, Egypt)	**–**	144	857	**–**	–	3
Argentina	**51**	51	50	**1**	1	1
Mexico	**5**	6	3	**–**	–	–
Bolivia	**1**	2	2	**–**	–	–
Egypt	**–**	–	–	**2**	3	3
Norway	**60**	47	48	**3**	2	3
Russia	**–**	7	30	**–**	–	–
Iraq	**62**	25		**–**		
Angola	**82**	33	1	**4**	2	3
Total equity-accounted entities	**261**	314	991	**9**	9	12
Total subsidiaries and equity-accounted entities[f]	**1,002**	1,111	1,851	**113**	102	100

[a] Includes condensate.
[b] Production excludes royalties due to others whether payable in cash or in kind where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[c] In 2023, bp disposed of its interests in Algeria. In 2022, bp disposed of its interests in Angola, its interest in Sunrise Oil Sands in Canada, its interest in Rumaila in Iraq, and certain Lower 48 onshore interests in the US and certain offshore interests in Australia. In 2021, bp disposed of 20% of its interest in Block 61 in Oman, its interest in Shearwater in the UK North Sea, and certain Lower 48 onshore interests in the US.
[d] All of the production from Canada in Subsidiaries is bitumen.
[e] 2022 reflects bp's estimated share of Rosneft production for the period 1 January to 27 February, averaged over the year (see Financial statements – Note 1). Includes production in respect of the non-controlling interest in Rosneft, including production held through bp's interests in Russia other than Rosneft.
[f] Includes 2 net mboe/d of NGLs from processing plants in which bp has an interest (2022 2mboe/d and 2021 3mboe/d).

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

bp's net production by country – natural gas

			million cubic feet per day
			bp net share of production[a]
	2023	2022	2021
Subsidiaries			
UK[b]	**247**	271	236
Total Europe	**247**	271	236
Lower 48 onshore[b]	**1,338**	1,148	1,043
Gulf of Mexico deepwater	**149**	143	154
Total US	**1,486**	1,291	1,197
Canada	**—**	—	2
Total Rest of North America	**—**	—	2
Total North America	**1,486**	1,291	1,199
Trinidad and Tobago	**1,191**	1,276	1,260
Total South America	**1,191**	1,276	1,260
Egypt	**1,220**	1,272	1,206
Algeria[b]	**16**	81	126
Total Africa	**1,236**	1,353	1,332
Azerbaijan	**714**	670	539
India	**283**	216	169
Oman[b]	**582**	599	571
Total Rest of Asia	**1,578**	1,485	1,279
Total Asia	**1,578**	1,485	1,279
Australia	**301**	331	332
Eastern Indonesia	**473**	421	429
Total Australasia	**774**	752	760
Total subsidiaries[c]	**6,512**	6,428	6,067
Equity-accounted entities (bp share)			
Rosneft[d] (Russia, Canada, Egypt, Vietnam)	**—**	238	1,380
Argentina	**247**	238	223
Bolivia	**50**	56	60
Mexico	**2**	2	1
Norway	**58**	66	66
Russia	**—**	10	42
Angola	**74**	64	77
Total equity-accounted entities[c]	**432**	674	1,849
Total subsidiaries and equity-accounted entities	**6,944**	7,101	7,915

[a] Production excludes royalties due to others whether payable in cash or in kind where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] In 2023, bp disposed of its interests in Algeria and certain Lower 48 onshore interests in the US. In 2022, bp disposed of certain Lower 48 onshore interests in the US. In 2021, bp disposed 20% of its interest in Block 61 in Oman, its interest in Shearwater in the UK North Sea, and certain Lower 48 onshore interests in the US.
[c] Natural gas production volumes exclude gas consumed in operations within the lease boundaries of the producing field, but the related reserves are included in the group's reserves.
[d] 2022 reflects bp's estimated share of Rosneft production for the period 1 January to 27 February, averaged over the year (see Financial statements – Note 1). Includes production in respect of the non-controlling interest in Rosneft, including production held through bp's interests in Russia other than Rosneft.

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

The following tables provide additional data and disclosures in relation to our oil and gas operations.

Average sales price per unit of production (realizations★)[a]

										$ per unit of production
	Europe		North America		South America	Africa	Asia		Australasia	Total group average
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
2023										
Crude oil[b]	**82.99**	**—**	**75.28**	**—**	**84.36**	**76.30**	**—**	**83.86**	**68.27**	**79.37**
Natural gas liquids	**46.52**	**—**	**19.26**	**—**	**30.76**	**44.41**	**—**	**—**	**33.47**	**23.79**
Gas	**16.71**	**—**	**2.08**	**—**	**3.58**	**4.82**	**—**	**7.72**	**8.89**	**5.60**
2022										
Crude oil[b]	102.54	—	90.05	84.88	99.09	102.00	—	98.74	86.11	95.70
Natural gas liquids	60.41	—	31.72	—	60.55	54.78	—	—	54.20	37.00
Gas	33.45	—	5.61	3.68	7.65	5.21	—	11.81	12.33	9.29
2021										
Crude oil[b]	71.99	—	62.58	52.49	67.62	68.98	—	67.94	61.46	65.81
Natural gas liquids	52.07	—	26.85	—	32.81	51.01	—	—	40.98	30.89
Gas	14.59	—	3.68	2.63	4.06	4.36	—	5.66	7.25	5.20
Equity-accounted entities[c]										
2023										
Crude oil[b]	**—**	**81.61**	**—**	**—**	**75.49**	**80.21**	**—**	**75.21**	**—**	**78.33**
Natural gas liquids	**—**	**—**	**—**	**—**	**30.95**	**42.89**	**N/A**	**—**	**—**	**36.70**
Gas	**—**	**12.80**	**—**	**—**	**3.66**	**—**	**—**	**—**	**—**	**5.15**
2022										
Crude oil[b]	—	71.14	—	—	78.05	86.73	102.84	90.16	—	90.18
Natural gas liquids[d]	—	—	—	—	46.64	—	N/A	—	—	46.64
Gas	—	24.23	—	—	4.75	—	4.35	—	—	6.91
2021										
Crude oil[b]	—	69.23	—	—	62.62	—	61.98	—	—	62.60
Natural gas liquids[d]	—	—	—	—	42.47	—	N/A	—	—	42.47
Gas	—	15.26	—	—	3.44	—	1.69	—	—	2.49

Average production cost per unit of production[e]

										$ per unit of production
	Europe		North America		South America	Africa	Asia		Australasia	Total group average
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
2023	**10.69**	**—**	**9.61**	**—**	**4.53**	**2.52**	**—**	**2.81**	**2.09**	**5.78**
2022	10.36	—	9.70	15.36	3.92	5.02	—	3.52	2.04	6.07
2021	13.97	—	9.17	13.18	4.49	6.17	—	4.92	2.27	6.82
Equity-accounted entities										
2023	**—**	**6.22**	**—**	**—**	**17.87**	**15.46**	**—**	**16.41**	**—**	**14.38**
2022	—	6.01	—	—	15.55	21.01	7.39	20.81	—	11.47
2021	—	9.75	—	—	11.21	—	2.76	—	—	3.82

a Units of production are barrels for liquids and thousands of cubic feet for gas. Realizations include transfers between businesses, except in the case of Russia.
b Includes condensate.
c In certain countries it is common for equity-accounted entities' agreements to include pricing clauses that require selling a significant portion of the entitled production to local governments or markets at discounted prices.
d Natural gas liquids for Russia are included in crude oil.
e Units of production are barrels for liquids and thousands of cubic feet for gas. Amounts do not include ad valorem and severance taxes.

Additional information for customers & products

Reconciliation of customers & products RC profit before interest and tax to underlying RC profit before interest and tax to adjusted EBITDA★ by business

			$ million
	2023	2022	2021
RC profit before interest and tax for customers & products	**4,230**	8,869	2,208
Less: Adjusting items gains (charges)	**(2,183)**	(1,920)	(1,044)
Underlying RC profit before interest and tax for customers & products	**6,413**	10,789	3,252
By business:			
customers – convenience & mobility	**2,644**	2,966	3,052
Castrol – included in customers	**730**	700	1,037
products – refining & trading	**3,769**	7,823	200
Add back: Depreciation, depletion and amortization	**3,548**	2,870	3,000
By business:			
customers – convenience & mobility	**1,736**	1,286	1,306
Castrol – included in customers	**167**	153	150
products – refining & trading	**1,812**	1,584	1,694
Adjusted EBITDA for customers & products	**9,961**	13,659	6,252
By business:			
customers – convenience & mobility	**4,380**	4,252	4,358
Castrol – included in customers	**897**	853	1,187
products – refining & trading	**5,581**	9,407	1,894

Sales volume

			thousand barrels per day
	2023	2022	2021
Marketing sales[a]	**2,718**	2,613	2,439
Trading/supply sales[b]	**358**	350	393
Total refined product sales	**3,076**	2,963	2,832
Crude oil[c]	**102**	184	249
Total	**3,178**	3,147	3,081

[a] Marketing sales include branded and unbranded sales of refined fuel products and lubricants to business-to-business and business-to-consumer customers, including service station dealers, jobbers, airlines, small and large resellers such as hypermarkets, and the military.
[b] Trading/supply sales are fuel sales to large unbranded resellers and other oil companies.
[c] Crude oil sales relate to third-party transactions executed primarily by trading and shipping. In addition, reported crude oil sales in 2023 includes 68 thousand barrels per day (2022 67 thousand barrels per day and 2021 50 thousand barrels per day) relating to volumes sold directly by the gas & low carbon energy and oil production & operations segments.

In the table above, volumes of crude oil and refined product trading/supply sales are presented on a basis consistent with income statement presentation. These figures do not correspond to actual volumes of physically traded energy products and are not intended for use in assessing emissions volumes or carbon intensity. Marketing volumes shown represent physically delivered transactions regardless of income statement presentation of such transactions.

Reconciliation of customers & products RC profit before interest and tax to convenience gross margin

			$ million
	2023	2022	2021
RC profit before interest and tax for customers & products	**4,230**	8,869	2,208
Subtract RC profit (loss) before interest and tax for refining & trading	**1,943**	6,008	(468)
	2,287	2,861	2,676
Net (favourable) adverse impact of adjusting items for convenience & mobility	**357**	105	376
Underlying RC profit before interest and tax for convenience & mobility	**2,644**	2,966	3,052
Subtract underlying RC profit before interest and tax for Castrol	**730**	700	1,037
Add back convenience & mobility (excluding Castrol) depreciation, depletion and amortization	**1,569**	1,133	1,156
Subtract convenience & mobility (excluding Castrol) production and manufacturing, distribution and administration expenses and adjusted for fuels, EV charging, aviation, B2B and midstream gross margin[a]	**1,363**	1,655	1,335
Subtract earnings from equity-accounted entities in convenience & mobility (excluding Castrol)	**457**	225	330
Convenience gross margin[b]	**1,663**	1,519	1,506
Foreign exchange effects	**–**	7	(122)
At constant foreign exchange	**1,663**	1,526	1,384
Convenience gross margin growth[c]	**9%**		

[a] Adjusted for portfolio changes.
[b] Excluding TravelCenters of America and adjusted for other portfolio changes.
[c] Values are at end 2023 foreign exchange rates. This requires a calculation of the comparative convenience gross margin ($ million) at current period foreign exchange rates (constant foreign exchange) to compare the current period value with the restated comparative period value.

★ See glossary on **page 373**

Retail sites[a]

	2023	2022	2021
			Number of bp-branded retail sites
US	**8,200**	7,750	7,450
Europe	**8,050**	8,150	8,250
Rest of world	**4,850**	4,750	4,800
Total	**21,100**	20,650	20,500

a Reported to the nearest 50. Includes sites operated by dealers, jobbers, franchisees, brand licensees or joint venture (JV) partners, under the bp brand. These may move to and from the bp brand as their fuel supply agreement or brand licence agreement expires and are renegotiated in the normal course of business. Retail sites are primarily branded *bp*, *ARCO*, *Amoco*, *Aral*, *Thorntons and* TravelCenters of America and also include sites in India through our Jio-bp JV.

Refinery throughputs[a b c]

	2023	2022	2021
			thousand barrels per day
US	**662**	678	719
Europe	**749**	804	787
Rest of world	**—**	22	88
Total	**1,411**	1,504	1,594
			%
Refining availability★	**96.1**	94.5	94.8

a This does not include bp’s interest in Pan American Energy Group.
b Refinery throughputs reflect crude oil and other feedstock volumes.
c On 28 February 2023, bp completed the sale of its 50% interest in the bp-Husky Toledo refinery in Ohio, US, to Cenovus Energy, its partner in the facility.

Refinery capacity

The following table[a b] summarizes bp's average daily crude distillation capacities as at 31 December 2023.

	Country	Refinery	Crude distillation capacities[c] thousand barrels per day
US			
US North West	US	Cherry Point	**251**
US Mid West		Whiting	**440**
			691
Europe			
North West Europe	Germany	Gelsenkirchen	**265**
		Lingen	**97**
	Netherlands	Rotterdam	**394**
Mediterranean	Spain	Castellón	**110**
			866
Total capacity at 31 December 2023			**1,557**

a This does not include bp’s interest in Pan American Energy Group.
b On 28 February 2023, bp completed the sale of its 50% interest in the bp-Husky Toledo refinery in Ohio, US, to Cenovus Energy, its partner in the facility.
c Crude distillation capacity is gross rated capacity, which is defined as the highest average sustained unit rate for a consecutive 30-day period under normal operational conditions.

Environmental expenditure

			$ million
	2023	2022	2021
Operating expenditure	**524**	416	362
Capital expenditure	**329**	224	222
Clean-ups	**23**	16	17
Additions to environmental remediation provision	**228**	502	363
Increase (decrease) in decommissioning provision	**920**	1,248	1,231

Operating and capital expenditure on the prevention, control, treatment or elimination of air and water emissions and solid waste is often not incurred as a separately identifiable transaction. Instead, it forms part of a larger transaction that includes, for example, normal operations and maintenance expenditure. The figures for environmental operating and capital expenditure in the table are therefore estimates, based on the definitions and guidelines of the American Petroleum Institute.

Environmental operating expenditure of $524 million in 2023 (2022 $416 million) showed an overall increase of 26%, largely due to increased expenditure in BP Rotterdam and BP North America Gas.

Environmental capital expenditure of $329 million in 2023 (2022 $224 million) showed an overall increase of 47% largely due to increased expenditure for BP Products North America and BP North America Gas.

Clean-up costs were $23 million in 2023 (2022 $16 million), representing oil spill clean-up costs and other associated remediation and disposal costs.

In addition to operating and capital expenditure, we also establish provisions for future environmental remediation work. Expenditure against such provisions normally occurs in subsequent periods and is not included in environmental operating expenditure reported for such periods.

Provisions for environmental remediation are made when a clean-up is probable and the amount of the obligation can be reliably estimated. Generally, this coincides with the commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites.

The extent and cost of future environmental restoration, remediation and abatement programmes are inherently difficult to estimate. They often depend on the extent of contamination, and the associated impact and timing of the corrective actions required, technological feasibility and bp's share of liability. Though the costs of future programmes could be significant and may be material to the results of operations in the period in which they are recognized, it is not expected that such costs will be material to the group's overall results of operations or financial position.

Additions to our environmental remediation provision reflect new liabilities and scope/cost reassessments of the remediation plans of a number of our sites, primarily in the US. The charge for environmental remediation provisions in 2023 arising from new and acquired sites was $37 million (2022 $67 million and 2021 $33 million).

In addition, we make provisions on installation of our oil and gas producing assets and related pipelines to meet the cost of eventual decommissioning. On installation of an oil or natural gas production facility, a provision is established that represents the discounted value of the expected future cost of decommissioning the asset.

In 2023, the net increase in the decommissioning provision was primarily due to recognition of additional provisions and changes in cost estimate assumptions.

We undertake periodic reviews of existing provisions. These reviews take account of revised cost assumptions, changes in decommissioning requirements and any technological developments.

Provisions for environmental remediation and decommissioning are usually established on a discounted basis, as required by IAS 37 'Provisions, Contingent Liabilities and Contingent Assets'.

Further details of decommissioning and environmental provisions appear in Financial statements – Note 23.

Regulation of the group's business

Our businesses and operations are subject to the laws and regulations applicable in each country, state or other regional or local area in which they occur. These cover virtually all aspects of bp's activities and include matters such as the acquisition of rights to develop and operate projects, production rates, royalties, environmental, health and safety protection, fuel specifications and transportation, trading, pricing, anti-trust, export, taxes, and foreign exchange.

Oil and gas contractual and regulatory framework

The terms and conditions of the leases, licences and contracts under which our upstream oil and gas interests are held vary from country to country. These leases, licences and contracts are generally granted by or entered into with a government entity or state-owned or controlled company and are sometimes entered into with private property owners. Arrangements with governmental or state entities usually take the form of licences or production-sharing agreements★ (PSAs), although arrangements with private entities and the US government entities are usually by lease.

Licences (or concessions) give the holder the right to explore for, develop and produce a commercial discovery. Under a licence, the holder bears the risk of exploration, development and production activities and provides the financing for these operations. In principle, the licence holder is entitled to all production, minus any royalties that are payable in kind. A licence holder is generally required to pay production taxes or royalties, which may be in cash or in kind.

In certain countries, separate licences are required for exploration and production activities, and in some cases production licences are limited to only a portion of the area covered by the original exploration licence.

PSAs entered into with a government entity or state-owned or state-controlled company generally require bp (alone or with other contracting companies) to provide all the financing and bear the risk of exploration and production activities in exchange for a share of the production remaining after royalties, if any. Less typically, bp may explore for, develop and produce hydrocarbons under a service agreement with the host entity in exchange for reimbursement of costs and/or a fee paid in cash rather than production.

bp frequently conducts its exploration and production activities in joint arrangements or co-ownership arrangements with other international oil companies, state-owned or -controlled companies and/or private companies. Conventionally, all costs, benefits, rights, obligations, liabilities and risks incurred in carrying out joint arrangement or co-ownership operations under a lease, licence or PSA are shared among the joint arrangement or co-owning parties according to agreed ownership interests which are set out in a joint operating agreement. To the extent that any liabilities arise, whether to governments or third parties, or as between the joint arrangement parties or co-owners themselves, each joint arrangement party or co-owner will generally be liable under the terms of a joint operating agreement to meet these in proportion to its ownership interest. Any agreed allocation of liability amongst the joint arrangement parties is, however, often different to the position under the relevant licence, lease or PSA which may provide for joint and several liability of the joint arrangement parties including for decommissioning obligations. In many upstream operations, a party (known as the operator) will be appointed (pursuant to a joint operating agreement) to carry out day to-day operations on behalf of the joint arrangement or co-ownership. The operator is typically one of the joint arrangement parties or a co-owner and will carry out its duties either through its own staff, or by contracting out various elements to third-party contractors or service providers. bp acts as operator on behalf of joint arrangements and co-ownerships in a number of countries.

Frequently, work (including drilling and related activities) will be contracted out to third-party service providers. The relevant contract will specify the work, the remuneration, and typically the risk allocation between the parties. Depending on the service to be provided, the contract may also contain provisions allocating risks and liabilities associated with pollution and environmental damage, damage to a well or hydrocarbon reservoirs and for claims from third parties or other losses. The allocation of those risks

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varies among contracts and is determined through negotiation between the parties.

In general, bp incurs income tax on income generated from production activities (whether under a licence or PSA). In addition, depending on the area, bp's production activities may be subject to a range of other taxes, levies and assessments, including special petroleum taxes and revenue taxes. The taxes imposed on oil and gas production profits and activities may be substantially higher than those imposed on other activities, for example in Egypt, the UK, the US and the United Arab Emirates.

Low carbon energy – renewables contractual and regulatory framework

The majority of our renewable assets are held indirectly through interests in incorporated joint ventures or special purpose entities (in either case, a Project Company). The renewables contractual and regulatory framework and the rights granted in relation to a renewable asset significantly vary from country to country. In some countries, the regulatory framework is still under development or subject to significant change as the renewables industry evolves.

In general terms the rights to a renewable asset are usually held by a Project Company through a package of assets that together form the renewable project owned by such Project Company, including:

- one or more leases, easements, or licences over land or seabed granted by a public or private individual or entity that grant the Project Company rights to develop, build and operate the renewable asset in such areas of land or seabed;
- one or more generation licences that grant the Project Company the right to produce and sell the electricity to the market;
- an interconnection agreement that grants the Project Company the right to connect the power project into the grid;
- an offtake agreement which, depending on the country's electricity market, is entered into with a utility company, a corporate buyer or a public entity; and
- potentially, a subsidy mechanism in the form of a feed in tariff, contract for difference, hedging mechanism or renewable energy certificate to support the development of the project.

The risk allocation between the developer/generator and the host government or private entity has not been standardized in the industry. However, in general terms the Project Company bears the risk of the development, construction and operation of the renewable energy project and secures the financing for these operations and receives any profit from the revenue generated through the offtake agreement and/or subsidy mechanism (if available).

US Inflation Reduction Act

The US Inflation Reduction Act (IRA), which was signed into law in August 2022, includes a significant package of largely supply-side measures supporting low carbon energy sources and decarbonization technologies in the US. The impact of the IRA both on bp's businesses and more widely on the US economy is likely to depend on various factors which are currently uncertain, including the implementation of the incentive programmes by the US authorities through the Department of Energy (DOE) and other agencies, as well as regulatory initiatives at the local and federal level.

In 2023, bp participated in applications for and was subsequently notified that it will be awarded various DOE grants related to certain of bp's low carbon energy and decarbonization projects. bp and its co-applicants are currently negotiating the applicable award agreements with the DOE and we anticipate finalizing these agreements in 2024.

Greenhouse gas regulation

In December 2015, nearly 200 nations at the United Nations climate change conference in Paris (COP21) agreed to the Paris Agreement which aims to hold the increase in the global average temperature to well below 2°C above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5°C above pre-industrial levels. Signatories aim to reach global peaking of greenhouse gas (GHG) emissions as soon as possible and to undertake rapid reductions thereafter, so as to achieve a balance between human caused emissions and removals by sinks of GHGs in the second half of this century. The Paris Agreement commits all signatories to submit Nationally Determined Contributions (NDCs) (i.e. pledges or plans of climate action) and pursue domestic measures aimed at achieving the objectives of their NDCs. Signatories are required to submit revised NDCs every five years, and the revised NDCs are expected to be more ambitious with each revision. The first global stocktake of progress was published by the United Nations in September 2023 and further assessments will occur every five years. The UAE conference (COP28) in Dubai, which took place in November and December 2023, marked the conclusion and outcome of this first stocktake and reached a 'consensus' which includes calls for an acceleration of efforts towards the phase-down of unabated coal power and to transition away from fossil fuels in energy systems.

More stringent national and regional measures relating to the transition to a lower carbon economy, such as the UK's 2050 net zero carbon emissions commitment, can be expected in the future. These measures could increase bp's production costs for certain products, increase compliance and litigation costs, increase demand for competing energy alternatives or products with lower-carbon intensity, and affect the sales and specifications of many of bp's products. Further, such measures could lead to constraints on production and supply and access to new reserves, particularly due to the long-term nature of many of bp's projects.

Certain current and announced GHG measures and developments potentially affecting bp's businesses in various markets in which bp operates are summarized below. For information on steps that bp is taking in relation to climate change issues and for details of bp's GHG reporting, see Sustainability – Net zero aims on page 48.

United States

In the US, bp's operations are affected by GHG regulation in a number of ways. The federal Clean Air Act (CAA) regulates air emissions, permitting, fuel specifications and other aspects of our production, refining, distribution and marketing activities.

In November, 2023, the Environmental Protection Agency (EPA) promulgated the "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review." These regulations are focused on methane emissions from oil and gas production at new and existing facilities and include significant requirements in the areas of fugitive emissions monitoring and repair, flaring, emission event reporting, process controller and pump emissions, and storage vessels.

The IRA requires EPA to collect an annual Waste Emissions Charge (WEC) on methane emissions from oil and natural gas facilities that exceed specific levels of emissions and methane intensity. The WEC is $900/metric ton of methane emissions occurring in 2024, $1,200/metric ton for emissions occurring in 2025, and $1,500/metric ton for emissions occurring in 2026 and years thereafter. In January 2024, EPA proposed regulations to implement the WEC provisions of the IRA. The date and details of those final regulations to be issued are uncertain.

Other EPA GHG and environmental regulations affect electricity generation practices and prices and have an impact on the market for fuels used to generate electricity and on renewable energy installations. These regulations are in flux due to changes in approach between presidential administrations, as well as lawsuits challenging those regulations.

In June 2022, the Supreme Court decision in West Virginia v. EPA limited EPA's regulatory authority to require electricity 'generation shifting' (e.g., from coal to natural gas or renewable sources). In May 2023, EPA proposed new carbon pollution standards for coal and gas-fired power plants. The proposed regulations would tighten emissions limits for those plants and require some plants to install carbon capture technology. The date and requirements of any final regulations issued are uncertain.

In April 2023, EPA proposed regulations to significantly tighten emissions standards for light- and medium-duty vehicles for model year (MY) 2027 and beyond. The proposed regulations are intended to spur emissions reductions technology on hydrocarbon-powered vehicles and to encourage the transition to electric vehicles. The date and requirements of any final regulations issued are uncertain.

The Energy Policy Act of 2005 and the Energy Independence and Security Act of 2007 impose the Renewable Fuel Standard (RFS), requiring transportation fuel sold in the United States to contain a minimum volume of renewable fuels. On June 21, 2023, EPA announced a final rule establishing biofuel volume requirements and associated percentage standards for cellulosic biofuel, biomass-based diesel (BBD), advanced biofuel, and total renewable fuel for 2023-25. Lawsuits have been filed challenging this final rule. In addition, certain state initiatives impose carbon-intensity reduction requirements on transportation fuels sold in those states (e.g. in California, Oregon and Washington).

The federal GHG Mandatory Reporting Rule requires operators of certain facilities and producers and importers/exporters of petroleum products to file annual GHG emissions reports with EPA quantifying direct emissions from affected facilities, as well as the emissions that would result from the release or combustion of the petroleum products imported, exported or produced.

A number of states, municipalities and regional organizations continue to advance climate initiatives that affect our US operations. For example, certain state initiatives impose carbon-intensity reduction requirements on transportation fuels sold in those states (e.g. in California, Oregon, and Washington). Recently, California proposed to increase the stringency of its Low Carbon Fuel Standard (LCFS) to achieve a 30% reduction in carbon intensity required by 2030 (up from 20%). The State of Washington enacted state-wide carbon cap and invest legislation and a Clean Fuel Program (similar to California's LCFS) in 2021. In 2022, the State of Washington finalized rules implementing both of those programmes.

Our US businesses are subject to increased GHG and other environmental requirements and regulatory uncertainty, including that the current or any future US administration could revise or revoke current or prior administration programmes, as well as the possibility of increased expenditures in having to comply with numerous diverse and non-uniform regulatory initiatives at the state and local level.

US fuel markets are affected by EPA and National Highway Traffic Safety Administration (NHTSA) regulation of light, medium and heavy-duty vehicle emissions (both fuel economy and tailpipe standards) as well as for non-road engines and vehicles and certain large GHG stationary emission sources. California also imposes Low Emission Vehicle (LEV) and Zero Emission Vehicle (ZEV) standards on vehicle manufacturers, and a number of other states, as allowed by CAA authority, have adopted California's standards. In August 2022, California finalized the next generation of its GHG and ZEV standards (referred to as 'ACC II'). California filed a waiver application with EPA in December 2023. Fifteen other states have adopted ACC II although EPA has not yet acted upon the application. These regulations may impact bp's product mix and demand for particular products in those states. In August 2020, California also entered into agreements with several carmakers to meet more demanding emissions standards in California. In March 2023, EPA granted California's request for a waiver of pre-emption covering, in part, its Advanced Clean Trucks Program, which mandates increasing quantities of ZEV sales for medium- and heavy-duty vehicles in the state. A legal challenge to that decision is pending in the U.S. Court of Appeals for the D.C. Circuit.

In 2021 and 2022, the Biden administration revised the fuel economy and tailpipe carbon dioxide emissions standards for passenger cars and light trucks covering model years (MY) 2023 through 2026. The revised standards are more stringent through MY 2026 than the August 2020 agreements California reached with several carmakers. EPA's new tailpipe carbon dioxide emissions standards were challenged in the U.S. Court of Appeals with a decision still pending. EPA has also restored California's Clean Air Act waiver allowing it to set its own GHG automotive tailpipe standards and for other states to adopt those standards. That decision has also been challenged in the U.S. Court of Appeals.

In December 2022, EPA promulgated regulations establishing new emission standards for oxides of nitrogen (NOx) and other pollutants for highway heavy-duty engines. California has also adopted a 'Heavy-Duty Low NOx Omnibus Regulation' which will require manufacturers to comply with stricter emissions standards and a number of other states have opted or are planning to opt into those California standards. The rule is being phased in, with the first phase effective in 2024. bp continues to monitor these rules for implications for fuels. These and other EPA initiatives to reduce GHG emissions may have a significant effect on the production, sale and profitability of many of bp's products in the US.

European Union

The EU has adopted a goal of achieving climate neutrality by 2050 as part of the European Green Deal and, subsequently, a 55% GHG reduction target by 2030 compared to 1990 levels. To achieve this target, EU member states and Parliament adopted most measures proposed as part of the so-called 'Fit for 55' package. These include revisions of the EU Emissions Trading Scheme (EU ETS) and a newly created Carbon Border Adjustment Mechanism (CBAM); the Renewable Energy Directive (RED) – including an obligation on transport fuel suppliers to increase the share of renewables of their fuel supply; a sustainable aviation fuel (SAF) blending mandate from 2025; and CO^2 targets for the sales of new vehicles which are expected to accelerate the decarbonisation of the transport sector and impact fuel demand.

Once fully adopted and implemented, this would inter alia lead to higher shares of renewables across all sectors (including transport), a reduced number of GHG emission allowances under the EU ETS, and a target of zero gramme of CO^2 per km for new passenger cars by 2035. The EU also adopted measures to reduce methane emissions.

Some EU member states have adopted national targets above and beyond current EU climate goals, such as Germany, with a climate neutrality target by 2045.

United Kingdom

In April 2021, the UK government announced a target of a 78% reduction in emissions by 2035 compared to 1990 levels.

The UK Emissions Trading System (UK ETS) launched on 1 January 2021 following the end of the Brexit transition period and the UK's participation in the EU ETS. It seeks to provide a carbon pricing mechanism as a tool for helping achieve the UK's net zero target and covers the same GHGs and sectors as the EU ETS. bp's North Sea operations are subject to the UK ETS.

In July 2023, the UK government published a response to a 2022 consultation on proposed changes to the UK ETS rules. That response included decisions to expand the scope of the scheme to include domestic maritime transport from 2026, waste incineration and energy from waste from 2028 and process emissions from carbon dioxide venting from the upstream oil and gas sector from 2025.

In December 2023, the UK ETS Authority published two consultations. One covers a review of the UK ETS markets policy and the other relates to a review of free allocation methodology for the stationary sectors under the UK ETS to better target those most at risk of carbon leakage.

Other countries and regions

China is operating emission trading pilot programmes in a number of cities and provinces. One of bp's subsidiaries in China is participating in these programmes. In February 2021 China introduced a national emissions trading market (National ETS). The National ETS is intended to be an essential tool for China to fulfil its commitment to reach peak emissions by 2030 and carbon neutrality by 2060. For now, the National ETS participants are limited to the key emission entities identified by each provincial-level government authority and approved by Ministry for Ecology and Environment of China. bp is not participating in the National ETS.

In October 2021, as part of its '1+N' climate policy framework, China issued working guidance setting out specific targets and measures for achieving peak carbon emissions and carbon neutrality, and an action plan which sets out the main objectives for the next decade to achieve peak carbon emissions by 2030. The working guidance is the '1' (i.e., a long-term approach to combating climate change), while 'N' are various policies starting with the action plan. In June 2022, 17 government authorities jointly released the National Climate Change Adaptation Strategy 2035 making overall plans to prepare the country to adapt to climate change from the present to 2035.

China's domestic voluntary carbon mechanism called the China Certified Emission Reduction (CCER) programme has been suspended since 2017. In 2023, significant progress toward relaunching the CCER has been made by relevant authorities, including the promulgation of a regulation on CCER trading for trial implementation and the publication of methodologies that will be used to quantify net emission reductions or removals for four types of projects (forestation, solar thermal power, offshore wind power generation and mangrove revegetation).

On 5 January 2024, China's State Council approved an interim regulation for the national emissions trading scheme. The final version was issued on 4 February 2024 which has provisions on defining the scale of the national

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carbon market, determining allocation of emissions allowances and data quality supervision.

Other environmental regulation

In addition to the GHG regulations referred to above, climate change programmes and regulation of unconventional oil and gas extraction under a number of environmental laws may have a significant effect on the production, sale and profitability of many of bp's products.

Environmental laws also require bp to remediate and restore areas affected by the release of hazardous substances or hydrocarbons associated with our operations or properties. These laws may apply to sites that bp currently owns or operates, sites that it previously owned or operated, or sites used for the disposal of its and other parties' waste. See Financial statements – Note 23 for information on provisions for environmental restoration and remediation.

A number of pending or anticipated governmental proceedings against certain bp group companies under environmental laws could result in monetary or other sanctions. Group companies are also subject to environmental claims for personal injury and property damage alleging the release of, or exposure to, hazardous substances. The costs associated with future environmental remediation obligations, governmental proceedings and claims could be significant and may be material to the results of operations in the period in which they are recognized. We cannot accurately predict the effects of future developments, such as stricter environmental laws and regulations or enforcement policies, or future events at our facilities on the group, and there can be no assurance that material liabilities and costs will not be incurred in the future. For a discussion of the group's environmental expenditure, see page 353 and for a discussion of legal proceedings, see page 242.

Significant health, safety and environmental legislation and regulation affecting our businesses and profitability, in addition to those referred to above, include the following:

United States

- The Clean Water Act regulates wastewater and other effluent discharges from bp's facilities, and bp is required to obtain discharge permits, install control equipment and implement operational controls and preventative measures.
- The Resource Conservation and Recovery Act (RCRA) regulates the generation, storage, transportation and disposal of wastes associated with our operations and can require corrective action at locations where such wastes have been disposed of or released. bp has incurred, or is likely to incur, liability under RCRA or similar state laws in connection with sites bp operates or previously operated.
- The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) can, in certain circumstances, impose the entire cost of investigation and remediation on a party who owned or operated a site contaminated with a hazardous substance, or who arranged for disposal of a hazardous substance at a site. bp has incurred, or is likely to incur, liability under CERCLA or similar state laws, including costs attributed to insolvent or unidentified parties. bp is also subject to claims for remediation costs and natural resource damages under CERCLA and other federal and state laws. CERCLA also requires the reporting on the releases of certain quantities of listed hazardous substances to designated government agencies.
- The Emergency Planning and Community Right-to-Know Act requires reporting on the storage, use and releases of certain quantities of listed extremely hazardous substances to designated government agencies.
- The Toxic Substances Control Act (TSCA) regulates bp's manufacture, import, export, sale and use of chemical substances and products. In addition, EPA has revised processes and procedures for prioritisation of existing chemicals for risk evaluation, assessment and management. Agency actions and announcements are monitored regularly to identify developments with potential impacts on chemical substances important to bp products and operations.
- The Occupational Safety and Health Act imposes workplace safety and health requirements on bp operations along with significant process safety management obligations, requiring continuous evaluation and improvement of operational practices to enhance safety and reduce workplace emissions at gas processing, refining and other regulated facilities.
- The Oil Pollution Act 1990 (OPA) imposes operational requirements, liability standards and other obligations governing the transportation of petroleum products in US waters. States may impose additional obligations. Alaska, West Coast and certain East Coast states impose additional requirements and stricter liability standards.
- The Outer Continental Shelf Land Act, the Mineral Leasing Act and other statutes give the Department of Interior (DOI) and the BLM authority to regulate operations and air emissions, including equipment and testing, on offshore and onshore operations on federal lands subject to DOI authority.
- The Endangered Species Act (ESA) and Marine Mammal Protection Act protect certain species' habitats from adverse human impacts by restricting operations or development at certain times and in certain places. In 2020, the US Fish and Wildlife Service published regulatory definitions impacting habitat designations under the ESA, but in June 2022, the Biden administration rescinded those definitions. The Biden administration rescission of those definitions could expand the geographic areas subject to habitat protections.

European Union

- The Industrial Emissions Directive (IED) 2010 provides the framework for granting permits for major industrial sites. A recently agreed revision of the IED could, once formally adopted and implemented, potentially set more stringent permitting requirements, and lead to a further tightening of emission limit values.
- The EU Registration, Evaluation Authorization and Restriction of Chemicals (REACH) Regulation 2006 requires registration of chemical substances manufactured in or imported into the EU, together with the submission of relevant hazard and risk data. REACH affects our manufacturing or trading/import operations in the EU. bp maintains compliance by checking whether imports are covered by the registrations of non-EU suppliers' representatives, preparing and submitting registration dossiers to cover new manufactured and imported substances, and updating previously submitted registrations as required.
- The Water Framework Directive (WFD) published in 2000 aims to protect the quantity and quality of ground and surface waters of the EU member states. The implementation in the EU member states is still ongoing, planned to be finalised by 2027. Future proceedings on the determination of pollutants/priority substances as well as environmental quality standards in line with the WFD may require additional compliance efforts and increased costs for managing freshwater withdrawals and discharges from bp's EU operations.
- The Corporate Sustainability Reporting Directive (CSRD) entered into force on 5 January 2023 introducing new requirements for companies with securities listed on an EU regulated market or which exceed a threshold for turnover derived in the EU, to include disclosures related to climate, the environment and wider sustainability issues. The CSRD also expands to in-scope entities the requirements introduced by the EU Taxonomy Regulation, to identify environmentally sustainable activities and then disclose metrics related to capital and operating expenditure and turnover associated with those activities. Disclosure requirements will be phased in from 2025, in respect of the 2024 financial year.

United Kingdom

- Following the UK's exit from the European Union, operative EU laws were retained in UK law by the European Union (Withdrawal) Act 2018 (EUWA). In June 2023, the Retained EU Law (Revocation and Reform) Act 2023 received Royal Assent. That Act allows for significant changes to the status, operation and content of retained EU law, including through amendments to the EUWA. However, the UK government has not issued a policy statement on how it intends to use these powers and therefore future amendments to and deviations from retained EU law including in respect of environmental matters are uncertain.
- Since the end of the transition period on 31 December 2020, there has been a parallel UK REACH regime which applies in Great Britain only, with EU REACH continuing to apply in Northern Ireland. UK REACH

contains equivalent requirements to EU REACH, although future developments and potential divergences are uncertain.

- The Environment Act 2021 comprises various key parts including governance, waste and resource efficiency, air quality and environmental recall, water, nature and biodiversity and conservation covenants. The governance parts include a comprehensive framework for legally binding environmental improvement targets; to establish a framework for future policy statements on environmental principles to protect the environment by making environmental considerations a key part of policy development process across government; and to establish the Office for Environmental Protection, an independent public body to have oversight of environmental matters. The UK government's first suite of environmental targets became law in January 2023, but these are not expected to have a material impact on bp.

Other countries and regions

Regulations governing the discharge of treated water have also been developed in countries outside of the US and EU including in Trinidad where bp commissioned a new wastewater treatment plant in 2020 to meet consent levels agreed with the regulators to apply relevant water discharge rules.

The Abidjan Convention, along with the Additional Protocol published in 2012, sets environmental quality standards for the discharge of chemicals to the marine environment. Mauritania and Senegal are both signatories to the Abidjan Convention. bp is currently constructing the offshore facilities to include produced water management systems to meet the environmental quality standards for our future gas operations in Mauritania and Senegal.

Environmental maritime regulations

bp's shipping operations are subject to extensive national and international regulations governing operations, training, pollution prevention, liability, and insurance. These include:

- Liability and spill prevention and planning requirements governing, among others, tankers, barges, and offshore facilities are imposed by OPA in US waters. OPA also mandates a levy on imported and domestically produced oil to fund oil spill responses. Some states, including Alaska, Washington, Oregon and California, impose additional liability for oil spills. Outside US territorial waters, bp shipping tankers are subject to international pollution prevention, liability, spill response and preparedness regulations developed through the UN's International Maritime Organization (IMO), including the International Convention on Civil Liability for Oil Pollution Damage, the International Convention for the Prevention of Pollution from Ships (MARPOL), the International Convention on Oil Pollution, Preparedness, Response and Co-operation, and the International Convention on Civil Liability for Bunker Oil Pollution Damage. In April 2010, the Hazardous and Noxious Substance (HNS) Protocol 2010 was adopted to address issues that have inhibited ratification of the International Convention on Liability and Compensation for Damage in Connection with the Carriage of Hazardous and Noxious Substances by Sea 1996. As at 31 December 2023, the HNS Convention had not entered into force.
- A global sulphur cap of 0.5% applies to marine fuel under MARPOL with a stricter 0.1% cap in environmentally sensitive areas. In order to comply, ships either need to consume low sulphur marine fuels, operate on alternative low sulphur fuels such as LNG or implement approved abatement technology to enable them to meet the low sulphur emissions requirements while continuing to use higher sulphur fuel. This global cap does not alter the lower 0.1% limits that apply in the sulphur oxides Emissions Control Areas established by the IMO.
- From 2023 all vessels over 400 gross tonnage became subject to IMO requirements as to energy efficiency design (EEXI) and the carbon intensity of operations (CII).
- Under EU legislation, maritime transport will be gradually brought into the scope of the EU ETS from 2024, applicable to all vessels over 5000 gross tonnage calling at EU ports regardless of a vessel's flag.
- Under the proposed Fuel EU Maritime Regulation, from 2025 ship owners will need to reduce the GHG intensity of their fuel use gradually over time, initially by 2% by 2030 and 80% by 2050.
- The Convention for the Protection of the Marine Environment of the North-East Atlantic (OSPAR), aims to protect the marine environment of the North-East Atlantic. The OSPAR 2012 recommendation and guideline for the implementation of a risk-based approach to the management of produced water discharges from offshore installations in the North Sea supports a key goal of working towards eliminating harmful discharges. In 2020 the International Association of Oil and Gas Producers issued a report 'Oil And Gas Risk Based Assessment of Offshore Produced Water Discharges' which presents industry good practice and aims to broaden the understanding and acceptance of Risk Based Assessment (RBA) techniques internationally and improve consistency in the application of assumptions, levels of conservatism, and selection of risk endpoints.

To meet its financial responsibility requirements, bp shipping maintains marine oil pollution liability insurance in respect of its operated ships to a maximum limit of $1 billion for each occurrence through mutual insurance associations (P&I Clubs), although there can be no assurance that a spill would necessarily be adequately covered by insurance or that liabilities would not exceed insurance recoveries.

International trade sanctions

During the period covered by this report, non-US subsidiaries, or other non-US entities of bp, conducted limited activities in, or with persons from, certain countries identified by the US Department of State as State Sponsors of Terrorism or otherwise subject to US, EU and UK sanctions (Sanctioned Countries). In 2023, sanctions restrictions were insignificant to the group's financial condition and results of operations. bp monitors its activities with Sanctioned Countries, persons from Sanctioned Countries and individuals and companies subject to US, EU and UK sanctions and seeks to comply with applicable sanctions laws and regulations.

bp has a 29.99% interest in and operates the Shah Deniz field in Azerbaijan (Shah Deniz), has a 29.99% interest in and performs some operations for a related gas pipeline entity, South Caucasus Pipeline Company Limited (SCPC), and has a 23.99% non-operating interest in a related gas marketing entity, Azerbaijan Gas Supply Company Limited (AGSC). Naftiran Intertrade Co. Limited and NICO SPV Limited (collectively, NICO) have a 10% non-operating interest in each of Shah Deniz and SCPC and an 8% non-operating interest in AGSC. Shah Deniz, SCPC and AGSC continue in operation as they were excluded from the application of US sanctions and fall within the exception for certain natural gas projects under Section 603 of the Iran Threat Reduction and Syria Human Rights Act of 2012 (ITRA).

On 3 December 2018 bp entered into an agreement with, among others, SOCAR and NICO pursuant to which SOCAR pays to BP Exploration (Shah Deniz) Limited (BPXSD), as the Shah Deniz operator, compensation for NICO's waiver of its right to lift its share of Shah Deniz condensate. Such amounts are used to cover cash calls to NICO in respect of operating costs due from NICO to BPXSD. On 12 February 2022, OFAC issued a renewed licence in relation to these arrangements which expires on 15 April 2024. An application for a further renewal has been submitted and is subject to OFAC's approval.

Following the imposition in 2011 of further US and EU sanctions against Syria, bp terminated all sales of crude oil and petroleum products into Syria, though bp continues to supply aviation fuel to non-governmental Syrian resellers outside of Syria.

bp has a joint arrangement in Cuba which imports, manufactures, markets and sells lubricants.

During 2014, the US and the EU imposed sanctions on certain sectors of the Russian economy (energy, finance and defence/military) and on certain individuals and entities, including Rosneft. These sectoral sanctions include restrictions on the provision of financial assistance, technical assistance, and services in relation to exploration and production activity in deepwater, shale, and offshore Arctic.

Additional US sanctions have been imposed since 2014, broadening the scope of US sanctions on Russia-related activity to include certain international deepwater, shale, and offshore Arctic projects as well as the provision of goods and services for Russian energy export pipelines.

In response to Russia's military action in Ukraine in 2022, the US, EU, UK and many other countries have imposed broad economic and trade sanctions. The scope of these sanctions includes restrictions on dealing with designated individuals and entities; restrictions on the Russian financial sector; blocking economic activity in certain areas of Ukraine not controlled by the Ukrainian government; prohibitions in relation to investment in Russia; prohibitions and restrictions relating to Russian origin oil and oil products; prohibitions and restrictions relating to Russian origin iron and steel products, prohibitions and restrictions relating to Russian origin metals, prohibitions and restrictions on the provision of certain legal advisory services, prohibitions and restrictions in relation to transportation, including shipping and aircraft; trade controls limiting the purchase and import of a wide range of goods from Russia, and export controls limiting the export of a wide range of goods and technical assistance to Russia.

In response, Russia has implemented counter-sanctions including restrictions on the divestment from Russian assets by foreign investors and restrictions on the payments of dividends to certain foreign shareholders, including those based in the UK, requiring such dividends to be paid in roubles into restricted bank accounts and a requirement for approval of the Russian government for transfers from any such bank accounts out of Russia.

The bp group does not source any materials directly from Russia, except deliveries of LNG from Russian sources under a small number of contracts predating the Russia and Ukraine conflict in compliance with all applicable sanctions. bp has also discontinued sales of our products to customers in Russia. Such sales were not material to the bp group. As a result, outside of our shareholding in Rosneft and related businesses in Russia, direct impacts due to exposure to Russia have not been material and are not expected to be material in the future. bp continues to monitor Russia related sanctions and other international restrictions for any impacts on our businesses and the exit of our shareholding in Rosneft. See page 173 for further information in relation to bp's shareholding in Rosneft.

bp maintains bank accounts and has registered and paid required fees to maintain registrations of patents and trademarks in certain Sanctioned Countries.

bp has equity interests in non-operated joint arrangements with air fuel sellers, resellers, and fuel delivery services around the world. From time to time, the joint arrangement operator or other partners may sell or deliver fuel to airlines from Sanctioned Countries or flights to Sanctioned Countries, without bp's involvement.

bp has no control over the activities non-controlled associates may undertake in Sanctioned Countries or with persons from Sanctioned Countries.

Disclosure pursuant to ITRA Section 219

To our knowledge, none of bp's activities, transactions or dealings are required to be disclosed pursuant to ITRA Section 219, with the following possible exceptions.

In 2023, payments in relation to tax with an aggregate US dollar equivalent value of approximately $27,000 were paid from a bp trust account held with Tadvin Co. to Iranian public entities on behalf of BP Iran. No gross revenues or net profits are attributable to BP Iran's activities.

In February 2023, we identified that our European Fleet Business had issued 10 fuel cards to the embassy and consulate of Iran in both Germany and Austria. Fuel cards enable holders to acquire goods and services at bp retail sites and at retail sites operated by acceptance partners in Europe without payment in cash. Goods and services purchased with fuel cards are invoiced on a monthly or bi-monthly basis. As disclosed in the *bp Annual Report and Form 20-F 2022*, in 2023 the total aggregate invoiced amount was approximately $2,700. bp has terminated the cards and related accounts.

Material contracts

On 4 April 2016 the district court approved the Consent Decree among BP Exploration & Production Inc., BP Corporation North America Inc., BP p.l.c., the United States and the states of Alabama, Florida, Louisiana, Mississippi and Texas (the Gulf states) which fully and finally resolved any and all natural resource damages (NRD) claims of the United States, the Gulf states, and their respective natural resource trustees and all Clean Water Act (CWA) penalty claims, and certain other claims of the United States and the Gulf states.

Concurrently, the definitive Settlement Agreement that bp entered into with the Gulf states (Settlement Agreement) with respect to State claims for economic, property and other losses became effective.

bp has filed the Consent Decree and the Settlement Agreement as exhibits to its *Annual Report and Form 20-F 2020* filed with the SEC. For further details of the Consent Decree and the Settlement Agreement, see Legal proceedings in *bp Annual Report and Form 20-F 2015*.

Property, plant and equipment

bp has freehold and leasehold interests in real estate and other tangible assets in numerous countries, but no individual property is significant to the group as a whole. For more on the significant subsidiaries★ of the group at 31 December 2023 and the group percentage of ordinary share capital see Financial statements – Note 37. For information on significant joint ventures★ and associates★ of the group see Financial statements – Notes 16 and 17.

Related party transactions

Transactions between the group and its significant joint ventures and associates are summarized in Financial statements – Note 16 and 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 2023 to 16 February 2024.

Corporate governance practices

In the US, bp ADSs are listed on the New York Stock Exchange (NYSE). The significant differences between bp's corporate governance practices as a UK company and those required by NYSE listing standards for US companies are listed as follows:

Independence

As set out on page 88, bp has adopted separate terms of reference for the board and each of its committees as part of its corporate governance framework. The terms of reference for the board and each of its committees are reviewed annually and were last updated with effect from 1 December 2021, excluding the audit committee terms of reference which were updated on 22 July 2022. The terms of reference reflect the UK Corporate Governance Code 2018 approach to corporate governance. As such, the way in which bp makes determinations of directors' independence differs from the NYSE approach.

bp's corporate governance framework requires that all non-executive directors be determined by the board to be 'independent in character and judgement and free from any business or other relationship which could materially interfere with the exercise of their judgement'. The bp board has determined that, in its judgement, all of the non-executive directors are independent. In doing so, however, the board did not explicitly take into consideration the independence requirements outlined in the NYSE's listing standards.

Committees

bp has a number of board committees that are broadly comparable in purpose and composition to those required by NYSE rules for domestic US companies. For instance, bp has a remuneration (rather than a compensation) committee. bp also has an audit committee, which NYSE rules require for both US companies and foreign private issuers. These committees are composed solely of non-executive directors whom the board has determined to be independent, in the manner described above.

Each committee operates under its own terms of reference together with a set of terms applicable to all the committees (see the board committee reports on pages 94-132and bp.com/governance).

Under US securities law and the listing standards of the NYSE, bp is required to have an audit committee that satisfies the requirements of Rule 10A-3 under the Exchange Act and Section 303A.06 of the NYSE Listed

Company Manual. bp's audit committee complies with these requirements. The bp audit committee does not have direct responsibility for the appointment, reappointment or removal of the independent auditors. Instead, it follows the UK Companies Act 2006 and the UK Corporate Governance Code 2018 by making recommendations to the board on these matters for it to put forward for shareholder approval at the AGM.

One of the NYSE's additional requirements for the audit committee states that at least one member of the audit committee is to have 'accounting or related financial management expertise'. The board determined that Tushar Morzaria possesses such expertise and also possesses the financial and audit committee experiences set forth in both the UK Corporate Governance Code 2018 and SEC rules (see Audit committee report on page 98). Mr Morzaria is the audit committee financial expert as defined in Item 16A of Form 20-F.

Summary of terms of reference for audit committee and remuneration committee

The audit committee's full terms of reference are available on our website at bp.com/governance. A summary of the committee's key responsibilities is provided below:

- Monitor and critically assess bp's financial statements and financial information, including the integrity of the financial reporting and related processes, context in which statements are made, compliance with relevant legal and regulatory requirements and financial reporting standards, including the Task Force on Climate-related Financial Disclosures (TCFD).
- Assess the going concern assumption and the longer-term viability statement as to bp's ability to continue to operate and meet its liabilities.
- Review and challenge the application and appropriateness of significant accounting policies and financial reporting judgements.
- Evaluate the risk to quality and effectiveness of the financial reporting process and, where requested by the board, advise whether the annual report and accounts are fair, balanced and understandable.
- Review the affordability of distributions to shareholders.
- Oversee the appointment, remuneration, independence and performance of the external auditor and the integrity of the audit process as a whole, including the engagement of the external auditor to supply non-audit services to bp.
- Review the effectiveness of the internal audit function, bp's internal financial controls and its systems of internal control and risk management.
- Monitor the principal risks allocated to the committee by the board and review the mitigations proposed by management in respect of risks associated with bp internal financial controls and reporting responsibilities and such emerging risks that may fall within scope.
- Review the systems in place to enable those who work for bp to raise concerns about improprieties in financial reporting or other issues, and for those matters to be investigated.

The remuneration committee's full terms of reference are available on our website at bp.com/governance. A summary of the committee's key responsibilities is provided below:

- Recommend to the board the remuneration principles and policies for the executive directors and leadership team while considering remuneration and related policies for the employees below the board and leadership team.
- Set and approve the terms of engagement, remuneration, benefits and termination of employment for the executive directors, leadership team, chief internal auditor and the company secretary in accordance with the policy.
- Prepare the annual remuneration report to shareholders to outline policy implementation.
- Approve the principles of any equity plan that requires shareholder approval.
- Ensure termination terms and payments to executive directors and the leadership team are appropriate and fair.
- Receive and consider regular updates on workforce views and engagement initiatives related to remuneration, insights and data from pay ratios and potential pay gaps as appropriate.
- Maintain appropriate dialogue with shareholders on remuneration matters.

Shareholder approval of equity compensation plans

The NYSE rules for US companies require that shareholders must be given the opportunity to vote on all equity-compensation plans and material revisions to those plans. bp complies with UK requirements that are similar to the NYSE rules. The board, however, does not explicitly take into consideration the NYSE's detailed definition of what are considered 'material revisions'.

Code of ethics

The company has adopted a code of ethics for its chief executive officer, chief financial officer, SVP accounting, reporting and control and SVP internal audit whose roles are equivalent to the SEC roles as required by the provisions of Section 406 of the Sarbanes-Oxley Act of 2002 and the rules issued by the SEC. There have been no waivers from the code of ethics relating to any officers. A copy of the code of ethics can be found at bp.com/codeofethics.

The NYSE rules require that US companies adopt and disclose a code of business conduct and ethics for directors, officers and employees. bp has adopted a code of conduct, which applies to all employees, officers and members of the board. This was updated and published in January 2023. In addition, bp has adopted a code of ethics as described above for the chief executive officer, chief financial officer, SVP accounting, reporting and control and SVP internal audit as required by the SEC. bp considers that these codes and policies address the matters specified in the NYSE rules for US companies. During 2021, the board adopted a diversity policy, which requires it to encourage a diverse and inclusive working environment in the boardroom, where everyone is accepted, valued and receives fair treatment according to their different needs and situations without discrimination or prejudice. The policy was reviewed by the board in 2022, and amendments were made to reflect regulatory changes and market practice. The updated policy was then approved and published in February 2023.

Controls and procedures

Evaluation of disclosure controls and procedures

The company maintains 'disclosure controls and procedures', as such term is defined in Exchange Act Rule 13a-15(e), that are designed to ensure that information required to be disclosed in reports the company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms, and that such information is accumulated and communicated to management, including the company's group chief executive and chief financial officer, as appropriate, to allow timely decisions regarding required disclosure.

In designing and evaluating our disclosure controls and procedures, our management, including the group chief executive and chief financial officer, recognize that any controls and procedures, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the disclosure controls and procedures are met. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud within the company, if any, have been detected. Further, in the design and evaluation of our disclosure controls and procedures our management necessarily was required to apply its judgement in evaluating the costs and benefits of possible control and procedure design options. Also, we have investments in unconsolidated entities. As we do not control these entities, our disclosure controls and procedures with respect to such entities are necessarily substantially more limited than those we maintain with respect to our consolidated subsidiaries★. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. The company's disclosure controls and procedures have been designed to meet, and management believes that they meet, reasonable assurance standards.

The company's management, with the participation of the company's group chief executive and chief financial officer, has evaluated the effectiveness of the company's disclosure controls and procedures pursuant to Exchange Act Rule 13a-15(b) as of the end of the period covered by this annual report. Based on that evaluation, the group chief executive and chief financial officer have concluded that the company's disclosure controls and procedures were effective at a reasonable assurance level.

★ See glossary on **page 373**

Management's report on internal control over financial reporting

Management of bp is responsible for establishing and maintaining adequate internal control over financial reporting. bp's internal control over financial reporting is a process designed under the supervision of the principal executive and financial officers to provide reasonable assurance regarding the reliability of financial reporting and the preparation of bp's financial statements for external reporting purposes in accordance with IFRS.

As of the end of the 2023 fiscal year, management conducted an assessment of the effectiveness of internal control over financial reporting in accordance with the criteria in the UK Financial Reporting Council's Guidance on Risk Management, Internal Control and Related Financial and Business Reporting relating to internal control over financial reporting. Based on this assessment, management has determined that bp's internal control over financial reporting as of 31 December 2023 was effective.

Management's assessment of the effectiveness of internal control over financial reporting excluded TravelCenters of America Inc. (TCA), which was acquired on 15 May 2023. TCA's financial statements constitute 2.1% and 1.5% of net and total assets respectively, 2.8% of revenues, and 4% of net income of the consolidated financial statement amounts as of and for the year ended 31 December 2023. This exclusion is in accordance with the general guidance issued by the SEC that an assessment of a recent business combination may be omitted from management's report on internal control over financial reporting in the first year of consolidation.

The company's internal control over financial reporting includes policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets; provide reasonable assurances that transactions are recorded as necessary to permit preparation of financial statements in accordance with IFRS and that receipts and expenditures are being made only in accordance with authorizations of management and the directors of bp; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of bp's assets that could have a material effect on our financial statements. bp's internal control over financial reporting as of 31 December 2023 has been audited by Deloitte LLP, an independent registered public accounting firm, as stated in their report appearing on page 163 of *bp Annual Report and Form 20-F 2023*.

Changes in internal control over financial reporting

There were no changes in the group's internal control over financial reporting that occurred during the period covered by the Form 20-F that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

Cyber security

Governance

The board oversees bp's internal control and risk management framework. The board is supported by the safety and sustainability committee which oversees cyber security risk and received reports from bp's chief information security officer (CISO) on cyber security incidents at every committee meeting in 2023, including information on bp's response to incidents. This allows an ongoing assessment by the committee of the effectiveness of bp's overall cyber security programme. A session is held once a year to review bp's roadmap and progress for addressing cyber security risk. Read more in the safety and sustainability committee report on page 103.

At management level, assessment and management of material risks from cyber security threats is led by bp's executive vice president of innovation & engineering (I&E), a member of bp's leadership team with deep experience in bp's engineering and operations functions, with support from bp's CISO, who has over 20 years of experience in the information technology industry. bp's digital safety operational risk committee brings together additional senior members of bp's digital leadership team to assist in ensuring that cyber security risks across bp are identified, understood, accurately quantified and are managed in accordance with bp's internal controls framework.

Risk management and strategy

bp has implemented a threat-focused strategy to assess cyber security risks and protect against, detect, respond to, and recover from cyber attacks. bp maintains internal teams focused on cyber security intelligence and emergency response to monitor the external threat landscape and the threats to bp's IT and operational technology infrastructure. bp partners with third-party specialists to augment its in-house capabilities as necessary. bp has a defined protocol for cyber incident notification based on severity and bp's internal cyber security teams brief the CISO, I&E EVP, other senior leadership and relevant board and management committees about incidents on an as needed basis.

Cyber security risk management is integrated into bp's overall risk management process. bp's entities are required to identify, assess and report key risks, including cyber security risks, to relevant members of senior leadership. bp maintains additional procedures to manage cyber security risks related to third-party service providers, including conducting information security assessments for certain providers, providing relevant trainings for bp employees, and maintaining information security requirements for suppliers.

Our business strategy, results of operations and financial condition have not been materially affected by risks from cyber security threats, including as a result of previously identified cyber security incidents. For more information on our cyber security related risks, see Risk Factors (pages 77-79).

Principal accountant's fees and services

The audit committee has established policies and procedures for the engagement of the independent registered public accounting firm, Deloitte LLP, to render audit and certain assurance services. The policy provides for pre-approval by the audit committee of specifically defined audit, audit related, non-audit and other services that are not prohibited by regulatory or other professional requirements. Deloitte is engaged for these services when its expertise and experience of bp are important. Most of this work is of an audit nature. The committee regularly reviews the policy, including in 2022, when it was updated to remove restrictions on EY following bp's announcement on 27 February 2022 of its intention to exit its interests in Rosneft and capture additional detail for the processes applicable to separately listed bp entities.

Under the policy, pre-approval is given for specific services within the following categories: i) audit-related services, such as those required by law or where the auditor is best placed to undertake such work on similar terms, ii) non-audit services required by law, such as reporting required by a regulatory authority, and iii) other services, such as additional assurance or updates on applicable law and accounting standards. bp operates a two-tier system for audit and non-audit services. For audit-related services, the audit committee has a pre-approved aggregate level, within which specific work may be approved by management. Non-audit services are pre-approved for management to authorize per individual engagement, but above a defined level must be approved by the chair of the audit committee or the full committee. The audit committee has delegated to the chair of the audit committee authority to approve permitted services provided that any decisions are reported to the committee at its next scheduled meeting. Any proposed service not included in the approved service list must be approved in advance of commencing the engagement by the audit committee chair or the full audit committee depending on the level of fee payable.

The audit committee evaluates the performance of the auditor each year. The audit fees payable to Deloitte are reviewed by the committee in the context of other global companies for cost effectiveness. The committee keeps under review the scope and results of audit work and the independence and objectivity of the auditor. External regulation and bp policy requires the auditor to rotate its lead audit partner every five years. See Financial statements – Note 36 and Audit committee report on page 98 for details of fees for services provided by the auditor.

Additional Directors' report disclosures

This section of *bp Annual Report and Form 20-F 2023* forms part of the Directors' report. Certain information has been included in the Strategic report that would otherwise be required to be disclosed in the Directors' report, as noted below.

Indemnity provisions

In accordance with bp's Articles of Association, on appointment each director is granted an indemnity from the company in respect of liabilities incurred as a result of their office, to the extent permitted by law. These indemnities were in force throughout the financial year and at the date of this report. In respect of those liabilities for which directors may not be indemnified, the company maintained a directors' and officers' liability insurance policy throughout 2023. During the year, a review of the terms and scope of the policy was undertaken as part of the annual renewal. Although their defence costs may be met, neither the company's indemnity nor insurance provides cover in the event that the director is proved to have acted fraudulently or dishonestly. Certain subsidiaries★ are trustees of the group's pension schemes. Each director of these subsidiaries is granted an indemnity from the company in respect of liabilities incurred as a result of such a subsidiary's activities as a trustee of the pension scheme, to the extent permitted by law. These indemnities were in force throughout the financial year and at the date of this report.

Financial risk management objectives and policies

The disclosures in relation to financial risk management objectives and policies, including the policy for hedging, are included in How we manage risk on pages 73-76, Liquidity and capital resources on page 340 and Financial statements – Notes 29 and 30.

Exposure to price risk, credit risk, liquidity risk and cash flow risk

The disclosures in relation to exposure to price risk, credit risk, liquidity risk and cash flow risk are included in Financial statements – Notes 29 and 30.

Important events since the end of the financial year

Disclosures of the particulars of the important events affecting bp which have occurred since the end of the financial year are included in the Strategic report as well as in other places in the Directors' report.

Likely future developments in the business

An indication of the likely future developments in the business of the company is included in the Strategic report.

Research and development

Indications of our activities in the field of research and development are provided throughout the Strategic report and the Directors' report. See also pages 16 and 197 for our expenditure on research and development.

Branches

As a global group our interests and activities are held or operated through subsidiaries, branches, joint arrangements★ or associates★ established in – and subject to the laws and regulations of – many different jurisdictions.

Employees

Disclosures in respect of how the directors have engaged with employees and had regard to their interests are included in Stakeholder engagement on pages 92-93.

The disclosures concerning policies in relation to the employment of disabled persons and employee involvement are included in Sustainability – our people on pages 70-72.

Employee share schemes

Certain shares held as a result of participation in some employee share plans carry voting rights. Voting rights in respect of such shares are exercisable via a nominee. Dividend waivers are in place in respect of unallocated shares held in employee share plan trusts.

Suppliers, customers and others

Disclosures in respect of how the directors have engaged with suppliers, customers and others in business relationships with the company are included in Stakeholder engagement on pages 92-93.

Change of control provisions

On 5 October 2015, the United States lodged with the district court in MDL 2179 a proposed Consent Decree between the United States, the Gulf states, BP Exploration & Production Inc., BP Corporation North America Inc. and BP p.l.c., to fully and finally resolve any and all natural resource damages claims of the United States, the Gulf states and their respective natural resource trustees and all Clean Water Act penalty claims, and certain other claims of the United States and the Gulf states. Concurrently, bp entered into a definitive Settlement Agreement with the five Gulf states (Settlement Agreement) with respect to state claims for economic, property and other losses. On 4 April 2016, the district court approved the Consent Decree, at which time the Consent Decree and Settlement Agreement became effective. The federal government and the Gulf states may jointly elect to accelerate the payments under the Consent Decree in the event of a change of control or insolvency of BP p.l.c., and the Gulf states individually have similar acceleration rights under the Settlement Agreement. For further details of the Consent Decree and the Settlement Agreement, see Legal proceedings in *BP Annual Report and Form 20-F 2015.*

Political donations, expenditure and contributions

Disclosures in relation to political donations, expenditure and contributions are included on page 72.

Greenhouse gas emissions, energy consumption and energy efficiency

Disclosures in relation to greenhouse gas emissions, energy consumption and energy efficiency are included in Sustainability on pages 51-52.

Disclosures required under Listing Rule 9.8.4R

The information required to be disclosed by Listing Rule 9.8.4R can be located as set out below:

Information required	Page
(1) Amount of interest capitalized	197
(2) – (4)	Not applicable
(5), (6) Waiver of director emoluments	128
(7) – (11)	Not applicable
(12), (13) Dividend waivers	361
(14)	Not applicable

Cautionary statement

In order to utilize the 'safe harbor' provisions of the United States Private Securities Litigation Reform Act of 1995 (the 'PSLRA') and the general doctrine of cautionary statements, bp is providing the following cautionary statement.

This document contains certain forecasts, projections and forward-looking statements - that is, statements related to future, not past, events and circumstances - with respect to the financial condition, results of operations and businesses of bp and certain of the plans and objectives of bp with respect to these items. These statements may generally, but not always, be identified by the use of words such as 'will', 'expects', 'is expected to', 'aims', 'should', 'may', 'objective', 'is likely to', 'intends', 'believes', 'anticipates', 'plans', 'we see' or similar expressions. In particular, among other statements, (i) certain statements in the Chair's letter (pages 4-5), Chief executive officer's letter (pages 6-7),the Strategic report (inside cover and pages 1-80), Additional disclosures (pages 335-362) and Shareholder information (pages 363-372), including but not limited to statements under the headings 'Energy Outlook', 'Our strategy in action', 'Consistency with the Paris goals' 'Our business model', 'Progress against our strategy', 'Our financial frame', '2024 guidance' and 'Our investment process' and including but not limited to statements regarding: plans and expectations relating to business, financial performance, results of operations, cash flow, capital expenditure, allocation of capital expenditure and bp's ability to maintain a robust cash position; plans and expectations regarding bp's financial frame, working capital, operating cash flow (and its ability to cover capital expenditure and shareholder distributions including the dividend and share buybacks), return on average capital employed, liquidity, capital discipline, credit rating, future shareholder distributions, amount or timing of payments related to divestment and other proceeds, net debt, future dividend payments and share buybacks; plans and expectations relating to bp's investment process and capital investment, including future capital investment allocation, expected IRR, access to capital and the restructuring of certain investments; plans and expectations relating to bp's intra-group funding and liquidity arrangements; plans and expectations relating to bp's ability to meet contractual obligations; expectations regarding inflation, oil and gas prices, price volatility, refining margins and price assumptions; plans and expectations relating to risk, including risk management processes and climate-related risks; plans and expectations regarding bp's transition growth engines, including plans to increase capital investment in these growth engines; plans and expectations regarding bp's oil and gas business, including related investment plans, oil and gas production targets, and divestment plans; plans and expectations regarding underlying replacement cost profit before interest, tax, depreciation and amortization, ROACE, adjusted EBITDA and adjusted EBIDA per share; plans, expectations and projections regarding bp's oil and gas resources and reserves; plans and expectations regarding bp's convenience and mobility business, including earnings, the development of EV charging, and the impact of the acquisition of TravelCenters of America; bp's aims related to sustainable aviation fuel; bp's plans and expectations regarding renewable power, including aims to expand renewable gas, wind and solar capacity, aims to develop hydrogen production and export, green and blue hydrogen, e-fuels, EV charging and power trading and expectations related to bp's wind and solar projects; bp's 2025 targets and 2030 aims relating to resilient hydrocarbons (including upstream unit production costs, upstream production, bp-operated upstream plant reliability, bp-operated refining availability, biofuels production, biogas supply volumes and LNG portfolio), convenience and mobility (including customer touchpoints per day, strategic convenience sites and electric vehicle charge points) and low carbon energy (including net hydrogen production, developed renewables to final investment decision and net installed renewables capacity); plans and expectations in relation to announced acquisitions and divestments including the outcome of any applicable third party approvals and timing of completion; bp's plans and expectations related to the energy transition (including its scenario analysis), climate change, sustainability, greenhouse gas emissions, water use and the replenishment of fresh water, bp's resilience across different climate scenarios, and bp's decarbonization and net zero aims and targets, its targets related to methane and carbon intensity of bp's products and the transition to a lower carbon economy and energy system; expectations relating to the effects of the Russia-Ukraine war including plans and expectations regarding impacts on bp; expectations regarding future legislative or regulatory action and its impact on bp, including regulatory action related to climate change and inflation and bp's plans regarding compliance with such actions; plans and expectations regarding bp's leadership team, board composition and workforce, including targets related to workforce recruitment, incentives and diversity; expectations regarding the costs of environmental restoration, remediation and abatement programmes; expectations regarding the future value of assets; plans and expectations regarding projects, joint ventures, partnerships, agreements and memoranda of understanding with governments, commercial entities and other third party partners; expectations regarding contingent liabilities, legal and trial proceedings, court decisions, potential investigations and civil actions by regulators, government entities and/or other entities or parties, and the timing and potential impact of such proceedings, settlement agreements relating to such proceedings and bp's intentions in respect thereof; plans and expectations regarding relationships with governments, customers, partners, suppliers, communities and key stakeholders; expectations regarding upstream production, total capital expenditure, depreciation, depletion and amortization, divestments and other proceeds, Gulf of Mexico oil spill payments, other businesses & corporate underlying annual charge, and the effective tax rate and the underlying effective tax rate; expectations that the majority of bp's existing upstream oil and gas properties will start decommissioning within the next two decades; expectations regarding fulfillment of existing delivery commitments for oil and gas; plans and expectations relating to major project start-ups; plans and expectations relating to launchpad; plans and expectations regarding bp ventures and its investments; plans and expectations relating to bp's refineries, including Solomon refining availability and net cash margins; plans and expectations relating to bp's research and development spend; plans and expectations regarding operations and safety; and (ii) certain statements in Corporate governance (pages 81-104) and the Directors' remuneration report (pages 105-132) and 'Other disclosures' (page 133) with regard to: the anticipated future composition of the board of directors and the effects thereof; the board's goals and areas of focus; plans and expectations regarding the expected impact of the mergers and acquisitions pipeline and capital expenditures (including the impact of bp's entry in the German offshore wind market); plans and expectations relating to the induction and training of new directors; plans and expectations regarding the diversity of the board and senior management; plans and expectations regarding directors' and senior management's share ownership and remuneration; plans regarding the governance and remuneration processes, including base pay and base salary increases and adjustments, performance share plan, various policies, updates to certain targets, measures and metrics relevant to remuneration and determination of bonuses and share plans, pension allowances and contributions, the vesting of shares under employee share plans, benefits and bonuses; plans relating to the societies in which bp operates and to maintain a strong reputation globally; and goals, activities and areas of focus of board committees, are all forward-looking in nature; plans and expectations regarding auditor reappointment and independence.

By their nature, forward-looking statements involve risk and uncertainty because they relate to events and depend on circumstances that will or may occur in the future and are outside the control of bp.

Actual results or outcomes, including the fair value of bp's Rosneft shareholding, may differ materially from those expressed in such statements, depending on a variety of factors, including: the extent and duration of the impact of current market conditions including the volatility of oil prices, the effects of bp's intention to exit its shareholding in Rosneft, overall global economic and business conditions impacting bp's business and demand for bp's products as well as the specific factors identified in the discussions accompanying such forward-looking statements; changes in consumer preferences and societal expectations; the pace of development and adoption of alternative energy solutions; developments in policy, law, regulation, technology and markets, including societal and investor sentiment related to the issue of climate change; the receipt of relevant third party and/or regulatory approvals; the timing and level of maintenance and/or turnaround activity; the timing and volume of refinery additions and outages; the timing of bringing new fields onstream; the timing, quantum and nature of certain acquisitions and divestments; future levels of industry product supply, demand and pricing, including supply growth in North America and continued base oil and additive supply shortages; OPEC+ quota restrictions; PSA and TSC effects; operational and safety problems; potential lapses in product quality; economic and financial market conditions generally or in various countries and regions; political stability and economic growth in relevant areas of the world; changes in laws and governmental regulations and policies, including related to climate change; changes in social attitudes and customer preferences; regulatory or legal actions including the types of enforcement action pursued and the nature of remedies sought or imposed; the actions of prosecutors, regulatory authorities and courts; delays in the processes for resolving claims; amounts ultimately payable and timing of payments relating to the Gulf of Mexico oil spill; exchange rate fluctuations; development and use of new technology; recruitment and retention of a skilled workforce; the success or otherwise of partnering; the actions of competitors, trading partners, contractors, subcontractors, creditors, rating agencies and others; bp's access to future credit resources; business disruption and crisis management; the impact on bp's reputation of ethical misconduct and non-compliance with regulatory obligations; trading losses; major uninsured losses; the possibility that international sanctions or other steps taken by competent authorities or any other relevant persons may impact bp's ability to sell its interests in Rosneft, or the price for which it could sell such interests; the actions of contractors; natural disasters and adverse weather conditions; changes in public expectations and other changes to business conditions; wars and acts of terrorism; cyber-attacks or sabotage; and other factors discussed elsewhere in this report including under Risk factors (pages 77-79). In addition to factors set forth elsewhere in this report, those set out above are important factors, although not exhaustive, that may cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements.

Statements regarding competitive position

Statements referring to bp's competitive position are based on the company's belief and, in some cases, rely on a range of sources, including investment analysts' reports, independent market studies and bp's internal assessments of the relevant market based on publicly available information about the financial results and performance of market participants.

Shareholder information

Share prices and listings

Markets and market prices

The primary market for the company's ordinary shares (trading symbol 'BP'), 8% cumulative first preference shares (trading symbol 'BP.A') and 9% cumulative second preference shares (trading symbol 'BP.B') is the London Stock Exchange (LSE). The company's ordinary shares are a constituent element of the Financial Times Stock Exchange 100 Index.

In the US, the company's securities are listed and traded on the New York Stock Exchange (NYSE) in the form of ADSs (trading symbol 'BP'), for which JPMorgan Chase Bank, N.A. is the depositary (the Depositary) and transfer agent. The Depositary's principal office is 383 Madison Avenue, Floor 11, New York, NY, 10179, US. Each ADS represents six ordinary shares. ADSs are evidenced by American depositary receipts (ADRs), which may be issued in either certificated or book entry form.

The company's ordinary shares are also traded in the form of a global depositary certificate representing the company's ordinary shares on the Frankfurt, Hamburg and Düsseldorf Stock Exchanges.

On 16 February 2024, 731,514,905 ADSs (equivalent to approximately 4,389,089,430 ordinary shares or some 25.79% of the total issued share capital, excluding shares held in treasury) were outstanding and were held by approximately 62,639 ADS holders. Of these, about 61,911 had registered addresses in the US at that date. One of the registered holders of ADSs represents approximately 1,369,679 underlying holders.

On 16 February 2024, there were approximately 200,279 ordinary shareholders. Of these shareholders, around 1,499 had registered addresses in the US and held a total of some 3,870,988 ordinary shares. On 16 February 2024, there were approximately 1,103 preference shareholders. Of these shareholders, around 14 had registered addresses in the US and held a total of some 2,773 preference shares.

Since a number of the ordinary shares and ADSs were held by brokers and other nominees, the number of holders in the US may not be representative of the number of beneficial holders or their respective country of residence.

Dividends

The company's current policy is to pay interim dividends on a quarterly basis on its ordinary shares.

Our policy is also to announce dividends for ordinary shares in US dollars and state an equivalent sterling dividend. Dividends on the company's ordinary shares will be paid in sterling and on the company's ADSs in US dollars. The rate of exchange used to determine the sterling amount equivalent is the average of the market exchange rates in London over the three business days prior to the sterling equivalent announcement date. The directors may choose to declare dividends in any currency provided that a sterling equivalent is announced. It is not the company's intention to change its current policy of announcing dividends on ordinary shares in US dollars.

Information regarding dividends announced and paid by the company on ordinary shares and preference shares is provided in the consolidated Financial statements – Note 10.

A Scrip Dividend Programme (Scrip Programme) was approved by shareholders in 2010 and was renewed for a further three years at the 2021 AGM. It enabled the company's ordinary shareholders and ADS holders to elect to receive dividends by way of new fully paid ordinary shares (or ADSs in the case of ADS holders) instead of cash. The operation of the Scrip Programme is always subject to the directors' decision to make the Scrip Programme offer available in respect of any particular dividend.

The company announced on 29 October 2019 and as part of all subsequent quarterly results announcements made since, that the board had suspended the Scrip Programme in respect of those quarterly dividends. The company does not expect to offer a scrip election for the foreseeable future. Ordinary shareholders and ADS holders (subject to certain exceptions) may be able to participate in dividend reinvestment plans. Any decisions with respect to future dividends will be made by the board of BP p.l.c. following the end of each quarter.

Future dividends will be dependent on future earnings, the financial condition of the group, the Risk factors set out on page 77 and other matters that may affect the business of the group set out in Our strategy on page 12 and in Liquidity and capital resources on page 340.

The quarterly dividend which is expected to be paid on 28 March 2024 in respect of the fourth quarter 2023 is 7.270 cents per ordinary share ($0.43620 per American Depositary Share (ADS)). The corresponding amount in sterling will be announced on 12 March 2024.

The following table shows dividends announced and paid by the company per ADS for the past five years.

Dividends per ADS[a]		March	June	September	December	Total
2019	UK pence	46.43	48.39	50.09	46.95	191.86
	US cents	61.50	61.50	61.50	61.50	246.00
2020	UK pence	48.94	50.05	24.26	23.50	146.75
	US cents	63.00	63.00	31.50	31.50	189.00
2021	UK pence	22.61	22.27	23.72	24.63	92.23
	US cents	31.50	31.50	32.76	32.76	128.52
2022	UK pence	24.96	26.13	31.01	29.64	111.74
	US cents	32.76	32.76	36.04	36.04	137.60
2023	**UK pence**	**33.30**	**31.85**	**34.39**	**34.42**	**133.97**
	US cents	**39.66**	**39.66**	**43.62**	**43.62**	**166.56**

a Dividends announced and paid by the company on ordinary and preference shares are provided in the consolidated Financial statements – Note 10.

There are no UK foreign exchange controls or other restrictions on the import or export of capital by, or on the payment of dividends to, non-resident holders of BP p.l.c. shares, or that materially affect the conduct of BP p.l.c's operations, other than restrictions applicable to certain countries and persons subject to UN, US, UK, or EU economic sanctions, to the extent these restrictions can be complied with in law.

Shareholder taxation information

This section describes the material US federal income tax and UK taxation consequences of owning ordinary shares or ADSs to a US holder who holds the ordinary shares or ADSs as capital assets for tax purposes. This section does not discuss tax consequences arising under the Medicare contribution tax on net investment income or the alternative minimum tax. It also does not apply inter alia to members of special classes of holders some of which may be subject to other rules, including: tax-exempt entities, life insurance companies, dealers in securities, traders in securities that elect a mark-to-market method of accounting for securities holdings, holders that, actually or constructively, hold 10% or more of the company's shares (as measured by voting power or value), holders that hold the shares or ADSs as part of a straddle or a hedging or conversion transaction, holders that purchase or sell the shares or ADSs as part of a wash sale for US federal income tax purposes, or holders whose functional currency is not the US dollar. In addition, if a partnership holds the shares or ADSs, the US federal income tax treatment of a partner will generally depend on the status of the partner and the tax treatment of the partnership and may not be described fully below.

A US holder is any beneficial owner of ordinary shares or ADSs that is for US federal income tax purposes (1) a citizen or resident of the US, (2) a US domestic corporation, (3) an estate whose income is subject to US federal income taxation regardless of its source, or (4) a trust if a US court can exercise primary supervision over the trust's administration and one or more US persons are authorized to control all substantial decisions of the trust.

This section is based on the tax laws of the United States, including the Internal Revenue Code of 1986, as amended, its legislative history, existing and proposed US Treasury regulations thereunder, published rulings and court decisions, and the taxation laws of the UK, all as currently in effect, as well as the income tax convention between the US and the UK that entered into force on 31 March 2003 (the Treaty). These laws are subject to change, possibly on a retroactive basis. This section further assumes that each obligation under the terms of the deposit agreement relating to bp ADSs and any related agreement will be performed in accordance with its terms.

For purposes of the Treaty and the estate and gift tax convention (the Estate Tax Convention) and for US federal income tax and UK taxation purposes, a holder of ADRs evidencing ADSs will be treated as the owner of the company's ordinary shares represented by those ADRs. Exchanges of ordinary shares for ADRs and ADRs for ordinary shares generally will not be subject to US federal income tax or to UK taxation other than stamp duty or stamp duty reserve tax, as described below.

Investors should consult their own tax advisor regarding the US federal, state and local, UK and other tax consequences of owning and disposing of ordinary shares and ADSs in their particular circumstances, and in particular whether they are eligible for the benefits of the Treaty in respect of their investment in the shares or ADSs.

Taxation of dividends

UK taxation

Under current UK taxation law, no withholding tax will be deducted from dividends paid by the company, including dividends paid to US holders. A shareholder that is a company resident for tax purposes in the UK or trading in the UK through a permanent establishment generally will not be taxable in the UK on a dividend it receives from the company. A shareholder who is an individual resident for tax purposes in the UK is subject to UK tax on dividends received from the company, including dividends received under the dividend reinvestment plan (DRIP) for ordinary shareholders, that are in excess of the annual dividend allowance.

For 2023/24 the dividend allowance is £1,000 which means there is no UK tax due on the first £1,000 of dividends received. Dividends above this level are subject to tax at 8.75% for basic tax payers, 33.75% for higher rate tax payers and 39.35% for additional rate tax payers.

Although the first £1,000 of dividend income is not subject to UK income tax, it does not reduce the total income for tax purposes. Dividends within the dividend allowance still count towards basic or higher rate bands, and may therefore affect the rate of tax paid on dividends received in excess of the £1,000 allowance. For instance, if an individual has an annual gross salary of £50,000 and also receives a dividend of £12,000 they will be subject to the following scenario. The individual's personal allowance and the basic rate tax band will be used up by the gross salary. The remaining part of the salary and the whole of the dividend will be subject to tax at the higher rate, although the dividend allowance will reduce the amount of dividend subject to tax. The dividend of £12,000 will be reduced by the dividend allowance of £1,000 leaving taxable dividend income of £11,000. The dividend will be taxed at 33.75% so that the total tax payable on the dividends is £3,712.

How the shareholder pays the tax arising on the dividend income depends on the amount of dividend income and salary they receive in the tax year. If less than £1,000 they will not need to report anything or pay any tax. If between £1,000 and £10,000, the shareholder can pay what they owe by: contacting the HMRC helpline; asking HMRC to change their tax code – the tax will be taken from their wages or pension or through completion of the 'Dividends' section of their self-assessment tax return, where one is already being filed. If over £10,000 they will be required to file a self-assessment tax return and should complete the 'Dividends' section with details of the amounts received.

US federal income taxation

A US holder is subject to US federal income taxation on the gross amount of any dividend paid by the company (including dividends paid but reinvested under the Global Invest Direct (GID) Dividend Reinvestment Plan for ADS holders) out of its current or accumulated earnings and profits (as determined for US federal income tax purposes). Dividends paid to a non-corporate US holder that constitute qualified dividend income will be taxable to the holder at a preferential rate, provided that the holder has a holding period in the ordinary shares or ADSs of more than 60 days during the 121-day period beginning 60 days before the ex-dividend date and meets other holding period requirements. Dividends paid by the company with respect to the ordinary shares or ADSs will generally be qualified dividend income.

For US federal income tax purposes, a dividend must be included in income when the US holder, in the case of ordinary shares, or the Depositary, in the case of ADSs, actually or constructively receives the dividend and will not be eligible for the dividends-received deduction generally allowed to US corporations in respect of dividends received from other US corporations.

US ADS holders should consult their own tax advisor regarding the US tax treatment of the dividend fee in respect of dividends. Dividends will generally be income from sources outside the US and generally will be 'passive category income' for purposes of computing a US holder's foreign tax credit limitation.

As noted above in UK taxation, a US holder will not be subject to UK withholding tax. Accordingly, the receipt of a dividend will not entitle the US holder to a foreign tax credit.

The amount of the dividend distribution on the ordinary shares that is paid in pounds sterling will be the US dollar value of the pounds sterling payments made, determined at the spot pounds sterling/US dollar rate on the date the dividend is distributed, regardless of whether the payment is, in fact, converted into US dollars. Generally, any gain or loss resulting from currency exchange fluctuations during the period from the date the pounds sterling dividend payment is distributed to the date the payment is converted into US dollars will be treated as ordinary income or loss and will not be eligible for the preferential tax rate on qualified dividend income. The gain or loss generally will be income or loss from sources within the US for foreign tax credit limitation purposes.

Distributions in excess of the company's earnings and profits, as determined for US federal income tax purposes, will be treated as a return of capital to the extent of the US holder's basis in the ordinary shares or ADSs and thereafter as capital gain, subject to taxation as described in 'Taxation of capital gains – US federal income taxation' section below.

In addition, the taxation of dividends may be subject to the rules for passive foreign investment companies (PFIC), described below under 'Taxation of capital gains – US federal income taxation'. Distributions made by a PFIC do not constitute qualified dividend income and are not eligible for the preferential tax rate applicable to such income.

Taxation of capital gains

UK taxation

A US holder may be liable for both UK and US tax in respect of a gain on the disposal of ordinary shares or ADSs if the US holder is (1) resident for tax purposes in the UK at the date of disposal, (2) if he or she has left the UK for a period not exceeding five complete tax years between the year of departure from and the year of return to the UK and acquired the shares before leaving the UK and was resident in the UK in the previous four out of seven tax years before the year of departure, (3) a US domestic corporation resident in the UK by reason of its business being managed or controlled in the UK or (4) a citizen of the US that carries on a trade or profession or vocation in the UK through a branch or agency or a corporation that carries on a trade, profession or vocation in the UK, through a permanent establishment, and that has used, held, or acquired the ordinary shares or ADSs for the purposes of such trade, profession or vocation of such branch, agency or permanent establishment. However, such persons may be entitled to a tax credit against their US federal income tax liability for the amount of UK capital gains tax or UK corporation tax on chargeable gains (as the case may be) that is paid in respect of such gain.

Under the Treaty, capital gains on dispositions of ordinary shares or ADSs generally will be subject to tax only in the jurisdiction of residence of the relevant holder as determined under both the laws of the UK and the US and as required by the terms of the Treaty.

Under the Treaty, individuals who are residents of either the UK or the US and who have been residents of the other jurisdiction (the US or the UK, as the case may be) at any time during the six years immediately preceding the relevant disposal of ordinary shares or ADSs may be subject to tax with respect to capital gains arising from a disposition of ordinary shares or ADSs of the company not only in the jurisdiction of which the holder is resident at the time of the disposition but also in the other jurisdiction.

For gains on or after 23 June 2010, the UK Capital Gains Tax rate will be dependent on the level of an individual's taxable income. Where total taxable income and gains after all allowable deductions are less than the upper limit of the basic rate income tax band of £37,700 (for 2023/24), the rate of Capital Gains Tax will be 10%. For gains (and any parts of gains) above that limit the rate will be 20%.

From 6 April 2008, entitlement to the annual exemption is based on an individual's circumstances (taking into account domicile status, remittance basis of taxation and number of years in the UK). For individuals who are entitled to the exemption for 2023/24, this has been set at £6,000. Corporation tax on chargeable gains is levied at 25% for companies from 1 April 2023.

US federal income taxation

A US holder who sells or otherwise disposes of ordinary shares or ADSs will recognize a capital gain or loss for US federal income tax purposes equal to the difference between the US dollar value of the amount realized on the disposition and the US holder's tax basis, determined in US dollars, in the ordinary shares or ADSs. Any such capital gain or loss generally will be long-term gain or loss, subject to tax at a preferential rate for a non-corporate US holder, if the US holder's holding period for such ordinary shares or ADSs exceeds one year. The tax basis of shares acquired through reinvested dividends under the GID Dividend Reinvestment Plan for ADS holders is equal to the fair market value of the stock on the investment date. The holding period for shares acquired under the plan begins the day after the applicable investment date.

Gain or loss from the sale or other disposition of ordinary shares or ADSs will generally be income or loss from sources within the US for foreign tax credit limitation purposes. The deductibility of capital losses is subject to limitations.

We do not believe that ordinary shares or ADSs will be treated as stock of a passive foreign investment company (PFIC) for US federal income tax purposes, but this conclusion is a factual determination that is made annually and thus is subject to change. If we are treated as a PFIC, unless a US holder elects to be taxed annually on a mark-to-market basis with respect to ordinary shares or ADSs, any gain realized on the sale or other disposition of ordinary shares or ADSs would in general not be treated as capital gain. Instead, a US holder would be treated as if he or she had realized such gain rateably over the holding period for ordinary shares or ADSs and would be taxed at the highest tax rate in effect for each such year to which the gain was allocated, in addition to which an interest charge in respect of the tax attributable to each such year would apply. Certain 'excess distributions' would be similarly treated if we were treated as a PFIC.

Additional tax considerations

Scrip Programme

Until the publication of the 2019 third quarter results, the company had an optional Scrip Programme, wherein holders of bp ordinary shares or ADSs could elect to receive any dividends in the form of new fully paid ordinary shares or ADSs of the company instead of cash. Please consult your tax advisor for the consequences to you.

UK inheritance tax

The Estate Tax Convention applies to inheritance tax. ADSs held by an individual who is domiciled for the purposes of the Estate Tax Convention in the US and is not for the purposes of the Estate Tax Convention a national of the UK will not be subject to UK inheritance tax on the individual's death or on transfer during the individual's lifetime unless, among other things, the ADSs are part of the business property of a permanent establishment situated in the UK used for the performance of independent personal services. In the exceptional case where ADSs are subject to both inheritance tax and US federal gift or estate tax, the Estate Tax Convention generally provides for tax payable in the US to be credited against tax payable in the UK or for tax paid in the UK to be credited against tax payable in the US, based on priority rules set forth in the Estate Tax Convention.

UK stamp duty and stamp duty reserve tax

The statements below relate to what is understood to be the current practice of HM Revenue & Customs in the UK under existing law.

Provided that any instrument of transfer is not executed in the UK and remains at all times outside the UK and the transfer does not relate to any matter or thing done or to be done in the UK, no UK stamp duty is payable on the acquisition or transfer of ADSs. Neither will an agreement to transfer ADSs in the form of ADRs give rise to a liability to stamp duty reserve tax.

Purchases of ordinary shares, as opposed to ADSs, through the CREST system of paperless share transfers will be subject to stamp duty reserve tax at 0.5%. The charge will arise as soon as there is an agreement for the transfer of the shares (or, in the case of a conditional agreement, when the condition is fulfilled). The stamp duty reserve tax will apply to agreements to transfer ordinary shares even if the agreement is made outside the UK between two non-residents. Purchases of ordinary shares outside the CREST system are subject either to stamp duty at a rate of £5 per £1,000 (or part, unless the stamp duty is less than £5, when no stamp duty is charged), or stamp duty reserve tax at 0.5%. Stamp duty and stamp duty reserve tax are generally the liability of the purchaser.

A subsequent transfer of ordinary shares to the Depositary's nominee will give rise to further stamp duty at the rate of £1.50 per £100 (or part) or stamp duty reserve tax at the rate of 1.5% of the value of the ordinary shares at the time of the transfer. For ADR holders electing to receive ADSs instead of cash, after the 2012 first quarter dividend payment, HM Revenue & Customs no longer seeks to impose 1.5% stamp duty reserve tax on issues of UK shares and securities to non-EU clearance services and depositary receipt systems.

Major shareholders

The disclosure of certain major and significant shareholdings in the share capital of the company is governed by the Companies Act 2006, the UK Financial Conduct Authority's Disclosure Guidance and Transparency Rules (DTR) and the US Securities Exchange Act of 1934.

Register of members holding bp ordinary shares as at 31 December 2023

Range of holdings	Number of ordinary shareholders	Percentage of total ordinary shareholders	Percentage of total ordinary share capital excluding shares held in treasury
1-200	51,421	25.55	0.01
201-1,000	65,819	32.70	0.21
1,001-10,000	73,508	36.52	1.35
10,001-100,000	9,162	4.55	1.12
100,001-1,000,000	767	0.38	1.61
Over 1,000,000[a]	598	0.30	95.70
Totals	201,275	100.00	100.00

a Includes JPMorgan Chase Bank, N.A. holding 25.93% of the total ordinary issued share capital (excluding shares held in treasury) as the approved depositary for ADSs, a breakdown of which is shown in the table below.

Register of holders of American depositary shares (ADSs) as at 31 December 2023[a]

Range of holdings	Number of ADS holders	Percentage of total ADS holders	Percentage of total ADSs
1-200	38,097	59.62	0.27
201-1,000	16,827	26.34	1.07
1,001-10,000	8,640	13.52	2.95
10,001-100,000	324	0.51	0.71
100,001-1,000,000	5	0.01	0.11
Over 1,000,000[b]	2	0.00	94.88
Totals	63,895	100.00	100.00

a One ADS represents six 25 cent ordinary shares.
b One holder of ADSs represents 1,355,412 approx. underlying shareholders.

As at 31 December 2023 there were also 1,106 preference shareholders. Preference shareholders represented 0.49% and ordinary shareholders represented 99.51% of the total issued nominal share capital of the company (excluding shares held in treasury) as at that date.

As at 16 February 2024, the total preference shares in issue comprised only 0.50% of the company's total issued nominal share capital (excluding shares held in treasury), the rest being ordinary shares.

Substantial shareholders

The following table shows holdings of 3% or more voting rights in ordinary shares of 25 cents in BP p.l.c. as per the most recent notification of each respective holder to bp under DTR 5. The percentage of voting rights detailed below was calculated as at the date of the relevant disclosures.

	As at 31 December 2023		As at 16 February 2024	
	Number of voting rights	Percentage of capital	Number of voting rights	Percentage of capital
BlackRock, Inc.	1,504,412,502	7.37	1,504,412,502	7.37
Norges Bank	545,382,375	3.02	545,382,375	3.02

There are no current disclosable interests in holdings of 3% or more voting rights in 8% cumulative first preference shares of £1 each and 9% cumulative second preference shares of £1 each.

Largest registered shareholders

Under the US Securities Exchange Act of 1934 bp is aware of the following interests as at 16 February 2024.

Ordinary shares of $0.25 in BP p.l.c.:

Holder	Holding of ordinary shares	Percentage of ordinary share capital excluding shares held in treasury
JPMorgan Chase Bank N.A., depositary for ADSs, through its nominee Guaranty Nominees Limited	4,389,089,431	25.79
BlackRock, Inc.	1,584,721,078	9.31
The Vanguard Group, Inc	777,280,749	4.57
Norges Bank	584,175,750	3.43

8% cumulative first preference shares of £1 each in BP p.l.c.:

Holder	Holding of 8% cumulative first preference shares	Percentage of class
Hargreaves Lansdown Asset Management Limited	1,378,892	19.06
Interactive Investor Share Dealing Services	1,009,513	13.96
Barclays, Plc.	658,957	9.11
Halifax Share Dealing Services	547,821	7.57
Canaccord Genuity Group Inc.	544,494	7.53
AJ Bell Securities, Ltd.	492,668	6.81

9% cumulative second preference shares of £1 each in BP p.l.c.:

Holder	Holding of 9% cumulative second preference shares	Percentage of class
Hargreaves Lansdown Asset Management Limited	884,655	16.16
Redmayne-Bentley LLP	564,500	10.31
Interactive Investor Share Dealing Services	498,946	9.12
AJ Bell Securities, Ltd.	460,885	8.42
Canaccord Genuity Group Inc.	351,605	6.42
Safra Group	347,500	6.35
Halifax Share Dealing Services	292,161	5.34

The company's major shareholders' voting rights may differ to their total interest and can be found under the substantial shareholders heading above where voting rights are over 3%.

Annual general meeting (AGM)

The 2024 AGM is scheduled to be held on Thursday 25 April 2024 at 11:00am BST. A separate notice convening the meeting is distributed to shareholders, which includes an explanation of the items of business to be considered at the meeting.

All resolutions for which notice has been given will be decided on a poll. Deloitte LLP have expressed their willingness to continue in office as auditors and a resolution for their reappointment is included in the *Notice of bp Annual General Meeting 2024*.

Memorandum and Articles of Association

The following summarizes certain provisions of the company's Memorandum and Articles of Association and applicable English law. This summary is qualified in its entirety by reference to the UK Companies Act 2006 (the Act) and the company's Memorandum and Articles of Association. The Memorandum and Articles of Association are available online at bp.com/usefuldocs.

The company's Articles of Association may be amended by a special resolution at a general meeting of the shareholders. At the AGM held on 21 May 2018 shareholders voted to adopt new Articles of Association to reflect developments in market practice and to provide clarification and additional flexibility where necessary or appropriate.

Objects and purposes

BP p.l.c. is a public company limited by shares and registered in England and Wales with the registered number 102498. The provisions regulating the operations of the company, known as its 'objects', were historically stated in a company's memorandum. The Act abolished the need to have object provisions and so at the AGM held on 15 April 2010 shareholders approved the removal of its objects clause together with all other provisions of its Memorandum that, by virtue of the Act, are treated as forming part of the company's Articles of Association.

Directors and secretary

The business and affairs of the company shall be managed by the directors. The company's Articles of Association provide that any person may be appointed by the existing directors or by the shareholders in a general meeting either as a replacement for another director or as an additional director. Any person appointed by the directors will hold office only until the next general meeting, notice of which is first given after their appointment and will then be eligible for re-election by the shareholders. A director may be removed by the company as provided for by applicable law and shall vacate office in certain circumstances as set out in the Articles of Association. In addition, the company may, by special resolution, remove a director before the expiration of his/her period of office and, subject to the Articles of Association, may by ordinary resolution appoint another person to be a director instead. There is no requirement for a director to retire on reaching any age.

The Articles of Association place a general prohibition on a director voting in respect of any contract or arrangement in which the director has a material interest other than by virtue of such director's interest in shares in the company. However, in the absence of some other material interest not indicated below, a director is entitled to vote and to be counted in a quorum for the purpose of any vote relating to a resolution concerning the following matters:

- The giving of security or indemnity with respect to any money lent or obligation taken by the director at the request or benefit of the company or any of its subsidiary undertakings.
- The giving of security or indemnity to a third party with respect to any debt or obligation of the company or any of its subsidiary undertakings for which the director has assumed responsibility.
- Any proposal in which the director is interested, concerning the underwriting of company securities or debentures or the giving of any security to a third party for a debt or obligation of the company or any of its subsidiary undertakings.
- Any proposal concerning any other company in which the director is interested, directly or indirectly (whether as an officer or shareholder or otherwise) provided that the director and persons connected with such director are not the holder or holders of 1% or more of the voting interest in the shares of such company.
- Any proposal concerning the purchase or maintenance of any insurance policy under which the director may benefit.
- Any proposal concerning the giving to the director of any other indemnity which is on substantially the same terms as indemnities given or to be given to all of the other directors or to the funding by the company of his expenditure on defending proceedings or the doing by the company of anything to enable the director to avoid incurring such expenditure where all other directors have been given or are to be given substantially the same arrangements.
- Any proposal concerning an arrangement for the benefit of the employees and directors or former employees and former directors of

★ See glossary on **page 373**

the company or any of its subsidiary undertakings, including but without being limited to a retirement benefits scheme and an employees' share scheme, which does not accord to any director any privilege or advantage not generally accorded to the employees or former employees to whom the arrangement relates.

The Act requires a director of a company who is in any way interested in a contract or proposed contract with the company to declare the nature of the director's interest at a meeting of the directors of the company. The definition of 'interest' includes the interests of spouses, children, companies and trusts. The Act also requires that a director must avoid a situation where a director has, or could have, a direct or indirect interest that conflicts, or possibly may conflict, with the company's interests. The Act allows directors of public companies to authorize such conflicts where appropriate, if a company's Articles of Association so permit. The company's Articles of Association permit the authorization of such conflicts. The directors may exercise all the powers of the company to borrow money, except that the amount remaining undischarged of all moneys borrowed by the company shall not, without approval of the shareholders, exceed two times the amount paid up on the share capital plus the aggregate of the amount of the capital and revenue reserves of the company and its subsidiary undertakings incorporated in the UK. Variation of the borrowing power of the board may only be affected by amending the Articles of Association.

Remuneration of non-executive directors shall be determined in the aggregate by resolution of the shareholders. Remuneration of executive directors is determined by the remuneration committee. This committee is made up of non-executive directors only. There is no requirement of share ownership for a director's qualification.

The Articles of Association provide entitlement to the directors' pensions and death and disability benefits to the directors' relations and dependants respectively.

The circumstances in which a director's office will automatically terminate include, amongst others: when a director ceases to hold an executive office of the company and the directors resolve that they should cease to be a director; if a medical practitioner provides an opinion that a director has become incapable of acting as a director and may remain so incapable for more than a further three months and the directors resolve that they should cease to be a director; and if all of the other directors vote in favour of a resolution stating that the person should cease to be a director.

The company secretary has express powers to delegate any of the powers or discretions conferred on him or her.

Dividend rights; other rights to share in company profits; capital calls

Shareholders of the company may, by resolution, declare dividends but no such dividend may be declared in excess of the amount recommended by the directors. The directors may also pay interim dividends without obtaining shareholder approval. No dividend may be paid other than out of profits available for distribution, as determined under IFRS and the Act. Dividends on ordinary shares are payable only after payment of dividends on bp preference shares. Any dividend unclaimed after a period of 10 years from the date of declaration of such dividend shall be forfeited and reverts to bp. If the company exercises its right to forfeit shares and sells shares belonging to an untraced shareholder then any entitlement to claim dividends or other monies unclaimed in respect of those shares will be for a period of 12 months after the sale. The company may take such steps as the directors decide are appropriate in the circumstances to trace the member entitled and the sale may be made at such time and on such terms as the directors may decide.

The directors have the power to declare and pay dividends in any currency provided that a sterling equivalent is announced. It is not the company's intention to change its current policy of paying dividends in US dollars. At the company's AGM held on 15 April 2010, shareholders approved the introduction of a Scrip Dividend Programme (Scrip Programme) and to include provisions in the Articles of Association to enable the company to operate the Scrip Programme. The Scrip Programme was renewed at the company's AGM held on 12 May 2021 for a further three years. The Scrip Programme enables ordinary shareholders and bp ADS holders to elect to receive new fully paid ordinary shares (or bp ADSs in the case of bp ADS holders) instead of cash. The operation of the Scrip Programme is always subject to the directors' decision to make the scrip offer available in respect of any particular dividend. Should the directors decide not to offer the scrip in respect of any particular dividend, cash will automatically be paid instead. The directors may determine in relation to any scrip dividend plan or programme how the costs of the programme will be met, the minimum number of ordinary shares required in order to be able to participate in the programme and any arrangements to deal with legal and practical difficulties in any particular territory.

Apart from shareholders' rights to share in bp's profits by dividend (if any is declared or announced), the Articles of Association provide that the directors may set aside:

- A special reserve fund out of the balance of profits each year to make up any deficit of cumulative dividend on the bp preference shares.
- A general reserve out of the balance of profits each year, which shall be applicable for any purpose to which the profits of the company may properly be applied. This may include capitalization of such sum, pursuant to an ordinary shareholders' resolution, and distribution to shareholders as if it were distributed by way of a dividend on the ordinary shares or in paying up in full unissued ordinary shares for allotment and distribution as bonus shares.

Any such sums so deposited may be distributed in accordance with the manner of distribution of dividends as described above.

Holders of shares are not subject to calls on capital by the company, provided that the amounts required to be paid on issue have been paid off. All shares are fully paid.

Share transfers and share certificates

The directors may permit transfers to be effected other than by an instrument in writing. Share certificates will not be required to be issued by the company if they are not required by law.

The company may charge an administrative fee in the event that a shareholder wishes to replace two or more certificates representing shares with a single certificate or wishes to surrender a single certificate and replace it with two or more certificates. All certificates are sent at the member's risk.

Voting rights

The Articles of Association of the company provide that voting on resolutions at a shareholders' meeting will be decided on a poll other than resolutions of a procedural nature, which may be decided on a show of hands. If voting is on a poll, every shareholder who is present in person or by proxy has one vote for every ordinary share held and two votes for every £5 in nominal amount of bp preference shares held. If voting is on a show of hands, each shareholder who is present at the meeting in person or whose duly appointed proxy is present in person will have one vote, regardless of the number of shares held, unless a poll is requested.

Shareholders do not have cumulative voting rights.

For the purposes of determining which persons are entitled to attend or vote at a shareholders' meeting and how many votes such persons may cast, the company may specify in the notice of the meeting a time, not more than 48 hours before the time of the meeting, by which a person who holds shares in registered form must be entered on the company's register of members in order to have the right to attend or vote at the meeting or to appoint a proxy to do so.

Holders on record of ordinary shares may appoint a proxy, including a beneficial owner of those shares, to attend, speak and vote on their behalf at any shareholders' meeting, provided that a duly completed proxy form is received not less than 48 hours (or such shorter time as the directors may determine) before the time of the meeting or adjourned meeting or, where the poll is to be taken after the date of the meeting, not less than 24 hours (or such shorter time as the directors may determine) before the time of the poll.

Record holders of bp ADSs are also entitled to attend, speak and vote at any shareholders' meeting of the company by the appointment by the approved depositary, JPMorgan Chase Bank N.A., of them as proxies in respect of the ordinary shares represented by their ADSs. Each such proxy may also appoint a proxy. Alternatively, holders of bp ADSs are entitled to vote by supplying their voting instructions to the Depositary, who will vote the ordinary shares represented by their ADSs in accordance with their instructions.

Proxies may be delivered electronically.

Corporations who are members of the company may appoint one or more persons to act as their representative or representatives at any shareholders' meeting provided that the company may require a corporate representative to produce a certified copy of the resolution appointing them before they are permitted to exercise their powers.

Matters are transacted at shareholders' meetings by the proposing and passing of resolutions, of which there are two types: ordinary or special.

An ordinary resolution requires the affirmative vote of a majority of the votes cast at a meeting at which there is a quorum. A special resolution requires the affirmative vote of not less than three quarters of the votes cast at a meeting at which there is a quorum. Any AGM requires 21 clear days' notice. The notice period for any other general meeting is 14 clear days subject to the company obtaining annual shareholder approval, failing which, a 21 clear day notice period will apply.

Liquidation rights; redemption provisions

In the event of a liquidation of bp, after payment of all liabilities and applicable deductions under UK laws and subject to the payment of secured creditors, the holders of bp preference shares would be entitled to the sum of (1) the capital paid up on such shares plus, (2) accrued and unpaid dividends and (3) a premium equal to the higher of (a) 10% of the capital paid up on the bp preference shares and (b) the excess of the average market price over par value of such shares on the LSE during the previous six months. The remaining assets (if any) would be divided pro rata among the holders of ordinary shares.

Without prejudice to any special rights previously conferred on the holders of any class of shares, bp may issue any share with such preferred, deferred or other special rights, or subject to such restrictions as the shareholders by resolution determine (or, in the absence of any such resolutions, by determination of the directors), and may issue shares that are to be or may be redeemed.

Variation of rights

The rights attached to any class of shares may be varied with the consent in writing of holders of 75% of the shares of that class or on the adoption of a special resolution passed at a separate meeting of the holders of the shares of that class. At every such separate meeting, all of the provisions of the Articles of Association relating to proceedings at a general meeting apply, except that the quorum with respect to a meeting to change the rights attached to the preference shares is 10% or more of the shares of that class, and the quorum to change the rights attached to the ordinary shares is one third or more of the shares of that class.

Shareholders' meetings and notices

Shareholders must provide bp with a postal or electronic address in the UK to be entitled to receive notice of shareholders' meetings. Holders of bp ADSs are entitled to receive notices under the terms of the deposit agreement relating to bp ADSs. The substance and timing of notices are described above under the heading Voting rights.

Under the Act, the AGM of shareholders must be held once every year, within each six-month period beginning with the day following the company's accounting reference date. All general meetings shall be held at a time and place determined by the directors. If any shareholders' meeting is adjourned for lack of quorum, notice of the time and place of the adjourned meeting may be given in any lawful manner, including electronically. Powers exist for action to be taken either before or at the meeting by authorized officers to ensure its orderly conduct and safety of those attending.

The directors have power to convene a general meeting which is a hybrid meeting, that is to provide facilities for shareholders to attend a meeting which is being held at a physical place by electronic means as well (but not to convene a purely electronic meeting).

The provisions of the Articles of Association in relation to satellite meetings permit facilities being provided by electronic means to allow those persons at each place to participate in the meeting.

Limitations on voting and shareholding

There are no limitations, either under the laws of the UK or under the company's Articles of Association, restricting the right of non-resident or foreign owners to hold or vote bp ordinary or preference shares in the company other than limitations that would generally apply to all of the shareholders and limitations applicable to certain countries and persons subject to EU economic sanctions or those sanctions adopted by the UK government which implement resolutions of the Security Council of the United Nations.

Disclosure of interests in shares

The Act permits a public company to give notice to any person whom the company believes to be or, at any time during the three years prior to the issue of the notice, to have been interested in its voting shares requiring them to disclose certain information with respect to those interests. Failure to supply the information required may lead to disenfranchisement of the relevant shares and a prohibition on their transfer and receipt of dividends and other payments in respect of those shares and any new shares in the company issued in respect of those shares. In this context the term 'interest' is widely defined and will generally include an interest of any kind whatsoever in voting shares, including any interest of a holder of bp ADSs.

Called-up share capital

Details of the allotted, called-up and fully-paid share capital at 31 December 2023 are set out in Financial statements – Note 31. In accordance with institutional investor guidelines, the company deems it appropriate to grant authority to the directors to allot shares and other securities and to disapply pre-emption rights by way of shareholders' resolutions at each AGM in place of authority granted by virtue of the company's Articles of Association. At the AGM on 27 April 2023, authorization was given to the directors to allot shares in the company and to grant rights to subscribe for, or to convert any security into, shares in the company up to an aggregate nominal amount as set out in the *Notice of Annual General Meeting 2023*. These authorities were given for the period until the next AGM in 2024 or 27 July 2024, whichever is the earlier. These authorities are renewed annually at the AGM.

Company records and service of notice

In relation to notices not covered by the Act, the reference to notice by advertisement in a national newspaper also includes advertisements via other means such as a public announcement.

Purchases of equity securities by the issuer and affiliated purchasers

During the 2023 financial year the company repurchased 1,262,982,632 ordinary shares with a nominal value of $0.25 each for a total consideration of $7,917,779,459 (including transaction costs), for the purpose of reducing the issued share capital of the company in order to return capital to shareholders and to offset the expected dilution from the vesting of awards under employee share schemes. The shares repurchased in 2023 represented 7.35% of the company's issued share capital, excluding shares held in treasury, on 31 December 2023. Of the shares repurchased in 2023, shares purchased under the 2022 AGM authority represented 3.57%, and shares purchased under the 2023 AGM authority represented 3.78%, of bp's issued share capital, excluding shares held in treasury, on 31 December 2023. A further 155,997,926 ordinary shares were repurchased between the end of the financial year and 16 February 2024 at a cost of $921,854,905 (including transaction costs) representing 0.91% of the company's issued share capital, excluding shares held in treasury, on 31 December 2023. All ordinary shares repurchased in 2023 and in 2024 up to 16 February under the share buyback programmes were cancelled.

Authorization for the company to make market purchases (as defined in section 693(4) of the Companies Act 2006) of ordinary shares with a nominal value of $0.25 each in the company was renewed at the company's 2023 AGM covering the period until the date of the company's 2024 AGM or 27 July 2024, whichever is earlier. The maximum number of ordinary shares to be purchased under this authority will not exceed 1,805,104,334 ordinary shares. The shares purchased will be cancelled.

The following table provides details of ordinary share purchases made (1) under the share buyback programmes and (2) by the Employee Share Ownership Plans (ESOPs) and other purchases of ordinary shares and ADSs made to satisfy the requirements of certain employee share-based payment plans.

	Total number of shares purchased[a]	**Average price paid per share $**	Number of shares purchased by ESOPs or for certain employee share-based plans[b]	Number of shares purchased under buyback programmes[c]	Maximum approximate dollar value of shares yet to be purchased under the programmes $ million
2023					
January 05 - January 31	**68,903,875**	**5.90**		68,903,875	N/A
February 01 - February 28	**102,718,280**	**6.59**		102,718,280	N/A
March 01 - March 31	**213,867,501**	**6.38**		213,867,501	N/A
April 03 - April 28	**141,850,648**	**6.66**		141,850,648	N/A
May 02 - May 31	**87,193,292**	**6.16**		87,193,292	N/A
June 01 - June 30	**100,436,661**	**5.88**		100,436,661	N/A
July 03 - July 31	**145,630,746**	**6.04**		145,630,746	N/A
August 01 - August 31	**83,873,967**	**6.13**		83,873,967	N/A
September 01 - September 29	**101,341,955**	**6.45**		101,341,955	N/A
October 02 - October 31	**91,937,237**	**6.51**		91,937,237	N/A
November 02 - November 30	**90,722,912**	**6.00**		90,722,912	N/A
December 01 - December 29	**59,193,301**	**5.97**	24,687,743	34,505,558	N/A
2024					
January 02 - January 31	**113,923,673**	**5.87**	7,312,257	106,611,416	N/A
February 02 - February 16	**49,386,510**	**6.02**		49,386,510	N/A

[a] All share purchases were of ordinary shares of $0.25 each and/or ADSs (each representing six ordinary shares) and were on/open market transactions.
[b] Transactions represent the purchases of ordinary shares and ADSs made to satisfy requirements of certain employee share-based payment plans.
[c] Share repurchases from 1 January to 3 February 2023 were made under a share buyback programme announced on 1 November 2022 for a period up to and including 3 February 2023. The company announced two programmes in one announcement on 7 February 2023. One covered a period up to and including 28 April 2023 and the other, relating to employee share schemes, was for a period up to and including 30 September 2023. On 2 May 2023 the company announced a programme covering a period up to and including 28 July 2023. On 1 August 2023 the company announced a programme covering a period up to and including 27 October 2023. On 31 October 2023 the company announced a programme covering a period up to and including 2 February 2024. On 6 February 2024 the company announced a programme covering a period up to and including 3 May 2024.

Fees and charges payable by ADS holders

The Depositary collects fees for delivery and surrender of ADSs directly from investors depositing shares or surrendering ADSs for the purpose of withdrawal or from intermediaries acting for them. The Depositary collects fees for making distributions to investors by deducting those fees from the amounts distributed or by selling a portion of the distributable property to pay the fees.

The charges of the Depositary payable by investors are as follows:

Type of service	Depositary actions	Fee
Depositing or substituting the underlying shares	Issuance of ADSs against the deposit of shares, including deposits and issuances in respect of: • Share distributions, stock splits, rights, merger. • Exchange of securities or other transactions or event or other distribution affecting the ADSs or deposited securities.	$5.00 per 100 ADSs (or portion thereof) evidenced by the new ADSs delivered.
Selling or exercising rights	Distribution or sale of securities, the fee being an amount equal to the fee for the execution and delivery of ADSs that would have been charged as a result of the deposit of such securities.	$5.00 per 100 ADSs (or portion thereof).
Withdrawing an underlying share	Acceptance of ADSs surrendered for withdrawal of deposited securities.	$5.00 for each 100 ADSs (or portion thereof) evidenced by the ADSs surrendered.
Expenses of the Depositary	Expenses incurred on behalf of holders in connection with: • Stock transfer or other taxes and governmental charges. • Delivery by cable, telex, electronic and facsimile transmission. • Transfer or registration fees, if applicable, for the registration of transfers of underlying shares. • Expenses of the Depositary in connection with the conversion of foreign currency into US dollars (which are paid out of such foreign currency).	Expenses payable are subject to agreement between the company and the Depositary by billing holders or by deducting charges from one or more cash dividends or other cash distributions.
Dividend fees	ADS holders who receive a cash dividend are charged a fee which bp uses to offset the costs associated with administering the ADS programme.	The Deposit Agreement provides that a fee of $0.05 or less per ADS can be charged. The current fee is $0.02 per bp ADS per calendar year (equivalent to $0.005 per bp ADS per quarter per cash distribution).
Global Invest Direct (GID) Plan	New investors and existing ADS holders can buy, sell or reinvest dividends into further bp ADSs by enrolling in bp's GID Plan, sponsored and administered by the Depositary.	Cost per transaction is $2.00 for recurring, $2.00 for one-time automatic investments, and $5.00 for investment made by check. Dividend reinvestment is 5% of the dividend amount up to a maximum of $5.00. Purchase trading commission is $0.12 per share.

Fees and payments made by the Depositary to the issuer

The Depositary has agreed to reimburse certain company expenses related to the company's ADS programme and incurred by the company in connection with the ADS programme arising during the year ended 31 December 2023. The Depositary reimbursed to the company, or paid amounts on the company's behalf to third parties, or waived its fees and expenses, of $16,165,200.95 for the year ended 31 December 2023.

The table below sets out the types of expenses that the Depositary has agreed to reimburse and the fees it has agreed to waive for standard costs associated with the administration of the ADS programme relating to the year ended 31 December 2023.

Category of expense reimbursed, waived or paid directly to third parties	Amount reimbursed, waived or paid directly to third parties for the year ended 31 December 2023
Fees for delivery and surrender of bp ADSs	1,763,093.64
Dividend fees[a]	14,400,550.21
Waived fees	1,557.10
Total	16,165,200.95

[a] Dividend fees are charged to ADS holders who receive a cash distribution, which bp uses to offset the costs associated with administering the ADS programme.

Under certain circumstances, including removal of the Depositary or termination of the ADS programme by the company, the company is required to repay the Depositary certain amounts reimbursed and/or expenses paid to or on behalf of the company during the 12-month period prior to notice of removal or termination.

Documents on display

The *bp Annual Report and Form 20-F 2023* is available online at bp.com/annualreport. To obtain a hard copy of bp's complete audited financial statements, free of charge, UK based shareholders should contact bp Distribution Services by calling +44 (0) 800 037 2172 or by emailing bpdistributionservices@bp.com. If based in the US or Canada shareholders should contact Issuer Direct by calling +1 888 301 2505 or by emailing bpreports@issuerdirect.com.

The company is subject to the information requirements of the US Securities Exchange Act of 1934 applicable to foreign private issuers. In accordance with these requirements, the company files its *Annual Report and Form 20-F* and other related documents with the SEC. The SEC maintains an internet site at sec.gov that contains reports and other information regarding issuers, including bp, that file electronically with the SEC. bp's SEC filings are also available at bp.com/sec. bp discloses in this report (see Corporate governance practices (Form 20-F Item 16G) on page 358) significant ways (if any) in which its corporate governance practices differ from those mandated for US companies under NYSE listing standards.

Shareholding administration

If you have any queries about the administration of shareholdings, such as change of address, change of ownership, dividend payment options or to change the way you receive your company documents (such as the *bp Annual Report and Form 20-F* and *Notice of bp Annual General Meeting*) please contact the bp Registrar or the bp ADS Depositary.

Holders of American Depositary Receipts may request to inspect the books of the Depositary and the listing of receipt holders by contacting the bp ADS Depositary.

Ordinary and preference shareholders

The bp Registrar, Link Group, Central Square,
29 Wellington Street,
Leeds, LS1 4DL
Freephone in the UK 0800 701107
From outside the UK +44 (0)371 277 1014
bp share centre mybpshares.com

ADS holders

bp Shareowner Services
PO Box 64504, St Paul, MN 55164-0504, US
Toll-free in the US +1 877 638 5672
From outside the US +1 651 306 4383

2024 shareholder calendar[a]

28 Mar 2024	Fourth quarter interim dividend payment for 2023
25 Apr 2024	Annual general meeting
07 May 2024	First quarter results announced
17 May 2024	Record date (to be eligible for the first quarter interim dividend)
28 Jun 2024	First quarter interim dividend payment for 2024
28 Jun 2024	8% and 9% preference shares record date
30 Jul 2024	Second quarter results announced
31 Jul 2024	8% and 9% preference shares dividend payment
09 Aug 2024	Record date (to be eligible for the second quarter interim dividend)
20 Sep 2024	Second quarter interim dividend payment for 2024
29 Oct 2024	Third quarter results announced
08 Nov 2024	Record date (to be eligible for the third quarter interim dividend)
20 Dec 2024	Third quarter interim dividend payment for 2024

[a] All future dates are provisional and may be subject to change. For the full calendar see bp.com/financialcalendar.

Glossary

Abbreviations

ADR
American depositary receipt.

ADS
American depositary share. 1 ADS = 6 ordinary shares.

Barrel (bbl)
159 litres, 42 US gallons.

bcf
Billion cubic feet.

bcfe
Billion cubic feet equivalent.

boe
Barrels of oil equivalent.

EJ/yr
Exajoules per year.

EVP
Executive vice president.

FPSO
Floating production, storage and offloading.

GAAP
Generally accepted accounting practice.

Gas
Natural gas.

gCO_2e/MJ
Grams of carbon dioxide equivalent per megajoule of energy.

GHG
Greenhouse gas.

GRI
Global Reporting Initiative.

$GtCO_2$
Gigatonnes of carbon dioxide.

GW
Gigawatt.

GWh
Gigawatt hour.

HSSE
Health, safety, security and environment.

IFRS
International Financial Reporting Standards.

kb/d
Thousand barrels per day.

KPIs
Key performance indicators.

kt
Thousand tonnes.

LNG
Liquefied natural gas.

LPG
Liquefied petroleum gas.

mb/d
Thousand barrels per day.

Mbbl
Million barrels.

mboe/d
Thousand barrels of oil equivalent per day.

mmb/d
Million barrels per day.

mmboe/d
Million barrels of oil equivalent per day.

mmBtu
Million British thermal units.

mmcf/d
Million cubic feet per day.

Mt
Million tonnes.

$MtCO_2e$
Million tonnes of CO_2 equivalent.

Mtpa
Million tonnes per annum.

MW
Megawatt.

MWe
Megawatt electrical.

MWp
Megawatt peak.

NGLs
Natural gas liquids.

PSA
Production-sharing agreement.

PTA
Purified terephthalic acid.

RC
Replacement cost.

SEC
The United States Securities and Exchange Commission.

TWh
Terawatt hour.

SVP
Senior vice president.

scfm
Standard cubit feet per minute

Definitions

Unless the context indicates otherwise, the definitions for the following glossary terms are given below.

Non-IFRS measures are sometimes referred to as alternative performance measures.

CA100+ resolution glossary

CA100+ resolution
The CA100+ resolution means the special resolution requisitioned by Climate Action 100+ and passed at bp's 2019 Annual General Meeting, the text of which is set out below.

Special resolution: Climate Action 100+ shareholder resolution on climate change disclosures

That in order to promote the long-term success of the company, given the recognized risks and opportunities associated with climate change, we as shareholders direct the company to include in its strategic report and/or other corporate reports, as appropriate, for the year ending 2019 onwards, a description of its strategy which the board considers, in good faith, to be consistent with the goals of Articles 2.1(a)(1) and 4.1(2) of the Paris Agreement (3) (the Paris goals), as well as:

(1) Capital expenditure: how the company evaluates the consistency of each new material capex investment, including in the exploration, acquisition or development of oil and gas resources and reserves and other energy sources and technologies, with (a) the Paris goals and separately (b) a range of other outcomes relevant to its strategy.

(2) Metrics and targets: the company's principal metrics and relevant targets or goals over the short, medium and/or long term, consistent with the Paris goals, together with disclosure of:

a. The anticipated levels of investment in (i) oil and gas resources and reserves; and (ii) other energy sources and technologies.

b. The company's targets to promote reductions in its operational greenhouse gas emissions, to be reviewed in line with changing protocols and other relevant factors.

c. The estimated carbon intensity of the company's energy products and progress on carbon intensity over time.

d. Any linkage between the above targets and executive remuneration.

(3) Progress reporting: an annual review of progress against (1) and (2) above.

Such disclosure and reporting to include the criteria and summaries of the methodology and core assumptions used, and to omit commercially confidential or competitively sensitive information and be prepared at reasonable cost; and provided that nothing in this resolution shall limit the company's powers to set and vary its strategy, or associated targets or metrics, or to take any action which it believes in good faith, would best promote the long-term success of the company.

The Paris goals

(1) Article 2.1(a) of the Paris Agreement states the goal of 'Holding the increase in the global average temperature to well-below-2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels, recognizing that this would significantly reduce the risks and impacts of climate change'.

(2) Article 4.1 of the Paris Agreement: In order to achieve the long-term temperature goal set out in Article 2, parties aim to reach global peaking of greenhouse gas emissions as soon as possible, recognizing that peaking will take longer for developing country parties, and to undertake rapid reductions thereafter in accordance with best available science, so as to achieve a balance between anthropogenic emissions by sources and removals by sinks of greenhouse gases in the second half of this century, on the basis of equity, and in the context of sustainable development and efforts to eradicate poverty.

(3) U.N. Framework Convention on Climate Change Conference of Parties, Twenty-First Session, Adoption of the Paris Agreement, U.N. Doc. FCCC/CP/2015/L.9/Rev.1 (Dec. 12, 2015).

New material capex investment

For the purposes of the 2023 evaluation discussed on pages 30-34, 'new material capex investment' means a decision taken by the resource commitment meeting (RCM) in 2023 to incur inorganic or organic investments greater than $250 million that relate to a new project or asset, extending an existing project or asset, or acquiring or increasing a share in a project, asset or entity.

There were nine investments that met the above criteria in 2023.

Material capex evaluation: Paris-consistency quantitative tests.

For the purposes of evaluating material capex investments for consistency with the Paris goals, two quantitative tests were applied, see page 33.

Operational carbon intensity (CI)

The annual average operational GHG emissions (TeCO_2e/unit), divided by the relevant unit of output:

- Per thousand barrels of oil equivalent in upstream.
- Per utilized equivalent distillation capacity in refining.
- per thousand tonnes of petrochemicals production.

Net zero aims and ambition glossary

Average carbon intensity of sold energy products

The rate of GHG emissions per unit of energy delivered (in grams CO_2e/MJ) estimated in respect of sold energy products★. GHG emissions are estimated on a lifecycle basis covering use, production, and distribution of sold energy products.

Emissions from the carbon in our upstream oil and gas production

Estimated CO_2 emissions from the combustion of upstream production of crude oil, natural gas and natural gas liquids (NGLs) based on bp's net share of production, excluding bp's share of Rosneft production and assuming that all produced volumes undergo full stoichiometric combustion to CO_2.

Energy product

For the purposes of our 2023 disclosures relating to our aim 3, we consider an energy product to be one that is generally used to satisfy an energy demand. In the case of fuels, to burn them to release their calorific content, and in the case of electricity to provide work or heat. For further information on products included in bp's 2023 aim 3 reporting see the basis of reporting *bp.com/basisofreporting*.

Methane intensity

Methane intensity refers to the amount of methane emissions from bp's operated upstream oil and gas assets as a percentage of the total gas that goes to market from those operations. Our methodology is aligned with the Oil and Gas Climate Initiative's (OGCI).

Net zero

References to global net zero in the phrase, 'to help the world get to net zero', means achieving '...a balance between anthropogenic emissions by sources and removals by sinks of greenhouse gases...on the basis of equity, and in the context of sustainable development and efforts to eradicate poverty', as set out in Article 4(1) of the Paris Agreement.

References to net zero for bp in the context of our ambition and aims 1, 2 and 3 mean achieving a balance between (a) the relevant Scope 1 and 2 emissions (for aim 1), Scope 3 emissions (for aim 2) or product lifecycle emissions (for aim 3) and (b) the aggregate of applicable deductions from qualifying activities such as sinks under our methodology at the applicable time.

Net zero★ operations

bp's aim to reach net zero operational greenhouse gas (CO2 and methane) emissions by 2050 or sooner, on a gross operational control basis, in accordance with bp's aim 1 which relates to our reported Scope 1 and 2 emissions. Any interim target or aim in respect of bp's aim 1 is defined in terms of absolute reductions relative to the baseline year of 2019.

Net zero★ production

bp's aim to reach net zero CO_2 emissions, in accordance with bp's aim 2, from the carbon in our upstream oil and gas production, in respect of the estimated CO_2 emissions from the combustion of upstream production of crude oil, natural gas and natural gas liquids (based on bp's net share of production, excluding bp's share of Rosneft production and assuming that all produced volumes undergo full stoichiometric combustion to CO_2). Aim 2 is bp's Scope 3 aim and relates to Scope 3 category 11 emissions within the selected boundary of bp's net share of upstream production of oil and gas. Any interim target or aim in respect of bp's aim 2 is defined in terms of absolute reductions relative to the baseline year of 2019.

Net zero★ sales

bp's aim to reach net zero for the carbon intensity of sold energy products★, in accordance with bp's aim 3. Any interim target or aim in respect of bp's aim 3 is defined in terms of reductions in the carbon intensity of the energy products we sell (in grams CO_2e/MJ) relative to the baseline year of 2019.

Physically traded energy products

For the purposes of aim 3, this includes trades in energy products★ which are physically settled, with the exception of, for example, financial trades and certain other transactions where the purpose or effect is that the volumes traded or supplied net off against each other.

Sold energy products

For the purposes of aim 3, these represent the energy products★ we sell to third parties including both marketed sales and physically traded energy products★. For these purposes, intercompany sales (sales between two group subsidiaries) are not included and equity-accounted entities are treated as third parties.

Sustainable emissions reductions (SER)

SERs result from actions or interventions that have led to ongoing reductions in Scope 1 (direct) and/or Scope 2 (indirect) greenhouse gas (GHG) emissions (carbon dioxide and methane) such that GHG emissions would have been higher in the reporting year if the intervention had not taken place. SERs must meet three criteria: a specific intervention that has reduced GHG emissions, the reduction must be quantifiable and the reduction is expected to be ongoing. Reductions are reportable for a 12-month period from the start of the intervention/action.

Adjusted EBIDA

Adjusted EBIDA is a non-IFRS measure and is defined as profit or loss for the period, adjusting for finance costs and net finance (income) or expense relating to pensions and other post-retirement benefits and taxation, inventory holding gains or losses before tax, net adjusting items★ before interest and tax, and taxation on an underlying RC basis, and adding back depreciation, depletion and amortization (pre-tax) and exploration expenditure written-off (net of adjusting items, pre-tax). bp believes that adjusted EBIDA is a useful measure for investors because it is a measure closely tracked by management to evaluate bp's operating performance and to make financial, strategic and operating decisions and because it may help investors to understand and evaluate, in the same manner as management, the underlying trends in bp's operational performance on a comparable basis, period on period. The nearest equivalent measure on an IFRS basis is profit or loss for the period. A reconciliation of profit or loss for the period to adjusted EBIDA is provided on page 383.

Adjusted EBIDA per share compound annual growth rate (CAGR)

Non-IFRS measure. Adjusted EBIDA per share is calculated based on the shares in issue at period end.

Adjusted EBITDA

Adjusted EBITDA is a non-IFRS measure presented for bp's operating segments and the group. Adjusted EBITDA for bp's operating segments is defined as replacement cost (RC) profit before interest and tax, excluding net adjusting items* before interest and tax, and adding back depreciation, depletion and amortization and exploration write-offs (net of adjusting items). Adjusted EBITDA by business is a further analysis of adjusted EBITDA for the customers & products businesses. bp believes it is helpful to disclose adjusted EBITDA by operating segment and by business because it reflects how the segments measure underlying business delivery. The nearest equivalent measure on an IFRS basis for the segment is RC profit or loss before interest and tax, which is bp's measure of profit or loss that is required to be disclosed for each operating segment under IFRS. A reconciliation to IFRS information is provided on pages 351 and 384.

Adjusted EBITDA for the group is defined as profit or loss for the period, adjusting for finance costs and net finance (income) or expense relating to pensions and other post-retirement benefits and taxation, inventory holding gains or losses before tax, net adjusting items before interest and tax, and adding back depreciation, depletion and amortization (pre-tax) and exploration expenditure written-off (net of adjusting items, pre-tax). The nearest equivalent measure on an IFRS basis for the group is profit or loss for the period. A reconciliation to IFRS information is provided on page 384.

We are unable to present reconciliations of forward-looking information for adjusted EBITDA for the group, strategic themes or transition growth engine, because without unreasonable efforts, we are unable to forecast accurately certain adjusting items required to calculate a meaningful comparable IFRS forward-looking financial measure. These items include inventory holding gains or losses, adjusting items and exploration expenditure written off that are difficult to predict in advance in order to include in an IFRS estimate.

Adjusted free cash flow

Adjusted free cash flow, as applicable to the directors' remuneration performance measure, is a non-IFRS measure and is defined as Operating cash flow less: (1) net cash used in investing activities as presented in the group cash flow statement; and (2) lease liability payments included in financing activities and adjusting for other proceeds reported within financing activities in the group cash flow statement and movements in lease creditor.

Adjusting items

Adjusting items are items that bp discloses separately because it considers such disclosures to be meaningful and relevant to investors. They are items that management considers to be important to period-on-period analysis of the group's results and are disclosed in order to enable investors to better understand and evaluate the group's reported financial performance. Adjusting items include gains and losses on the sale of businesses and fixed assets, impairments, environmental and other provisions and charges, restructuring, integration and rationalization costs, fair value accounting effects, costs relating to the Gulf of Mexico oil spill and other items. Adjusting items within equity-accounted earnings are reported net of incremental income tax reported by the equity-accounted entity. Adjusting items are used as a reconciling adjustment to derive underlying RC profit or loss and related underlying measures which are non-IFRS measures. An analysis of adjusting items by segment and type is shown on page 337.

Associate

An entity over which the group has significant influence and that is neither a subsidiary nor a joint arrangement of the group. Significant influence is the power to participate in the financial and operating policy decisions of the investee but is not control or joint control over those policies.

Biofuels production

Biofuels production is average thousands of barrels of biofuel production per day during the period covered net to bp. This includes equivalent ethanol production, bp Bunge biopower for grid export, refining co-processing and standalone hydrogenated vegetable oil (HVO).

Biogas supply volumes

Biogas supply volumes is the average thousands of barrels of oil equivalent per day of production and offtakes during the period covered net to bp.

Bio-refinery

A facility that is dedicated to processing biological materials (including waste oil and crop waste) to produce biofuels such as biodiesel and sustainable aviation fuel, which may be blended to customer specifications with other components such as hydrocarbons at co-located or adjacent terminals and tanks.

Blue hydrogen

Hydrogen made from natural gas in combination with carbon captured and stored (CCS).

Capital employed

Non-IFRS measure. It is defined as total equity plus finance debt.

Capital expenditure

Total cash capital expenditure as stated in the group cash flow statement. Capital expenditure for the operating segments, gas & low carbon energy businesses and customers & products businesses is presented on the same basis.

Cash balance point

Cash balance point is defined as the implied Brent oil price 2021 real to balance bp's sources and uses of cash assuming an average bp refining marker margin around $11/bbl and Henry Hub at $3/mmBtu in 2021 real terms.

Commodity trading contracts

bp participates in regional and global commodity trading markets in order to manage, transact and hedge the crude oil, refined products and natural gas that the group either produces or consumes in its manufacturing operations. The range of contracts the group enters into in its commodity trading operations is described below. Using these contracts, in combination with rights to access storage and transportation capacity, allows the group to access advantageous pricing differences between locations, time periods and grades.

Exchange-traded commodity derivatives

Contracts that are typically in the form of futures and options traded on a recognized exchange, such as Nymex and ICE. Such contracts are traded in standard specifications for the main marker crude oils, such as Brent and West Texas Intermediate; the main product grades, such as gasoline and gasoil; and for natural gas and power. Gains and losses, otherwise referred to as variation margin, are generally settled on a daily basis with the relevant exchange. These contracts are used for the trading and risk management of crude oil, refined products, and natural gas and power. Realized and unrealized gains and losses on exchange-traded commodity derivatives are included in sales and other operating revenues for accounting purposes.

Over-the-counter (OTC) contracts

Contracts that are typically in the form of forwards, swaps and options. Some of these contracts are traded bilaterally between counterparties or through brokers, others may be cleared by a central clearing counterparty. These contracts can be used both for trading and risk management activities. Realized and unrealized gains and losses on OTC contracts are included in sales and other operating revenues for accounting purposes. Many grades of crude oil bought and sold use standard contracts including US domestic light sweet crude oil, commonly referred to as West Texas Intermediate, and a standard North Sea crude blend – Brent, Forties, Oseberg and Ekofisk (BFOE). Forward contracts are used in connection with the purchase of crude oil supplies for refineries and for marketing and sales of the group's oil production and refined products. The contracts typically contain standard delivery and settlement terms. These transactions call for physical delivery of oil with consequent operational and price risk. However, various means exist and are used from time to time, to settle obligations under the contracts in cash rather than through physical delivery. Physically settled BFOE contracts delivered by cargo additionally specify a standard volume and tolerance.

Gas and power OTC markets are highly developed in North America and the UK, where commodities can be bought and sold for delivery in future periods. These contracts are negotiated between two parties to purchase and sell gas and power at a specified price, with delivery and settlement at a future date. Typically, the contracts specify delivery terms for the underlying commodity. Some of these transactions are not settled physically as they can be net settled by transacting offsetting sale or purchase contracts for the same location and delivery period. The contracts contain standard terms such as delivery point, pricing mechanism, settlement terms and specification of the commodity. Typically, volume, price and term (e.g. daily, monthly and balance of month) are the main variable contract terms.

Swaps are typically contractual obligations to exchange cash flows between two parties. A typical swap transaction usually references a floating price and a fixed price with the net difference of the cash flows being settled. Options give the holder the right, but not the obligation, to buy or sell crude, oil products, natural gas or power at a specified price on or before a specific future date. Amounts under these derivative financial instruments are settled at expiry. Typically, netting agreements are used to limit credit exposure and support liquidity.

Spot and term contracts

Spot contracts are contracts to purchase or sell a commodity at the market price prevailing on or around the delivery date when title to the inventory is taken. Term contracts are contracts to purchase or sell a commodity at regular intervals over an agreed term. Though spot and term contracts may have a standard form, there is no offsetting mechanism in place. As such, these transactions result in physical delivery with operational and price risk. Spot and term contracts typically relate to purchases of crude for a refinery, products for marketing, or third-party natural gas, or sales of the group's oil production, oil products or gas production to third parties. For accounting purposes, spot and term sales are included in sales and other operating revenues when title passes. Similarly, spot and term purchases are included in purchases for accounting purposes.

Consolidation adjustment – UPII

Unrealized profit in inventory arising on inter-segment transactions.

Convenience gross margin

Non-IFRS measure. Convenience gross margin is calculated as RC profit before interest and tax for the customers & products segment, excluding RC profit before interest and tax for the refining & trading business (a non-IFRS measure), and adjusting items★ (as defined above) for the convenience & mobility business to derive underlying RC profit before interest and tax for the convenience & mobility business; subtracting underlying RC profit before interest and tax for the Castrol business; adding back depreciation, depletion and amortization, production and manufacturing, distribution and administration expenses for convenience & mobility (excluding *Castrol*); subtracting earnings from equity-accounted entities in the convenience & mobility business (excluding *Castrol*) and gross margin for the retail fuels, EV charging, aviation, B2B and midstream businesses. bp believes it is helpful because this measure may help investors to understand and evaluate, in the same way as management, our progress against our strategic objectives of convenience growth. The nearest IFRS measure is RC profit before interest and tax for the customers & products segment. A reconciliation of RC profit before interest and tax for the customers & products segment to convenience gross margin is provided on page 351.

Convenience gross margin growth

Non-IFRS measure. See convenience gross margin definition above. Convenience gross margin growth at constant foreign exchange is a non-IFRS measure. This metric requires a calculation of the comparative convenience gross margin ($ million) at current period foreign exchange rates (constant foreign exchange) and compares the current period value with the restated comparative period value, which results in the growth % at constant foreign exchange rates. bp believes the convenience gross margin growth at constant foreign exchange are useful measures because these measures may help investors to understand and evaluate, in the same way as management, our progress against our strategic objectives of redefining convenience. The nearest IFRS measure to convenience gross margin is RC profit before interest and tax for the customer & products segment.

Convenience & EV gross margin growth (%)

Non-IFRS measure. See convenience gross margin and EV gross margin definitions. Convenience and EV gross margin growth at constant foreign exchange is a non-IFRS measure. This metric, as applicable to the directors' remuneration performance measure, requires a calculation of the comparative convenience and EV gross margin ($ million) at current period foreign exchange rates (constant foreign exchange) and compares the current period value with the restated comparative period value, which results in the growth % at constant foreign exchange rates. The nearest IFRS measure to convenience gross margin and EV gross margin is RC profit before interest and tax for the customer & products segment.

Cumulative cash costs reductions

Non-IFRS measure. Cash costs is defined as production and manufacturing expenses plus distribution and administration expenses and excludes costs that are classified as adjusting items and costs that are variable, primarily with volumes (such as freight costs). It also includes exploration geological and geophysical costs, which are included in the exploration expenses line in the group income statement. Cumulative cash cost reductions by the end of 2022 compared to 2019 baseline, as applicable to the directors' remuneration performance measure, are defined as reinvent headcount savings, restructuring, location, agile, operational and other savings, less agreed portfolio changes and costs in direct support of growth.

Customer touchpoints

Customer touchpoints are the number of retail customer transactions per day on bp forecourts globally. These include transactions involving fuel and/or convenience across all channels of trade.

Developed renewables to final investment decision (FID)

Total generating capacity for assets developed to FID by all entities where bp has an equity share (proportionate to equity share). If asset is subsequently sold bp will continue to record capacity as developed to FID. If bp equity share increases developed capacity to FID will increase proportionately to share increase for any assets where bp held equity at the point of FID.

Divestment proceeds

Disposal proceeds as per the group cash flow statement.

Dividend yield

Sum of the four quarterly dividends announced in respect of the year as a percentage of the year-end share price.

Dutch Title Transfer Facility

The TTF (Title Transfer Facility) is the virtual trading point for natural gas in the Netherlands. It is commonly used as a benchmark hub for gas prices in Europe.

Effective tax rate (ETR) on replacement cost (RC) profit or loss

Non-IFRS measure. The ETR on RC profit or loss is calculated by dividing taxation on a RC basis by RC profit or loss before tax. Taxation on a RC basis for the group is calculated as taxation as stated on the group income statement adjusted for taxation on inventory holding gains and losses. Information on RC profit or loss is provided below. bp believes it is helpful to disclose the ETR on RC profit or loss because this measure excludes the impact of price changes on the replacement of inventories and allows for more meaningful comparisons between reporting periods. Taxation on a RC basis and ETR on RC profit or loss are non-IFRS measures. The nearest equivalent measure on an IFRS basis is the ETR on profit or loss for the period. A reconciliation to IFRS information is provided on page 382.

Electric vehicle charge points / EV charge points

Defined as the number of connectors on a charging device, operated by either bp or a bp joint venture, as adjusted to be reflective of bp's accounting share of joint arrangements.

EV gross margin

Non-IFRS measure. EV gross margin, as applicable to the directors' remuneration performance measure, is calculated as RC profit before interest and tax for the customers & products segment, excluding RC profit before interest and tax for the refining & trading business (a non-IFRS measure), and adjusting items★ (as defined above) for the convenience & mobility business to derive underlying RC profit before interest and tax for the convenience & mobility business; subtracting underlying RC profit before interest and tax for the Castrol business; adding back depreciation, depletion and amortization, production and manufacturing, distribution and administration expenses for convenience & mobility (excluding Castrol); subtracting earnings from equity-accounted entities in the convenience & mobility business (excluding Castrol) and gross margin for the convenience and retail fuels, aviation, B2B and midstream businesses. The nearest IFRS measure to EV gross margin is RC profit before interest and tax for the customer & products segment.

Fair value accounting effects

Non-IFRS adjustments to our IFRS profit (loss).They reflect the difference between the way bp manages the economic exposure and internally measures performance of certain activities and the way those activities are measured under IFRS. Fair value accounting effects are included within adjusting items. They relate to certain of the group's commodity, interest rate and currency risk exposures as detailed below. Other than as noted below, the fair value accounting effects described are reported in both the gas & low carbon energy and customer & products segments.

bp uses derivative instruments to manage the economic exposure relating to inventories above normal operating requirements of crude oil, natural gas and petroleum products. Under IFRS, these inventories are recorded at historical cost. The related derivative instruments, however, are required to be recorded at fair value with gains and losses recognized in the income statement. This is because hedge accounting is either not permitted or not followed, principally due to the impracticality of effectiveness-testing requirements. Therefore, measurement differences in relation to recognition of gains and losses occur. Gains and losses on these inventories, other than net realizable value provisions, are not recognized until the commodity is sold in a subsequent accounting period. Gains and losses on the related derivative commodity contracts are recognized in the income statement, from the time the derivative commodity contract is entered into, on a fair value basis using forward prices consistent with the contract maturity.

bp enters into physical commodity contracts to meet certain business requirements, such as the purchase of crude for a refinery or the sale of bp's gas production. Under IFRS these physical contracts are treated as derivatives and are required to be fair valued when they are managed as part of a larger portfolio of similar transactions. Gains and losses arising are recognized in the income statement from the time the derivative commodity contract is entered into.

IFRS require that inventory held for trading is recorded at its fair value using period-end spot prices, whereas any related derivative commodity instruments are required to be recorded at values based on forward prices consistent with the contract maturity. Depending on market conditions, these forward prices can be either higher or lower than spot prices, resulting in measurement differences.

bp enters into contracts for pipelines and other transportation, storage capacity, oil and gas processing, liquefied natural gas (LNG) and certain gas and power contracts that, under IFRS, are recorded on an accruals basis. These contracts are risk-managed using a variety of derivative instruments that are fair valued under IFRS. This results in measurement differences in relation to recognition of gains and losses.

The way that bp manages the economic exposures described above, and measures performance internally, differs from the way these activities are measured under IFRS. bp calculates this difference for consolidated entities by comparing the IFRS result with management's internal measure of performance. We believe that disclosing management's estimate of this difference provides useful information for investors because it enables investors to see the economic effect of these activities as a whole.

These include:

- Under management's internal measure of performance the inventory, transportation and capacity contracts in question are valued based on fair value using relevant forward prices prevailing at the end of the period.
- Fair value accounting effects also include changes in the fair value of the near-term portions of LNG contracts that fall within bp's risk management framework. LNG contracts are not considered derivatives, because there is insufficient market liquidity, and they are therefore accrual accounted under IFRS. However, oil and natural gas derivative financial instruments used to risk manage the near-term portions of the LNG contracts are fair valued under IFRS. The fair value accounting effect, which is reported in the gas and low carbon energy segment, represents the change in value of LNG contracts that are being risk managed and which is reflected in the underlying result, but not in reported earnings. Management believes that this gives a better representation of performance in each period.

Furthermore, the fair values of derivative instruments used to risk manage certain other oil, gas, power and other contracts, are deferred to match with the underlying exposure. The commodity contracts for business requirements are accounted for on an accruals basis.

In addition, fair value accounting effects include changes in the fair value of derivatives entered into by the group to manage currency exposure and interest rate risks relating to hybrid bonds to their respective first call periods. The hybrid bonds which were issued on 17 June 2020 are classified as equity instruments and were recorded in the balance sheet at that date at their USD equivalent issued value. Under IFRS these equity instruments are not remeasured from period to period, and do not qualify for application of hedge accounting. The derivative instruments relating to the hybrid bonds, however, are required to be recorded at fair value with mark to market gains and losses recognized in the income statement. Therefore, measurement differences in relation to the recognition of gains and losses occur. The fair value accounting effect, which is reported in the other businesses & corporate segment, eliminates the fair value gains and losses of these derivative financial instruments that are recognized in the income statement. We believe that this gives a better representation of performance, by more appropriately reflecting the economic effect of these risk management activities, in each period.

Fast / Fast charging

Fast charging comprises rapid charging★ and ultra-fast charging★.

Finance debt ratio

Finance debt ratio is defined as the ratio of finance debt to the total of finance debt plus total equity.

Gearing and net debt

Non-IFRS measures. Net debt is calculated as finance debt, as shown in the balance sheet, plus the fair value of associated derivative financial instruments that are used to hedge foreign currency exchange and interest rate risks relating to finance debt, for which hedge accounting is applied, less cash and cash equivalents. Net debt does not include accrued interest, which is reported within other receivables and other payables on the balance sheet and for which the associated cash flows are presented as operating cash flows in the group cash flow statement. Gearing is defined as the ratio of net debt to the total of net debt plus total equity. bp believes these measures provide useful information to investors. Net debt enables investors to see the economic effect of finance debt, related hedges and cash and cash equivalents in total. Gearing enables investors to see how significant net debt is relative to total equity. The derivatives are reported on the balance sheet within the headings 'Derivative financial instruments'. See Financial statements – Note 27 for information on finance debt, which is the nearest equivalent measure to net debt on an IFRS basis. The nearest equivalent IFRS measure to gearing on an IFRS basis is finance debt ratio.

We are unable to present reconciliations of forward-looking information for net debt or gearing to finance debt and total equity, because without unreasonable efforts, we are unable to forecast accurately certain adjusting items required to present a meaningful comparable IFRS forward-looking financial measure. These items include fair value asset (liability) of hedges related to finance debt and cash and cash equivalents, that are difficult to predict in advance in order to include in an IFRS estimate.

Gearing including leases and net debt including leases

Non-IFRS measures. Net debt including leases is calculated as net debt plus lease liabilities, less the net amount of partner receivables and payables relating to leases entered into on behalf of joint operations. Gearing including leases is defined as the ratio of net debt including leases to the total of net debt including leases plus total equity. bp believes these measures provide useful information to investors as they enable investors to understand the impact of the group's lease portfolio on net debt and gearing. See Financial statements – Note 27 for information on finance debt, which is the nearest equivalent measure to net debt including leases on an IFRS basis. The nearest equivalent IFRS measure to gearing including leases on an IFRS basis is finance debt ratio. A reconciliation to IFRS information is provided on page 339.

Green hydrogen

Hydrogen produced by electrolysis of water using renewable power.

Grey hydrogen

Produced via natural gas or coal without CCUS.

Hydrocarbons

Liquids and natural gas. Natural gas is converted to oil equivalent at 5.8 billion cubic feet = 1 million barrels.

Hydrogen pipeline

Hydrogen projects which have not been developed to final investment decision (FID) but which have advanced to the concept development stage.

Inorganic capital expenditure

A subset of capital expenditure on a cash basis and a non-IFRS measure. Inorganic capital expenditure comprises consideration in business combinations and certain other significant investments made by the group. It is reported on a cash basis. bp believes that this measure provides useful information as it allows investors to understand how bp's management invests funds in projects which expand the group's activities through acquisition. The nearest equivalent measure on an IFRS basis is capital expenditure on a cash basis. Further information and a reconciliation to IFRS information is provided on page 336.

Installed renewables capacity

Installed renewables capacity is bp's share of capacity for operating assets owned by entities where bp has an equity share.

Inventory holding gains and losses

Inventory holding gains and losses are non-IFRS adjustments to our IFRS profit (loss) and represent:

- The difference between the cost of sales calculated using the replacement cost of inventory and the cost of sales calculated on the first-in first-out (FIFO) method after adjusting for any changes in provisions where the net realizable value of the inventory is lower than its cost. Under the FIFO method, which we use for IFRS reporting of inventories other than for trading inventories, the cost of inventory charged to the income statement is based on its historical cost of purchase or manufacture, rather than its replacement cost. In volatile energy markets, this can have a significant distorting effect on reported income. The amounts disclosed as inventory holding gains and losses represent the difference between the charge to the income statement for inventory on a FIFO basis (after adjusting for any related movements in net realizable value provisions) and the charge that would have arisen based on the replacement cost of inventory. For this purpose, the replacement cost of inventory is calculated using data from each operation's production and manufacturing system, either on a monthly basis, or separately for each transaction where the system allows this approach.
- An adjustment relating to certain trading inventories that are not price risk managed which relate to a minimum inventory volume that is required to be held to maintain underlying business activities. This adjustment represents the movement in fair value of the inventories due to prices, on a grade-by-grade basis, during the period. This is calculated from each operation's inventory management system on a monthly basis using the discrete monthly movement in market prices for these inventories.

The amounts disclosed are not separately reflected in the financial statements as a gain or loss. No adjustment is made in respect of the cost of inventories held as part of a trading position and certain other temporary inventory positions that are price risk-managed. See Replacement cost (RC) profit or loss definition below.

Joint arrangement

An arrangement in which two or more parties have joint control.

Joint control

Contractually agreed sharing of control over an arrangement, which exists only when decisions about the relevant activities require the unanimous consent of the parties sharing control.

Joint operation

A joint arrangement whereby the parties that have joint control of the arrangement have rights to the assets, and obligations for the liabilities, relating to the arrangement.

Joint venture

A joint arrangement whereby the parties that have joint control of the arrangement have rights to the net assets of the arrangement.

Liquids

Comprises crude oil, condensate and natural gas liquids. For the oil production & operations segment, it also includes bitumen.

LNG portfolio

LNG portfolio refers to bp group's LNG equity production plus additional long-term merchant LNG volumes.

LNG train

An LNG train is a processing facility used to liquefy and purify natural gas in the formation of LNG.

Low carbon activity

An activity relating to low carbon including: renewable electricity; bioenergy; electric vehicles and other future mobility solutions; trading and marketing low carbon products; blue or green hydrogen★ and carbon capture, use and storage (CCUS).

Note that, while there is some overlap of activities, these terms do not mean the same as bp's strategic focus area of low carbon energy or our low carbon energy sub-segment, reported within the gas & low carbon energy segment.

Low carbon activity investment

Capital investment in relation to low carbon activity★.

Major projects

Have a bp net investment of at least $250 million, or are considered to be of strategic importance to bp or of a high degree of complexity.

Operating cash flow

Net cash provided by (used in) operating activities as stated in the group cash flow statement. When used in the context of a segment rather than the group, the terms refer to the segment's share thereof.

Operating management system (OMS)

bp's OMS helps us manage risks in our operating activities by setting out bp's principles for good operating practice. It brings together bp requirements on health, safety, security, the environment, social responsibility and operational reliability, as well as related issues, such as maintenance, contractor relations and organizational learning, into a common management system.

Organic capital expenditure

Non-IFRS measure. Organic capital expenditure comprises capital expenditure on a cash basis less inorganic capital expenditure. bp believes that this measure provides useful information as it allows investors to understand how bp's management invests funds in developing and maintaining the group's assets. The nearest equivalent measure on an IFRS basis is capital expenditure on a cash basis. An analysis of organic capital expenditure by segment and region, and a reconciliation to IFRS information is provided on page 336.

We are unable to present reconciliations of forward-looking information for organic capital expenditure to total cash capital expenditure, because without unreasonable efforts, we are unable to forecast accurately the adjusting item, inorganic capital expenditure, that is difficult to predict in advance in order to derive the nearest IFRS estimate.

Production-sharing agreement / contract (PSA / PSC)

An arrangement through which an oil and gas company bears the risks and costs of exploration, development and production. In return, if exploration is successful, the oil company receives entitlement to variable physical volumes of hydrocarbons, representing recovery of the costs incurred and a stipulated share of the production remaining after such cost recovery.

Rapid / Rapid charging

Rapid charging includes electric vehicle charging of greater or equal to 50kW and less than 150kW.

Realizations

Realizations are the result of dividing revenue generated from hydrocarbon sales, excluding revenue generated from purchases made for resale and royalty volumes, by revenue generating hydrocarbon production volumes. Revenue generating hydrocarbon production reflects the bp share of production as adjusted for any production which does not generate revenue. Adjustments may include losses due to shrinkage, amounts consumed during processing, and contractual or regulatory host committed volumes such as royalties. For the gas & low carbon energy and oil production & operations segments, realizations include transfers between businesses.

Refining availability

Represents Solomon Associates' operational availability for bp-operated refineries, which is defined as the percentage of the year that a unit is available for processing after subtracting the annualized time lost due to turnaround activity and all planned mechanical, process and regulatory downtime.

Refining marker margin (RMM)

The average of regional indicator margins weighted for bp's crude refining capacity in each region. Each regional marker margin is based on product yields and a marker crude oil deemed appropriate for the region. The regional indicator margins may not be representative of the margins achieved by bp in any period because of bp's particular refinery configurations and crude and product slate.

Replacement cost (RC) profit or loss / RC profit or loss attributable to bp shareholders

Reflects the replacement cost of inventories sold in the period and is calculated as profit or loss attributable to bp shareholders, adjusting for inventory holding gains and losses (net of tax). RC profit or loss for the group is not a recognized IFRS measure. bp believes this measure is useful to illustrate to investors the fact that crude oil and product prices can vary significantly from period to period and that the impact on our reported result under IFRS can be significant. Inventory holding gains and losses vary from period to period due to changes in prices as well as changes in underlying inventory levels. In order for investors to understand the operating performance of the group excluding the impact of price changes on the replacement of inventories, and to make comparisons of operating performance between reporting periods, bp's management believes it is helpful to disclose this measure. The nearest equivalent measure on an IFRS basis is profit or loss attributable to bp shareholders. See Financial statements – Note 5. A reconciliation to IFRS information is provided on page 382.

Reported recordable injury frequency

Reported recordable injury frequency measures the number of reported work-related employee and contractor incidents that result in a fatality or injury per 200,000 hours worked. This represents reported incidents occurring within bp's operational HSSE reporting boundary. That boundary includes bp's own operated facilities and certain other locations or situations.

Renewables pipeline

Renewable projects satisfying the criteria below until the point they can be considered developed to FID:

Site based projects that have obtained land exclusivity rights, or for power purchase agreement based projects an offer has been made to the counterparty, or for auction projects pre-qualification criteria has been met, or for acquisition projects post a binding offer has been accepted.

Reserves replacement ratio

The extent to which the year's production has been replaced by proved reserves added to our reserve base. The ratio is expressed in oil-equivalent terms and includes changes resulting from discoveries, improved recovery and extensions and revisions to previous estimates, but excludes changes resulting from acquisitions and disposals.

Retail sites

Retail sites include sites operated by dealers, jobbers, franchisees or brand licensees or joint venture (JV) partners, under the bp brand. These may move to and from the bp brand as their fuel supply agreement or brand licence agreement expires and are renegotiated in the normal course of business. Retail sites are primarily branded *bp*, *ARCO*, *Amoco*, *Aral*, *Thorntons*, and TravelCenters of America and also includes sites in India through our Jio-bp JV.

Return on average capital employed

Non-IFRS measure. Return on average capital employed (ROACE) is defined as underlying replacement cost profit, which is defined as profit or loss attributable to bp shareholders adjusted for inventory holding gains and losses, adjusting items and related taxation on inventory holding gains and losses and adjusting items total taxation, after adding back non-controlling interest and interest expense net of tax, divided by the average of the beginning and ending balances of total equity plus finance debt, excluding cash and cash equivalents and goodwill as presented on the group balance sheet over the periods presented. Interest expense before tax is finance costs as presented on the group income statement, excluding lease interest, the unwinding of the discount on provisions and other payables and other adjusting items reported in finance costs. bp believes it is helpful to disclose the ROACE because this measure gives an indication of the company's capital efficiency. The nearest IFRS measures of the numerator and denominator are profit or loss for the period attributable to bp shareholders and total equity respectively. The reconciliation of the numerator and denominator is provided on page 383.

We are unable to present forward-looking information of the nearest IFRS measures of the numerator and denominator for ROACE, because without unreasonable efforts, we are unable to forecast accurately certain adjusting items required to calculate a meaningful comparable IFRS forward-looking financial measure. These items include inventory holding gains or losses and interest net of tax, that are difficult to predict in advance in order to include in an IFRS estimate.

Strategic convenience sites

Strategic convenience sites are retail sites, within the bp portfolio, which sell bp-supplied vehicle energy (e.g. *bp*, *Aral*, *Arco*, *Amoco*, *Thorntons*, *bp pulse*, *TravelCenters of America* and *PETRO*) and either carry one of the strategic convenience brands (e.g. M&S, Rewe to Go) or a differentiated bp-controlled convenience offer. To be considered a strategic convenience site, the convenience offer should have a demonstrable level of differentiation in the market in which it operates. Strategic convenience site count includes sites under a pilot phase.

Subsidiary
An entity that is controlled by the bp group. Control of an investee exists when an investor is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee.

Surplus cash flow
Surplus cash flow does not represent the residual cash flow available for discretionary expenditures. It is a non-IFRS financial measure that should be considered in addition to, not as a substitute for or superior to, net cash provided by operating activities, reported in accordance with IFRS. The surplus cash flow forms part of bp's financial frame.

Surplus cash flow refers to the net surplus of sources of cash over uses of cash, after reaching the $35 billion net debt target. Sources of cash include net cash provided by operating activities, cash provided from investing activities and cash receipts relating to transactions involving non-controlling interests. Uses of cash include lease liability payments, payments on perpetual hybrid bond, dividends paid, cash capital expenditure, the cash cost of share buybacks to offset the dilution from vesting of awards under employee share schemes, cash payments relating to transactions involving non-controlling interests and currency translation differences relating to cash and cash equivalents as presented on the condensed group cash flow statement.

For 2022, the sources of cash includes other proceeds related to the proceeds from the disposal of a loan note related to the Alaska divestment. The cash was received in the fourth quarter 2021, was reported as a financing cash flow and was not included in other proceeds at the time due to potential recourse from the counterparty. The proceeds are being recognized as the potential recourse reduces.

The components of our sources of cash and uses of cash are provided on page 339.

Technical service contract (TSC)
Technical service contract is an arrangement through which an oil and gas company bears the risks and costs of exploration, development and production. In return, the oil and gas company receives entitlement to variable physical volumes of hydrocarbons, representing recovery of the costs incurred and a profit margin which reflects incremental production added to the oilfield.

Tier 1 and tier 2 process safety events
Tier 1 events are losses of primary containment from a process of greatest consequence – causing harm to a member of the workforce, damage to equipment from a fire or explosion, a community impact or exceeding defined quantities. Tier 2 events are those of lesser consequence. These represent reported incidents occurring within bp's operational HSSE reporting boundary. That boundary includes bp's own operated facilities and certain other locations or situations.

Tight oil and gas
Natural oil and gas reservoirs locked in hard sandstone rocks with low permeability, making the underground formation extremely tight.

Transition growth
Activities, represented by a set of transition growth engines, that transition bp toward its objective to be an integrated energy company, and that comprise our low carbon activity★ alongside other businesses that support transition, such as our power trading and marketing business and convenience.

Transition growth investment
Capital investment in relation to transition growth★, that is aligned to our aim 5 (to increase the proportion of investment we make into our non-oil and -gas businesses. For this purpose, we define 'oil and gas' activities as those primarily encompassing the production, refining and sale of fossil hydrocarbons and their products and those associated with the dedicated gas and oil trading businesses).

UK National Balancing Point
A virtual trading location for sale, purchase and exchange of UK natural gas. It is the pricing and delivery point for the Intercontinental Exchange natural gas futures contract.

Ultra fast / Ultra-fast charging
Electric vehicle charging of greater than or equal to 150kW.

Unconventionals
Resources found in geographic accumulations over a large area, that usually present additional challenges to development such as low permeability or high viscosity. Examples include shale gas and oil, coalbed methane, gas hydrates and natural bitumen deposits. These typically require specialized extraction technology such as hydraulic fracturing or steam injection.

Underlying effective tax rate (ETR)
Non-IFRS measure. The underlying ETR is calculated by dividing taxation on an underlying replacement cost (RC) basis by underlying RC profit or loss before tax. Taxation on an underlying RC basis for the group is calculated as taxation as stated on the group income statement adjusted for taxation on inventory holding gains and losses and adjusting items total taxation. Information on underlying RC profit or loss is provided below. Taxation on an underlying RC basis presented for the operating segments is calculated through an allocation of taxation on an underlying RC basis to each segment. bp believes it is helpful to disclose the underlying ETR because this measure may help investors to understand and evaluate, in the same manner as management, the underlying trends in bp's operational performance on a comparable basis, period on period. Taxation on an underlying RC basis and underlying ETR are non-IFRS measures. The nearest equivalent measure on an IFRS basis is the ETR on profit or loss for the period.

We are unable to present reconciliations of forward-looking information for underlying ETR to ETR on profit or loss for the period, because without unreasonable efforts, we are unable to forecast accurately certain adjusting items required to present a meaningful comparable IFRS forward-looking financial measure. These items include the taxation on inventory holding gains and losses and adjusting items, that are difficult to predict in advance in order to include in an IFRS estimate. A reconciliation to IFRS information is provided on page 382.

Underlying production
Production after adjusting for acquisitions and divestments and entitlement impacts in our production-sharing agreements (PSAs). 2023 underlying production, when compared with 2022, is production after adjusting for acquisitions and divestments, curtailments, and entitlement impacts in our production-sharing agreements/contracts and technical service contract.

Underlying replacement cost (RC) profit or loss / underlying RC profit or loss attributable to bp shareholders
Non-IFRS measure. RC profit or loss★ (as defined above) after excluding net adjusting items and related taxation. See page 337 for additional information on the adjusting items that are used to arrive at underlying RC profit or loss in order to enable a full understanding of the items and their financial impact. **Underlying RC profit or loss before interest and tax** for the operating segments or customers & products businesses is calculated as RC profit or loss (as defined above) including profit or loss attributable to non-controlling interests before interest and tax for the operating segments and excluding net adjusting items for the respective operating segment or business.

bp believes that underlying RC profit or loss is a useful measure for investors because it is a measure closely tracked by management to evaluate bp's operating performance and to make financial, strategic and operating decisions and because it may help investors to understand and evaluate, in the same manner as management, the underlying trends in bp's operational performance on a comparable basis, period on period, by adjusting for the effects of these adjusting items. The nearest equivalent measure on an IFRS basis for the group is profit or loss attributable to bp shareholders. The nearest equivalent measure on an IFRS basis for segments and businesses is RC profit or loss before interest and taxation. A reconciliation to IFRS information is provided on page 382 for the group and pages 39-47 for the segments.

Underlying RC profit or loss per share and underlying RC profit or loss per ADS

Non-IFRS measures. Earnings per share is defined in Note 11. Underlying RC profit or loss per ordinary share is calculated using the same denominator as earnings per share as defined in the consolidated financial statements. The numerator used is underlying RC profit or loss attributable to bp shareholders rather than profit or loss attributable to bp shareholders. Underlying RC profit or loss per ADS is calculated as outlined above for underlying RC profit or loss per share except the denominator is adjusted to reflect one ADS equivalent to six ordinary shares. bp believes it is helpful to disclose the underlying RC profit or loss per ordinary share and per ADS because these measures may help investors to understand and evaluate, in the same manner as management, the underlying trends in bp's operational performance on a comparable basis, period on period. The nearest equivalent measure on an IFRS basis is basic earnings per share based on profit or loss for the period attributable to bp shareholders. A reconciliation to IFRS information is provided on page 382.

upstream

upstream includes oil and natural gas field development and production within the gas & low carbon energy and oil production & operations segments. References to upstream exclude Rosneft.

upstream / hydrocarbon plant reliability

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

upstream unit production costs

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

West Texas Intermediate (WTI)

A light sweet crude oil, priced at Cushing, Oklahoma, which serves as a benchmark price for purchases of oil in the US.

Working capital

Movements in inventories and other current and non-current assets and liabilities as stated in the group cash flow statement.

Trade marks

Trade marks of the bp group appear throughout this report. They include:

Aral, Aral pulse, BP, bp pulse, Castrol, Castrol ON, PETRO, Amoco, TA, Thorntons, Gigahub

Trade marks:

REWE to Go – a registered trade mark of REWE.

Non-IFRS measures reconciliations

Reconciliation of profit or loss for the period to underlying RC profit or loss★

					$ million
	2023	2022	2021	2020	2019
Profit (loss) for the year attributable to bp shareholders	**15,239**	(2,487)	7,565	(20,305)	4,026
Inventory holding (gains) losses★, before tax	**1,236**	(1,351)	(3,655)	2,868	(667)
Taxation charge (credit) on inventory holding gains and losses	**(292)**	332	829	(667)	156
RC profit (loss)★ for the year	**16,183**	(3,506)	4,739	(18,104)	3,515
Net (favourable) adverse impact of adjusting items★, before tax	**(1,143)**	29,781	8,697	16,649	8,263
Adjusting items total taxation	**(1,204)**	1,378	(621)	(4,235)	(1,788)
Underlying RC profit or loss for the year	**13,836**	27,653	12,815	(5,690)	9,990

Reconciliation of basic earnings per ordinary share to underlying RC profit per ordinary share★

			Per ordinary share – cents
	2023	2022	2021
Profit (loss) for the year attributable to bp shareholders	**87.78**	(13.10)	37.57
Inventory holding (gains) losses★, before tax	**7.12**	(7.12)	(18.16)
Taxation charge (credit) on inventory holding gains and losses	**(1.69)**	1.75	4.12
	93.21	(18.47)	23.53
Net (favourable) adverse impact of adjusting items★, before tax	**(6.58)**	156.84	43.21
Taxation charge (credit) on adjusting items	**(6.94)**	7.26	(3.09)
Underlying RC profit for the year	**79.69**	145.63	63.65

Reconciliation of basic earnings per ADS to underlying RC profit per ADS★

			Per ADS – dollars
	2023	2022	2021
Profit (loss) for the year attributable to bp shareholders	**5.27**	(0.79)	2.25
Inventory holding (gains) losses★, before tax	**0.43**	(0.43)	(1.09)
Taxation charge (credit) on inventory holding gains and losses	**(0.11)**	0.11	0.25
	5.59	(1.11)	1.41
Net (favourable) adverse impact of adjusting items★, before tax	**(0.40)**	9.41	2.59
Taxation charge (credit) on adjusting items	**(0.41)**	0.44	(0.19)
Underlying RC profit for the year	**4.78**	8.74	3.82

Reconciliation of effective tax rate (ETR) to ETR on RC profit or loss and underlying ETR★

Taxation (charge) credit

			$ million
	2023	2022	2021
Taxation on profit or loss before taxation for the year	**(7,869)**	(16,762)	(6,740)
Adjusted for taxation on inventory holding gains and losses	**292**	(332)	(829)
Taxation on a RC profit or loss basis	**(8,161)**	(16,430)	(5,911)
Adjusted for adjusting items total taxation	**1,204**	(1,378)	621
Taxation on an underlying RC basis	**(9,365)**	(15,052)	(6,532)

Effective tax rate

			%
	2023	2022	2021
ETR on profit or loss before taxation for the year	**33**	109	44
Adjusted for inventory holding gains and losses	**–**	8	7
ETR on RC profit or loss	**33**	117	51
Adjusted for adjusting items total taxation	**6**	(83)	(19)
Underlying ETR	**39**	34	32

Return on average capital employed (ROACE)★

					$ million
	2023	2022	2021	2020	2019
Profit (loss) for the year attributable to bp shareholders	**15,239**	(2,487)	7,565	(20,305)	4,026
Inventory holding (gains) losses★, before tax	**1,236**	(1,351)	(3,655)	2,868	(667)
Taxation charge (credit) on inventory holding gains and losses	**(292)**	332	829	(667)	156
Adjusting items★, before tax	**(1,143)**	29,781	8,697	16,649	8,263
Taxation charge (credit) on adjusting items	**(1,204)**	1,378	(621)	(4,235)	(1,788)
Underlying RC profit	**13,836**	27,653	12,815	(5,690)	9,990
Interest expense[a]	**2,569**	1,632	1,322	1,808	2,032
Taxation on interest expense	**(661)**	(296)	(195)	(406)	(288)
Non-controlling interests (NCI)	**641**	1,130	922	(424)	164
	16,385	30,119	14,864	(4,712)	11,898
Total equity	**85,493**	82,990	90,439	85,568	100,708
Finance debt	**51,954**	46,944	61,176	72,664	67,724
Capital employed	**137,447**	129,934	151,615	158,232	168,432
Less: Goodwill	**12,472**	11,960	12,373	12,480	11,868
Cash and cash equivalents	**33,030**	29,195	30,681	31,111	22,472
	91,945	88,779	108,561	114,641	134,092
Average capital employed excluding goodwill and cash and cash equivalents	**90,362**	98,670	111,601	124,367	133,050
Profit (loss) for the year attributable to bp shareholders divided by total equity	**17.8%**	(3.0)%	8.4%	(23.7)%	4.0%
ROACE	**18.1%**	30.5%	13.3%	(3.8)%	8.9%

[a] Finance costs, as reported in the Group income statement, were $3,840 million (2022 $2,703 million, 2021 $2,857 million, 2020 $3,115 million, 2019 $3,489 million). Interest expense is finance costs excluding lease interest of $346 million (2022 $257 million, 2021 $306 million, 2020 $350 million), unwinding of discount on provisions and other payables of $912 million (2022 $808 million, 2021 $890 million, 2020 $957 million, 2019 $1,074 million) and other adjusting items related to finance costs of $13 million (2022 $6 million, 2021 $339 million).

Adjusted EBIDA★

			$ million
	2023	2022	2021
Profit (loss) for the period	**15,880**	(1,357)	8,487
Finance costs	**3,840**	2,703	2,857
Net finance (income) expense relating to pensions and other post-retirement benefits	**(241)**	(69)	(2)
Taxation	**7,869**	16,762	6,740
Profit before interest and tax	**27,348**	18,039	18,082
Inventory holding (gains) losses, before tax	**1,236**	(1,351)	(3,655)
	28,584	16,688	14,427
Net (favourable) adverse impact of adjusting items, before interest and tax	**(1,548)**	29,356	7,915
	27,036	46,044	22,342
Taxation on an underlying RC basis[a]	**(9,365)**	(15,052)	(6,532)
	17,671	30,992	15,810
Add back:			
Depreciation, depletion and amortization	**15,928**	14,318	14,805
Exploration expenditure written off	**746**	385	168
Adjusted EBIDA	**34,345**	45,695	30,783

[a] A definition for taxation on an underlying RC basis is included under Underlying ETR in the glossary on page 380.

Adjusted EBITDA★

			$ million
	2023	2022	2021
Profit (loss) for the period	**15,880**	(1,357)	8,487
Finance costs	**3,840**	2,703	2,857
Net finance (income) expense relating to pensions and other post-retirement benefits	**(241)**	(69)	(2)
Taxation	**7,869**	16,762	6,740
Profit (loss) before interest and tax	**27,348**	18,039	18,082
Inventory holding (gains) losses, before tax	**1,236**	(1,351)	(3,655)
	28,584	16,688	14,427
Net (favourable) adverse impact of adjusting items, before interest and tax	**(1,548)**	29,356	7,915
Underlying RC profit (loss) before interest and tax	**27,036**	46,044	22,342
Add back:			
Depreciation, depletion and amortization	**15,928**	14,318	14,805
Exploration expenditure written off	**746**	385	168
Adjusted EBITDA	**43,710**	60,747	37,315

Reconciliation of RC profit before interest and tax for gas & low carbon energy and oil production & operations to adjusted EBITDA★

			$ million
	2023	2022	2021
gas & low carbon energy			
RC profit before interest and tax	**14,080**	14,696	2,133
Less: Net favourable (adverse) impact of adjusting items★	**5,358**	(1,367)	(5,395)
Underlying RC profit before interest and tax★	**8,722**	16,063	7,528
Add back: Depreciation, depletion and amortization	**5,680**	5,008	4,464
Exploration expenditure written off	**362**	2	43
Adjusted EBITDA	**14,764**	21,073	12,035
oil production & operations			
RC profit before interest and tax	**11,191**	19,721	10,501
Less: Net favourable (adverse) impact of adjusting items	**(1,590)**	(503)	209
Underlying RC profit before interest and tax	**12,781**	20,224	10,292
Add back: Depreciation, depletion and amortization	**5,692**	5,564	6,528
Exploration expenditure written off	**384**	383	125
Adjusted EBITDA	**18,857**	26,171	16,945

The Directors' report on pages 81-104, 105 (in respect of the remuneration committee), 133-135, 247-274 and 335-384 was approved by the board and signed on its behalf by Ben J. S. Mathews, company secretary on 8 March 2024.

BP p.l.c.
Registered in England and Wales No. 102498

Signatures

The registrant hereby certifies that it meets all of the requirements for filing on Form 20-F and that it has duly caused and authorized the undersigned to sign this annual report on its behalf.

BP p.l.c.
(Registrant)

/s/ Ben J. S. Mathews
Company secretary
8 March 2024

Cross reference to Form 20-F

Information about this report

This document constitutes the Annual Report and Accounts in accordance with UK requirements and the Annual Report on Form 20-F in accordance with the US Securities Exchange Act of 1934, for BP p.l.c. for the year ended 31 December 2023. A cross reference to Form 20-F requirements is included on page 386.

This document contains the Strategic report on the inside front cover and pages 1-80 and the Directors' report on pages 81-104, 105 (in part only), 133-135, 247-274 and 335-384. The Strategic report and the Directors' report together include the management report required by DTR 4.1 of the UK Financial Conduct Authority's Disclosure Guidance and Transparency Rules. The Directors' remuneration report is on pages 105-132. The consolidated financial statements of the group are on pages 137-246 and the corresponding reports of the auditor are on pages 138-163. The parent company financial statements of BP p.l.c. are on pages 275-334.

The Directors' statements (comprising the Statement of directors' responsibilities; Risk management and internal control; Longer-term viability; Going concern; and Fair, balanced and understandable), the independent auditor's report on the annual report and accounts to the members of BP p.l.c., the parent company financial statements of BP p.l.c. and corresponding auditor's report do not form part of bp's Annual Report on Form 20-F as filed with the SEC.

bp Annual Report and Form 20-F 2023 may be downloaded from *bp.com/annualreport*. No material on the bp website, other than the items identified as *bp Annual Report* and *Form 20-F 2023*, forms any part of this document. References in this document to other documents on the bp website, such as *bp Energy Outlook*, *bp Net Zero Ambition Progress Update* and *bp Sustainability Report* are included as an aid to their location and are not incorporated by reference into this document.

BP p.l.c. is the parent company of the bp group of companies. The company was incorporated in 1909 in England and Wales and changed its name to BP p.l.c. in 2001. Where we refer to the company, we mean BP p.l.c. The company and each of its subsidiaries★ are separate legal entities. Unless otherwise stated or the context otherwise requires, the term "BP" or "bp" and terms such as "we", "us" and "our" are used in this report for convenience to refer to one or more of the members of the bp group instead of identifying a particular entity or entities. Information in this document reflects 100% of the assets and operations of the company and its subsidiaries that were consolidated at the date or for the periods indicated, including non-controlling interests.

The company's primary share listing is the London Stock Exchange. In the US, the company's securities are traded on the New York Stock Exchange (NYSE) in the form of ADSs (see page 364 for more details) and in Germany in the form of a global depositary certificate representing bp ordinary shares traded on the Frankfurt, Hamburg and Düsseldorf Stock Exchanges.

The term 'shareholder' in this report means, unless the context otherwise requires, investors in the equity capital of BP p.l.c., both direct and indirect. As the company's shares, in the form of ADSs, are listed on the NYSE, an Annual Report on Form 20-F is filed with the SEC. Ordinary shares are ordinary fully paid shares in BP p.l.c. of 25 cents each. Preference shares are cumulative first preference shares and cumulative second preference shares in BP p.l.c. of £1 each.

Registered office and our worldwide headquarters:	**Our agent in the US:**
BP p.l.c.	**BP America Inc.**
1 St James's Square	501 Westlake Park Boulevard
London SW1Y 4PD	Houston, Texas 77079
UK	US
Tel +44 (0)20 7496 4000	Tel +1 281 366 2000

Registered in England and Wales No. 102498.
London Stock Exchange symbol 'BP.'

Exhibits

The following documents are filed in the Securities and Exchange Commission (SEC) EDGAR system, as part of this Annual Report on Form 20-F, and can be viewed on the SEC's website.

Exhibit 1	Memorandum and Articles of Association of BP p.l.c.***†
Exhibit 2	Description of rights of each class of securities registered under Section 12 of the Securities Exchange Act of 1934†
Exhibit 4.1	The BP Executive Directors' Incentive Plan**†
Exhibit 4.4	Director's Service Agreement for K Thomson†
Exhibit 4.7	Director's Service Agreement for M Auchincloss†
Exhibit 4.10	The BP Share Award Plan 2015***†
Exhibit 8	Subsidiaries (included as Note 37 to the Financial Statements)
Exhibit 11	Code of Ethics*†
Exhibit 12	Rule 13a – 14(a) Certifications†
Exhibit 13	Rule 13a – 14(b) Certifications#†
Exhibit 15.1	Consent of Netherland, Sewell & Associates†
Exhibit 15.2	Report of Netherland, Sewell & Associates†
Exhibit 15.3	Consent Decree***†
Exhibit 15.4	Gulf states Settlement Agreement***†
Exhibit 15.5	Consent of Deloitte LLP†
Exhibit 17	Guaranteed Securities†
Exhibit 97	Executive Compensation Clawback Policy
Exhibit 101	Inline XBRL data files
Exhibit 104	Cover page interactive data file (formatted as Inline XBRL and contained in Exhibit 101)

* Incorporated by reference to the company's Annual Report on Form 20-F for the year ended 31 December 2009.

** Incorporated by reference to the company's Annual Report on Form 20-F for the year ended 31 December 2014.

*** Incorporated by reference to the company's Annual Report on Form 20-F for the year ended 31 December 2015.

**** Incorporated by reference to the company's Annual Report on Form 20-F for the year ended 31 December 2019.

***** Incorporated by reference to the company's Annual Report on Form 20-F for the year ended 31 December 2020.

\# Furnished only.

† Included only in the annual report filed in the Securities and Exchange Commission EDGAR system.

The total amount of long-term securities of BP p.l.c. and its subsidiaries under any one instrument does not exceed 10% of their total assets on a consolidated basis.

The company agrees to furnish copies of any or all such instruments to the SEC on request.

★ See glossary on **page 373**