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

							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)**

$ million

							2006
	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	–	1,516	–	–	–	1,516
Other investments – unlisted	29	–	181	–	–	–	181
Loans		958	–	–	–	–	958
Trade and other receivables	31	38,474	–	–	–	–	38,474
Derivative financial instruments	34	–	–	12,811	587	–	13,398
Cash at bank and in hand	32	2,052	–	–	–	–	2,052
Cash equivalents – listed	32	–	29	–	–	–	29
Cash equivalents – unlisted	32	–	509	–	–	–	509
Financial liabilities							
Trade and other payables	33	–	–	–	–	(38,227)	(38,227)
Derivative financial instruments	34	–	–	(13,490)	(137)	–	(13,627)
Accruals		–	–	–	–	(7,108)	(7,108)
Finance debt	35	–	–	–	–	(24,010)	(24,010)
		41,484	2,235	(679)	450	(69,345)	(25,855)

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 and the integrated supply and trading functions. The purpose of the committee is to advise on financial risks and the appropriate financial risk governance framework for the group. The committee provides assurance to the CFO and the group chief executive (GCE), and via the GCE to the board, that the group's financial risk-taking activity is governed by appropriate policies and procedures and that financial risks are identified, measured and managed in accordance with group policies and group risk appetite.

The group's trading activities in the oil, natural gas and power markets are managed within the integrated supply and trading function, while activities in the financial markets are managed by the treasury function. All derivative activity, whether for risk management or entrepreneurial purposes, is carried out by specialist teams that have the appropriate skills, experience and supervision. These teams are subject to close financial and management control, meeting generally accepted industry practice and reflecting the principles of the Group of Thirty Global Derivatives Study recommendations.

The integrated supply and trading function maintains formal governance processes that provide oversight of market risk.

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.

28 Financial instruments and financial risk factors *continued*

(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 has developed policies aimed at managing the volatility inherent in certain of its natural business exposures and in accordance with these policies the group enters into various transactions using derivative financial and commodity instruments (derivatives). Derivatives are contracts whose value is derived from one or more underlying financial or commodity instruments, indices or prices that are defined in the contract. The group also trades derivatives in conjunction with its risk management activities.

The group mainly measures its market risk exposure 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 trading value-at-risk model takes account of 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 included in these calculations. For options, a linear approximation is included in the value-at-risk models when full revaluation is not possible. Market risk exposure in respect of embedded derivatives is not included in the value-at-risk table. A separate sensitivity analysis is 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 a 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 an increase or a decrease in fair values greater than the trading value at risk on one occasion per month if the portfolio were left unchanged.

Value at risk for 1 day at 95% confidence interval

$ million

				2007				2006
	High	**Low**	**Average**	**Year end**	High	Low	Average	Year end
Group trading	**50**	**24**	**35**	**38**	57	22	34	30
Oil price trading	**46**	**16**	**26**	**34**	56	16	29	22
Natural gas price trading	**32**	**9**	**16**	**15**	29	10	19	15
Power price trading	**6**	**1**	**3**	**5**	11	2	6	3
Currency trading	**6**	**1**	**3**	**2**	5	–	2	–
Interest rate trading	**11**	**–**	**5**	**2**	1	–	1	–
Other trading	**7**	**–**	**2**	**1**	–	–	–	–

(i) Commodity price risk

The group's risk management policy requires the management of only certain short-term exposures in respect of its equity share of oil and natural gas production and certain of its refinery and marketing activities. 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.

In addition, the group has embedded derivatives relating to certain natural gas and LNG contracts. Key information on these contracts is given below.

	At 31 December 2007	At 31 December 2006
Remaining contract terms	**9 months to 11 years**	2 to 12 years
Contractual/notional amount	**3,889 million therms**	4,968 million therms
Discount rate – nominal risk free	**4.5%**	4.5%
Net fair value liability	**$2,085 million**	$2,064 million

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

$ million

				2007				2006
	Gas price	**Gas oil and fuel oil price**	**Power price**	**Discount rate**	Gas price	Gas oil and fuel oil price	Power price	Discount rate
Favourable 10% change	**317**	**72**	**37**	**31**	332	7	45	31
Unfavourable 10% change	**(368)**	**(84)**	**(34)**	**(32)**	(341)	(7)	(41)	(32)

28 Financial instruments and financial risk factors *continued*

These sensitivities are hypothetical and should not be considered to be predictive of future performance. Changes in fair value generally cannot be extrapolated because the relationship of change in assumption to change in fair value may not be linear. In addition, for the purposes of this analysis, in this 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 2007, the foreign currency value at risk was $60 million (2006 $107 million). At no point over the past two 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 futures. The main exposures are sterling and euro, and at 31 December 2007 open contracts were in place for $732 million sterling and $931 million euro capital expenditures, with over 80% of the deals maturing within two years (2006 $630 million sterling and $957 million euro capital expenditures with over 95% of the deals maturing within two years).

For other UK and European operational requirements the group predominantly uses cylinders to hedge the estimated exposures on a 12-month rolling basis at minimal cost. At 31 December 2007, the main open positions consisted of receive sterling, pay US dollar, purchased call and sold put options for $2,800 million; and receive euro, pay US dollar cylinders for $1,400 million.

In addition, most of the group's borrowings are in US dollars or are hedged with respect to the US dollar. At 31 December 2007, the total of foreign currency borrowings not swapped into US dollars amounted to $1,045 million (2006 $957 million). Of this total, $268 million (2006 $300 million) of these borrowings were denominated in currencies other than the functional currency of the individual operating unit, $191 million in Canadian dollars and $77 million in Trinidad & Tobago dollars (2006 $224 million in Canadian dollars and $76 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 $27 million (2006 $30 million).

(iii) Interest rate risk

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

BP is also exposed to interest rate risk from the possibility that changes in interest rates will affect future cash flows or the fair values of its financial instruments, principally finance debt. While the group issues debt in a variety of currencies based on market opportunities, it uses derivatives to swap the debt to a US dollar exposure with an overall profile of one-third fixed rate to two-thirds floating rate. The proportion of floating rate debt net of interest rate swaps at 31 December 2007 was 68% of total finance debt outstanding (2006 73%). The weighted average interest rate on finance debt is 5% (2006 5%).

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 2008, it is estimated that the group's profit before taxation for 2008 would decrease by approximately $168 million (2006 $180 million). 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 2007 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 an overall reduction in economic activity that could accompany such an increase in interest rates.

(iv) Equity price risk

The group holds equity investments 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. On disposal, accumulated fair value changes are recycled to the income statement. Such investments are typically made for strategic purposes. At 31 December 2007, it is estimated that a change of 10% in equity prices would result in an immediate charge or credit to equity of $162 million (2006 $152 million).

At 31 December 2007, 70% of the carrying amount of non-current available-for-sale financial assets represented one equity investment, thus the group's exposure is concentrated on changes in the share prices of this equity in particular. For further information see Note 29.

(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.

28 Financial instruments and financial risk factors *continued*

The group has a credit policy, approved by the CFO, that is designed to ensure that consistent processes are in place throughout the group to measure and control credit risk. Credit risk is considered as part of the risk-reward balance of doing business. On entering into any business contract the extent to which the arrangement exposes the group to credit risk is considered. Key requirements of the policy 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.

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 2007, the maximum credit exposure was $53,498 million (2006 $55,420 million). This does not take into account collateral held of $474 million (2006 $689 million). In addition, credit exposure exists in relation to guarantees issued by group companies under which amounts outstanding at 31 December 2007 were $443 million (2006 $1,123 million) in respect of liabilities of jointly controlled entities and associates and $601 million (2006 $789 million) in respect of liabilities of other third parties.

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

Reports are regularly prepared and presented to the GFRC that cover the group’s overall credit exposure and expected loss trends, exposure by segment, and overall quality of the portfolio. The reports also include details of the largest counterparties by exposure level and expected loss, and details of counterparties on the group watchlist.

It is estimated that over 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 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 2007 or 31 December 2006.

$ million

Trade and other receivables at 31 December	**2007**	2006
Neither impaired nor past due	**35,167**	34,737
Impaired (net of valuation allowance)	**145**	101
Not impaired and past due in the following periods		
within 30 days	**2,350**	2,404
31 to 60 days	**273**	475
61 to 90 days	**311**	253
over 90 days	**464**	504
	38,710	38,474

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

$ million

	2007	2006
At 1 January	**421**	374
Exchange adjustments	**34**	32
Charge for the year	**175**	158
Utilization	**(224)**	(143)
At 31 December	**406**	421

28 Financial instruments and financial risk factors *continued*

(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 2007, 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 for at least four years (2006 $4,700 million of which $4,300 million are in place for at least five years). 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 $15 billion of debt for maturities of one month or longer. At 31 December 2007, the amount drawn down against the DIP was $10,438 million (2006 $7,893 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 2007, the amount drawn down under the US Shelf was $2,500 million (2006 nil).

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

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.

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 $2,880 million (2006 $2,744 million) with earliest contractual repayment dates within one year have expected repayment dates ranging from 1 to 35 years (2006 1 to 34 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 $1,899 million (2006 $1,976 million) that mature over 10 years.

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

$ million

			2007			2006
	Trade and other payables	**Accruals**	**Finance debt**	Trade and other payables	Accruals	Finance debt
Within one year	**39,576**	**6,640**	**16,561**	37,696	6,147	13,864
1 to 2 years	**147**	**351**	**8,011**	100	349	4,146
2 to 3 years	**62**	**245**	**3,515**	80	227	4,354
3 to 4 years	**26**	**78**	**1,447**	57	81	723
4 to 5 years	**30**	**49**	**2,352**	68	61	776
5 to 10 years	**197**	**200**	**1,100**	226	240	1,778
Over 10 years	**24**	**36**	**1,447**	–	3	1,650
	40,062	**7,599**	**34,433**	38,227	7,108	27,291

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. The embedded derivatives associated with these contracts are all financial assets. There are no cash outflows associated with embedded derivatives that are financial liabilities because these are all related to sales contracts.

$ million

		2007		2006
	Embedded derivatives	**Held-for-trading derivatives**	Embedded derivatives	Held-for-trading derivatives
Within one year	**699**	**82,465**	707	68,369
1 to 2 years	**659**	**8,541**	602	8,535
2 to 3 years	**641**	**2,906**	472	2,852
3 to 4 years	**627**	**707**	483	913
4 to 5 years	**624**	**338**	490	413
5 to 10 years	**2,342**	**592**	2,335	1,626
Over 10 years	**–**	**447**	–	280
	5,592	**95,996**	**5,089**	82,988

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28 Financial instruments and financial risk factors *continued*

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
	2007	2006
Within one year	**1,708**	1,228
1 to 2 years	**1,220**	1,711
2 to 3 years	**3,759**	2,772
3 to 4 years	**365**	117
4 to 5 years	**1,650**	–
5 to 10 years	**105**	220
Over 10 years	**–**	–
	8,807	6,048

29 Other investments

		$ million
	2007	2006
Listed	**1,617**	1,516
Unlisted	**213**	181
	1,830	1,697

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.

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 $1,285 million at 31 December 2007.

30 Inventories

		$ million
	2007	2006
Crude oil	**8,157**	5,357
Natural gas	**160**	127
Refined petroleum and petrochemical products	**14,723**	10,817
	23,040	16,301
Supplies	**1,517**	1,222
	24,557	17,523
Trading inventories	**1,997**	1,392
	26,554	18,915
Cost of inventories expensed in the income statement	**200,766**	187,183

31 Trade and other receivables

				$ million
		2007		2006
	Current	**Non-current**	Current	Non-current
Financial assets				
Trade receivables	**33,012**	**–**	32,460	–
Amounts receivable from jointly controlled entities	**888**	**–**	830	–
Amounts receivable from associates	**380**	**–**	268	–
Other receivables	**3,462**	**968**	4,054	862

	37,742	**968**	37,612	862
Non-financial assets				
Other receivables	**278**	**–**	1,080	–
	38,020	**968**	38,692	862

Trade and other receivables are predominantly non-interest bearing.

32 Cash and cash equivalents

		$ million
	2007	2006
Cash at bank and in hand	**2,996**	2,052
Cash equivalents		
Listed	**3**	29
Unlisted	**563**	509
	3,562	2,590

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 2007 includes $1,294 million (2006 $773 million) that is restricted. This relates principally to amounts on deposit to cover initial margins on trading exchanges.

33 Trade and other payables

				$ million
		2007		2006
	Current	**Non-current**	Current	Non-current
Financial liabilities				
Trade payables	**30,735**	**–**	28,319	–
Amounts payable to jointly controlled entities	**66**	**–**	119	–
Amounts payable to associates	**650**	**–**	273	–
Other payables	**8,125**	**486**	8,985	531
	39,576	**486**	37,696	531
Non-financial liabilities				
Production and similar taxes	**803**	**765**	852	899
Other payables	**2,773**	**–**	3,688	–
	3,576	**765**	4,540	899
	43,152	**1,251**	42,236	1,430

Trade and other payables are predominantly interest free.

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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

	2007		2006	
	Fair value asset	**Fair value liability**	Fair value asset	Fair value liability
Derivatives held for trading				
Currency derivatives	**147**	**(317)**	137	(32)
Oil price derivatives	**3,214**	**(3,432)**	2,664	(2,368)
Natural gas price derivatives	**4,388**	**(4,022)**	6,558	(5,703)
Power price derivatives	**1,121**	**(1,140)**	3,232	(3,190)
Other derivatives	**30**	**–**	113	–
	8,900	**(8,911)**	12,704	(11,293)
Embedded derivatives				
Natural gas and LNG contracts	**255**	**(2,340)**	107	(2,171)
Interest rate contracts	**–**	**(33)**	–	(26)
	255	**(2,373)**	107	(2,197)
Cash flow hedges	**348**	**(97)**	219	(33)
Fair value hedges				
Currency forwards, futures and swaps	**430**	**(9)**	228	(13)
Interest rate swaps	**89**	**(17)**	33	(91)
	519	**(26)**	261	(104)
Hedges of net investments in foreign operations	**40**	**–**	107	–
	10,062	**(11,407)**	13,398	(13,627)
Of which – current	**6,321**	**(6,405)**	10,373	(9,424)
– non-current	**3,741**	**(5,002)**	3,025	(4,203)

34 Derivative financial instruments *continued*

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. The fair values at the year end are not materially unrepresentative of the position throughout the year.

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**
Fair value of contracts at 1 January 2007	**105**	**296**	**855**	**42**	**113**
Contracts realized or settled in the year	**(109)**	**(289)**	**(602)**	**(68)**	**(83)**
Fair value of options at inception	**–**	**28**	**168**	**36**	**–**
Fair value of other new contracts entered into during the year	**–**	**–**	**1**	**–**	**–**
Changes in fair values relating to price	**(167)**	**(253)**	**(58)**	**(20)**	**–**
Exchange adjustments	**1**	**–**	**2**	**(9)**	**–**
Fair value of contracts at 31 December 2007	**(170)**	**(218)**	**366**	**(19)**	**30**

$ million

	Currency	Oil price	Natural gas price	Power price	Other
Fair value of contracts at 1 January 2006	23	(61)	529	183	–
Contracts realized or settled in the year	(16)	85	(327)	(37)	(106)
Fair value of options at inception	–	36	247	(70)	45
Fair value of other new contracts entered into during the year	–	–	2	1	–
Change in fair value due to changes in valuation techniques or key assumptions	–	1	–	–	–
Changes in fair values relating to price	98	231	421	(22)	174
Exchange adjustments	–	4	(17)	(13)	–
Fair value of contracts at 31 December 2006	105	296	855	42	113

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.

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34 Derivative financial instruments *continued*

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

$ million

	2007		2006	
	Natural gas price	**Power price**	Natural gas price	Power price
Fair value of contracts not recognized through the income statement at 1 January	**36**	**–**	39	10
Fair value of new contracts at inception not recognized in the income statement	**1**	**–**	2	1
Fair value recognized in the income statement	**(1)**	**–**	(5)	(11)
Fair value of contracts not recognized through profit at 31 December	**36**	**–**	36	–

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

$ 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**

$ million

							2006
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	117	–	12	3	2	3	137
Oil price derivatives	2,520	116	20	7	1	–	2,664
Natural gas price derivatives	4,532	919	374	166	114	453	6,558
Power price derivatives	2,845	274	86	27	–	–	3,232
Other derivatives	64	26	23	–	–	–	113
	10,078	1,335	515	203	117	456	12,704

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

$ 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)**

$ million

							2006
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	(8)	(7)	(12)	(2)	(2)	(1)	(32)
Oil price derivatives	(2,230)	(89)	(29)	(19)	(1)	–	(2,368)
Natural gas price derivatives	(3,931)	(875)	(273)	(109)	(86)	(429)	(5,703)
Power price derivatives	(2,777)	(289)	(98)	(26)	–	–	(3,190)
	(8,946)	(1,260)	(412)	(156)	(89)	(430)	(11,293)

34 Derivative financial instruments *continued*

The following tables show the net fair value of derivatives held for trading at 31 December analysed by maturity period and by methodology of fair value estimation.

$ 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	**119**	**3**	**49**	**2**	**(9)**	**1**	**165**
Prices sourced from observable data or market corroboration	**(212)**	**58**	**(57)**	**82**	**37**	**–**	**(92)**
Prices based on models and other valuation methods	**(39)**	**(19)**	**(14)**	**(18)**	**(7)**	**13**	**(84)**
	(132)	**42**	**(22)**	**66**	**21**	**14**	**(11)**

$ million

							2006
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Prices actively quoted	191	62	60	33	–	2	348
Prices sourced from observable data or market corroboration	911	29	54	19	36	4	1,053
Prices based on models and other valuation methods	30	(14)	(12)	(6)	(8)	20	10
	1,132	77	102	46	28	26	1,411

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 loss of $94 million (2006 $117 million loss and 2005 $130 million gain).

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 $376 million (2006 $2,842 million gain and 2005 $838 million gain).

Embedded derivatives

Prior to the development of an active gas trading market, UK gas contracts were priced using a basket of available price indices, primarily relating to oil products. 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.

These contracts are valued using models with inputs that include price curves for each of the different products that are built up from active market pricing data and extrapolated to the expiry of the contracts in 2018 using the maximum available external pricing information. Additionally, where limited data exists for certain products, prices are interpolated using historic and long-term pricing relationships. Price volatility data is also an input for the models.

34 Derivative financial instruments *continued*

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

$ million

	2007		2006	
	Natural gas and LNG price	**Interest rate**	Natural gas and LNG price	Interest rate
Fair value of contracts at 1 January	**(2,064)**	**(26)**	(2,511)	(30)
Contracts realized or settled in the year	**449**	**–**	762	–
Changes in valuation techniques or key assumptions	**130**	**–**	–	–
Changes in fair values relating to price	**(567)**	**(7)**	21	4
Exchange adjustments	**(33)**	**–**	(336)	–
Fair value of contracts at 31 December	**(2,085)**	**(33)**	(2,064)	(26)

Embedded derivative assets have the following fair values and maturities.

$ million

							2007
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Natural gas and LNG embedded derivatives	**193**	**18**	**15**	**7**	**10**	**12**	**255**

$ million

							2006
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Natural gas and LNG embedded derivatives	49	58	–	–	–	–	107

Embedded derivative liabilities have the following fair values and maturities.

$ million

							2007
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Natural gas and LNG embedded derivatives	**(554)**	**(437)**	**(299)**	**(244)**	**(219)**	**(587)**	**(2,340)**
Interest rate embedded derivatives	**(33)**	**–**	**–**	**–**	**–**	**–**	**(33)**
	(587)	**(437)**	**(299)**	**(244)**	**(219)**	**(587)**	**(2,373)**

$ million

							2006
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Natural gas and LNG embedded derivatives	(444)	(433)	(320)	(218)	(186)	(570)	(2,171)
Interest rate embedded derivatives	–	(26)	–	–	–	–	(26)
	(444)	(459)	(320)	(218)	(186)	(570)	(2,197)

The following tables show the net fair value of embedded derivatives at 31 December analysed by maturity period and by methodology of fair value estimation.

$ 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	**(455)**	**(419)**	**(284)**	**(237)**	**(209)**	**(575)**	**(2,179)**
	(394)	**(419)**	**(284)**	**(237)**	**(209)**	**(575)**	**(2,118)**

							$ million
							2006
	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	49	58	–	–	–	–	107
Prices based on models and other valuation methods	(444)	(459)	(320)	(218)	(186)	(570)	(2,197)
	(395)	(401)	(320)	(218)	(186)	(570)	(2,090)

The net change in fair value of contracts based on models and other valuation methods during the year is a gain of $18 million (2006 gain of $423 million and 2005 loss of $1,773 million).

34 Derivative financial instruments *continued*

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

			$ million
	2007	2006	2005
Natural gas and LNG embedded derivatives	**–**	604	(2,034)
Interest rate embedded derivatives	**(7)**	4	(13)
Fair value gain (loss)	**(7)**	608	(2,047)

The fair value gain (loss) in the above table includes $12 million of exchange losses (2006 $179 million of exchange losses and 2005 $115 million of exchange gains) arising on contracts that are denominated in a currency other than the functional currency of the individual operating unit.

Cash flow hedges

At 31 December 2007, the group held futures currency 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 gain of $74 million (2006 $93 million and 2005 $36 million loss). Of this, a gain of $143 million is included in production and manufacturing expenses (2006 $162 million gain and 2005 $33 million gain) and a loss of $69 million is included in finance costs (2006 $69 million loss and 2005 $69 million loss). The amount removed from equity during the period and included in the carrying amount of non-financial assets was a gain of $40 million (2006 $6 million gain and nil for 2005).

The amounts retained in equity at 31 December 2007 are expected to mature and affect the income statement by a $48 million gain in 2008, a loss of $10 million in 2009 and a gain of $28 million in 2010 and beyond.

Fair value hedges

At 31 December 2007, the group held interest rate and currency swap contracts as fair value hedges of the interest rate risk on fixed rate debt issued by the group. The receive leg of the swap contracts is largely identical for all critical aspects to the terms of the underlying debt and thus the hedging is highly effective. The gain on the hedging derivative instruments taken to the income statement in 2007 was $334 million (2006 $257 million) offset by a loss on the fair value of the finance debt of $327 million (2006 $257 million loss).

The interest rate and currency swaps have an average maturity of one to two years, (2006 two to three 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 2007, the hedge had a fair value of $40 million (2006 $107 million) and the loss on the hedge recognized in equity in 2007 was $67 million (2006 $105 million gain, 2005 $58 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
			2007			2006
	Within 1 year[a]	**After 1 year**	**Total**	Within 1 year[a]	After 1 year	Total
Bank loans	**542**	**978**	**1,520**	543	806	1,349
Other loans	**14,607**	**14,026**	**28,633**	12,321	9,525	21,846
Total borrowings	**15,149**	**15,004**	**30,153**	12,864	10,331	23,195
Net obligations under finance leases	**245**	**647**	**892**	60	755	815
	15,394	**15,651**	**31,045**	12,924	11,086	24,010

[a] Amounts due within one year include current maturities of long-term debt and borrowings that are expected to be repaid later than the earliest contractual repayment dates of within one year. US Industrial Revenue/Municipal Bonds of $2,880 million (2006 $2,744 million) with earliest contractual repayment dates within one year have expected repayment dates ranging from 1 to 35 years (2006 1 to 34 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 $1,899 million (2006 $1,976 million) that mature over 10 years.

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35 Finance debt *continued*

The following table shows, by major currency, the group's finance debt at 31 December 2007 and 2006 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
						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**
						2006
US dollar	5	3	5,998	6	17,055	23,053
Sterling	–	–	–	5	35	35
Euro	3	8	61	4	134	195
Other currencies	7	8	299	8	428	727
			6,358		17,652	24,010

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
	2007	2006
Future minimum lease payments payable within		
1 year	**268**	82
2 to 5 years	**393**	376
Thereafter	**630**	873
	1,291	1,331
Less finance charges	**399**	516
Net obligations	**892**	815
Of which – payable within 1 year	**245**	60
– payable within 2 to 5 years	**217**	164
– payable thereafter	**430**	591

35 Finance debt *continued*

Fair values

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

Long-term borrowings in the table below include the portion of debt that matures in the year from 31 December 2007, whereas in the balance sheet the amount would be reported as 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

	2007		2006	
	Fair value	**Carrying amount**	Fair value	Carrying amount
Short-term borrowings	**11,212**	**11,212**	9,661	9,661
Long-term borrowings	**19,094**	**18,941**	13,580	13,534
Net obligations under finance leases	**908**	**892**	832	815
Total finance debt	**31,214**	**31,045**	24,073	24,010

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 maintain capital discipline in relation to investing activities while progressively growing the dividend per share. A managed share buyback programme is used to return to shareholders all sustainable free cash flow in excess of the group's investment and dividend needs. From 2008, the group intends to rebalance returns to shareholders by increasing the dividend component. As a result, the level of free cash flow allocated to share buybacks is likely to be lower; however, we will continue to use share buybacks as a mechanism to return excess cash to shareholders when appropriate.

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, less cash and cash equivalents. 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 2007 the net debt ratio was 23% (2006 20%).

$ million

	2007	2006
Gross debt	**31,045**	24,010
Cash and cash equivalents	**3,562**	2,590
Net debt	**27,483**	21,420
Equity	**94,652**	85,465
Net debt ratio	**23%**	20%

An analysis of changes in net debt is provided below.

$ million

		2007			2006	
Movement in net debt	**Finance debt**	**Cash and cash equivalents**	**Net debt**	Finance debt	Cash and cash equivalents	Net debt
At 1 January	**(24,010)**	**2,590**	**(21,420)**	(19,162)	2,960	(16,202)
Exchange adjustments	**(122)**	**135**	**13**	(172)	47	(125)
Debt acquired	**–**	**–**	**–**	(13)	–	(13)
Net cash flow	**(6,411)**	**837**	**(5,574)**	(4,049)	(417)	(4,466)
Fair value hedge adjustment	**(368)**	**–**	**(368)**	(581)	–	(581)
Other movements	**(134)**	**–**	**(134)**	(33)	–	(33)
At 31 December	**(31,045)**	**3,562**	**(27,483)**	(24,010)	2,590	(21,420)
Equity			**94,652**			85,465

37 Provisions

$ 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**

$ million

	Decommissioning	Environmental	Litigation and other	Total
At 1 January 2006	6,450	2,311	2,795	11,556
Exchange adjustments	13	31	44	88
New or increased provisions	2,142	423	1,611	4,176
Write-back of unused provisions	–	(355)	(270)	(625)
Unwinding of discount	153	45	47	245
Utilization	(179)	(324)	(1,068)	(1,571)
Deletions	(214)	(4)	(7)	(225)
At 31 December 2006	8,365	2,127	3,152	13,644
Of which – expected to be incurred within 1 year	324	444	1,164	1,932
– expected to be incurred in more than 1 year	8,041	1,683	1,988	11,712

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 and discounted using a real discount rate of 2.0% (2006 2.0%) . These costs are generally expected to be incurred over the next 30 years. While the provision is based on the best estimate of future costs and the economic lives of the facilities and pipelines, there is uncertainty regarding both the amount and timing of incurring these costs.

Provisions for environmental remediation are made when a clean-up is probable and the amount is reliably determinable. Generally, this coincides with commitment to a formal plan of action or, if earlier, on divestment or 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% (2006 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 2007 are provisions for litigation of $1,737 million (2006 $1,474 million) for deferred employee compensation of $761 million (2006 $760 million) and provisions for expected rental shortfalls on surplus properties of $320 million (2006 $320 million). New or increased provisions made for 2007 included an amount of $500 million (2006 $425 million) in respect of the Texas City incident, of which, disbursements to claimants in 2007 were $314 million (2006 $863 million) and the provision at 31 December 2007 was $456 million (2006 $270 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 4.5% (2006 4.5%) or a real discount rate of 2.0% (2006 2.0%), as appropriate.

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

The level of contributions to funded defined benefit plans is the amount needed to provide adequate funds to meet pension obligations as they fall due. During 2007, contributions of $524 million (2006 $438 million and 2005 $340 million) and $97 million (2006 $181 million and 2005 $279 million) were made to the UK plans and US plans respectively. In addition, contributions of $127 million (2006 $136 million and 2005 $140 million) were made to other funded defined benefit plans. The aggregate level of contributions in 2008 is expected to be approximately $500 million.

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 2007.

The material financial assumptions used for estimating the benefit obligations of the various plans are set out below. The assumptions used to evaluate accrued pension and other post-retirement benefits at 31 December in any year are used to determine pension and other post-retirement expense for the following year, that is, the assumptions at 31 December 2007 are used to determine the pension liabilities at that date and the pension cost for 2008.

%

Financial assumptions	UK			US			Other		
	2007	2006	2005	**2007**	2006	2005	**2007**	2006	2005
Discount rate for pension plan liabilities	**5.7**	5.1	4.75	**6.1**	5.7	5.50	**5.6**	4.8	4.00
Discount rate for post-retirement benefit plans	**n/a**	n/a	n/a	**6.4**	5.9	5.50	**n/a**	n/a	n/a
Rate of increase in salaries[a]	**5.1**	4.7	4.25	**4.2**	4.2	4.25	**3.7**	3.6	3.25
Rate of increase for pensions in payment	**3.2**	2.8	2.50	**–**	–	–	**1.8**	1.8	1.75
Rate of increase in deferred pensions	**3.2**	2.8	2.50	**–**	–	–	**1.2**	1.1	1.00
Inflation	**3.2**	2.8	2.50	**2.4**	2.4	2.50	**2.2**	2.2	2.00

[a] This assumption includes an 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. Mortality assumptions reflect best practice in the countries in which we provide pensions, and have been chosen with regard to the latest available published tables adjusted where appropriate to reflect the experience of the group and an extrapolation of past longevity improvements into the future. BP's most substantial pension liabilities are in the UK, the US and Germany where our assumptions are as follows:

Years

Mortality assumptions	UK			US			Germany		
	2007	2006	2005	**2007**	2006	2005	**2007**	2006	2005
Life expectancy at age 60 for a male currently aged 60	**24.0**	23.9	23.0	**24.3**	24.2	21.9	**22.4**	22.2	22.1
Life expectancy at age 60 for a female currently aged 60	**26.9**	26.8	26.0	**26.1**	26.0	25.6	**27.0**	26.9	26.7
Life expectancy at age 60 for a male currently aged 40	**25.1**	25.0	23.9	**25.8**	25.8	21.9	**25.3**	25.2	25.0
Life expectancy at age 60 for a female currently aged 40	**27.9**	27.8	26.9	**27.0**	26.9	25.6	**29.7**	29.6	29.4

The assumed future US healthcare cost trend rate is as follows:

%

	2007	2006	2005
Initial US healthcare cost trend rate	**9.0**	9.3	10.3
Ultimate US healthcare cost trend rate	**5.0**	5.0	5.0
Year in which ultimate trend rate is reached	**2013**	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.

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38 Pensions and other post-retirement benefits *continued*

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	55-85
Fixed income/cash	15-35
Property/real estate	0-10

Some of the group's pension funds use derivatives as part of their asset mix and to manage the level of risk. The group's main pension funds do not directly invest 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.

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.

	2007		2006		2005	
	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**	**24,106**	7.5	23,631	7.50	18,465
Bonds	**4.4**	**5,279**	4.7	3,881	4.25	2,719
Property	**6.5**	**1,259**	6.5	1,370	6.50	1,097
Cash	**5.6**	**977**	3.8	379	3.50	1,001
	7.3	**31,621**	7.0	29,261	7.00	23,282
US pension plans						
Equities	**8.5**	**6,610**	8.5	6,528	8.50	5,961
Bonds	**5.0**	**1,347**	5.0	1,371	4.75	1,079
Property	**8.0**	**16**	8.0	15	8.00	21
Cash	**3.6**	**72**	3.2	41	3.00	256
	8.0	**8,045**	8.0	7,955	8.00	7,317
US other post-retirement benefit plans						
Equities	**8.5**	**17**	8.5	19	8.50	20
Bonds	**5.0**	**6**	5.0	7	4.75	8
	7.6	**23**	7.5	26	7.25	28
Other plans						
Equities	**8.1**	**1,260**	7.6	1,158	7.50	991
Bonds	**5.0**	**1,491**	4.6	1,199	4.00	943
Property	**5.7**	**145**	4.7	120	5.75	130
Cash	**4.2**	**214**	3.0	191	1.50	216
	6.4	**3,110**	5.8	2,668	5.50	2,280

The assumed rate of investment return and discount rate 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 2008	(419)	415
Discount rate		
Effect on pension and other post-retirement benefit expense in 2008	(84)	114
Effect on pension and other post-retirement benefit obligation at 31 December 2007	(5,039)	6,459

The assumed US healthcare cost trend rate has a significant effect on the amounts reported. A one-percentage point change in the assumed US healthcare cost trend rate would have had the following effects:

	One-percentage point ($ million)	
	Increase	Decrease
Effect on US other post-retirement benefit expense in 2008	32	(26)
Effect on US other post-retirement obligation at 31 December 2007	358	(295)

38 Pensions and other post-retirement benefits *continued*

					$ million
					2007
Analysis of the amount charged to profit before interest and taxation	UK pension plans	US pension plans	US other post-retirement benefit plans	Other plans	Total
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 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 fund's investments are treated as being part of the investment return, the costs of administering our pensions fund benefits are generally included in current service cost and the costs of administering our other post-retirement benefits 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 fund 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.

At 31 December 2007 reimbursement balances due from or to other companies in respect of pensions amounted to $496 million reimbursement assets (2006 $479 million) and $72 million reimbursement liabilities (2006 $71 million). These balances are not included as part of the pension liability, but are reflected elsewhere in the group balance sheet.

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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
Movements in benefit obligation during the year					
Benefit obligation at 1 January	20,063	7,900	3,478	7,414	38,855
Exchange adjustments	2,748	–	–	632	3,380
Current service cost	432	216	42	139	829
Past service cost	(74)	38	–	39	3
Interest cost	1,006	423	186	325	1,940
Curtailment	(20)	–	–	–	(20)
Settlement	(22)	–	–	–	(22)
Special termination benefits[c]	46	–	–	227	273
Contributions by plan participants	38	–	–	5	43
Benefit payments (funded plans)[d]	(981)	(615)	(4)	(149)	(1,749)
Benefit payments (unfunded plans)[d]	–	(37)	(211)	(321)	(569)
Acquisitions	–	–	–	–	–
Disposals	143	(18)	–	(7)	118
Actuarial gain on obligation	(90)	(212)	(191)	(155)	(648)
Benefit obligation at 31 December	23,289	7,695	3,300	8,149	42,433
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	23,282	7,317	28	2,280	32,907
Exchange adjustments	3,325	–	–	122	3,447
Expected return on plan assets[a, e]	1,711	564	2	133	2,410
Contributions by plan participants	38	–	–	5	43
Contributions by employers (funded plans)	438	181	–	136	755
Benefit payments (funded plans)[d]	(981)	(615)	(4)	(149)	(1,749)
Acquisitions	–	–	–	–	–
Disposals	143	(13)	–	–	130
Actuarial gain on plan assets[e]	1,305	521	–	141	1,967
Fair value of plan assets at 31 December	29,261	7,955	26	2,668	39,910
Surplus (deficit) at 31 December	5,972	260	(3,274)	(5,481)	(2,523)
Represented by					
Asset recognized	6,089	617	–	47	6,753
Liability recognized	(117)	(357)	(3,274)	(5,528)	(9,276)

	5,972	260	(3,274)	(5,481)	(2,523)
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	6,089	601	(30)	(379)	6,281
Unfunded	(117)	(341)	(3,244)	(5,102)	(8,804)
	5,972	260	(3,274)	(5,481)	(2,523)
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(23,172)	(7,354)	(56)	(3,047)	(33,629)
Unfunded	(117)	(341)	(3,244)	(5,102)	(8,804)
	(23,289)	(7,695)	(3,300)	(8,149)	(42,433)

[a] The costs of managing the fund’s investments are treated as being part of the investment return, the costs of administering our pensions fund benefits are generally included in current service cost and the costs of administering our other post-retirement benefits 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 and Europe.
[d] The benefit payments amount shown above comprises $2,266 million benefits plus $52 million of fund 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

Analysis of the amount charged to profit before interest and taxation	UK pension plans	US pension plans	US other post-retirement benefit plans	Other plans	Total
					2005
Current service cost[a]	379	216	50	140	785
Past service cost	5	(10)	(5)	51	41
Settlement, curtailment and special termination benefits	37	–	–	10	47
Payments to defined contribution plans	–	158	–	14	172
Total operating charge	421	364	45	215	1,045
Innovene operations	(38)	(24)	(3)	(21)	(86)
Continuing operations[b]	383	340	42	194	959
Analysis of the amount credited (charged) to other finance expense					
Expected return on plan assets	1,456	557	2	123	2,138
Interest on plan liabilities	(1,003)	(444)	(207)	(368)	(2,022)
Other finance income (expense)	453	113	(205)	(245)	116
Innovene operations	(10)	(5)	2	10	(3)
Continuing operations	443	108	(203)	(235)	113
Analysis of the amount recognized in the statement of recognized income and expense					
Actual return less expected return on pension plan assets	3,111	96	–	157	3,364
Change in assumptions underlying the present value of the plan liabilities	(1,884)	(59)	236	(470)	(2,177)
Experience gains and losses arising on the plan liabilities	(14)	(197)	(17)	16	(212)
Actuarial gain (loss) recognized in statement of recognized income and expense	1,213	(160)	219	(297)	975

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

$ million

History of surplus (deficit) and of experience gains and losses	**2007**	2006	2005	2004	2003
Benefit obligation at 31 December	**43,100**	42,433	38,855	39,945	35,995
Fair value of plan assets at 31 December	**42,799**	39,910	32,907	31,712	27,853
Surplus (deficit)	**(301)**	(2,523)	(5,948)	(8,233)	(8,142)
Experience gains and losses on plan liabilities	**(200)**	(124)	(212)	(468)	873
Actual return less expected return on pension plan assets	**302**	1,967	3,364	1,349	2,392
Actual return on plan assets	**3,157**	4,377	5,502	3,332	3,892
Actuarial gain recognized in statement of recognized income and expense	**1,717**	2,615	975	107	76
Cumulative amount recognized in statement of recognized income and expense	**5,490**	3,773	1,158	183	76

Estimated future benefit payments

The expected benefit payments, which reflect expected future service, as appropriate, but exclude fund expenses, up until 2017 are as follows:

$ million

	UK pension plans	**US pension plans**	**US other post-retirement benefit plans**	**Other plans**	**Total**
2008	**1,112**	**629**	**224**	**534**	**2,499**
2009	**1,183**	**656**	**227**	**533**	**2,599**
2010	**1,252**	**670**	**235**	**529**	**2,686**
2011	**1,334**	**681**	**240**	**521**	**2,776**
2012	**1,378**	**716**	**242**	**516**	**2,852**
2013-2017	**7,650**	**3,301**	**1,243**	**2,551**	**14,745**

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39 Called up share capital

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

	2007		2006		2005	
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	**21,457,301**	**5,364**	20,657,045	5,164	21,525,978	5,382
Issue of new shares for employee share schemes	**69,273**	**18**	64,854	16	82,144	20
Issue of ordinary share capital for TNK-BP	**–**	**–**	111,151	28	108,629	27
Repurchase of ordinary share capital	**(663,150)**	**(166)**	(358,374)	(90)	(1,059,706)	(265)
Other[a]	**–**	**–**	982,625	246	–	–
At 31 December	**20,863,424**	**5,216**	21,457,301	5,364	20,657,045	5,164
		5,237		5,385		5,185
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 663,149,528 ordinary shares (2006 1,334,362,750 and 2005 1,059,706,481 ordinary shares) for a total consideration of $7,497 million (2006 $15,481 million and 2005 $11,597 million), of which all were for cancellation. At 31 December 2007 150,966,096 (2006 99,045,000 and 2005 nil) ordinary shares bought back were awaiting cancellation. These shares have been excluded from ordinary shares in issue shown above. At 31 December 2007, 1,940,638,808 shares of nominal value $485 million were held in treasury (2006 1,946,804,533 shares of nominal value $487 million). The maximum number of shares held in treasury during the year was 1,946,804,533 shares of nominal value $487 million, representing 9.1% of the called up ordinary share capital of the company. During 2007, 1,700,000 treasury shares were gifted to the ESOP trust and 4,465,725 treasury shares were re-issued in relation to employee share schemes, in total representing less than 0.1% of the ordinary share capital of the company. The nominal value of these shares was $2 million and the total proceeds received were $35 million.

Transaction costs of share repurchases amounted to $40 million (2006 $83 million and 2005 $63 million).

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40 Capital and reserves

	Share capital	Share premium account	Capital redemption reserve	Merger reserve
At 1 January 2007	**5,385**	**9,074**	**839**	**27,201**
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)	–	–	–	–
Repurchase of ordinary share capital	**(166)**	–	**166**	–
Share-based payments (net of tax)	**18**	**507**	–	**5**
Cash flow hedges marked to market (net of tax)	–	–	–	–
Cash flow hedges recycling (net of tax)	–	–	–	–
Profit for the year	–	–	–	–
Dividends	–	–	–	–
At 31 December 2007	**5,237**	**9,581**	**1,005**	**27,206**

	Share capital	Share premium account	Capital redemption reserve	Merger reserve
At 1 January 2006	5,185	7,371	749	27,190
Currency translation differences (net of tax)	–	–	–	–
Actuarial gain relating to pension and other post-retirement benefits (net of tax)	–	–	–	–
Issue of ordinary share capital for TNK-BP	28	1,222	–	–
Available-for-sale investments marked to market (net of tax)	–	–	–	–
Available-for-sale investments recycling (net of tax)	–	–	–	–
Repurchase of ordinary share capital	(90)	–	90	–
Share-based payments (net of tax)	16	481	–	11
Cash flow hedges marked to market (net of tax)	–	–	–	–
Cash flow hedges recycling (net of tax)	–	–	–	–
Profit for the year	–	–	–	–
Dividends	–	–	–	–
Other[b]	246	–	–	–
At 31 December 2006	5,385	9,074	839	27,201

	Share capital	Share premium account	Capital redemption reserve	Merger reserve
At 31 December 2004	5,403	5,636	730	27,162
Adoption of IAS 39	–	–	–	–
At 1 January 2005	5,403	5,636	730	27,162
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)	–	–	–	–
Issue of ordinary share capital for TNK-BP	27	1,223	–	–
Available-for-sale investments marked to market (net of tax)	–	–	–	–
Available-for-sale investments recycling (net of tax)	–	–	–	–
Repurchase of ordinary share capital	(265)	–	19	–
Share-based payments (net of tax)	20	512	–	28
Cash flow hedges marked to market (net of tax)	–	–	–	–
Cash flow hedges recycling (net of tax)	–	–	–	–
Profit for the year	–	–	–	–
Dividends	–	–	–	–
At 31 December 2005	5,185	7,371	749	27,190

[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 4.
[b] Reclassification in respect of share repurchases in 2005.

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$ million

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
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)
–	–	–	–	–	–	–	(7,997)	(7,997)	–	(7,997)
(5)	94	70	–	–	–	337	(9)	1,017	–	1,017
–	–	–	–	–	138	–	–	138	–	138
–	–	–	–	–	(71)	–	–	(71)	–	(71)
–	–	–	–	–	–	–	20,845	20,845	324	21,169
–	–	–	–	–	–	–	(8,106)	(8,106)	(227)	(8,333)
–	(60)	(22,112)	6,540	481	106	1,196	64,510	93,690	962	94,652

$ million

Other reserve	Own shares	Treasury shares	Foreign currency translation reservea	Available-for-sale investments	Cash flow hedges	Share-based payment reserve	Profit and loss account	BP shareholders' equity	Minority interest	Total equity
16	(140)	(10,598)	2,943	385	(234)	643	46,151	79,661	789	80,450
–	(19)	–	1,742	27	6	–	–	1,756	49	1,805
–	–	–	–	–	–	–	1,795	1,795	–	1,795
–	–	–	–	–	–	–	–	1,250	–	1,250
–	–	–	–	478	–	–	–	478	–	478
–	–	–	–	(504)	–	–	–	(504)	–	(504)
–	–	(11,472)	–	–	–	–	(4,009)	(15,481)	–	(15,481)
(11)	5	134	–	–	–	216	(79)	773	–	773
–	–	–	–	–	313	–	–	313	–	313
–	–	–	–	–	(46)	–	–	(46)	–	(46)
–	–	–	–	–	–	–	22,315	22,315	286	22,601
–	–	–	–	–	–	–	(7,686)	(7,686)	(283)	(7,969)
–	–	(246)	–	–	–	–	–	–	–	–
5	(154)	(22,182)	4,685	386	39	859	58,487	84,624	841	85,465

$ million

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
44	(82)	–	5,616	–	–	443	31,940	76,892	1,343	78,235
–	–	–	–	230	(118)	–	(355)	(243)	–	(243)
44	(82)	–	5,616	230	(118)	443	31,585	76,649	1,343	77,992
–	12	–	(2,453)	(35)	(3)	–	–	(2,479)	(18)	(2,497)
–	–	–	(220)	–	–	–	–	(220)	–	(220)
–	–	–	–	–	–	–	619	619	–	619
–	–	–	–	–	–	–	–	1,250	–	1,250
–	–	–	–	232	–	–	–	232	–	232
–	–	–	–	(42)	–	–	–	(42)	–	(42)
–	–	(10,601)	–	–	–	–	(750)	(11,597)	–	(11,597)
(28)	(70)	3	–	–	–	200	30	695	–	695
–	–	–	–	–	(149)	–	–	(149)	–	(149)
–	–	–	–	–	36	–	–	36	–	36
–	–	–	–	–	–	–	22,026	22,026	291	22,317
–	–	–	–	–	–	–	(7,359)	(7,359)	(827)	(8,186)
16	(140)	(10,598)	2,943	385	(234)	643	46,151	79,661	789	80,450

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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 to be 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 arrangements.

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 translations 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 on available-for-sale investments. On disposal, 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 arrangements 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

$ million

Effect of share-based payment transactions on the group's result and financial position	**2007**	2006	2005
Total expense recognized for equity-settled share-based payment transactions	**412**	405	348
Total expense recognized for cash-settled share-based payment transactions	**16**	14	20
Total expense recognized for share-based payment transactions	**428**	419	368
Closing balance of liability for cash-settled share-based payment transactions	**40**	38	48
Total intrinsic value for vested cash-settled share-based payments	**22**	23	41

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

Plans for executive directors
Executive Directors' Incentive Plan (EDIP) – share element (2005 onwards)
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. In addition, for the group chief executive, 27% of the grant is based on long-term leadership (LTL) measures. After the performance period, the shares that vest (net of tax) are then subject to a three-year retention period. The director's remuneration report on pages 62-72 includes full details of this plan.

41 Share-based payments *continued*

Executive Directors' Incentive Plan (EDIP) – share element (pre-2005)

An equity-settled incentive share plan for executive directors driven by three performance measures over a three-year performance period. The primary measure is BP's shareholder return against the market (SHRAM) versus that of the companies within the FTSE All World Oil & Gas Index. This accounts for nearly two-thirds of the potential total award, with the remainder being assessed on BP's relative return on average capital employed (ROACE) and earnings per share (EPS) growth compared with the other oil majors. After the performance period, the shares that vest (net of tax) are then subject to a three-year retention period. The director's remuneration report on pages 62-72 includes full details of this plan. For 2005 and subsequent years, the share element of EDIP was amended as described above.

Executive Directors' Incentive Plan (EDIP) – share option element (pre-2005)

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) (2005 onwards)

An equity-settled incentive share plan for senior employees driven by two performance measures over a three-year performance period. The award of 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 shares awarded is increased to take account of the net dividends that would have been received during the performance period, assuming that such dividends had been reinvested. With regard to leaver provisions, the general rule is that leaving employment during the performance period will preclude an award of 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.

Long Term Performance Plan (LTPP) (pre-2005)

An equity-settled incentive share plan for senior employees driven by three performance measures over a three-year performance period. The primary measure is BP's SHRAM versus that of the companies within the FTSE All World Oil & Gas Index. This accounts for nearly two-thirds of the potential total award, with the remainder being assessed on BP's relative ROACE and EPS growth compared with the other oil majors. Shares are awarded at the end of the performance period and are then subject to a three-year retention period. With regard to leaver provisions, the general rule is that leaving during the performance period will preclude an award of 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. This plan was replaced by the MTPP for 2005 onwards.

Deferred Annual Bonus Plan (DAB)

An equity-settled restricted share plan for senior employees. The award value is equal to 50% of the annual cash bonus awarded for the preceding performance year (the 'performance period'). The shares are restricted for a period of three years (the 'restriction period'). Shares accrue dividends during the restriction period and these are reinvested. 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 an award of shares. However, special arrangements apply where the participant leaves for a qualifying reason. Similarly, if a participant ceases to be employed by BP prior to the end of the restriction period, the general rule is that the restricted shares will be forfeited. Special arrangements apply where the participant leaves for a qualifying reason.

Performance Share Plan (PSP)

An equity-settled restricted share plan for senior professionals and team leaders. The award takes into account the recipient's performance in the prior calendar year (the 'performance period'). Shares, provided initially as share units, are restricted for a period of three years (the 'restriction period'). Share units accrue notional dividends during the restriction period and these are 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 award, share units are converted into shares. With regard to leaver provisions, the general rule is that leaving during the performance period will preclude an award of share units. If a participant ceases to be employed by BP prior to the end of the restriction period, the general rule is that share units will lapse. Special arrangements apply where the participant leaves for a qualifying reason.

Restricted Share Plan (RSP)

An equity-settled restricted share plan used predominantly for senior employees in special circumstances (such as recruitment and retention). There are no performance conditions but the shares are subject to a three-year restriction period. During the restriction period, shares accrue dividends, which are reinvested. With regard to leaver provisions, the general rule is that ceasing employment during the restriction period will result in the forfeit of shares. However, special arrangements apply where the participant leaves for a qualifying reason.

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 10th 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.

41 Share-based payments *continued*

Savings and matching plans

BP ShareSave Plan

This is a savings-related share option plan, under which employees save on a monthly basis, over a three- or five-year period, towards the purchase of shares at a fixed price determined when the option is granted. This price is usually set at a 20% discount to the market price at the time of grant. The option must be exercised within six months of maturity of the savings contract; otherwise it lapses. The plan is run in the UK and options are granted annually, usually in June. Participants leaving for a qualifying reason 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 EDIP, MTPP, LTPP, DAB and the BP ShareMatch Plans. 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 2007, the ESOPs held 6,448,838 shares (2006 12,795,887 shares and 2005 14,560,003 shares) for potential future awards, which had a market value of $79 million (2006 $142 million and 2005 $156 million).

Share option transactions		**2007**		2006		2005
	Number of options	**Weighted average exercise price $**	Number of options	Weighted average exercise price $	Number of options	Weighted average exercise price $
Outstanding at beginning of the year	**426,471,462**	**8.25**	450,453,502	7.64	470,263,808	7.16
Granted during the year	**6,004,025**	**9.11**	53,977,639	11.18	54,482,053	10.24
Forfeited during the year	**(3,924,714)**	**9.10**	(7,169,710)	8.69	(4,844,827)	8.30
Exercised during the year	**(69,715,558)**	**6.94**	(70,658,480)	6.52	(68,687,976)	6.40
Expired during the year	**(740,972)**	**8.68**	(131,489)	7.99	(759,556)	6.75
Outstanding at the end of the year	**358,094,243**	**8.51**	426,471,462	8.25	450,453,502	7.64
Exercisable at the end of the year	**238,707,055**	**7.70**	236,726,966	7.41	222,729,398	7.54

As share options are exercised continuously throughout the year, the weighted average share price during the year of $11.72 (2006 $11.85 and 2005 $10.77) is representative of the weighted average share price at the date of exercise. For the options outstanding at 31 December 2007, 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 $**
$5.10 – $6.79	**66,360,194**	**3.88**	**6.15**	**55,509,664**	**6.23**
$6.80 – $8.50	**162,364,928**	**4.00**	**8.02**	**156,236,204**	**8.04**
$8.51 – $10.21	**55,021,656**	**4.89**	**9.28**	**26,961,187**	**8.78**
$10.22 – $11.92	**74,347,465**	**7.80**	**11.13**	**–**	**–**
	358,094,243	**4.90**	**8.51**	**238,707,055**	**7.70**

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41 Share-based payments *continued*

Fair values and associated details for options and shares granted

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

Options granted in 2005	BPSOP	ShareSave 3 year	ShareSave 5 year
Option pricing model used	Binomial	Binomial	Binomial
Weighted average fair value	$2.34	$2.76	$2.94
Weighted average share price	$10.85	$10.49	$10.49
Weighted average exercise price	$10.63	$7.96	$7.96
Expected volatility	18%	18%	18%
Option life	10 years	3.5 years	5.5 years
Expected dividends	2.72%	3.00%	3.00%
Risk free interest rate	4.25%	4.00%	4.25%
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 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

Shares granted in 2005	MTPP-TSR	MTPP-FCF	EDIP-TSR	EDIP-LTL	RSP
Number of equity instruments granted (million)	9.3	8.4	3.7	0.5	0.3
Weighted average fair value	$5.72	$11.04	$3.87	$10.13	$11.04
Fair value measurement basis	Monte Carlo	Market value	Monte Carlo	Market value	Market value

The group used a Monte Carlo simulation to fair value the TSR element of the 2007, 2006 and 2005 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.

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42 Employee costs and numbers

$ million

Employee costs	2007	2006	2005
Wages and salaries[a]	**9,560**	8,411	8,695
Social security costs	**771**	751	754
Share-based payments	**428**	419	368
Pension and other post-retirement benefit costs	**504**	770	929
	11,263	10,351	10,746
Innovene operations	**–**	–	(892)
Continuing operations	**11,263**	10,351	9,854

Number of employees at 31 December	2007	2006	2005
Exploration and Production	**19,800**	19,000	17,000
Refining and Marketing[b]	**69,000**	69,500	70,800
Gas, Power and Renewables	**4,500**	4,500	4,100
Other businesses and corporate	**4,300**	4,000	4,300
	97,600	97,000	96,200
By geographical area			
UK	**17,000**	16,900	16,500
Rest of Europe	**19,900**	20,200	21,300
US	**33,000**	33,700	34,400
Rest of World	**27,700**	26,200	24,000
	97,600	97,000	96,200

	2007					2006				
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**	**6,600**	**8,700**	**19,700**	3,300	700	6,100	8,100	18,200
Refining and Marketing	**10,600**	**18,600**	**23,500**	**16,300**	**69,000**	11,300	19,300	24,900	15,000	70,500
Gas, Power and Renewables	**300**	**700**	**1,800**	**1,500**	**4,300**	300	700	1,600	1,700	4,300
Other businesses and corporate	**2,100**	**200**	**1,700**	**200**	**4,200**	1,900	200	1,900	100	4,100
	16,700	**20,200**	**33,600**	**26,700**	**97,200**	16,800	20,900	34,500	24,900	97,100

	2005				
Average number of employees	UK	Rest of Europe	US	Rest of World	Total
Exploration and Production	3,000	600	5,300	7,300	16,200
Refining and Marketing	11,100	19,700	26,200	14,000	71,000
Gas, Power and Renewables	200	800	1,500	1,400	3,900
Other businesses and corporate	3,800	3,900	3,600	300	11,600
	18,100	25,000	36,600	23,000	102,700

[a] Includes termination payments of $422 million (2006 $257 million and 2005 $348 million). A restructuring was announced in October 2007, the implementation of which is expected to continue through 2008 and into 2009. Additional restructuring charges to the income statement of around $1 billion are expected in 2008.
[b] Includes 25,900 (2006 26,100 and 2005 27,800) service station staff.

43 Remuneration of directors and senior management

Remuneration of directors

$ million

	2007	2006	2005
Total for all directors			
Emoluments	**26**	14	18
Gains made on the exercise of share options	**2**	12	–
Amounts awarded under incentive schemes	**10**	14	8

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 $3 million (2006 and 2005 nil) and compensation for loss of office of $1 million (2006 and 2005 nil).

Pension contributions
Six 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 2007.

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43 Remuneration of directors and senior management *continued*

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 62-72.

Remuneration of senior management

$ million

	2007	2006	2005
Total for all senior management			
Short-term employee benefits	**37**	30	25
Post-retirement benefits	**7**	4	4
Share-based payments	**22**	26	27

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 $3 million (2006 and 2005 nil) and compensation for loss of office of $1 million (2006 $5 million, 2005 nil).

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 2007 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 47% interest (reduced during 2001 from 50% by a sale of 3% 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 & Refining, which, along with a predecessor company, 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 on the group's results of operations, financial position or liquidity.

44 Contingent liabilities *continued*

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 2007 amounted to $8,263 million (2006 $9,773 million). In addition, at 31 December 2007, the group had contracts in place for future capital expenditure relating to investments in jointly controlled entities of $1,039 million (2006 $32 million) and investments in associates of $74 million (2006 $36 million).

Capital commitments of jointly controlled entities amounted to $2,273 million (2006 $1,217 million).

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46 Subsidiaries, jointly controlled entities and associates

The more important subsidiaries, jointly controlled entities and associates of the group at 31 December 2007 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 Chemicals Investments	100	England	Petrochemicals
*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			
			Refining and

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 Chemicals	100	England	Petrochemicals
BP Oil UK	100	England	Refining and 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			
BP America Production Company			
BP Amoco Chemical Company			
BP Company North America			
BP Corporation North America	100	US	Exploration and production, gas, power and renewables, refining and marketing, pipelines and petrochemicals
BP Exploration (Alaska) Inc.			

Deutsche BP	100	Germany	marketing and petrochemicals	BP Products North America	
				BP West Coast Products	
Indonesia					
BP Berau	100	US	Exploration and production	Standard Oil Co.	
BP West Java	100	US	Exploration and production	BP Capital Markets America	Finance

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46 Subsidiaries, jointly controlled entities and associates *continued*

Jointly controlled entities	%	Country of incorporation or registration	Principal activities
Atlantic 4 Holdings	38	US	LNG manufacture
Atlantic LNG 2/3 Company of Trinidad and Tobago	43	Trinidad & Tobago	LNG manufacture
Elvary Neftegaz Holdings BV	49	Netherlands	Exploration and appraisal
LukArco	46	Netherlands	Exploration and production, pipelines
Pan American Energy[a]	60	US	Exploration and production
Ruhr Oel	50	Germany	Refining and marketing and petrochemicals
Shanghai SECCO Petrochemical Co.	50	China	Petrochemicals
TNK-BP	50	British Virgin Islands	Integrated oil operations

[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

									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)	(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[c,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.

[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. 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' acitivies 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] The Exploration and Production profit before interest and tax is set out below.

$ million

									2007
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**
Mid-stream activities	**123**	**(7)**	**472**	**42**	**6**	**(10)**	**(112)**	**116**	**630**
Total profit before interest and tax	**3,693**	**1,383**	**7,758**	**3,356**	**1,305**	**3,116**	**1,893**	**4,434**	**26,938**

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

$ million

									2006
	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
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,e]	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.

[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. 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 accretion expense attributable to exploration and production activities amounting to $153 million. Under IFRS, accretion expense is included in other

finance expense in the group income statement.

[e] The Exploration and Production profit before interest and tax is set out below.

$ million

									2006
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
Mid-stream activities	250	(14)	(31)	85	(31)	(11)	(24)	18	242
Total profit before interest and tax	5,838	1,210	9,327	3,775	1,509	2,933	2,657	2,380	29,629

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

$ million

									2005
	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Capitalized costs at 31 December									
Gross capitalized costs									
Proved properties	31,552	4,608	46,288	9,585	2,922	12,183	–	5,184	112,322
Unproved properties	276	135	1,547	583	1,124	656	185	155	4,661
	31,828	4,743	47,835	10,168	4,046	12,839	185	5,339	116,983
Accumulated depreciation	22,302	2,949	22,016	4,919	1,508	6,112	–	1,200	61,006
Net capitalized costs	9,526	1,794	25,819	5,249	2,538	6,727	185	4,139	55,977

The group's share of jointly controlled entities' and associates' net capitalized costs at 31 December 2005 was $10,670 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	–	–	29	34	–	–	–	–	63
	–	–	29	34	–	–	–	–	63
Exploration and appraisal costs[b]	51	7	606	133	11	264	126	68	1,266
Development costs	790	188	2,965	681	186	1,691	–	1,177	7,678
Total costs	841	195	3,600	848	197	1,955	126	1,245	9,007

The group's share of jointly controlled entities' and associates' costs incurred in 2005 was $1,205 million: in Russia $845 million and Rest of Americas $360 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	4,667	635	2,048	2,260	1,045	1,350	–	690	12,695
Sales between businesses	2,458	976	14,842	2,863	782	2,402	–	4,796	29,119
	7,125	1,611	16,890	5,123	1,827	3,752	–	5,486	41,814
Exploration expenditure	32	1	426	84	6	81	37	17	684
Production costs	1,082	118	1,814	578	159	460	–	180	4,391
Production taxes	485	33	610	281	54	–	–	1,536	2,999
Other costs (income)[c]	1,857	(55)	2,200	537	170	98	8	2,042	6,857
Depreciation, depletion and amortization	1,548	220	2,288	675	162	542	–	193	5,628
Impairments and (gains) losses on sale of businesses and fixed assets	44	(1,038)	232	(133)	–	–	2	–	(893)
	5,048	(721)	7,570	2,022	551	1,181	47	3,968	19,666
Profit before taxation[d,e]	2,077	2,332	9,320	3,101	1,276	2,571	(47)	1,518	22,148
Allocable taxes	405	880	3,377	1,390	447	1,043	(1)	409	7,950
Results of operations	1,672	1,452	5,943	1,711	829	1,528	(46)	1,109	14,198

The group's share of jointly controlled entities' and associates' results of operations (including the group's share of total TNK-BP results) in 2005 was a profit of $3,029 million after deducting interest of $226 million, taxation of $1,250 million and minority interest of $104 million.

[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. 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, the fair value loss on embedded derivatives $1,688 million and a $265 million charge incurred on the cancellation of an intragroup gas supply contract. The UK region includes a $530 million charge offset by corresponding gains primarily in the US, relating to the group's self-insurance programme.
[d] Excludes accretion expense attributable to exploration and production activities amounting to $122 million. Under IFRS, accretion expense is included in other

finance expense in the group income statement.

[e] The Exploration and Production profit before interest and tax is set out below.

$ million

									2005
Exploration and production activities									
Group (as above)	2,077	2,332	9,320	3,101	1,276	2,571	(47)	1,518	22,148
Jointly controlled entities and associates	–	–	–	309	35	–	2,685	–	3,029
Mid-stream activities	52	(11)	172	148	(20)	(39)	(1)	24	325
Total profit before interest and tax	2,129	2,321	9,492	3,558	1,291	2,532	2,637	1,542	25,502

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Additional information for US reporting

BP has taken advantage of the SEC ruling of 15 November 2007 that eliminated the requirement to provide a reconciliation from IFRS to US GAAP.

48 Suspended exploration well costs

Included within the total exploration expenditure of $5,252 million (2006 $4,110 million and 2005 $4,008 million) shown as part of intangible assets (see Note 25) is an amount of $2,342 million (2006 $1,863 million and 2005 $1,931 million) representing costs directly associated with exploration wells.

The carried costs of exploration wells are subject to technical, commercial and management review at least once per year to confirm the continued intent to develop or otherwise extract value from the discovery. In evaluating whether costs incurred meet the criteria for initial and continued capitalization, management uses two main criteria: (i) that exploration drilling is still under way or firmly planned, or (ii) that it has been determined, or work is under way to determine, that the discovery is economically viable based on a range of technical and commercial considerations and sufficient progress is being made on establishing development plans and timing.

The following table provides the year-end balances and movements for suspended exploration well costs.

			$ million
	2007	2006	2005
Capitalized exploration well costs			
At 1 January	**1,863**	1,931	1,680
Additions pending determination of proved reserves	**773**	590	565
Exploration well costs written off in the year	**(94)**	(168)	(81)
Costs of exploration wells divested in the year	**(27)**	(36)	(72)
Reclassified to tangible assets following determination of proved reserves	**(173)**	(251)	(161)
Reclassified to investment in jointly controlled entity	**–**	(203)	–
At 31 December	**2,342**	1,863	1,931

The following table provides an ageing profile of suspended exploration wells.

At 31 December		**2007**		2006		2005
	Cost $ million	**Wells gross**	Cost $ million	Wells gross	Cost $ million	Wells gross
Age						
Less than 1 year	**761**	**35**	611	45	593	46
1 to 5 years	**1,081**	**73**	736	64	823	69
6 to 10 years	**224**	**30**	267	37	309	42
More than 10 years	**276**	**35**	249	26	206	20
Total	**2,342**	**173**	1,863	172	1,931	177

The following table provides an analysis of the amount of drilling costs directly associated with exploration wells.

			2007			2006			2005
	Cost $ million	**Wells gross**	**Projects**	Cost $ million	Wells gross	Projects	Cost $ million	Wells gross	Projects
Exploration well costs									
Projects with first capitalized exploration well drilled in the 12 months ending 31 December	**168**	**11**	**7**	188	17	12	451	31	14
Other projects with recent or planned drilling activity	**1,502**	**92**	**24**	894	86	21	718	65	20
Projects with completed exploration activity	**672**	**70**	**27**	781	69	27	762	81	28
At 31 December	**2,342**	**173**	**58**	1,863	172	60	1,931	177	62

Exploration projects frequently involve the drilling of multiple wells over a number of years and several discoveries may be grouped into a single development project. The table above shows a total of 51 projects that have exploration well costs that have been capitalized for more than twelve months as at 31 December 2007. Of these, there are 24 projects where exploratory wells have been drilled in the preceding 12 months or further exploratory drilling is planned in the next year. Projects with completed exploration activity comprise a total of 27 projects, whose costs totalled $672 million at 31 December 2007. Details of the activities being undertaken to progress these projects towards development are shown below.

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48 Suspended exploration well costs *continued*

Country	Project	Cost $ million	2007 wells gross	Years wells drilled	Anticipated year of development project sanction	Comment
Angola	Chumbo	26	2	2003-2005	2011-2014	Assessment of hydrocarbon quantities as potentially commercial completed; development option identified and under evaluation; development plan for FPSO submitted.
	Plutao/Saturno/Marte/Venus	51	5	2002-2005	2008	Assessment of hydrocarbon quantities as potentially commercial completed; development option using FPSO identified and under evaluation.
	Cravo/Lirio/Orquidea/Violeta	32	7	1998-2006	2009	Assessment of hydrocarbon quantities as potentially commercial completed; development option using FPSO identified and under evaluation.
		109	14			
Egypt	Ras El Bar Seth	3	1	1995	2008	Assessment of hydrocarbon quantities as potentially commercial completed; development options identified and under evaluation; development planned through tie-back to existing infrastructure; gas sale agreement in place.
	Western Mediterranean Block B	13	3	2002-2004	2008-2010	Assessment of hydrocarbon quantities as potentially commercial completed; development options identified and under evaluation; seismic survey completed and under review; concession agreement amendment negotiations under way.
	East Delta Deep Marine	11	2	2002-2006	2011	Assessment of hydrocarbon quantities as potentially commercial completed; development options identified and under evaluation involving tie-back to existing infrastructure.
		27	6			
Indonesia	Tangguh Phase II	51	9	1994-1997	2009-2011	Assessment of hydrocarbon quantities as potentially commercial completed; assessment of economic aspects of project in progress; onshore and offshore development options identified and under evaluation. This is the second phase of the LNG project that is currently under development.
		51	9			
Trinidad	Coconut	47	1	2005	2014	Assessment of hydrocarbon quantities as potentially commercial completed; assessment of economic aspects of project in progress; development options identified and under evaluation; planned subsea tie-back to existing infrastructure.
	Corallita/Lantana	24	2	1996	2008	Assessment of hydrocarbon quantities as potentially commercial completed; development options identified and under evaluation; planned subsea tie-back to existing infrastructure fields dedicated to LNG gas contract delivery; dependent upon capacity in existing infrastructure.
	Manakin	22	1	2000	2011	Assessment of hydrocarbon quantities as potentially commercial completed; assessment of economic aspects of project in progress; development options identified and under evaluation;

			planned subsea tie-back to existing production facilities and LNG train; inter-governmental discussions on unitization continue.
	93	4	

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48 Suspended exploration well costs *continued*

Country	Project	Cost $ million	2007 wells gross	Years wells drilled	Anticipated year of development project sanction	Comment
UK	Andrew	14	1	1998	2008	Assessment of hydrocarbon quantities as potentially commercial completed; development options identified and under evaluation; development awaiting capacity in existing infrastructure; negotiations under way for gas sales contract.
	Devenick	90	3	1983-2001	2008-2009	Assessment of hydrocarbon quantities as potentially commercial completed; assessment of economic aspects of project in progress; development options identified and under evaluation; development may be in conjunction with Harding Gas project nearby.
	Puffin	29	9	1982-1991	2009-2010	Assessment of hydrocarbon quantities as potentially commercial completed; further assessment of economic and developmental aspects of project to be undertaken; sub-surface and feasibility review under way; development awaiting capacity in existing infrastructure.
	Kessog	35	4	1986-1987	2010	Assessment of hydrocarbon quantities as potentially commercial completed; further assessment of economic and developmental aspects of project in progress.
	Suilven	20	3	1995-1998	2010-2011	Assessment of hydrocarbon quantities as potentially commercial completed; assessment of economic and developmental aspects of project in progress; development anticipated to be by tie-back to existing production vessel; awaiting capacity in existing infrastructure.
		188	20			
US	Liberty	20	1	1997	2008	Assessment of hydrocarbon quantities as potentially commercial completed; development options identified and under evaluation; planned tie-back via extended reach drilling from existing infrastructure; memoranda of understanding with two key permitting agencies have been secured.
	Mad Dog Deep	48	1	2005	2009-2011	Assessment of hydrocarbon quantities as potentially commercial completed; assessment of economic and developmental aspects of project under way.
	Mad Dog Southwest Ridge	34	3	2005	2010	Assessment of hydrocarbon quantities as potentially commercial completed; assessment of economic aspects of project under way; development options identified and under evaluation; development expected to be by subsea tieback.
		102	5			
Vietnam	Hai Thach	65	3	1995-2002	2009	Assessment of hydrocarbon quantities as potentially commercial completed; assessment of economic aspects of project in place; development options identified and under evaluation; licence extension secured.
	Kim Cuong Tay	13	1	1995	2010-2012	Initial assessment of hydrocarbon quantities as potentially commercial completed; further assessment of developmental aspects of project to be undertaken; further seismic study planned for 2008.
		78	4			
Miscellaneous smaller projects		24	8			
		672	70			

Certain projects that were classified as projects with completed exploration drilling activity at 31 December 2006 are not classified as such at 31 December 2007:

- The following projects were sanctioned for development in 2007: Skarv in Norway and Chachalaca in Trinidad & Tobago.
- In Colombia, $43 million relating to the Volcanera project was written off.

– In the US, the Entrada field was disposed of.

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49 Auditors’ remuneration for US reporting

$ million

	2007	2006	2005
Audit fees – Ernst & Young			
Group audit	**37**	36	31
Audit-related regulatory reporting	**7**	9	6
Statutory audit of subsidiaries	**19**	19	23
	63	64	60
Innovene operations	**–**	–	(8)
Continuing operations	**63**	64	52
Fees for other services – Ernst & Young			
Further assurance services			
Acquisition and disposal due diligence	**1**	3	2
Pension plan audits	**1**	–	1
Other further assurance services	**8**	5	23
Tax services			
Compliance services	**–**	1	10
Advisory services	**2**	–	–
	12	9	36
Innovene operations	**–**	–	(1)
Continuing operations	**12**	9	35

Audit fees for 2007 include $7 million of additional fees for 2006 (2006 $5 million of additional fees for 2005 and 2005 $4 million of additional fees for 2004). Audit fees are included in the income statement within distribution and administration expenses.

Other further assurance services include $1 million (2006 $nil and 2005 $4 million) in respect of advice on accounting, auditing and financial reporting matters; $nil (2006 $nil and 2005 $16 million) in respect of internal accounting and risk management control reviews; $5 million (2006 $5 million and 2005 $3 million) in respect of non-statutory audits and $2 million (2006 $nil and 2005 $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.

50 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
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
2005					
Fixed assets – Investments[b]	168	18	(13)	(1)	172
Doubtful debts[b]	526	67	(30)	(189)	374

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

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51 Computation of ratio of earnings to fixed charges (unaudited)

$ million, except ratios

For the year ended 31 December	2007	2006	2005	2004	2003
Profit before taxation	**31,611**	35,142	31,421	24,966	17,731
Group's share of income in excess of dividends from equity-accounted entities	**(1,359)**	–	(710)	(81)	(666)
Capitalized interest, net of amortization	**(183)**	(341)	(193)	(133)	(123)
	30,069	34,801	30,518	24,752	16,942
Fixed charges					
Interest expense	**1,110**	718	559	440	482
Rental expense representative of interest	**1,033**	946	605	619	460
Capitalized interest	**323**	478	351	204	190
	2,466	2,142	1,515	1,263	1,132
Total adjusted earnings available for payment of fixed charges	**32,535**	36,943	32,033	26,015	18,074
Ratio of earnings to fixed charges	**13.2**	17.2	21.1	20.6	16.0

52 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., and 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 operating 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.

Income statement

$ million

For the year ended 31 December	Issuer	Guarantor			2007
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Sales and other operating revenues	**5,243**	**–**	**284,365**	**(5,243)**	**284,365**
Earnings from jointly controlled entities – after interest and tax	**–**	**–**	**3,135**	**–**	**3,135**
Earnings from associates – after interest and tax	**–**	**–**	**697**	**–**	**697**
Equity-accounted income of subsidiaries – after interest and tax	**586**	**21,201**	**–**	**(21,787)**	**–**
Interest and other revenues	**758**	**205**	**377**	**(586)**	**754**
Total revenues	**6,587**	**21,406**	**288,574**	**(27,616)**	**288,951**
Gains on sale of businesses and fixed assets	**1**	**–**	**2,486**	**–**	**2,487**
Total revenues and other income	**6,588**	**21,406**	**291,060**	**(27,616)**	**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**	**30,553**	**(22,265)**	**32,352**
Finance costs	**–**	**381**	**1,207**	**(478)**	**1,110**
Other finance expense (income)	**49**	**(820)**	**402**	**–**	**(369)**
Profit before taxation	**3,530**	**20,924**	**28,944**	**(21,787)**	**31,611**
Taxation	**1,081**	**79**	**9,282**	**–**	**10,442**
Profit for the year	**2,449**	**20,845**	**19,662**	**(21,787)**	**21,169**

Attributable to					
BP shareholders	**2,449**	**20,845**	**19,338**	**(21,787)**	**20,845**
Minority interest	**–**	**–**	**324**	**–**	**324**
	2,449	**20,845**	**19,662**	**(21,787)**	**21,169**

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52 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	627	187	881	(994)	701
Total revenues	6,009	23,306	270,782	(29,495)	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	274,496	(29,600)	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	33,751	(24,673)	35,658
Finance costs	–	702	895	(879)	718
Other finance expense (income)	11	(675)	462	–	(202)
Profit before taxation from continuing operations	3,436	23,106	32,394	(23,794)	35,142
Taxation	1,243	686	10,587	–	12,516
Profit from continuing operations	2,193	22,420	21,807	(23,794)	22,626
Profit (loss) from Innovene operations	–	–	(25)	–	(25)
Profit for the year	2,193	22,420	21,782	(23,794)	22,601
Attributable to					
BP shareholders	2,193	22,420	21,496	(23,794)	22,315
Minority interest	–	–	286	–	286
	2,193	22,420	21,782	(23,794)	22,601

Income statement

$ million

For the year ended 31 December					2005
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Sales and other operating revenues	5,052	–	239,792	(5,052)	239,792
Earnings from jointly controlled entities – after interest and tax	–	–	3,083	–	3,083
Earnings from associates – after interest and tax	–	–	460	–	460
Equity-accounted income of subsidiaries – after interest and tax	576	22,255	–	(22,831)	–
Interest and other revenues	454	556	749	(1,146)	613
Total revenues	6,082	22,811	244,084	(29,029)	243,948
Gains on sale of businesses and fixed assets	1	–	1,537	–	1,538
Total revenues and other income	6,083	22,811	245,621	(29,029)	245,486
Purchases	729	–	167,349	(5,052)	163,026
Production and manufacturing expenses	536	–	21,056	–	21,592

Production and similar taxes	352	–	2,658	–	3,010
Depreciation, depletion and amortization	445	–	8,326	–	8,771
Impairment and losses on sale of businesses and fixed assets	–	–	468	–	468
Exploration expense	1	–	683	–	684
Distribution and administration expenses	19	629	13,163	(105)	13,706
Fair value (gain) loss on embedded derivatives	–	–	2,047	–	2,047
Profit before interest and taxation from continuing operations	4,001	22,182	29,871	(23,872)	32,182
Finance costs	169	590	898	(1,041)	616
Other finance expense (income)	14	(443)	574	–	145
Profit before taxation from continuing operations	3,818	22,035	28,399	(22,831)	31,421
Taxation	1,138	9	8,141	–	9,288
Profit from continuing operations	2,680	22,026	20,258	(22,831)	22,133
Profit (loss) from Innovene operations	–	–	184	–	184
Profit for the year	2,680	22,026	20,442	(22,831)	22,317
Attributable to					
BP shareholders	2,680	22,026	20,151	(22,831)	22,026
Minority interest	–	–	291	–	291
	2,680	22,026	20,442	(22,831)	22,317

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52 Condensed consolidating information on certain US subsidiaries *continued*

Balance sheet

$ million

At 31 December	Issuer	Guarantor			2007
	BP Exploration (Alaska) Inc.	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 surplus	–	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	15,986	840	44,686	(23,492)	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	85,122	(23,492)	78,916
Assets classified as held for sale	–	–	1,286	–	1,286
	16,202	1,084	86,408	(23,492)	80,202
Total assets	28,129	125,019	228,898	(145,970)	236,076
Current liabilities					
Trade and other payables	5,233	3,115	58,296	(23,492)	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
	5,594	3,125	91,841	(23,492)	77,068
Liabilities directly associated with assets classified as held for sale	–	–	163	–	163
	5,594	3,125	92,004	(23,492)	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	8,864	5,081	154,856	(27,377)	141,424

Net assets	**19,265**	**119,938**	**74,042**	**(118,593)**	**94,652**
Equity					
BP shareholders’ equity	**19,265**	**119,938**	**73,080**	**(118,593)**	**93,690**
Minority interest	**–**	**–**	**962**	**–**	**962**
Total equity	**19,265**	**119,938**	**74,042**	**(118,593)**	**94,652**

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52 Condensed consolidating information on certain US subsidiaries *continued*

Balance sheet *(continued)*

$ million

At 31 December					2006
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Non-current assets					
Property, plant and equipment	5,838	–	85,161	–	90,999
Goodwill	–	–	10,780	–	10,780
Intangible assets	309	–	4,937	–	5,246
Investments in jointly controlled entities	–	–	15,074	–	15,074
Investments in associates	–	2	5,973	–	5,975
Other investments	–	–	1,697	–	1,697
Subsidiaries – equity-accounted basis	2,586	107,717	–	(110,303)	–
Fixed assets	8,733	107,719	123,622	(110,303)	129,771
Loans	1,735	1,196	1,052	(3,166)	817
Other receivables	–	–	862	–	862
Derivative financial instruments	–	–	3,025	–	3,025
Prepayments	–	–	1,034	–	1,034
Defined benefit pension plan surplus	–	5,662	1,091	–	6,753
	10,468	114,577	130,686	(113,469)	142,262
Current assets					
Loans	–	–	141	–	141
Inventories	154	–	18,761	–	18,915
Trade and other receivables	15,710	3,074	47,450	(27,542)	38,692
Derivative financial instruments	–	–	10,373	–	10,373
Prepayments	15	–	2,991	–	3,006
Current tax receivable	–	–	544	–	544
Cash and cash equivalents	(5)	(21)	2,616	–	2,590
	15,874	3,053	82,876	(27,542)	74,261
Assets classified as held for sale	–	–	1,078	–	1,078
	15,874	3,053	83,954	(27,542)	75,339
Total assets	26,342	117,630	214,640	(141,011)	217,601
Current liabilities					
Trade and other payables	4,908	5,185	59,685	(27,542)	42,236
Derivative financial instruments	–	–	9,424	–	9,424
Accruals	–	10	6,137	–	6,147
Finance debt	55	–	12,869	–	12,924
Current tax payable	1,705	–	930	–	2,635
Provisions	–	–	1,932	–	1,932
	6,668	5,195	90,977	(27,542)	75,298
Liabilities directly associated with assets classified as held for sale	–	–	54	–	54
	6,668	5,195	91,031	(27,542)	75,352
Non-current liabilities					
Other payables	249	27	4,320	(3,166)	1,430
Derivative financial instruments	–	–	4,203	–	4,203
Accruals	–	30	931	–	961
Finance debt	–	–	11,086	–	11,086
Deferred tax liabilities	1,780	1,506	14,830	–	18,116
Provisions	640	–	11,072	–	11,712
Defined benefit pension plan and other post-retirement benefit plan deficits	–	–	9,276	–	9,276
	2,669	1,563	55,718	(3,166)	56,784
Total liabilities	9,337	6,758	146,749	(30,708)	132,136

Net assets	17,005	110,872	67,891	(110,303)	85,465
Equity					
BP shareholders’ equity	17,005	110,872	67,050	(110,303)	84,624
Minority interest	–	–	841	–	841
Total equity	17,005	110,872	67,891	(110,303)	85,465

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52 Condensed consolidating information on certain US subsidiaries *continued*

Cash flow statement

$ million

2007

	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	**BP p.l.c.**	**Other subsidiaries**	**Eliminations and reclassifications**	**BP group**
Net cash provided by operating activities	**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	Guarantor			
	BP Exploration (Alaska) Inc.	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

$ million

2005

	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Net cash provided by operating activities of continuing operations	3,558	19,835	23,592	(21,234)	25,751
Net cash provided by (used in) operating activities of Innovene operations	–	–	970	–	970
Net cash provided by operating activities	3,558	19,835	24,562	(21,234)	26,721
Net cash used in investing activities	(346)	(2,410)	1,027	–	(1,729)
Net cash used in financing activities	(3,218)	(17,426)	(23,893)	21,234	(23,303)
Currency translation differences relating to cash and cash equivalents	–	–	(88)	–	(88)
(Decrease) increase in cash and cash equivalents	(6)	(1)	1,608	–	1,601
Cash and cash equivalents at beginning of year	(1)	4	1,356	–	1,359
Cash and cash equivalents at end of year	(7)	3	2,964	–	2,960

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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 14.

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

Supplementary information on oil and natural gas (unaudited) *continued*

Movements in estimated net proved reserves

2007

Natural gas[a] — billion cubic feet

	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
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 royally 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.

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Supplementary information on oil and natural gas (unaudited) *continued*

Movements in estimated net proved reserves

2006

Crude oil[a]

million barrels

	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
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 natural gas liquids (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 a 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.

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Supplementary information on oil and natural gas (unaudited) *continued*

Movements in estimated net proved reserves

2006

Natural gas[a]									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.

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Supplementary information on oil and natural gas (unaudited) *continued*

Movement in estimated net proved reserves

2005

Crude oil[a]

million barrels

	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Subsidiaries									
At 1 January 2005									
Developed	559	231	2,041	311	65	204	–	62	3,473
Undeveloped	210	109	1,211	299	85	643	–	725	3,282
	769	340	3,252	610	150	847	–	787	6,755
Changes attributable to									
Revisions of previous estimates	(31)	(8)	103	(21)	21	(190)	–	(148)	(274)
Purchases of reserves-in-place	–	–	2	–	–	–	–	–	2
Discoveries and extensions	11	–	40	3	11	83	–	–	148
Improved recovery	32	21	217	1	–	2	–	7	280
Production[b]	(101)	(27)	(200)	(53)	(17)	(64)	–	(34)	(496)
Sales of reserves-in-place	–	(15)	(1)	(39)	–	–	–	–	(55)
	(89)	(29)	161	(109)	15	(169)	–	(175)	(395)
At 31 December 2005[c]									
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[e]	501	165	678	–	612	6,360
Equity-accounted entities (BP share)									
At 1 January 2005									
Developed	–	–	–	204	1	–	1,863	592	2,660
Undeveloped	–	–	–	125	–	–	294	100	519
	–	–	–	329	1	–	2,157	692	3,179
Changes attributable to									
Revisions of previous estimates	–	–	–	1	–	–	319	119	439
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	2	–	–	–	–	2
Improved recovery	–	–	–	25	–	–	–	–	25
Production	–	–	–	(26)	–	–	(333)	(57)	(416)
Sales of reserves-in-place	–	–	–	–	–	–	(24)	–	(24)
	–	–	–	2	–	–	(38)	62	26
At 31 December 2005[d]									
Developed	–	–	–	207	1	–	1,688	590	2,486
Undeveloped	–	–	–	124	–	–	431	164	719
	–	–	–	331	1	–	2,119	754	3,205

[a] Crude oil includes natural gas liquids (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 58 thousand barrels a day.

[c] Includes 818 million barrels of NGLs. Also includes 29 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[d] Includes 33 million barrels of NGLs. Also includes 95 million barrels of crude oil in respect of the 4.47% minority interest in TNK-BP.
[e] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 85 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.

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Supplementary information on oil and natural gas (unaudited) *continued*

Movement in estimated net proved reserves

2005

Natural gas[a] billion cubic feet

	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Subsidiaries									
At 1 January 2005									
Developed	2,498	248	10,811	4,101	1,624	1,015	–	282	20,579
Undeveloped	1,183	1,254	3,270	10,663	5,419	1,886	–	1,396	25,071
	3,681	1,502	14,081	14,764	7,043	2,901	–	1,678	45,650
Changes attributable to									
Revisions of previous estimates	(102)	11	447	104	(133)	152	–	15	494
Purchases of reserves-in-place	–	–	66	2	–	–	–	–	68
Discoveries and extensions	21	19	47	225	204	44	–	–	560
Improved recovery	111	19	1,773	87	–	–	–	10	2,000
Production[b]	(425)	(44)	(1,018)	(888)	(280)	(163)	–	(80)	(2,898)
Sales of reserves-in-place	–	(1,182)	(14)	(230)	–	–	–	–	(1,426)
	(395)	(1,177)	1,301	(700)	(209)	33	–	(55)	(1,202)
At 31 December 2005[c]									
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
Equity-accounted entities (BP share)									
At 1 January 2005									
Developed	–	–	–	1,397	107	–	214	60	1,778
Undeveloped	–	–	–	977	69	–	10	23	1,079
	–	–	–	2,374	176	–	224	83	2,857
Changes attributable to									
Revisions of previous estimates	–	–	–	26	(81)	–	1,337	102	1,384
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	28	–	–	–	–	28
Improved recovery	–	–	–	66	–	–	–	–	66
Production[b]	–	–	–	(154)	(19)	–	(184)	(3)	(360)
Sales of reserves-in-place	–	–	–	–	–	–	(119)	–	(119)
	–	–	–	(34)	(100)	–	1,034	99	999
At 31 December 2005[d]									
Developed	–	–	–	1,492	50	–	1,089	130	2,761
Undeveloped	–	–	–	848	26	–	169	52	1,095
	–	–	–	2,340	76	–	1,258	182	3,856

[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 174 billion cubic feet of natural gas consumed in operations, 147 billion cubic feet in subsidiaries and 27 billion cubic feet in equity-accounted entities.
[c] Includes 3,812 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[d] Includes 57 billion cubic feet of natural gas in respect of the 4.47% minority interest in TNK-BP.

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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 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
At 31 December 2005								
Future cash inflows[a]	68,200	18,600	261,800	75,600	34,600	46,300	38,200	543,300
Future production cost[b]	21,700	3,900	55,800	15,200	6,900	7,800	7,400	118,700
Future development cost[b]	2,200	1,000	16,300	4,300	3,500	6,100	4,600	38,000
Future taxation[c]	17,600	10,200	65,300	28,800	7,300	10,600	6,000	145,800
Future net cash flows	26,700	3,500	124,400	27,300	16,900	21,800	20,200	240,800
10% annual discount[d]	8,500	1,400	63,700	12,600	9,600	8,700	8,100	112,600
Standardized measure of discounted future net cash flows[e]	18,200	2,100	60,700	14,700	7,300	13,100	12,100	128,200

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

$ million

	2007	2006	2005
Sales and transfers of oil and gas produced, net of production costs	**(28,300)**	(35,800)	(24,300)
Development costs incurred during the year	**9,400**	8,200	7,100
Extensions, discoveries and improved recovery, less related costs	**12,300**	7,900	10,100
Net changes in prices and production cost	**102,100**	(43,900)	84,200
Revisions of previous reserves estimates	**(12,200)**	(9,500)	(17,400)
Net change in taxation	**(28,300)**	32,200	(20,500)
Future development costs	**(7,800)**	(7,000)	(5,800)
Net change in purchase and sales of reserves-in-place	**(700)**	(2,500)	(2,500)
Addition of 10% annual discount	**9,100**	12,800	8,800
Total change in the standardized measure during the year[f]	**55,600**	(37,600)	39,700

[a] The year-end marker prices used were Brent $96.02/bbl, Henry Hub $7.10/mmBtu (2006 Brent $58.93/bbl, Henry Hub $5.52/mmBtu; 2005 Brent $58.21/bbl, Henry Hub $9.52/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 $2,300 million at 31 December 2007 ($1,300 million at 31 December 2006 and $2,700 million at 31 December 2005).
[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 2007, the group's share of the standardized measure of discounted future net cash flows of equity-accounted entities amounted to $28,300 million ($14,700 million at 31 December 2006 and $19,300 million at 31 December 2005).

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 2007, 2006 and 2005.

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
2007	**201**	**51**	**513**	**82**	**41**	**195**	**–**	**221**	**1,304**
2006	253	61	547	108	44	177	–	161	1,351
2005	277	75	612	144	47	175	–	93	1,423
Natural gas[c]									million cubic feet per day
2007	**768**	**29**	**2,174**	**2,798**	**699**	**468**	**–**	**286**	**7,222**
2006	936	91	2,376	2,645	727	430	–	207	7,412
2005	1,090	108	2,546	2,384	751	422	–	211	7,512
Equity-accounted entities (BP share)									
Crude oil[b]									thousand barrels per day
2007	**–**	**–**	**–**	**77**	**1**	**–**	**832**	**200**	**1,110**
2006	–	–	–	77	1	–	876	170	1,124
2005	–	–	–	71	–	–	911	157	1,139
Natural gas[c]									million cubic feet per day
2007	**–**	**–**	**–**	**429**	**33**	**–**	**451**	**8**	**921**
2006	–	–	–	416	37	–	544	8	1,005
2005	–	–	–	375	47	–	482	8	912

[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 of 31 December 2007. 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 2007										
Oil wells[a]	– gross	**274**	**81**	**5,885**	**3,524**	**352**	**646**	**19,393**	**1,536**	**31,691**
	– net	**147**	**26**	**2,093**	**1,925**	**152**	**538**	**8,252**	**255**	**13,388**
Gas wells[b]	– gross	**303**	**–**	**18,173**	**2,274**	**681**	**90**	**47**	**131**	**21,699**
	– net	**140**	**–**	**11,462**	**1,383**	**249**	**42**	**23**	**88**	**13,387**

[a] Includes approximately 1,016 gross (289 net) multiple completion wells (more than one formation producing into the same well bore).
[b] Includes approximately 2,489 gross (1,591 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.

	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Oil and natural gas acreage at 31 December 2007									Thousands of acres

Developed	– gross	**428**	**143**	**7,414**	**2,793**	**1,235**	**541**	**4,071**	**1,870**	**18,495**
	– net	**201**	**34**	**4,742**	**1,310**	**319**	**225**	**1,768**	**690**	**9,289**
Undeveloped[a]	– gross	**1,696**	**505**	**6,451**	**11,529**	**7,450**	**15,759**	**13,821**	**14,412**	**71,623**
	– net	**967**	**227**	**4,574**	**5,912**	**2,782**	**9,755**	**5,777**	**5,969**	**35,963**

[a] Undeveloped acreage includes leases and concessions.

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Supplementary information on oil and natural gas (unaudited) *continued*

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
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
2005									
Exploratory									
Productive	0.5	0.8	10.7	2.0	0.3	2.0	14.5	–	30.8
Dry	0.3	–	6.4	1.0	0.3	1.3	5.2	–	14.5
Development									
Productive	10.6	3.5	473.9	151.7	22.7	17.9	212.8	12.1	905.2
Dry	–	0.3	5.0	3.3	0.4	1.0	17.7	0.3	28.0

Drilling and production activities in progress

The following table shows the number of exploratory and development oil and natural gas wells in the process of being drilled by the group and its equity-accounted entities as of 31 December 2007. 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 2007									
Exploratory									
Gross	**–**	**1**	**26**	**5**	**1**	**3**	**28**	**2**	**66**
Net	**–**	**0.5**	**12.1**	**1.9**	**0.2**	**1.3**	**13.5**	**0.5**	**30.0**
Development									
Gross	**6**	**2**	**258**	**39**	**12**	**25**	**30**	**9**	**381**
Net	**2.5**	**0.5**	**130.5**	**23.1**	**5.0**	**8.9**	**12.5**	**2.7**	**185.7**

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 2008