24. 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	Note	Loans and receivables	Available-for-sale financial assets	At fair value through profit and loss	Derivative hedging instruments	Financial liabilities measured at amortized cost	Total carrying amount
							2009
Financial assets							
Other investments	25	–	1,567	–	–	–	1,567
Loans		1,288	–	–	–	–	1,288
Trade and other receivables	27	31,016	–	–	–	–	31,016
Derivative financial instruments	31	–	–	7,960	972	–	8,932
Cash and cash equivalents	28	6,570	1,769	–	–	–	8,339
Financial liabilities							
Trade and other payables	30	–	–	–	–	(34,325)	(34,325)
Derivative financial instruments	31	–	–	(7,389)	(766)	–	(8,155)
Accruals		–	–	–	–	(6,905)	(6,905)
Finance debt	32	–	–	–	–	(34,627)	(34,627)
		38,874	3,336	571	206	(75,857)	(32,870)

$ million

At 31 December	Note	Loans and receivables	Available-for-sale financial assets	At fair value through profit and loss	Derivative hedging instruments	Financial liabilities measured at amortized cost	Total carrying amount
							2008
Financial assets							
Other investments	25	–	855	–	–	–	855
Loans		1,163	–	–	–	–	1,163
Trade and other receivables	27	29,489	–	–	–	–	29,489
Derivative financial instruments	31	–	–	12,501	1,063	–	13,564
Cash and cash equivalents	28	5,609	2,588	–	–	–	8,197
Financial liabilities							
Trade and other payables	30	–	–	–	–	(33,140)	(33,140)
Derivative financial instruments	31	–	–	(13,173)	(2,075)	–	(15,248)
Accruals		–	–	–	–	(7,527)	(7,527)
Finance debt	32	–	–	–	–	(33,204)	(33,204)
		36,261	3,443	(672)	(1,012)	(73,871)	(35,851)

The fair value of finance debt is shown in Note 32. For all other financial instruments, the carrying amount is either the fair value, or approximates the fair value.

Financial risk factors

The group is exposed to a number of different financial risks arising from natural business exposures as well as its use of financial instruments including: market risks relating to commodity prices, foreign currency exchange rates, interest rates and equity prices; credit risk; and liquidity risk.

The group financial risk committee (GFRC) advises the group 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 group treasurer and the heads of the finance, tax and the integrated supply and trading functions. 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 group chief executive (GCE), and via the GCE 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 and power markets are managed within the integrated supply and trading function, while activities in the financial markets are managed by the treasury function. 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 integrated supply and trading function maintains formal governance processes that provide oversight of market risk associated with trading activity. These processes meet generally accepted industry practice and reflect the principles of the Group of Thirty Global Derivatives Study recommendations. A policy and risk committee monitors and validates limits and risk exposures, reviews incidents and validates risk-related policies, methodologies and procedures. A commitments committee approves value-at-risk delegations, the trading of new products, instruments and strategies and material commitments.

24. Financial instruments and financial risk factors continued

In addition, the integrated supply and trading function undertakes derivative activity for risk management purposes under a separate 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 market price movements that the group is exposed to include oil, natural gas and power prices (commodity price risk), foreign currency exchange rates, interest rates, equity prices and other indices that could adversely affect the value of the group's financial assets, liabilities or expected future cash flows. The group enters into derivatives in a well established entrepreneurial trading operation. In addition, the group has developed a control framework aimed at managing the volatility inherent in certain of its natural business exposures. In accordance with this control framework the group enters into various transactions using derivatives for risk management purposes.

The group measures market risk exposure arising from its trading positions using value-at-risk techniques. These techniques are based on a variance/covariance model or a Monte Carlo simulation and make a statistical assessment of the market risk arising from possible future changes in market prices over a 24-hour period. The calculation of the range of potential changes in fair value takes into account a snapshot of the end-of-day exposures and the history of one-day price movements, together with the correlation of these price movements. The value-at-risk measure is supplemented by stress testing and tail risk analysis.

The trading value-at-risk model is used for derivative financial instrument types such as: interest rate forward and futures contracts, swap agreements, options and swaptions; foreign exchange forward and futures contracts, swap agreements and options; and oil, natural gas and power price forwards, futures, swap agreements and options. Additionally, where physical commodities or non-derivative forward contracts are held as part of a trading position, they are also reflected in the value-at-risk model. For options, a linear approximation is included in the value-at-risk models when full revaluation is not possible.

The value-at-risk table does not incorporate any of the group's natural business exposures or any derivatives entered into to risk manage those exposures. Market risk exposure in respect of embedded derivatives is also not included in the value-at-risk table. Instead separate sensitivity analyses are disclosed below.

Value-at-risk limits are in place for each trading activity and for the group's trading activity in total. The board has delegated an overall limit of $100 million value at risk in support of this trading activity. The high and low values at risk indicated in the table below for each type of activity are independent of each other. Through the portfolio effect the high value at risk for the group as a whole is lower than the sum of the highs for the constituent parts. The potential movement in fair values is expressed to a 95% confidence interval. This means that, in statistical terms, one would expect to see a decrease in fair values greater than the trading value at risk on one occasion per month if the portfolio were left unchanged.

								$ million
Value at risk for 1 day at 95% confidence interval				2009				2008
	High	**Low**	**Average**	**Year end**	High	Low	Average	Year end
Group trading	**79**	**24**	**45**	**30**	76	20	37	69
Oil price trading	**75**	**9**	**29**	**12**	69	12	25	63
Natural gas price trading	**70**	**15**	**33**	**31**	50	12	24	23
Power price trading	**14**	**3**	**5**	**5**	14	3	7	4
Currency trading	**4**	**–**	**2**	**2**	4	–	2	–
Interest rate trading	**7**	**–**	**3**	**3**	7	–	2	1
Other trading	**4**	**1**	**2**	**3**	5	1	2	2

The major components of market risk are commodity price risk, foreign currency exchange risk, interest rate risk and equity price risk, each of which is discussed below.

(i) Commodity price risk

The group's integrated supply and trading function uses conventional financial and commodity instruments and physical cargoes available in the related commodity markets. Oil and natural gas swaps, options and futures are used to mitigate price risk. Power trading is undertaken using a combination of over-the-counter forward contracts and other derivative contracts, including options and futures. This activity is on both a standalone basis and in conjunction with gas derivatives in relation to gas-generated power margin. In addition, NGLs are traded around certain US inventory locations using over-the-counter forward contracts in conjunction with over-the-counter swaps, options and physical inventories. Trading value-at-risk information in relation to these activities is shown in the table above.

As described above, the group also carries out risk management of certain natural business exposures using over-the-counter swaps and exchange futures contracts. Together with certain physical supply contracts that are classified as derivatives, these contracts fall outside of the value-at-risk framework. For these derivative contracts the sensitivity of the net fair value to an immediate 10% increase or decrease in all reference prices would have been $73 million at 31 December 2009 (2008 $90 million). This figure does not include any corresponding economic benefit or disbenefit that would arise from the natural business exposure which would be expected to offset the gain or loss on the over-the-counter swaps and exchange futures contracts mentioned above.

In addition, the group has embedded derivatives relating to certain natural gas contracts. The net fair value of these contracts was a liability of $1,331 million at 31 December 2009 (2008 liability of $1,867 million). Key information on the natural gas contracts is given below.

At 31 December	**2009**	2008
Remaining contract terms	**9 months to 8 years 9 months**	1 year 9 months to 9 years 9 months
Contractual/notional amount	**2,460 million therms**	3,585 million therms
Discount rate – nominal risk free	**4.0%**	2.5%

24. Financial instruments and financial risk factors continued

For these embedded derivatives the sensitivity of the net fair value to an immediate 10% favourable or adverse change in the key assumptions is as follows.

								$ million
At 31 December				2009				2008
	Gas price	Oil price	Power price	Discount rate	Gas price	Oil price	Power price	Discount rate
Favourable 10% change	**175**	**26**	**23**	**20**	291	81	27	16
Unfavourable 10% change	**(215)**	**(43)**	**(19)**	**(20)**	(289)	(81)	(27)	(16)

The sensitivities for risk management activity and embedded derivatives are hypothetical and should not be considered to be predictive of future performance. In addition, for the purposes of this analysis, in the above table, the effect of a variation in a particular assumption on the fair value of the embedded derivatives is calculated independently of any change in another assumption. In reality, changes in one factor may contribute to changes in another, which may magnify or counteract the sensitivities. Furthermore, the estimated fair values as disclosed should not be considered indicative of future earnings on these contracts.

(ii) Foreign currency exchange risk

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 above. This activity is described as currency trading in the value at risk table above.

Since BP has global operations, fluctuations in foreign currency exchange rates can have significant effects on the group’s reported results. 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 conversion 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 minimize 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 dealing with any material residual foreign currency exchange risks.

The group manages these exposures by constantly reviewing the foreign currency economic value at risk and managing such risk to keep the 12-month foreign currency value at risk below $200 million. At 31 December 2009, the foreign currency value at risk was $140 million (2008 $70 million). At no point over the past three years did the value at risk exceed the maximum risk limit. The most significant exposures relate to capital expenditure commitments and other UK and European operational requirements, for which a hedging programme is in place and hedge accounting is claimed as outlined in Note 31.

For highly probable forecast capital expenditures the group locks in the US dollar cost of non-US dollar supplies by using currency forwards and futures. The main exposures are sterling, Canadian dollar, euro, Norwegian krone, Australian dollar, Korean won, and at 31 December 2009 open contracts were in place for $800 million sterling, $491 million Canadian dollar, $299 million euro, $240 million Norwegian krone, $215 million Australian dollar, $51 million Korean won and $41 million Singapore dollar capital expenditures maturing within six years, with over 65% of the deals maturing within two years (2008 $949 million sterling, $712 million Canadian dollar, $553 million euro, $392 million Norwegian krone, $303 million Australian dollar and $187 million Korean won capital expenditures maturing within seven years with over 65% of the deals maturing within two years).

For other UK, European, Canadian and Australian operational requirements the group uses cylinders and currency forwards to hedge the estimated exposures on a 12-month rolling basis. At 31 December 2009, the open positions relating to cylinders consisted of receive sterling, pay US dollar, purchased call and sold put options (cylinders) for $1,887 million (2008 $1,660 million); receive euro, pay US dollar cylinders for $1,716 million (2008 $1,612 million); receive Canadian dollar, pay US dollar cylinders for $300 million (2008 $250 million); and receive Australian dollar, pay US dollar cylinders for $297 million (2008 $455 million). At 31 December 2009 there were no open positions relating to currency forwards (2008 buy sterling, sell US dollar currency forwards for $816 million; buy euro, sell US dollar currency forwards for $141 million; buy Canadian dollar, sell US dollar, currency forwards for $50 million; and buy Australian dollar, sell US dollar currency forwards for $90 million).

In addition, most of the group’s borrowings are in US dollars or are hedged with respect to the US dollar. At 31 December 2009, the total foreign currency net borrowings not swapped into US dollars amounted to $465 million (2008 $1,037 million). Of this total, $113 million was denominated in currencies other than the functional currency of the individual operating unit being entirely Canadian dollars (2008 $92 million, being entirely Canadian dollars). It is estimated that a 10% change in the corresponding exchange rates would result in an exchange gain or loss in the income statement of $11 million (2008 $9 million).

(iii) Interest rate risk

Where the group enters into money market contracts for entrepreneurial trading purposes the activity is controlled using value-at-risk techniques as described above. This activity is described as interest rate trading in the value-at-risk table above.

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 in a variety of currencies based on market opportunities, it uses derivatives to swap the debt to a US dollar floating rate exposure but in certain defined circumstances maintains a fixed rate exposure for a proportion of debt. The proportion of floating rate debt net of interest rate swaps at 31 December 2009 was 63% of total finance debt outstanding (2008 72%). The weighted average interest rate on finance debt at 31 December 2009 is 2% (2008 3%) and the weighted average maturity of fixed rate debt is four years (2008 three years).

24. Financial instruments and financial risk factors continued

The group's earnings are sensitive to changes in interest rates on the floating rate element of the group's finance debt. If the interest rates applicable to floating rate instruments were to have increased by 1% on 1 January 2010, it is estimated that the group's profit before taxation for 2010 would decrease by approximately $219 million (2008 $239 million decrease in 2009). This assumes that the amount and mix of fixed and floating rate debt, including finance leases, remains unchanged from that in place at 31 December 2009 and that the change in interest rates is effective from the beginning of the year. Where the interest rate applicable to an instrument is reset during a quarter it is assumed that this occurs at the beginning of the quarter and remains unchanged for the rest of the year. In reality, the fixed/floating rate mix will fluctuate over the year and interest rates will change continually. Furthermore, the effect on earnings shown by this analysis does not consider the effect of any other changes in general economic activity that may accompany such an increase in interest rates.

(iv) Equity price risk

The group holds equity investments, typically made for strategic purposes, that are classified as non-current available-for-sale financial assets and are measured initially at fair value with changes in fair value recognized in other comprehensive income. Accumulated fair value changes are recycled to the income statement on disposal, or when the investment is impaired. No impairment losses have been recognized in 2009
(2008 $546 million and 2007 nil) relating to listed non-current available-for-sale investments. For further information see Note 25.

At 31 December 2009, it is estimated that an increase of 10% in quoted equity prices would result in an immediate credit to other comprehensive income of $130 million (2008 $59 million credit to other comprehensive income), whilst a decrease of 10% in quoted equity prices would result in an immediate charge to other comprehensive income of $130 million (2008 $48 million charge to profit or loss and $11 million charge to other comprehensive income).

At 31 December 2009, 73% (2008 56%) of the carrying amount of non-current available-for-sale financial assets represented the group's stake in Rosneft, thus the group's exposure is concentrated on changes in the share price of this equity in particular.

(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.

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 are formal delegated authorities to the sales and marketing teams to incur credit risk and to a specialized credit function to set counterparty limits; the establishment of credit systems and processes to ensure that counterparties are rated and limits set; and systems to monitor exposure against limits and report regularly on those exposures, and immediately on any excesses, and to track and report credit losses. The treasury function provides a similar credit risk management activity with respect to group-wide exposures to banks and other financial institutions.

In the current economic environment the group has placed increased emphasis on the management of credit risk. Policies and procedures were reviewed in 2008 and credit exposures arising from physical commodity and derivative transactions with banks and other counterparties have been reduced in 2008 and 2009, mainly through netting and collateral arrangements.

Before trading with a new counterparty can start, its creditworthiness is assessed and a credit rating is allocated that indicates the probability of default, along with a credit exposure limit. The assessment process takes into account all available qualitative and quantitative information about the counterparty and the group, if any, to which the counterparty belongs. The counterparty's business activities, financial resources and business risk management processes are taken into account in the assessment, to the extent that this information is publicly available or otherwise disclosed to BP by the counterparty, together with external credit ratings, if any, including ratings prepared by Moody's Investor Service and Standard & Poor's. Creditworthiness continues to be evaluated after transactions have been initiated and a watchlist of higher-risk counterparties is maintained.

The group does not aim to remove credit risk but expects to experience a certain level of credit losses. The group attempts to mitigate credit risk by entering into contracts that permit netting and allow for termination of the contract on the occurrence of certain events of default. Depending on the creditworthiness of the counterparty, the group may require collateral or other credit enhancements such as cash deposits or letters of credit and parent company guarantees. Trade receivables and payables, and derivative assets and liabilities, are presented on a net basis where unconditional netting arrangements are in place with counterparties and where there is an intent to settle amounts due on a net basis. The maximum credit exposure associated with financial assets is equal to the carrying amount. At 31 December 2009, the maximum credit exposure was $49,575 million (2008 $52,413 million). Collateral received and recognized in the balance sheet at the year-end was $549 million
(2008 $1,121 million) and collateral held off balance sheet was $48 million (2008 $203 million). Credit exposure exists in relation to guarantees issued by group companies under which amounts outstanding at 31 December 2009 were $319 million (2008 $223 million) in respect of liabilities of jointly controlled entities and associates and $667 million (2008 $613 million) in respect of liabilities of other third parties.

Notwithstanding the processes described above, significant unexpected credit losses can occasionally occur. Exposure to unexpected losses increases with concentrations of credit risk that exist when a number of counterparties are involved in similar activities or operate in the same industry sector or geographical area, which may result in their ability to meet contractual obligations being impacted by changes in economic, political or other conditions. The group's principal customers, suppliers and financial institutions with which it conducts business are located throughout the world. In addition, these risks are managed by maintaining a group watchlist and aggregating multi-segment exposures to ensure that a material credit risk is not missed.

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. The reports also include details of the largest counterparties by exposure level and expected loss, and details of counterparties on the group watchlist.

Table of Contents

24. Financial instruments and financial risk factors continued

Some mitigation of credit exposure is achieved by: netting arrangements; credit support agreements which require the counterparty to provide collateral or other credit risk mitigation; and credit insurance and other risk transfer instruments.

For the contracts comprising derivative financial instruments in an asset position at 31 December 2009, it is estimated that over 80% (2008 over 80%) of the unmitigated credit exposure is to counterparties of investment grade credit quality.

Trade and other receivables of the group are analysed in the table below. By comparing the BP credit ratings to the equivalent external credit ratings, it is estimated that approximately 55-60% (2008 approximately 60-65%) of the unmitigated trade receivables portfolio exposure is of investment grade credit quality. With respect to the trade and other receivables that are neither impaired nor past due, there are no indications as of the reporting date that the debtors will not meet their payment obligations.

The group does not typically renegotiate the terms of trade receivables; however, if a renegotiation does take place, the outstanding balance is included in the analysis based on the original payment terms. There were no significant renegotiated balances outstanding at 31 December 2009 or 31 December 2008.

		$ million
Trade and other receivables at 31 December	**2009**	2008
Neither impaired nor past due	**29,426**	25,838
Impaired (net of valuation allowance)	**91**	73
Not impaired and past due in the following periods		
within 30 days	**808**	1,323
31 to 60 days	**151**	489
61 to 90 days	**76**	596
over 90 days	**464**	1,170
	31,016	29,489

The movement in the valuation allowance for trade receivables is set out below.

		$ million
Trade and other receivables at 31 December	**2009**	2008
At 1 January	**391**	406
Exchange adjustments	**12**	(32)
Charge for the year	**157**	191
Utilization	**(130)**	(174)
At 31 December	**430**	391

(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, subsidiaries pool their cash surpluses to treasury, 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.

In managing its liquidity risk, the group has access to a wide range of funding at competitive rates through capital markets and banks. The group’s treasury function centrally co-ordinates relationships with banks, borrowing requirements, foreign exchange requirements and cash management. The group believes it has access to sufficient funding through the commercial paper markets and by using undrawn committed borrowing facilities to meet foreseeable borrowing requirements. At 31 December 2009, the group had substantial amounts of undrawn borrowing facilities available, including committed facilities of $4,950 million, of which $4,550 million are in place through to the fourth quarter of 2011, unchanged from the position as at 31 December 2008. These facilities are with a number of international banks and borrowings under them would be at pre-agreed rates.

The group has in place a European Debt Issuance Programme (DIP) under which the group may raise $20 billion of debt for maturities of one month or longer. At 31 December 2009, the amount drawn down against the DIP was $11,403 million (2008 $10,334 million). In addition, the group has in place an unlimited US Shelf Registration under which it may raise debt with maturities of one month or longer.

The group has long-term debt ratings of Aa1 (stable outlook) and AA (stable outlook), assigned respectively by Moody’s and Standard and Poor’s, unchanged from 2008.

Despite recent increased uncertainty in the financial markets, including a lack of liquidity for some borrowers, we have been able to issue $11 billion of long-term debt during 2009 and issue short-term commercial paper at competitive rates, as and when required. As an additional precautionary measure, we have increased and maintained the cash and cash equivalents held by the group to $8.3 billion at the end of 2009 and $8.2 billion at the end of 2008, compared with $3.6 billion at the end of 2007.

The amounts shown for finance debt in the table below include expected interest payments on borrowings and the future minimum lease payments with respect to finance leases.

24. Financial instruments and financial risk factors continued

There are amounts included within finance debt that we show in the table below as due within one year to reflect the earliest contractual repayment dates but that are expected to be repaid over the maximum long-term maturity profiles of the contracts as described in Note 32. US Industrial Revenue/Municipal Bonds of $2,895 million (2008 $3,166 million) with earliest contractual repayment dates within one year have expected repayment dates ranging from 1 to 33 years (2008 1 to 40 years). The bondholders typically have the option to tender these bonds for repayment on interest reset dates; however, any bonds that are tendered are usually remarketed and BP has not experienced any significant repurchases. BP considers these bonds to represent long-term funding when internally assessing the maturity profile of its finance debt. Similar treatment is applied for loans associated with long-term gas supply contracts totalling $1,622 million (2008 $1,806 million) that mature within eight years.

The table also shows the timing of cash outflows relating to trade and other payables and accruals.

						$ million
			2009			2008
	Trade and other payables	**Accruals**	**Finance debt**	Trade and other payables	Accruals	Finance debt
Within one year	**31,413**	**6,202**	**9,790**	30,598	6,743	16,670
1 to 2 years	**1,059**	**231**	**6,861**	402	359	5,934
2 to 3 years	**1,089**	**106**	**5,359**	898	77	3,419
3 to 4 years	**566**	**78**	**5,528**	902	72	2,647
4 to 5 years	**67**	**49**	**3,151**	223	67	5,072
5 to 10 years	**85**	**163**	**5,723**	53	164	1,316
Over 10 years	**46**	**76**	**1,150**	64	45	1,050
	34,325	**6,905**	**37,562**	33,140	7,527	36,108

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 31. Management does not currently anticipate any cash flows that could be of a significantly different amount, or could occur earlier than the expected maturity analysis provided.

The table below shows cash outflows for derivative hedging instruments based upon contractual payment dates. The amounts reflect the maturity profile of the fair value liability where the instruments will be settled net, and 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 interest rate swaps hedging non-US dollar finance debt. 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 for the receive leg of derivatives that are settled separately from the pay leg, which amount to $7,999 million at 31 December 2009 (2008 $8,545 million) to be received on the same day as the related cash outflows.

		$ million
	2009	2008
Within one year	**2,826**	3,426
1 to 2 years	**1,395**	3,024
2 to 3 years	**1,669**	1,037
3 to 4 years	**1,349**	1,731
4 to 5 years	**1,104**	1,389
5 to 10 years	**322**	129
	8,665	10,736

The group has issued third-party guarantees, as described above under credit risk. These amounts represent the maximum exposure of the group, substantially all of which could be called within one year.

Table of Contents

25. Other investments

	2009 ($ million)	2008 ($ million)
Listed	**1,296**	592
Unlisted	**271**	263
	1,567	855

Other investments comprise equity investments that have no fixed maturity date or coupon rate. These investments are classified as available-for-sale financial assets and as such are recorded at fair value with the gain or loss arising as a result of changes in fair value recorded directly in equity. Accumulated fair value changes are recycled to the income statement on disposal, or when the investment is impaired.

The fair value of listed investments has been determined by reference to quoted market bid prices and as such are in level 1 of the fair value hierarchy. Unlisted investments are stated at cost less accumulated impairment losses and are in level 3 of the fair value hierarchy.

The most significant investment is the group's stake in Rosneft which had a fair value of $1,138 million at 31 December 2009 (2008 $483 million). The fair value gain arising on revaluation of this investment during 2009 has been recorded within other comprehensive income. In 2008, an impairment loss of $517 million was recognized in the income statement relating to the Rosneft investment (see Note 3). In 2009, impairment losses were incurred of $13 million (2008 $17 million) relating to unlisted investments and nil (2008 $29 million) relating to other listed investments.

26. Inventories

	2009 ($ million)	2008 ($ million)
Crude oil	**6,237**	4,396
Natural gas	**105**	107
Refined petroleum and petrochemical products	**12,337**	9,318
	18,679	13,821
Supplies	**1,661**	1,588
	20,340	15,409
Trading inventories	**2,265**	1,412
	22,605	16,821
Cost of inventories expensed in the income statement	**163,772**	266,982

The inventory valuation at 31 December 2009 is stated net of a provision of $46 million (2008 $1,412 million) to write inventories down to their net realizable value. The net movement in the year in respect of inventory net realizable value provisions was $1,366 million credit (2008 $1,295 million charge).

27. Trade and other receivables

	2009 Current	2009 Non-current	2008 Current	2008 Non-current
				$ million
Financial assets				
Trade receivables	**22,604**	**–**	22,869	–
Amounts receivable from jointly controlled entities	**1,317**	**11**	1,035	–
Amounts receivable from associates	**417**	**298**	219	–
Other receivables	**4,949**	**1,420**	4,656	710
	29,287	**1,729**	28,779	710
Non-financial assets				
Other receivables	**244**	**–**	482	–
	29,531	**1,729**	29,261	710

Trade and other receivables are predominantly non-interest bearing. See Note 24 for further information.

28. Cash and cash equivalents

	$ million 2009	2008
Cash at bank and in hand	**3,359**	3,442
Term bank deposits	**3,211**	2,167
Other cash equivalents	**1,769**	2,588
	8,339	8,197

Cash and cash equivalents comprise cash in hand; current balances with banks and similar institutions; term deposits of three months or less with banks and similar institutions; and short-term highly liquid investments that are readily convertible to known amounts of cash, are subject to insignificant risk of changes in value and have a maturity of three months or less from the date of acquisition. The carrying amounts of cash at bank and in hand and term bank deposits 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 2009 includes $1,095 million (2008 $2,133 million) that is restricted. This relates principally to amounts required to cover initial margins on trading exchanges.

See Note 24 for further information.

29. Valuation and qualifying accounts

	2009		2008		2007	$ million
	Doubtful debts	**Fixed assets – investments**	Doubtful debts	Fixed assets – investments	Doubtful debts	Fixed assets – investments
At 1 January	**391**	**935**	406	146	421	151
Charged to costs and expenses	**157**	**66**	191	647	175	158
Charged to other accounts[a]	**12**	**6**	(32)	143	34	2
Deductions	**(130)**	**(658)**	(174)	(1)	(224)	(165)
At 31 December	**430**	**349**	391	935	406	146

[a] Principally exchange adjustments.

Valuation and qualifying accounts are deducted in the balance sheet from the assets to which they apply.

30. Trade and other payables

	2009		2008	$ million
	Current	**Non-current**	Current	Non-current
Financial liabilities				
Trade payables	**22,886**	**–**	20,129	–
Amounts payable to jointly controlled entities	**304**	**2,419**	292	2,255
Amounts payable to associates	**692**	**298**	295	–
Other payables	**7,531**	**195**	9,882	287
	31,413	**2,912**	30,598	2,542
Non-financial liabilities				
Production and similar taxes	**757**	**286**	445	538
Other payables	**3,034**	**–**	2,601	–
	3,791	**286**	3,046	538
	35,204	**3,198**	33,644	3,080

Trade and other payables are predominantly interest free. See Note 24 for further information.

31. Derivative financial instruments

An outline of the group's financial risks and the objectives and policies pursued in relation to those risks is set out in Note 24.

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. Additionally, the group has a well-established entrepreneurial trading operation that is undertaken in conjunction with these activities using a similar range of contracts.

IAS 39 prescribes strict criteria for hedge accounting, whether as a cash flow or fair value hedge or a hedge of a net investment in a foreign operation, and requires that any derivative that does not meet these criteria should be classified as held for trading and fair valued, with gains and losses recognized in the income statement.

The fair values of derivative financial instruments at 31 December are set out below.

				$ million
		2009		2008
	Fair value asset	**Fair value liability**	Fair value asset	Fair value liability
Derivatives held for trading				
Currency derivatives	**318**	**(226)**	278	(273)
Oil price derivatives	**1,140**	**(1,191)**	3,813	(3,523)
Natural gas price derivatives	**5,636**	**(3,960)**	6,945	(6,113)
Power price derivatives	**682**	**(497)**	978	(904)
Other derivatives	**47**	**(47)**	90	(96)
	7,823	**(5,921)**	12,104	(10,909)
Embedded derivative commodity contracts	**137**	**(1,468)**	397	(2,264)
Cash flow hedges				
Currency forwards, futures and cylinders	**182**	**(114)**	120	(1,175)
Cross-currency interest rate swaps	**44**	**(298)**	109	(558)
	226	**(412)**	229	(1,733)
Fair value hedges				
Currency forwards, futures and swaps	**490**	**(232)**	465	(342)
Interest rate swaps	**256**	**(122)**	367	–
	746	**(354)**	832	(342)
Hedges of net investments in foreign operations	**–**	**–**	2	–
	8,932	**(8,155)**	13,564	(15,248)
Of which – current	**4,967**	**(4,681)**	8,510	(8,977)
– non-current	**3,965**	**(3,474)**	5,054	(6,271)

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 24.

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
							2009
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Currency derivatives	**162**	**83**	**33**	**22**	**16**	**2**	**318**
Oil price derivatives	**814**	**136**	**69**	**59**	**44**	**18**	**1,140**
Natural gas price derivatives	**2,958**	**1,059**	**582**	**354**	**186**	**497**	**5,636**
Power price derivatives	**496**	**139**	**32**	**12**	**3**	**–**	**682**
Other derivatives	**47**	**–**	**–**	**–**	**–**	**–**	**47**
	4,477	**1,417**	**716**	**447**	**249**	**517**	**7,823**

31. Derivative financial instruments continued

							$ million
							2008
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	53	90	67	37	20	11	278
Oil price derivatives	3,368	353	61	11	11	9	3,813
Natural gas price derivatives	3,940	1,090	545	436	271	663	6,945
Power price derivatives	688	256	31	1	2	–	978
Other derivatives	90	–	–	–	–	–	90
	8,139	1,789	704	485	304	683	12,104

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

							$ million
							2009
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Currency derivatives	**(110)**	**(58)**	**(20)**	**(32)**	**(4)**	**(2)**	**(226)**
Oil price derivatives	**(1,083)**	**(67)**	**(29)**	**(11)**	**(1)**	**–**	**(1,191)**
Natural gas price derivatives	**(2,381)**	**(607)**	**(248)**	**(222)**	**(78)**	**(424)**	**(3,960)**
Power price derivatives	**(335)**	**(109)**	**(39)**	**(11)**	**(3)**	**–**	**(497)**
Other derivatives	**(47)**	**–**	**–**	**–**	**–**	**–**	**(47)**
	(3,956)	**(841)**	**(336)**	**(276)**	**(86)**	**(426)**	**(5,921)**

							$ million
							2008
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	(257)	–	(2)	(1)	(13)	–	(273)
Oil price derivatives	(3,001)	(458)	(36)	(18)	(9)	(1)	(3,523)
Natural gas price derivatives	(3,484)	(987)	(438)	(310)	(283)	(611)	(6,113)
Power price derivatives	(722)	(159)	(18)	(4)	(1)	–	(904)
Other derivatives	(95)	(1)	–	–	–	–	(96)
	(7,559)	(1,605)	(494)	(333)	(306)	(612)	(10,909)

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 'day-one profit or loss'. This deferred gain or loss is recognized in the income statement over the life of the contract until substantially all of the remaining contract term 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 from this initial valuation are recognized immediately through the income statement.

The following table shows the changes in the day-one profits and losses deferred on the balance sheet.

				$ million
		2009		2008
	Oil price	**Natural gas price**	Oil price	Natural gas price
Fair value of contracts not recognized through the income statement at 1 January	**32**	**83**	–	36
Fair value of new contracts at inception not recognized in the income statement	**–**	**(14)**	66	49
Fair value recognized in the income statement	**(11)**	**(36)**	(34)	(2)
Fair value of contracts not recognized through the income statement at 31 December	**21**	**33**	32	83

Table of Contents

31. Derivative financial instruments continued

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.

IFRS 7 'Financial Instruments: Disclosures' sets out a fair value hierarchy which consists of three levels that describe the methodology of estimation as follows:

- Level 1 – using quoted prices in active markets for identical assets or liabilities.
- Level 2 – using inputs for the asset or liability, other than quoted prices, that are observable either directly (i.e. as prices) or indirectly (i.e. derived from prices).
- Level 3 – using inputs for the asset or liability that are not based on observable market data such as prices based on internal models or other valuation methods.

This information is presented on a gross basis, that is, before netting by counterparty.

							$ million
							2009
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Fair value of derivative assets							
Level 1	**163**	**76**	**23**	**17**	**10**	**1**	**290**
Level 2	**9,544**	**2,182**	**915**	**357**	**146**	**–**	**13,144**
Level 3	**264**	**188**	**162**	**148**	**128**	**527**	**1,417**
	9,971	**2,446**	**1,100**	**522**	**284**	**528**	**14,851**
Less: netting by counterparty	**(5,494)**	**(1,029)**	**(384)**	**(75)**	**(35)**	**(11)**	**(7,028)**
	4,477	**1,417**	**716**	**447**	**249**	**517**	**7,823**
Fair value of derivative liabilities							
Level 1	**(95)**	**(39)**	**(14)**	**(24)**	**–**	**(1)**	**(173)**
Level 2	**(9,086)**	**(1,681)**	**(597)**	**(234)**	**(47)**	**–**	**(11,645)**
Level 3	**(269)**	**(150)**	**(109)**	**(93)**	**(74)**	**(436)**	**(1,131)**
	(9,450)	**(1,870)**	**(720)**	**(351)**	**(121)**	**(437)**	**(12,949)**
Less: netting by counterparty	**5,494**	**1,029**	**384**	**75**	**35**	**11**	**7,028**
	(3,956)	**(841)**	**(336)**	**(276)**	**(86)**	**(426)**	**(5,921)**
Net fair value	**521**	**576**	**380**	**171**	**163**	**91**	**1,902**

							$ million
							2008
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Fair value of derivative assets							
Level 1	40	43	30	7	6	2	128
Level 2	19,737	3,477	871	508	225	56	24,874
Level 3	687	196	148	140	137	672	1,980
	20,464	3,716	1,049	655	368	730	26,982
Less: netting by counterparty	(12,325)	(1,927)	(345)	(170)	(64)	(47)	(14,878)
	8,139	1,789	704	485	304	683	12,104
Fair value of derivative liabilities							
Level 1	(227)	–	(2)	–	(13)	–	(242)
Level 2	(19,106)	(3,345)	(683)	(356)	(217)	(27)	(23,734)
Level 3	(551)	(187)	(154)	(147)	(140)	(632)	(1,811)
	(19,884)	(3,532)	(839)	(503)	(370)	(659)	(25,787)
Less: netting by counterparty	12,325	1,927	345	170	64	47	14,878
	(7,559)	(1,605)	(494)	(333)	(306)	(612)	(10,909)
Net fair value	580	184	210	152	(2)	71	1,195

31. Derivative financial instruments continued

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.

	Currency	Oil price	Natural gas price	Power price	Other	Total
						$ million
Net fair value of contracts at 1 January 2009	**3**	**149**	**17**	**–**	**–**	**169**
Gains (losses) recognized in the income statement	**(1)**	**205**	**91**	**–**	**(1)**	**294**
Settlements	**–**	**(91)**	**(5)**	**–**	**–**	**(96)**
Purchases	**–**	**–**	**–**	**1**	**–**	**1**
Sales	**–**	**–**	**–**	**(2)**	**1**	**(1)**
Transfers out of level 3	**(2)**	**(50)**	**(4)**	**–**	**–**	**(56)**
Transfers in to level 3	**–**	**2**	**(25)**	**–**	**–**	**(23)**
Exchange adjustments	**–**	**–**	**(2)**	**–**	**–**	**(2)**
Net fair value of contracts at 31 December 2009	**–**	**215**	**72**	**(1)**	**–**	**286**

	Currency	Oil price	Natural gas price	Power price	Other	Total
						$ million
Net fair value of contracts at 1 January 2008	(17)	1	(67)	(1)	–	(84)
Gains recognized in the income statement	8	148	160	–	–	316
Settlements	–	18	3	1	–	22
Transfers out of level 3	12	(25)	(79)	–	–	(92)
Transfers in to level 3	–	7	3	–	–	10
Exchange adjustments	–	–	(3)	–	–	(3)
Net fair value of contracts at 31 December 2008	3	149	17	–	–	169

The amount recognized in the income statement for the year relating to level 3 derivatives still held at 31 December 2009 was a $278 million gain (2008 $199 million gain relating to derivatives still held at 31 December 2008).

Gains and losses relating to derivative contracts are included either within sales and other operating revenues or within purchases in the income statement depending upon the nature of the activity and type of contract involved. The contract types treated in this way include futures, options, swaps and certain forward sales and forward purchases contracts. 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. Also included within sales and other operating revenues are gains and losses on inventory held for trading purposes. The total amount relating to all of these items was a net gain of $3,735 million (2008 $6,721 million net gain and 2007 $376 million net gain).

Embedded derivatives

Prior to the development of an active gas trading market, UK gas contracts were priced using a basket of available price indices, primarily relating to oil products, power and inflation. After the development of an active UK gas market, certain contracts were entered into or renegotiated using pricing formulae not directly related to gas prices, for example, oil product and power prices. In these circumstances, pricing formulae have been determined to be derivatives, embedded within the overall contractual arrangements that are not clearly and closely related to the underlying commodity. The resulting fair value relating to these contracts is recognized on the balance sheet with gains or losses recognized in the income statement.

All the embedded derivatives are valued using inputs that include price curves for each of the different products that are built up from active market pricing data. Where necessary, these are extrapolated to the expiry of the contracts (the last of which is in 2018) using all available external pricing information. Additionally, where limited data exists for certain products, prices are interpolated using historic and long-term pricing relationships.

Embedded derivative assets 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
							2009
Commodity price embedded derivatives	**134**	**–**	**–**	**–**	**–**	**3**	**137**

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
							$ million
							2008
Commodity price embedded derivatives	50	116	75	45	36	75	397

31. Derivative financial instruments continued

Embedded derivative liabilities 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
							2009
Commodity price embedded derivatives	**(154)**	**(236)**	**(231)**	**(227)**	**(232)**	**(388)**	**(1,468)**

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
							$ million
							2008
Commodity price embedded derivatives	(404)	(322)	(365)	(303)	(271)	(599)	(2,264)

The following table shows the fair value of embedded derivative assets and liabilities analysed by maturity period and by methodology of fair value estimation.

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
							$ million
							2009
Fair value of embedded derivative assets							
Level 1	**–**	**–**	**–**	**–**	**–**	**–**	**–**
Level 2	**–**	**–**	**–**	**–**	**–**	**–**	**–**
Level 3	**134**	**–**	**–**	**–**	**–**	**3**	**137**
	134	**–**	**–**	**–**	**–**	**3**	**137**
Fair value of embedded derivative liabilities							
Level 1	**–**	**–**	**–**	**–**	**–**	**–**	**–**
Level 2	**–**	**–**	**–**	**–**	**–**	**–**	**–**
Level 3	**(154)**	**(236)**	**(231)**	**(227)**	**(232)**	**(388)**	**(1,468)**
	(154)	**(236)**	**(231)**	**(227)**	**(232)**	**(388)**	**(1,468)**
Net fair value	**(20)**	**(236)**	**(231)**	**(227)**	**(232)**	**(385)**	**(1,331)**

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
							$ million
							2008
Fair value of embedded derivative assets							
Level 1	–	–	–	–	–	–	–
Level 2	35	–	–	–	–	–	35
Level 3	15	116	75	45	36	75	362
	50	116	75	45	36	75	397
Fair value of embedded derivative liabilities							
Level 1	–	–	–	–	–	–	–
Level 2	(10)	–	–	–	–	–	(10)
Level 3	(394)	(322)	(365)	(303)	(271)	(599)	(2,254)
	(404)	(322)	(365)	(303)	(271)	(599)	(2,264)
Net fair value	(354)	(206)	(290)	(258)	(235)	(524)	(1,867)

31. Derivative financial instruments continued

The following table shows the changes during the year in the net fair value of embedded derivatives within level 3 of the fair value hierarchy.

				$ million
	2009			2008
	Commodity price	Commodity price	Interest rate	Total
Net fair value of contracts at 1 January	**(1,892)**	(2,146)	(33)	(2,179)
Settlements	**221**	414	38	452
Gains (losses) recognized in the income statement[a]	**535**	(1,011)	(5)	(1,016)
Exchange adjustments	**(195)**	851	–	851
Net fair value of contracts at 31 December	**(1,331)**	(1,892)	–	(1,892)

a The amount for gains (losses) recognized in the income statement for 2009 includes a loss of $224 million arising as a result of refinements in the modelling and valuation methods used for these contracts.

The amount recognized in the income statement for the year relating to level 3 embedded derivatives still held at 31 December 2009 was a $347 million gain (2008 $985 million loss relating to embedded derivatives still held at 31 December 2008).

The fair value gain (loss) on embedded derivatives is shown below.

			$ million
	2009	2008	2007
Commodity price embedded derivatives	**607**	(106)	–
Interest rate embedded derivatives	**–**	(5)	(7)
Fair value gain (loss)	**607**	(111)	(7)

Cash flow hedges

At 31 December 2009, the group held currency forwards and futures contracts and cylinders that were being used to hedge the foreign currency risk of highly probable forecast transactions, as well as cross-currency interest rate swaps to fix the US dollar interest rate and US dollar redemption value, with matching critical terms on the currency leg of the swap with the underlying non-US dollar debt issuance. Note 24 outlines the management of risk aspects for currency and interest rate risk. For cash flow hedges the group only claims hedge accounting for the intrinsic value on the currency with any fair value attributable to time value taken immediately to the income statement. There were no highly probable transactions for which hedge accounting has been claimed that have not occurred and no significant element of hedge ineffectiveness requiring recognition in the income statement. For cash flow hedges the pre-tax amount removed from equity during the period and included in the income statement is a loss of $366 million (2008 loss of $45 million and 2007 gain of $74 million). Of this, a loss of $332 million is included in production and manufacturing expenses (2008 $1 million loss and 2007 $143 million gain) and a loss of $34 million is included in finance costs (2008 $44 million loss and 2007 $69 million loss). The amount removed from equity during the period and included in the carrying amount of non-financial assets was a loss of $136 million (2008 $38 million gain and 2007 $40 million gain).

The amounts retained in equity at 31 December 2009 are expected to mature and affect the income statement by a $146 million gain in 2010, a loss of $26 million in 2011 and a loss of $65 million in 2012 and beyond.

Fair value hedges

At 31 December 2009, the group held interest rate and cross-currency interest rate swap contracts as fair value hedges of the interest rate risk on fixed rate debt issued by the group. The effectiveness of each hedge relationship is quantitatively assessed and demonstrated to continue to be highly effective. The loss on the hedging derivative instruments taken to the income statement in 2009 was $98 million (2008 $2 million gain and 2007 $334 million gain) offset by a gain on the fair value of the finance debt of $117 million (2008 $20 million loss and 2007 $327 million loss).

The interest rate and cross-currency interest rate swaps have an average maturity of four to five years, (2008 three to four years) and are used to convert sterling, euro, Swiss franc, Australian dollar, Japanese yen and Hong Kong dollar denominated borrowings into US dollar floating rate debt. Note 24 outlines the group's approach to interest rate risk management.

Hedges of net investments in foreign operations

The group held currency swap contracts as a hedge of a long-term investment in a UK subsidiary that expired in 2009. At 31 December 2008, the hedge had a fair value of $2 million and the loss on the hedge recognized in equity in 2008 was $38 million (2007 $67 million loss). US dollars had been sold forward for sterling purchased and matched the underlying liability with no significant ineffectiveness reflected in the income statement.

32. Finance debt

						$ million
			2009			2008
	Within 1 year[a]	**After 1 year**	**Total**	Within 1 year[a]	After 1 year	Total
Borrowings	**9,018**	**25,020**	**34,038**	15,647	16,937	32,584
Net obligations under finance leases	**91**	**498**	**589**	93	527	620
	9,109	**25,518**	**34,627**	15,740	17,464	33,204

[a] Amounts due within one year include current maturities of long-term debt and borrowings that are expected to be repaid later than the earliest contractual repayment dates of within one year. US Industrial Revenue/Municipal Bonds of $2,895 million (2008 $3,166 million) with earliest contractual repayment dates within one year have expected repayment dates ranging from 1 to 33 years (2008 1 to 40 years). The bondholders typically have the option to tender these bonds for repayment on interest reset dates; however, any bonds that are tendered are usually remarketed and BP has not experienced any significant repurchases. BP considers these bonds to represent long-term funding when internally assessing the maturity profile of its finance debt. Similar treatment is applied for loans associated with long-term gas supply contracts totalling $1,622 million (2008 $1,806 million) that mature within eight years.

The following table shows, by major currency, the group's finance debt at 31 December and the weighted average interest rates achieved at those dates 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**
						2009
US dollar	**4**	**4**	**12,525**	**1**	**20,566**	**33,091**
Euro	**4**	**2**	**63**	**2**	**1,199**	**1,262**
Other currencies	**6**	**14**	**171**	**3**	**103**	**274**
			12,759		**21,868**	**34,627**
						2008
US dollar	5	3	9,005	2	22,116	31,121
Sterling	–	–	–	6	21	21
Euro	4	3	74	4	1,330	1,404
Other currencies	7	10	216	7	442	658
			9,295		23,909	33,204

Finance leases

The group uses finance leases to acquire property, plant and equipment. These leases have terms of renewal but no purchase options and escalation clauses. Renewals are at the option of the lessee. Future minimum lease payments under finance leases are set out below.

		$ million
	2009	2008
Future minimum lease payments payable within		
1 year	**109**	116
2 to 5 years	**329**	361
Thereafter	**407**	439
	845	916
Less finance charges	**256**	296
Net obligations	**589**	620
Of which – payable within 1 year	**91**	93
– payable within 2 to 5 years	**202**	234
– payable thereafter	**296**	293

Table of Contents

32. Finance debt continued

Fair values

The estimated fair value of finance debt is shown in the table below together with the carrying amount as reflected in the balance sheet.

Long-term borrowings in the table below include the portion of debt that matures in the year from 31 December 2009, whereas in the balance sheet the amount would be reported within current liabilities.

The carrying amount of the group's short-term borrowings, comprising mainly commercial paper, bank loans, overdrafts and US Industrial Revenue/Municipal Bonds, approximates their fair value. The fair value of the group's long-term borrowings and finance lease obligations is estimated using quoted prices or, where these are not available, discounted cash flow analyses based on the group's current incremental borrowing rates for similar types and maturities of borrowing.

				$ million
	2009		2008	
	Fair value	**Carrying amount**	Fair value	Carrying amount
Short-term borrowings	**5,144**	**5,144**	9,913	9,913
Long-term borrowings	**29,918**	**28,894**	23,239	22,671
Net obligations under finance leases	**599**	**589**	638	620
Total finance debt	**35,661**	**34,627**	33,790	33,204

See Note 24 for further information.

33. Capital disclosures and analysis of changes in net debt

The group defines capital as the total equity of the group. The group's objective for managing capital is to deliver competitive, secure and sustainable returns to maximize long-term shareholder value. BP is not subject to any externally-imposed capital requirements.

The group's approach to managing capital is set out in its financial framework. The group aims to strike the right balance for shareholders, between current returns via the dividend, sustained investment for long-term growth and maintaining a prudent gearing level. At the beginning of 2008, the group rebalanced distributions away from share buybacks in favour of dividends. During 2009, the company did not repurchase any of its own shares.

The group monitors capital on the basis of the net debt ratio, that is, the ratio of net debt to net debt plus equity. Net debt is calculated as gross 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 claimed, less cash and cash equivalents. Net debt and net debt ratio are non-GAAP measures. BP uses these measures to provide useful information to investors. Net debt enables investors to see the economic effect of gross debt, related hedges and cash and cash equivalents in total. The net debt ratio enables investors to see how significant net debt is relative to equity from shareholders. 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. We believe that a net debt ratio in the range 20-30% provides an efficient capital structure and an appropriate level of financial flexibility.

At 31 December 2009 the net debt ratio was 20% (2008 21%).

		$ million
At 31 December	**2009**	2008
Gross debt	**34,627**	33,204
Less: Cash and cash equivalents	**8,339**	8,197
Less: Fair value asset (liability) of hedges related to finance debt	**127**	(34)
Net debt	**26,161**	25,041
Equity	**102,113**	92,109
Net debt ratio	**20%**	21%

An analysis of changes in net debt is provided below.

						$ million
		2009				2008
Movement in net debt	**Finance debt[a]**	**Cash and cash equivalents**	**Net debt**	Finance debt[a]	Cash and cash equivalents	Net debt
At 1 January	**(33,238)**	**8,197**	**(25,041)**	(30,379)	3,562	(26,817)
Exchange adjustments	**(60)**	**110**	**50**	102	(184)	(82)
Net cash flow	**(1,141)**	**32**	**(1,109)**	(2,825)	4,819	1,994
Other movements	**(61)**	**—**	**(61)**	(136)	—	(136)
At 31 December	**(34,500)**	**8,339**	**(26,161)**	(33,238)	8,197	(25,041)

[a] Including fair value of associated derivative financial instruments.

34. Provisions

					$ million
	Decommissioning	**Environmental**	**Litigation**	**Other**	**Total**
At 1 January 2009	**8,418**	**1,691**	**1,446**	**2,098**	**13,653**
Exchange adjustments	**398**	**15**	**22**	**29**	**464**
New or increased provisions	**169**	**588**	**302**	**1,256**	**2,315**
Write-back of unused provisions	**—**	**(259)**	**(99)**	**(228)**	**(586)**
Unwinding of discount	**184**	**32**	**15**	**16**	**247**
Change in discount rate	**324**	**18**	**(35)**	**8**	**315**
Utilization	**(383)**	**(308)**	**(574)**	**(361)**	**(1,626)**
Deletions	**(90)**	**(58)**	**(1)**	**(3)**	**(152)**
At 31 December 2009	**9,020**	**1,719**	**1,076**	**2,815**	**14,630**
Of which – expected to be incurred within 1 year	**287**	**368**	**433**	**572**	**1,660**
– expected to be incurred in more than 1 year	**8,733**	**1,351**	**643**	**2,243**	**12,970**

					$ million
	Decommissioning	Environmental	Litigation	Other	Total
At 1 January 2008	9,501	2,107	1,737	1,750	15,095
Exchange adjustments	(1,208)	(45)	(1)	(106)	(1,360)
New or increased provisions	327	270	886	1,173	2,656
Write-back of unused provisions	—	(107)	(383)	(130)	(620)
Unwinding of discount	202	43	22	20	287
Utilization	(402)	(512)	(815)	(609)	(2,338)
Deletions	(2)	(65)	—	—	(67)
At 31 December 2008	8,418	1,691	1,446	2,098	13,653
Of which – expected to be incurred within 1 year	322	418	521	284	1,545
– expected to be incurred in more than 1 year	8,096	1,273	925	1,814	12,108

The group makes full provision for the future cost of decommissioning oil and natural gas production facilities and related pipelines on a discounted basis on the installation of those facilities. The provision for the costs of decommissioning these production facilities and pipelines at the end of their economic lives has been estimated using existing technology, at current prices or long-term assumptions, depending on the expected timing of the activity, and discounted using a real discount rate of 1.75% (2008 2.0%). These costs are generally expected to be incurred over the next 30 years. While the provision is based on the best estimate of future costs and the economic lives of the facilities and pipelines, there is uncertainty regarding both the amount and timing of incurring these costs.

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 commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites. The provision for environmental liabilities has been estimated using existing technology, at current prices and discounted using a real discount rate of 1.75% (2008 2.0%). The majority of these costs are expected to be incurred over the next 10 years. The extent and cost of future remediation programmes are inherently difficult to estimate. They depend on the scale of any possible contamination, the timing and extent of corrective actions, and also the group’s share of the liability.

The litigation category includes provisions for matters related to, for example, commercial disputes, product liability, and allegations of exposures of third parties to toxic substances. Included within the other category at 31 December 2009 are provisions for deferred employee compensation of $789 million (2008 $792 million) and for expected rental shortfalls on surplus properties of $246 million (2008 $251 million). These provisions are discounted using either a nominal discount rate of 4.0% (2008 2.5%) or a real discount rate of 1.75% (2008 2.0%), as appropriate.

35. 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 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 the employees' pensionable salary and length of service. Defined benefit plans may be externally funded or unfunded. The assets of funded plans are generally held in separately administered trusts.

In particular, the primary pension arrangement in the UK is a funded final salary pension plan under which retired employees draw the majority of their benefit as an annuity. During 2009, BP announced that, with effect from 1 April 2010, it will close its UK plan to new joiners other than some of those joining the North Sea SPU. The plan will remain open to those employees who joined BP on or before 31 March 2010.

In the US, a range of retirement arrangements are provided. These include a funded final salary pension plan for certain heritage employees and a cash balance arrangement for new hires. Retired US employees typically take their pension benefit in the form of a lump sum payment. US employees are also eligible to participate in a defined contribution (401k) plan in which employee contributions are matched with company contributions.

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 2009, contributions of $9 million (2008 $6 million and 2007 $524 million) and $795 million (2008 $362 million and 2007 $97 million) were made to the UK plans and US plans respectively. In addition, contributions of $204 million (2008 $130 million and 2007 $127 million) were made to other funded defined benefit plans. The aggregate level of contributions in 2010 is expected to be approximately $1,000 million, and includes contributions in all countries that we expect to be required to make by law or under contractual agreements as well as an allowance for discretionary funding.

Certain group companies, principally in the US, provide post-retirement healthcare and life insurance benefits to their retired employees and dependants. The entitlement to these benefits is usually based on the employee remaining in service until retirement age and completion of a minimum period of service. The plans are funded to a limited extent.

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 2009. The group's principal plans are subject to a formal actuarial valuation every three years in the UK, with valuations being required more frequently in many other countries. The most recent formal actuarial valuation of the UK pension plans was as at 31 December 2008.

The material financial assumptions used for estimating 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 accrued pension and other post-retirement benefits at 31 December. The same assumptions are used to determine pension and other post-retirement benefit expense for the following year, that is, the assumptions at 31 December 2009 are used to determine the pension liabilities at that date and the pension expense for 2010.

									%
Financial assumptions			UK			US			Other
	2009	2008	2007	**2009**	2008	2007	**2009**	2008	2007
Discount rate for pension plan liabilities	**5.8**	6.3	5.7	**5.4**	6.3	6.1	**5.8**	5.7	5.6
Discount rate for other post-retirement benefit plans	**n/a**	n/a	n/a	**5.8**	6.2	6.4	**n/a**	n/a	n/a
Rate of increase in salaries	**5.3**	4.9	5.1	**4.2**	2.2	4.2	**3.8**	3.5	3.7
Rate of increase for pensions in payment	**3.4**	3.0	3.2	**—**	—	—	**1.8**	1.7	1.8
Rate of increase in deferred pensions	**3.4**	3.0	3.2	**—**	—	—	**1.2**	1.0	1.2
Inflation	**3.4**	3.0	3.2	**2.4**	0.4	2.4	**2.3**	2.0	2.2

Our discount rate assumptions are based on third-party AA corporate bond indices and for our largest plans in the UK, US and Germany 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 we use either this approach, or the central bank inflation target, or advice from the local actuary depending on the information that is available to us. 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.

Our assumptions for the rate of increase in salaries are based on our inflation assumption plus an allowance for expected long-term real salary growth. These include allowance for promotion-related salary growth, of between 0.3% and 0.4% depending on country. In addition to the financial assumptions, we regularly review the demographic and mortality assumptions.

35. Pensions and other post-retirement benefits continued

The mortality assumptions reflect best practice in the countries in which we provide pensions, and have been chosen with regard to the latest available 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 Germany where our mortality assumptions are as follows:

									Years
Mortality assumptions			UK			US			Germany
	2009	2008	2007	**2009**	2008	2007	**2009**	2008	2007
Life expectancy at age 60 for a male currently aged 60	**26.0**	25.9	24.0	**24.6**	24.4	24.3	**23.2**	23.0	22.4
Life expectancy at age 60 for a male currently aged 40	**29.0**	28.9	25.1	**26.1**	25.9	25.8	**26.1**	25.9	25.3
Life expectancy at age 60 for a female currently aged 60	**28.6**	28.5	26.9	**26.3**	26.1	26.1	**27.8**	27.6	27.0
Life expectancy at age 60 for a female currently aged 40	**31.5**	31.4	27.9	**27.2**	27.0	27.0	**30.4**	30.3	29.7

Our assumptions for future US healthcare cost trend rate reflect the rate of actual cost increases seen in recent years for the initial trend rate, and the ultimate trend rate reflects our long-term expectations based on past healthcare cost inflation seen over a longer period of time. The assumed future US healthcare cost trend rate is as follows:

			%
	2009	2008	2007
Initial US healthcare cost trend rate	**8.2**	8.6	9.0
Ultimate US healthcare cost trend rate	**5.0**	5.0	5.0
Year in which ultimate trend rate is reached	**2017**	2015	2013

Pension plan assets are generally held in trusts. The primary objective of the trusts is to accumulate pools of assets sufficient to meet the obligations of the various 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 significant proportion of the assets are held in equities, owing to a higher expected 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 long-term asset allocation policy for the major plans is as follows:

	Policy range
Asset category	%
Total equity	45-75
Bonds/cash	17.5-50
Property/real estate	0-10

Some of the group’s pension plans use derivative financial instruments as part of their asset mix and to manage the level of risk. The group’s main pension plans do not invest directly in either securities or property/real estate of the company or of any subsidiary.

Return on asset assumptions reflect the group’s expectations built up by asset class and by plan. The group’s expectation is derived from a combination of historical returns over the long term and the forecasts of market professionals. Our assumption for return on equities is based on a long-term view, and the size of the resulting equity risk premium over government bond yields is reviewed each year for reasonableness. Our assumption for return on bonds reflects the portfolio mix of government fixed-interest, index-linked and corporate bonds.

35. Pensions and other post-retirement benefits continued

The expected long-term rates of return and market values of the various categories of asset held by the defined benefit plans at 31 December are set out below. The market values shown include the effects of derivative financial instruments. The amounts classified as equities include investments in companies listed on stock exchanges as well as unlisted investments. The market value of unlisted investments at 31 December 2009 was $2,956 million (2008 $2,819 million and 2007 $2,491 million). The market value of pension assets at the end of 2009 is higher than at the end of 2008 due to a rise in the market value of investments when expressed in their local currencies and an increase in value that arises from changes in exchange rates (increasing the reported value of investments when expressed in US dollars). Movements in the value of plan assets during the year are shown in detail in the table on page 162.

		2009		2008		2007
	Expected long-term rate of return	Market value	Expected long-term rate of return	Market value	Expected long-term rate of return	Market value
	%	$ million	%	$ million	%	$ million
UK pension plans						
Equities	**8.0**	**16,945**	8.0	13,704	8.0	24,106
Bonds	**5.3**	**3,701**	6.1	3,258	4.4	5,279
Property	**6.5**	**1,269**	6.5	978	6.5	1,259
Cash	**1.1**	**634**	2.9	299	5.6	977
	7.3	**22,549**	7.4	18,239	7.3	31,621
US pension plans						
Equities	**8.5**	**4,326**	8.5	3,991	8.5	6,610
Bonds	**4.8**	**1,218**	3.7	1,247	5.0	1,347
Property	**8.0**	**8**	8.0	8	8.0	16
Cash	**0.9**	**271**	1.9	131	3.6	72
	8.0	**5,823**	8.0	5,377	8.0	8,045
US other post-retirement benefit plans						
Equities	**8.5**	**8**	8.5	9	8.5	17
Bonds	**4.8**	**4**	3.7	4	5.0	6
	7.6	**12**	7.3	13	7.6	23
Other plans						
Equities	**8.6**	**1,091**	8.4	799	8.1	1,260
Bonds	**4.4**	**1,651**	4.2	1,481	5.0	1,491
Property	**6.5**	**82**	6.3	127	5.7	145
Cash	**2.0**	**245**	3.1	118	4.2	214
	5.9	**3,069**	5.8	2,525	6.4	3,110

The assumed rate of investment return, discount rate, inflation, US healthcare cost trend rate and the mortality assumptions all have a significant effect on the amounts reported.

A one-percentage point change in the following assumptions for the group's plans would have had the effects shown in the table below. The effects shown for the expense in 2010 include current service cost and interest on plan liabilities.

		$ million
	One-percentage point	
	Increase	Decrease
Investment return		
Effect on pension and other post-retirement benefit expense in 2010	**(313)**	**313**
Discount rate		
Effect on pension and other post-retirement benefit expense in 2010	**(75)**	**98**
Effect on pension and other post-retirement benefit obligation at 31 December 2009	**(4,778)**	**6,084**
Inflation rate		
Effect on pension and other post-retirement benefit expense in 2010	**424**	**(343)**
Effect on pension and other post-retirement benefit obligation at 31 December 2009	**4,394**	**(3,706)**
US healthcare cost trend rate		
Effect on US other post-retirement benefit expense in 2010	**31**	**(28)**
Effect on US other post-retirement obligation at 31 December 2009	**339**	**(304)**

One additional year of longevity in the mortality assumptions would have the effects shown in the table below. The effect shown for the expense in 2010 includes current service cost and interest on plan liabilities.

				$ million
	UK pension plans	US pension plans	US other post-retirement benefit plans	German pension plans
One additional year's longevity				
Effect on pension and other post-retirement benefit expense in 2010	**39**	**5**	**4**	**9**
Effect on pension and other post-retirement benefit obligation at 31 December 2009	**528**	**90**	**62**	**149**

35. Pensions and other post-retirement benefits continued

					$ million
					2009
	UK pension plans	US pension plans	US other post-retirement benefit plans	Other plans	Total
Analysis of the amount charged to profit before interest and taxation					
Current service cost[a]	311	243	48	117	719
Past service cost	–	–	(22)	1	(21)
Settlement, curtailment and special termination benefits	37	–	–	53	90
Payments to defined contribution plans	–	205	–	28	233
Total operating charge[b]	348	448	26	199	1,021
Analysis of the amount credited (charged) to other finance expense					
Expected return on plan assets	1,426	405	1	147	1,979
Interest on plan liabilities	(1,112)	(456)	(183)	(420)	(2,171)
Other finance income (expense)	314	(51)	(182)	(273)	(192)
Analysis of the amount recognized in other comprehensive income					
Actual return less expected return on pension plan assets	1,761	617	2	169	2,549
Change in assumptions underlying the present value of the plan liabilities	(2,217)	(501)	(50)	(42)	(2,810)
Experience gains and losses arising on the plan liabilities	(141)	(229)	71	(122)	(421)
Actuarial (loss) gain recognized in other comprehensive income	(597)	(113)	23	5	(682)
Movements in benefit obligation during the year					
Benefit obligation at 1 January	16,655	7,534	3,003	7,655	34,847
Exchange adjustments	1,896	–	–	363	2,259
Current service cost[a]	311	243	48	117	719
Past service cost	–	–	(22)	1	(21)
Interest cost	1,112	456	183	420	2,171
Curtailment	–	–	–	11	11
Settlement	–	–	–	(3)	(3)
Special termination benefits[c]	37	–	–	45	82
Contributions by plan participants	37	–	–	10	47
Benefit payments (funded plans)[d]	(977)	(1,371)	(4)	(209)	(2,561)
Benefit payments (unfunded plans)[d]	(4)	(73)	(191)	(399)	(667)
Disposals	–	–	–	(42)	(42)
Actuarial (gain) loss on obligation	2,358	730	(21)	164	3,231
Benefit obligation at 31 December[a e]	21,425	7,519	2,996	8,133	40,073
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	18,239	5,377	13	2,525	26,154
Exchange adjustments	2,054	–	–	242	2,296
Expected return on plan assets[a f]	1,426	405	1	147	1,979
Contributions by plan participants	37	–	–	10	47
Contributions by employers (funded plans)	9	795	–	204	1,008
Benefit payments (funded plans)[d]	(977)	(1,371)	(4)	(209)	(2,561)
Disposals	–	–	–	(19)	(19)
Actuarial gain on plan assets[f]	1,761	617	2	169	2,549
Fair value of plan assets at 31 December	22,549	5,823	12	3,069	31,453
Surplus (deficit) at 31 December	1,124	(1,696)	(2,984)	(5,064)	(8,620)
Represented by					
Asset recognized	1,290	–	–	100	1,390
Liability recognized	(166)	(1,696)	(2,984)	(5,164)	(10,010)
	1,124	(1,696)	(2,984)	(5,064)	(8,620)
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	1,287	(1,280)	(33)	(164)	(190)
Unfunded	(163)	(416)	(2,951)	(4,900)	(8,430)
	1,124	(1,696)	(2,984)	(5,064)	(8,620)
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(21,262)	(7,103)	(45)	(3,233)	(31,643)
Unfunded	(163)	(416)	(2,951)	(4,900)	(8,430)
	(21,425)	(7,519)	(2,996)	(8,133)	(40,073)

[a] The costs of managing the plan's investments are treated as being part of the investment return, the costs of administering our pension plan benefits are generally included in current service cost and the costs of administering our other post-retirement benefit plans are included in the benefit obligation.
[b] Included within production and manufacturing expenses and distribution and administration expenses.
[c] The charge for special termination benefits represents the increased liability arising as a result of early retirements occurring as part of restructuring programmes.
[d] The benefit payments amount shown above comprises $3,174 million benefits plus $54 million of plan expenses incurred in the administration of the benefit.
[e] The benefit obligation for other plans includes $3,880 million for the German plan, which is largely unfunded.
[f] The actual return on plan assets is made up of the sum of the expected return on plan assets and the actuarial gain on plan assets as disclosed above.

At 31 December 2009, reimbursement balances due from or to other companies in respect of pensions amounted to $443 million reimbursement assets (2008 $455 million) and $14 million reimbursement liabilities (2008 $61 million). These balances are not included as part of the pension liability, but are reflected elsewhere in the group balance sheet.

35. Pensions and other post-retirement benefits continued

	UK pension plans	US pension plans	US other post-retirement benefit plans	Other plans	Total
					$ million
					2008
Analysis of the amount charged to profit before interest and taxation					
Current service cost[a]	448	235	40	128	851
Past service cost	7	74	–	1	82
Settlement, curtailment and special termination benefits	30	–	–	12	42
Payments to defined contribution plans	–	170	–	25	195
Total operating charge[b]	485	479	40	166	1,170
Analysis of the amount credited (charged) to other finance expense					
Expected return on plan assets	2,094	632	2	194	2,922
Interest on plan liabilities	(1,239)	(444)	(198)	(450)	(2,331)
Other finance income (expense)	855	188	(196)	(256)	591
Analysis of the amount recognized in other comprehensive income					
Actual return less expected return on pension plan assets	(6,946)	(2,895)	(8)	(404)	(10,253)
Change in assumptions underlying the present value of the plan liabilities	1,570	3	215	214	2,002
Experience gains and losses arising on the plan liabilities	(73)	(194)	18	70	(179)
Actuarial (loss) gain recognized in other comprehensive income	(5,449)	(3,086)	225	(120)	(8,430)
Movements in benefit obligation during the year					
Benefit obligation at 1 January	23,927	7,409	3,178	8,586	43,100
Exchange adjustments	(6,408)	–	–	(628)	(7,036)
Current service cost[a]	448	235	40	128	851
Past service cost	7	74	–	1	82
Interest cost	1,239	444	198	450	2,331
Curtailment	–	–	–	(3)	(3)
Settlement	(3)	–	–	(3)	(6)
Special termination benefits[c]	33	–	–	18	51
Contributions by plan participants	42	–	–	12	54
Benefit payments (funded plans)[d]	(1,131)	(767)	(4)	(203)	(2,105)
Benefit payments (unfunded plans)[d]	(2)	(52)	(176)	(419)	(649)
Actuarial (gain) loss on obligation	(1,497)	191	(233)	(284)	(1,823)
Benefit obligation at 31 December[a e]	16,655	7,534	3,003	7,655	34,847
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	31,621	8,045	23	3,110	42,799
Exchange adjustments	(7,447)	–	–	(314)	(7,761)
Expected return on plan assets[a f]	2,094	632	2	194	2,922
Contributions by plan participants	42	–	–	12	54
Contributions by employers (funded plans)	6	362	–	130	498
Benefit payments (funded plans)[d]	(1,131)	(767)	(4)	(203)	(2,105)
Actuarial loss on plan assets[f]	(6,946)	(2,895)	(8)	(404)	(10,253)
Fair value of plan assets at 31 December	18,239	5,377	13	2,525	26,154
Surplus (deficit) at 31 December	1,584	(2,157)	(2,990)	(5,130)	(8,693)
Represented by					
Asset recognized	1,682	–	–	56	1,738
Liability recognized	(98)	(2,157)	(2,990)	(5,186)	(10,431)
	1,584	(2,157)	(2,990)	(5,130)	(8,693)
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	1,682	(1,734)	(31)	(354)	(437)
Unfunded	(98)	(423)	(2,959)	(4,776)	(8,256)
	1,584	(2,157)	(2,990)	(5,130)	(8,693)
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(16,557)	(7,111)	(44)	(2,879)	(26,591)
Unfunded	(98)	(423)	(2,959)	(4,776)	(8,256)
	(16,655)	(7,534)	(3,003)	(7,655)	(34,847)

[a] The costs of managing the plan's investments are treated as being part of the investment return, the costs of administering our pension plan benefits are generally included in current service cost and the costs of administering our other post-retirement benefit plans are included in the benefit obligation.
[b] Included within production and manufacturing expenses and distribution and administration expenses.
[c] The charge for special termination benefits represents the increased liability arising as a result of early retirements occurring as part of restructuring programmes.
[d] The benefit payments amount shown above comprises $2,697 million benefits plus $57 million of plan expenses incurred in the administration of the benefit.
[e] The benefit obligation for other plans includes $3,837 million for the German plan, which is largely unfunded.
[f] The actual return on plan assets is made up of the sum of the expected return on plan assets and the actuarial loss on plan assets as disclosed above.

Table of Contents

35. Pensions and other post-retirement benefits continued

					$ million
					2007
	UK pension plans	US pension plans	US other post-retirement benefit plans	Other plans	Total
Analysis of the amount charged to profit before interest and taxation					
Current service cost[a]	492	227	43	132	894
Past service cost	5	10	–	–	15
Settlement, curtailment and special termination benefits	36	–	–	2	38
Payments to defined contribution plans	–	184	–	25	209
Total operating charge[b]	533	421	43	159	1,156
Analysis of the amount credited (charged) to other finance expense					
Expected return on plan assets	2,075	613	2	165	2,855
Interest on plan liabilities	(1,198)	(425)	(190)	(390)	(2,203)
Other finance income (expense)	877	188	(188)	(225)	652
Analysis of the amount recognized in other comprehensive income					
Actual return less expected return on pension plan assets	406	(28)	–	(76)	302
Change in assumptions underlying the present value of the plan liabilities	513	358	137	607	1,615
Experience gains and losses arising on the plan liabilities	(162)	(27)	29	(40)	(200)
Actuarial gain recognized in other comprehensive income	757	303	166	491	1,717

[a] The costs of managing the plan's investments are treated as being part of the investment return, the costs of administering our pension plan benefits are generally included in current service cost, and the costs of administering our other post-retirement benefit plans are included in the benefit obligation.
[b] Included within production and manufacturing expenses and distribution and administration expenses.

					$ million
	2009	2008	2007	2006	2005
History of surplus (deficit) and of experience gains and losses					
Benefit obligation at 31 December	**40,073**	34,847	43,100	42,433	38,855
Fair value of plan assets at 31 December	**31,453**	26,154	42,799	39,910	32,907
Deficit	**(8,620)**	(8,693)	(301)	(2,523)	(5,948)
Experience losses on plan liabilities	**(421)**	(178)	(200)	(124)	(212)
Actual return less expected return on pension plan assets	**2,549**	(10,253)	302	1,967	3,364
Actual return on plan assets	**4,528**	(7,331)	3,157	4,377	5,502
Actuarial (loss) gain recognized in other comprehensive income	**(682)**	(8,430)	1,717	2,615	975
Cumulative amount recognized in other comprehensive income	**(3,622)**	(2,940)	5,490	3,773	1,158

Estimated future benefit payments

The expected benefit payments, which reflect expected future service, as appropriate, but exclude plan expenses, up until 2019 are as follows:

					$ million
	UK pension plans	**US pension plans**	**US other post-retirement benefit plans**	**Other plans**	**Total**
2010	**1,003**	**618**	**201**	**612**	**2,434**
2011	**1,019**	**637**	**206**	**587**	**2,449**
2012	**1,061**	**679**	**208**	**581**	**2,529**
2013	**1,095**	**677**	**213**	**578**	**2,563**
2014	**1,148**	**672**	**218**	**584**	**2,622**
2015-2019	**6,496**	**3,275**	**1,123**	**2,835**	**13,729**

36. Called-up share capital

The allotted, called-up and fully paid share capital at 31 December was as follows:

	2009		2008		2007	
Issued	Shares (thousand)	$ million	Shares (thousand)	$ million	Shares (thousand)	$ million
8% cumulative first preference shares of £1 each	**7,233**	**12**	7,233	12	7,233	12
9% cumulative second preference shares of £1 each	**5,473**	**9**	5,473	9	5,473	9
		21		21		21
Ordinary shares of 25 cents each						
At 1 January	**20,618,458**	**5,155**	20,863,424	5,216	21,457,301	5,364
Issue of new shares for employee share schemes[a]	**11,207**	**3**	24,791	6	69,273	18
Repurchase of ordinary share capital[b]	**–**	**–**	(269,757)	(67)	(663,150)	(166)
At 31 December	**20,629,665**	**5,158**	20,618,458	5,155	20,863,424	5,216
		5,179		5,176		5,237
Authorized						
8% cumulative first preference shares of £1 each	**7,250**	**12**	7,250	12	7,250	12
9% cumulative second preference shares of £1 each	**5,500**	**9**	5,500	9	5,500	9
Ordinary shares of 25 cents each	**36,000,000**	**9,000**	36,000,000	9,000	36,000,000	9,000

[a] Consideration received relating to the issue of new shares for employee share schemes amounted to $84 million (2008 $180 million and 2007 $492 million).
[b] Purchased for a total consideration of nil (2008 $2,914 million and 2007 $7,497 million), all of which were for cancellation. At 31 December 2009, 112,803,287 (2008 150,444,408 and 2007 150,966,096) ordinary shares bought back were awaiting cancellation. These shares have been excluded from ordinary shares in issue shown above. Transaction costs of share repurchases amounted to nil (2008 $16 million and 2007 $40 million).

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.

Treasury shares

	2009		2008		2007	
	Shares (thousand)	Nominal value $ million	Shares (thousand)	Nominal value $ million	Shares (thousand)	Nominal value $ million
At 1 January	**1,888,151**	**472**	1,940,639	485	1,946,805	487
Shares gifted to the Employee Share Ownership Plans	**(1,265)**	**(1)**	(10,000)	(2)	(1,700)	–
Shares transferred at market price to the Employee Share Ownership Plans	**–**	**–**	(20,000)	(5)	–	–
Shares re-issued to employee share schemes	**(17,109)**	**(4)**	(22,488)	(6)	(4,466)	(2)
At 31 December	**1,869,777**	**467**	1,888,151	472	1,940,639	485

For each year presented, the balance at 1 January represents the maximum number of shares held in treasury during the year, representing 9.2% (2008 9.3% and 2007 9.1%) of the called-up ordinary share capital of the company.

During 2009, the movement in treasury shares represented less than 0.1% (2008 0.25% and 2007 less than 0.1%) of the ordinary share capital of the company.

37. Capital and reserves

	Share capital	Share premium account	Capital redemption reserve
At 1 January 2009	**5,176**	**9,763**	**1,072**
Currency translation differences (including recycling)	**–**	**–**	**–**
Actuarial gain relating to pensions and other post-retirement benefits	**–**	**–**	**–**
Available-for-sale investments (including recycling)	**–**	**–**	**–**
Cash flow hedges (including recycling)	**–**	**–**	**–**
Profit for the year	**–**	**–**	**–**
Total comprehensive income	**–**	**–**	**–**
Dividends	**–**	**–**	**–**
Share-based payments[a]	**3**	**84**	**–**
Changes in associates' equity	**–**	**–**	**–**
Minority interest buyout	**–**	**–**	**–**
At 31 December 2009	**5,179**	**9,847**	**1,072**

	Share capital	Share premium account	Capital redemption reserve
At 1 January 2008	5,237	9,581	1,005
Currency translation differences (including recycling)	–	–	–
Actuarial gain relating to pensions and other post-retirement benefits	–	–	–
Available-for-sale investments (including recycling)	–	–	–
Cash flow hedges (including recycling)	–	–	–
Profit for the year	–	–	–
Total comprehensive income	–	–	–
Dividends	–	–	–
Repurchase of ordinary share capital	(67)	–	67
Share-based payments[a]	6	182	–
Minority interest buyout	–	–	–
At 31 December 2008	5,176	9,763	1,072

	Share capital	Share premium account	Capital redemption reserve
At 1 January 2007	5,385	9,074	839
Currency translation differences (including recycling)	–	–	–
Actuarial gain relating to pensions and other post-retirement benefits	–	–	–
Available-for-sale investments (including recycling)	–	–	–
Cash flow hedges (including recycling)	–	–	–
Profit for the year	–	–	–
Total comprehensive income	–	–	–
Dividends	–	–	–
Repurchase of ordinary share capital	(166)	–	166
Share-based payments[a]	18	507	–
At 31 December 2007	5,237	9,581	1,005

[a] Includes new share issues and movements in own shares and treasury shares where these relate to share-based payment plans.

$ million

Merger reserve	Other reserve	Own shares	Treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Share-based payment reserve	Profit and loss account	BP shareholders' equity	Minority interest	Total equity
27,206	**–**	**(326)**	**(21,513)**	**2,353**	**63**	**(866)**	**1,295**	**67,080**	**91,303**	**806**	**92,109**
–	**–**	**–**	**–**	**2,458**	**(2)**	**(37)**	**–**	**–**	**2,419**	**(56)**	**2,363**
–	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**(478)**	**(478)**	**–**	**(478)**
–	**–**	**–**	**–**	**–**	**693**	**–**	**–**	**–**	**693**	**–**	**693**
–	**–**	**–**	**–**	**–**	**–**	**925**	**–**	**–**	**925**	**–**	**925**
–	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**16,578**	**16,578**	**181**	**16,759**
–	**–**	**–**	**–**	**2,458**	**691**	**888**	**–**	**16,100**	**20,137**	**125**	**20,262**
–	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**(10,483)**	**(10,483)**	**(416)**	**(10,899)**
–	**–**	**112**	**210**	**–**	**–**	**–**	**289**	**23**	**721**	**–**	**721**
–	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**(43)**	**(43)**	**–**	**(43)**
–	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**(22)**	**(22)**	**(15)**	**(37)**
27,206	**–**	**(214)**	**(21,303)**	**4,811**	**754**	**22**	**1,584**	**72,655**	**101,613**	**500**	**102,113**

Merger reserve	Other reserve	Own shares	Treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Share-based payment reserve	Profit and loss account	BP shareholders' equity	Minority interest	Total equity
27,206	–	(60)	(22,112)	6,540	481	106	1,196	64,510	93,690	962	94,652
–	–	–	–	(4,187)	–	–	–	–	(4,187)	(75)	(4,262)
–	–	–	–	–	–	–	–	(5,828)	(5,828)	–	(5,828)
–	–	–	–	–	(418)	–	–	–	(418)	–	(418)
–	–	–	–	–	–	(972)	–	–	(972)	–	(972)
–	–	–	–	–	–	–	–	21,157	21,157	509	21,666
–	–	–	–	(4,187)	(418)	(972)	–	15,329	9,752	434	10,186
–	–	–	–	–	–	–	–	(10,342)	(10,342)	(425)	(10,767)
–	–	–	–	–	–	–	–	(2,414)	(2,414)	–	(2,414)
–	–	(266)	599	–	–	–	99	(3)	617	–	617
–	–	–	–	–	–	–	–	–	–	(165)	(165)
27,206	–	(326)	(21,513)	2,353	63	(866)	1,295	67,080	91,303	806	92,109

Merger reserve	Other reserve	Own shares	Treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Share-based payment reserve	Profit and loss account	BP shareholders' equity	Minority interest	Total equity
27,201	5	(154)	(22,182)	4,685	386	39	859	58,487	84,624	841	85,465
–	–	–	–	1,855	–	–	–	–	1,855	24	1,879
–	–	–	–	–	–	–	–	1,290	1,290	–	1,290
–	–	–	–	–	95	–	–	–	95	–	95
–	–	–	–	–	–	67	–	–	67	–	67
–	–	–	–	–	–	–	–	20,845	20,845	324	21,169
–	–	–	–	1,855	95	67	–	22,135	24,152	348	24,500
–	–	–	–	–	–	–	–	(8,106)	(8,106)	(227)	(8,333)
–	–	–	–	–	–	–	–	(7,997)	(7,997)	–	(7,997)
5	(5)	94	70	–	–	–	337	(9)	1,017	–	1,017
27,206	–	(60)	(22,112)	6,540	481	106	1,196	64,510	93,690	962	94,652

37. 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.

Other reserve
The balance on the other reserve represented the fair value of the consideration given in excess of the nominal value of the ordinary shares issued in the ARCO acquisition on the exercise of ARCO share options.

Own shares
Own shares represent BP shares held in Employee Share Ownership Plans (ESOPs) to meet the future requirements of the employee share-based payment plans.

Treasury shares
Treasury shares represent BP shares repurchased and available for re-issue.

Foreign currency translation reserve
The foreign currency translation reserve is used to record exchange differences arising from the translation of the financial statements of foreign operations. Upon disposal of foreign operations, the related accumulated exchange differences are recycled to the income statement. This reserve is also used to record the effect of hedging net investments in foreign operations.

Available-for-sale investments
This reserve records the changes in fair value of available-for-sale investments. On disposal or impairment, the cumulative changes in fair value are recycled 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. When the hedged transaction occurs, the gain or loss on the hedging instrument is transferred out of equity to either profit or loss or the carrying value of assets, as appropriate. If the forecast transaction is no longer expected to occur the gain or loss recognized in equity is transferred to profit or loss.

Share-based payment reserve
This reserve represents cumulative amounts charged to profit in respect of employee share-based payment plans where the scheme has not yet been settled by means of an award of shares to an individual.

Profit and loss account
The balance held on this reserve is the accumulated retained profits of the group.

Table of Contents

37. 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
			2009
	Pre-tax	**Tax**	**Net of tax**
Currency translation differences (including recycling)	**1,799**	**564**	**2,363**
Actuarial loss relating to pensions and other post-retirement benefits	**(682)**	**204**	**(478)**
Available-for-sale investments (including recycling)	**707**	**(14)**	**693**
Cash flow hedges (including recycling)	**1,154**	**(229)**	**925**
Other comprehensive income	**2,978**	**525**	**3,503**

			$million
			2008
	Pre-tax	Tax	Net of tax
Currency translation differences (including recycling)	(4,362)	100	(4,262)
Actuarial loss relating to pensions and other post-retirement benefits	(8,430)	2,602	(5,828)
Available-for-sale investments (including recycling)	(468)	50	(418)
Cash flow hedges (including recycling)	(1,166)	194	(972)
Other comprehensive income	(14,426)	2,946	(11,480)

			$million
			2007
	Pre-tax	Tax	Net of tax
Currency translation differences (including recycling)	1,740	139	1,879
Actuarial gain relating to pensions and other post-retirement benefits	1,717	(427)	1,290
Available-for-sale investments (including recycling)	109	(14)	95
Cash flow hedges (including recycling)	41	26	67
Other comprehensive income	3,607	(276)	3,331

38. Share-based payments

Effect of share-based payment transactions on the group's result and financial position

			$ million
	2009	2008	2007
Total expense recognized for equity-settled share-based payment transactions	**506**	524	412
Total expense (credit) recognized for cash-settled share-based payment transactions	**15**	(16)	16
Total expense recognized for share-based payment transactions	**521**	508	428
Closing balance of liability for cash-settled share-based payment transactions	**32**	21	40
Total intrinsic value for vested cash-settled share-based payments	**7**	2	22

For ease of presentation, option and share holdings detailed in the tables within this note are stated as UK ordinary share equivalents in US dollars. US employees are granted American Depositary Shares (ADSs) or options over the company's ADSs (one ADS is equivalent to six ordinary shares). The share-based payment plans that existed during the year are detailed below. All plans are ongoing unless otherwise stated.

Plans for executive directors

Executive Directors' Incentive Plan (EDIP) – share element

An equity-settled incentive plan for executive directors with a three-year performance period. For share plan performance periods 2007-2009 and 2008-2010 the award of shares is determined by comparing BP's total shareholder return (TSR) against the other oil majors (ExxonMobil, Shell, Total and Chevron). For the performance period 2009-2011 the award of shares is determined 50% on TSR versus a competitor group of oil majors (which in this period also included ConocoPhillips) and 50% on a balanced scorecard (BSC) of three underlying performance measures versus the same competitor group. After the performance period, the shares that vest (net of tax) are then subject to a three-year retention period. The directors' remuneration report on pages 77 to 88 includes full details of the plan.

Executive Directors' Incentive Plan (EDIP) – share option element

An equity-settled share option plan for executive directors that permits options to be granted at an exercise price no lower than the market price of a share on the date that the option is granted. The options are exercisable up to the seventh anniversary of the grant date and the last grants were made in 2004. From 2005 onwards the remuneration committee's policy is not to make further grants of share options to executive directors.

Plans for senior employees

The group operates a number of equity-settled share plans under which share units are granted to its senior leaders and certain 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 during the three-year period will normally preclude the conversion of units into shares, but special arrangements apply where the participant leaves for a qualifying reason.

Grants are settled in cash where participants are located in a country whose regulatory environment prohibits the holding of BP shares.

Performance unit plans

The number of units granted is made by reference to level of seniority of the employees. The number of units converted to shares is determined by reference to performance measures over the three-year performance period. The main performance measure used is BP's TSR compared against the other oil majors. In addition, free cash flow (FCF) is used as a performance measure for one of the performance plans. Plans included in this category are the Competitive Performance Plan (CPP), the Medium Term Performance Plan (MTPP) and, in part, the Performance Share Plan (PSP).

Restricted share unit plans

Share unit grants under BP's restricted plans typically take into account the employee's performance in either the current or the prior year, track record of delivery, business and leadership skills and long-term potential. One restricted share unit plan used in special circumstances for senior employees, such as recruitment and retention, normally has no performance conditions. Plans included in this category are the Executive Performance Plan (EPP), the Restricted Share Plan (RSP), the Deferred Annual Bonus Plan (DAB) and, in part, the Performance Share Plan (PSP).

BP Share Option Plan (BPSOP)

Share options with an exercise price equivalent to the market price of a share immediately preceding the date of grant were granted to participants annually until 2006. There were no performance conditions and the options are exercisable between the third and tenth anniversaries of the grant date.

Savings and matching plans

BP ShareSave Plan

This is a savings-related share option plan under which employees save on a monthly basis, over a three- or five-year period, towards the purchase of shares at a fixed price determined when the option is granted. This price is usually set at a 20% discount to the market price at the time of grant. The option must be exercised within six months of maturity of the savings contract; otherwise it lapses. The plan is run in the UK and options are granted annually, usually in June. Participants leaving for a qualifying reason have six months in which to use their savings to exercise their options on a pro-rated basis.

38. Share-based payments continued

BP ShareMatch Plans

These are matching share plans under which BP matches employees’ own contributions of shares up to a predetermined limit. The plans are run in the UK and in more than 70 other countries. The UK plan is run on a monthly basis with shares being held in trust for five years before they can be released free of any income tax and national insurance liability. In other countries the plan is run on an annual basis with shares being held in trust for three years. The plan is operated on a cash basis in those countries where there are regulatory restrictions preventing the holding of BP shares. When the employee leaves BP all shares must be removed from trust and units under the plan operated on a cash basis must be encashed.

Local plans

In some countries BP provides local scheme benefits, the rules and qualifications for which vary according to local circumstances.

Employee Share Ownership Plans (ESOPs)

ESOPs have been established to acquire BP shares to satisfy any awards made to participants under the BP share plans as required. The ESOPs have waived their rights to dividends on shares held for future awards and are funded by the group. Until such time as the company’s own shares held by the ESOP trusts vest unconditionally to employees, the amount paid for those shares is deducted in arriving at shareholders’ equity (see Note 37). Assets and liabilities of the ESOPs are recognized as assets and liabilities of the group.

At 31 December 2009 the ESOPs held 18,062,246 shares (2008 29,051,082 shares and 2007 6,448,838 shares) for potential future awards, which had a market value of $174 million (2008 $220 million and 2007 $79 million).

Share option transactions	2009 Number of options	2009 Weighted average exercise price $	2008 Number of options	2008 Weighted average exercise price $	2007 Number of options	2007 Weighted average exercise price $
Outstanding at 1 January	**326,254,599**	**8.70**	358,094,243	8.51	426,471,462	8.25
Granted	**9,679,836**	**6.55**	8,062,899	8.96	6,004,025	9.11
Forfeited	**(5,954,325)**	**8.81**	(2,502,784)	8.50	(3,924,714)	9.10
Exercised	**(21,293,871)**	**7.53**	(37,277,895)	6.97	(69,715,558)	6.94
Expired	**(12,790,882)**	**8.01**	(121,864)	7.00	(740,972)	8.68
Outstanding at 31 December	**295,895,357**	**8.73**	326,254,599	8.70	358,094,243	8.51
Exercisable at 31 December	**274,685,068**	**8.80**	260,178,938	8.22	238,707,055	7.70

As share options are exercised continuously throughout the year, the weighted average share price during the year of $9.10 (2008 $10.87 and 2007 $11.72) is representative of the weighted average share price at the date of exercise. For the options outstanding at 31 December 2009, the exercise price ranges and weighted average remaining contractual lives are shown below.

Range of exercise prices	Options outstanding Number of shares	Options outstanding Weighted average remaining life Years	Options outstanding Weighted average exercise price $	Options exercisable Number of shares	Options exercisable Weighted average exercise price $
$6.18 – $7.61	**53,511,852**	**3.31**	**6.43**	**43,956,777**	**6.40**
$7.62 – $9.05	**143,736,259**	**2.48**	**8.18**	**137,625,273**	**8.16**
$9.06 – $10.48	**27,046,156**	**4.10**	**9.83**	**21,501,928**	**10.01**
$10.49 – $11.92	**71,601,090**	**5.81**	**11.14**	**71,601,090**	**11.14**
	295,895,357	**3.58**	**8.73**	**274,685,068**	**8.80**

Fair values and associated details for options and shares granted

	2009 ShareSave 3 year	2009 ShareSave 5 year	2008 ShareSave 3 year	2008 ShareSave 5 year	2007 ShareSave 3 year	2007 ShareSave 5 year
Option pricing model used	**Binomial**	**Binomial**	Binomial	Binomial	Binomial	Binomial
Weighted average fair value	**$1.07**	**$1.07**	$1.82	$1.74	$3.57	$3.79
Weighted average share price	**$7.87**	**$7.87**	$11.26	$11.26	$12.10	$12.10
Weighted average exercise price	**$6.92**	**$6.92**	$9.70	$9.70	$9.13	$9.13
Expected volatility	**32%**	**32%**	23%	23%	21%	21%
Option life	**3.5 years**	**5.5 years**	3.5 years	5.5 years	3.5 years	5.5 years
Expected dividends	**7.40%**	**7.40%**	4.60%	4.60%	3.48%	3.48%
Risk free interest rate	**3.00%**	**3.75%**	5.00%	5.00%	5.75%	5.75%
Expected exercise behaviour	**100% year 4**	**100% year 6**	100% year 4	100% year 6	100% year 4	100% year 6

The group uses a valuation model to determine the fair value of options granted. The model uses the implied volatility of ordinary share price for the quarter within which the grant date of the relevant plan falls. The fair value is adjusted for the expected rates of early cancellation. Management is responsible for all inputs and assumptions in relation to the model, including the determination of expected volatility.

38. Share-based payments continued

Shares granted in 2009	CPP	EPP	EDIP-TSR	EDIP-BSC	RSP	DAB	PSP
Number of equity instruments granted (million)	**1.4**	**7.6**	**2.1**	**2.1**	**2.4**	**38.9**	**16.5**
Weighted average fair value	**$9.76**	**$6.56**	**$2.74**	**$7.27**	**$8.76**	**$6.56**	**$8.32**
Fair value measurement basis	**Monte Carlo**	**Market value**	**Monte Carlo**	**Market value**	**Market value**	**Market value**	**Monte Carlo**

Shares granted in 2008	MTPP-TSR	MTPP-FCF	EDIP-TSR	EDIP-RET[a]	RSP	DAB	PSP
Number of equity instruments granted (million)	9.1	9.1	2.6	0.5	7.7	5.8	16.7
Weighted average fair value	$5.07	$10.34	$4.55	$11.13	$8.83	$10.34	$12.89
Fair value measurement basis	Monte Carlo	Market value	Monte Carlo	Market value	Market value	Market value	Monte Carlo

Shares granted in 2007	MTPP-TSR	MTPP-FCF	EDIP-TSR	EDIP-LTL[b]	RSP	DAB	PSP
Number of equity instruments granted (million)	9.4	8.5	4.5	0.5	7.7	4.4	14.8
Weighted average fair value	$4.73	$10.02	$2.81	$9.92	$11.93	$10.02	$12.37
Fair value measurement basis	Monte Carlo	Market value	Monte Carlo	Market value	Market value	Market value	Monte Carlo

[a] EDIP – retention element.
[b] EDIP – long-term leadership element.

The group used a Monte Carlo simulation to determine the fair value of the TSR element of the 2009, 2008 and 2007 CPP, PSP, MTPP and EDIP plans. In accordance with the rules of the plans the model simulates BP's TSR and compares it against our principal strategic competitors over the three-year period of the plans. The model takes into account the historic dividends, share price volatilities and covariances of BP and each comparator company to produce a predicted distribution of relative share performance. This is applied to the reward criteria to give an expected value of the TSR element.

Accounting expense does not necessarily represent the actual value of share-based payments made to recipients, which are determined by the remuneration committee according to established criteria.

39. Employee costs and numbers

Employee costs	**2009**	2008	2007
			$ million
Wages and salaries[a]	**9,702**	10,388	9,808
Social security costs	**780**	805	771
Share-based payments	**521**	508	428
Pension and other post-retirement benefit costs	**1,213**	579	504
	12,216	12,280	11,511

Number of employees at 31 December	**2009**	2008	2007
Exploration and Production	**21,500**	21,400	21,800
Refining and Marketing[b]	**51,600**	61,500	67,200
Other businesses and corporate	**7,200**	9,100	9,100
	80,300	92,000	98,100
By geographical area			
US	**22,800**	29,300	33,000
Non-US[b]	**57,500**	62,700	65,100
	80,300	92,000	98,100

		2009			2008			2007	
Average number of employees	**US**	**Non-US**	**Total**	US	Non-US	Total	US	Non-US	Total
Exploration and Production	**7,900**	**13,800**	**21,700**	7,800	13,800	21,600	7,700	13,800	21,500
Refining and Marketing	**14,700**	**40,700**	**55,400**	21,600	43,400	65,000	23,400	43,900	67,300
Other businesses and corporate	**2,300**	**5,800**	**8,100**	2,600	6,500	9,100	2,500	5,900	8,400
	24,900	**60,300**	**85,200**	32,000	63,700	95,700	33,600	63,600	97,200

[a] Includes termination payments of $945 million (2008 $669 million and 2007 $422 million).
[b] Includes 13,900 (2008 21,200 and 2007 24,500) service station staff.

40. Remuneration of directors and senior management

Remuneration of directors

	2009	2008	2007
			$ million
Total for all directors			
Emoluments	**19**	19	26
Gains made on the exercise of share options	**2**	1	2
Amounts awarded under incentive schemes	**2**	–	10

Emoluments
These amounts comprise fees paid to the non-executive chairman and the non-executive directors and, for executive directors, salary and benefits earned during the relevant financial year, plus bonuses awarded for the year. Ex gratia superannuation payments of $3 million were included in 2007. Also included was compensation for loss of office of $1 million in 2008 and $1 million in 2007.

Pension contributions
Three executive directors participated in a non-contributory pension scheme established for UK employees by a separate trust fund to which contributions are made by BP based on actuarial advice. Two US executive directors participated in the US BP Retirement Accumulation Plan during 2009.

Office facilities for former chairmen and deputy chairmen
It is customary for the company to make available to former chairmen and deputy chairmen, who were previously employed executives, the use of office and basic secretarial facilities following their retirement. The cost involved in doing so is not significant.

Further information
Full details of individual directors' remuneration are given in the directors' remuneration report on pages 77 to 88.

Remuneration of directors and senior management

	2009	2008	2007
			$ million
Total for all senior management			
Short-term employee benefits	**36**	34	35
Post-retirement benefits	**3**	4	6
Share-based payments	**20**	20	22

Senior management, in addition to executive and non-executive directors, includes other senior managers who are members of the executive management team.

Short-term employee benefits
In addition to fees paid to the non-executive chairman and non-executive directors, these amounts comprise, for executive directors and senior managers, salary and benefits earned during the year, plus cash bonuses awarded for the year. Deferred annual bonus awards, to be settled in shares, are included in share-based payments. Short-term employee benefits includes an ex gratia superannuation payment of nil (2008 nil and 2007 $3 million) and compensation for loss of office of $6 million (2008 $3 million and 2007 $1 million).

Post-retirement benefits
The amounts represent the estimated cost to the group of providing defined benefit 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'. The main plans in which senior management have participated are the EDIP and MTPP. For details of these plans refer to Note 38.

41. Contingent liabilities

There were contingent liabilities at 31 December 2009 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 is included in Note 24.

Lawsuits arising out of the Exxon Valdez oil spill in Prince William Sound, Alaska, in March 1989 were filed against Exxon (now ExxonMobil), Alyeska Pipeline Service Company (Alyeska), which operates the oil terminal at Valdez, and the other oil companies that own Alyeska. Alyeska initially responded to the spill until the response was taken over by Exxon. BP owns a 46.9% interest (reduced during 2001 from 50% by a sale of 3.1% to Phillips) in Alyeska through a subsidiary of BP America Inc. and briefly indirectly owned a further 20% interest in Alyeska following BP's combination with Atlantic Richfield Company (Atlantic Richfield). Alyeska and its owners have settled all the claims against them under these lawsuits. Exxon has indicated that it may file a claim for contribution against Alyeska for a portion of the costs and damages that Exxon has incurred. BP will defend any such claims vigorously. It is not possible to estimate any financial effect.

In the normal course of the group's business, legal proceedings are pending or may be brought against BP group entities arising out of current and past operations, including matters related to commercial disputes, product liability, antitrust, premises-liability claims, general environmental claims and allegations of exposures of third parties to toxic substances, such as lead pigment in paint, asbestos and other chemicals. BP believes that the impact of these legal proceedings on the group's results of operations, liquidity or financial position will not be material.

With respect to lead pigment in paint in particular, Atlantic Richfield, a subsidiary of BP, has been named as a co-defendant in numerous lawsuits brought in the US alleging injury to persons and property. Although it is not possible to predict the outcome of the legal proceedings, Atlantic Richfield believes it has valid defences that render the incurrence of a liability remote; however, the amounts claimed and the costs of implementing the remedies sought in the various cases could be substantial. The majority of the lawsuits have been abandoned or dismissed against Atlantic Richfield. No lawsuit against Atlantic Richfield has been settled nor has Atlantic Richfield been subject to a final adverse judgment in any proceeding. Atlantic Richfield intends to defend such actions vigorously.

The group files income tax returns in many jurisdictions throughout the world. Various tax authorities are currently examining the group's income tax returns. Tax returns contain matters that could be subject to differing interpretations of applicable tax laws and regulations and the resolution of tax positions through negotiations with relevant tax authorities, or through litigation, can take several years to complete. While it is difficult to predict the ultimate outcome in some cases, the group does not anticipate that there will be any material impact upon the group's results of operations, financial position or liquidity.

The group is subject to numerous national and local 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, 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 cost are inherently difficult to estimate. However, the estimated cost of known environmental obligations has been provided in these accounts in accordance with the group's accounting policies. While the amounts of future costs could be significant and could be material to the group's results of operations in the period in which they are recognized, it is not practical to estimate the amounts involved. BP does not expect these costs to have a material effect on the group's financial position or liquidity.

The group also has obligations to decommission oil and natural gas production facilities and related pipelines. Provision is made for the estimated costs of these activities, however there is uncertainty regarding both the amount and timing of these costs, given the long-term nature of these obligations. BP believes that the impact of any reasonably foreseeable changes to these provisions on the group's results of operations, financial position or liquidity will not be material.

The group generally restricts its purchase of insurance to situations where this is required for legal or contractual reasons. This is because external insurance is not considered an economic means of financing losses for the group. Losses will therefore be borne as they arise rather than being spread over time through insurance premiums with attendant transaction costs. The position is reviewed periodically.

42. Capital commitments

Authorized future capital expenditure for property, plant and equipment by group companies for which contracts had been placed at 31 December 2009 amounted to $9,812 million (2008 $14,062 million). In addition, at 31 December 2009, the group had contracts in place for future capital expenditure relating to investments in jointly controlled entities of $622 million (2008 $644 million) and investments in associates of $170 million (2008 $160 million).

BP's share of capital commitments of jointly controlled entities amounted to $926 million (2008 $1,540 million).

43. Subsidiaries, jointly controlled entities and associates

The more important subsidiaries, jointly controlled entities and associates of the group at 31 December 2009 and the group percentage of ordinary share capital or joint venture interest (to nearest whole number) are set out below. The principal country of operation is generally indicated by the company's country of incorporation or by its name. Those 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 investments in subsidiaries, jointly controlled entities and associates will be attached to the parent company's annual return made to the Registrar of Companies.

Subsidiaries	%	Country of incorporation	Principal activities
International			
*BP Corporate Holdings	100	England	Investment holding
BP Exploration Op. Co.	100	England	Exploration and production
*BP Global Investments	100	England	Investment holding
*BP International	100	England	Integrated oil operations
BP Oil International	100	England	Integrated oil operations
*BP Shipping	100	England	Shipping
*Burmah Castrol	100	Scotland	Lubricants
Jupiter Insurance	100	Guernsey	Insurance
Algeria			
BP Amoco Exploration (In Amenas)	100	Scotland	Exploration and production
BP Exploration (El Djazair)	100	Bahamas	Exploration and production
Angola			
BP Exploration (Angola)	100	England	Exploration and production
Australia			
BP Oil Australia	100	Australia	Integrated oil operations
BP Australia Capital Markets	100	Australia	Finance
BP Developments Australia	100	Australia	Exploration and production
BP Finance Australia	100	Australia	Finance
Azerbaijan			
Amoco Caspian Sea Petroleum	100	British Virgin Islands	Exploration and production
BP Exploration (Caspian Sea)	100	England	Exploration and production
Canada			
BP Canada Energy	100	Canada	Exploration and production
BP Canada Finance	100	Canada	Finance
Egypt			
BP Egypt Co.	100	US	Exploration and production
Germany			
Deutsche BP	100	Germany	Refining and marketing and petrochemicals
Indonesia			
BP Berau	100	US	Exploration and production

Subsidiaries	%	Country of incorporation	Principal activities
Netherlands			
BP Capital	100	Netherlands	Finance
BP Nederland	100	Netherlands	Refining and marketing
New Zealand			
BP Oil New Zealand	100	New Zealand	Marketing
Norway			
BP Norge	100	Norway	Exploration and production
Spain			
BP España	100	Spain	Refining and marketing
South Africa			
*BP Southern Africa	75	South Africa	Refining and marketing
Trinidad & Tobago			
BP Trinidad and Tobago	70	US	Exploration and production
UK			
BP Capital Markets	100	England	Finance
BP Oil UK	100	England	Marketing
Britoil	100	Scotland	Exploration and production
US			
*BP Holdings North America	100	England	Investment holding
Atlantic Richfield Co.			
BP America			
BP America Production Company			
BP Amoco Chemical Company			
BP Company North America	100	US	Exploration and production, refining and marketing, pipelines and petrochemicals
BP Corporation North America			
BP Exploration (Alaska) Inc.			
BP Products North America			
BP West Coast Products			
Standard Oil Co.			
BP Capital Markets America			Finance

43. Subsidiaries, jointly controlled entities and associates continued

Jointly controlled entities	%	Country of incorporation or registration	Principal activities
Angola LNG Supply Services	14	US	LNG processing and transportation
Atlantic 4 Holdings	38	US	LNG manufacture
Atlantic LNG 2/3 Company of Trinidad and Tobago	43	Trinidad & Tobago	LNG manufacture
BP-Husky Refining	50	US	Refining
Elvary Neftegaz Holdings BV	49	Netherlands	Exploration and appraisal
Pan American Energy[a]	60	US	Exploration and production
Petromonagas	17	Venezuela	Exploration and production
Ruhr Oel	50	Germany	Refining and marketing and petrochemicals
Shanghai SECCO Petrochemical Co.	50	China	Petrochemicals
Sunrise Oil Sands	50	Canada	Exploration and production
United Gas Derivatives Company	33	Egypt	LNG manufacture
Watson Cogeneration[a]	51	US	Power generation

[a]The entity is not controlled by BP as certain key business decisions require joint approval of both BP and the minority partner. It is therefore classified as a jointly controlled entity rather than a subsidiary.

Associates	%	Country of incorporation	Principal activities
Abu Dhabi			
Abu Dhabi Marine Areas	37	England	Crude oil production
Abu Dhabi Petroleum Co.	24	England	Crude oil production
Azerbaijan			
The Baku-Tbilisi-Ceyhan Pipeline Co.	30	Cayman Islands	Pipelines
South Caucasus Pipeline Co.	26	Cayman Islands	Pipelines
Russia			
TNK-BP	50	British Virgin Islands	Integrated oil operations
Trinidad & Tobago			
Atlantic LNG Company of Trinidad and Tobago	34	Trinidad & Tobago	LNG manufacture

44. Condensed consolidating information on certain US subsidiaries

BP p.l.c. fully and unconditionally guarantees the payment obligations of its 100% owned subsidiary BP Exploration (Alaska) Inc. under the BP Prudhoe Bay Royalty Trust. The following financial information for BP p.l.c., BP Exploration (Alaska) Inc. and all other subsidiaries on a condensed consolidating basis is intended to provide investors with meaningful and comparable financial information about BP p.l.c. and its subsidiary issuers of registered securities and is provided pursuant to Rule 3-10 of Regulation S-X in lieu of the separate financial statements of each subsidiary issuer of public debt securities. Investments include the investments in subsidiaries recorded under the equity method for the purposes of the condensed consolidating financial information. Equity income of subsidiaries is the group’s share of profit related to such investments. The eliminations and reclassifications column includes the necessary amounts to eliminate the intercompany balances and transactions between BP p.l.c., BP Exploration (Alaska) Inc. and other subsidiaries. The financial information presented in the following tables for BP Exploration (Alaska) Inc. for all years includes equity income arising from subsidiaries of BP Exploration (Alaska) Inc. some of which operate outside of Alaska and excludes the BP group’s midstream operations in Alaska that are reported through different legal entities and that are included within the ‘other subsidiaries’ column in these tables. BP p.l.c. also fully and unconditionally guarantees securities issued by BP Capital Markets p.l.c. and BP Capital Markets America Inc. These companies are 100%-owned finance subsidiaries of BP p.l.c.

Income statement

$ million

For the year ended 31 December					2009
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Sales and other operating revenues	4,189	–	239,272	(4,189)	239,272
Earnings from jointly controlled entities – after interest and tax	–	–	1,286	–	1,286
Earnings from associates – after interest and tax	–	–	2,615	–	2,615
Equity-accounted income of subsidiaries – after interest and tax	838	17,315	–	(18,153)	–
Interest and other revenues	17	144	832	(201)	792
Gains on sale of businesses and fixed assets	–	9	2,173	(9)	2,173
Total revenues and other income	5,044	17,468	246,178	(22,552)	246,138
Purchases	510	–	167,451	(4,189)	163,772
Production and manufacturing expenses	970	–	22,232	–	23,202
Production and similar taxes	602	–	3,150	–	3,752
Depreciation, depletion and amortization	424	–	11,682	–	12,106
Impairment and losses on sale of businesses and fixed assets	–	–	2,333	–	2,333
Exploration expense	–	–	1,116	–	1,116
Distribution and administration expenses	27	1,145	12,974	(108)	14,038
Fair value gain on embedded derivatives	–	–	(607)	–	(607)
Profit before interest and taxation	2,511	16,323	25,847	(18,255)	26,426
Finance costs	22	26	1,155	(93)	1,110
Net finance (income) expense relating to pensions and other post-retirement benefits	10	(310)	492	–	192
Profit before taxation	2,479	16,607	24,200	(18,162)	25,124
Taxation	583	20	7,762	–	8,365
Profit for the year	1,896	16,587	16,438	(18,162)	16,759
Attributable to					
BP shareholders	1,896	16,587	16,257	(18,162)	16,578
Minority interest	–	–	181	–	181
	1,896	16,587	16,438	(18,162)	16,759

44. Condensed consolidating information on certain US subsidiaries continued

Income statement continued

					$ million
For the year ended 31 December					2008
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Sales and other operating revenues	6,782	–	361,143	(6,782)	361,143
Earnings from jointly controlled entities – after interest and tax	–	–	3,023	–	3,023
Earnings from associates – after interest and tax	–	–	798	–	798
Equity-accounted income of subsidiaries – after interest and tax	469	20,295	–	(20,764)	–
Interest and other revenues	514	173	1,025	(976)	736
Gains on sale of businesses and fixed assets	–	–	1,353	–	1,353
Total revenues and other income	7,765	20,468	367,342	(28,522)	367,053
Purchases	895	–	272,869	(6,782)	266,982
Production and manufacturing expenses	1,083	–	25,673	–	26,756
Production and similar taxes	2,343	–	6,610	–	8,953
Depreciation, depletion and amortization	365	–	10,620	–	10,985
Impairment and losses on sale of businesses and fixed assets	–	–	1,733	–	1,733
Exploration expense	–	–	882	–	882
Distribution and administration expenses	22	28	15,469	(107)	15,412
Fair value loss on embedded derivatives	–	–	111	–	111
Profit before interest and taxation	3,057	20,440	33,375	(21,633)	35,239
Finance costs	158	169	2,089	(869)	1,547
Net finance (income) expense relating to pensions and other post-retirement benefits	–	(822)	231	–	(591)
Profit before taxation	2,899	21,093	31,055	(20,764)	34,283
Taxation	944	(64)	11,737	–	12,617
Profit for the year	1,955	21,157	19,318	(20,764)	21,666
Attributable to					
BP shareholders	1,955	21,157	18,809	(20,764)	21,157
Minority interest	–	–	509	–	509
	1,955	21,157	19,318	(20,764)	21,666

44. Condensed consolidating information on certain US subsidiaries continued

Income statement continued

$ million

For the year ended 31 December					2007
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Sales and other operating revenues	5,243	–	284,365	(5,243)	284,365
Earnings from jointly controlled entities – after interest and tax	–	–	3,135	–	3,135
Earnings from associates – after interest and tax	–	–	697	–	697
Equity-accounted income of subsidiaries – after interest and tax	586	21,201	–	(21,787)	–
Interest and other revenues	758	205	1,166	(1,375)	754
Gains on sale of businesses and fixed assets	1	–	2,486	–	2,487
Total revenues and other income	6,588	21,406	291,849	(28,405)	291,438
Purchases	650	–	205,359	(5,243)	200,766
Production and manufacturing expenses	897	–	23,328	–	24,225
Production and similar taxes	1,052	–	4,651	–	5,703
Depreciation, depletion and amortization	388	–	10,191	–	10,579
Impairment and losses on sale of businesses and fixed assets	–	–	1,679	–	1,679
Exploration expense	–	–	756	–	756
Distribution and administration expenses	22	921	14,536	(108)	15,371
Fair value loss on embedded derivatives	–	–	7	–	7
Profit before interest and taxation	3,579	20,485	31,342	(23,054)	32,352
Finance costs	49	381	2,230	(1,267)	1,393
Net finance (income) expense relating to pensions and other post-retirement benefits	–	(820)	168	–	(652)
Profit before taxation	3,530	20,924	28,944	(21,787)	31,611
Taxation	1,055	79	9,308	–	10,442
Profit for the year	2,475	20,845	19,636	(21,787)	21,169
Attributable to					
BP shareholders	2,475	20,845	19,312	(21,787)	20,845
Minority interest	–	–	324	–	324
	2,475	20,845	19,636	(21,787)	21,169

44. Condensed consolidating information on certain US subsidiaries continued

Balance sheet

At 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	$ million 2009 BP group
Non-current assets					
Property, plant and equipment	7,366	–	100,909	–	108,275
Goodwill	–	–	8,620	–	8,620
Intangible assets	321	–	11,227	–	11,548
Investments in jointly controlled entities	–	–	15,296	–	15,296
Investments in associates	–	2	12,961	–	12,963
Other investments	–	–	1,567	–	1,567
Subsidiaries – equity-accounted basis	4,424	101,760	–	(106,184)	–
Fixed assets	12,111	101,762	150,580	(106,184)	158,269
Loans	283	1,178	5,490	(5,912)	1,039
Other receivables	–	–	1,729	–	1,729
Derivative financial instruments	–	–	3,965	–	3,965
Prepayments	–	–	1,407	–	1,407
Deferred tax assets	–	–	516	–	516
Defined benefit pension plan surpluses	–	1,071	319	–	1,390
	12,394	104,011	164,006	(112,096)	168,315
Current assets					
Loans	–	–	249	–	249
Inventories	221	–	22,384	–	22,605
Trade and other receivables	18,529	30,707	35,852	(55,557)	29,531
Derivative financial instruments	–	–	4,967	–	4,967
Prepayments	8	2	1,743	–	1,753
Current tax receivable	–	–	209	–	209
Cash and cash equivalents	(22)	28	8,333	–	8,339
	18,736	30,737	73,737	(55,557)	67,653
Total assets	31,130	134,748	237,743	(167,653)	235,968
Current liabilities					
Trade and other payables	4,662	2,374	83,725	(55,557)	35,204
Derivative financial instruments	–	–	4,681	–	4,681
Accruals	–	27	6,175	–	6,202
Finance debt	55	–	9,054	–	9,109
Current tax payable	172	–	2,292	–	2,464
Provisions	–	–	1,660	–	1,660
	4,889	2,401	107,587	(55,557)	59,320
Non-current liabilities					
Other payables	229	4,254	4,627	(5,912)	3,198
Derivative financial instruments	–	–	3,474	–	3,474
Accruals	–	74	629	–	703
Finance debt	–	–	25,518	–	25,518
Deferred tax liabilities	1,872	149	16,641	–	18,662
Provisions	1,048	–	11,922	–	12,970
Defined benefit pension plan and other post-retirement benefit plan deficits	–	–	10,010	–	10,010
	3,149	4,477	72,821	(5,912)	74,535
Total liabilities	8,038	6,878	180,408	(61,469)	133,855
Net assets	23,092	127,870	57,335	(106,184)	102,113
Equity					
BP shareholders' equity	23,092	127,870	56,835	(106,184)	101,613
Minority interest	–	–	500	–	500
Total equity	23,092	127,870	57,335	(106,184)	102,113

44. Condensed consolidating information on certain US subsidiaries continued

Balance sheet continued

At 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
					$ million 2008
Non-current assets					
Property, plant and equipment	6,959	–	96,241	–	103,200
Goodwill	–	–	9,878	–	9,878
Intangible assets	243	–	10,017	–	10,260
Investments in jointly controlled entities	–	–	23,826	–	23,826
Investments in associates	–	2	3,998	–	4,000
Other investments	–	–	855	–	855
Subsidiaries – equity-accounted basis	3,585	111,730	–	(115,315)	–
Fixed assets	10,787	111,732	144,815	(115,315)	152,019
Loans[a]	354	1,174	1,393	(1,926)	995
Other receivables	–	–	710	–	710
Derivative financial instruments	–	–	5,054	–	5,054
Prepayments	–	–	1,338	–	1,338
Defined benefit pension plan surpluses	–	1,516	222	–	1,738
	11,141	114,422	153,532	(117,241)	161,854
Current assets					
Loans	–	–	168	–	168
Inventories	198	–	16,623	–	16,821
Trade and other receivables[a]	18,302	6,129	35,745	(30,915)	29,261
Derivative financial instruments	–	–	8,510	–	8,510
Prepayments	37	–	3,013	–	3,050
Current tax receivable	–	–	377	–	377
Cash and cash equivalents	(10)	11	8,196	–	8,197
	18,527	6,140	72,632	(30,915)	66,384
Total assets	29,668	120,562	226,164	(148,156)	228,238
Current liabilities					
Trade and other payables	5,070	2,602	57,032	(31,060)	33,644
Derivative financial instruments	–	–	8,977	–	8,977
Accruals	–	7	6,736	–	6,743
Finance debt	55	–	15,685	–	15,740
Current tax payable	162	–	2,982	–	3,144
Provisions	–	–	1,545	–	1,545
	5,287	2,609	92,957	(31,060)	69,793
Non-current liabilities					
Other payables	398	33	4,430	(1,781)	3,080
Derivative financial instruments	–	–	6,271	–	6,271
Accruals	–	47	737	–	784
Finance debt	–	–	17,464	–	17,464
Deferred tax liabilities	1,630	322	14,246	–	16,198
Provisions	1,074	–	11,034	–	12,108
Defined benefit pension plan and other post-retirement benefit plan deficits	–	–	10,431	–	10,431
	3,102	402	64,613	(1,781)	66,336
Total liabilities	8,389	3,011	157,570	(32,841)	136,129
Net assets	21,279	117,551	68,594	(115,315)	92,109
Equity					
BP shareholders' equity	21,279	117,551	67,788	(115,315)	91,303
Minority interest	–	–	806	–	806
Total equity	21,279	117,551	68,594	(115,315)	92,109

[a]Within Non-current assets – Loans, the amount of loans receivable by BP Exploration (Alaska) Inc. (BPXA) has been increased by $145 million from the amounts previously reported and within Current liabilities – Trade and other payables, the amount of other payables of BPXA has been increased by $145 million to better reflect the commercial relationship between BPXA and certain other BP subsidiaries.

44. Condensed consolidating information on certain US subsidiaries continued

Cash flow statement

					$ million
					2009
	Issuer	**Guarantor**			
	BP Exploration (Alaska) Inc.	**BP p.l.c.**	**Other subsidiaries**	**Eliminations and reclassifications**	**BP group**
Net cash provided by operating activities	**1,022**	**14,514**	**47,466**	**(35,286)**	**27,716**
Net cash used in investing activities	**(935)**	**(4,227)**	**(12,971)**	**–**	**(18,133)**
Net cash used in financing activities	**(99)**	**(10,270)**	**(34,468)**	**35,286**	**(9,551)**
Currency translation differences relating to cash and cash equivalents	**–**	**–**	**110**	**–**	**110**
(Decrease) increase in cash and cash equivalents	**(12)**	**17**	**137**	**–**	**142**
Cash and cash equivalents at beginning of year	**(10)**	**11**	**8,196**	**–**	**8,197**
Cash and cash equivalents at end of year	**(22)**	**28**	**8,333**	**–**	**8,339**

					$ million
					2008
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Net cash provided by operating activities[a]	1,105	12,665	41,600	(17,275)	38,095
Net cash used in investing activities	(896)	–	(21,871)	–	(22,767)
Net cash used in financing activities[a]	(209)	(12,898)	(14,677)	17,275	(10,509)
Currency translation differences relating to cash and cash equivalents	–	–	(184)	–	(184)
(Decrease) increase in cash and cash equivalents	–	(233)	4,868	–	4,635
Cash and cash equivalents at beginning of year	(10)	244	3,328	–	3,562
Cash and cash equivalents at end of year	(10)	11	8,196	–	8,197

[a]Net cash provided by operating activities and net cash used in financing activities for BP Exploration (Alaska) Inc. have both been reduced by $5,688 million from the amounts previously reported to better reflect the substance of the commercial relationship between BP Exploration (Alaska) Inc. and certain other BP subsidiaries.

					$ million
					2007
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Net cash provided by operating activities[b]	716	15,403	25,195	(16,605)	24,709
Net cash used in investing activities	(532)	1	(14,306)	–	(14,837)
Net cash used in financing activities[b]	(189)	(15,139)	(10,312)	16,605	(9,035)
Currency translation differences relating to cash and cash equivalents	–	–	135	–	135
(Decrease) increase in cash and cash equivalents	(5)	265	712	–	972
Cash and cash equivalents at beginning of year	(5)	(21)	2,616	–	2,590
Cash and cash equivalents at end of year	(10)	244	3,328	–	3,562

[b]Net cash provided by operating activities and net cash used in financing activities for BP Exploration (Alaska) Inc. have both been reduced by $2,356 million from the amounts previously reported to better reflect the substance of the commercial relationship between BP Exploration (Alaska) Inc. and certain other BP subsidiaries.

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), in accordance with revised SEC and FASB requirements. The comparative information for 2008 and 2007 is also presented on this basis. For 2009, where relevant, information for equity-accounted entities is provided in the same level of detail as for subsidiaries. Also for 2009, proved reserves are based on revised SEC definitions.

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 (LKH) 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 (HKO) 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 favorable than in the reservoir as a whole, the operation of an installed program 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 program 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 20 to 22.

Financial statements

Oil and natural gas exploration and production activities

	Europe		North America		South America	Africa	Asia		Australasia	Total
$ million, 2009	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries[a]										
Capitalized costs at 31 December[b]										
Gross capitalized costs										
Proved properties	35,096	6,644	64,366	3,967	8,346	24,476	–	10,900	2,894	156,689
Unproved properties	752	–	5,464	147	198	2,377	–	733	1,039	10,710
	35,848	6,644	69,830	4,114	8,544	26,853	–	11,633	3,933	167,399
Accumulated depreciation	26,794	3,306	31,728	2,309	4,837	12,492	–	4,798	1,038	87,302
Net capitalized costs	9,054	3,338	38,102	1,805	3,707	14,361	–	6,835	2,895	80,097
Costs incurred for the year ended 31 December[b]										
Acquisition of properties[c]										
Proved	179	–	(17)	–	–	–	–	306	–	468
Unproved	(1)	–	370	1	–	18	–	–	10	398
	178	–	353	1	–	18	–	306	10	866
Exploration and appraisal costs[d]	183	–	1,377	79	78	712	8	315	53	2,805
Development	751	1,054	4,208	386	453	2,707	–	560	277	10,396
Total costs	1,112	1,054	5,938	466	531	3,437	8	1,181	340	14,067
Results of operations for the year ended 31 December										
Sales and other operating revenues[e]										
Third parties	2,239	68	4,759	99	1,525	1,846	–	636	785	11,957
Sales between businesses	2,482	809	11,313	484	1,409	5,313	–	6,257	726	28,793
	4,721	877	16,072	583	2,934	7,159	–	6,893	1,511	40,750
Exploration expenditure	59	–	663	80	16	219	8	49	22	1,116
Production costs	1,243	164	2,821	284	395	908	15	361	70	6,261
Production taxes	(3)	–	649	1	220	–	–	2,854	72	3,793
Other costs (income)[f]	(1,259)	51	2,353	145	184	144	76	967	178	2,839
Depreciation, depletion and amortization	1,148	185	3,857	170	697	2,041	–	757	96	8,951
Impairments and (gains) losses on sale of businesses and fixed assets	(122)	(7)	(208)	–	(11)	(1)	–	(702)[j]	–	(1,051)
	1,066	393	10,135	680	1,501	3,311	99	4,286	438	21,909
Profit before taxation[g]	3,655	484	5,937	(97)	1,433	3,848	(99)	2,607	1,073	18,841
Allocable taxes	1,568	76	1,902	(58)	916	1,517	(25)	682	2	6,580
Results of operations	2,087	408	4,035	(39)	517	2,331	(74)	1,925	1,071	12,261
Exploration and Production segment replacement cost profit before interest and tax										
Exploration and production activities – subsidiaries (as above)	3,655	484	5,937	(97)	1,433	3,848	(99)	2,607	1,073	18,841
Midstream activities – subsidiaries[h]	925	17	719	833	17	(27)	(37)	518	(315)	2,650
Equity-accounted entities[i]	–	5	29	134	630	56	1,924	531	–	3,309
Total replacement cost profit before interest and tax	4,580	506	6,685	870	2,080	3,877	1,788	3,656	758	24,800

[a] These tables contain information relating to oil and natural gas exploration and production activities of subsidiaries. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation are excluded. In addition, our midstream activities of marketing and trading of natural gas, power and NGL’s in the US, Canada, UK and Europe are excluded. The most significant midstream pipeline interests include the Trans-Alaska Pipeline System, the Forties Pipeline System, the Central Area Transmission System pipeline, the South Caucasus Pipeline and the Baku-Tbilisi-Ceyhan pipeline. Major LNG activities are located in Trinidad, Indonesia and Australia and BP is also investing in the LNG business in Angola.
[b] Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.
[c] Includes costs capitalized as a result of asset exchanges.
[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] Presented net of transportation costs, purchases and sales taxes.
[f] Includes property taxes, other government take and the fair value gain on embedded derivatives of $663 million. The UK region includes a $783 million gain offset by corresponding charges primarily in the US, relating to the group self-insurance programme.
[g] Excludes the unwinding of the discount on provisions and payables amounting to $308 million which is included in finance costs in the group income statement.
[h] Midstream activities exclude inventory holding gains and losses.
[i] The profits of equity-accounted entities are included after interest and tax.
[j] Includes the gain on disposal of upstream assets associated with our sale of our 46% stake in LukArco (see Note 3).

Table of Contents

Oil and natural gas exploration and production activities continued

$ million

										2009
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Equity-accounted entities (BP share)[a]										
Capitalized costs at 31 December[b]										
Gross capitalized costs										
Proved properties	–	–	–	–	5,789	–	13,266	2,259	–	21,314
Unproved properties	–	–	–	1,378	197	–	737	–	–	2,312
	–	–	–	1,378	5,986	–	14,003	2,259	–	23,626
Accumulated depreciation	–	–	–	–	2,084	–	5,550	1,739	–	9,373
Net capitalized costs	–	–	–	1,378	3,902	–	8,453	520	–	14,253
Costs incurred for the year ended 31 December[b]										
Acquisition of properties[c]										
Proved	–	–	–	–	–	–	–	–	–	–
Unproved	–	–	–	–	31	–	10	–	–	41
	–	–	–	–	31	–	10	–	–	41
Exploration and appraisal costs[d]	–	–	–	–	21	–	77	3	–	101
Development	–	–	–	30	538	–	1,182	246	–	1,996
Total costs	–	–	–	30	590	–	1,269	249	–	2,138
Results of operations for the year ended 31 December										
Sales and other operating revenues[e]										
Third parties	–	–	–	–	1,977	–	4,919	351	–	7,247
Sales between businesses	–	–	–	–	–	–	2,838	–	–	2,838
	–	–	–	–	1,977	–	7,757	351	–	10,085
Exploration expenditure	–	–	–	–	23	–	37	–	–	60
Production costs	–	–	–	–	354	–	1,428	159	–	1,941
Production taxes	–	–	–	–	702	–	2,597	–	–	3,299
Other costs (income)	–	–	–	–	(69)	–	12	(2)	–	(59)
Depreciation, depletion and amortization	–	–	–	–	281	–	1,073	274	–	1,628
Impairments and (gains) losses on sale of businesses and fixed assets	–	–	–	–	–	–	72	–	–	72
	–	–	–	–	1,291	–	5,219	431	–	6,941
Profit before taxation	–	–	–	–	686	–	2,538	(80)	–	3,144
Allocable taxes	–	–	–	–	270	–	501	–	–	771
Results of operations	–	–	–	–	416	–	2,037	(80)	–	2,373
Exploration and production activities — equity-accounted entities (as above)	–	–	–	–	416	–	2,037	(80)	–	2,373
Midstream and other activities after tax[f]	–	5	29	134	214	56	(113)	611	–	936
Total replacement cost profit after interest and tax	–	5	29	134	630	56	1,924	531	–	3,309

[a]These tables contain information relating to oil and natural gas exploration and production activities of equity-accounted entities. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation as well as downstream activities of TNK-BP are excluded. The amounts reported for equity-accounted entities exclude the corresponding amounts for their equity-accounted entities.
[b]Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.
[c]Includes costs capitalized as a result of asset exchanges.
[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]Presented net of transportation costs, purchases and sales taxes.
[f]Includes interest, minority interest and the net results of equity-accounted entities of equity-accounted entities.

Table of Contents

Oil and natural gas exploration and production activities continued

$ million

	Europe		North America		South America	Africa	Asia		Australasia	Total
2008	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries[a]										
Capitalized costs at 31 December[b]										
Gross capitalized costs										
Proved properties	34,614	5,507	59,918	3,517	7,934	21,563	–	10,689	2,581	146,323
Unproved properties	626	–	5,006	165	134	2,011	–	465	1,018	9,425
	35,240	5,507	64,924	3,682	8,068	23,574	–	11,154	3,599	155,748
Accumulated depreciation	26,564	3,125	28,511	2,141	4,217	10,451	–	4,395	945	80,349
Net capitalized costs	8,676	2,382	36,413	1,541	3,851	13,123	–	6,759	2,654	75,399

The group’s share of equity-accounted entities’ net capitalized costs at 31 December 2008 was $13,393 million.

	UK	Rest of Europe	US	Rest of North America	South America	Africa	Russia	Rest of Asia	Australasia	Total
Costs incurred for the year ended 31 December[b]										
Acquisition of properties[c]										
Proved	–	–	1,374	2	–	–	–	136	–	1,512
Unproved	4	–	2,942	–	–	–	–	41	–	2,987
	4	–	4,316	2	–	–	–	177	–	4,499
Exploration and appraisal costs[d]	137	–	862	33	90	838	12	269	49	2,290
Development	907	695	4,914	309	768	2,966	–	859	349	11,767
Total costs	1,048	695	10,092	344	858	3,804	12	1,305	398	18,556

The group’s share of equity-accounted entities’ costs incurred in 2008 was $3,259 million: in Russia $1,921 million, South America $1,039 million, and Rest of Asia $299 million.

	UK	Rest of Europe	US	Rest of North America	South America	Africa	Russia	Rest of Asia	Australasia	Total
Results of operations for the year ended 31 December										
Sales and other operating revenues[e]										
Third parties	3,865	105	8,010	147	3,339	3,745	–	1,186	860	21,257
Sales between businesses	4,374	1,416	15,610	1,237	2,605	6,022	–	11,249	1,171	43,684
	8,239	1,521	23,620	1,384	5,944	9,767	–	12,435	2,031	64,941
Exploration expenditure	121	1	305	32	30	213	14	140	26	882
Production costs	1,357	150	3,002	289	429	875	18	485	62	6,667
Production taxes[f]	503	–	2,603	2	358	–	–	5,510	110	9,086
Other costs (income)[f g]	(28)	(43)	3,440	343	198	(122)[k]	196	2,064	226	6,274
Depreciation, depletion and amortization	1,049	199	2,729	181	730	2,120	–	788	87	7,883
Impairments and (gains) losses on sale of businesses and fixed assets	–	–	308	2	4	8	–	219	–	541
	3,002	307	12,387	849	1,749	3,094	228	9,206	511	31,333
Profit before taxation[h]	5,237	1,214	11,233	535	4,195	6,673	(228)	3,229	1,520	33,608
Allocable taxes	2,280	883	3,857	205	2,218	2,672	(36)	984	513	13,576
Results of operations	2,957	331	7,376	330	1,977	4,001	(192)	2,245	1,007	20,032

The group’s share of equity-accounted entities’ results of operations (including the group’s share of total TNK-BP results) in 2008 was a profit of $2,793 million after deducting interest of $355 million, taxation of $1,217 million and minority interest of $169 million.

	UK	Rest of Europe	US	Rest of North America	South America	Africa	Russia	Rest of Asia	Australasia	Total
Exploration and Production segment replacement cost profit before interest and tax										
Exploration and production activities										
Subsidiaries (as above)	5,237	1,214	11,233	535	4,195	6,673	(228)	3,229	1,520	33,608
Equity-accounted entities	(1)	–	1	40	304	(1)	2,259	191	–	2,793
Midstream activities[i j]	743	16	490	673	274	112	–	(272)	(129)	1,907
Total replacement cost profit before interest and tax	5,979	1,230	11,724	1,248	4,773	6,784	2,031	3,148	1,391	38,308

[a] These tables contain information relating to oil and natural gas exploration and production activities. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation are excluded. In addition, our midstream activities of marketing and trading of natural gas, power and NGLs in the US, Canada, UK and Europe are excluded. The most significant midstream pipeline interests include the Trans-Alaska Pipeline System, the Forties Pipeline System, the Central Area Transmission System pipeline, the South Caucasus Pipeline and the Baku-Tbilisi-Ceyhan pipeline. Major LNG activities are located in Trinidad, Indonesia and Australia and BP is also investing in the LNG business in Angola. The group’s share of equity-accounted entities’ activities are excluded from the tables and included in the footnotes, with the exception of Abu Dhabi production taxes, which are included in the results of operations above.
[b] Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.
[c] Includes costs capitalized as a result of asset exchanges.
[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] Presented net of transportation costs, purchases and sales taxes.
[f] Comparative figures have been restated to include in Production taxes amounts previously reported within Other costs (income) amounting to $2,427 million.
[g] Includes property taxes, other government take and the fair value loss on embedded derivatives of $102 million. The UK region includes a $499 million gain offset by corresponding charges primarily in the US, relating to the group self-insurance programme.
[h] Excludes the unwinding of the discount on provisions and payables amounting to $285 million which is included in finance costs in the group income statement.
[i] Includes a $517 million write-down of our investment in Rosneft based on its quoted market price at the end of the year.
[j] Midstream activities exclude inventory holding gains and losses.
[k] Includes $367 million previously reported within the ‘Other’ region.

Oil and natural gas exploration and production activities continued

	Europe		North America		South America	Africa	Asia		Australasia	Total
										$ million
										2007
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries[a]										
Capitalized costs at 31 December[b]										
Gross capitalized costs										
Proved properties	34,774	4,925	53,079	3,261	7,366	18,333	–	9,629	1,495	132,862
Unproved properties	606	–	1,660	182	115	1,533	4	536	1,001	5,637
	35,380	4,925	54,739	3,443	7,481	19,866	4	10,165	2,496	138,499
Accumulated depreciation	25,515	2,925	25,500	1,968	3,560	8,315	–	3,638	423	71,844
Net capitalized costs	9,865	2,000	29,239	1,475	3,921	11,551	4	6,527	2,073	66,655

The group’s share of equity-accounted entities’ net capitalized costs at 31 December 2007 was $11,787 million.

	UK	Rest of Europe	US	Rest of North America	South America	Africa	Russia	Rest of Asia	Australasia	Total
Costs incurred for the year ended 31 December[b]										
Acquisition of properties[c]										
Proved	–	–	245	–	–	–	–	232	–	477
Unproved	–	–	54	16	–	321	–	126	–	517
	–	–	299	16	–	321	–	358	–	994
Exploration and appraisal costs[d]	209	16	646	40	32	677	119	118	35	1,892
Development	804	443	3,861	240	817	2,634	–	1,109	245	10,153
Total costs	1,013	459	4,806	296	849	3,632	119	1,585	280	13,039

The group’s share of equity-accounted entities’ costs incurred in 2007 was $2,552 million: in Russia $1,787 million, South America $569 million, and Rest of Asia $196 million.

	UK	Rest of Europe	US	Rest of North America	South America	Africa	Russia	Rest of Asia	Australasia	Total
Results of operations for the year ended 31 December										
Sales and other operating revenues[e]										
Third parties	4,503	434	1,436	147	1,995	2,219	–	1,388	681	12,803
Sales between businesses	2,260	902	14,353	868	2,274	3,223	–	10,137	816	34,833
	6,763	1,336	15,789	1,015	4,269	5,442	–	11,525	1,497	47,636
Exploration expenditure	46	–	252	57	77	183	116	18	7	756
Production costs	1,658	147	2,782	267	503	637	2	470	64	6,530
Production taxes[f]	227	3	1,260	1	272	–	–	3,914	56	5,733
Other costs (income)[f g]	(419)	123	2,505	237	158	224[j]	169	1,316	366	4,679
Depreciation, depletion and amortization	1,569	207	2,118	169	653	1,372	–	1,148	52	7,288
Impairments and (gains) losses on sale of businesses and fixed assets	112	(534)	(413)	(38)	(5)	(76)	–	–	–	(954)
	3,193	(54)	8,504	693	1,658	2,340	287	6,866	545	24,032
Profit before taxation[h]	3,570	1,390	7,285	322	2,611	3,102	(287)	4,659	952	23,604
Allocable taxes	1,664	611	2,560	35	1,167	1,462	3	1,133	267	8,902
Results of operations	1,906	779	4,725	287	1,444	1,640	(290)	3,526	685	14,702

The group’s share of equity-accounted entities’ results of operations (including the group’s share of total TNK-BP results) in 2007 was a profit of $2,704 million after deducting interest of $401 million, taxation of $1,355 million and minority interest of $215 million.

	UK	Rest of Europe	US	Rest of North America	South America	Africa	Russia	Rest of Asia	Australasia	Total
Exploration and Production segment replacement cost profit before interest and tax										
Exploration and production activities										
Subsidiaries (as above)	3,570	1,390	7,285	322	2,611	3,102	(287)	4,659	952	23,604
Equity-accounted entities	–	–	1	(33)	414	–	2,292	30	–	2,704
Midstream activities[i]	15	12	643	626	13	96	(112)	38	(37)	1,294
Total replacement cost profit before interest and tax	3,585	1,402	7,929	915	3,038	3,198	1,893	4,727	915	27,602

[a] These tables contain information relating to oil and natural gas exploration and production activities. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation are excluded. In addition, our midstream activities of marketing and trading of natural gas, power and NGLs in the US, Canada, UK and Europe are excluded. The most significant midstream pipeline interests include the Trans-Alaska Pipeline System, the Forties Pipeline System, the Central Area Transmission System pipeline, the South Caucasus Pipeline and the Baku-Tbilisi-Ceyhan pipeline. Major LNG activities are located in Trinidad, Indonesia and Australia. The group’s share of equity-accounted entities’ activities are excluded from the tables and included in the footnotes with the exception of the Abu Dhabi operations which are included in the results of operations above.

[b] Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

[c] Includes costs capitalized as a result of asset exchanges.

[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] Presented net of transportation costs, purchases and sales taxes.

[f] Comparative figures have been restated to include in Production taxes amounts previously reported within Other costs (income) amounting to $1,690 million.

[g] Includes property taxes, other government take and the fair value gain on embedded derivatives of $47 million. The UK region includes a $409 million gain offset by corresponding charges primarily in the US, relating to the group self-insurance programme.

[h] Excludes the unwinding of the discount on provisions and payables amounting to $179 million which is included in finance costs in the group income statement.

[i] Midstream activities exclude inventory holding gains and losses.

[j] Includes $24 million previously reported within the ‘Other’ region.

Movements in estimated net proved reserves

million barrels

Crude oil[a]	Europe		North America		South America	Africa	Asia		Australasia	2009 Total
	UK	Rest of Europe	US[e]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2009										
Developed	410	81	1,717	11	47	464	–	195	56	2,981
Undeveloped	119	194	1,273	1	55	496	–	488	58	2,684
	529	275	2,990	12	102	960	–	683	114	5,665
Changes attributable to										
Revisions of previous estimates	7	(1)	165	2	18	(121)	–	(128)	3	(55)
Improved recovery	42	7	82	–	7	32	–	31	2	203
Purchases of reserves-in-place	1	–	–	–	–	–	–	1	–	2
Discoveries and extensions	184	–	73	–	–	114	–	–	7	378
Production[b]	(61)	(14)	(237)	(2)	(22)	(109)	–	(45)	(11)	(501)
Sales of reserves-in-place	(8)	–	–	–	–	–	–	(26)	–	(34)
	165	(8)	83	–	3	(84)	–	(167)	1	(7)
At 31 December 2009[c]										
Developed	403	83	1,862	11	49	422	–	182	58	3,070
Undeveloped	291	184	1,211	1	56	454	–	334	57	2,588
	694	267	3,073	12	105	876	–	516	115	5,658
Equity-accounted entities (BP share)[f]										
At 1 January 2009										
Developed	–	–	–	–	399	–	2,227	499	–	3,125
Undeveloped	–	–	–	–	409	11	944	199	–	1,563
	–	–	–	–	808	11	3,171	698	–	4,688
Changes attributable to										
Revisions of previous estimates	–	–	–	–	2	(2)	590	(28)	–	562
Improved recovery	–	–	–	–	50	–	8	–	–	58
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	3	–	87	–	–	90
Production	–	–	–	–	(37)	–	(307)	(71)	–	(415)
Sales of reserves-in-place	–	–	–	–	(14)	–	–	(116)	–	(130)
	–	–	–	–	4	(2)	378	(215)	–	165
At 31 December 2009[d]										
Developed	–	–	–	–	407	–	2,351	363	–	3,121
Undeveloped	–	–	–	–	405	9	1,198	120	–	1,732
	–	–	–	–	812	9	3,549	483	–	4,853
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2009										
Developed	410	81	1,717	11	446	464	2,227	694	56	6,106
Undeveloped	119	194	1,273	1	464	507	944	687	58	4,247
	529	275	2,990	12	910	971	3,171	1,381	114	10,353
At 31 December 2009										
Developed	403	83	1,862	11	456	422	2,351	545	58	6,191
Undeveloped	291	184	1,211	1	461	463	1,198	454	57	4,320
	694	267	3,073	12	917	885	3,549	999	115	10,511

[a] Crude oil includes NGLs and condensate. 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] Excludes NGLs from processing plants in which an interest is held of 26 thousand barrels a day.
[c] Includes 819 million barrels of NGLs. Also includes 23 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[d] Includes 20 million barrels of NGLs. Also includes 243 million barrels of crude oil in respect of the 6.86% minority interest in TNK-BP.
[e] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 68 million barrels upon which a net profits royalty will be payable over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.
[f] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

Table of Contents

Movements in estimated net proved reserves continued

Natural gas[a]										billion cubic feet 2009
	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 2009										
Developed	1,822	61	9,059	659	3,316	1,050	–	1,102	1,887	18,956
Undeveloped	582	402	5,473	468	7,434	1,382	–	1,308	4,000	21,049
	2,404	463	14,532	1,127	10,750	2,432	–	2,410	5,887	40,005
Changes attributable to										
Revisions of previous estimates	(114)	(8)	549	43	322	270	–	(231)	22	853
Improved recovery	34	–	550	5	322	49	–	82	75	1,117
Purchases of reserves-in-place	159	–	–	–	–	–	–	31	–	190
Discoveries and extensions	150	–	496	94	105	59	–	–	531	1,435
Production[b]	(243)	(9)	(907)	(100)	(929)	(249)	–	(241)	(189)	(2,867)
Sales of reserves-in-place	(118)	–	(4)	–	–	–	–	(223)	–	(345)
	(132)	(17)	684	42	(180)	129	–	(582)	439	383
At 31 December 2009[c]										
Developed	1,602	49	9,583	716	3,177	1,107	–	1,579	3,219	21,032
Undeveloped	670	397	5,633	453	7,393	1,454	–	249	3,107	19,356
	2,272	446	15,216	1,169	10,570	2,561	–	1,828	6,326	40,388
Equity-accounted entities (BP share)[e]										
At 1 January 2009										
Developed	–	–	–	–	1,498	–	1,560	176	–	3,234
Undeveloped	–	–	–	–	1,023	182	653	111	–	1,969
	–	–	–	–	2,521	182	2,213	287	–	5,203
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(26)	(17)	204	(19)	–	142
Improved recovery	–	–	–	–	314	–	1	4	–	319
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	6	–	23	–	–	29
Production[b]	–	–	–	–	(165)	–	(219)	(25)	–	(409)
Sales of reserves-in-place	–	–	–	–	(388)	–	–	(154)	–	(542)
	–	–	–	–	(259)	(17)	9	(194)	–	(461)
At 31 December 2009[d]										
Developed	–	–	–	–	1,252	–	1,703	80	–	3,035
Undeveloped	–	–	–	–	1,010	165	519	13	–	1,707
	–	–	–	–	2,262	165	2,222	93	–	4,742
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2009										
Developed	1,822	61	9,059	659	4,814	1,050	1,560	1,278	1,887	22,190
Undeveloped	582	402	5,473	468	8,457	1,564	653	1,419	4,000	23,018
	2,404	463	14,532	1,127	13,271	2,614	2,213	2,697	5,887	45,208
At 31 December 2009										
Developed	1,602	49	9,583	716	4,429	1,107	1,703	1,659	3,219	24,067
Undeveloped	670	397	5,633	453	8,403	1,619	519	262	3,107	21,063
	2,272	446	15,216	1,169	12,832	2,726	2,222	1,921	6,326	45,130

[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] Includes 195 billion cubic feet of natural gas consumed in operations, 164 billion cubic feet in subsidiaries, 31 billion cubic feet in equity-accounted entities and excludes 16 billion cubic feet of produced non-hydrocarbon components which meet regulatory requirements for sales.
[c] Includes 3,068 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[d] Includes 131 billion cubic feet of natural gas in respect of the 5.79% minority interest in TNK-BP.
[e] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

Movements in estimated net proved reserves continued

Crude oil[a]	Europe: UK	Europe: Rest of Europe	North America: US[e]	North America: Rest of North America	South America	Africa	Asia: Russia	Asia: Rest of Asia	Australasia	Total
										million barrels
										2008
Subsidiaries										
At 1 January 2008										
Developed	414	105	1,882	13	102	256	–	121	44	2,937
Undeveloped	123	169	1,265	1	202	350	–	372	73	2,555
	537	274	3,147	14	304	606	–	493	117	5,492
Changes attributable to										
Revisions of previous estimates	16	(11)	(212)	1	7	264	–	194	5	264
Improved recovery	39	28	182	–	8	18	–	43	3	321
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	64	–	5	173	–	–	–	242
Production[b]	(63)	(16)	(191)	(3)	(23)	(101)	–	(47)	(11)	(455)
Sales of reserves-in-place	–	–	–	–	(199)	–	–	–	–	(199)
	(8)	1	(157)	(2)	(202)	354	–	190	(3)	173
At 31 December 2008[c]										
Developed	410	81	1,717	11	47	464	–	195	56	2,981
Undeveloped	119	194	1,273	1	55	496	–	488	58	2,684
	529	275	2,990	12	102	960	–	683	114	5,665
Equity-accounted entities (BP share)[f]										
At 1 January 2008										
Developed	–	–	–	–	328	–	2,094	574	–	2,996
Undeveloped	–	–	–	–	243	–	1,137	205	–	1,585
	–	–	–	–	571	–	3,231	779	–	4,581
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(3)	11	217	(1)	–	224
Improved recovery	–	–	–	–	62	–	–	–	–	62
Purchases of reserves-in-place	–	–	–	–	199	–	–	–	–	199
Discoveries and extensions	–	–	–	–	13	–	26	–	–	39
Production	–	–	–	–	(34)	–	(302)	(80)	–	(416)
Sales of reserves-in-place	–	–	–	–	–	–	(1)	–	–	(1)
	–	–	–	–	237	11	(60)	(81)	–	107
At 31 December 2008[d]										
Developed	–	–	–	–	399	–	2,227	499	–	3,125
Undeveloped	–	–	–	–	409	11	944	199	–	1,563
	–	–	–	–	808	11	3,171	698	–	4,688
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2008										
Developed	414	105	1,882	13	430	256	2,094	695	44	5,933
Undeveloped	123	169	1,265	1	445	350	1,137	577	73	4,140
	537	274	3,147	14	875	606	3,231	1,272	117	10,073
At 31 December 2008										
Developed	410	81	1,717	11	446	464	2,227	694	56	6,106
Undeveloped	119	194	1,273	1	464	507	944	687	58	4,247
	529	275	2,990	12	910	971	3,171	1,381	114	10,353

[a]Crude oil includes NGLs and condensate. 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]Excludes NGLs from processing plants in which an interest is held of 19 thousand barrels a day.
[c]Includes 807 million barrels of NGLs. Also includes 21 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[d]Includes 36 million barrels of NGLs. Also includes 216 million barrels of crude oil in respect of the 6.80% minority interest in TNK-BP.
[e]Proved reserves in the Prudhoe Bay field in Alaska include an estimated 54 million barrels upon which a net profits royalty will be payable over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.
[f]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]	Europe		North America		South America	Africa	Asia		Australasia	2008 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2008										
Developed	2,049	63	10,670	608	3,075	990	–	1,270	1,135	19,860
Undeveloped	553	410	4,705	421	7,973	1,410	–	1,269	4,529	21,270
	2,602	473	15,375	1,029	11,048	2,400	–	2,539	5,664	41,130
Changes attributable to										
Revisions of previous estimates	23	(8)	(2,063)	51	(456)	142	–	–	361	(1,950)
Improved recovery	77	9	1,322	16	159	6	–	108	2	1,699
Purchases of reserves-in-place	–	–	183	–	–	–	–	–	–	183
Discoveries and extensions	–	–	549	125	948	82	–	37	–	1,741
Production[b]	(298)	(11)	(834)	(94)	(946)	(198)	–	(274)	(140)	(2,795)
Sales of reserves-in-place	–	–	–	–	(3)	–	–	–	–	(3)
	(198)	(10)	(843)	98	(298)	32	–	(129)	223	(1,125)
At 31 December 2008[c]										
Developed	1,822	61	9,059	659	3,316	1,050	–	1,102	1,887	18,956
Undeveloped	582	402	5,473	468	7,434	1,382	–	1,308	4,000	21,049
	2,404	463	14,532	1,127	10,750	2,432	–	2,410	5,887	40,005
Equity-accounted entities (BP share)[e]										
At 1 January 2008										
Developed	–	–	–	–	1,478	–	808	187	–	2,473
Undeveloped	–	–	–	–	831	–	353	113	–	1,297
	–	–	–	–	2,309	–	1,161	300	–	3,770
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(96)	182	1,273	(2)	–	1,357
Improved recovery	–	–	–	–	301	–	–	11	–	312
Purchases of reserves-in-place	–	–	–	–	3	–	–	–	–	3
Discoveries and extensions	–	–	–	–	192	–	–	–	–	192
Production[b]	–	–	–	–	(188)	–	(221)	(22)	–	(431)
Sales of reserves-in-place	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	212	182	1,052	(13)	–	1,433
At 31 December 2008[d]										
Developed	–	–	–	–	1,498	–	1,560	176	–	3,234
Undeveloped	–	–	–	–	1,023	182	653	111	–	1,969
	–	–	–	–	2,521	182	2,213	287	–	5,203
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2008										
Developed	2,049	63	10,670	608	4,553	990	808	1,457	1,135	22,333
Undeveloped	553	410	4,705	421	8,804	1,410	353	1,382	4,529	22,567
	2,602	473	15,375	1,029	13,357	2,400	1,161	2,839	5,664	44,900
At 31 December 2008										
Developed	1,822	61	9,059	659	4,814	1,050	1,560	1,278	1,887	22,190
Undeveloped	582	402	5,473	468	8,457	1,564	653	1,419	4,000	23,018
	2,404	463	14,532	1,127	13,271	2,614	2,213	2,697	5,887	45,208

[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] Includes 193 billion cubic feet of natural gas consumed in operations, 149 billion cubic feet in subsidiaries, 44 billion cubic feet in equity-accounted entities and excludes 17 billion cubic feet of produced non-hydrocarbon components which meet regulatory requirements for sales.
[c] Includes 3,108 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[d] Includes 131 billion cubic feet of natural gas in respect of the 5.92% minority interest in TNK-BP.
[e] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

Movements in estimated net proved reserves continued

Crude oil[a]	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[f]	Rest of North America			Russia	Rest of Asia		
									million barrels	2007
Subsidiaries										
At 1 January 2007										
Developed	458	189	1,916	15	115	193	–	104	51	3,041
Undeveloped	146	97	1,292	2	235	512	–	487	81	2,852
	604	286	3,208	17	350	705	–	591	132	5,893
Changes attributable to										
Revisions of previous estimates	(1)	(25)	18	–	(29)	(133)	–	(29)	(5)	(204)
Improved recovery	7	1	99	–	6	12	–	6	–	131
Purchases of reserves-in-place	–	–	25	–	–	–	–	8	–	33
Discoveries and extensions	–	31	60	–	1	93	–	–	2	187
Production[b]	(73)	(19)	(169)	(3)	(24)	(71)	–	(83)	(12)	(454)
Sales of reserves-in-place	–	–	(94)	–	–	–	–	–	–	(94)
	(67)	(12)	(61)	(3)	(46)	(99)	–	(98)	(15)	(401)
At 31 December 2007[c]										
Developed	414	105	1,882	13	102	256	–	121	44	2,937
Undeveloped	123	169	1,265	1	202	350	–	372	73	2,555
	537	274	3,147	14	304	606	–	493	117	5,492
Equity-accounted entities (BP share)[d,g]										
At 1 January 2007										
Developed	–	–	–	–	221	–	2,200	521	–	2,942
Undeveloped	–	–	–	–	139	–	644	163	–	946
	–	–	–	–	360	–	2,844	684	–	3,888
Changes attributable to										
Revisions of previous estimates	–	–	–	–	178	–	413	167	–	758
Improved recovery	–	–	–	–	59	–	–	1	–	60
Purchases of reserves-in-place	–	–	–	–	–	–	16	–	–	16
Discoveries and extensions	–	–	–	–	2	–	283	–	–	285
Production	–	–	–	–	(28)	–	(304)	(73)	–	(405)
Sales of reserves-in-place	–	–	–	–	–	–	(21)	–	–	(21)
	–	–	–	–	211	–	387	95	–	693
At 31 December 2007[e]										
Developed	–	–	–	–	328	–	2,094	574	–	2,996
Undeveloped	–	–	–	–	243	–	1,137	205	–	1,585
	–	–	–	–	571	–	3,231	779	–	4,581
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2007										
Developed	458	189	1,916	15	336	193	2,200	625	51	5,983
Undeveloped	146	97	1,292	2	374	512	644	650	81	3,798
	604	286	3,208	17	710	705	2,844	1,275	132	9,781
At 31 December 2007										
Developed	414	105	1,882	13	430	256	2,094	695	44	5,933
Undeveloped	123	169	1,265	1	445	350	1,137	577	73	4,140
	537	274	3,147	14	875	606	3,231	1,272	117	10,073

[a] Crude oil includes NGLs and condensate. 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] Excludes NGLs from processing plants in which an interest is held of 54 thousand barrels a day.
[c] Includes 739 million barrels of NGLs. Also includes 20 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[d] The BP group holds interests, through associates, in onshore and offshore concessions in Abu Dhabi, expiring in 2014 and 2018 respectively. During the second quarter of 2007, we updated our reporting policy in Abu Dhabi to be consistent with general industry practice and as a result have started reporting production and reserves there gross of production taxes. This change resulted in an increase in our reserves of 153 million barrels and in our production of 33mb/d.
[e] Includes 26 million barrels of NGLs. Also includes 210 million barrels of crude oil in respect of the 6.51% minority interest in TNK-BP.
[f] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 98 million barrels upon which a net profits royalty will be payable over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.
[g] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

Table of Contents

Movements in estimated net proved reserves continued

billion cubic feet

Natural gas[a] 2007	Europe UK	Europe Rest of Europe	North America US	North America Rest of North America	South America	Africa	Asia Russia	Asia Rest of Asia	Australasia	Total
Subsidiaries										
At 1 January 2007										
Developed	1,968	242	10,438	627	3,305	1,032	–	808	882	19,302
Undeveloped	825	56	4,660	310	8,884	1,675	–	1,781	4,675	22,866
	2,793	298	15,098	937	12,189	2,707	–	2,589	5,557	42,168
Changes attributable to										
Revisions of previous estimates	93	(37)	744	(72)	(204)	(146)	–	(21)	140	497
Improved recovery	15	1	326	32	–	9	–	100	16	499
Purchases of reserves-in-place	–	–	23	–	–	–	–	109	–	132
Discoveries and extensions	–	293	95	237	12	17	–	–	88	742
Production[b]	(299)	(14)	(879)	(98)	(949)	(187)	–	(238)	(137)	(2,801)
Sales of reserves-in-place	–	(68)	(32)	(7)	–	–	–	–	–	(107)
	(191)	175	277	92	(1,141)	(307)	–	(50)	107	(1,038)
At 31 December 2007[c]										
Developed	2,049	63	10,670	608	3,075	990	–	1,270	1,135	19,860
Undeveloped	553	410	4,705	421	7,973	1,410	–	1,269	4,529	21,270
	2,602	473	15,375	1,029	11,048	2,400	–	2,539	5,664	41,130
Equity-accounted entities (BP share)[e]										
At 1 January 2007										
Developed	–	–	–	–	1,460	–	1,087	222	–	2,769
Undeveloped	–	–	–	–	735	–	184	75	–	994
	–	–	–	–	2,195	–	1,271	297	–	3,763
Changes attributable to										
Revisions of previous estimates	–	–	–	–	73	–	61	9	–	143
Improved recovery	–	–	–	–	195	–	–	16	–	211
Purchases of reserves-in-place	–	–	–	–	–	–	8	–	–	8
Discoveries and extensions	–	–	–	–	22	–	–	–	–	22
Production[b]	–	–	–	–	(176)	–	(179)	(22)	–	(377)
Sales of reserves-in-place	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	114	–	(110)	3	–	7
At 31 December 2007[d]										
Developed	–	–	–	–	1,478	–	808	187	–	2,473
Undeveloped	–	–	–	–	831	–	353	113	–	1,297
	–	–	–	–	2,309	–	1,161	300	–	3,770
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2007										
Developed	1,968	242	10,438	627	4,765	1,032	1,087	1,030	882	22,071
Undeveloped	825	56	4,660	310	9,619	1,675	184	1,856	4,675	23,860
	2,793	298	15,098	937	14,384	2,707	1,271	2,886	5,557	45,931
At 31 December 2007										
Developed	2,049	63	10,670	608	4,553	990	808	1,457	1,135	22,333
Undeveloped	553	410	4,705	421	8,804	1,410	353	1,382	4,529	22,567
	2,602	473	15,375	1,029	13,357	2,400	1,161	2,839	5,664	44,900

[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] Includes 202 billion cubic feet of natural gas consumed in operations, 161 billion cubic feet in subsidiaries, 41 billion cubic feet in equity-accounted entities and excludes 10.9 billion cubic feet of produced non-hydrocarbon components which meet regulatory requirements for sales.
[c] Includes 3,211 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[d] Includes 68 billion cubic feet of natural gas in respect of the 5.88% minority interest in TNK-BP.
[e] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

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

The following tables set out the standardized measure of discounted future net cash flows, and changes therein, relating to crude oil and natural gas production from the group’s estimated proved reserves. This information is prepared in compliance with FASB Oil and Gas Disclosures requirements.

Future net cash flows have been prepared on the basis of certain assumptions which may or may not be realized. These include the timing of future production, the estimation of crude oil and natural gas reserves and the application of average crude oil and natural gas prices and exchange rates from the previous 12 months. Furthermore, both proved reserves estimates and production forecasts are subject to revision as further technical information becomes available and economic conditions change. BP cautions against relying on the information presented because of the highly arbitrary nature of the assumptions on which it is based and its lack of comparability with the historical cost information presented in the financial statements.

										$ million
										2009
	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 2009										
Subsidiaries										
Future cash inflows[a]	50,800	17,700	204,000	4,900	26,400	58,400	–	36,100	32,500	430,800
Future production cost[b]	20,000	8,000	91,300	2,700	6,700	12,000	–	9,200	11,000	160,900
Future development cost[b]	5,000	2,500	24,900	1,000	5,600	12,200	–	6,400	3,100	60,700
Future taxation[c]	12,900	3,700	27,300	200	5,800	11,300	–	4,700	4,500	70,400
Future net cash flows	12,900	3,500	60,500	1,000	8,300	22,900	–	15,800	13,900	138,800
10% annual discount[d]	5,800	1,600	29,500	500	3,200	9,800	–	6,300	7,300	64,000
Standardized measure of discounted future net cash flows[e]	7,100	1,900	31,000	500	5,100	13,100	–	9,500	6,600	74,800
Equity-accounted entities (BP share)[f]										
Future cash inflows[a]	–	–	–	–	37,700	–	96,700	30,000	–	164,400
Future production cost[b]	–	–	–	–	17,000	–	65,200	25,200	–	107,400
Future development cost[b]	–	–	–	–	4,000	–	10,200	3,100	–	17,300
Future taxation[c]	–	–	–	–	5,200	–	4,300	100	–	9,600
Future net cash flows	–	–	–	–	11,500	–	17,000	1,600	–	30,100
10% annual discount[d]	–	–	–	–	6,800	–	7,900	800	–	15,500
Standardized measure of discounted future net cash flows[g] [h]	–	–	–	–	4,700	–	9,100	800	–	14,600
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows	7,100	1,900	31,000	500	9,800	13,100	9,100	10,300	6,600	89,400

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	(18,900)	(3,400)	(22,300)
Previously estimated development costs incurred during the year	11,700	2,100	13,800
Extensions, discoveries and improved recovery, less related costs	8,500	1,600	10,100
Net changes in prices and production cost	37,200	5,900	43,100
Revisions of previous reserves estimates	(4,300)	(200)	(4,500)
Net change in taxation	(10,600)	(1,600)	(12,200)
Future development costs	(600)	900	300
Net change in purchase and sales of reserves-in-place	(100)	(900)	(1,000)
Addition of 10% annual discount	4,700	900	5,600
Total change in the standardized measure during the year[i]	27,600	5,300	32,900

[a] The marker prices used were Brent $59.91/bbl, Henry Hub $3.82/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 using 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] Minority interest in BP Trinidad and Tobago LLC amounted to $1,300 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] Minority interest in TNK-BP amounted to $600 million.
[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] 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

	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 2008										
Subsidiaries										
Future cash inflows[a]	36,400	13,800	165,800	6,400	26,300	40,400	–	31,400	24,200	344,700
Future production cost[b]	18,100	6,300	80,400	2,700	7,200	11,600	–	11,800	10,700	148,800
Future development cost[b]	3,300	2,900	25,600	1,300	7,200	10,900	–	7,500	3,200	61,900
Future taxation[c]	7,300	2,300	17,500	500	5,500	6,600	–	2,400	2,800	44,900
Future net cash flows	7,700	2,300	42,300	1,900	6,400	11,300	–	9,700	7,500	89,100
10% annual discount[d]	2,200	1,200	21,000	1,000	2,900	5,500	–	4,200	3,900	41,900
Standardized measure of discounted future net cash flows[e]	5,500	1,100	21,300	900	3,500	5,800	–	5,500	3,600	47,200
Equity-accounted entities (BP share)[g]										
Standardized measure of discounted future net cash flows[h]	–	–	–	–	3,600	–	4,800	900	–	9,300
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows[e]	5,500	1,100	21,300	900	7,100	5,800	4,800	6,400	3,600	56,500
At 31 December 2007										
Subsidiaries										
Future cash inflows[a]	72,100	29,500	350,100	7,500	60,200	63,300	–	55,100	41,900	679,700
Future production cost[b]	27,500	7,500	109,800	3,000	14,900	9,900	–	9,700	11,600	193,900
Future development cost[b]	4,000	3,300	21,900	700	5,800	8,300	–	3,900	3,700	51,600
Future taxation[c]	20,200	13,000	71,600	900	20,800	17,100	–	9,800	8,600	162,000
Future net cash flows	20,400	5,700	146,800	2,900	18,700	28,000	–	31,700	18,000	272,200
10% annual discount[d]	6,500	2,800	76,000	1,300	8,200	9,400	–	12,600	9,200	126,000
Standardized measure of discounted future net cash flows[e]	13,900	2,900	70,800	1,600	10,500	18,600	–	19,100	8,800	146,200
Equity-accounted entities (BP share)[g]										
Standardized measure of discounted future net cash flows[h]	–	–	–	–	5,000	–	21,700	3,000	–	29,700
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows[e]	13,900	2,900	70,800	1,600	15,500	18,600	21,700	22,100	8,800	175,900

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

$ million

	2008	2007
Sales and transfers of oil and gas produced, net of production costs	(43,600)	(28,300)
Previously estimated development costs incurred during the year	9,400	9,400
Extensions, discoveries and improved recovery, less related costs	4,400	12,300
Net changes in prices and production cost	(146,800)	102,100
Revisions of previous reserves estimates	1,200	(12,200)
Net change in taxation	69,400	(28,300)
Future development costs	(7,400)	(7,800)
Net change in purchase and sales of reserves-in-place	(200)	(700)
Addition of 10% annual discount	14,600	9,100
Total change in the standardized measure during the year of subsidiaries[f]	(99,000)	55,600

[a] The year-end marker prices used were 2008 Brent $36.55/bbl, Henry Hub $5.63/mmBtu and 2007 Brent $96.02/bbl, Henry Hub $7.10/mmBtu.
[b] Production costs, which include production taxes, and development costs relating to future production of proved reserves are based on year-end cost levels and assume continuation of existing economic conditions. Future decommissioning costs are included.
[c] Taxation is computed using 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] Minority interest in BP Trinidad and Tobago LLC amounted to $900 million at 31 December 2008 and $2,300 million at 31 December 2007.
[f] Total change in the standardized measure during the year includes the effect of exchange rate movements.
[g] The standardized measure of discounted future net cash flows of equity-accounted entities includes standardized measure of discounted future net cash flows of equity-acccounted investments of those entities.
[h] Minority interest in TNK-BP amounted to $300 million at 31 December 2008 and $1,400 million at 31 December 2007.

Table of Contents

Operational and statistical information

The following tables present operational and statistical information related to production, drilling, productive wells and acreage.

Crude oil and natural gas production

The following table shows crude oil and natural gas production for the years ended 31 December 2009, 2008 and 2007.

Production for the year[a]

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
Crude oil[b]										thousand barrels per day
2009	**168**	**40**	**665**	**8**	**61**	**304**	**–**	**123**	**31**	**1,400**
2008	173	43	538	9	66	277	–	128	29	1,263
2007	201	51	513	8	74	195	–	228	34	1,304
Natural gas[c]										million cubic feet per day
2009	**618**	**16**	**2,316**	**263**	**2,492**	**621**	**–**	**610**	**514**	**7,450**
2008	759	23	2,157	245	2,532	484	–	696	381	7,277
2007	768	29	2,174	255	2,543	468	–	609	376	7,222
Equity-accounted entities (BP share)										
Crude oil[b]										thousand barrels per day
2009	**–**	**–**	**–**	**–**	**101**	**–**	**840**	**194**	**–**	**1,135**
2008	–	–	–	–	92	–	826	220	–	1,138
2007	–	–	–	–	77	–	832	201	–	1,110
Natural gas[c]										million cubic feet per day
2009	**–**	**–**	**–**	**–**	**392**	**–**	**601**	**42**	**–**	**1,035**
2008	–	–	–	–	454	–	564	39	–	1,057
2007	–	–	–	–	429	–	451	41	–	921

[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]Crude oil includes natural gas liquids and condensate.
[c]Natural gas production excludes gas consumed in operations.

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 2009. 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. These tables do not include any information relating to our recent entry into Iraq.

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Number of productive wells at 31 December 2009										
Oil wells[a] – gross	**282**	**83**	**5,793**	**197**	**3,650**	**668**	**20,593**	**1,657**	**13**	**32,936**
– net	**151**	**26**	**2,090**	**76**	**2,045**	**529**	**8,750**	**303**	**2**	**13,972**
Gas wells[b] – gross	**279**	**–**	**21,974**	**1,852**	**487**	**104**	**46**	**563**	**68**	**25,373**
– net	**133**	**–**	**12,359**	**1,236**	**171**	**47**	**23**	**258**	**15**	**14,242**

[a]Includes approximately 3,982 gross (1,750 net) multiple completion wells (more than one formation producing into the same well bore).
[b]Includes approximately 2,834 gross (1,841 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.

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Oil and natural gas acreage at 31 December 2009										Thousands of acres
Developed – gross	**366**	**65**	**7,587**	**1,186**	**1,740**	**539**	**4,123**	**2,191**	**200**	**17,997**
– net	**201**	**19**	**4,609**	**850**	**470**	**222**	**1,794**	**842**	**39**	**9,046**
Undeveloped[a] – gross	**1,602**	**486**	**7,985**	**6,967**	**7,361**	**105,512**	**10,357**	**15,191**	**4,109**	**159,570**
– net	**919**	**226**	**4,979**	**5,009**	**3,471**	**33,341**	**4,683**	**6,597**	**911**	**60,136**

[a]Undeveloped acreage includes leases and concessions.

Table of Contents

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
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
2009										
Exploratory										
Productive	**0.1**	**–**	**47.2**	**–**	**3.0**	**4.5**	**7.0**	**5.3**	**0.6**	**67.7**
Dry	**0.2**	**–**	**4.2**	**–**	**–**	**1.4**	**4.5**	**6.0**	**0.2**	**16.5**
Development										
Productive	**9.3**	**1.5**	**403.8**	**17.9**	**135.4**	**20.8**	**293.0**	**45.8**	**1.6**	**929.1**
Dry	**–**	**–**	**3.3**	**–**	**–**	**0.5**	**4.0**	**0.4**	**0.6**	**8.8**
2008										
Exploratory										
Productive	0.8	–	2.4	–	4.4	4.3	12.5	0.5	0.6	25.5
Dry	–	0.5	0.9	0.1	0.4	2.6	23.0	0.5	0.4	28.4
Development										
Productive	6.6	0.5	379.8	28.3	112.5	18.6	10.0	45.4	4.5	606.2
Dry	0.2	–	1.1	0.9	2.9	1.5	19.5	2.1	–	28.2
2007										
Exploratory										
Productive	1.6	–	4.1	0.5	–	6.1	16.0	1.7	1.1	31.1
Dry	–	–	0.7	0.5	–	1.6	9.0	1.4	–	13.2
Development										
Productive	0.4	0.8	401.2	36.0	10.0	15.3	246.0	27.5	2.1	739.3
Dry	0.6	–	4.2	8.8	–	–	9.5	–	–	23.1

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 at 31 December 2009. Suspended development wells and long-term suspended exploratory wells are also included in the table.

	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 2009										
Exploratory										
Gross	**–**	**–**	**112.0**	**4.0**	**–**	**5.0**	**8.0**	**3.0**	**–**	**132.0**
Net	**–**	**–**	**30.2**	**1.8**	**–**	**2.6**	**4.0**	**2.0**	**–**	**40.6**
Development										
Gross	**4.0**	**1.0**	**366.0**	**30.0**	**15.0**	**23.0**	**45.0**	**16.0**	**–**	**500.0**
Net	**2.7**	**0.3**	**176.9**	**19.8**	**9.2**	**7.5**	**20.0**	**3.4**	**–**	**239.8**

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/D.J. JACKSON
D.J. Jackson
Company Secretary

Dated: 5 March 2010