28. 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							2008
	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
Financial assets							
Other investments – listed	**29**	**–**	**592**	**–**	**–**	**–**	**592**
Other investments – unlisted	**29**	**–**	**263**	**–**	**–**	**–**	**263**
Loans		**1,163**	**–**	**–**	**–**	**–**	**1,163**
Trade and other receivables	**31**	**29,489**	**–**	**–**	**–**	**–**	**29,489**
Derivative financial instruments	**34**	**–**	**–**	**12,501**	**1,063**	**–**	**13,564**
Cash at bank and in hand	**32**	**4,001**	**–**	**–**	**–**	**–**	**4,001**
Cash equivalents – listed	**32**	**–**	**4,060**	**–**	**–**	**–**	**4,060**
Cash equivalents – unlisted	**32**	**–**	**136**	**–**	**–**	**–**	**136**
Financial liabilities							
Trade and other payables	**33**	**–**	**–**	**–**	**–**	**(33,140)**	**(33,140)**
Derivative financial instruments	**34**	**–**	**–**	**(13,173)**	**(2,075)**	**–**	**(15,248)**
Accruals		**–**	**–**	**–**	**–**	**(7,527)**	**(7,527)**
Finance debt	**35**	**–**	**–**	**–**	**–**	**(33,204)**	**(33,204)**
		34,653	**5,051**	**(672)**	**(1,012)**	**(73,871)**	**(35,851)**

$ million

At 31 December							2007
	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
Financial assets							
Other investments – listed	29	–	1,617	–	–	–	1,617
Other investments – unlisted	29	–	213	–	–	–	213
Loans		1,164	–	–	–	–	1,164
Trade and other receivables	31	38,710	–	–	–	–	38,710
Derivative financial instruments	34	–	–	9,155	907	–	10,062
Cash at bank and in hand	32	2,996	–	–	–	–	2,996
Cash equivalents – listed	32	–	3	–	–	–	3
Cash equivalents – unlisted	32	–	563	–	–	–	563
Financial liabilities							
Trade and other payables	33	–	–	–	–	(40,062)	(40,062)
Derivative financial instruments	34	–	–	(11,284)	(123)	–	(11,407)
Accruals		–	–	–	–	(7,599)	(7,599)
Finance debt	35	–	–	–	–	(31,045)	(31,045)
		42,870	2,396	(2,129)	784	(78,706)	(34,785)

The fair value of finance debt is shown in Note 35. 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.

28. Financial instruments and financial risk factors continued

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.

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.

During recent periods of increased volatility in financial markets the group's policies in relation to managing market risk continue to be appropriate and are outlined in further detail below. 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				2008				2007
	High	**Low**	**Average**	**Year end**	High	Low	Average	Year end
Group trading	**76**	**20**	**37**	**69**	50	24	35	38
Oil price trading	**69**	**12**	**25**	**63**	46	16	26	34
Natural gas price trading	**50**	**12**	**24**	**23**	32	9	16	15
Power price trading	**14**	**3**	**7**	**4**	6	1	3	5
Currency trading	**4**	**–**	**2**	**–**	6	1	3	2
Interest rate trading	**7**	**–**	**2**	**1**	11	–	5	2
Other trading	**5**	**1**	**2**	**2**	7	–	2	1

(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. 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.

28. Financial instruments and financial risk factors continued

As described above, the group also carries out risk management of certain short-term natural business exposures using over-the-counter swaps and exchange futures contracts with a duration of less than three years. In past periods commodity price risk relating to this activity has been managed using value-at-risk measures. For 2008 a separate control framework is now used as described under market risk above. 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 $90 million at 31 December 2008. This figure does not include any corresponding economic benefit or disbenefit that would arise from the natural business exposure which would be expected to largely offset the gain or loss on the derivatives.

In addition, the group has embedded derivatives relating to certain natural gas and crude oil contracts. The net fair value of these embedded derivatives was a liability of $1,867 million at 31 December 2008 (2007 liability of $2,085 million). Key information on the natural gas contracts is given below.

At 31 December	2008	2007
Remaining contract terms	**1 year 9 months to 9 years 9 months**	9 months to 11 years
Contractual/notional amount	**3,585 million therms**	3,889 million therms
Discount rate – nominal risk free	**2.5%**	4.5%

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

								$ million
At 31 December				2008				2007
	Gas price	**Oil price**	**Power price**	**Discount rate**	Gas price	Oil price	Power price	Discount rate
Favourable 10% change	**291**	**81**	**27**	**16**	317	72	37	31
Unfavourable 10% change	**(289)**	**(81)**	**(27)**	**(16)**	(368)	(84)	(34)	(32)

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 2008, the foreign currency value at risk was $70 million (2007 $60 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 34.

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, euro, Norwegian krone, Australian dollar, Korean won and Canadian dollar, and at 31 December 2008 open contracts were in place for $949 million sterling, $553 million euro, $392 million Norwegian krone, $303 million Australian dollar, $187 million Korean won and $712 million Canadian dollar capital expenditures maturing within seven years, with over 65% of the deals maturing within two years (2007 $732 million sterling, $931 million euro, $479 million Norwegian krone, $38 million Australian dollar, $243 million Korean won and $7 million Canadian dollar capital expenditures maturing within eight years with over 80% 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 2008, the open positions relating to cylinders consisted of receive sterling, pay US dollar, purchased call and sold put options (cylinders) for $1,660 million (2007 $2,800 million); receive euro, pay US dollar cylinders for $1,612 million (2007 $1,400 million); receive Canadian dollar, pay US dollar cylinders for $250 million (2007 nil); and receive Australian dollar, pay US dollar cylinders for $455 million (2007 $382 million).
At 31 December 2008, the open positions relating to currency forwards consisted of buy sterling, sell US dollar, currency forwards for $816 million (2007 nil); buy euro, sell US dollar currency forwards for $141 million (2007 nil); buy Canadian dollar, sell US dollar, currency forwards for $50 million (2007 nil); and buy Australian dollar, sell US dollar, currency forwards for $90 million (2007 nil).

In addition, most of the group's borrowings are in US dollars or are hedged with respect to the US dollar. At 31 December 2008, the total foreign currency net borrowings not swapped into US dollars amounted to $1,037 million (2007 $1,045 million). Of this total, $92 million was denominated in currencies other than the functional currency of the individual operating unit being entirely Canadian dollars (2007 $268 million, being $191 million in Canadian dollars and $77 million in Trinidad & Tobago 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 $9 million (2007 $27 million).

28. Financial instruments and financial risk factors continued

(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 2008 was 72% of total finance debt outstanding (2007 68%). The weighted average interest rate on finance debt at 31 December 2008 is 3% (2007 5%) and the weighted average maturity of fixed rate debt is three years (2007 two years).

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 2009, it is estimated that the group’s profit before taxation for 2009 would decrease by approximately $239 million (2007 $168 million decrease in 2008). 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 2008 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 directly in equity. Accumulated fair value changes are recycled to the income statement on disposal, or when the investment is impaired. Impairment losses of $546 million have been recognized in 2008 relating to listed non-current available-for-sale investments. For further information see Note 29.

At 31 December 2008, it is estimated that an increase of 10% in quoted equity prices would result in an immediate credit to equity of $59 million (2007 $162 million credit to equity), whilst a decrease of 10% in quoted equity prices would result in an immediate charge to profit or loss of $48 million and a charge to equity of $11 million (2007 $162 million charge to equity).

At 31 December 2008, 56% (2007 70%) 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 processes have been reviewed during the year and credit exposures with banks and others have been reduced through netting and collateral arrangements, or reduced activity where appropriate.

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 the group 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. Once assigned a credit rating, each counterparty is allocated a maximum exposure limit.

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 and other 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 2008, the maximum credit exposure was $52,413 million (2007 $53,498 million). Collateral received and recognized in the balance sheet at the year-end was $1,121 million (2007 $39 million) and collateral held off balance sheet was $203 million (2007 $474 million). Credit exposure exists in relation to guarantees issued by group companies under which amounts outstanding at 31 December 2008 were $223 million (2007 $443 million) in respect of liabilities of jointly controlled entities and associates and $613 million (2007 $601 million) in respect of liabilities of other third parties.

28. Financial instruments and financial risk factors continued

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.

It is estimated that over 80% (2007 80%) of the counterparties to the contracts comprising the derivative financial instruments in an asset position are 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 60-65% (2007 65-70%) of the trade receivables portfolio exposure are of investment grade 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 2008 or 31 December 2007.

		$ million
Trade and other receivables at 31 December	**2008**	2007
Neither impaired nor past due	**25,838**	35,167
Impaired (net of valuation allowance)	**73**	145
Not impaired and past due in the following periods		
within 30 days	**1,323**	2,350
31 to 60 days	**489**	273
61 to 90 days	**596**	311
over 90 days	**1,170**	464
	29,489	38,710

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

		$ million
	2008	2007
At 1 January	**406**	421
Exchange adjustments	**(32)**	34
Charge for the year	**191**	175
Utilization	**(174)**	(224)
At 31 December	**391**	406

(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 2008, 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 until at least the fourth quarter of 2011 (2007 $4,950 million, of which $4,550 million are in place until at least the fourth quarter of 2011). 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 2008, the amount drawn down against the DIP was $10,334 million (2007 $10,438 million). In addition, the group has in place a US Shelf Registration under which it may raise $10 billion of debt with maturities of one month or longer. At 31 December 2008, the amount drawn down under the US Shelf was $6,500 million (2007 $2,500 million).

The group has long-term debt ratings of Aa1 (stable outlook) and AA (stable outlook), (2007 Aa1 (stable outlook) and AA+ (negative outlook)) assigned respectively by Moody's and Standard and Poor's.

Despite current uncertainty in the financial market including a lack of liquidity for some borrowers, we have been able to issue $5 billion of long-term debt in the fourth quarter of 2008. In addition, we have been able to issue short-term commercial paper at competitive rates. In the context of unforeseen market volatility, we have however, increased the cash and cash equivalents held by the group to $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.

28. 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 35. US Industrial Revenue/Municipal Bonds of $3,166 million (2007 $2,880 million) with earliest contractual repayment dates within one year have expected repayment dates ranging from 1 to 40 years (2007 1 to 35 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 $1,806 million (2007 $1,899 million) that mature within nine years.

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

						$ million
At 31 December			2008			2007
	Trade and other payables	**Accruals**	**Finance debt**	Trade and other payables	Accruals	Finance debt
Within one year	**30,598**	**6,743**	**16,670**	39,576	6,640	16,561
1 to 2 years	**402**	**359**	**5,934**	147	351	8,011
2 to 3 years	**898**	**77**	**3,419**	62	245	3,515
3 to 4 years	**902**	**72**	**2,647**	26	78	1,447
4 to 5 years	**223**	**67**	**5,072**	30	49	2,352
5 to 10 years	**53**	**164**	**1,316**	197	200	1,100
Over 10 years	**64**	**45**	**1,050**	24	36	1,447
	33,140	**7,527**	**36,108**	40,062	7,599	34,433

The group manages liquidity risk associated with derivative contracts on a portfolio basis, considering both physical commodity sale and purchase contracts together with financially-settled derivative assets and liabilities.

The held-for-trading derivatives amounts in the table below represent the total contractual cash outflows by period for the purchases of physical commodities under derivative contracts and the estimated cash outflows of financially-settled derivative liabilities. The group also holds derivative contracts for the sale of physical commodities and financially-settled derivative assets that are expected to generate cash inflows that will be available to the group to meet cash outflows on purchases and liabilities. These contracts are excluded from the table below. The amounts disclosed for embedded derivatives represent the contractual cash outflows of purchase contracts some of which have embedded derivatives associated with them which are financial assets.

				$ million
At 31 December		2008		2007
	Embedded derivatives	**Held-for-trading derivatives**	Embedded derivatives	Held-for-trading derivatives
Within one year	**562**	**60,270**	699	82,465
1 to 2 years	**403**	**8,189**	659	8,541
2 to 3 years	**470**	**2,437**	641	2,906
3 to 4 years	**509**	**1,111**	627	707
4 to 5 years	**535**	**841**	624	338
5 to 10 years	**1,538**	**2,087**	2,342	592
Over 10 years	**–**	**553**	–	447
	4,017	**75,488**	5,592	95,996

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 to 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.

		$ million
At 31 December	**2008**	2007
Within one year	**3,426**	1,708
1 to 2 years	**3,024**	1,220
2 to 3 years	**1,037**	3,759
3 to 4 years	**1,731**	365
4 to 5 years	**1,389**	1,650
5 to 10 years	**129**	105
	10,736	8,807

29. Other investments

	$ million 2008	2007
Listed	**592**	1,617
Unlisted	**263**	213
	855	1,830

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. Unlisted investments are stated at cost less accumulated impairment losses.

The most significant investment is the group's stake in Rosneft which had a fair value of $483 million at 31 December 2008 (2007 $1,285 million). During 2008, an impairment loss of $517 million was recognized relating to the Rosneft investment (see Note 11), $29 million relating to other listed investments and $17 million relating to unlisted investments (2007 $80 million relating to unlisted investments).

30. Inventories

	$ million 2008	2007
Crude oil	**4,396**	8,157
Natural gas	**107**	160
Refined petroleum and petrochemical products	**9,318**	14,723
	13,821	23,040
Supplies	**1,588**	1,517
	15,409	24,557
Trading inventories	**1,412**	1,997
	16,821	26,554
Cost of inventories expensed in the income statement	**266,982**	200,766

The inventory valuation at 31 December 2008 is stated net of a provision of $1,412 million (2007 $117 million) to write inventories down to their net realizable value. The net movement in the provision during the year was a charge of $1,295 million (2007 $86 million credit).

31. Trade and other receivables

				$ million
		2008		2007
	Current	**Non-current**	Current	Non-current
Financial assets				
Trade receivables	**22,869**	**–**	33,012	–
Amounts receivable from jointly controlled entities	**1,035**	**–**	888	–
Amounts receivable from associates	**219**	**–**	380	–
Other receivables	**4,656**	**710**	3,462	968
	28,779	**710**	37,742	968
Non-financial assets				
Other receivables	**482**	**–**	278	–
	29,261	**710**	38,020	968

Trade and other receivables are predominantly non-interest bearing.

32. Cash and cash equivalents

		$ million
	2008	2007
Cash at bank and in hand	**4,001**	2,996
Cash equivalents		
Listed	**4,060**	3
Unlisted	**136**	563
	8,197	3,562

Cash and cash equivalents comprise cash in hand; current balances 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.

Cash and cash equivalents at 31 December 2008 includes $2,133 million (2007 $1,294 million) that is restricted. This relates principally to amounts on deposit to cover initial margins on trading exchanges.

33. Trade and other payables

				$ million
		2008		2007
	Current	**Non-current**	Current	Non-current
Financial liabilities				
Trade payables	**20,129**	**–**	30,735	–
Amounts payable to jointly controlled entities	**292**	**2,255**	66	–
Amounts payable to associates	**295**	**–**	650	–
Other payables	**9,882**	**287**	8,125	486
	30,598	**2,542**	39,576	486
Non-financial liabilities				
Production and similar taxes	**445**	**538**	803	765
Other payables	**2,601**	**–**	2,773	–
	3,046	**538**	3,576	765
	33,644	**3,080**	43,152	1,251

Trade and other payables are predominantly interest free.

34. 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 28.

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 profit or loss.

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.

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

				$ million
		2008		2007
	Fair value asset	**Fair value liability**	Fair value asset	Fair value liability
Derivatives held for trading				
Currency derivatives	**278**	**(273)**	147	(317)
Oil price derivatives	**3,813**	**(3,523)**	3,214	(3,432)
Natural gas price derivatives	**6,945**	**(6,113)**	4,388	(4,022)
Power price derivatives	**978**	**(904)**	1,121	(1,140)
Other derivatives	**90**	**(96)**	30	–
	12,104	**(10,909)**	8,900	(8,911)
Embedded derivatives				
Commodity contracts	**397**	**(2,264)**	255	(2,340)
Interest rate contracts	**–**	**–**	–	(33)
	397	**(2,264)**	255	(2,373)
Cash flow hedges				
Currency forwards, futures and cylinders	**120**	**(1,175)**	226	(45)
Cross-currency interest rate swaps	**109**	**(558)**	122	(52)
	229	**(1,733)**	348	(97)
Fair value hedges				
Cross-currency interest rate swaps	**465**	**(342)**	430	(9)
Interest rate swaps	**367**	**–**	89	(17)
	832	**(342)**	519	(26)
Hedges of net investments in foreign operations	**2**	**–**	40	–
	13,564	**(15,248)**	10,062	(11,407)
Of which – current	**8,510**	**(8,977)**	6,321	(6,405)
– non-current	**5,054**	**(6,271)**	3,741	(5,002)

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 28.

The following tables show further information on the fair value of derivatives and other financial instruments held for trading purposes.

Changes during the year in the net fair value of derivatives held for trading purposes were as follows.

						$ million
	Currency	**Oil price**	**Natural gas price**	**Power price**	**Other**	**Total**
Fair value of contracts at 1 January 2008	**(170)**	**(218)**	**366**	**(19)**	**30**	**(11)**
Contracts realized or settled in the year	**24**	**190**	**(216)**	**3**	**(15)**	**(14)**
Fair value of options at inception	**–**	**(216)**	**(201)**	**34**	**–**	**(383)**
Fair value of other new contracts entered into during the year	**–**	**66**	**49**	**–**	**–**	**115**
Changes in fair values relating to price	**151**	**468**	**881**	**60**	**(21)**	**1,539**
Exchange adjustments	**–**	**–**	**(47)**	**(4)**	**–**	**(51)**
Fair value of contracts at 31 December 2008	**5**	**290**	**832**	**74**	**(6)**	**1,195**

34. Derivative financial instruments continued

						$ million
	Currency	Oil price	Natural gas price	Power price	Other	Total
Fair value of contracts at 1 January 2007	105	296	855	42	113	1,411
Contracts realized or settled in the year	(109)	(289)	(602)	(68)	(83)	(1,151)
Fair value of options at inception	–	28	168	36	–	232
Fair value of other new contracts entered into during the year	–	–	1	–	–	1
Changes in fair values relating to price	(167)	(253)	(58)	(20)	–	(498)
Exchange adjustments	1	–	2	(9)	–	(6)
Fair value of contracts at 31 December 2007	(170)	(218)	366	(19)	30	(11)

If at inception of a contract the valuation cannot be supported by observable market data, any gain 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’. This deferred gain 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 is recognized in income. Changes in valuation from this initial valuation are recognized immediately through income.

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

				$ million
	2008		2007	
	Oil price	**Natural gas price**	Oil price	Natural gas price
Fair value of contracts not recognized through the income statement at 1 January	**–**	**36**	–	36
Fair value of new contracts at inception not recognized in the income statement	**66**	**49**	–	1
Fair value recognized in the income statement	**(34)**	**(2)**	–	(1)
Fair value of contracts not recognized through profit at 31 December	**32**	**83**	–	36

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

							$ 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**

							$ million
							2007
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	123	10	6	5	1	2	147
Oil price derivatives	2,545	471	113	39	26	20	3,214
Natural gas price derivatives	2,170	677	333	283	216	709	4,388
Power price derivatives	819	250	52	–	–	–	1,121
Other derivatives	12	18	–	–	–	–	30
	5,669	1,426	504	327	243	731	8,900

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

							$ 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)**

34. Derivative financial instruments continued

							$ million
							2007
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	(145)	(99)	(32)	(16)	(15)	(10)	(317)
Oil price derivatives	(2,735)	(512)	(135)	(25)	(22)	(3)	(3,432)
Natural gas price derivatives	(2,089)	(527)	(298)	(219)	(185)	(704)	(4,022)
Power price derivatives	(832)	(246)	(61)	(1)	–	–	(1,140)
	(5,801)	(1,384)	(526)	(261)	(222)	(717)	(8,911)

The following table shows the fair value of derivative assets held for trading, analysed by maturity period and by methodology of fair value estimation.

							$ million
							2008
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Prices actively quoted	**40**	**43**	**30**	**7**	**6**	**2**	**128**
Prices sourced from observable data or market corroboration	**7,628**	**1,614**	**553**	**361**	**190**	**56**	**10,402**
Prices based on models and other valuation methods	**471**	**132**	**121**	**117**	**108**	**625**	**1,574**
	8,139	**1,789**	**704**	**485**	**304**	**683**	**12,104**

							$ million
							2007
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Prices actively quoted	169	53	49	3	–	2	276
Prices sourced from observable data or market corroboration	5,417	1,174	363	225	140	–	7,319
Prices based on models and other valuation methods	83	199	92	99	103	729	1,305
	5,669	1,426	504	327	243	731	8,900

The following table shows the fair value of derivative liabilities held for trading, analysed by maturity period and by methodology of fair value estimation.

							$ million
							2008
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Prices actively quoted	**(227)**	**–**	**(2)**	**–**	**(13)**	**–**	**(242)**
Prices sourced from observable data or market corroboration	**(6,997)**	**(1,482)**	**(365)**	**(209)**	**(182)**	**(27)**	**(9,262)**
Prices based on models and other valuation methods	**(335)**	**(123)**	**(127)**	**(124)**	**(111)**	**(585)**	**(1,405)**
	(7,559)	**(1,605)**	**(494)**	**(333)**	**(306)**	**(612)**	**(10,909)**

							$ million
							2007
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Prices actively quoted	(50)	(50)	–	(1)	(9)	(1)	(111)
Prices sourced from observable data or market corroboration	(5,629)	(1,116)	(420)	(143)	(103)	–	(7,411)
Prices based on models and other valuation methods	(122)	(218)	(106)	(117)	(110)	(716)	(1,389)
	(5,801)	(1,384)	(526)	(261)	(222)	(717)	(8,911)

Prices actively quoted refers to the fair value of contracts valued solely using quoted prices in an active market. Prices sourced from observable data or market corroboration refers to the fair value of contracts valued in part using active quotes and in part using observable, market-corroborated data, for example, swaps and physical forward contracts. Prices based on models and other valuation methods refers to the fair value of a contract valued in part using internal models due to the absence of quoted prices, including over-the-counter options. The net change in fair value of contracts based on models and other valuation methods during the year was a gain of $253 million (2007 $94 million loss and 2006 $117 million loss).

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 gain of $6,721 million (2007 $376 million gain and 2006 $2,842 million gain).

34. Derivative financial instruments continued

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.

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

						$ million
			2008			2007
	Commodity price	**Interest rate**	**Total**	Commodity price	Interest rate	Total
Fair value of contracts at 1 January	**(2,085)**	**(33)**	**(2,118)**	(2,064)	(26)	(2,090)
Contracts realized or settled in the year	**294**	**38**	**332**	449	–	449
Changes in valuation techniques or key assumptions	**–**	**–**	**–**	130	–	130
Changes in fair values relating to price	**(928)**	**(5)**	**(933)**	(567)	(7)	(574)
Exchange adjustments	**852**	**–**	**852**	(33)	–	(33)
Fair value of contracts at 31 December	**(1,867)**	**–**	**(1,867)**	(2,085)	(33)	(2,118)

Embedded derivative assets have the following fair values and maturities.

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

							$ million
							2007
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Commodity price embedded derivatives	193	18	15	7	10	12	255

Embedded derivative liabilities have the following fair values and maturities.

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

							$ million
							2007
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Commodity price embedded derivatives	(554)	(437)	(299)	(244)	(219)	(587)	(2,340)
Interest rate embedded derivatives	(33)	–	–	–	–	–	(33)
	(587)	(437)	(299)	(244)	(219)	(587)	(2,373)

34. Derivative financial instruments continued

Embedded derivative assets have the following fair values when analysed by maturity period and by methodology of fair value estimation.

							$ million
							2008
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Prices actively quoted	**–**	**–**	**–**	**–**	**–**	**–**	**–**
Prices sourced from observable data or market corroboration	**35**	**–**	**–**	**–**	**–**	**–**	**35**
Prices based on models and other valuation methods	**15**	**116**	**75**	**45**	**36**	**75**	**362**
	50	**116**	**75**	**45**	**36**	**75**	**397**

							$ million
							2007
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Prices actively quoted	–	–	–	–	–	–	–
Prices sourced from observable data or market corroboration	61	–	–	–	–	–	61
Prices based on models and other valuation methods	132	18	15	7	10	12	194
	193	18	15	7	10	12	255

Embedded derivative liabilities have the following fair values when analysed by maturity period and by methodology of fair value estimation.

							$ million
							2008
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Prices actively quoted	**–**	**–**	**–**	**–**	**–**	**–**	**–**
Prices sourced from observable data or market corroboration	**(10)**	**–**	**–**	**–**	**–**	**–**	**(10)**
Prices based on models and other valuation methods	**(394)**	**(322)**	**(365)**	**(303)**	**(271)**	**(599)**	**(2,254)**
	(404)	**(322)**	**(365)**	**(303)**	**(271)**	**(599)**	**(2,264)**

							$ million
							2007
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Prices actively quoted	–	–	–	–	–	–	–
Prices sourced from observable data or market corroboration	–	–	–	–	–	–	–
Prices based on models and other valuation methods	(587)	(437)	(299)	(244)	(219)	(587)	(2,373)
	(587)	(437)	(299)	(244)	(219)	(587)	(2,373)

The net change in fair value of contracts based on models and other valuation methods during the year is a gain of $287 million (2007 gain of $18 million and 2006 gain of $423 million).

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

			$ million
	2008	2007	2006
Commodity price embedded derivatives	**(106)**	–	604
Interest rate embedded derivatives	**(5)**	(7)	4
Fair value (loss) gain	**(111)**	(7)	608

The fair value gain (loss) in the above table includes $496 million of exchange gains (2007 $12 million of exchange losses and 2006 $179 million of exchange losses) arising on contracts that are denominated in a currency other than the functional currency of the individual operating unit.

34. Derivative financial instruments continued

Cash flow hedges

At 31 December 2008, 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 28 outlines the management of risk aspects for currency and interest rate risk. For cash flow hedges the group only claims for the intrinsic value on the currency with any fair value attributable to time value taken immediately to profit or loss. 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 $45 million (2007 gain of $74 million and 2006 gain of $93 million). Of this, a loss of $1 million is included in production and manufacturing expenses (2007 $143 million gain and 2006 $162 million gain) and a loss of $44 million is included in finance costs (2007 $69 million loss and 2006 $69 million loss). The amount removed from equity during the year and included in the carrying amount of non-financial assets was a gain of $38 million (2007 $40 million gain and 2006 $6 million gain).

The amounts retained in equity at 31 December 2008 are expected to mature and affect the income statement by a $826 million loss in 2009, a loss of $92 million in 2010 and a loss of $182 million in 2011 and beyond.

Fair value hedges

At 31 December 2008, 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 gain on the hedging derivative instruments taken to the income statement in 2008 was $2 million (2007 $334 million gain and 2006 $257 million gain) offset by a loss on the fair value of the finance debt of $20 million (2007 $327 million loss and 2006 $257 million loss).

The interest rate and cross-currency interest rate swaps have an average maturity of three to four years, (2007 one to two years) and are used to convert sterling, euro, Swiss franc and Australian dollar denominated borrowings into US dollar floating rate debt. Note 28 outlines the group's approach to interest rate risk management.

Hedges of net investments in foreign operations

The group holds currency swap contracts as a hedge of a long-term investment in a UK subsidiary expiring in 2009. At 31 December 2008, the hedge had a fair value of $2 million (2007 $40 million) and the loss on the hedge recognized in equity in 2008 was $38 million (2007 $67 million loss and 2006 $105 million gain). US dollars have been sold forward for sterling purchased and match the underlying liability with no significant ineffectiveness reflected in the income statement.

35. Finance debt

						$ million
			2008			2007
	Within 1 year[a]	After 1 year	Total	Within 1 year[a]	After 1 year	Total
Borrowings	**15,647**	**16,937**	**32,584**	15,149	15,004	30,153
Net obligations under finance leases	**93**	**527**	**620**	245	647	892
	15,740	**17,464**	**33,204**	15,394	15,651	31,045

[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 $3,166 million (2007 $2,880 million) with earliest contractual repayment dates within one year have expected repayment dates ranging from 1 to 40 years (2007 1 to 35 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 $1,806 million (2007 $1,899 million) that mature within nine years.

35. Finance debt continued

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		
	Weighted average interest rate %	Weighted average time for which rate is fixed Years	Amount $ million	Weighted average interest rate %	Amount $ million	Total $ million
						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**
						2007
US dollar	5	2	9,541	5	20,460	30,001
Sterling	–	–	–	6	35	35
Euro	4	4	81	5	107	188
Other currencies	7	13	268	7	553	821
			9,890		21,155	31,045

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
	2008	2007
Future minimum lease payments payable within		
1 year	**116**	268
2 to 5 years	**361**	393
Thereafter	**439**	630
	916	1,291
Less finance charges	**296**	399
Net obligations	**620**	892
Of which – payable within 1 year	**93**	245
– payable within 2 to 5 years	**234**	217
– payable thereafter	**293**	430

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 2008, 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
		2008		2007
	Fair value	**Carrying amount**	Fair value	Carrying amount
Short-term borrowings	**9,913**	**9,913**	11,212	11,212
Long-term borrowings	**23,239**	**22,671**	19,094	18,941
Net obligations under finance leases	**638**	**620**	908	892
Total finance debt	**33,790**	**33,204**	31,214	31,045

36. 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 balance returns to shareholders between long-term growth and current returns via the dividend whilst maintaining capital discipline in relation to investing activities and taking action on costs to respond to the current environment. At the beginning of 2008, the group rebalanced returns to shareholders by increasing the dividend component. As a result, the share buyback programme was curtailed and then suspended in September in light of the uncertain environment.

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 2008 the net debt ratio was 21% (2007 22%).

		$ million
At 31 December	**2008**	2007
Gross debt	**33,204**	31,045
Less: Cash and cash equivalents	**8,197**	3,562
Less: Fair value (liability) asset of hedges related to finance debt	**(34)**	666
Net debt	**25,041**	26,817
Equity	**92,109**	94,652
Net debt ratio	**21%**	22%

An analysis of changes in net debt is provided below.

						$ million
	2008			2007		
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	**(30,379)**	**3,562**	**(26,817)**	(23,712)	2,590	(21,122)
Exchange adjustments	**102**	**(184)**	**(82)**	(122)	135	13
Net cash flow	**(2,825)**	**4,819**	**1,994**	(6,411)	837	(5,574)
Other movements	**(136)**	**–**	**(136)**	(134)	–	(134)
At 31 December	**(33,238)**	**8,197**	**(25,041)**	(30,379)	3,562	(26,817)

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

Revised definition of net debt

Net debt has been redefined to include 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. The derivatives are reported on the balance sheet within the headings 'Derivative financial instruments'. Amounts for comparative periods are presented on a consistent basis.

		$ million
		2007
	As amended	As reported
Net debt	26,817	27,483
Equity	94,652	94,652
Ratio of net debt to net debt plus equity	22%	23%

37. Provisions

				$ million
	Decommissioning	**Environmental**	**Litigation and other**	**Total**
At 1 January 2008	**9,501**	**2,107**	**3,487**	**15,095**
Exchange adjustments	**(1,208)**	**(45)**	**(107)**	**(1,360)**
New or increased provisions	**327**	**270**	**2,059**	**2,656**
Write-back of unused provisions	**–**	**(107)**	**(513)**	**(620)**
Unwinding of discount	**202**	**43**	**42**	**287**
Utilization	**(402)**	**(512)**	**(1,424)**	**(2,338)**
Deletions	**(2)**	**(65)**	**–**	**(67)**
At 31 December 2008	**8,418**	**1,691**	**3,544**	**13,653**
Of which – expected to be incurred within 1 year	**322**	**418**	**805**	**1,545**
– expected to be incurred in more than 1 year	**8,096**	**1,273**	**2,739**	**12,108**

				$ million
	Decommissioning	Environmental	Litigation and other	Total
At 1 January 2007	8,365	2,127	3,152	13,644
Exchange adjustments	168	19	11	198
New or increased provisions	1,163	373	1,376	2,912
Write-back of unused provisions	–	(151)	(196)	(347)
Unwinding of discount	195	44	44	283
Utilization	(297)	(305)	(899)	(1,501)
Deletions	(93)	–	(1)	(94)
At 31 December 2007	9,501	2,107	3,487	15,095
Of which – expected to be incurred within 1 year	447	431	1,317	2,195
– expected to be incurred in more than 1 year	9,054	1,676	2,170	12,900

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 2.0% (2007 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. Where BP has entered into a contract for the execution of decommissioning activity, these amounts are generally reported within accruals or other payables.

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 2.0% (2007 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.

Included within the litigation and other category at 31 December 2008 are provisions for litigation of $1,446 million (2007 $1,737 million), for deferred employee compensation of $792 million (2007 $761 million) and for expected rental shortfalls on surplus properties of $251 million (2007 $320 million). To the extent that these liabilities are not expected to be settled within the next three years, the provisions are discounted using either a nominal discount rate of 2.5% (2007 4.5%) or a real discount rate of 2.0% (2007 2.0%), as appropriate. No additional provisions were made during 2008 in respect of the Texas City incident (in 2007 the provision was increased by $500 million). Disbursements to claimants in 2008 were $410 million (2007 $314 million) and the provision at 31 December 2008 was $46 million (2007 $456 million).

38. 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 that remains open to new employees. Retired employees draw the majority of their benefit as an annuity.

In the US, a range of retirement arrangements is 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 2008, contributions of $6 million (2007 $524 million and 2006 $438 million) and $362 million (2007 $97 million and 2006 $181 million) were made to the UK plans and US plans respectively. In addition, contributions of $130 million (2007 $127 million and 2006 $136 million) were made to other funded defined benefit plans. The aggregate level of contributions in all countries in 2009 is expected to be approximately $500 million, and includes contributions 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 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 2008 are used to determine the pension liabilities at that date and the pension expense for 2009.

									%
Financial assumptions			UK			US			Other
	2008	2007	2006	**2008**	2007	2006	**2008**	2007	2006
Discount rate for pension plan liabilities	**6.3**	5.7	5.1	**6.3**	6.1	5.7	**5.7**	5.6	4.8
Discount rate for post-retirement benefit plans	**n/a**	n/a	n/a	**6.2**	6.4	5.9	**n/a**	n/a	n/a
Rate of increase in salaries	**4.9**	5.1	4.7	**2.2**	4.2	4.2	**3.5**	3.7	3.6
Rate of increase for pensions in payment	**3.0**	3.2	2.8	**–**	–	–	**1.7**	1.8	1.8
Rate of increase in deferred pensions	**3.0**	3.2	2.8	**–**	–	–	**1.0**	1.2	1.1
Inflation	**3.0**	3.2	2.8	**0.4**	2.4	2.4	**2.0**	2.2	2.2

Our discount rate assumptions are based on third-party AA corporate bond indices and for our largest schemes in the UK and US we use yields which reflect the maturity profile of the expected benefit payments. The inflation rate assumptions for our UK and US schemes 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 for 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.

38. Pensions and other post-retirement benefits continued

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. As part of the triannual valuation of our UK pensions funds, our UK mortality assumption was reviewed and updated at end-2008 resulting in an increase in the liability of around $900 million. 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
	2008	2007	2006	**2008**	2007	2006	**2008**	2007	2006
Life expectancy at age 60 for a male currently aged 60	**25.9**	24.0	23.9	**24.4**	24.3	24.2	**23.0**	22.4	22.2
Life expectancy at age 60 for a male currently aged 40	**28.9**	25.1	25.0	**25.9**	25.8	25.8	**25.9**	25.3	25.2
Life expectancy at age 60 for a female currently aged 60	**28.5**	26.9	26.8	**26.1**	26.1	26.0	**27.6**	27.0	26.9
Life expectancy at age 60 for a female currently aged 40	**31.4**	27.9	27.8	**27.0**	27.0	26.9	**30.3**	29.7	29.6

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 medical inflation seen over a longer period of time. The assumed future US healthcare cost trend rate is as follows:

			%
	2008	2007	2006
Initial US healthcare cost trend rate	**8.6**	9.0	9.3
Ultimate US healthcare cost trend rate	**5.0**	5.0	5.0
Year in which ultimate trend rate is reached	**2015**	2013	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 obligation 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:

Asset category	Policy range %
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.

38. 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 2008 was $2,819 million (2007 $2,491 million and 2006 $1,506 million). The market value of pension assets at the end of 2008 is lower than at the end of 2007 due to a fall in the market value of investments when expressed in their local currencies and a reduction in value that arises from changes in exchange rates (reducing 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 160.

		2008		2007		2006
	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**	**13,704**	8.0	24,106	7.5	23,631
Bonds	**6.1**	**3,258**	4.4	5,279	4.7	3,881
Property	**6.5**	**978**	6.5	1,259	6.5	1,370
Cash	**2.9**	**299**	5.6	977	3.8	379
	7.4	**18,239**	7.3	31,621	7.0	29,261
US pension plans						
Equities	**8.5**	**3,991**	8.5	6,610	8.5	6,528
Bonds	**3.7**	**1,247**	5.0	1,347	5.0	1,371
Property	**8.0**	**8**	8.0	16	8.0	15
Cash	**1.9**	**131**	3.6	72	3.2	41
	8.0	**5,377**	8.0	8,045	8.0	7,955
US other post-retirement benefit plans						
Equities	**8.5**	**9**	8.5	17	8.5	19
Bonds	**3.7**	**4**	5.0	6	5.0	7
	7.3	**13**	7.6	23	7.5	26
Other plans						
Equities	**8.4**	**799**	8.1	1,260	7.6	1,158
Bonds	**4.2**	**1,481**	5.0	1,491	4.6	1,199
Property	**6.3**	**127**	5.7	145	4.7	120
Cash	**3.1**	**118**	4.2	214	3.0	191
	5.8	**2,525**	6.4	3,110	5.8	2,668

The assumed rate of investment return, discount rate, inflation and the assumed US healthcare cost trend rate all have a significant effect on the amounts reported. A one-percentage point change in these assumptions for the group's plans would have had the following effects:

		$ million
	One-percentage point	
	Increase	**Decrease**
Investment return		
Effect on pension and other post-retirement benefit expense in 2009	**(256)**	**258**
Discount rate		
Effect on pension and other post-retirement benefit expense in 2009	**(88)**	**129**
Effect on pension and other post-retirement benefit obligation at 31 December 2008	**(3,783)**	**4,818**
Inflation rate		
Effect on pension and other post-retirement benefit expense in 2009	**375**	**(286)**
Effect on pension and other post-retirement benefit obligation at 31 December 2008	**3,407**	**(2,783)**
US healthcare cost trend rate		
Effect on US other post-retirement benefit expense in 2009	**29**	**(23)**
Effect on US other post-retirement obligation at 31 December 2008	**335**	**(277)**

38. Pensions and other post-retirement benefits continued

$ million

					2008
	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]	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 the statement of recognized income and expense					
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 statement of recognized income and expense	(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]	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 e]	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[e]	(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 pensions 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 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.

At 31 December 2008 reimbursement balances due from or to other companies in respect of pensions amounted to $455 million reimbursement assets (2007 $496 million) and $61 million reimbursement liabilities (2007 $72 million). These balances are not included as part of the pension liability, but are reflected elsewhere in the group balance sheet.

38. Pensions and other post-retirement benefits continued

	UK pension plans	US pension plans	US other post-retirement benefit plans	Other plans	Total
					$ million
					2007
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 the statement of recognized income and expense					
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 statement of recognized income and expense	757	303	166	491	1,717
Movements in benefit obligation during the year					
Benefit obligation at 1 January	23,289	7,695	3,300	8,149	42,433
Exchange adjustments	394	–	–	917	1,311
Current service cost[a]	492	227	43	132	894
Past service cost	5	10	–	–	15
Interest cost	1,198	425	190	390	2,203
Curtailment	(7)	–	–	–	(7)
Settlement	(3)	–	–	–	(3)
Special termination benefits[c]	46	–	–	2	48
Contributions by plan participants	43	–	–	12	55
Benefit payments (funded plans)[d]	(1,085)	(580)	(5)	(182)	(1,852)
Benefit payments (unfunded plans)[d]	(3)	(37)	(184)	(379)	(603)
Acquisitions	–	–	–	141	141
Disposals	(91)	–	–	(29)	(120)
Actuarial gain on obligation	(351)	(331)	(166)	(567)	(1,415)
Benefit obligation at 31 December[a]	23,927	7,409	3,178	8,586	43,100
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	29,261	7,955	26	2,668	39,910
Exchange adjustments	488	–	–	316	804
Expected return on plan assets[a e]	2,075	613	2	165	2,855
Contributions by plan participants	43	–	–	12	55
Contributions by employers (funded plans)	524	97	–	127	748
Benefit payments (funded plans)[d]	(1,085)	(580)	(5)	(182)	(1,852)
Acquisitions	–	–	–	101	101
Disposals	(91)	(12)	–	(21)	(124)
Actuarial gain (loss) on plan assets[e]	406	(28)	–	(76)	302
Fair value of plan assets at 31 December	31,621	8,045	23	3,110	42,799
Surplus (deficit) at 31 December	7,694	636	(3,155)	(5,476)	(301)
Represented by					
Asset recognized	7,818	989	–	107	8,914
Liability recognized	(124)	(353)	(3,155)	(5,583)	(9,215)
	7,694	636	(3,155)	(5,476)	(301)
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	7,818	978	(29)	(263)	8,504
Unfunded	(124)	(342)	(3,126)	(5,213)	(8,805)
	7,694	636	(3,155)	(5,476)	(301)
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(23,803)	(7,067)	(52)	(3,373)	(34,295)
Unfunded	(124)	(342)	(3,126)	(5,213)	(8,805)
	(23,927)	(7,409)	(3,178)	(8,586)	(43,100)

[a] The costs of managing the plan’s investments are treated as being part of the investment return, the costs of administering our pensions 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 a restructuring programme in the UK.
[d] The benefit payments amount shown above comprises $2,398 million benefits plus $57 million of plan expenses incurred in the administration of the benefit.
[e] 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.

38. Pensions and other post-retirement benefits continued

$ million

2006	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]	432	216	42	139	829
Past service cost	(74)	38	–	39	3
Settlement, curtailment and special termination benefits	4	–	–	227	231
Payments to defined contribution plans	–	161	–	16	177
Total operating charge[b]	362	415	42	421	1,240
Analysis of the amount credited (charged) to other finance expense					
Expected return on plan assets	1,711	564	2	133	2,410
Interest on plan liabilities	(1,006)	(423)	(186)	(325)	(1,940)
Other finance income (expense)	705	141	(184)	(192)	470
Analysis of the amount recognized in the statement of recognized income and expense					
Actual return less expected return on pension plan assets	1,305	521	–	141	1,967
Change in assumptions underlying the present value of the plan liabilities	114	195	111	352	772
Experience gains and losses arising on the plan liabilities	(24)	17	80	(197)	(124)
Actuarial gain recognized in statement of recognized income and expense	1,395	733	191	296	2,615

[a]The costs of managing the plan's investments are treated as being part of the investment return, the costs of administering our pensions 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

	2008	2007	2006	2005	2004
History of surplus (deficit) and of experience gains and losses					
Benefit obligation at 31 December	**34,847**	43,100	42,433	38,855	39,945
Fair value of plan assets at 31 December	**26,154**	42,799	39,910	32,907	31,712
Deficit	**(8,693)**	(301)	(2,523)	(5,948)	(8,233)
Experience losses on plan liabilities	**(178)**	(200)	(124)	(212)	(468)
Actual return less expected return on pension plan assets	**(10,253)**	302	1,967	3,364	1,349
Actual return on plan assets	**(7,331)**	3,157	4,377	5,502	3,332
Actuarial (loss) gain recognized in statement of recognized income and expense	**(8,430)**	1,717	2,615	975	107
Cumulative amount recognized in statement of recognized income and expense	**(2,940)**	5,490	3,773	1,158	183

Estimated future benefit payments

The expected benefit payments, which reflect expected future service, as appropriate, but exclude plan expenses, up until 2018 are as follows:

$ million

	UK pension plans	**US pension plans**	**US other post-retirement benefit plans**	**Other plans**	**Total**
2009	**941**	**795**	**194**	**525**	**2,455**
2010	**969**	**798**	**200**	**512**	**2,479**
2011	**942**	**771**	**207**	**506**	**2,426**
2012	**941**	**787**	**211**	**506**	**2,445**
2013	**941**	**754**	**214**	**496**	**2,405**
2014-2018	**4,704**	**3,645**	**1,111**	**2,501**	**11,961**

39. Called-up share capital

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

	2008		2007		2006	
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	**20,863,424**	**5,216**	21,457,301	5,364	20,657,045	5,164
Issue of new shares for employee share schemes	**24,791**	**6**	69,273	18	64,854	16
Issue of ordinary share capital for TNK-BP	**–**	**–**	–	–	111,151	28
Repurchase of ordinary share capital	**(269,757)**	**(67)**	(663,150)	(166)	(358,374)	(90)
Other[a]	**–**	**–**	–	–	982,625	246
At 31 December	**20,618,458**	**5,155**	20,863,424	5,216	21,457,301	5,364
		5,176		5,237		5,385
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]Reclassification in respect of share repurchases in 2005.

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.

Repurchase of ordinary share capital

The company purchased 269,757,188 ordinary shares (2007 663,149,528 and 2006 1,334,362,750 ordinary shares) for a total consideration of $2,914 million (2007 $7,497 million and 2006 $15,481 million), all of which were for cancellation. At 31 December 2008, 150,444,408 (2007 150,966,096 and 2006 99,045,000) ordinary shares bought back were awaiting cancellation. These shares have been excluded from ordinary shares in issue shown above. At 31 December 2008, 1,888,151,157 shares of nominal value $472 million were held in treasury (2007 1,940,638,808 shares of nominal value $485 million). The maximum number of shares held in treasury during the year was 1,940,638,808 shares of nominal value $485 million (2007 1,946,804,533 shares of nominal value $487 million), representing 9.3% (2007 9.1%) of the called-up ordinary share capital of the company.

During 2008, 10,000,000 treasury shares (2007 1,700,000 treasury shares) were gifted to the Employee Share Ownership Plans (ESOPs), 20,000,000 treasury shares were transferred at market price to the ESOPs, and 22,487,651 treasury shares (2007 4,465,725 treasury shares) were reissued in relation to employee share schemes, in total representing 0.25% (2007 less than 0.1%) of the ordinary share capital of the company. The nominal value of these shares was $13 million (2007 $2 million) and the total proceeds received from the re-issues in relation to employee share schemes were $75 million (2007 $35 million).

Transaction costs of share repurchases amounted to $16 million (2007 $40 million and 2006 $83 million).

40. Capital and reserves

	Share capital	Share premium account	Capital redemption reserve
At 1 January 2008	**5,237**	**9,581**	**1,005**
Recognized income and expense			
Currency translation differences (net of tax)	–	–	–
Actuarial loss relating to pension and other post-retirement benefits (net of tax)	–	–	–
Available-for-sale investments marked to market (net of tax)	–	–	–
Available-for-sale investments recycling (net of tax)	–	–	–
Cash flow hedges marked to market (net of tax)	–	–	–
Cash flow hedges recycling (net of tax)	–	–	–
Tax on share-based payments	–	–	–
Profit for the year	–	–	–
Total recognized income and expense for the year	–	–	–
Dividends	–	–	–
Repurchase of ordinary share capital	**(67)**	–	**67**
Share-based payments	**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
Recognized income and expense			
Currency translation differences (net of tax)	–	–	–
Exchange gain on translation of foreign operations transferred to (profit) or loss on sale (net of tax)	–	–	–
Actuarial gain relating to pension and other post-retirement benefits (net of tax)	–	–	–
Available-for-sale investments marked to market (net of tax)	–	–	–
Available-for-sale investments recycling (net of tax)	–	–	–
Cash flow hedges marked to market (net of tax)	–	–	–
Cash flow hedges recycling (net of tax)	–	–	–
Tax on share-based payments	–	–	–
Profit for the year	–	–	–
Total recognized income and expense for the year	–	–	–
Dividends	–	–	–
Repurchase of ordinary share capital	(166)	–	166
Share-based payments	18	507	–
At 31 December 2007	5,237	9,581	1,005

	Share capital	Share premium account	Capital redemption reserve
At 1 January 2006	5,185	7,371	749
Recognized income and expense			
Currency translation differences (net of tax)	–	–	–
Actuarial gain relating to pension and other post-retirement benefits (net of tax)	–	–	–
Available-for-sale investments marked to market (net of tax)	–	–	–
Available-for-sale investments recycling (net of tax)	–	–	–
Cash flow hedges marked to market (net of tax)	–	–	–
Cash flow hedges recycling (net of tax)	–	–	–
Tax on share-based payments	–	–	–
Profit for the year	–	–	–
Total recognized income and expense for the year	–	–	–
Dividends	–	–	–
Repurchase of ordinary share capital	(90)	–	90
Issue of ordinary share capital for TNK-BP	28	1,222	–
Share-based payments	16	481	–
Other[b]	246	–	–
Currency translation differences (net of tax)	–	–	–
At 31 December 2006	5,385	9,074	839

[a]At 31 December 2006, the foreign currency translation reserve included $122 million relating to non-current assets held for sale. During 2007, this was included in the $147 million recycled to the income statement relating to disposals in 2007. For further details see Note 5.
[b]Reclassification in respect of share repurchases in 2005.

$ 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	**–**	**(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)**
–	**–**	**–**	**–**	**–**	**(944)**	**–**	**–**	**–**	**(944)**	**–**	**(944)**
–	**–**	**–**	**–**	**–**	**526**	**–**	**–**	**–**	**526**	**–**	**526**
–	**–**	**–**	**–**	**–**	**–**	**(984)**	**–**	**–**	**(984)**	**–**	**(984)**
–	**–**	**–**	**–**	**–**	**–**	**12**	**–**	**–**	**12**	**–**	**12**
–	**–**	**–**	**–**	**–**	**–**	**–**	**(190)**	**–**	**(190)**	**–**	**(190)**
–	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**21,157**	**21,157**	**509**	**21,666**
–	**–**	**–**	**–**	**(4,187)**	**(418)**	**(972)**	**(190)**	**15,329**	**9,562**	**434**	**9,996**
–	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**(10,342)**	**(10,342)**	**(425)**	**(10,767)**
–	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**(2,414)**	**(2,414)**	**–**	**(2,414)**
–	**–**	**(266)**	**599**	**–**	**–**	**–**	**289**	**(3)**	**807**	**–**	**807**
–	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**(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[a]	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
–	–	–	–	2,002	–	–	–	–	2,002	24	2,026
–	–	–	–	(147)	–	–	–	–	(147)	–	(147)
–	–	–	–	–	–	–	–	1,290	1,290	–	1,290
–	–	–	–	–	152	–	–	–	152	–	152
–	–	–	–	–	(57)	–	–	–	(57)	–	(57)
–	–	–	–	–	–	138	–	–	138	–	138
–	–	–	–	–	–	(71)	–	–	(71)	–	(71)
–	–	–	–	–	–	–	213	–	213	–	213
–	–	–	–	–	–	–	–	20,845	20,845	324	21,169
–	–	–	–	1,855	95	67	213	22,135	24,365	348	24,713
–	–	–	–	–	–	–	–	(8,106)	(8,106)	(227)	(8,333)
–	–	–	–	–	–	–	–	(7,997)	(7,997)	–	(7,997)
5	(5)	94	70	–	–	–	124	(9)	804	–	804
27,206	–	(60)	(22,112)	6,540	481	106	1,196	64,510	93,690	962	94,652

Merger reserve	Other reserve	Own shares	Treasury shares	Foreign currency translation reserve[a]	Available-for-sale investments	Cash flow hedges	Share-based payment reserve	Profit and loss account	BP shareholders' equity	Minority interest	Total equity
27,190	16	(140)	(10,598)	2,943	385	(234)	643	46,151	79,661	789	80,450
–	–	–	–	1,742	27	6	–	–	1,775	49	1,824
–	–	–	–	–	–	–	–	1,795	1,795	–	1,795
–	–	–	–	–	478	–	–	–	478	–	478
–	–	–	–	–	(504)	–	–	–	(504)	–	(504)
–	–	–	–	–	–	313	–	–	313	–	313
–	–	–	–	–	–	(46)	–	–	(46)	–	(46)
–	–	–	–	–	–	–	26	–	26	–	26
–	–	–	–	–	–	–	–	22,315	22,315	286	22,601
–	–	–	–	1,742	1	273	26	24,110	26,152	335	26,487
–	–	–	–	–	–	–	–	(7,686)	(7,686)	(283)	(7,969)
–	–	–	(11,472)	–	–	–	–	(4,009)	(15,481)	–	(15,481)
–	–	–	–	–	–	–	–	–	1,250	–	1,250
11	(11)	5	134	–	–	–	190	(79)	747	–	747
–	–	–	(246)	–	–	–	–	–	–	–	–
–	–	(19)	–	–	–	–	–	–	(19)	–	(19)
27,201	5	(154)	(22,182)	4,685	386	39	859	58,487	84,624	841	85,465

40. 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 represents 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.

41. Share-based payments

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

			$ million
	2008	2007	2006
Total expense recognized for equity-settled share-based payment transactions	**524**	412	405
Total (credit) expense recognized for cash-settled share-based payment transactions	**(16)**	16	14
Total expense recognized for share-based payment transactions	**508**	428	419
Closing balance of liability for cash-settled share-based payment transactions	**21**	40	38
Total intrinsic value for vested cash-settled share-based payments	**2**	22	23

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.

41. Share-based payments continued

Plans for executive directors

Executive Directors’ Incentive Plan (EDIP) – share element

An equity-settled incentive share plan for executive directors driven by one performance measure over a three-year performance period. The award of shares is determined by comparing BP’s total shareholder return (TSR) against the other oil majors. After the performance period, the shares that vest (net of tax) are then subject to a three-year retention period. In February 2008 it was considered appropriate to strengthen the retention element of remuneration for two executive directors. The remuneration committee granted, on a one-off basis, a restricted share award to those two executive directors. The shares will vest subject to continued service, in equal tranches, after three and five years. Vesting of each tranche is dependent on the committee being satisfied, at each vesting date, with the performance of the individuals. These retention awards have been granted under EDIP which permits awards to be made, on an exceptional basis, subject to a requirement of continued service over a specific period. The directors’ remuneration report on pages 73 to 83 includes full details of this 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. Options vest over three years (one-third each after one, two and three years respectively) and must be exercised within seven years of the date of grant. 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

Medium Term Performance Plan (MTPP)

An equity-settled restricted share unit plan for senior employees driven by two performance measures over a three-year performance period. At the end of the performance period units are converted into shares. The amount of units converted to shares is determined by comparing BP’s TSR against the other oil majors and, additionally, by comparing free cash flow (FCF) against a threshold established for the period. For a small group of particularly senior employees only the TSR measure is applicable in determining the award. The number of units converted into shares is increased to take account of the net notional dividends that would have been received during the performance period, assuming that such dividends would have been reinvested. With regard to leaver provisions the general rule is that leaving employment during the performance period will preclude the conversion of units into shares. However, special arrangements apply where the participant leaves for a qualifying reason and employment ceases after completion of the first year of the performance period. The current policy of the company, which is reflected in the terms of the MTPP, is that senior employees subject to the plan should meet a minimum shareholding requirement. Grants will not be made under this plan after 2008.

Senior Employees Deferred Annual Bonus Plan (DAB)

An equity-settled restricted share unit plan for senior employees. In 2008 the grant value is equal to 50% (2007 and 2006 50%) of the annual cash bonus awarded for the preceding performance year (the ‘performance period’). For 2009 this will increase to 100%. The units are restricted for a period of three years (the ‘restriction period’), during which they accrue net notional dividends which are treated as having been reinvested. At the end of the restriction period units are converted into shares. With regard to leaver provisions, if a participant ceases to be employed by BP prior to the end of the performance period the general rule is that this will preclude the grant of units. If a participant ceases to be employed by BP prior to the end of the restriction period the general rule is that this will preclude the conversion of units into shares. However, special arrangements apply where the participant leaves for a qualifying reason.

Integrated Supply and Trading Deferred Annual Bonus Plan (IST DAB)

An equity-settled restricted share unit plan for traders in the IST function. The plan operates under the DAB but the rules differ in certain respects from that plan. If eligible, a portion of a trader’s annual cash bonus (the ‘base grant’), awarded for the preceding performance year (the ‘performance period’), plus an additional 25% of that amount (the ‘additional grant’),will be deferred in restricted share units. The units are restricted over a period of three calendar years, during which they accrue net notional dividends, which are treated as having been reinvested. At the end of the restriction period units are converted into shares. One third of the base grant vests after one and two calendar years respectively, with the final third plus the additional grant vesting after three calendar years. With regard to leaver provisions, if a participant ceases to be employed by BP prior to the end of the restriction period the general rule is that this will preclude the conversion of units into shares. Special arrangements apply where the participant leaves for a qualifying reason.

Performance Share Plan (PSP)

An equity-settled restricted share unit plan for senior professionals and team leaders. The grant takes into account the recipient’s performance in the prior calendar year (the ‘performance period’). The units are restricted for a period of three years (the ‘restriction period’), during which they accrue net notional dividends, which are treated as having been reinvested. At the end of the restriction period additional units may be awarded based on BP’s TSR performance against the other oil majors. At the end of the restriction period units are converted into shares. With regard to leaver provisions the general rule is that leaving during the performance period will preclude the grant of units. If a participant ceases to be employed by BP prior to the end of the restriction period the general rule is that this will preclude the conversion of units into shares. Special arrangements apply where the participant leaves for a qualifying reason.

Restricted Share Plan (RSP)

An equity-settled restricted share unit plan used predominantly for senior employees in special circumstances (such as recruitment and retention). There are generally no performance conditions but the units are subject to a three-year restriction period, during which they accrue net notional dividends which are treated as having been reinvested. At the end of the restricted period the units are converted into shares. With regard to leaver provisions, if a participant ceases to be employed by BP prior to the end of the restriction period the general rule is that this will preclude the conversion of units into shares. However, special arrangements apply where the participant leaves for a qualifying reason.

41. Share-based payments continued

BP Share Option Plan (BPSOP)

An equity-settled share option plan that applies to certain categories of employees. Participants are granted share options with an exercise price no lower than the market price of a share immediately preceding the date of grant. There are no performance conditions and the options are exercisable between the third and tenth anniversaries of the grant date. The general rule is that the options will lapse if the participant leaves employment before the end of the third calendar year from the date of grant (and that vested options are exercisable within $3^1/_2$ years from the date of leaving). However, special arrangements apply where the participant leaves for a qualifying reason and employment ceases after the end of the calendar year of the date of grant. From 2007 share options no longer form a regular element of our incentive plans.

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-year 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 will have six months in which to use their savings to exercise their options on a pro rated basis.

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.

The above share plans are indicated as being equity-settled. In certain countries however, it is not possible to award shares to employees owing to local legislation. In these instances the award will be settled in cash, calculated as the cash equivalent of the value to the employee of an equity-settled plan.

Cash plans

Cash-settled share-based payments/Stock Appreciation Rights (SARs)

These are cash-settled share-based payments available to certain employees that require the group to pay the intrinsic value of the cash option/SAR/restricted shares to the employee at the date of exercise or on maturity. The cash options/SARs have the same rules as the BPSOP plan and the cash restricted share plans (MTPP, DAB, PSP, RSP) have the same rules as their equity-settled counterparts.

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 40). Assets and liabilities of the ESOPs are recognized as assets and liabilities of the group.

At 31 December 2008 the ESOPs held 29,051,082 shares (2007 6,448,838 shares and 2006 12,795,887 shares) for potential future awards, which had a market value of $220 million (2007 $79 million and 2006 $142 million).

Share option transactions	**2008**		2007		2006	
	Number of options	**Weighted average exercise price $**	Number of options	Weighted average exercise price $	Number of options	Weighted average exercise price $
Outstanding at 1 January	**358,094,243**	**8.51**	426,471,462	8.25	450,453,502	7.64
Granted	**8,062,899**	**8.96**	6,004,025	9.11	53,977,639	11.18
Forfeited	**(2,502,784)**	**8.50**	(3,924,714)	9.10	(7,169,710)	8.69
Exercised	**(37,277,895)**	**6.97**	(69,715,558)	6.94	(70,658,480)	6.52
Expired	**(121,864)**	**7.00**	(740,972)	8.68	(131,489)	7.99
Outstanding at 31 December	**326,254,599**	**8.70**	358,094,243	8.51	426,471,462	8.25
Exercisable at 31 December	**260,178,938**	**8.22**	238,707,055	7.70	236,726,966	7.41

41. Share-based payments continued

As share options are exercised continuously throughout the year, the weighted average share price during the year of $10.87 (2007 $11.72 and 2006 $11.85) is representative of the weighted average share price at the date of exercise. For the options outstanding at 31 December 2008, the exercise price ranges and weighted average remaining contractual lives are shown below.

	Options outstanding			Options exercisable	
Range of exercise prices	Number of shares	Weighted average remaining life Years	Weighted average exercise price $	Number of shares	Weighted average exercise price $
$5.71 – $7.25	**51,430,951**	**3.81**	**6.39**	**48,919,680**	**6.35**
$7.26 – $8.80	**159,708,260**	**3.12**	**8.11**	**157,933,135**	**8.11**
$8.81 – $10.36	**42,960,673**	**4.53**	**9.53**	**26,083,268**	**9.83**
$10.37 – $11.92	**72,154,715**	**6.81**	**11.14**	**27,242,855**	**10.67**
	326,254,599	**4.23**	**8.70**	**260,178,938**	**8.22**

Fair values and associated details for options and shares granted

Options granted in 2008	ShareSave 3 year	ShareSave 5 year
Option pricing model used	**Binomial**	**Binomial**
Weighted average fair value	**$1.82**	**$1.74**
Weighted average share price	**$11.26**	**$11.26**
Weighted average exercise price	**$9.70**	**$9.70**
Expected volatility	**23%**	**23%**
Option life	**3.5 years**	**5.5 years**
Expected dividends	**4.60%**	**4.60%**
Risk free interest rate	**5.00%**	**5.00%**
Expected exercise behaviour	**100% year 4**	**100% year 6**

Options granted in 2007	ShareSave 3 year	ShareSave 5 year
Option pricing model used	Binomial	Binomial
Weighted average fair value	$3.57	$3.79
Weighted average share price	$12.10	$12.10
Weighted average exercise price	$9.13	$9.13
Expected volatility	21%	21%
Option life	3.5 years	5.5 years
Expected dividends	3.48%	3.48%
Risk free interest rate	5.75%	5.75%
Expected exercise behaviour	100% year 4	100% year 6

Options granted in 2006	BPSOP	ShareSave 3 year	ShareSave 5 year
Option pricing model used	Binomial	Binomial	Binomial
Weighted average fair value	$2.46	$2.88	$3.08
Weighted average share price	$11.07	$11.08	$11.08
Weighted average exercise price	$11.17	$9.10	$9.10
Expected volatility	22%	24%	24%
Option life	10 years	3.5 years	5.5 years
Expected dividends	3.23%	3.40%	3.40%
Risk free interest rate	4.50%	5.00%	4.75%
Expected exercise behaviour	5% years 4-9, 70% year 10	100% year 4	100% year 6

The group uses an appropriate valuation model of expected volatility of US ADSs for the quarter within which the grant date of the relevant plan falls. Management is responsible for all inputs and assumptions in relation to that model, including the determination of expected volatility.

Shares granted in 2008	MTPP-TSR	MTPP-FCF	EDIP-TSR	EDIP-RET	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**

41. Share-based payments continued

Shares granted in 2007	MTPP-TSR	MTPP-FCF	EDIP-TSR	EDIP-LTL	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

Shares granted in 2006	MTPP-TSR	MTPP-FCF	EDIP-TSR	EDIP-LTL	RSP	DAB
Number of equity instruments granted (million)	8.7	7.8	3.3	0.5	0.5	3.5
Weighted average fair value	$7.28	$11.23	$4.87	$11.23	$11.07	$11.06
Fair value measurement basis	Monte Carlo	Market value	Monte Carlo	Market value	Market value	Market value

The group used a Monte Carlo simulation to fair value the TSR element of the 2008, 2007 and 2006 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.

42. Employee costs and numbers

$ million

Employee costs	2008	2007	2006
Wages and salaries[a c]	**10,388**	9,808	8,703
Social security costs	**805**	771	751
Share-based payments	**508**	428	419
Pension and other post-retirement benefit costs	**579**	504	770
	12,280	11,511	10,643

Number of employees at 31 December	2008	2007	2006
Exploration and Production	**21,400**	21,800	21,400
Refining and Marketing[b c]	**61,500**	67,200	68,000
Other businesses and corporate[c]	**9,100**	9,100	7,600
	92,000	98,100	97,000
By geographical area			
UK	**15,900**	17,000	16,900
Rest of Europe	**19,400**	19,900	20,200
US	**29,300**	33,000	33,700
Rest of World[b]	**27,400**	28,200	26,200
	92,000	98,100	97,000

	2008					2007				
Average number of employees	**UK**	**Rest of Europe**	**US**	**Rest of World**	**Total**	UK	Rest of Europe	US	Rest of World	Total
Exploration and Production	**3,700**	**700**	**7,800**	**9,400**	**21,600**	3,800	700	7,700	9,300	21,500
Refining and Marketing	**9,300**	**18,300**	**21,600**	**15,800**	**65,000**	10,300	18,600	23,400	15,000	67,300
Other businesses and corporate	**3,400**	**800**	**2,600**	**2,300**	**9,100**	2,600	900	2,500	2,400	8,400
	16,400	**19,800**	**32,000**	**27,500**	**95,700**	16,700	20,200	33,600	26,700	97,200

[a] Includes termination payments of $669 million (2007 $422 million and 2006 $257 million). A restructuring was announced in October 2007, the implementation of which continues in 2009.
[b] Includes 21,200 (2007 24,500 and 2006 26,100) service station staff.
[c] A minor amendment has been made to the comparative figures to include some employee costs which had been previously incorrectly excluded and to correct headcount data.

42. Employee costs and numbers continued

Average number of employees	UK	Rest of Europe	US	Rest of World	Total
					2006
Exploration and Production	3,500	800	7,100	9,000	20,400
Refining and Marketing	11,100	19,300	24,800	14,100	69,300
Other businesses and corporate	2,200	800	2,600	1,800	7,400
	16,800	20,900	34,500	24,900	97,100

43. Remuneration of directors and senior management

Remuneration of directors

			$ million
	2008	2007	2006
Total for all directors			
Emoluments	**19**	26	14
Gains made on the exercise of share options	**1**	2	12
Amounts awarded under incentive schemes	**–**	10	14

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. This includes an ex gratia superannuation payment of nil (2007 $3 million and 2006 nil) and compensation for loss of office of $1 million (2007 $1 million and 2006 nil).

Pension contributions
Four 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. One US executive director participated in the US BP Retirement Accumulation Plan during 2008.

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 73 to 83.

Remuneration of senior management

			$ million
	2008	2007	2006
Total for all senior management			
Short-term employee benefits	**40**	37	30
Post-retirement benefits	**4**	7	4
Share-based payments	**20**	22	26

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 bonuses awarded for the year. This includes an ex gratia superannuation payment of nil (2007 $3 million and 2006 nil) and compensation for loss of office of $3 million (2007 $1 million and 2006 $5 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, MTPP and LTPP. For details of these plans refer to Note 41.

44. Contingent liabilities

There were contingent liabilities at 31 December 2008 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 28.

Approximately 200 lawsuits were filed in State and Federal Courts in Alaska seeking compensatory and punitive damages arising out of the Exxon Valdez oil spill in Prince William Sound in March 1989. Most of those suits named 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 which it has incurred. If any claims are asserted by Exxon that affect Alyeska and its owners, BP will defend the claims vigorously. It is not possible to estimate any financial effect.

Since 1987, Atlantic Richfield, a current subsidiary of BP, has been named as a co-defendant in numerous lawsuits brought in the US alleging injury to persons and property caused by lead pigment in paint. The majority of the lawsuits have been abandoned or dismissed as against Atlantic Richfield. Atlantic Richfield is named in these lawsuits as alleged successor to International Smelting and Refining and another company that manufactured lead pigment during the period 1920-1946. Plaintiffs include individuals and governmental entities. Several of the lawsuits purport to be class actions. The lawsuits (depending on plaintiff) seek various remedies, including: compensation to lead-poisoned children; cost to find and remove lead paint from buildings; medical monitoring and screening programmes; public warning and education on lead hazards; reimbursement of government healthcare costs and special education for lead-poisoned citizens; and punitive damages. No lawsuit against Atlantic Richfield has been settled nor has Atlantic Richfield been subject to a final adverse judgment in any proceeding. The amounts claimed and, if such suits were successful, the costs of implementing the remedies sought in the various cases could be substantial. While it is not possible to predict the outcome of these legal actions, Atlantic Richfield believes that it has valid defences and it intends to defend such actions vigorously and thus the incurrence of a liability by Atlantic Richfield is remote. Consequently, BP believes that the impact of these lawsuits on the group's results of operations, financial position or liquidity will not be material.

In addition, various group companies are parties to legal actions and claims that arise in the ordinary course of the group's business. While the outcome of such legal proceedings cannot be readily foreseen, BP believes that they will be resolved without material effect on the group's results of operations, financial position or liquidity. 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 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.

45. Capital commitments

Authorized future capital expenditure for property, plant and equipment by group companies for which contracts had been placed at 31 December 2008 amounted to $14,062 million (2007 $8,263 million). In addition, at 31 December 2008, the group had contracts in place for future capital expenditure relating to investments in jointly controlled entities of $644 million (2007 $1,039 million) and investments in associates of $160 million (2007 $74 million).

Capital commitments of jointly controlled entities amounted to $1,540 million (2007 $2,273 million).

46. Subsidiaries, jointly controlled entities and associates

The more important subsidiaries, jointly controlled entities and associates of the group at 31 December 2008 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
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
BP Egypt Gas Co.	100	US	Exploration and production
Germany			
Deutsche BP	100	Germany	Refining and marketing and petrochemicals
Indonesia			
BP Berau	100	US	Exploration and production
BP West Java	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 (LNG)	100	Netherlands	Exploration and production
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
Jupiter Insurance	100	Guernsey	Insurance
US			
*BP Holdings North America	100	England	Investment holding
Atlantic Richfield Co.			
BP America			Exploration and production, refining and marketing, pipelines and petrochemicals
BP America Production Company			
BP Amoco Chemical Company	100	US	
BP Company North America			
BP Corporation North America			
BP Exploration (Alaska) Inc.			
BP Products North America			
BP West Coast Products			
Standard Oil Co.			
BP Capital Markets America			Finance

46. 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
Fowler 1 Holdings	50	US	Wind farm development
LukArco	46	Netherlands	Exploration and production, pipelines
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
TNK-BP	50	British Virgin Islands	Integrated oil operations
United Gas Derivatives Company	33	Egypt	NGL extraction

[a] Pan American Energy 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
Trinidad & Tobago			
Atlantic LNG Company of Trinidad and Tobago	34	Trinidad & Tobago	LNG manufacture

47. Oil and natural gas exploration and production activities[a]

									$ million
									2008
	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Capitalized costs at 31 December									
Gross capitalized costs									
Proved properties	34,614	5,507	59,918	11,451	4,720	21,563	–	8,550	146,323
Unproved properties	626	–	5,006	299	1,019	2,011	–	464	9,425
	35,240	5,507	64,924	11,750	5,739	23,574	–	9,014	155,748
Accumulated depreciation	26,564	3,125	28,511	6,358	2,181	10,451	–	3,159	80,349
Net capitalized costs	8,676	2,382	36,413	5,392	3,558	13,123	–	5,855	75,399

The group’s share of jointly controlled entities’ and associates’ net capitalized costs at 31 December 2008 was $13,393 million.

	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Costs incurred for the year ended 31 December									
Acquisition of properties									
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[b]	137	–	862	123	79	838	12	239	2,290
Development	907	695	4,914	1,077	465	2,966	–	743	11,767
Total costs	1,048	695	10,092	1,202	544	3,804	12	1,159	18,556

The group’s share of jointly controlled entities’ and associates’ costs incurred in 2008 was $3,259 million: in Russia $1,921 million, Rest of Americas $1,039 million, Asia Pacific $24 million and other $275 million.

	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Results of operations for the year ended 31 December									
Sales and other operating revenues									
Third parties	3,865	105	8,010	3,573	1,410	3,745	–	549	21,257
Sales between businesses	4,374	1,416	15,610	3,755	1,420	6,022	–	11,087	43,684
	8,239	1,521	23,620	7,328	2,830	9,767	–	11,636	64,941
Exploration expenditure	121	1	305	62	41	213	14	125	882
Production costs	1,357	150	3,002	718	213	875	18	334	6,667
Production taxes	503	–	2,603	360	110	–	–	3,083	6,659
Other costs (income)[c]	(28)	(43)	3,440	541	309	245	196	4,041	8,701
Depreciation, depletion and amortization	1,049	199	2,729	911	251	2,120	–	624	7,883
Impairments and (gains) losses on sale of businesses and fixed assets	–	–	308	6	219	8	–	–	541
	3,002	307	12,387	2,598	1,143	3,461	228	8,207	31,333
Profit before taxation[d]	5,237	1,214	11,233	4,730	1,687	6,306	(228)	3,429	33,608
Allocable taxes	2,280	883	3,857	2,423	618	2,672	(36)	879	13,576
Results of operations	2,957	331	7,376	2,307	1,069	3,634	(192)	2,550	20,032

The group’s share of jointly controlled entities’ and associates’ 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 Americas	Asia Pacific	Africa	Russia	Other	Total
Exploration and Production segment profit before interest and tax									
Exploration and production activities									
Group (as above)	5,237	1,214	11,233	4,730	1,687	6,306	(228)	3,429	33,608
Jointly controlled entities and associates	(1)	–	1	344	48	(1)	2,259	143	2,793
Midstream activities[e]	743	16	425	619	(228)	112	–	(173)	1,514
Total profit before interest and tax	5,979	1,230	11,659	5,693	1,507	6,417	2,031	3,399	37,915

[a] This note contains 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 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 jointly controlled entities’ and associates’ 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] Includes exploration and appraisal drilling expenditures, which are capitalized within intangible fixed assets, and geological and geophysical exploration costs, which are charged to income as incurred.
[c] 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.
[d] 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.
[e] Includes a $517 million write-down of our investment in Rosneft based on its quoted market price at the end of the year.

47. Oil and natural gas exploration and production activities[a] continued

$ million

									2007
	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Capitalized costs at 31 December									
Gross capitalized costs									
Proved properties	34,774	4,925	53,079	10,627	3,528	18,333	–	7,596	132,862
Unproved properties	606	–	1,660	297	1,188	1,533	4	349	5,637
	35,380	4,925	54,739	10,924	4,716	19,866	4	7,945	138,499
Accumulated depreciation	25,515	2,925	25,500	5,528	1,508	8,315	–	2,553	71,844
Net capitalized costs	9,865	2,000	29,239	5,396	3,208	11,551	4	5,392	66,655

The group’s share of jointly controlled entities’ and associates’ net capitalized costs at 31 December 2007 was $11,787 million.

	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Costs incurred for the year ended 31 December									
Acquisition of properties									
Proved	–	–	245	–	–	–	–	232	477
Unproved	–	–	54	16	–	321	–	126	517
	–	–	299	16	–	321	–	358	994
Exploration and appraisal costs[b]	209	16	646	72	51	677	119	102	1,892
Development costs	804	443	3,861	1,057	333	2,634	–	1,021	10,153
Total costs	1,013	459	4,806	1,145	384	3,632	119	1,481	13,039

The group’s share of jointly controlled entities’ and associates’ costs incurred in 2007 was $2,552 million: in Russia $1,787 million, Rest of Americas $569 million, Asia Pacific $17 million and other $179 million.

	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Results of operations for the year ended 31 December									
Sales and other operating revenues									
Third parties	4,503	434	1,436	2,142	1,148	2,219	–	921	12,803
Sales between businesses	2,260	902	14,353	3,142	970	3,223	–	9,983	34,833
	6,763	1,336	15,789	5,284	2,118	5,442	–	10,904	47,636
Exploration expenditure	46	–	252	134	11	183	116	14	756
Production costs	1,658	147	2,782	770	190	637	2	344	6,530
Production taxes	227	3	1,260	273	56	–	–	2,224	4,043
Other costs (income)[c]	(419)	123	2,505	395	378	200	169	3,018	6,369
Depreciation, depletion and amortization	1,569	207	2,118	822	205	1,372	–	995	7,288
Impairments and (gains) losses on sale of businesses and fixed assets	112	(534)	(413)	(43)	–	(76)	–	–	(954)
	3,193	(54)	8,504	2,351	840	2,316	287	6,595	24,032
Profit before taxation[d]	3,570	1,390	7,285	2,933	1,278	3,126	(287)	4,309	23,604
Allocable taxes	1,664	611	2,560	1,202	321	1,462	3	1,079	8,902
Results of operations	1,906	779	4,725	1,731	957	1,664	(290)	3,230	14,702

The group’s share of jointly controlled entities’ and associates’ 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 Americas	Asia Pacific	Africa	Russia	Other	Total
Exploration and Production segment profit before interest and tax									
Exploration and production activities									
Group (as above)	3,570	1,390	7,285	2,933	1,278	3,126	(287)	4,309	23,604
Jointly controlled entities and associates	–	–	1	381	21	–	2,292	9	2,704
Midstream activities	15	13	709	699	(108)	96	(112)	109	1,421
Total profit before interest and tax	3,585	1,403	7,995	4,013	1,191	3,222	1,893	4,427	27,729

[a] This note contains 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 and the Baku-Tbilisi-Ceyhan pipeline. Major LNG activities are located in Trinidad, Indonesia and Australia. The group’s share of jointly controlled entities’ and associates’ 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] Includes exploration and appraisal drilling expenditures, which are capitalized within intangible fixed assets, and geological and geophysical exploration costs, which are charged to income as incurred.

[c] 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.

[d] 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.

47. Oil and natural gas exploration and production activities[a] continued

$ million

	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
									2006
Capitalized costs at 31 December									
Gross capitalized costs									
Proved properties	32,528	4,951	44,856	9,404	3,569	15,516	–	6,278	117,102
Unproved properties	423	116	1,443	379	1,155	936	1	137	4,590
	32,951	5,067	46,299	9,783	4,724	16,452	1	6,415	121,692
Accumulated depreciation	22,908	3,175	19,724	4,618	1,709	6,944	–	1,708	60,786
Net capitalized costs	10,043	1,892	26,575	5,165	3,015	9,508	1	4,707	60,906

The group’s share of jointly controlled entities’ and associates’ net capitalized costs at 31 December 2006 was $10,870 million.

	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Costs incurred for the year ended 31 December									
Acquisition of properties									
Proved	–	–	–	–	–	–	–	–	–
Unproved	–	–	74	8	2	70	–	–	154
	–	–	74	8	2	70	–	–	154
Exploration and appraisal costs[b]	132	26	838	135	45	434	73	82	1,765
Development costs	794	214	3,579	820	238	2,356	–	1,108	9,109
Total costs	926	240	4,491	963	285	2,860	73	1,190	11,028

The group’s share of jointly controlled entities’ and associates’ costs incurred in 2006 was $1,688 million: in Russia $1,109 million, Rest of Americas $424 million, Asia Pacific $16 million and other $139 million.

	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Results of operations for the year ended 31 December									
Sales and other operating revenues									
Third parties	5,378	628	1,381	2,196	1,159	1,647	–	768	13,157
Sales between businesses	2,329	1,024	14,572	3,229	807	2,875	–	7,640	32,476
	7,707	1,652	15,953	5,425	1,966	4,522	–	8,408	45,633
Exploration expenditure	20	(1)	634	132	11	132	17	100	1,045
Production costs	1,312	145	2,311	638	155	509	–	238	5,308
Production taxes	492	38	887	295	63	–	–	2,079	3,854
Other costs (income)[c]	(867)	90	2,561	478	154	104	32	3,121	5,673
Depreciation, depletion and amortization	1,612	213	2,083	685	175	865	–	510	6,143
Impairments and (gains) losses on sale of businesses and fixed assets	(450)	(57)	(1,880)	42	(99)	(31)	–	–	(2,475)
	2,119	428	6,596	2,270	459	1,579	49	6,048	19,548
Profit before taxation[d]	5,588	1,224	9,357	3,155	1,507	2,943	(49)	2,360	26,085
Allocable taxes	2,567	793	3,136	1,443	472	1,328	3	737	10,479
Results of operations	3,021	431	6,221	1,712	1,035	1,615	(52)	1,623	15,606

The group’s share of jointly controlled entities’ and associates’ results of operations (including the group’s share of total TNK-BP results) in 2006 was a profit of $3,302 million after deducting interest of $324 million, taxation of $1,804 million and minority interest of $193 million.

	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Exploration and Production segment profit before interest and tax									
Exploration and production activities									
Group (as above)	5,588	1,224	9,357	3,155	1,507	2,943	(49)	2,360	26,085
Jointly controlled entities and associates	–	–	1	535	33	1	2,730	2	3,302
Midstream activities	519	154	617	445	(196)	37	(24)	14	1,566
Total profit before interest and tax	6,107	1,378	9,975	4,135	1,344	2,981	2,657	2,376	30,953

[a]This note contains information relating to oil and natural gas exploration and production activities. Midstream activities of natural gas gathering and distribution and the operation of the main pipelines and tankers 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 main midstream activities are the Alaskan transportation facilities, the Forties Pipeline system and the Central Area Transmission System. The group’s share of jointly controlled entities’ and associates’ activities is excluded from the tables and included in the footnotes with the exception of the Abu Dhabi operations, which are included in the income and expenditure items above.
[b]Includes exploration and appraisal drilling expenditures, which are capitalized within intangible fixed assets, and geological and geophysical exploration costs, which are charged to income as incurred.
[c]Includes the value of royalty oil sold on behalf of others where royalty is payable in cash, property taxes, other government take and the fair value gain on embedded derivatives $515 million.
[d]Excludes the unwinding of the discount on provisions and payables amounting to $153 million which is included in finance costs in the group income statement.

Additional information for US reporting

48. Auditor’s remuneration for US reporting

			$ million
	2008	2007	2006
Audit fees – Ernst & Young			
Group audit	**34**	37	36
Audit-related regulatory reporting	**6**	7	9
Statutory audit of subsidiaries	**17**	19	19
	57	63	64
Fees for other services – Ernst & Young			
Further assurance services			
Acquisition and disposal due diligence	**2**	1	3
Pension plan audits	**1**	1	–
Other further assurance services	**5**	8	5
Tax services			
Compliance services	**–**	–	1
Advisory services	**2**	2	–
	10	12	9

Audit fees for 2008 include $3 million of additional fees for 2007 (2007 $7 million of additional fees for 2006 and 2006 $5 million of additional fees for 2005). Audit fees are included in the income statement within distribution and administration expenses.

Other further assurance services include nil (2007 $1 million and 2006 nil) in respect of advice on accounting, auditing and financial reporting matters; $5 million (2007 $5 million and 2006 $5 million) in respect of non-statutory audits and nil (2007 $2 million and 2006 nil) in respect of project assurance and advice on business and accounting process improvement.

The tax services relate to income tax and indirect tax compliance, employee tax services and tax advisory services.

The audit committee has established pre-approval policies and procedures for the engagement of Ernst & Young to render audit and certain assurance and tax services. The audit fees payable to Ernst & Young are reviewed by the audit committee in the context of other global companies for cost-effectiveness. Ernst & Young performed further assurance and tax services that were not prohibited by regulatory or other professional requirements and were pre-approved by the committee. Ernst & Young is engaged for these services when its expertise and experience of BP are important. Most of this work is of an audit nature. Tax services were awarded either through a full competitive tender process or following an assessment of the expertise of Ernst & Young compared with that of other potential service providers. These services are for a fixed term.

49. Valuation and qualifying accounts

					$ million
		Additions			
	Balance at 1 January	Charged to costs and expenses	Charged to other accounts[a]	Deductions	Balance at 31 December
2008					
Fixed assets – Investments[b]	**146**	**647**	**143**	**(1)**	**935**
Doubtful debts[b]	**406**	**191**	**(32)**	**(174)**	**391**
2007					
Fixed assets – Investments[b]	151	158	2	(165)	146
Doubtful debts[b]	421	175	34	(224)	406
2006					
Fixed assets – Investments[b]	172	26	(3)	(44)	151
Doubtful debts[b]	374	158	32	(143)	421

[a]Principally currency transactions.
[b]Deducted in the balance sheet from the assets to which they apply.

50. Computation of ratio of earnings to fixed charges (unaudited)

					$ million, except ratios
For the year ended 31 December	**2008**	2007	2006	2005	2004
Profit before taxation	**34,283**	31,611	35,142	31,421	24,966
Group’s share of income in excess of dividends from equity-accounted entities	**(93)**	(1,359)	–	(710)	(81)
Capitalized interest, net of amortization	**56**	(183)	(341)	(193)	(133)
	34,246	30,069	34,801	30,518	24,752
Fixed charges					
Interest expense	**1,157**	1,110	718	559	440
Rental expense representative of interest	**1,231**	1,033	946	605	619
Capitalized interest	**162**	323	478	351	204
	2,550	2,466	2,142	1,515	1,263
Total adjusted earnings available for payment of fixed charges	**36,796**	32,535	36,943	32,033	26,015
Ratio of earnings to fixed charges	**14.4**	13.2	17.2	21.1	20.6

51. 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. BP p.l.c. also fully and unconditionally guarantees securities issued by BP Canada Finance Company, BP Capital Markets p.l.c. and BP Capital Markets America Inc. These companies are 100%-owned finance subsidiaries of BP p.l.c.

51. Condensed consolidating information on certain US subsidiaries continued

Income statement

For the year ended 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
					$ million 2008
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
Total revenues	7,765	20,468	365,989	(28,522)	365,700
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	–	28,100	–	29,183
Production and similar taxes	2,343	–	4,183	–	6,526
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 (gain) 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

For the year ended 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
					$ million 2007
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[a]	758	205	1,166	(1,375)	754
Total revenues	6,587	21,406	289,363	(28,405)	288,951
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	–	25,018	–	25,915
Production and similar taxes	1,052	–	2,961	–	4,013
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 (gain) loss on embedded derivatives	–	–	7	–	7
Profit before interest and taxation	3,579	20,485	31,342	(23,054)	32,352
Finance costs[a]	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[a]	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

51. Condensed consolidating information on certain US subsidiaries continued

Income statement continued

					$ million
For the year ended 31 December					2006
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Sales and other operating revenues	4,812	–	265,906	(4,812)	265,906
Earnings from jointly controlled entities – after interest and tax	–	–	3,553	–	3,553
Earnings from associates – after interest and tax	–	–	442	–	442
Equity-accounted income of subsidiaries – after interest and tax	570	23,119	–	(23,689)	–
Interest and other revenues[a]	627	187	1,509	(1,622)	701
Total revenues	6,009	23,306	271,410	(30,123)	270,602
Gains on sale of businesses and fixed assets	–	105	3,714	(105)	3,714
Total revenues and other income	6,009	23,411	275,124	(30,228)	274,316
Purchases	566	–	191,429	(4,812)	187,183
Production and manufacturing expenses	814	–	22,479	–	23,293
Production and similar taxes	665	–	2,956	–	3,621
Depreciation, depletion and amortization	374	–	8,754	–	9,128
Impairment and losses on sale of businesses and fixed assets	109	–	440	–	549
Exploration expense	14	–	1,031	–	1,045
Distribution and administration expenses	20	278	14,264	(115)	14,447
Fair value (gain) loss on embedded derivatives	–	–	(608)	–	(608)
Profit before interest and taxation from continuing operations	3,447	23,133	34,379	(25,301)	35,658
Finance costs[a]	11	702	1,780	(1,507)	986
Net finance (income) expense relating to pensions and other post-retirement benefits	–	(675)	205	–	(470)
Profit before taxation from continuing operations	3,436	23,106	32,394	(23,794)	35,142
Taxation[a]	1,005	686	10,825	–	12,516
Profit from continuing operations	2,431	22,420	21,569	(23,794)	22,626
Profit (loss) from Innovene operations	–	–	(25)	–	(25)
Profit for the year	2,431	22,420	21,544	(23,794)	22,601
Attributable to					
BP shareholders	2,431	22,420	21,258	(23,794)	22,315
Minority interest	–	–	286	–	286
	2,431	22,420	21,544	(23,794)	22,601

[a]Within the 2006 and 2007 income statements, the tax charge for BP Exploration (Alaska) Inc has been reduced by $238 million for 2006 and $26 million for 2007 from the amounts previously disclosed, and the tax charge for Other subsidiaries has been increased by $238 million and $26 million respectively from the amounts previously disclosed. This change has been made to reflect the allocation of tax charges between BP Exploration (Alaska) Inc and other Alaskan subsidiaries in the BP group. As a result of this immaterial change, the profit for the year relating to BP Exploration (Alaska) Inc has increased by $238 million in 2006 and $26 million in 2007 and the profit for the year relating to Other subsidiaries has decreased by $238 million and $26 million respectively. There is no impact on the consolidated group profit for the year. In addition, for Other subsidiaries the amount of interest and other revenues in 2007 has been increased by $789 million (2006, $628 million) and the amount of finance costs has increased by the same amounts. This change has been made to properly reflect interest between group entities. Corresponding adjustments have been to the Eliminations and reclassifications amounts. The BP group amounts are unchanged. This immaterial change has no impact upon profit for the year for Other subsidiaries or BP group.

51. Condensed consolidating information on certain US subsidiaries continued

Balance sheet

					$ million
At 31 December					2008
	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
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	209	1,174	1,393	(1,781)	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
	10,996	114,422	153,532	(117,096)	161,854
Current assets					
Loans	–	–	168	–	168
Inventories	198	–	16,623	–	16,821
Trade and other receivables	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	29,523	120,562	226,164	(148,011)	228,238
Current liabilities					
Trade and other payables	4,925	2,602	57,032	(30,915)	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
	5,142	2,609	92,957	(30,915)	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	8,244	3,011	157,570	(32,696)	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

51. Condensed consolidating information on certain US subsidiaries continued

Balance sheet continued

					$ million
At 31 December					2007
	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Non-current assets					
Property, plant and equipment	6,310	–	91,679	–	97,989
Goodwill	–	–	11,006	–	11,006
Intangible assets	349	–	6,303	–	6,652
Investments in jointly controlled entities	–	–	18,113	–	18,113
Investments in associates	–	2	4,577	–	4,579
Other investments	–	–	1,830	–	1,830
Subsidiaries – equity-accounted basis	3,117	115,476	–	(118,593)	–
Fixed assets	9,776	115,478	133,508	(118,593)	140,169
Loans	2,151	1,192	1,541	(3,885)	999
Other receivables	–	–	968	–	968
Derivative financial instruments	–	–	3,741	–	3,741
Prepayments	–	–	1,083	–	1,083
Defined benefit pension plan surpluses	–	7,265	1,649	–	8,914
	11,927	123,935	142,490	(122,478)	155,874
Current assets					
Loans	–	–	165	–	165
Inventories	202	–	26,352	–	26,554
Trade and other receivables[a]	15,986	840	44,422	(23,228)	38,020
Derivative financial instruments	–	–	6,321	–	6,321
Prepayments	24	–	3,565	–	3,589
Current tax receivable	–	–	705	–	705
Cash and cash equivalents	(10)	244	3,328	–	3,562
	16,202	1,084	84,858	(23,228)	78,916
Assets classified as held for sale	–	–	1,286	–	1,286
	16,202	1,084	86,144	(23,228)	80,202
Total assets	28,129	125,019	228,634	(145,706)	236,076
Current liabilities					
Trade and other payables[a]	4,969	3,115	58,296	(23,228)	43,152
Derivative financial instruments	–	–	6,405	–	6,405
Accruals	–	10	6,630	–	6,640
Finance debt	55	–	15,339	–	15,394
Current tax payable	306	–	2,976	–	3,282
Provisions	–	–	2,195	–	2,195
	5,330	3,125	91,841	(23,228)	77,068
Liabilities directly associated with assets classified as held for sale	–	–	163	–	163
	5,330	3,125	92,004	(23,228)	77,231
Non-current liabilities					
Other payables	559	27	4,550	(3,885)	1,251
Derivative financial instruments	–	–	5,002	–	5,002
Accruals	–	44	915	–	959
Finance debt	–	–	15,651	–	15,651
Deferred tax liabilities	1,765	1,885	15,565	–	19,215
Provisions	946	–	11,954	–	12,900
Defined benefit pension plan and other post-retirement benefit plan deficits	–	–	9,215	–	9,215
	3,270	1,956	62,852	(3,885)	64,193
Total liabilities	8,600	5,081	154,856	(27,113)	141,424
Net assets	19,529	119,938	73,778	(118,593)	94,652
Equity					
BP shareholders' equity	19,529	119,938	72,816	(118,593)	93,690
Minority interest	–	–	962	–	962
Total equity	19,529	119,938	73,778	(118,593)	94,652

[a]Within Current liabilities – Trade and other payables, the amount of other payables for BP Exploration (Alaska) Inc. has been reduced by $264 million from the amount previously reported and within Current assets – Trade and other receivables the amount of other receivables for other subsidiaries has been reduced by $264 million from the amounts previously reported, with a corresponding change to intercompany eliminations within the Eliminations and reclassifications column. As a result of this immaterial change, the net assets and BP shareholders' equity of BP Exploration (Alaska) Inc. have increased by $264 million and the net assets and BP shareholders' equity of Other subsidiaries have decreased by $264 million. This change has been made to reflect the allocation of tax liabilities between BP Exploration (Alaska) Inc. and other Alaskan subsidiaries in the BP group. There is no impact on the BP group total equity.

51. Condensed consolidating information on certain US subsidiaries continued

Cash flow statement

$ million

2008	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Net cash provided by operating activities	**6,793**	**12,665**	**35,703**	**(17,066)**	**38,095**
Net cash used in investing activities	**(896)**	**–**	**(21,871)**	**–**	**(22,767)**
Net cash used in financing activities	**(5,897)**	**(12,898)**	**(8,780)**	**17,066**	**(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**

$ million

2007	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Net cash provided by operating activities	3,072	15,403	22,839	(16,605)	24,709
Net cash used in investing activities	(532)	1	(14,306)	–	(14,837)
Net cash used in financing activities	(2,545)	(15,139)	(7,956)	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

$ million

2006	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Net cash provided by operating activities	3,522	20,628	29,030	(25,008)	28,172
Net cash used in investing activities	(379)	843	(9,982)	–	(9,518)
Net cash used in financing activities	(3,141)	(21,495)	(19,443)	25,008	(19,071)
Currency translation differences relating to cash and cash equivalents	–	–	47	–	47
(Decrease) increase in cash and cash equivalents	2	(24)	(348)	–	(370)
Cash and cash equivalents at beginning of year	(7)	3	2,964	–	2,960
Cash and cash equivalents at end of year	(5)	(21)	2,616	–	2,590

Supplementary information on oil and natural gas (unaudited)

Movements in estimated net proved reserves

For details of BP's governance process for the booking of oil and natural gas reserves, see page 15. BP estimates proved reserves for reporting purposes in accordance with SEC rules and relevant guidance. As currently required, these proved reserve estimates are based on prices and costs as of the date the estimate is made. There was a rapid and substantial decline in oil prices in the fourth quarter of 2008 that was not matched by a similar reduction in operating costs by the end of the year. BP does not expect that these economic conditions will continue. However, our 2008 reserves are calculated on the basis of operating activities that would be undertaken were year-end prices and costs to persist.

									2008
Crude oil[a]									million barrels
	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Subsidiaries									
At 1 January 2008									
Developed	414	105	1,882	115	61	256	–	104	2,937
Undeveloped	123	169	1,265	203	77	350	–	368	2,555
	537	274	3,147	318	138	606	–	472	5,492
Changes attributable to									
Revisions of previous estimates	16	(11)	(212)	8	16	264	–	183	264
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	64	5	–	173	–	–	242
Improved recovery	39	28	182	8	6	18	–	40	321
Production[b]	(63)	(16)	(191)	(26)	(14)	(101)	–	(44)	(455)
Sales of reserves-in-place	–	–	–	(199)	–	–	–	–	(199)
	(8)	1	(157)	(204)	8	354	–	179	173
At 31 December 2008[c]									
Developed	410	81	1,717	58	77	464	–	174	2,981
Undeveloped	119	194	1,273	56	69	496	–	477	2,684
	529	275	2,990[e]	114	146	960	–	651	5,665
Equity-accounted entities (BP share)									
At 1 January 2008									
Developed	–	–	–	328	1	–	2,094	573	2,996
Undeveloped	–	–	–	243	–	–	1,137	205	1,585
	–	–	–	571	1	–	3,231	778	4,581
Changes attributable to									
Revisions of previous estimates	–	–	–	(3)	–	11	217	(1)	224
Purchases of reserves-in-place	–	–	–	199	–	–	–	–	199
Discoveries and extensions	–	–	–	13	–	–	26	–	39
Improved recovery	–	–	–	62	–	–	–	–	62
Production	–	–	–	(34)	–	–	(302)	(80)	(416)
Sales of reserves-in-place	–	–	–	–	–	–	(1)	–	(1)
	–	–	–	237	–	11	(60)	(81)	107
At 31 December 2008[d]									
Developed	–	–	–	399	1	–	2,227	498	3,125
Undeveloped	–	–	–	409	–	11	944	199	1,563
	–	–	–	808	1	11	3,171	697	4,688

[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 per 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.

Supplementary information on oil and natural gas (unaudited) continued

Movements in estimated net proved reserves continued

Natural gas[a]	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
									2008
									billion cubic feet
Subsidiaries									
At 1 January 2008									
Developed	2,049	63	10,670	3,683	1,822	990	–	583	19,860
Undeveloped	553	410	4,705	8,394	4,817	1,410	–	981	21,270
	2,602	473	15,375	12,077	6,639	2,400	–	1,564	41,130
Changes attributable to									
Revisions of previous estimates	23	(8)	(2,063)	(405)	326	142	–	35	(1,950)
Purchases of reserves-in-place	–	–	183	–	–	–	–	–	183
Discoveries and extensions	–	–	549	1,073	–	82	–	37	1,741
Improved recovery	77	9	1,322	175	56	6	–	54	1,699
Production[b]	(298)	(11)	(834)	(1,040)	(264)	(198)	–	(150)	(2,795)
Sales of reserves-in-place	–	–	–	(3)	–	–	–	–	(3)
	(198)	(10)	(843)	(200)	118	32	–	(24)	(1,125)
At 31 December 2008[c]									
Developed	1,822	61	9,059	3,975	2,482	1,050	–	507	18,956
Undeveloped	582	402	5,473	7,902	4,275	1,382	–	1,033	21,049
	2,404	463	14,532	11,877	6,757	2,432	–	1,540	40,005
Equity-accounted entities (BP share)									
At 1 January 2008									
Developed	–	–	–	1,478	39	–	808	148	2,473
Undeveloped	–	–	–	831	37	–	353	76	1,297
	–	–	–	2,309	76	–	1,161	224	3,770
Changes attributable to									
Revisions of previous estimates	–	–	–	(96)	(2)	182	1,273	–	1,357
Purchases of reserves-in-place	–	–	–	3	–	–	–	–	3
Discoveries and extensions	–	–	–	192	–	–	–	–	192
Improved recovery	–	–	–	301	11	–	–	–	312
Production[b]	–	–	–	(188)	(12)	–	(221)	(10)	(431)
Sales of reserves-in-place	–	–	–	–	–	–	–	–	–
	–	–	–	212	(3)	182	1,052	(10)	1,433
At 31 December 2008[d]									
Developed	–	–	–	1,498	37	–	1,560	139	3,234
Undeveloped	–	–	–	1,023	36	182	653	75	1,969
	–	–	–	2,521	73	182	2,213	214	5,203

[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 16.9 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.

Supplementary information on oil and natural gas (unaudited) continued

Movements in estimated net proved reserves continued

									2007
Crude oil[a]									million barrels
	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Subsidiaries									
At 1 January 2007									
Developed	458	189	1,916	130	67	193	–	88	3,041
Undeveloped	146	97	1,292	237	86	512	–	482	2,852
	604	286	3,208	367	153	705	–	570	5,893
Changes attributable to									
Revisions of previous estimates	(1)	(25)	18	(29)	(7)	(133)	–	(27)	(204)
Purchases of reserves-in-place	–	–	25	–	–	–	–	8	33
Discoveries and extensions	–	31	60	1	2	93	–	–	187
Improved recovery	7	1	99	6	5	12	–	1	131
Production[b]	(73)	(19)	(169)	(27)	(15)	(71)	–	(80)	(454)
Sales of reserves-in-place	–	–	(94)	–	–	–	–	–	(94)
	(67)	(12)	(61)	(49)	(15)	(99)	–	(98)	(401)
At 31 December 2007[c]									
Developed	414	105	1,882	115	61	256	–	104	2,937
Undeveloped	123	169	1,265	203	77	350	–	368	2,555
	537	274	3,147[f]	318	138	606	–	472	5,492
Equity-accounted entities (BP share)[d]									
At 1 January 2007									
Developed	–	–	–	221	1	–	2,200	520	2,942
Undeveloped	–	–	–	139	–	–	644	163	946
	–	–	–	360	1	–	2,844	683	3,888
Changes attributable to									
Revisions of previous estimates	–	–	–	178	–	–	413	167	758
Purchases of reserves-in-place	–	–	–	–	–	–	16	–	16
Discoveries and extensions	–	–	–	2	–	–	283	–	285
Improved recovery	–	–	–	59	–	–	–	1	60
Production	–	–	–	(28)	–	–	(304)	(73)	(405)
Sales of reserves-in-place	–	–	–	–	–	–	(21)	–	(21)
	–	–	–	211	–	–	387	95	693
At 31 December 2007[e]									
Developed	–	–	–	328	1	–	2,094	573	2,996
Undeveloped	–	–	–	243	–	–	1,137	205	1,585
	–	–	–	571	1	–	3,231	778	4,581

[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 per 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.

Supplementary information on oil and natural gas (unaudited) continued

Movements in estimated net proved reserves continued

Natural gas[a]	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
									2007
									billion cubic feet
Subsidiaries									
At 1 January 2007									
Developed	1,968	242	10,438	3,932	1,359	1,032	–	331	19,302
Undeveloped	825	56	4,660	9,194	5,202	1,675	–	1,254	22,866
	2,793	298	15,098	13,126	6,561	2,707	–	1,585	42,168
Changes attributable to									
Revisions of previous estimates	93	(37)	744	(276)	140	(146)	–	(21)	497
Purchases of reserves-in-place	–	–	23	–	–	–	–	109	132
Discoveries and extensions	–	293	95	249	88	17	–	–	742
Improved recovery	15	1	326	32	111	9	–	5	499
Production[b]	(299)	(14)	(879)	(1,047)	(261)	(187)	–	(114)	(2,801)
Sales of reserves-in-place	–	(68)	(32)	(7)	–	–	–	–	(107)
	(191)	175	277	(1,049)	78	(307)	–	(21)	(1,038)
At 31 December 2007[c]									
Developed	2,049	63	10,670	3,683	1,822	990	–	583	19,860
Undeveloped	553	410	4,705	8,394	4,817	1,410	–	981	21,270
	2,602	473	15,375	12,077	6,639	2,400	–	1,564	41,130
Equity-accounted entities (BP share)									
At 1 January 2007									
Developed	–	–	–	1,460	52	–	1,087	170	2,769
Undeveloped	–	–	–	735	23	–	184	52	994
	–	–	–	2,195	75	–	1,271	222	3,763
Changes attributable to									
Revisions of previous estimates	–	–	–	73	(2)	–	61	11	143
Purchases of reserves-in-place	–	–	–	–	–	–	8	–	8
Discoveries and extensions	–	–	–	22	–	–	–	–	22
Improved recovery	–	–	–	195	16	–	–	–	211
Production[b]	–	–	–	(176)	(13)	–	(179)	(9)	(377)
Sales of reserves-in-place	–	–	–	–	–	–	–	–	–
	–	–	–	114	1	–	(110)	2	7
At 31 December 2007[d]									
Developed	–	–	–	1,478	39	–	808	148	2,473
Undeveloped	–	–	–	831	37	–	353	76	1,297
	–	–	–	2,309	76	–	1,161	224	3,770

[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.

Supplementary information on oil and natural gas (unaudited) continued

Movements in estimated net proved reserves continued

Crude oil[a]	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
									2006
									million barrels
Subsidiaries									
At 1 January 2006									
Developed	496	225	1,984	215	70	142	–	69	3,201
Undeveloped	184	86	1,429	286	95	536	–	543	3,159
	680	311	3,413	501	165	678	–	612	6,360
Changes attributable to									
Revisions of previous estimates	(3)	(11)	(108)	(9)	–	2	–	16	(113)
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–
Discoveries and extensions	3	–	48	–	1	67	–	–	119
Improved recovery	26	9	95	13	4	22	–	–	169
Production[b]	(92)	(23)	(178)	(39)	(17)	(64)	–	(58)	(471)
Sales of reserves-in-place	(10)	–	(62)	(99)	–	–	–	–	(171)
	(76)	(25)	(205)	(134)	(12)	27	–	(42)	(467)
At 31 December 2006[c]									
Developed	458	189	1,916	130	67	193	–	88	3,041
Undeveloped	146	97	1,292	237	86	512	–	482	2,852
	604	286	3,208[e]	367	153	705	–	570	5,893
Equity-accounted entities (BP share)									
At 1 January 2006									
Developed	–	–	–	207	1	–	1,688	590	2,486
Undeveloped	–	–	–	124	–	–	431	164	719
	–	–	–	331	1	–	2,119	754	3,205
Changes attributable to									
Revisions of previous estimates	–	–	–	(2)	–	–	1,215	(8)	1,205
Purchases of reserves-in-place	–	–	–	28	–	–	–	–	28
Discoveries and extensions	–	–	–	1	–	–	–	–	1
Improved recovery	–	–	–	34	–	–	–	–	34
Production	–	–	–	(28)	–	–	(320)	(63)	(411)
Sales of reserves-in-place	–	–	–	(4)	–	–	(170)	–	(174)
	–	–	–	29	–	–	725	(71)	683
At 31 December 2006[d]									
Developed	–	–	–	221	1	–	2,200	520	2,942
Undeveloped	–	–	–	139	–	–	644	163	946
	–	–	–	360	1	–	2,844	683	3,888

[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 to make lifting and sales arrangements independently.
[b] Excludes NGLs from processing plants in which an interest is held of 55 thousand barrels per day.
[c] Includes 779 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 28 million barrels of NGLs. Also includes 179 million barrels of crude oil in respect of the 6.29% minority interest in TNK-BP.
[e] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 81 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.

Supplementary information on oil and natural gas (unaudited) continued

Movements in estimated net proved reserves continued

Natural gas[a]									2006 billion cubic feet
	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Subsidiaries									
At 1 January 2006									
Developed	2,382	245	11,184	3,560	1,459	934	–	281	20,045
Undeveloped	904	80	4,198	10,504	5,375	2,000	–	1,342	24,403
	3,286	325	15,382	14,064	6,834	2,934	–	1,623	44,448
Changes attributable to									
Revisions of previous estimates	(343)	11	(922)	(291)	(92)	(69)	–	33	(1,673)
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–
Discoveries and extensions	101	–	116	–	21	5	–	2	245
Improved recovery	144	–	1,755	344	71	6	–	9	2,329
Production[b]	(370)	(38)	(941)	(982)	(273)	(169)	–	(82)	(2,855)
Sales of reserves-in-place	(25)	–	(292)	(9)	–	–	–	–	(326)
	(493)	(27)	(284)	(938)	(273)	(227)	–	(38)	(2,280)
At 31 December 2006[c]									
Developed	1,968	242	10,438	3,932	1,359	1,032	–	331	19,302
Undeveloped	825	56	4,660	9,194	5,202	1,675	–	1,254	22,866
	2,793	298	15,098	13,126	6,561	2,707	–	1,585	42,168
Equity-accounted entities (BP share)									
At 1 January 2006									
Developed	–	–	–	1,492	50	–	1,089	130	2,761
Undeveloped	–	–	–	848	26	–	169	52	1,095
	–	–	–	2,340	76	–	1,258	182	3,856
Changes attributable to									
Revisions of previous estimates	–	–	–	7	13	–	217	47	284
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	23	–	–	–	–	23
Improved recovery	–	–	–	73	1	–	–	–	74
Production[b]	–	–	–	(171)	(15)	–	(204)	(7)	(397)
Sales of reserves-in-place	–	–	–	(77)	–	–	–	–	(77)
	–	–	–	(145)	(1)	–	13	40	(93)
At 31 December 2006[d]									
Developed	–	–	–	1,460	52	–	1,087	170	2,769
Undeveloped	–	–	–	735	23	–	184	52	994
	–	–	–	2,195	75	–	1,271	222	3,763

[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 to make lifting and sales arrangements independently.
[b] Includes 178 billion cubic feet of natural gas consumed in operations, 147 billion cubic feet in subsidiaries, 31 billion cubic feet in equity-accounted entities and excludes 8.3 billion cubic feet of produced non-hydrocarbon components which meet regulatory requirements for sales.
[c] Includes 3,537 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[d] Includes 99 billion cubic feet of natural gas in respect of the 7.77% minority interest in TNK-BP.

Supplementary information on oil and natural gas (unaudited) continued

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 measures 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 the requirements of FASB Statement of Financial Accounting Standards No. 69 – 'Disclosures about Oil and Gas Producing Activities'.

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 year-end crude oil and natural gas prices and exchange rates. Furthermore, both 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 assumptions on which it is based and its lack of comparability with the historical cost information presented in the financial statements.

$ million

	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Other	Total
At 31 December 2008								
Future cash inflows[a]	**36,400**	**13,800**	**165,800**	**32,700**	**28,400**	**40,400**	**27,200**	**344,700**
Future production cost[b]	**18,100**	**6,300**	**80,400**	**9,900**	**12,100**	**11,600**	**10,400**	**148,800**
Future development cost[b]	**3,300**	**2,900**	**25,600**	**8,500**	**3,800**	**10,900**	**6,900**	**61,900**
Future taxation[c]	**7,300**	**2,300**	**17,500**	**6,000**	**3,200**	**6,600**	**2,000**	**44,900**
Future net cash flows	**7,700**	**2,300**	**42,300**	**8,300**	**9,300**	**11,300**	**7,900**	**89,100**
10% annual discount[d]	**2,200**	**1,200**	**21,000**	**3,900**	**4,600**	**5,500**	**3,500**	**41,900**
Standardized measure of discounted future net cash flows[e]	**5,500**	**1,100**	**21,300**	**4,400**	**4,700**	**5,800**	**4,400**	**47,200**
At 31 December 2007								
Future cash inflows[a]	72,100	29,500	350,100	67,700	47,600	63,300	49,400	679,700
Future production cost[b]	27,500	7,500	109,800	17,900	12,800	9,900	8,500	193,900
Future development cost[b]	4,000	3,300	21,900	6,500	4,100	8,300	3,500	51,600
Future taxation[c]	20,200	13,000	71,600	21,700	9,700	17,100	8,700	162,000
Future net cash flows	20,400	5,700	146,800	21,600	21,000	28,000	28,700	272,200
10% annual discount[d]	6,500	2,800	76,000	9,500	10,300	9,400	11,500	126,000
Standardized measure of discounted future net cash flows[e]	13,900	2,900	70,800	12,100	10,700	18,600	17,200	146,200
At 31 December 2006								
Future cash inflows[a]	45,300	18,200	218,900	46,800	36,800	47,700	36,200	449,900
Future production cost[b]	20,700	4,700	71,300	14,900	9,400	8,700	7,200	136,900
Future development cost[b]	3,300	1,500	18,600	4,900	3,800	6,600	3,900	42,600
Future taxation[c]	10,300	9,400	43,100	12,900	7,000	10,600	5,800	99,100
Future net cash flows	11,000	2,600	85,900	14,100	16,600	21,800	19,300	171,300
10% annual discount[d]	3,200	1,000	45,600	6,200	9,000	8,400	7,300	80,700
Standardized measure of discounted future net cash flows[e]	7,800	1,600	40,300	7,900	7,600	13,400	12,000	90,600

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

$ million

	2008	2007	2006
Sales and transfers of oil and gas produced, net of production costs	**(43,600)**	(28,300)	(35,800)
Previously estimated development costs incurred during the year	**9,400**	9,400	8,200
Extensions, discoveries and improved recovery, less related costs	**4,400**	12,300	7,900
Net changes in prices and production cost	**(146,800)**	102,100	(43,900)
Revisions of previous reserves estimates	**1,200**	(12,200)	(9,500)
Net change in taxation	**69,400**	(28,300)	32,200
Future development costs	**(7,400)**	(7,800)	(7,000)
Net change in purchase and sales of reserves-in-place	**(200)**	(700)	(2,500)
Addition of 10% annual discount	**14,600**	9,100	12,800
Total change in the standardized measure during the year[f]	**(99,000)**	55,600	(37,600)

[a]The year-end marker prices used were Brent $36.55/bbl, Henry Hub $5.63/mmBtu (2007 Brent $96.02/bbl, Henry Hub $7.10/mmBtu and 2006 Brent $58.93/bbl, Henry Hub $5.52/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 ($2,300 million at 31 December 2007 and $1,300 million at 31 December 2006).
[f]Total change in the standardized measure during the year includes the effect of exchange rate movements.

Supplementary information on oil and natural gas (unaudited) continued

Equity-accounted entities

In addition, at 31 December 2008, the group's share of the standardized measure of discounted future net cash flows of equity-accounted entities amounted to $9,000 million ($28,300 million at 31 December 2007 and $14,700 million at 31 December 2006), excluding minority interest.

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 2008, 2007 and 2006.

Production for the year[a]

	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Subsidiaries									
Crude oil[b]									thousand barrels per day
2008	**173**	**43**	**538**	**75**	**37**	**277**	**–**	**120**	**1,263**
2007	201	51	513	82	41	195	–	221	1,304
2006	253	61	547	108	44	177	–	161	1,351
Natural gas[c]									million cubic feet per day
2008	**759**	**23**	**2,157**	**2,777**	**699**	**484**	**–**	**378**	**7,277**
2007	768	29	2,174	2,798	699	468	–	286	7,222
2006	936	91	2,376	2,645	727	430	–	207	7,412
Equity-accounted entities (BP share)									
Crude oil[b]									thousand barrels per day
2008	**–**	**–**	**–**	**92**	**1**	**–**	**826**	**219**	**1,138**
2007	–	–	–	77	1	–	832	200	1,110
2006	–	–	–	77	1	–	876	170	1,124
Natural gas[c]									million cubic feet per day
2008	**–**	**–**	**–**	**454**	**31**	**–**	**564**	**8**	**1,057**
2007	–	–	–	429	33	–	451	8	921
2006	–	–	–	416	37	–	544	8	1,005

[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 2008. 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.

	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Number of productive wells at 31 December 2008									
Oil wells[a] – gross	**273**	**81**	**5,960**	**3,695**	**250**	**669**	**19,991**	**1,622**	**32,541**
– net	**147**	**25**	**2,120**	**2,023**	**108**	**544**	**8,503**	**268**	**13,738**
Gas wells[b] – gross	**310**	**–**	**20,913**	**2,326**	**466**	**99**	**44**	**134**	**24,292**
– net	**142**	**–**	**11,948**	**1,397**	**166**	**45**	**22**	**89**	**13,809**

[a]Includes approximately 966 gross (255 net) multiple completion wells (more than one formation producing into the same well bore).
[b]Includes approximately 2,631 gross (1,737 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.

Supplementary information on oil and natural gas (unaudited) continued

Oil and natural gas acreage at 31 December 2008	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
									Thousands of acres
Developed – gross	**390**	**64**	**7,657**	**3,151**	**1,251**	**500**	**4,072**	**1,876**	**18,961**
– net	**193**	**18**	**4,783**	**1,414**	**327**	**212**	**1,768**	**692**	**9,407**
Undeveloped[a] – gross	**1,615**	**519**	**7,733**	**15,586**	**7,433**	**21,524**	**10,079**	**14,832**	**79,321**
– net	**916**	**234**	**5,332**	**9,081**	**2,782**	**16,009**	**4,544**	**6,098**	**44,996**

[a]Undeveloped acreage includes leases and concessions.

Net oil and gas wells completed or abandoned

The following table shows the number of net productive and dry exploratory and development oil and natural gas wells completed or abandoned in the years indicated by the group and its equity-accounted entities. Productive wells include wells in which hydrocarbons were encountered and the drilling or completion of which, in the case of exploratory wells, has been suspended pending further drilling or evaluation. A dry well is one found to be incapable of producing hydrocarbons in sufficient quantities to justify completion.

	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
2008									
Exploratory									
Productive	**0.8**	**–**	**2.4**	**4.4**	**1.1**	**4.3**	**12.5**	**–**	**25.5**
Dry	**–**	**0.5**	**0.9**	**0.5**	**0.4**	**2.6**	**23.0**	**0.5**	**28.4**
Development									
Productive	**6.6**	**0.5**	**379.8**	**140.8**	**23.3**	**18.6**	**10.0**	**26.6**	**606.2**
Dry	**0.2**	**–**	**1.1**	**3.8**	**0.8**	**1.5**	**19.5**	**1.3**	**28.2**
2007									
Exploratory									
Productive	1.6	–	4.1	0.5	1.1	6.1	16.0	1.7	31.1
Dry	–	–	0.7	0.5	0.4	1.6	9.0	1.0	13.2
Development									
Productive	0.4	0.8	401.2	46.0	13.8	15.3	246.0	15.8	739.3
Dry	0.6	–	4.2	8.8	–	–	9.5	–	23.1
2006									
Exploratory									
Productive	0.1	0.1	2.9	0.5	1.0	3.2	15.6	1.4	24.8
Dry	–	–	7.4	1.0	1.5	0.5	5.7	0.3	16.4
Development									
Productive	4.9	1.6	418.8	154.0	12.4	23.8	227.2	14.5	857.2
Dry	–	–	4.5	5.0	0.2	–	20.8	1.0	31.5

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 2008. Suspended development wells and long-term suspended exploratory wells are also included in the table.

	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
At 31 December 2008									
Exploratory									
Gross	**2.0**	**–**	**27.0**	**5.0**	**1.0**	**4.0**	**7.0**	**3.0**	**49.0**
Net	**0.2**	**–**	**12.8**	**2.8**	**0.2**	**2.6**	**3.0**	**2.3**	**23.9**
Development									
Gross	**8.0**	**2.0**	**480.0**	**27.0**	**8.0**	**15.0**	**20.0**	**20.0**	**580.0**
Net	**4.8**	**0.5**	**291.5**	**16.1**	**3.2**	**6.1**	**7.5**	**5.6**	**335.3**

Miscellaneous terms

In this document, unless the context otherwise requires, the following terms shall have the meaning set out below.

ADR
American depositary receipt.

ADS
American depositary share.

AGM
Annual general meeting.

Amoco
The former Amoco Corporation and its subsidiaries.

Atlantic Richfield
Atlantic Richfield Company and its subsidiaries.

Associate
An entity, including an unincorporated entity such as a partnership, over which the group has significant influence and that is neither a subsidiary nor a joint venture. Significant influence is the power to participate in the financial and operating policy decisions of an entity but is not control or joint control over those policies.

Barrel
42 US gallons.

b/d
barrels per day.

boe
barrels of oil equivalent.

BP, BP group or the group
BP p.l.c. and its subsidiaries.

Burmah Castrol
Burmah Castrol PLC and its subsidiaries.

Cent or c
One-hundredth of the US dollar.

The company
BP p.l.c.

Dollar or $
The US dollar.

EU
European Union.

Gas
Natural gas.

Hydrocarbons
Crude oil and natural gas.

IFRS
International Financial Reporting Standards.

Joint control
Joint control is the contractually agreed sharing of control over an economic activity, and exists only when the strategic financial and operating decisions relating to the activity require the unanimous consent of the parties sharing control (the venturers).

Joint venture
A contractual arrangementwhereby two or more parties undertake an economic activity that is subject to joint control.

Jointly controlled asset
A joint venture where the venturers jointly control, and often have a direct ownership interest in the assets of the venture. The assets are used to obtain benefits for the venturers. Each venturer may take a share of the output from the assets and each bears an agreed share of the expenses incurred.

Jointly controlled entity
A joint venture that involves the establishment of acorporation, partnership or other entity in which each venturer has an interest. A contractual arrangement between the venturers establishes joint control over the economic activity of the entity.

Liquids
Crude oil, condensate and natural gas liquids.

LNG
Liquefied natural gas.

London Stock Exchange or LSE
London Stock Exchange plc.

LPG
Liquefied petroleum gas.

mb/d
thousand barrels per day.

mboe/d
thousand barrels of oil equivalent per day.

mmBtu
million British thermal units.

mmboe
million barrels of oil equivalent.

mmcf
million cubic feet.

mmcf/d
million cubic feet per day.

MTBE
Methyl tertiary butyl ether.

MW
Megawatt.

NGLs
Natural gas liquids.

OPEC
Organization of Petroleum Exporting Countries.

Ordinary shares
Ordinary fully paid shares in BP p.l.c. of 25c each.

Pence or p
One-hundredth of a pound sterling.

Pound, sterling or £
The pound sterling.

Preference shares
Cumulative First Preference Shares and Cumulative Second Preference Shares in BP p.l.c. of £1 each.

PSA
Production-sharing agreement.

SEC
The United States Securities and Exchange Commission.

Subsidiary
An entity that is controlled by the BP group. Control is the power to govern the financial and operating policies of an entity so as to obtain the benefits from its activities.

Tonne
2,204.6 pounds.

UK
United Kingdom of Great Britain and Northern Ireland.

US
United States of America.

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: 4 March 2009