BP PLC
Form 20-F
June 28, 2004
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 20-F

(Mark One)

[ ] REGISTRATION STATEMENT PURSUANT TO SECTION 12(b) or (g)

OF THE SECURITIES EXCHANGE ACT OF 1934
OR

[ü] **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)**

OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2003
OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)

OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to
Commission file number 1-6262

BP p.l.c.

(Exact name of Registrant as specified in its charter)

ENGLAND and WALES

(Jurisdiction of incorporation or organization)

1 St James s Square

London

SW1Y 4PD

England

(Address of principal executive offices)

Securities registered or to be registered pursuant to Section 12(b) of the Act.

Title of each class	Name of each exchange on which registered
Ordinary Shares of 25c each	**Chicago Stock Exchange***

New York Stock Exchange*

Pacific Exchange, Inc.*

*Not for trading, but only in connection with the registration of American Depositary Shares, pursuant to the requirements of the Securities and Exchange Commission

Securities registered or to be registered pursuant to Section 12(g) of the Act.

None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act.

None

Indicate the number of outstanding shares of each of the issuer s classes of capital or common stock as of the close of the period covered by the annual report.

Ordinary Shares of 25c each	**22,122,610,104**
Cumulative First Preference Shares of £1 each	**7,232,838**
Cumulative Second Preference Shares of £1 each	**5,473,414**

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes ü No

Indicate by check mark which financial statement item the Registrant has elected to follow.

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CERTAIN DEFINITIONS

Unless the context indicates otherwise, the following terms have the meanings shown below:

Oil and natural gas reserves

Proved oil and gas reserves Proved reserves are defined by the SEC in Rule 4-10(a) of Regulation S-X, paragraphs (2), (2i), (2ii) and (2iii). Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

(i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes: (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed programme in the reservoir, provides support for the engineering analysis on which the project or program was based.

(iii) Estimates of proved reserves do not include the following:

(a) oil that may become available from known reservoirs but is classified separately as indicated additional reserves ;

(b) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;

(c) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and

(d) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved developed reserves Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and natural gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included as proved developed reserves only after testing by a pilot project or after the operation of an installed programme has confirmed through production response that increased recovery will be achieved.

Proved undeveloped reserves Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances are estimates of proved undeveloped reserves attributable to acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

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Miscellaneous terms

ADR American Depositary Receipt.

ADS American Depositary Share.

Amoco The former Amoco Corporation and its subsidiaries.

Atlantic Richfield Atlantic Richfield Company and its subsidiaries.

Associated undertaking An undertaking in which the BP Group has a participating interest and over whose operating and financial policy the BP Group exercises a significant influence (presumed to be the case where 20% or more of the voting rights are held) and which is not a subsidiary undertaking.

Barrel 42 US gallons.

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

Burmah Castrol Burmah Castrol plc and its subsidiaries.

Cent or c One hundredth of the US dollar.

The Company BP p.l.c.

Liquids Crude oil, condensate and natural gas liquids.

Dollar or $ The US dollar.

FSA Financial Services Authority.

Gas Natural Gas.

Hydrocarbons Crude oil and natural gas.

Joint venture an entity in which the Group has a long-term interest and shares control with one or more co-venturers.

LNG Liquefied Natural Gas.

London Stock Exchange or LSE London Stock Exchange Limited.

LPG Liquefied Petroleum Gas.

MTBE Methyl Tertiary Butyl Ether.

NGL Natural Gas Liquid.

Noon Buying Rate The noon buying rate in New York City for cable transfers in pounds as certified for customs purposes by the Federal Reserve Bank of New York.

OECD Organization for Economic Cooperation and Development.

OPEC The Organization of Petroleum Exporting Countries.

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

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Pence or p One hundredth of a pound.

Pound , sterling or £ The pound sterling.

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

Subsidiary undertaking An undertaking in which the BP Group holds a majority of the voting rights.

Tonne 2,204.6 pounds.

UK United Kingdom of Great Britain and Northern Ireland.

UK GAAP Generally Accepted Accounting Practice in the UK.

Undertaking A body corporate, partnership or an unincorporated association, carrying on a trade or business.

US or USA United States of America.

US GAAP Generally Accepted Accounting Principles in the USA.

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PART I

ITEM 1 IDENTITY OF DIRECTORS, SENIOR MANAGEMENT AND ADVISORS

Not applicable.

ITEM 2 OFFER STATISTICS AND EXPECTED TIMETABLE

Not applicable.

ITEM 3 KEY INFORMATION

SELECTED FINANCIAL INFORMATION

Summary

This information has been extracted or derived from the audited financial statements of the BP Group presented elsewhere herein or otherwise included with BP p.l.c. s Annual Reports on Form 20-F for the relevant years which have been filed with the Securities and Exchange Commission, as reclassified to conform with the accounting presentation adopted in this annual report.

	Years ended December 31,				
	2003	2002	2001	2000	1999
	($ million except per share amounts)				
UK GAAP					
Income statement data					
Turnover	236,045	180,186	175,389	161,826	101,180
Less: joint ventures	3,474	1,465	1,171	13,764	17,614
Group turnover	232,571	178,721	174,218	148,062	83,566
Profit for the year	10,267	6,845	6,556	10,120	4,566
Per ordinary share: (cents)					
Profit for the year:					
Basic	46.30	30.55	29.21	46.77	23.55

Diluted	45.87	30.41	29.04	46.46	23.42
Dividends per share (cents)	26.00	24.00	22.00	20.50	20.00
Dividends per share (pence)	15.517	15.638	15.436	13.791	12.339
Ordinary share data (a)					
Average number outstanding of 25 cents ordinary shares (shares million undiluted)	22,171	22,397	22,436	21,638	19,386
Average number outstanding of 25 cents ordinary shares (shares million diluted)	22,429	22,504	22,574	21,783	19,497
Balance sheet data					
Total assets	177,572	159,125	141,970	144,862	89,481
Net assets	77,063	70,047	65,759	66,152	38,092
Share capital	5,552	5,616	5,629	5,653	4,892
BP shareholders interest	75,938	69,409	65,161	65,584	37,031
Finance debt due after more than one year	12,869	11,922	12,327	14,772	9,644
Debt to borrowed and invested capital (b)	14%	15%	16%	18%	20%

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	Years ended December 31,				
	2003	2002	2001	2000	1999
	($ million except per share amounts)				
US GAAP					
Income statement data					
Revenues	232,571	178,721	174,218	148,062	83,566
Profit for the year	13,143	8,397	4,164	10,183	4,596
Comprehensive income	20,088	10,544	2,649	7,730	3,674
Profit per ordinary share: (cents)					
Basic	59.27	37.48	18.55	47.05	23.70
Diluted	58.70	37.30	18.44	46.74	23.56
Profit per American Depositary Share: (cents)					
Basic	355.62	224.88	111.30	282.30	142.20
Diluted	352.20	223.80	110.64	280.44	141.36
Balance sheet data					
Total assets	186,359	164,103	145,990	151,966	90,262
Net assets	80,889	67,759	62,920	66,122	38,899
BP shareholders interest	79,764	67,121	62,322	65,554	37,838

(a) The number of ordinary shares shown have been used to calculate per share amounts for both UK and US GAAP.

(b) Finance debt due after more than one year, as a percentage of such debt plus BP and minority shareholders interests.

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Dividends

BP has paid dividends on its ordinary shares in each year since 1917. In 2000 and thereafter, dividends were, and are expected to continue to be, paid quarterly in March, June, September and December. Until their shares have been exchanged for BP ADSs, Amoco and Atlantic Richfield shareholders do not have the right to receive dividends.

BP currently announces dividends for ordinary shares in US dollars and states an equivalent pounds sterling dividend. Dividends on BP ordinary shares will be paid in pounds sterling and on BP ADSs in US dollars. The rate of exchange used to determine the sterling amount equivalent is the average of the forward exchange rate in London over the five business days prior to the announcement date. The directors may choose to declare dividends in any currency provided that a sterling equivalent is announced, but it is not the Company s intention to change its current policy of announcing dividends on ordinary shares in US dollars.

The following table shows dividends announced by the Company per ADS for each of the past five years, together with the refund but before deduction of withholding taxes as described in Item 10 Additional Information Taxation on page 166. Refund means an amount equal to the tax credit available to individual shareholders resident in the UK in respect of such dividend, less a withholding tax equal to 15% (but limited to the amount of the tax credit) of the aggregate of such tax credit and such dividend.

For dividends paid after April 30, 2004, there will be no refund available to shareholders resident in the US. Refer to Item 10 Additional Information Taxation for more information.

		Quarterly				
Dividends per American Depositary Share (a)		First	Second	Third	Fourth	Total
1999	UK pence	20.5	20.8	20.2	20.8	82.3
	US cents	33.3	33.3	33.3	33.4	133.3
	Can. cents	48.7	50.1	48.6	48.5	195.9
2000	UK pence	21.5	22.3	24.0	24.1	91.9
	US cents	33.3	33.3	35.0	35.0	136.6
	Can. cents	49.7	49.8	53.6	53.2	206.3
2001	UK pence	24.4	26.1	25.4	27.0	102.9
	US cents	35.0	36.7	36.7	38.3	146.7
	Can. cents	53.7	56.0	58.5	61.0	229.2
2002	UK pence	27.0	25.8	26.0	25.4	104.2
	US cents	38.3	40.0	40.0	41.7	160.0
	Can. cents	60.1	63.0	62.3	63.8	249.2
2003	UK pence	26.3	26.9	25.7	24.5	103.4
	US cents	41.7	43.3	43.3	45.0	173.3
	Can. cents	60.3	60.0	56.8	59.7	236.8

(a) With effect from October 4, 1999 BP split (or subdivided) its ordinary share capital. As a result, the number of BP ordinary shares held at the close of business on Friday October 1, 1999, doubled, and holders of ADSs received a two-for-one stock split.

A dividend reinvestment plan was introduced with effect from the fourth quarterly 1998 dividend, whereby holders of BP ordinary shares can elect to reinvest the net cash dividend in shares purchased on the London Stock Exchange. This plan is not available to any person resident in the USA or Canada, or in any jurisdiction outside the UK where such an offer requires compliance by the Company with any governmental or regulatory procedures or any similar formalities.

A dividend reinvestment plan is, however, available for holders of ADSs through JPMorgan Chase Bank.

Future dividends will be dependent upon future earnings, the financial condition of the Group, the Risk Factors set out below, and other matters which may affect the business of the Group set out in Item 5 Operating and Financial Review and Prospects on page 78.

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RISK FACTORS

We urge you to carefully consider the risks described below. If any of these risks actually occur, our business, financial condition and results of operations could suffer, and the trading price and liquidity of our securities could decline, in which case you may lose all or part of your investment.

External Risks

There are a number of risks that arise as a result of the business climate, which are not directly controllable.

Competition Risk: The oil, gas and petrochemicals industries are highly competitive. There is strong competition, both within the oil and gas industry and with other industries, in supplying the fuel needs of commerce, industry and the home. Competition puts pressure on product prices, affects oil products marketing and requires continuous management focus on reducing unit costs and improving efficiency.

Price Risk: Oil prices are subject to international supply and demand. Political developments (especially in the Middle East) and the outcome of meetings of OPEC can particularly affect world supply and oil prices. In addition to the adverse effect on revenues, margins and profitability from any future fall in oil and natural gas prices, a prolonged period of low prices or other indicators would lead to a review for impairment of the BP Group s oil and natural gas properties. This review would reflect management s view of long-term oil and natural gas prices. Such a review could result in a charge for impairment which could have a significant effect on the BP Group s results of operations in the period in which it occurs.

Regulatory Risks: The oil industry is subject to regulation and intervention by governments throughout the world in such matters as the award of exploration and production interests, the imposition of specific drilling obligations, environmental protection controls, controls over the development and decommissioning of a field (including restrictions on production) and, possibly, nationalization, expropriation or cancellation of contract rights. The oil industry is also subject to the payment of royalties and taxation, which tend to be high compared with those payable in respect of other commercial activities. As a result of new laws and regulations or other factors, we could be required to curtail or cease certain operations, causing our production to decrease, or we could incur additional costs.

Developing Country Risk: We have operations in developing countries where political, economic and social transition is taking place. Some countries have experienced political instability, expropriation or nationalization of property, civil strife, strikes, acts of war and insurrections. Any of these conditions occurring could disrupt or terminate our operations, causing our development activities to be curtailed or terminated in these areas or our production to decline and could cause us to incur additional costs.

Currency Risk: Crude oil prices are generally set in US dollars while sales of refined products may be in a variety of currencies. Fluctuation in exchange rates can therefore give rise to foreign exchange exposures.

Economic Risk - Refining and Petrochemicals Market: Refining profitability can be volatile with both periodic oversupply and supply tightness in various regional markets. Sectors of the chemicals industry are also subject to fluctuations in supply and demand within the petrochemicals market, with consequent effect on prices and profitability.

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Reputational Risks

We set ourselves high standards of corporate citizenship and aspire to contribute to a better quality of life through the products and services we provide. This may create risks to our reputation if it is perceived that our actions are not aligned to these standards and aspirations.

Social Responsibility Risk: Risk could arise if it is perceived that we are not respecting or advancing the economic and social progress of the communities in which we operate.

Environmental Risk: We seek to conduct our activities in such a manner that there is no or minimum damage to the environment. Risk could arise if we do not apply our resources to overcome the perceived trade-off between global access to energy and the protection or improvement of the natural environment.

Compliance Risk: Incidents of non-compliance with applicable laws and regulation or ethical misconduct could be damaging to our reputation and shareholder value.

Operational Risks

Inherent in our operations are hazards which require continual oversight and control. If operational risks materialized it could result in loss of life, damage to the environment or loss of production.

Drilling and Production Risk: Exploration and production require high levels of investment and have particular economic risks and opportunities. They are subject to natural hazards and other uncertainties, including those relating to the physical characteristics of an oil or natural gas field. The cost of drilling, completing or operating wells is often uncertain. We may be required to curtail, delay or cancel drilling operations because of a variety of factors including unexpected drilling conditions, pressure or irregularities in geological formations, equipment failures or accidents, adverse weather conditions and compliance with governmental requirements.

Technical Integrity Risk: There is a risk of loss of containment of hydrocarbons and other hazardous material at operating sites, pipelines or during transportation by road, rail or sea.

Security Risk: Acts of terrorism that threaten our plants and offices, pipelines, transportation or computer systems would severely disrupt business and operations.

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FORWARD-LOOKING STATEMENTS

In order to utilize the Safe Harbor provisions of the United States Private Securities Litigation Reform Act of 1995, BP is providing the following cautionary statement. This document contains certain forward-looking statements with respect to the financial condition, results of operations and businesses of BP and certain of the plans and objectives of BP with respect to these items. These statements may generally, but not always, be identified by the use of words such as will , expects , is expected to , should , may , is likely to , intends , believes , plan similar expressions. In particular, among other statements, (i) certain statements in Item 4 Information on the Company and Item 5 Operating and Financial Review and Prospects with regard to management aims and objectives, future capital expenditure, future hydrocarbon production volume, date or period(s) in which production is scheduled or expected to come on stream or a project or action is scheduled or expected to be completed, capacity of planned plants or facilities and impact of health, safety and environmental regulations; (ii) the statements in Item 4 Information on the Company with regard to planned expansion, investment or other projects and future regulatory actions; and (iii) the statements in Item 5 Operating and Financial Review and Prospects, including under Liquidity and Capital Resources with regard to future cash flows, future levels of capital expenditure and divestments, working capital, expected payments under contractual and commercial commitments; under Outlook with regard to global and certain regional economies, oil and gas prices and realizations, expectations for supply and demand, refining and marketing margins, petrochemical margins and sales; and under Prospects with regard to the plans and prospects of the Group, forward-looking rules of thumb, changes to BP s financial reporting due to the adoption of FRS 17, operating capital employed/capital in service, cash returns, underlying cash flows, finding and development costs, BP s intentions with respect to shareholder distributions and share buybacks, gearing, opportunities for material acquisitions and costs for providing pension and other postretirement benefits are all forward-looking in nature.

By their nature, forward-looking statements involve risk and uncertainty because they relate to events and depend on circumstances that will or may occur in the future and are outside the control of BP. Actual results may differ materially from those expressed in such statements, depending on a variety of factors, including the specific factors identified in the discussions accompanying such forward-looking statements; the timing of bringing new fields on stream; future levels of industry product supply, demand and pricing; operational problems; general economic conditions; political stability and economic growth in relevant areas of the world; changes in laws and governmental regulations; exchange rate fluctuations; development and use of new technology; successful partnering; the actions of competitors; natural disasters and adverse weather conditions; changes in public expectations and other changes to business conditions; wars and acts of terrorism or sabotage; and other factors discussed elsewhere in this report including under Risk Factors above. In addition to factors set forth elsewhere in this report, the factors set forth above are important factors, although not exhaustive, that may cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements.

STATEMENTS REGARDING COMPETITIVE POSITION

Statements made in Item 4 Information on the Company, referring to BP s competitive position are based on the Company s belief, and in some cases rely on a range of sources, including investment analysts reports, independent market studies and BP s internal assessments of market share based on publicly available information about the financial results and performance of market participants.

SPECIAL NOTICE

The Company has received comments from the Staff of the SEC relating to our Annual Report on Form 20-F for the year ended December 31, 2002, and as of the date of filing this 2003 Form 20-F, the SEC review process is still ongoing.

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ITEM 4 INFORMATION ON THE COMPANY

GENERAL

Unless otherwise indicated, information in this Item reflects 100% of the assets and operations of the Company and its subsidiaries which were consolidated at the date or for the periods indicated, including minority interests. Also, unless otherwise indicated, figures for business turnover include sales between BP businesses.

BP was created on December 31, 1998 by the merger of Amoco Corporation, incorporated in Indiana, USA, in 1889, and The British Petroleum Company p.l.c., registered in 1909 in England and Wales. The resulting company, BP p.l.c. is a public limited company, registered in England and Wales.

BP is one of the world s leading oil companies on the basis of market capitalization and proved reserves. Our worldwide headquarters is located in London, UK. Our registered address is:

BP p.l.c.

1 St James s Square

London SW1Y 4PD

United Kingdom

Tel: +44 (0)20 7496 4000

Internet address: www.bp.com

Our agent in the USA is:

BP America Inc.

4101 Winfield Road

Warrenville, Illinois 60555

Tel: +1 630 821 2222

Overview of the Group

Our operating business segments are Exploration and Production; Gas, Power and Renewables; Refining and Marketing; and Petrochemicals. Exploration and Production s activities include oil and natural gas exploration and field development and production (upstream activities), together with pipeline transportation and natural gas processing (midstream activities). Gas, Power and Renewables activities include marketing and trading of natural gas, NGL, new market development and LNG, and solar and renewables. The activities of Refining and Marketing include oil supply and trading as well as refining and marketing (downstream activities). Petrochemicals activities include manufacturing, marketing and distribution. The Group provides high quality technological support for all its businesses through its research and engineering activities.

These segments fall into two groupings: the Resources Business comprising Exploration and Production; and Customer Facing Businesses comprising Refining and Marketing, Petrochemicals and Gas, Power and Renewables.

The Group s operating business segments are managed on a global basis and not on a regional basis. Geographical information for the Group and segments is given to provide additional information for investors, but does not reflect the way BP manages its activities. Information by geographical area is provided for production and reserves in response to the requirements of Appendix A to Item 4D of Form 20-F.

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We have well established operations in Europe, the USA, Canada, South America, Australasia and parts of Africa. Currently, more than 70% of the Group s capital is invested in Organization for Economic Cooperation and Development (OECD) countries with just under 40% of our fixed assets located in the USA, and just under 30% located in the UK and the Rest of Europe.

We believe that BP has a strong portfolio of assets in each of its four main segments:

In Exploration and Production we have upstream interests in 25 countries. In addition to our drive to maximize the value of our existing portfolio we are creating new profit centres. Exploration and Production activities are managed through operating units which are accountable for the day-to-day management of the segment s activities. An operating unit is accountable for one or more fields. Profit centres comprise one or more operating units. Profit centres are, or are expected to become, areas that provide significant production and income for the segment. Our new profit centres are in the Deepwater Gulf of Mexico, Trinidad, Angola, Algeria, Azerbaijan, Russia and Asia Pacific, where we believe we have competitive advantage and which we believe provide the foundation for volume growth and improved margins in the future. We also have significant midstream activities to support our upstream interests.

In Gas, Power and Renewables, we have growing marketing and trading businesses in North America (USA and Canada), the UK and the rest of Europe. Our marketing and trading activities include natural gas, LNG, NGL and power. Our international natural gas monetization activities, which are our efforts to identify and capture worldwide opportunities to sell our upstream natural gas resources, are focused on growing natural gas markets including the USA, Canada, Spain and many of the emerging markets of the Asia Pacific region, notably China. We are involved in power projects in the USA, UK, Spain and South Korea.

In Refining and Marketing we have a strong presence in the USA. We market under the Amoco and BP brands in the Midwest, East, and Southeast, and under the ARCO brand on the West Coast. In Europe we have a strong retail position and increased our presence in 2002 by acquiring Veba Oil (Veba). The Veba transaction expanded our refining position in Germany and our marketing position in Germany and Central Europe. Veba markets gasoline under the Aral brand, which is now our principal retail brand in Germany and in the Czech Republic. We have established or are growing businesses elsewhere in the world under the BP brand.

In Petrochemicals, we are the world s third largest petrochemical company, based on production capacity, with strong manufacturing and marketing bases in the USA and Europe. We are growing in the Asia Pacific region, where we already have interests in a number of production facilities. Our strategy is focused on seven core products, with the aim of providing world-class performance in all aspects of our activities. We are now managing our portfolio in two distinct parts Aromatics and Acetyls (A&A), comprising PTA, PX and acetic acid, and Olefins and Derivatives (O&D) comprising ethylene and related co-products, polypropylene, HDPE and acrylonitrile. On April 27, 2004 we announced our intention to set up a separate corporate entity for the O&D businesses. It is our intention to make a public offering of this new entity at an appropriate time. Based on the estimated lead time required for such a transaction, and depending on market circumstances, we are aiming to make such an offering in the second half of 2005. We intend to retain and grow the A&A businesses, which will be transferred to the Refining and Marketing segment on January 1, 2005.

Acquisitions and Disposals

There were no significant acquisitions in 2001. Disposals in 2001 comprised a number of small transactions, with total proceeds of $2,903 million.

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With effect from February 1, 2002, BP acquired a majority stake in Veba from E.ON. Veba owns Aral, Germany s biggest fuels retailer. BP paid E.ON $1.6 billion in cash and assumed some $1.0 billion of debt in return for 51% and operational control of Veba. Under the terms of the agreement, E.ON had the option to require BP to buy the remaining 49% of Veba.

On June 30, 2002, BP purchased the remaining 49% of Veba from E.ON for $2.4 billion. Separately, E.ON acquired BP s wholly-owned subsidiary Gelsenberg, which held a 25.5% stake in Germany s largest natural gas distributor, Ruhrgas, for $2.3 billion.

As a condition of regulatory approval of the deal, BP was required to dispose of 4% of the combined 26.5% retail market share of BP and Aral in Germany, 45% of its stake in the Bayernoil refinery, two of its three shareholdings in the ARG ethylene pipeline, and to make it possible for a new entrant to supply aviation fuel on competitive terms at Frankfurt airport. During 2003, BP fully complied with the conditions imposed.

Separately, BP and E.ON sold the bulk of Veba s oil and natural gas exploration and production business to Petro-Canada for $1.6 billion in the second quarter of 2002.

In addition to the sale of Veba s exploration and production business, 2002 disposal proceeds of $6,782 million included $2,338 million from the sale of our investment in Ruhrgas, with the balance of the proceeds coming from a number of other transactions.

In August 2003, BP and Alfa Group and Access-Renova (AAR) completed a transaction first announced in February 2003 to create the third largest oil company operating in Russia based on production volume. The company, TNK-BP, is a 50:50 joint venture between BP and AAR, and operates in Russia and the Ukraine. BP s share of the result of the TNK-BP joint venture has been included within the Exploration and Production segment from August 29, 2003.

AAR contributed its holdings in TNK and Sidanco, its share of Rusia Petroleum, its stake in the Rospan gasfield in West Siberia and its interest in the Sakhalin IV and V exploration licence to the joint venture. BP contributed its holding in Sidanco, its stake in Rusia Petroleum and its holding in the BP Moscow retail network. Neither AAR s association with Slavneft, nor BP s interest in LukArco or the Russian elements of BP s international businesses such as lubricants, marine and aviation were included in this transaction.

In addition, BP paid AAR $2.6 billion in cash upon completion of the transaction, which was subsequently reduced by receipt of pre-acquisition dividends net of transaction costs of $0.3 billion, and subject to the terms of its agreement with AAR, will pay three annual tranches of $1.25 billion in BP shares, valued at market prices prior to each annual payment. BP s net investment in TNK-BP following this transaction was $6.7 billion.

In January 2004, BP and AAR completed a subsequent transaction to include AAR s 50% stake in Slavneft within TNK-BP, at which time BP paid $1.35 billion to AAR. Slavneft was previously held equally by AAR and Sibneft. TNK-BP and Sibneft will continue to work together to finalize an agreement to split the main assets of Slavneft between the two companies.

Disposal proceeds in 2003 amounted to $6,432 million, and resulted primarily from the sale of various upstream interests and completion of divestments required as a condition of approval of the Veba acquisition.

On January 13, 2004, BP sold its 2% stake in PetroChina Company Limited (PetroChina) for $1.65 billion. On February 10, 2004 we sold our 2.1% stake in Sinopec for $0.7 billion.

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Financial and Operating Information

The following table summarizes the Group s turnover, profit and capital expenditure for the last five years and total assets at the end of each of those years.

	Years ended December 31,				
	2003	2002	2001	2000	1999
			($ million)		
Turnover	236,045	180,186	175,389	161,826	101,180
Less: joint ventures	3,474	1,465	1,171	13,764	17,614
Group turnover (sales to third parties)	232,571	178,721	174,218	148,062	83,566
Total operating profit (a)	16,429	11,375	14,127	18,407	10,622
Profit for the year*	10,267	6,845	6,556	10,120	4,566
Capital expenditure and acquisitions	20,075 (b)	19,111 (b)	14,124	47,613 (b)	7,345 (c)
Total assets	177,572	159,125	141,970	144,862	89,481

* After minority shareholders interest

(a) Operating profit is a UK GAAP measure of trading performance. It excludes profits and losses on the sale of fixed assets and businesses or termination of operations and fundamental restructuring costs, interest expense and taxation.

(b) Capital expenditure and acquisitions for 2003 includes $5,794 million for the acquisition of our interest in TNK-BP, for 2002 includes $5,038 million for the acquisition of Veba, for 2000 includes $27,506 million for the acquisition of Atlantic Richfield and $8,936 million for other significant one-off cash investments.

(c) Capital expenditure and acquisitions in 1999 reflected reduced investment following the merger of BP and Amoco.

With the exception of the Atlantic Richfield acquisition, which was a share transaction, all capital expenditure and acquisitions during the last five years have been financed from cash flow from operations, disposal proceeds and external financing.

Information for 2003, 2002 and 2001 concerning the profits and assets attributable to the businesses and to the geographical areas in which the Group operates is set forth in Item 18 Financial Statements Note 47 on page F-87.

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The following table shows our production for the last five years and the estimated proved oil and natural gas reserves at the end of each of those years.

	Years ended December 31,				
	2003	2002	2001	2000	1999
Total crude oil production (thousand barrels per day) (a)	2,121	2,018	1,931	1,928	2,061
Total natural gas production (million cubic feet per day) (a)	8,613	8,707	8,632	7,609	6,067
Estimated net proved crude oil reserves (million barrels) (b)	7,214	7,762	7,217	6,508	6,535
Estimated net proved natural gas reserves (billion cubic feet) (b)	45,155	45,844	42,959	41,100	33,802
Total estimated net proved crude oil reserves (million barrels) (c)	10,081	9,165	8,376	7,643	7,572
Total estimated net proved natural gas reserves (billion cubic feet) (d)	48,024	48,789	46,175	43,918	35,526

(a) Includes BP s share of equity-accounted entities.

(b) Net proved reserves of crude oil and natural gas exclude production royalties due to others, whether royalty is payable in cash or in kind, and reserves of equity-accounted entities.

(c) Including reserves of equity-accounted entities. Includes 152 million barrels (17 million barrels at December 31, 2002 and 20 million barrels at December 31, 2001) in respect of the 30% minority interest in BP Trinidad and Tobago LLC and the 5.4% minority interest held in subsidiaries of TNK-BP.

(d) Including reserves of equity-accounted entities. Includes 4,505 billion cubic feet of natural gas (1,185 billion cubic feet at December 31, 2002 and 1,258 billion cubic feet at December 31, 2001) in respect of the 30% minority interest in Trinidad and Tobago LLC and the 5.4% minority interest held in subsidiaries of TNK-BP.

During 2003, 1,289 million barrels of oil and natural gas, on an oil equivalent* basis (mmboe), were added to BP s proved reserves (excluding purchases, sales and equity-accounted entities), more than replacing the volume produced. After allowing for production, which amounted to 1,085 mmboe, BP s proved reserves, excluding equity-accounted entities, increased to 14,999 mmboe. These proved reserves are mainly located in the USA (40%), Rest of Americas (23%) and the UK (11%).

* Natural gas is converted to oil equivalent at 5.8 billion cubic feet (bcf) = 1 million barrels.

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SEGMENTAL INFORMATION

The following tables show turnover and profit before interest and tax by business and by geographical area for the years ended December 31, 2003, 2002 and 2001.

	Years ended December 31,								
	2003			2002			2001		
Turnover (a)	Total sales	Sales between businesses	Sales to third parties	Total sales	Sales between businesses	Sales to third parties	Total sales	Sales between businesses	Sales to third parties
		($ million)			($ million)			($ million)	
By business									
Exploration and Production	31,341	23,279	8,062	25,753	18,556	7,197	28,229	19,660	8,569
Gas, Power and Renewables	65,445	1,963	63,482	37,357	1,320	36,037	39,442	2,954	36,488
Refining and Marketing	149,477	4,448	145,029	125,836	3,366	122,470	120,233	2,903	117,330
Petrochemicals	16,075	592	15,483	13,064	557	12,507	11,515	233	11,282
Other businesses and corporate	515		515	510		510	549		549
Group turnover	262,853	30,282	232,571	202,520	23,799	178,721	199,968	25,750	174,218
Share of joint venture sales			3,474			1,465			1,171
			236,045			180,186			175,389

	Total sales	Sales between areas	Sales to third parties	Total sales	Sales between areas	Sales to third parties	Total sales	Sales between areas	Sales to third parties
		($ million)			($ million)			($ million)	
By geographical area									
UK (b)	54,971	15,275	39,696	48,748	14,673	34,075	47,618	13,467	34,151
Rest of Europe	50,582	8,672	41,910	46,518	7,980	38,538	36,701	7,603	29,098
USA	108,910	2,169	106,741	80,381	2,099	78,282	84,696	939	83,757
Rest of World	52,498	8,274	44,224	34,401	6,575	27,826	33,911	6,699	27,212
	266,961	34,390	232,571	210,048	31,327	178,721	202,926	28,708	174,218
Share of joint venture sales									
UK			144			129			13
Rest of Europe			290			298			30

USA	177	236	318
Rest of World	2,863	802	810
	3,474	1,465	1,171

(a) Turnover to third parties is stated by origin, which is not materially different from turnover by destination. Transfers between Group companies are made at market prices, taking into account the volumes involved.

(b) UK area includes the UK-based international activities of Refining and Marketing.

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Analysis of profit	Group operating profit (a)	Joint ventures	Associated undertakings	Total operating profit (a)	Exceptional items (b)	Profit before interest and tax
			($ million)			
Year ended December 31, 2003						
By business						
Exploration and Production	12,754	914	272	13,940	913	14,853
Gas, Power & Renewables	481		(3)	478	(6)	472
Refining and Marketing	2,128	29	135	2,292	(213)	2,079
Petrochemicals	550	(19)	92	623	38	661
Other businesses and corporate	(922)		18	(904)	99	(805)
	14,991	924	514	16,429	831	17,260
By geographical area						
UK (c)	2,590	(19)	14	2,585	717	3,302
Rest of Europe	1,966		12	1,978	(151)	1,827
USA	5,485	27	79	5,591	(347)	5,244
Rest of World	4,950	916	409	6,275	612	6,887
	14,991	924	514	16,429	831	17,260
Year ended December 31, 2002						
By business						
Exploration and Production	8,598	343	268	9,209	(726)	8,483
Gas, Power & Renewables	298		107	405	1,551	1,956
Refining and Marketing	1,717	24	180	1,921	613	2,534
Petrochemicals	551	(20)	10	541	(256)	285
Other businesses and corporate	(753)		52	(701)	(14)	(715)
	10,411	347	617	11,375	1,168	12,543
By geographical area						
UK (c)	1,788	(14)	10	1,784	(88)	1,696
Rest of Europe	1,856	(2)	132	1,986	1,817	3,803
USA	3,305	17	136	3,458	(242)	3,216
Rest of World	3,462	346	339	4,147	(319)	3,828
	10,411	347	617	11,375	1,168	12,543
Year ended December 31, 2001						
By business						
Exploration and Production	11,796	373	186	12,355	195	12,550
Gas, Power & Renewables	223		184	407		407
Refining and Marketing	1,712	83	195	1,990	471	2,461
Petrochemicals	(201)	(17)	116	(102)	(297)	(399)
Other businesses and corporate	(598)		75	(523)	166	(357)
	12,932	439	756	14,127	535	14,662

By geographical area						
UK (c)	2,435	(5)	13	2,443	(319)	2,124
Rest of Europe	1,138	(4)	236	1,370	33	1,403
USA	5,619	77	186	5,882	289	6,171
Rest of World	3,740	371	321	4,432	532	4,964
	12,932	439	756	14,127	535	14,662

(a) Group operating profit and total operating profit are before interest expense, which is attributable to the corporate function. Transfers between Group companies are made at market prices taking into account the volumes involved.

(b) Exceptional items comprise profit or loss on the sale of fixed assets and businesses or termination of operations.

(c) UK area includes the UK-based international activities of Refining and Marketing.

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EXPLORATION AND PRODUCTION

The activities of our Exploration and Production business include oil and natural gas exploration and field development and production the upstream activities as well as the management of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities the midstream activities. We have Exploration and Production interests in 25 countries. Areas of activity include the USA, UK, Norway, Canada, South America, Africa, the Middle East and Asia Pacific. Production during 2003 came from 23 countries. Our most significant midstream activities are in three major pipelines the Trans Alaska Pipeline System (TAPS, BP 46.9%); the Forties Pipeline System (FPS, BP 100%) and the Central Area Transmission System pipeline (CATS, BP 29.5%) both in the UK sector of the North Sea; and three major LNG plants the Atlantic LNG plant in Trinidad (BP 34% in Train 1, 42% in Trains 2 and 3, and 38% in Train 4), in Indonesia through our interests in the Sanga-Sanga Production Sharing Agreement (PSA, BP 38%), which supplies natural gas to the Bontang LNG plant and in Australia through our share of LNG from the North West Shelf natural gas development (BP 16.7%).

With effect from January 1, 2004, we have transferred certain of our Natural Gas Liquid processing plants to the Gas, Power and Renewables segment in order to consolidate the management of our global NGL activity. This will have no impact on the Exploration and Production segment s reported production. Our 2003 results have not been restated to reflect this transfer. The impact that this would have had on our 2003 segment results is shown under Transfer of Natural Gas Liquids Activities on page 112 in Item 5 Operating and Financial Review and Prospects Group Operating Results.

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Turnover (a)	31,341	25,753	28,229
Total operating profit	13,940	9,209	12,355
Total assets	79,344	72,801	70,017
Capital expenditure and acquisitions	15,452	9,699	8,861
		($ per barrel)	
Average BP crude oil realizations (b)	28.23	24.06	23.27
Average BP NGL realizations (b)	19.26	12.85	16.27
Average BP liquids realizations (b) (c)	27.25	22.69	22.50
Average West Texas Intermediate oil price	31.06	26.14	25.89
Average Brent oil price	28.83	25.03	24.44
		($ per thousand cubic feet)	
Average BP natural gas realizations (b)	3.39	2.46	3.30
Average BP US natural gas realizations (b)	4.47	2.63	3.99
		($ per mmbtu)	
Average Henry Hub gas price (d)	5.37	3.22	4.26

(a) Excludes BP s share of joint venture turnover of $2,587 million in 2003, $539 million in 2002 and $666 million in 2001.

(b) The Exploration and Production business does not undertake any hedging activity. Consequently, realizations reflect the market price achieved.

(c) Crude oil and natural gas liquids.

(d) Henry Hub First of Month Index.

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Our upstream activities are divided between existing profit centres that is our operations in Alaska, Egypt, Latin America (including Argentina, Brazil, Colombia, Mexico and Venezuela), Middle East (including Abu Dhabi, Sharjah and Pakistan), North America Gas (Onshore US, the Gulf of Mexico Shelf and Canada) and the North Sea (UK, Netherlands and Norway); and new profit centres that is our operations in Asia Pacific (Australia, Vietnam, Indonesia and China), Azerbaijan, Algeria, Angola, Trinidad, Deepwater Gulf of Mexico and Russia.

The Exploration and Production strategy is to:

- create new profit centres by accessing areas with the potential for large oil and natural gas fields; exploring successfully and pursuing only the best projects for development;

- manage the performance of producing assets by investing only in the best available opportunities and optimizing operating efficiency; and

- sell assets that are no longer strategic to us and have greater value to others.

This strategy is underpinned by a focus on investing in a portfolio of large, lower-cost oil and natural gas fields chosen for their potentially strong return on capital employed. We seek to manage those assets safely with maximum capital and operating efficiency. We are currently developing new profit centres in which we have a distinctive position. These new profit centres augment the production assets in our existing profit centres, providing greater reach, investment choice and opportunity for growth.

In support of growth, 2003 capital expenditure and acquisitions was $15.5 billion, including $5.8 billion for the purchase of our interest in TNK-BP. 2002 capital expenditure and acquisitions at $9.7 billion was 9% higher than the 2001 level of $8.9 billion. Excluding acquisitions, capital expenditure in 2003 was $9.7 billion compared with $9.3 billion in 2002 and $8.6 billion in 2001. Development expenditure incurred in 2003, excluding midstream activities, was $7,547 million compared with $7,235 million in 2002 and $6,858 million in 2001. This reflects the investment we have been making in our new profit centres and the development phase on many of our major projects. Capital expenditure excluding acquisitions for 2004 is planned to be approximately $9 billion.

Upstream Activities

Exploration

The Group explores for oil and natural gas under a wide range of licensing, joint venture and other contractual agreements. We may do this alone or, more frequently, with partners. BP acts as operator for many of these ventures.

Our exploration and appraisal costs in 2003 were $826 million compared to $1,108 million in 2002. About 34% of 2003 exploration and appraisal capital was directed towards appraisal activity as we delineated the discoveries made during 2000, 2001, and 2002. In 2003, we participated in 74 gross (32 net) exploration and appraisal wells in 19 countries. The principal areas of activity were Angola, Egypt and the USA.

Total exploration expense in 2003 of $542 million (2002, $644 million) includes the write-off of unsuccessful drilling activity in Colombia (Niscota - $62 million) and in Brazil (Reki - $30 million).

In 2003, we obtained upstream rights in several new tracts, which include the following:

- In Egypt, BP were awarded six new blocks in the Gulf of Suez and northern Red Sea.

- In the Gulf of Mexico, BP was successful in the Outer Continental Shelf Lease Sales 185 and 187 with bids on 80 blocks, of which 58 were won, for an overall success rate of 73%. BP also gained leases in Louisiana state waters where we were 100% successful in purchasing the blocks we bid on.

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In 2003, we were involved in discoveries in Angola, Azerbaijan, Egypt and the USA. In most cases, reserve bookings from these fields will depend on the results of ongoing technical and commercial evaluations, including appraisal drilling. Our 2003 discoveries included the following:

In Angola, BP made further discoveries in the ultra deep water (greater than 1,500 metres) acreage with the Saturno and Marte wells in Block 31 (BP 26.7% and operator), and in Block 18 (BP 50% and operator) with the Cesio and Chumbo discoveries. Continued success was experienced in the established partner-operated deepwater blocks; in Block 15 (BP 26.7%) the Clochas, Kakocha and Tchihumba discoveries, and in Block 17 (BP 16.7%) the Hortensia and Acacia discoveries.

In Egypt, BP successfully appraised the 2002 Ruby discovery with the Ruby-2 well in the West Mediterranean Deep Water Concession (BP 80%) in the Nile Delta. In the Gulf of Suez, BP drilled the discovery well Saqqara-1 in the LL87 block. This was the largest oil discovery in the Gulf of Suez in nearly 14 years.

In the Deepwater Gulf of Mexico, a discovery was made with the Tubular Bells well (BP 50% and operator) in the Mississippi Canyon.

In Azerbaijan a deeper reservoir was discovered in the Shah Deniz field.

2004 activity has resulted in further discoveries with the Bavuca well in Angola Block 15 (BP 26.7%) and in Egypt with the Raven 1 well in the North Alexandria Concession (BP 60% and operator) and the Taurt well in the Ras El Barr concession (BP 50% and operator).

Reserves and Production

BP manages its hydrocarbon resources in three major categories: prospect inventory; non-proved reserves and proved reserves. When a discovery is made, volumes transfer from the prospect inventory to the non-proved reserve category. The reserves move through various non-proved reserves sub-categories as their technical and commercial maturity increase through appraisal activity. Reserves in a field will only be categorized as proved when all the criteria for attribution of proved status have been met including an internally imposed requirement for project sanction, or for sanction expected within six months. Internal approval and final investment decision are what we refer to as project sanction.

At the point of sanction, all booked reserves will be categorized as proved undeveloped (PUD). Volumes will subsequently be recategorized from PUD to proved developed (PD) as a consequence of development activity. The first PD bookings will occur at the point of first oil or gas production. Major development projects typically take one to four years from the time of initial booking to the start of production. Adjustments may be made to booked reserves due to production, reservoir performance, commercial factors, acquisition and divestment activity and additional reservoir development activity.

BP has an internal process to control the quality of reserve bookings which forms part of an holistic and integrated system of internal control. BP s process to manage reserve bookings has been centrally controlled for over 15 years and it currently has several key elements.

The first key element is the accountabilities of certain officers of the Company which ensure that there is clear responsibility for review and, where appropriate, endorsement of changes to reserves bookings; that the review is independent of the operating business unit for the integrity and accuracy of the reserve estimates; and that there are effective controls in the reserve approval process and verification that the Group s reserve estimates and the related financial impacts are reported in a timely manner.

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The second key element is the capital allocation processes whereby delegated authority is exercised to commit to capital projects that are consistent with the delivery of the Group s business plan. A formal review process exists to review that both technical and commercial criteria are met prior to the commitment of capital to projects.

The third key element is Internal Audit, whose role includes systematically examining the effectiveness of the Group s financial controls designed to assure the reliability of reporting and safeguarding of assets and examining the Group s compliance with laws, regulations and internal standards.

The fourth key element is a quarterly due diligence review, which is separate and independent from the operating business units, of reserves associated with properties where technical, operational or commercial issues have arisen.

The fifth and final key element is that we have established criteria whereby reserves above certain thresholds require central authorization. Furthermore, the volumes booked under these authorization levels are reviewed on a periodic basis. The frequency of review is determined according to field size and ensures that more than 70% of the BP reserves base undergoes central review every two years and more than 80% is reviewed every four years.

There is no direct link between compensation for executive directors and reserves replacement. Below the level of the executive director in the Exploration and Production segment, no specific portion of compensation bonuses has been directly related to oil and gas reserves targets. Additions to proved reserves was one of several indicators by which the performance of a business unit in the Exploration and Production business segment was assessed for purposes of determining compensation bonuses. Other indicators included production costs, changes in working capital, drilling days, operating efficiency and greenhouse gas emissions.

For 2004, BP s variable pay program for the senior managers in the Exploration and Production business segment will be based on Annual Bonus Contracts. Annual Bonus Contracts are made up of two elements, one of which is based on certain elements of financial performance (cash from operations, capital expenditure, divestments) of the Group as a whole. The other is based on agreed items from the business performance plan, one of which, if they choose, could relate to oil and gas reserves.

Details of our net proved reserves of crude oil, condensate, natural gas liquids and natural gas at December 31, 2003, 2002 and 2001 and reserves changes for each of the three years then ended are set out in the Supplementary Oil and Gas Information section in Item 18 - Supplementary Oil and Gas Information beginning on page S-1. We disclose our share of reserves held in joint ventures and associated companies although we do not control these entities or the assets held by such entities.

Of the Group s oil and gas reserves held in consolidated companies, approximately 94% have been estimated by the Group s petroleum engineers and approximately 6% have been estimated by others such as the field operator or independent engineering consultants. Of the oil and gas reserves held in equity-accounted companies, approximately 24% have been estimated by the Group s petroleum engineers. The majority of the rest consists of reserves in TNK-BP which have been estimated by independent engineering consultants. For significant properties where BP has adopted the proved reserve estimates of others, BP s petroleum engineers reviewed such estimates before making their assessment of volumes to be booked by BP.

Our proved reserves are associated with both concessions (tax and royalty arrangements) and production sharing agreements (PSAs). In a concession, the consortium of which we are a part is entitled to the reserves that can be produced over the licence period, which may be the life of the field. In a PSA, we are entitled to recover volumes that equate to costs incurred to develop and produce the reserves and an agreed share of the remaining volumes or the economic equivalent. As part of our entitlement is driven by the monetary amount of costs to be recovered, price fluctuations will have an impact on both production volumes and reserves. 14% of our proved reserves are associated with PSAs. The main countries in which we operate under PSA arrangements are Algeria, Angola, Azerbaijan, Egypt, Indonesia and Vietnam.

In our UK GAAP financial reporting, the Group uses its long-term planning prices in determining estimates of its proved reserves, which is an accepted practice under UK accounting rules for oil and gas companies contained in the Statement of Recommended Practice, Accounting for Oil and Gas Exploration, Development, Production and Decommissioning Activities (UK SORP). Planning prices are the long term price assumptions on which the Group makes decisions to invest in the development of a field. Using planning prices for estimating proved reserves removes the impact of the volatility inherent in using year-end spot prices on our reserve base and on cash flow expectations over the long term. The Group s planning prices for estimating reserves through the end of 2003 were $16/bbl for oil and $2.70/mscf for natural gas. From 2004 we increased our planning prices to $20/bbl for oil and $3.50/mscf for natural gas. Applying higher year-end prices to reserve estimates has the effect of increasing proved reserves associated with concessions (tax and royalty arrangements) for which additional development opportunities become economical at higher prices or where higher prices make it more economical to extend the life of a field. On the other hand, applying higher year-end prices to reserves in fields subject to PSAs has the effect of decreasing proved reserves from those fields because higher prices result in lower volume entitlements. On an aggregate basis, the impact on our proved reserves of using higher year-end prices instead of our planning prices is broadly in balance, although there are relatively larger variations on a regional basis. We believe that our long-term planning price assumptions provide the most appropriate basis for estimating oil and gas reserves and we will continue to use this basis for our UK reporting.

In determining reasonable certainty for UK SORP purposes, BP applies a number of additional internally imposed assessment principles such as the requirement for internal approval and final investment decision (which we refer to as project sanction), or for such project sanction within six months and, for additional reserves in existing fields, the requirement that the reserves be included in the business plan and scheduled for development within three years. These principles are also applied for SEC reporting purposes.

The company has received comments from the Staff of the SEC relating to the Annual Report on Form 20-F for the year ended December 31, 2002 and as of the date of filing this Form 20-F this review process is still ongoing. The Company s proved reserves estimates for the year ended December 31, 2003 reported in this Form 20-F reflect year-end prices and some adjustments which have been made vis-à-vis individual asset reserve estimates based on different applications of certain SEC interpretations of SEC regulations relating to the use of technology (mainly seismic) to estimate reserves in the reservoir away from wellbores and the reporting of fuel gas (i.e., gas used for fuel in operations on the lease) within proved reserves. On an aggregate basis, the net impact of these changes, comprising some reductions and some additions, is an increase of 23 mmboe included in our total proved reserves of 18,361 mmboe (including equity-accounted entities) compared to our reserves under UK SORP. Reserve estimates for prior years have not been adjusted (The 2003 year-end marker prices used were Brent $30.10/bbl and Henry Hub $5.76/mmbtu). These changes, together with the other 2003 movements in proved reserves, are reflected in the tables showing movements in oil and gas reserves by region in the Supplementary Oil and Gas Information on pages S-1 and S-5. These changes had no material impact on our profit for the year as adjusted to accord with US GAAP.

Total hydrocarbon proved reserves, on an oil equivalent basis and excluding equity-accounted entities, comprised 14,999 mmboe at December 31, 2003, a decrease of 4.3% compared with December 31, 2002. Natural gas represents about 50% of these reserves. This reduction includes net sales of 871 mmboe. The proved reserve replacement ratio, at 119% (2002 175%, 2001 191%), exceeded production for the eleventh consecutive year. The proved reserve replacement ratio (also known as the production replacement ratio) is the extent to which production is replaced by proved reserve additions. This ratio is expressed in oil equivalent terms and includes changes resulting from revisions to previous estimates, improved recovery, extensions, discoveries and other additions, excluding the impact of sales and purchases of reserves-in-place and excluding reserves related to equity-accounted entities. By their nature, there is always some risk involved in the ultimate development and production of reserves, including but not limited to final regulatory approval, the installation of new or additional infrastructure as well as changes in oil and gas prices and the continued availability of additional development capital. The proved reserve replacement ratio including sales and purchases of reserves-in-place but excluding equity-accounted entities was 39% (2002 190%, 2001 191%) and including both sales and purchases of reserves-in-place and equity-accounted entities was 160% (2002 198%, 2001 191%).

In 2003, total additions to the Group s proved reserves (excluding sales and purchases of reserves-in-place and equity-accounted entities) amounted to 1,289 mmboe, mostly through extensions to existing fields and discoveries of new fields. Of these reserve additions, approximately 65% are associated with new projects and are proved undeveloped reserve additions and the remainder are in existing developments where they represent a mixture of proved developed and proved undeveloped. Major new development projects typically take one to four years from the time of initial booking to the start of production. The principal reserve additions were in Angola (Greater Plutonio and Dalia), Norway (Ormen Lange), UKCS (Rhum), Azerbaijan (Shah Deniz), Gulf of Mexico (Atlantis) and Australia (Northwest Shelf LNG) and it is planned to bring these into production over the period 2004 - 2008.

Total hydrocarbon proved reserves, on an oil equivalent basis and including equity-accounted entities, comprised 18,361 mmboe at December 31, 2003, an increase of 4.5% compared with December 31, 2002. Natural gas represents about 45% of these reserves. This increase includes purchases of 1,657 mmboe, of which 1,600 mmboe represents the incremental addition as a result of the purchase of 50% of TNK-BP and sales of 1,016 mmboe following completion of the divestment of assets in the North Sea primarily Forties and the Bacton Area in the UK and Gyda in Norway, along with a package of assets in the Gulf of Mexico shelf and the dilution of our gas assets, In Amenas and In Salah, in Algeria.

Additions to proved developed reserves in 2003 were 1,370 mmboe. This included some reserves which were previously classified as proved undeveloped. The proved developed reserve replacement ratio (including both sales and purchases of reserves-in-place and equity-accounted entities) was 105% (2002 118%, 2001 95%).

In our existing profit centres our decline rates are averaging in the 3% to 4% range over the period 2002-2004. Beyond 2004, we estimate the decline will be approximately 3% per annum from 2004-2008. The decline rate is mitigated by the development of new projects and the investment in incremental reserves in and around existing fields. Cash returns will reduce slightly as we manage the decline. In our new profit centres, we anticipate strong volume growth and increasing cash returns. For a definition and discussion of cash returns, see Item 5 Operating and Financial Review and Prospects Prospects on page 101.

Our total hydrocarbon production (including equity-accounted entities) during 2003 averaged 3,606 thousand barrels of oil equivalent per day (mboe/d), an increase of 87 mboe/d, or 2.5% compared with 2002; this includes the 135 mboe/d impact of divestments offset by the inclusion of 205 mboe/d TNK-BP incremental volumes from August 29, 2003. 35% of our production was in the USA, 17% in the UK and 17% from equity-accounted entities, of which 53% is from TNK-BP and the former Sidanco. Total production for 2004 is estimated at an average of over 4 million barrels of oil equivalent per day (mmboe/d).

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The following tables show BP s aggregate estimated net proved reserves as at December 31, 2003.

Estimated net proved reserves of liquids at December 31, 2003 (a) (b)

	Developed	Undeveloped	Total
		(millions of barrels)	
UK	697	245	942
Rest of Europe	236	127	363
USA	1,902	1,499	3,401
Rest of Americas	385	354	739
Asia Pacific	82	81	163
Africa	190	632	822
Russia			
Other	73	711	784
	3,565	3,649	7,214
Equity-accounted entities			2,867
Total Group and BP share of equity-accounted entities			10,081

Estimated net proved reserves of natural gas at December 31, 2003 (a) (b)

	Developed	Undeveloped	Total
		(billion cubic feet)	
UK	2,996	1,095	4,091
Rest of Europe	262	1,255	1,517
USA	11,482	3,337	14,819
Rest of Americas	4,212	11,531	15,743
Asia Pacific	1,976	3,026	5,002
Africa	640	2,188	2,828
Russia			
Other	255	900	1,155
	21,823	23,332	45,155
Equity-accounted entities			2,869
Total Group and BP share of equity-accounted entities			48,024

Total proved reserves (mmboe)	18,361

(a) Net proved reserves of crude oil and natural gas, stated as of December 31, 2003, exclude production royalties due to others, whether payable in cash or in kind, and include minority interests in consolidated operations. We disclose our share of reserves held in joint ventures and associated undertakings that are accounted for by the equity method although we do not control these entities or the assets held by such entities.

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(b) In certain deepwater fields, such as fields in the Gulf of Mexico, BP has claimed proved reserves before production flow tests are conducted in part because of the significant safety, cost and environmental implications of conducting these tests. The industry has made substantial technological improvements in understanding, measuring and delineating reservoir properties without the need for flow tests. The general method of reserves assessment to determine reasonable certainty of commercial recovery which BP employs relies on the integration of three types of data: (1) well data used to assess the local characteristics and conditions of reservoirs and fluids; (2) field scale seismic data to allow the interpolation and extrapolation of these characteristics outside the immediate area of the local well control; and (3) data from relevant analog fields. Well data includes appraisal wells or sidetrack holes, full logging suites, core data and fluid samples. BP considers the integration of this data in certain cases to be superior to a flow test in providing a better understanding of the overall reservoir performance. The collection of data from logs, cores, wireline formation testers, pressures and fluid samples calibrated to each other and to the seismic data can allow reservoir properties to be determined over a greater volume than the localized volume of investigation associated with a short term flow test.

Historically, proved reserves recorded using these methods have been validated by actual production levels. BP has booked proved reserves in 18 fields in the deepwater Gulf of Mexico prior to production flow testing. Fourteen of these are now in production. Holstein, Mad Dog, Thunder Horse and Atlantis are due to begin production over the period 2004-2006.

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The following tables show BP s production by major field for 2003, 2002 and 2001.

Liquids

Production	Field or Area	Interest	Net production 2003	2002	2001
		(%)	(thousand barrels per day)		
Alaska	Prudhoe Bay*	26.4	105	113	123
	Kuparuk	39.2	73	74	76
	Northstar*	98.6	46	36	3
	Milne Point*	100.0	44	44	45
	Other	Various	43	42	41
Total Alaska			311	309	288
Lower 48 States onshore (a)	Total	Various	160	192	213
Gulf of Mexico (a)	Mars	28.5	43	41	42
	Horn Mountain*	66.6	42	1	
	King*	100.0	31	12	
	Pompano*	73.6	15	23	21
	Ursa	22.7	17	20	23
	Other	Various	107	167	157
Total Gulf of Mexico			255	264	243
Total USA			726	765	744
UK offshore (a)	ETAP	Various	56	61	80
	Foinaven*	Various	55	72	60
	Schiehallion/Loyal*	Various	42	43	40
	Magnus*	85.0	39	31	37
	Harding*	70.0	34	42	42
	Andrew*	62.8	17	23	25
	Forties*(b)	96.1	10	50	51
	Other	Various	95	107	114
Total UK offshore			348	429	449
UK onshore	Wytch Farm*	67.8	29	32	36
Total UK			377	461	485
Norway (a)	Draugen	18.4	25	37	40
	Valhall*	28.1	21	21	22
	Ula*	80.0	16	18	18
Other Norway and Netherlands	Various	Various	22	28	20

Total Rest of Europe	84	104	100

* BP operated.

BP operates the majority of the fields in this area.

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Production	Field or Area	Interest	Net production 2003	2002	2001
		(%)	(thousand barrels per day)		
Angola	Various	Various	35	29	1
Australia	Various	16.7	40	43	40
Azerbaijan	Azeri-Chirag-Gunashli*	34.1	38	38	35
Canada	Various	Various	13	16	18
Colombia (a)	Various	Various	53	46	48
Egypt	Various	Various	73	85	91
Trinidad	Various	100.0	74	67	48
Venezuela (a)	Various	Various	53	51	54
Other (a)	Various	Various	49	61	59
Total Rest of World			428	436	394
Total Group			1,615	1,766	1,723
Equity-accounted entities					
Abu Dhabi (c)	Various	Various	138	113	126
Argentina - Pan American Energy	Various	Various	60	53	50
Russia - TNK-BP (a)	Various	Various	228		
- Sidanco	Various	Various	68	73	20
Other	Various	Various	12	13	12
Total equity-accounted entities			506	252	208
Total Group and BP share of equity-accounted entities (d)			2,121	2,018	1,931

* BP operated.

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Natural gas (e)

Production	Field or Area	Interest	Net Production 2003	2002	2001
		(%)	(million cubic feet per day)		
Lower 48 States onshore (a)	San Juan Coal*	Various	578	601	615
	San Juan Conventional	Various	224	196	217
	Arkoma	Various	201	206	219
	Hugoton	Various	182	169	180
	Tuscaloosa	Various	136	138	187
	Jonah*	75.2	119	113	109
	Wamsutter*	70.5	111	108	100
	Other	Various	558	715	733
Total Lower 48 States onshore			2,109	2,246	2,360
Gulf of Mexico (a)	Marlin*	78.2	93	106	79
	King s Peak*	100.0	91	16	
	Mica	50.0	57	58	27
	Other	Various	695	1,005	1,077
Total Gulf of Mexico			936	1,185	1,183
Alaska	Various	Various	83	52	11
Total USA			3,128	3,483	3,554
UK offshore (a)	Bruce*	37.0	222	221	256
	Braes	Various	174	116	100
	Marnock*	62.0	98	135	125
	West Sole*	100.0	73	72	81
	Shearwater	27.5	70	66	19
	Armada	18.2	58	71	71
	Britannia	9.0	55	56	65
	Other	Various	696	813	996
Total UK			1,446	1,550	1,713
Netherlands	P/18-2*	48.7	30	41	47
	Other	Various	37	46	52
Norway (a)	Various	Various	52	60	48
Total Rest of Europe			119	147	147

* BP operated.

BP operates the majority of the fields in this area.

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Production		Field or Area	Interest	Net production 2003	2002	2001
			(%)	(million cubic feet per day)		
Rest of World						
Australia		Various	16.7	285	295	237
Canada		Kirby*	95.0	48	66	72
		Other	Various	374	448	512
China		Yacheng*	34.3	74	102	108
Egypt		Ha py	50.0	83	74	66
		Temsah	50.0	66	84	26
		Other	Various	104	98	98
Indonesia		Sanga-Sanga (direct)	26.3	165	174	164
		Pagerungan*	100.0	121	189	242
		Other*	46.0	97	94	95
Sharjah		Sajaa*	40.0	101	110	125
		Other	40.0	19	24	35
Trinidad		Amherstia*	100.0	624	492	244
		Mahogany*	100.0	503	521	529
		Immortelle*	100.0	235	154	128
		Parang*	100.0	152		
		Flamboyant*	100.0	68	40	52
		Other*	100.0	112	31	58
Other (a)		Various	Various	168	148	82
Total Rest of World				3,399	3,144	2,873
Total Group				8,092	8,324	8,287
Equity-accounted entities						
Argentina	- Pan American Energy	Various	Various	281	251	236
Russia	- TNK-BP (a)	Various	Various	96		
	- Sidanco	Various	Various	33	6	
Other		Various	Various	111	126	109
Total equity-accounted entities				521	383	345
Total Group and BP share of equity-accounted entities				8,613	8,707	8,632

* BP operated.

(a) In 2003, BP and the Alfa Group and Access-Renova merged certain of their Russian and Ukranian oil and gas businesses to create TNK-BP. BP also acquired the interests of Amerada Hess in Colombia and disposed of its interests in Forties, Montrose/Arbroath and Bacton Area assets in the UK North Sea, Gyda in Norway, LL652 in Venezuela, QHD and Liuhua in China, the Malaysia Thailand Joint Development Area, Aspen in the Gulf of Mexico, various shallow water fields in the Gulf of Mexico and various fields in the US Lower 48 states. In 2002, BP acquired additional working interest in the Badin acreage (Pakistan) from the government and disposed of its interest in the Al Rayyan field (Qatar), Qadirpur field (Pakistan) and Elgin/Franklin field (UK). In 2001, BP purchased part of the interests of Statoil in Vietnam and the interest of Inaquimicas in Cusiana/Cupiagua in Colombia.

(b) The sale of BP s interest in the Forties field was completed on April 2, 2003.

(c) The BP Group holds proportionate interests, through associated undertakings, in onshore and offshore concessions in Abu Dhabi expiring in 2014 and 2018, respectively.

(d) Includes NGLs from processing plants in which an interest is held of 70 mb/d, 69 mb/d, and 78 mb/d for 2003, 2002 and 2001, respectively.

(e) Natural gas production volumes exclude gas consumed in operations within the lease boundaries of the producing field.

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United States

2003 liquids production at 726 thousand barrels per day (mb/d) decreased 5% from 2002, while natural gas production at 3,128 million cubic feet per day (mmcf/d) decreased 10% compared with 2002.

Crude oil production was maintained at the 2002 level, with divestments and natural reservoir declines (25 mb/d) being offset by new projects and gains in operating efficiency (24 mb/d). The decline in the Natural Gas Liquids component of liquids production (39 mb/d) was caused by divestments, lower gas throughput and processing elections not to strip NGLs from produced gas (in order to sell rich gas in a high gas price environment) thus resulting in lower commercial NGL production. Gas production was lower because of divestments, natural reservoir decline and investment choices (436 mmcf/d), partly offset by new project startups and continuing ramp-up of 2002 projects (81 mmcf/d). Operational efficiency in the USA, i.e., actual production as a percentage of production capacity, was much improved in 2003, up 3% over 2002 to 93% due to less weather-related downtime and performance improvements.

Development expenditure in the USA (excluding midstream) during 2003 was $3,486 million, compared with $3,618 million in 2002 and $3,723 million in 2001. This reflects our continued focus on only investing in the best opportunities and optimizing operating efficiency.

Our activities within the United States take place in four main areas. Significant events during 2003 within each of these are indicated below.

Deepwater Gulf of Mexico

Deepwater Gulf of Mexico is one of our new profit centres and our largest area of growth in the United States. In 2003, our Deepwater Gulf of Mexico crude oil production was 215 mb/d, up 5% from 2002 levels. Gas production was 561 mmcf/d, up over 10% from 2002 levels.

Growth in 2003 was driven by new field startup activity, as well as strong performance from the existing major hubs. Key events include:

Production ramp up at the Horn Mountain (BP 66.6% and operator) and King s Peak (BP 100% and operator) fields. Both fields began production in late 2002.

The King West subsea project (BP 100% and operator) started production in June 2003.

Production from the Na Kika Development (BP 50% and operator) commenced in November 2003. The development consists of 5 fields and 10 subsea wells connected to a centrally-located floating host facility.

Mardi Gras transportation system construction is on track and the first segment, the Okeanos Gas Gathering System, started up in conjunction with first production from the Na Kika field in November.

The second phase of the Princess project (BP 22.69%), a 3-well subsea development to the Ursa platform, began producing in December 2003.

Development of four major projects continued in the Gulf of Mexico during 2003   Holstein (BP 50% and operator) is on track to start up late 2004 with the final stages of construction underway. Mad Dog (BP 60.5% and operator) and Thunder Horse (BP 75% and operator) are scheduled to commence production in 2005 with Atlantis (BP 56% and operator) following in 2006. These projects will be the major contributor to the anticipated growth in production from 312 mboe/d to 550 mboe/d.

Additionally, the divestment of the Aspen field (BP 40% and operator) was concluded in the second quarter of 2003 as part of BP s ongoing portfolio review to focus on high quality assets and to stop investing in those where others may see greater value.

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On January 30, 2004, we sold 45% of our interest in King s Peak in Deepwater Gulf of Mexico to Marubeni Oil & Gas (USA).

On May 22, 2004, the Mars platform was shut in due to a small leak.

Gulf of Mexico Shelf

The Shelf is a mature basin, with decline rates that average 40-50% per year. On March 13, 2003 BP completed the sale of 61 fields to Apache Corporation, which accounted for approximately 40% of 2002 production. In 2003, BP s gas production from Gulf of Mexico Shelf operations was 375 mmcf/d, which was down 44% compared to 2002. Liquids production was 39 mb/d, down 34% compared to 2002. The year-on-year drop in production is attributed to the divestment, normal decline and reduced capital spending. Capital spending has reduced from $428 million in 2002 to $205 million in 2003. This is as a result of our divestment programme as well as focusing our capital expenditure on better opportunities elsewhere in the segment. We operate more than 150 platforms and 350 wells on the Shelf and we drilled a total of 15 operated wells in 2003.

Lower 48 States

In the Lower 48 States we are one of the largest producers of natural gas, accounting for over 5% of total US onshore natural gas production. Production comes from over 12,000 wells, distributed across more than 600 oil and gas fields, of which we operate nearly 80%. Assets are situated principally in the states of Colorado, Kansas, Louisiana, New Mexico, Oklahoma, Texas and Wyoming.

Total production in 2003 was down 10% compared with 2002. Natural decline and strategic portfolio divestments accounted for 3% each and reduced gas throughput and changes in processing elections accounted for the remainder. In 2003, total liquids production was 160 mb/d and natural gas production was 2,109 mmcf/d.

In 2003, we drilled over 400 operated wells and maintained a level programme of activity utilizing, on average, 26 drilling and 50 service rigs. Year-on-year improvements continue to be delivered in safety, capital and cost efficiency across all the basins where we operate. Additionally, our environmental leadership has continued with a 286 kilotonnes (kte) reduction of CO_2 emissions, through delivery of focused greenhouse gas (GHG) reduction projects, including the installation of solar panels to power some of our pumping units at our wells in the San Juan South region.

Our production in the onshore Lower 48 States was derived primarily from two main areas:

- In the Western Basins (Colorado, New Mexico, and Wyoming) our assets produced 1,255 mmcf/d (94% operated) of natural gas and 78 mb/d of liquids in 2003.

In the Gulf Coast and Mid-Continental basins (Kansas, Louisiana, New Mexico, Oklahoma and Texas) our assets produced 854 mmcf/d (62% operated) of natural gas and 48 mb/d of liquids in 2003.

Alaska

In Alaska, crude oil production in 2003 was 311 mb/d, an increase of 0.6% from 2002, due principally to increases in Northstar production and development of satellite fields around Prudhoe Bay and Kuparuk.

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Key activities during 2003 in Alaska included:

As part of maximising the productivity of our existing profit centres, active reservoir management at Alaska s largest producing field, Prudhoe Bay, and the associated satellites (BP 26.4% and operator) included an ongoing active infill and new well drilling programme with 80 wells, which generated net production of 8.2 mboe/d. In 2003, BP had 6.5 operated rig-years (6 rigs full time, 1 rig half time) working across the North Slope. At the Milne Point Unit, 20 wells were drilled with 8 miles of horizontal hole achieving 45% lower non-productive time than 2003. The Northstar Unit drilled 8 wells in 2003, and the Endicott Unit drilled 4 sidetrack wells.

The Northstar Oil Field (BP 98.58%) completed its second full year of operations with operating efficiency and production rates well ahead of 2002 levels. Improved equipment reliability and the completion of additional development wells enabled an estimated operating efficiency rate of 86.5% and a daily gross production average of 63 mb/d.

Two agencies completed their investigations into the August 2002 A-22 well explosion with BP s full cooperation. The Alaska Department of Labor Occupational Health and Safety Division assessed a penalty of $6,300 in February 2003, which BP did not contest. The Alaska Oil and Gas Conservation Commission released its staff report on the incident in mid-December and proposed an enforcement action and a penalty in excess of $2.5 million. BP is contesting the penalty.

The Y-36 flowline spill occurred at Greater Prudhoe Bay in May 2003, spilling an estimated 1,300 gallons (US) of crude and 5,000 gallons (US) of produced water. The spill was caused by external corrosion beneath the flowline s insulation. The flowline has since been repaired and there has been no long-term damage to the environment. BP had noted increased corrosion of this type in late 2001 and nearly tripled its mitigation programme in 2003. As operator, BP expends approximately $50 million (gross) annually on corrosion management programmes at Greater Prudhoe Bay.

United Kingdom

We are the largest producer of oil and gas in the UK. In 2003, total liquids production was 377 mb/d, an 18% decrease on 2002, and gas production was 1,446 mmscf/d, a 7 % decrease on 2002. This decrease in production was driven by the divestment during 2003 of the Forties, Montrose/Arbroath and Bacton Area assets to Apache Corporation, Paladin Resources and Perenco, respectively, (49%) along with the natural decline of the mature North Sea basin and operational problems in the second and third quarters (51%). These operational problems included a compressor shutdown on Foinaven (BP operated), well integrity concerns on the Shearwater field (Shell operated) and a gearbox failure on Eastern Trough Area Project (BP operated). All fields were returned to production during the year. Our activities in the North Sea are focused on operations efficiency, in-field drilling and selected new field developments. Our development expenditure in the UK was $740 million in 2003 compared to $895 million in 2002 and $930 million in 2001.

Significant activities in 2003 included the following:

The Clair Phase I Development (BP 28.9% and operator) is in mid-construction and on schedule for first oil in late 2004.

In 2003, all major construction contracts were awarded for the Rhum development (BP 50% and operator) and fabrication was initiated. Rhum is a high pressure, high temperature gas field that is the first of its type for BP in the region. The field will be developed via a 44 km subsea tieback to the Bruce platforms. Startup is scheduled for 2005.

In 2003, cumulative oil production in the Harding field (BP 70% and operator) and in the Andrew field (BP 62.75% and operator) exceeded the total amounts estimated when the reserves

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were originally booked. Success in both fields is attributed to the application of new technologies and best practice reservoir management.

The Braemar field (BP 52%) began production at the end of the third quarter, following tie-back to the East Brae platform.

On the Machar field (BP 100% and operator) a project to sustain production by gas lifting the wells was completed and a significant new production well sanctioned for 2004 startup.

At Wytch Farm (BP 67.8% and operator) a seismic survey was shot offshore to define well locations for a 10-well extended reach drilling programme started in 2004.

On the Lomond (BP 22.2% and operator) and Erskine (BP 50%, ChevronTexaco operated) fields, mid-life compression projects have been sanctioned to extend field life. Mid-life compression refers to the installation of compression facilities on the platform which will supplement the natural pressure of the reservoir and thereby increase the flow rate of hydrocarbons.

The Ravenspurn North (BP 53.5% and operator) gas sales contract was renegotiated to transfer the control of production from the buyer to the joint venture partners with effect from October 1, 2003.

A one-off gas sales deal was agreed for Amethyst (BP 59.5% and operator) to increase gas sales during the 2003 summer period.

The NW Hutton (BP 26% and operator) well decommissioning was completed on January 22, 2004 with the removal of the last conductor. The total cost of decommissioning was $17.6 million (BP share).

Rest of Europe

Development expenditure, excluding midstream, in the Rest of Europe was $236 million compared with $219 million in 2002 and $271 million in 2001.

Norway

Production in Norway decreased from 113 mboe/d in 2002 to 92 mboe/d in 2003, a decline of 18%. The principal reasons behind this were: a reduction in Draugen production capacity and delays in restoring production from Rogn South wells following a shutdown; the SE1 well on Ula proved water in the main target rather than oil, hence the anticipated decline mitigation was not achieved; and Tambar, having reached plateau in 2002, was impacted by post-plateau natural decline. The total impact of these items was a decrease of 17 mboe/d. In addition, on September 1, 2003 we sold our 61% interest in the Gyda field to Talisman Energy (6 mboe/d). We have maintained production at 2002 levels on Valhall as a result of the Flank project coming on stream (first oil in the second quarter of 2003) and a high level of operating efficiency.

Main activities and achievements in 2003:

Valhall Water Injection project following technical difficulties in positioning the jacket foundation piles, repairs were successfully carried out and the topside was installed in the third quarter.

Valhall Flank Development Flank South achieved first oil in May 2003 and the North platform was installed in the third quarter with first oil achieved on January 7, 2004.

Ormen Lange The unit operating agreement, plan of development and the joint venture agreements for an export pipeline to the UK were agreed and approved by the partnership in December. BP has a 10.3% interest in this project.

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Rest of World

Development expenditure, excluding midstream, in Rest of World was $3,085 million in 2003 compared with $2,503 million in 2002 and $1,934 million in 2001.

Rest of Americas

Canada

In Canada, our 2003 production was 86 mboe/d, down 18% from 2002, mainly due to natural field decline. The Alberta Energy and Utilities Board ordered the industry to shut-in production from certain shallow gas fields overlaying bitumen deposits in northeastern Alberta with effect from September 1, 2003. BP s production impacted by this order was 1.3 mboe/d on an annualized basis. BP and other producers are pursuing legal and regulatory options challenging the shut-in requirement in addition to seeking appropriate compensation from the Alberta Government. Natural gas makes up 85% of Canada s production.

On February 9, 2004, we signed a sale and purchase agreement with Fairborne Energy Ltd. to sell a package of non-core assets in Alberta, Canada for $88 million. These assets contributed approximately 3 mboe/d during 2003.

Trinidad

In Trinidad, gas volumes increased by 37% over 2002. The increase in natural gas sales was principally driven by the successful startup of Atlantic LNG Train 3 in the second quarter of 2003, as well as a full year of sales to Atlantic LNG Train 2. During the year, BP completed the installation of Cassia B, the world s largest offshore processing facility (2 bcf/d), linked in to the new Bombax 48 gas pipeline evacuation system, which was successfully commissioned in the second quarter of 2003. Our next field development (Cannonball) was sanctioned in the fourth quarter of 2003. First gas is targeted for the fourth quarter of 2005.

On January 2, 2003, Repsol exercised their option to acquire an additional 20% interest in BP s upstream assets in Trinidad, taking their total interest in BP Trinidad and Tobago LLC to 30%. This transaction gives leverage for our upstream position in Trinidad to access gas markets and growth opportunities in Spain, thus providing a further platform for BP s future gas growth in Trinidad.

On May 15, 2003, we sold our 15% stake in the Titan Methanol Company, based in Trinidad, to Methanex Corporation. The Atlas methanol plant the world s largest, in which BP has a 36.9% interest commenced production on June 2, 2004.

Venezuela

In Venezuela three of the four base assets are reactivation projects (projects that are expected to continue and improve exploitation in mature fields) consisting of two operated properties, Boqueron and Desarollo Zuli Occidental (DZO), and one non-operated property, Jusepin, under risk service agreements to produce oil for the state oil company, Petroleos de Venezuela S.A. (PDVSA). A fourth asset, Cerro Negro, a non-operated property that is a heavy oil project from which production is sold directly by BP, was held for sale in

2002. In the absence of partner approval for the sale, the agreement was terminated in December 2003. There are no immediate plans to remarket this asset. During 2003 we executed a sale and purchase agreement to sell DZO and Boqueron to Perenco. In the first quarter of 2004, the sales agreement lapsed and we will now retain these fields. We had previously reported an exceptional loss on disposal of $217 million in respect of these assets, which has now been reversed. As a result of the lapse of the agreement, an impairment charge of $186 million was recognized in the first quarter of 2004. LL-652, also a reactivation project, was sold and transferred to ChevronTexaco during the year. The impact of the national strike, which began in December 2002, was 5 mb/d in 2003, with production back to pre-strike levels by mid-March 2003.

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Colombia

In Colombia, BP completed operations in November on the Niscota exploration well after testing water with traces of non-commercial hydrocarbons. While this well has been written off, additional prospectivity and disposition of the contract area will be determined in the second half of 2004 after evaluation of data obtained from drilling activities.

Argentina and Bolivia

In Argentina and Bolivia, activity is conducted through Pan American Energy (PAE), in which BP holds a 60% interest, and which is accounted for by the equity method. In 2003, total production of 117 mboe/d represented an increase of 10.3% over 2002, with oil increasing by 10.4% and gas by 10.2%. The main increase in oil production came from the continued focus on drilling and waterfloods in Golfo San Jorge in Argentina, where oil production was 52 mb/d compared to 45 mb/d in 2002. The field is now producing at its highest level since inception in 1958 and further expansion programmes are planned. Despite the economic crisis in Argentina, GDP increased by 8.7% in 2003. Gas demand grew due to the higher activity level, colder than normal weather and lack of hydroelectric power due to lower than average rainfall. Gas prices continued to be depressed. PAE also has interests in gas pipelines, electricity generation plants and other midstream infrastructure assets.

Africa

Algeria

In 2003, BP sold 50% and 49% of its interests in In Amenas and In Salah, respectively, to Statoil. Formal Algerian approval is currently outstanding.

In Algeria, BP and the Algerian state company, Sonatrach, continued development activities of the In Salah project (BP 51%), which is expected to start up in mid-2004. The first stage comprises the development of three of the seven deep Saharan natural gas fields expected to supply the fast-growing markets of Southern Europe.

BP and Sonatrach continued to progress the development of the In Amenas (BP 50%) project, expected to start up in early 2006.

Angola

Angola has several key projects which provide the foundation for volume growth over the next few years. Activities in 2003 included the following:

In Block 17 (BP 16.7%), the Jasmim field, a tie-back to the Girassol hub, commenced production in the fourth quarter of 2003. The Dalia project commenced development in the first quarter of 2003.

In Block 15 (BP 26.7%), the Xikomba field commenced production in the fourth quarter of 2003. Development activities progressed on Kizomba A and Kizomba B, with production expected to commence in the second half of 2004 on Kizomba A.

In Block 18 (BP 50% and operator), work has continued on the Greater Plutonio development, with internal sanction granted in the first quarter of 2003.

In Block 31 (BP 26.7% and operator), a 2-year extension to the initial exploration phase was granted in the second quarter of 2003.

Angolan oil projects have associated gas which BP is seeking both economic and environmental solutions for production and distribution as part of the Angola LNG project.

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Egypt

In Egypt, the Gulf of Suez Petroleum Company (GUPCO), a joint venture operating company between BP and the Egyptian General Petroleum Corporation, carries out our oil production operations. GUPCO operates seven PSAs in the Gulf of Suez and Western Desert, encompassing more than forty fields.

In 2003, physical gas production in Egypt was held close to 2002 rates. BP s 2003 PSA gas production reached 253 mmscf/d from the Ras El Barr, Temsah and other concessions.

BP has a 33% interest in the joint venture United Gas Derivatives, currently constructing a 1.1 bcf/d NGL extraction plant. Plant startup is scheduled in the fourth quarter of 2004. Temsah and Ha py development projects are on schedule to deliver 100% of the fields daily contracted quantities to ensure supply feedstock for the NGL plant.

Asia Pacific

Indonesia

BP is the largest private supplier of natural gas to Java through its holdings in the Offshore Northwest Java (46% BP) and Kangean (100% BP) Production Sharing Contracts.

Vietnam

BP participates in the country s biggest foreign investment, the Nam Con Son gas project. This is an integrated resource and infrastructure project including offshore gas production, pipeline transportation system and power plant. Gas sales from Block 6.1 (BP 35% and operator) commenced in early 2003. The gas is sold under a long-term agreement for electricity generation in Vietnam, including the Phu My 3 power plant (BP 33.33%), which commenced operations on March 1, 2004.

China

The Yacheng field (BP 34.3% and operator) supplies, under a long-term contract, 100% of the natural gas requirement of Castle Peak Power Company for Hong Kong power generation. Some natural gas is also piped to Hainan Island, where it is sold to the Fuel and Chemical Company of Hainan, also under a long-term contract. The Yacheng field operatorship was transferred to China National Offshore Oil Corporation (CNOOC) on January 1, 2004. In 2003, we have divested our interests in our other fields, QHD and Liuhua, to CNOOC.

Australia

We are one of six equal partners (BP 16.7%) in the North West Shelf (NWS) Venture. The operation covers offshore production platforms, a floating storage vessel, trunklines, and onshore gas processing plants, and is currently the principal supplier to the domestic market in Western Australia. During 2003, a fourth LNG Train was under construction and is on track to be commissioned in the second half of 2004, and a second trunkline was commissioned in February 2004.

Russia

Acquistion of TNK-BP interest

On August 29, 2003, BP and AAR (the Alfa Group and Access-Renova) completed the deal to combine their Russian and Ukrainian oil and gas businesses and create TNK-BP, a new company registered in the British Virgin Islands owned 50:50 and managed jointly by BP and AAR. The consideration from BP to AAR comprised an immediate $2.6 billion in cash (which was subsequently reduced by receipt of pre-acquisition dividends net of transaction costs of $0.3 billion) for its stake in the new company together with three annual tranches of $1.25 billion in BP shares payable on the subsequent anniversaries of the closing date. The assets contributed by BP included existing interests in Sidanco and Rusia, as well as its interest in the retail business in Moscow. The deal did not include BP s interest in Sakhalin or its Castrol operations in Russia. The net BP investment, after adjusting for pre-acquisition dividends, amounted to $6.7 billion. BP also agreed with AAR to incorporate AAR s 50% interest in Slavneft into TNK-BP in

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return for a cash payment by BP of $1.35 billion, subject to adjustments. This transaction was completed on January 16, 2004. Overall, this represents the largest transaction in Russian corporate history, as well as being the largest foreign indirect investment in Russia.

TNK-BP is jointly controlled by BP and Alfa Group and Access Renova (AAR). BP holds 50% of the voting rights in TNK-BP. BP s investment in TNK-BP is accounted as a joint venture under the gross equity method and as such we have reflected 50% of the proved reserves of TNK-BP as at December 31, 2003 (1.8 billion barrels of oil, of which 1.4 billion are developed). The reserves which were incremental to those contributed from our investment in Sidanco (1.6 billion barrels of oil) are shown as a purchase of reserves in place in equity-accounted entities. The return on our investment in TNK-BP is expected to come through cash dividends. Earnings for the period August 29 to December 31, were accretive to BP returns on capital and we expect this to continue at current prices. As with our other assets, an increase in oil prices will increase the returns on our investment. Our expected return on this investment in both the short and long term is estimated to be comparable to that of our non-Russian activity.

The shareholder agreement between BP and AAR establishes TNK-BP in the British Virgin Islands with English law principles governing the legal system. The shareholder agreement establishes joint control between AAR and BP. BP and AAR have equal representation on the TNK-BP Board, with AAR nominating the Chairman and Chairman of the Remuneration Committee, and BP the Vice Chairman and Chairman of the Audit Committee. BP appoints the Chief Executive Officer of TNK-BP and holds half of the senior management positions.

On June 11, 2004 BP and AAR agreed to change the dates on which BP is due, under the terms of that agreement, to issue AAR with three tranches of BP p.l.c. shares, each tranche with a value of $1.25 billion. The issue dates have been changed from August 29, 2004, August 29, 2005 and August 29, 2006 to September 20, 2004, September 20, 2005 and September 20, 2006, respectively. The issue dates have been moved in order to avoid BP s third quarter ex-dividend date falling within the calculation period for determining the number of BP p.l.c. shares to be issued to AAR in each tranche, thereby reducing the potential for volatility during that period. There is no incremental cost to BP or its shareholders as a result of this change in issue dates.

TNK-BP

TNK-BP has proved reserves of 3.6 billion barrels of oil, of which 2.8 billion are developed. Daily oil production currently amounts to some 1.3 million barrels of oil a day. The production base is largely centred in West Siberia (Samotlor, Nizhnevartovskoye Nefedobyvaushee Predpriyatie, Nyagan), which contributes about 0.8 million barrels a day, together with Volga Urals (Orenburgneft) contributing 0.4 million barrels a day. In excess of 50% of total oil production is currently exported as crude and 15% as refined product. Downstream, TNK-BP owns five refineries in Russia and Ukraine (including Ryazan and Lisichansk), with throughput of 0.5 million barrels a day (25 million tonnes a year). In retail, TNK-BP owns more than 2,100 filling stations in Russia and the Ukraine with a share of the Moscow retail market in excess of 20%. The workforce currently amounts to approximately 100,000 people.

BP s investment in TNK-BP is accounted for under the gross equity method. Production for the four-month post-completion period averaged 713 mboe/d; this generated some $392 million of net income in an environment where Urals marker prices (NW Europe) averaged around $27.3/bbl (from August 29, 2003). In full-year terms, BP s share of production averaged 244 mboe/d. A dividend of $297 million received in the fourth quarter was credited against the net investment cost and reduced net cash outflow to $2.35 billion.

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Slavneft

On January 16, 2004 a payment of $1.35 billion was made to AAR to incorporate AAR s 50% interest in Slavneft into TNK-BP. Slavneft will be included in the results of our 50% interest in TNK-BP in 2004. Slavneft has current production rates exceeding 0.3 million barrels of oil per day. It has two refineries in Russia (Yaroslavl) and an interest in the Mozyr refinery (Belarus) with total throughput of 384,000 barrels a day, as well as more than 550 retail filling stations in Russia.

Other

Middle East and Pakistan

Production in the Gulf States was dominated by the production entitlement of associated undertakings in Abu Dhabi, where we have equity interests of 9.5% and 14.7% in onshore and offshore concessions, respectively. In 2003, production in Abu Dhabi was up around 23% from 2002 as a result of OPEC quota increases.

In Pakistan, BP is the largest foreign operator producing around 43% of the country s oil and 8% of its natural gas on a gross basis.

Azerbaijan

BP, as operator of the Azerbaijan International Operating Company (AIOC), manages and has a 34.1% interest in the Azeri-Chirag-Gunashli (ACG) oil fields in the Caspian Sea, offshore Azerbaijan. The Azeri project continued in 2003 and is on track to deliver first oil from central Azeri in the first quarter 2005. Phase 3 of ACG full field development commenced the detailed engineering stage and is targeting sanction in 2004.

The Shah Deniz natural gas field (BP 25.5% and operator) was sanctioned in 2003 and remains on track to deliver first gas in 2006.

Midstream Activities

Oil and Natural Gas Transportation

The Group has direct or indirect interests in certain crude oil transportation systems, the principal ones of which are the Trans Alaska Pipeline System (TAPS) in the USA and the Forties Pipelines System (FPS) in the UK sector of the North Sea. We also operate the Central Area Transmission System (CATS) for natural gas in the UK sector of the North Sea.

BP, as BTC operator, manages and holds a 30.1% interest in the Baku-Tbilisi-Ceyhan (BTC) oil pipeline currently under construction. AIOC operates the Western Export Route Pipeline between Azerbaijan and the Black Sea coast of Georgia and the Azeri leg of the Northern Export Route Pipeline between Azerbaijan and Russia.

Our onshore US crude oil and product pipelines and related transportation assets are included under Refining and Marketing in this item. Revenue is earned on pipelines through charging tariffs. Our gas marketing business is described under Gas, Power and Renewables in this item.

Activity in oil and natural gas transportation during 2003 included:

Alaska

BP owns a 46.9% interest in TAPS, with the balance owned by four other companies. TAPS transported production from Prudhoe Bay and the other North Slope fields averaging 991 mb/d during 2003.

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There are a number of unresolved protests regarding tariffs charged for shipping oil through TAPS. These protests were filed between 1986 and 2003 with the Federal Energy Regulatory Commission and the Regulatory Commission of Alaska (RCA). In 2002, the RCA issued an Order requiring refunds to be made to TAPS shippers of intrastate crude oil for the years 1997 through 2000. BP has appealed this Order to the Alaska Superior Court. Pending the outcome of a hearing on intrastate rates from 2001 forward, the RCA imposed temporary intrastate rates (consistent with its 2002 Order) effective July 1, 2003.

The use of US-built and US-flagged ships is required when transporting Alaskan oil to markets in the USA. In accordance with this, BP America Inc. has a chartered fleet of nine US-flagged tankers to transport Alaskan crude oil to markets. Over the next few years, we plan to begin replacing our US-flagged fleet as existing ships are retired in accordance with the Oil Pollution Act of 1990. For discussion of the Oil Pollution Act of 1990, see Environmental Protection Maritime Oil Spill Regulations on page 69. BP has contracted for the delivery of four 1.3 million-barrel-capacity, double-hull tankers for use in transporting North Slope oil to West Coast refineries. The ships are being constructed by NASSCO in San Diego with deliveries in years 2004, 2005 and 2006. The first vessel was floated from drydock in November of 2003, in keeping with a 2004 delivery.

North Sea

FPS (BP 100%) is an integrated oil and NGLs transportation and processing system that handles production from over 40 fields in the Central North Sea. The system has a capacity of more than 1 mmb/d, with average throughput in 2003 at 751 mb/d.

During the fourth quarter of 2003, FPS reached agreement with Encana and others to transport and process hydrocarbons from the Buzzard Field. This is the largest UK sector transportation and processing deal in the last 10 years.

BP operates and has a 29.5% interest in CATS, a 400-kilometre natural gas pipeline system in the central UK sector of the North Sea. The pipeline has a transportation capacity of 1.7 bcf/d to a natural gas terminal at Teesside, Northeast England. CATS offers natural gas transportation services or transportation and processing via two 600 mmcf/d processing trains. In 2003, throughput was 1.6 bcf/d.

In addition, BP operates the Dimlington/Easington gas processing terminal (BP 100%) on Humberside and the Sullom Voe Gas Terminal in the Shetlands, which celebrated 25 years of operations in November 2003.

Asia (including the former Soviet Union)

BP, as BTC operator, manages and holds a 30.1% interest in the Baku-Tbilisi-Ceyhan (BTC) oil pipeline which is currently under construction and is on schedule to be ready for line fill by early 2005.

The South Caucasus pipeline (SCP) for the transport of gas from Shah Deniz in Azerbaijan to the Turkish border was sanctioned in February 2003. BP is the operator and holds a 25.5% interest.

Through the LukArco joint venture, BP holds a 5.75% interest in the Caspian Pipeline Consortium (CPC) pipeline. CPC is a 1,510-kilometre pipeline from Kazakhstan to the Russian port of Novorossiysk. The initial construction phase was completed in April 2003 on budget at a gross cost of $2.6 billion. The pipeline has an initial capacity of 28.2 million tonnes (approximately 225 mmboe) a year and carries crude oil from the Tengiz field (BP 2.3%). In addition to our interest in LukArco, we hold a separate 0.87% interest in CPC through a 49% holding in Kazakhstan Pipeline Ventures.

Gulf of Mexico

Construction continued on the Mardi Gras pipeline system (BP approximately 65% and operator). When complete, the network of pipelines will extend in total more than 450 miles, and lie in waters of greater than 7,000 feet deep. It will be the largest capacity deepwater pipeline ever built.

Liquefied Natural Gas

Within BP, Exploration and Production is responsible for the supply of LNG and Gas, Power and Renewables is responsible for the subsequent marketing and distribution of LNG (see details under Gas, Power and Renewables New Market Development and LNG on page 45).

Significant activity during 2003 included the following:

We have a 10% equity shareholding in the Abu Dhabi Gas Liquefaction Company, which in 2003 supplied 5.4 million tonnes (263 bcf) of LNG, up 2% on 2002.

In Australia, we are one of six equal partners (BP 16.7%) in the North West Shelf Venture. The joint venture operation covers offshore production platforms, a floating storage vessel, trunklines, and onshore gas processing plants. During 2003, a fourth LNG Train and second trunkline were under construction and are expected to be commissioned in 2004.

In Indonesia, BP participates in Indonesia s LNG exports through its holdings in the Sanga-Sanga (BP 38%) PSA. Sanga-Sanga delivers around 30% of the total gas feed to the Bontang LNG plant.

In addition, we have interests in the Wiriagar (BP 38% and operator), Berau (BP 48% and operator) and Muturi (BP 1%) PSAs in Northwest Papua. These PSAs will provide the natural gas feed to the Tangguh LNG project (BP 37% and operator), which is expected to become the third LNG centre in Indonesia. In 2003, as part of our strategy to serve gas markets in Southern China, we sold 12.5% of our Tangguh share to CNOOC. During 2003, BP continued to actively pursue LNG sales opportunities and secure lender commitment for the Tangguh development.

In Trinidad, Atlantic LNG Train 3 (BP 42%) was commissioned in the second quarter. In June 2003, the government of Trinidad and Tobago approved the Atlantic LNG Train 4 project - one of the largest LNG production plants in the world with a capacity of 5.2 million tonnes (253 bcf) per annum of LNG production. Train 4 is currently under construction and due to start up at the end of 2005.

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GAS, POWER AND RENEWABLES

The strategic purpose of the Gas, Power and Renewables segment is to maximize the value of BP s gas through marketing, to enhance the value of BP s natural gas liquids production and to build a profitable renewables business.

The segment is organized into four main activities: marketing and trading; natural gas liquids (NGL); new market development and LNG; and solar and renewables. On January 1, 2004, a number of worldwide NGL producing assets were transferred to Gas, Power and Renewables from the Exploration and Production segment in order to consolidate the management of our global NGL activity. The transferred assets include seven gas processing plants, six of which are located in the mid-continent of the United States in the Permian, Anadarko and Hugoton basins, and one in Northern Europe. BP is currently a partner in the construction of a gas processing plant, NGL storage and export facilities in Egypt which has also been transferred to this segment. The total operating profit for these transferred assets was $106 million in 2003, but the data below has not been restated to include this amount.

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Turnover	65,445	37,357	39,442
Total operating profit	478	405	407
Total assets	10,260	6,927	5,775
Capital expenditure and acquisitions	359	408	492

We seek to maximize the value of our gas by targeting higher value customer segments in selected markets and to optimize supply around our physical and contractual assets. Marketing and trading activities are focused on the relatively open and deregulated natural gas and power markets of North America, the United Kingdom and certain parts of continental Europe. Some small elements of long-term natural gas contracting activity are also still included within the Exploration and Production business segment because of the nature of gas markets and the long-term sales contracts.

Our NGLs business is engaged in the processing, fractionation and marketing of ethane, propane, butanes and pentanes extracted from natural gas. Our NGL activity is underpinned by our upstream asset base and serves third-party markets for both chemicals and clean fuels and also supplies BP s petrochemicals and refining activities.

New market development and LNG activities involve developing opportunities to capture sales for our upstream natural gas resources and are conducted in close collaboration with the Exploration and Production business. Our strategy is to capture a greater share of the growth in the international demand for natural gas and is focused on markets which offer significant prospects for growth. These include the USA, Canada, UK, Spain and many of the emerging markets of the Asia Pacific region, notably China, where we believe there could be substantial growth in demand. For our undeveloped gas resources, we believe the key is to gain markets ahead of supply with a longer-term aim of allowing natural gas resources to move into the market with the same ease that oil does today. Our LNG activities involve the marketing of BP and third-party LNG.

Our solar and renewables activities include the development, production and marketing of solar panels and the development of wind farms on certain company sites.

Other activities include gas-fired power generation projects, where our principal focus is on projects that will utilize our equity natural gas. Projects that will reduce Group power costs and/or reduce overall emissions are also a key focus area. BP continues to pursue the development of hydrogen fuel technology.

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Capital expenditure and acquisitions for 2003 was $359 million compared with $408 million in 2002 and $492 million in 2001. Excluding acquisitions, capital expenditure for 2003, 2002 and 2001 was $359 million, $335 million and $352 million, respectively. Capital expenditure excluding acquisitions for 2004 is planned to be around $600 million (including the NGL activity transferred from the Exploration and Production segment on January 1, 2004); the increase over the 2003 level is due to higher spending on the Guangdong terminal in China and the power project in Korea.

Marketing and Trading Activities

Our gas marketing and trading activities are concentrated in the markets of North America and the United Kingdom. Gas sales volumes have increased from 18.8 billion cubic feet per day (bcf/d) in 2001 to 21.6 bcf/d in 2002 and 26.3 bcf/d in 2003. Most of this growth was realized in the USA and Canada. Canada volumes are reported in the Rest of World volumes.

	Years ended December 31,		
Gas sales volumes (a)	2003	2002	2001
	(million cubic feet per day)		
UK	2,631	2,372	2,641
Rest of Europe	441	399	213
USA	11,528	9,315	8,327
Rest of World	11,669	9,535	7,613
Total	26,269	21,621	18,794

(a) Includes marketing, trading and supply sales.

Our policy toward natural gas price risk is described in Item 11 Quantitative and Qualitative Disclosures about Market Risk on page 175.

North America

BP is one of the leading wholesale marketers and traders of natural gas in North America, the world s largest natural gas market, a business which has been built on the foundation of our position as the continent s leading producer of gas based on volumes. Our North American total natural gas sales volumes have grown from 13.4 bcf/d in 2001 to 16.1 bcf/d in 2002 and to 20.6 bcf/d in 2003. Of these sales volumes, 4.1 bcf/d was supplied from BP upstream producing operations in 2001, 4.0 bcf/d in 2002 and 3.6 bcf/d in 2003. The decline in BP production in 2003 was primarily due to the divestment of various properties.

Our North American natural gas marketing and trading strategy seeks to provide unconstrained market access for BP s equity gas, increase margin through targeting higher value customer segments and optimizing around our network of connected assets to reduce cost of goods sold. These assets include those owned by BP and those contractually accessed through agreements with third parties such as pipelines and terminals.

United Kingdom

The natural gas market in the UK is significant in size and is one of the most progressive in terms of deregulation when compared with other European markets. BP is one of the largest producers of natural gas in the UK based on volumes. Our total natural gas sales volumes in the UK were 2.6 bcf/d in 2003, 2.4 bcf/d in 2002 and 2.6 bcf/d in 2001. Of these volumes, 1.5 bcf/d (2002 1.6 bcf/d and 2001 1.7 bcf/d) were supplied by BP s Exploration and Production operations. The majority of natural gas sales are to commercial and industrial customers, power generation companies and to other gas wholesalers via long-term supply deals. Some of the natural gas continues to be sold under long-term natural gas supply contracts that were entered into prior to market deregulation.

We have a 10% interest in the Interconnector, a 1.9-bcf/d, 240-kilometre, 40-inch diameter subsea natural gas pipeline between Bacton in the UK and Zeebrugge in Belgium, which effectively links the natural gas markets of the UK and continental Europe.

Rest of Europe

We are building a natural gas and power marketing and trading business in Europe. Our interest in the European market is driven by the size and growth potential of the market, deregulation and the proximity of BP natural gas supplies.

In Europe, our main marketing activities are currently in Spain. The Spanish natural gas market has continued to grow and is now deregulated ahead of the deadlines set by European law. Since April 2000, we have built a market position which currently places us as number two behind the incumbent Gas Natural. In July 2002, we purchased 5% of the shares in Enagas, the owner and operator of the majority of the high pressure Spanish gas transport grid and three of Spain s four regasification terminals.

Natural Gas Liquids

	Years ended December 31,		
NGL sales volumes	2003	2002	2001
	(thousand barrels per day)		
UK			
Rest of Europe			
USA	164	196	221
Rest of World	182	214	189
Total	346	410	410

BP is one of the leading producers and marketers of NGLs, based on sales volumes, in North America. NGLs, which are produced from gas chiefly sourced out of Alberta, Canada and the US onshore and Gulf Coast, are used as a heating fuel and as a feedstock for refineries and chemicals plants. NGLs are sold to petrochemical plants and refineries at prevailing market prices. In addition, a significant amount of NGLs are marketed on a wholesale basis under annual supply contracts that provide for price redetermination based on prevailing market prices.

We operate natural gas processing facilities across North America with a total capacity of 8.2 bcf/d. These facilities, which we own or have an interest in, are located in major production areas across North America including Alberta, Canada, the US Rockies, the San Juan basin and coast of the Gulf of Mexico. We also own or have an interest in fractionation plants (which process the natural gas liquids stream into its separate component products) in Canada and the USA, and own or lease storage capacity in Alberta, Eastern Canada, the US Gulf Coast and mid-continent regions.

New Market Development and LNG

Our new market development and LNG activities are focused on developing worldwide opportunities to capture international natural gas sales for our upstream natural gas resources.

BP Exploration and Production has interests in major existing LNG projects in Trinidad and Tobago, ADGAS in Abu Dhabi, the North West Shelf in Australia and we also supply gas (from Virginia Indonesia Co.) to the Bontang LNG project in Indonesia. Additional LNG supplies are being pursued through expansions of existing LNG plants in Trinidad and Tobago, the North West Shelf in Australia and greenfield developments such as Tangguh in Indonesia.

In April 2003, a third LNG train commenced operations in Trinidad, with initial deliveries to Lake Charles, Louisiana and, following Federal Energy Regulatory Commission (FERC) approval, to the Cove Point regasification facility in Maryland. BP has capacity access at the Cove Point terminal, which was officially commissioned in August and is operated by Dominion Resources. The Government of Trinidad and Tobago announced in June 2003 its approval for the Atlantic LNG Train 4 project in Trinidad. BP will be the largest shareholder in the new plant as well as the largest supplier of gas for liquefaction at the plant.

At Bilbao, northern Spain, construction was completed on Europe s first integrated LNG regasification and power generation complex (BP 25%). In November, BP signed a six-year sales and purchase agreement with Oman LNG who will supply 3.6 million tonnes (175 bcf) of LNG over the contract term starting in 2004. The shipments are intended for BP customers in Spain.

The Tangguh LNG project (BP 37.2%) in Indonesia was selected as the preferred supplier of LNG to two South Korean companies SK Power Company Limited and POSCO in what is the world s fastest growing LNG market. POSCO is the world s second largest steel maker and SK Power, at the time, was 100% owned by SK Corporation (SK Corp), South Korea s largest oil refiner. The bid process to purchase LNG was the first undertaken by South Korea s private sector and is for the supply of up to 1.35 million tonnes per annum (66 bcf per annum) of LNG for a 20-year term starting in 2005.

In late December 2003, BP and BPMIGAS, Indonesia s executive agency for oil and gas, signed a Heads of Agreement with Sempra Energy LNG Corp. for a 20-year supply of LNG from Indonesian sources to markets in the US and Mexico. Under the agreement, 3.7 million tonnes of LNG per annum (180 bcf per annum) will be delivered from the Tangguh fields over a period of 15 years beginning in 2007 to Sempra s proposed LNG import and regasification terminal near Ensenada in Baja California, Mexico. Sempra s terminal, when completed, will have the capacity to process up to 1 bcf/d of natural gas. During 2004, the parties to the Agreement intend to negotiate a definitive agreement.

The successful Tangguh supply bids are in addition to the LNG sales contract secured in 2002 for 2.6 million tonnes per annum (127 bcf per annum) for the Fujian LNG project in China commencing in 2007. The Tangguh project now has agreements in various stages of completion for 7 million tonnes per annum (341 bcf per annum).

In Southeast China, the feasibility study report for the Guangdong LNG project (BP 30%) has been approved by the Chinese Government and the contract to form a joint venture company to construct the terminal and trunkline was signed in February 2004. First gas is scheduled for mid-2006 under the gas purchase agreement signed with Australia LNG in October 2002 that will involve deliveries from the North West Shelf project (BP 16.7%).

BP and Sonatrach announced in October 2003 that they are to form a joint venture that will provide the first new supplies of LNG to the UK market with scope to expand the arrangement to the US and other markets. The two companies were also successful in bidding for the long-term capacity rights in the Isle of Grain import regasification facility which is being developed on the Medway River, 20 miles east of London and which is owned and operated by National Grid Transco (NGT). The capacity rights will enable the two companies to source and then supply around 3.7 million tonnes per annum (182 bcf per annum) of LNG into the UK market from 2005 representing approximately 5% of UK demand.

In December 2003, BP submitted its pre-filing request to FERC to construct an LNG regasification terminal located on the Delaware River in the state of New Jersey. This was approved in early January

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2004. The pre-filing process is a collaborative approach, coordinated by FERC, under which the various federal and state agencies having jurisdiction are engaged in the process, along with other potential stakeholders. The Project anticipates receiving final FERC approval in the middle of 2005. This timing should allow BP to begin construction during the third quarter of 2005 with a view to beginning terminal operation during the second half of 2008.

In March and June 2003, BP took delivery of the second and third of three new leased LNG ships from Samsung Heavy Industries in Korea. These ships are mainly employed in supplying our BP customers in Spain with supply from ADGAS and Qatar under short-term contracts signed in 2002. Our first LNG ship, the British Trader celebrated its first full year of service in mid-November and is mainly employed in lifting LNG cargoes from Trinidad and delivering to the US.

Solar and Renewables

Global market trends indicate a general move towards greener energy sources, including solar and wind. BP intends to participate in this developing market.

During 2003, BP has repositioned BP Solar in order to improve business performance. A number of specific restructuring measures have been taken in order to improve short-term results with the need to provide opportunities for long-term growth. These decisions involved the consolidation of manufacturing operations in Spain, staff and other overhead reductions across the global business and restructuring provisions related to improving the overall efficiency of the business. In addition, BP completed its exit from the manufacture of thin film solar products (announced in 2002). This will allow the Group to focus on core markets supported by global technology and manufacturing functions.

Our solar energy business in 2003 grew 6% to 71 megawatts (MW) of solar panels generating capacity (2002, 67 MW). This growth rate was lower than historical rates due to a near-term focus on restructuring the business. BP began production in its new 30 MW facility in Madrid, Spain in 2003.

Our Home Solutions programme, an extension of our brand directly into California, New York and New Jersey residential markets, was launched in 2003. It successfully generated awareness around the benefits of solar and is expected to result in over 400 new installations of solar electric systems.

During 2003, BP successfully reached agreement with the Phillipines Department of Agricultural Reform to begin the installation of specific solar packages on 79 Agrarian Reform Communities (ARC) in the region of Mindanao, targeted at improving social welfare, increasing agricultural productivity and empowering local ARC and farmer s organizations. The solar packages include lighting and electricity supply, vaccine refrigeration, potable water provision, communal lighting, etc.

We are building expertise in wind energy and implementing wind projects on selected BP sites. In 2002 we started up our 22.5 MW wind farm at the Nerefco oil refinery (both the refinery and wind farm are jointly owned with ChevronTexaco (BP 69%)) in the Netherlands, which provides electricity to the local grid.

Other Activities

We participate in power projects that support the marketing and sale of our natural gas and in cogeneration projects (i.e., power plants that produce more than one type of energy, typically power and steam) on certain BP refining and chemical manufacturing sites.

During the year, a 776 MW gas-fired power generation facility and an associated LNG regasification facility at Bilbao, Spain (BP 25% share in each) were completed and entered commercial operation.

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In December 2003, BP announced that it would acquire a 35% interest in SK Power, a company that was established to develop, finance, construct and operate a 1,074 MW gas-fired combined cycle power plant located in Kwangyang Province, South Korea. This was subsequent to the selection of the Tangguh LNG project as preferred supplier of LNG to SK Power and POSCO, which is detailed in the New Market Development and LNG section above. SK Corp will retain the remaining 65% interest in the power plant, the total cost of which is expected to be around $600 million and is expected to commence operations in 2006.

We have two further power generation construction projects underway. A 50 MW cogeneration plant is under construction near Southampton, UK (BP 100%), and a 570 MW cogeneration plant as part of a 50:50 joint venture with Cinergy Solutions, Inc. at Texas City, Texas commenced operations in early 2004. Texas City is BP s largest refining and petrochemical complex. BP will supply natural gas to the Texas City plant and will use the excess generation capacity to support power marketing and trading activities.

We own a 400 MW gas-fired power plant at Great Yarmouth in the UK (BP 100%). We are operating the plant and selling electric power, with BP providing the natural gas to the plant.

In alternative fuels, we are exploring market opportunities for hydrogen fuel cells through participation in various industry projects and organisations promoting fuel cells for transport and stationary power.

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REFINING AND MARKETING

Our Refining and Marketing business is responsible for the supply and trading, refining, marketing and transportation of crude oil and petroleum products to wholesale and retail customers. BP markets its products in over 100 countries. We operate primarily in Europe and North America, but also market our products across Australasia and in parts of Southeast Asia, Africa and Central and South America.

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Turnover (a)	149,477	125,836	120,233
Total operating profit	2,292	1,921	1,990
Total assets	60,088	55,815	43,553
Capital expenditure and acquisitions	3,080	7,753	2,415
		($ per barrel)	
Global Indicator Refining Margin (b)	3.88	2.11	4.06

(a) Excludes BP s share of joint venture turnover of $453 million in 2003, $415 million in 2002 and $403 million in 2001.

(b) The Global Indicator Refining Margin is the average of six regional industry indicator margins which we weight for BP s crude refining capacity in each region. Each regional indicator margin is based on a single representative crude with product yields characteristic of the typical level of upgrading complexity. The refining margins are industry specific rather than BP specific measures, which we believe are useful to investors in analysing trends in the industry and their impact on our results. The margins are calculated by BP based on published crude oil and product prices and take account of fuel utilization and catalyst costs. No account is taken of BP s other cash and non-cash costs of refining, such as wages and salaries and plant depreciation. The indicator margin may not be representative of the margins achieved by BP in any period because of BP s particular refining configurations and crude and product slate.

There are four areas of business in Refining and Marketing: Refining, Retail, Lubricants and Business to Business Marketing. Our strategy is to grow through focused investment in key assets and market positions. In all areas, we aim for greater operational efficiency, and at the same time we seek to improve our asset portfolio. The acquisition of Veba s marketing and refining operations in 2002 provided an important addition of high quality assets to our operations.

Refining and Marketing manages a portfolio of assets that we believe are competitively advantaged across the chain of downstream activities. Such advantage may derive from several factors, including location, operating cost and physical asset quality.

We are one of the major refiners of gasoline and hydrocarbon products in the USA, Europe and Australia. We have significant retail and business to business market positions in the USA, UK, Germany and the rest of Europe, Australasia, Africa and Southeast Asia and we are enhancing our presence in China and Mexico.

Divestments mandated in connection with the Veba transaction as a condition of regulatory approval of the deal were completed with the sale of a 45% stake in Bayernoil refinery, an 18% stake in the Trans Alpine Pipeline (TAL), 741 retail stations in Germany, 55 stations in Hungary and 11 in Slovakia in separate packages to PKN Orlen and OMV AG, for a total of $580 million in cash and assumption of debt.

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In March 2004, BP and the Singapore Petroleum Company Limited (SPC) announced that conditional agreement had been reached for SPC to purchase BP s interests and one-third stake in Singapore Refining Company Private Limited (SRC) for $140 million. Subsequent to this announcement we were notified that the remaining shareholders wished to exercise their preemption rights. This will result in BP s one-third share being divided equally between the two remaining shareholders in SRC, namely Caltex Singapore Private Ltd and SPC. As a result, these two companies will also acquire BP s one-sixth equity interest in Tanker Mooring Services Company Pte Ltd (TMS). The transaction is expected to be concluded in mid-2004.

In the first quarter of 2004, BP and Lembaga Tabung Angkatan Tentera (LTAT) announced that agreement had been reached for LTAT to purchase BP s 70% shareholding in the BP Malaysia Sdn Bhd fuels business. Subject to receiving the necessary regulatory consents, this transaction is expected to be concluded during the third quarter of 2004.

The decision to divest the Singapore and Malaysian fuels business is part of BP s global strategy of concentrating on markets and segments where we believe we can obtain scale and build a significant presence. The sale has no impact on BP s other activities in Malaysia.

Capital expenditure and acquisitions in 2003 was $3,080 million compared with $7,753 million in 2002 (including $5,038 million for the Veba acquisition) and $2,415 million in 2001. Excluding acquisitions, capital expenditure was $3,006 million in 2003 compared with $2,682 million in 2002 and $2,386 million in 2001. Capital expenditure excluding acquisitions is expected to be around $2.8 billion in 2004.

Refining

The Company s global refining strategy is to own interests in and to operate advantaged refineries that provide distinctive returns through vertical integration with our marketing and trading operations and horizontal integration with other parts of the Group s business. Refining s focus is to maintain and improve competitive position through sustainable, safe, reliable and efficient operations of the refining system and disciplined investment for growth.

For BP, the strategic advantage of a refinery relates to the refinery s location, the refinery s scale and its configuration to produce fuels in line with the demand of the region from low-cost feedstocks. Efficient operations are measured primarily using regional refining surveys conducted by third parties. The surveys assess our competitive position against benchmarked industry measures for margin, energy efficiency and costs per barrel. Investments in our refineries are focused on maintaining our competitive position and developing the capability to produce the cleaner fuels that meet our customers and the communities requirements.

In December 2003, we announced the sale of our European Special Products business, including the Neuhof base oil refinery in Hamburg, Germany. The sale was completed in January 2004.

In June 2004, the shareholders of the ATAS Refinery (Anadolu Tasfiyehanesi A.S.) in Mersin, Turkey announced that the refinery will continue its operations as a fuels supply terminal henceforth. ATAS will commence a process to change its operations to become a terminal in early September 2004 and will be operated by the same partners and continue to supply petroleum fuels to southern Turkey.

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The following table summarizes the BP Group interests and crude distillation capacities (at December 31, 2003):

	Refinery	Group interest (b) %	Crude distillation capacities (a) (mb/d) Total	BP Share
UK	Coryton*	100.00	172	172
	Grangemouth*	100.00	207	207
Total UK			379	379
Rest of Europe				
France	Lavéra*	100.00	218	218
	Reichstett	17.00	84	14
Germany	Bayernoil*	22.50	267	60
	Gelsenkirchen*	50.00	272	136
	Karlsruhe	12.00	308	37
	Lingen*	100.00	87	87
	Neuhof*	100.00		
	Schwedt	18.75	221	42
Netherlands	Nerefco*	69.00	400	276
Spain	Castellón*	100.00	110	110
Turkey	Mersin* (c)	68.00	100	68
Total Rest of Europe			2,067	1,048
USA				
California	Carson*	100.00	260	260
Washington	Cherry Point*	100.00	232	232
Indiana	Whiting*	100.00	420	420
Ohio	Toledo*	100.00	155	155
Texas	Texas City*	100.00	470	470
Total USA			1,537	1,537
Rest of World				
Australia	Bulwer*	100.00	92	92
	Kwinana*	100.00	139	139
New Zealand	Whangerei	23.66	109	25
Singapore	SRC*+	33.00	248	82
Kenya	Mombasa	17.00	90	15
South Africa	Durban	50.00	182	91
Total Rest of World			860	444
Total			4,843	3,408

* Indicates refineries operated by BP.

Indicates lubricants refinery which does not have crude distillation capacity. The sale of our interest in this refinery was completed in January 2004.

\+ The sale of our interest in this refinery was announced in March, 2004.

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(a) Gross rated capacity is defined as the maximum achievable utilization of capacity (24-hour assessment) based on standard feed.

(b) BP share of equity, which is not necessarily the same as BP share of processing entitlements.

(c) The closure of the refinery and transformation to a fuels terminal was announced in June 2004.

The following table outlines by region the volume of crude oil and feedstock processed by BP for its own account and for third parties and for the Group by other refiners under processing agreements. Corresponding BP refinery capacity utilization data are summarized.

	Years ended December 31,		
	2003	2002	2001
Refinery throughputs (a)	(thousand barrels per day)		
UK	397	389	364
Rest of Europe	932	918	663
USA	1,386	1,439	1,526
Rest of World	382	357	376
	3,097	3,103	2,929
For BP by others		14	14
Total	3,097	3,117	2,943
Refinery capacity utilization			
Crude distillation capacity at December 31, (b)	3,408	3,534	3,259
Crude distillation capacity utilization (c)	91%	91%	94%
United States	91%	93%	95%
UK and Rest of Europe	90%	91%	94%
Rest of World	94%	85%	93%

(a) Refinery throughput reflects crude and other feedstock volumes.

(b) Crude gross rated capacity is defined as the maximum achievable utilization of capacity (24 hour assessment) based on standard feed.

(c) Crude distillation capacity utilization is defined as the percentage utilization of capacity per calendar day over the year after making allowances for average annual shutdowns at BP refineries (i.e. net rated capacity).

BP s 2003 refinery throughput increased in the Rest of Europe compared with 2002, primarily due to higher margins. In 2002 lower margins required that many of the refineries reduce throughput. The decrease in the USA in 2003 was due to the sale of the Yorktown, Virginia refinery in May 2002, reducing capacity by 23 mb/d, and the balance was due to major turnaround activities in 2003 compared with 2002.

Capacity utilization in the US was affected by various power outages and the hurricane Claudette during 2003.

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Marketing

Marketing comprises three business areas: Retail, Lubricants and Business to Business Marketing. We market a comprehensive range of refined oil products worldwide. These products include gasoline, gasoil, marine and aviation fuels, heating fuels, LPG, lubricants and bitumen.

The following table sets out refined product sales by area.

	Years ended December 31,		
Sales of refined products (a)	2003	2002	2001
	(thousand barrels per day)		
Marketing sales:			
UK (b)	271	253	266
Rest of Europe	1,316	1,467	1,062
USA	1,797	1,874	1,866
Rest of World	648	586	603
Total marketing sales (c)	4,032	4,180	3,797
Trading/supply sales (d)	2,692	2,383	2,409
Total refined products	6,724	6,563	6,206
	($ million)		
Proceeds from sale of refined products	102,003	87,520	82,241

(a) Excludes sales to other BP businesses.

(b) UK area includes the UK-based international activities of Refining and Marketing.

(c) Marketing sales are sales to service stations, end-consumers, bulk buyers, jobbers, i.e., third parties who own networks of a number of service stations and small resellers.

(d) Trading/supply sales are to large unbranded resellers and other oil companies.

The following table sets out marketing sales by major product group:

Years ended December 31,

Marketing sales by product	2003	2002	2001
	(thousand barrels per day)		
Aviation fuel	532	529	515
Gasolines	1,694	1,744	1,659
Middle distillates	1,199	1,232	1,077
Fuel oil	312	451	351
Other products	295	224	195
Total marketing sales	4,032	4,180	3,797

In marketing, our aim is to increase total margin by focusing on both volumes and margin per unit. We do this by growing our customer base, both in existing and new markets, by attracting new customers and by covering a wider geographic area. We also work to improve the efficiency of our operations through reducing the cost of goods sold and improving our product mix. In addition, we recognize that our customers are demanding a wider choice of fuels, particularly fuels that are cleaner and more efficient. Through our integrated refining and marketing operations, we believe we are better able to meet these customer demands.

BP s marketing sales volumes were lower in 2003 mainly due to planned portfolio changes. The planned portfolio impacts were the sale of Veba retail sites in Germany, the sale of retail sites in Cyprus and the transfer of retail sites in Russia to TNK-BP.

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Retail

Success in retail relies on having superior locations, a superior offer, and executing that offer well, time after time. Our strategy is to focus our capital into the best locations in the high growth metropolitan markets where we can be number one or two in market share, whilst continuing to upgrade our offers and drive for operational efficiencies.

We are working to make our offer continuously more attractive to customers so that they come preferentially to BP. There are two components of our retail offer. The convenience offer, where we sell convenience items to customers from advantaged locations in metropolitan areas and the fuel offer, which we deploy in all our markets, in many cases without the convenience offer. We have a high quality shop offer in each of our key markets, whether it is the new BP Connect offer in Europe and the Eastern USA, am/pm west of the Rocky Mountains, or the Aral offer in Germany. Each of these brands carries a very strong offer itself, but we are also sharing best practices between them. We have also upgraded our fuel offer with the introduction of Ultimate gasoline and diesel, which have greater efficiency and power and lesser environmental impacts. We launched the new fuels in UK, Spain, Greece and three markets in the United States during the past year.

Our strategic focus has resulted in investment in our convenience offer through increased numbers of BP Connect sites and in our premium fuels offer with the rollout of BP Ultimate diesel and gasoline. This strategic focus will continue going forward with roll-out of our convenience and premium fuels offers in high-growth metropolitan markets where we can be number one or two.

Our focus on operational efficiencies through targeted programmes of performance improvement has allowed us to increase our fuel throughput per site and increase our store sales per square metre. This strategic focus on executing excellence will continue going forward as we target increased fuel and store efficiencies.

Across the network, our large format stores achieved store sales growth above the market average, and we plan to invest primarily in additional store space on existing real estate in our core metropolitan convenience markets. During 2003, our same store sales across Australia, Europe and the USA grew 3%, a lower rate than the previous year driven by overall weaker economic growth. Same site fuel volumes grew in these areas by 0.5%.

	Years ended December 31,		
Shop sales (a)	2003	2002	2001
		($ million)	
UK	567	527	458
Rest of Europe	3,000	2,638	904
USA	1,620	1,585	1,510
Rest of World	521	421	362
Total	5,708	5,171	3,234
Direct managed	2,090	1,869	1,650
Franchise	3,508	3,216	1,504
Shop alliances	110	86	80

Total	5,708	5,171	3,234

(a) Shop sales reported are sales through direct-managed stations, franchises and the BP share of shop alliances and joint ventures. Sales figures exclude sales taxes and lottery sales but include quick service restaurant sales.

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Our retail network is largely concentrated in Europe and the USA, with established operations in Australasia, Southeast Asia and Southern Africa. We are developing networks in China and Mexico. In 2003, we concluded the mandatory divestments of about 800 stations in Germany following the acquisition of the Aral network (approximately 3,200 service stations in Germany and Central Europe) in 2002. The rationalization of the portfolio includes the divestment of the Aral-branded sites in Slovakia and Hungary.

BP s worldwide network consists of approximately 28,000 stations branded BP, Amoco, ARCO and Aral. Whilst in Austria and Poland all sites have now been rebranded to BP, in Germany the network is about to become single branded Aral. As planned, the 41 stations in which we have an interest in the Moscow metropolitan area have become part of TNK-BP, our Russian joint venture, with effect from the third quarter of 2003.

BP expects its total number of service stations to decline further in future years reflecting the continued optimization of our retail network and efforts to increase the consistency of our site offer. We also continue to improve the efficiency of our retail asset network through a process of regular review. During 2003, further portfolio upgrading has been concluded by divesting sites and networks.

In 2003 we accelerated our rollout of BP Connect sites primarily in the UK and USA continuing our retail strategy that builds on our advantaged locations, strong market positions and brand. These are service stations with large convenience stores featuring our branded BP Connect offer that provide our customers cleaner fuels, a wider range of services and a distinctive food offer. The new BP Connect sites include service stations that are new, those that have been rebuilt, and those where extensive upgrading and remodelling has taken place. At December 31, 2003, 496 BP Connect stations were open (this count reflects the transfer of 41 sites to TNK-BP). In addition the number of stations with the new BP Helios design increased by about 6,300 during 2003 to a total of 16,745.

At December 31, 2003, BP s retail network in the USA comprised approximately 14,700 service stations of which approximately 10,600 were owned by jobbers. Through regular review and execution of business opportunities we are continuing to concentrate our ownership of real estate in markets designated for development of the convenience offer. In the USA, we increased the number of stations with the new BP Helios design by approximately 5,100 in 2003.

In the UK and the Rest of Europe, BP s network comprised about 9,500 service stations at December 31, 2003. In 2003 we opened 49 BP Connect sites in Europe with the majority being in metropolitan areas of the UK. The number of stations throughout Europe that use the new BP Helios design was about 6,400 by the end of 2003.

Our distinctive fuel product offer has expanded through the launches of our BP Ultimate gasoline and diesel products in Greece, Portugal, Spain and the UK and expansion across the network in the USA and Australia.

At December 31, 2003, BP s retail network in the rest of the world comprised some 3,600 service stations. Our established networks are primarily in Australia, New Zealand, Southern Africa and Southeast Asia. BP is growing in China through two strategic alliances. BP s joint venture with PetroChina in Guangdong Province in the coastal region of China had 400 stations at December 31, 2003. BP has agreed in principle with Sinopec to form a second alliance through a joint venture to acquire, revamp or build 500 fuels service stations in the Zhejang Province, in Eastern China. The Sinopec joint venture is expected to start development of sites in 2004, subject to obtaining government approvals.

Lubricants

We manufacture and market lubricant products and also supply related products and services to business customers and end-consumers in over 60 countries directly, and to the rest of the world through local distributors. Our business is concentrated on the higher margin sectors of automotive lubricants, especially in the consumer sector, but also has a strong presence in business markets such as commercial vehicle fleets, aviation, marine and specialized industrial segments.

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We aim to achieve growth by further focusing our resources and capabilities on selected market sectors. Customer focus, distinctive brands and superior technology remain the cornerstone of our long-term strategy.

BP markets through its two major brands, Castrol and BP, and several secondary brands including Duckhams and Veedol. The Veba acquisition strengthened our lubricants position in Germany and in Central Europe with the addition of the Aral brand to the BP Lubricants portfolio.

In the consumer sector of the automotive segment we supply lubricants, other products and related business services to intermediate customers (e.g., retailers, workshops) who in turn serve end-consumers (e.g., car, motorcycle, leisure craft owners) in the mature markets of Western Europe and North America and also in the fast growing markets of the developing world (e.g., Russia, China, India, Middle East, South America and Africa). The Castrol brand is recognized worldwide and we believe it provides us with a significant competitive advantage.

In commercial vehicle and general industrial markets we supply lubricants and lubricant-related services to the transportation industry and to automotive manufacturers.

Business to Business Marketing

Our Business to Business Marketing encompasses marketing a comprehensive range of products to other businesses. This business aims to build relationships with customers that not only purchase a wide variety of products in large quantities but also additional services. Logistics play a crucial role in this business. We aim to attract more customers through innovation in multi-product offers and cleaner fuels, packaged with a range of value-added services and solutions.

Our aviation business sells fuels and lubricants to airlines and general aviation customers, as well as providing technical services to airlines and airports. During the last few years, our aviation business has strengthened its position in established markets and pursued opportunities in new or emerging markets. The business now markets in approximately 95 countries and is the third largest jet fuel supplier globally.

Our liquefied petroleum gas (LPG) businesses sell bulk, bottled, automotive and wholesale products to a wide range of customers in over 20 countries. During the past few years, our LPG business has strengthened its position in established markets, pursued opportunities in new and emerging markets and rationalized its operations. During 2003, we continued to grow our LPG business in China, where we now have sole ownership over three key importing facilities in the important markets of Eastern and Southern China. With imports of over 1.5 million tonnes in 2003 and the capacity to grow to 2.5 million tonnes per annum, BP is now the number one importer of LPG into the China market.

In our marine business, we supply lubricants and fuels on a global basis to major shipping companies as well as to smaller operators. We are the leading global participant in the marine lubricants market where we operate in over 800 ports, have offices in 40 countries and supply points in 80 countries.

In our specialized industrial segment, we supply metal-working fluids and lubricants alongside a range of business services, such as fluid management, to equipment manufacturing customers. We also have a significant high performance industrial lubricants business in some key markets.

Our European Business Marketing (EBM) business comprises a portfolio of Business to Business, Business to Consumers, Bitumen and certain Cards activities throughout Europe. Thus, EBM supplies commercial and industrial customers and private end consumers with fuel oil, motor spirit, diesel, heating oil and lubricants. EBM also offers a fuel and service card for fleet and truck customers, as well as supplying industrial customers with bitumen for the road and roof industries.

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Supply and Trading

We are one of the world s major traders of crude oil and refined products, dealing extensively in physical and futures markets. Our portfolio of purchases and sales is spread among spot, term, exchange and other arrangements, and covers a range of sources and customers to match the location and quality requirements of the Group s refineries and various markets, whilst seeking to ensure flexibility and cost competitiveness. In addition, the Group s oil-trading function undertakes trading in physical and paper markets in order to contribute to the Group s income.

Refer to Item 11 Quantitative and Qualitative Disclosures About Market Risk on page 170 for further information.

Transportation

Our Refining and Marketing business owns, operates or has an interest in extensive transportation facilities for crude oil, refined products and petrochemical feedstock in the US. It also has interests in a number of crude oil and product pipelines in the UK, the Rest of Europe and in the US.

We transport crude oil to our refineries principally by ship and through pipelines from our import terminals. We have interests in crude oil pipelines in the UK, the Rest of Europe and in the US.

Bulk products are transported between refineries and storage terminals by pipeline, ship, barge, and rail. Onward delivery to customers is primarily by road. We have interests in major product pipelines in the UK, the Rest of Europe and in the US.

In September, our BP Pipelines business closed the transaction for the sale of 90% of its Cushing to Chicago Pipeline System (CCPS) to Enbridge retaining 10% in line with Pipeline strategy to maximize the value of our assets.

Shipping

BP Shipping owns or operates an international fleet of crude oil and product tankers and LNG carriers transporting cargoes for the Group and for third parties. It also offers a wide range of marine-related services to Group and third-party customers.

Excluding BP companies in the USA, at December 31, 2003 the Group controlled or operated an international fleet of twenty-eight oil tankers and eight LNG ships, with capacity of approximately 1.08 million cubic meters. The Group had four Very Large Crude Carriers, fourteen Medium Crude Carriers, nine Product Carriers, and one North Sea shuttle tanker. It also operated three LNG carriers to trade globally, four LNG carriers for Abu Dhabi contracted gas and one LNG carrier for the Western Australia North West Shelf (NWS) project. BP holds an interest in six NWS gas carriers, of which this is one.

BP companies in the USA had seven Large Crude Carriers, three Medium Crude Carriers, and four Product Carriers totalling approximately 1.4 million dead weight tonnes (dwt) on long-term charter. BP owns four barges totalling 0.1 million dwt.

BP is in the middle of a new building programme, which saw 12 leased ships delivered into service in 2003.

These ships will be manned by either BP Maritime Services personnel or by those from a third party who provide the manning services for some of our new ships, whilst operating to BP Shipping s standards and reporting requirements. All the chartering of ships is controlled by BP Shipping, and the ships are utilized to carry either BP cargoes or third-party cargoes.

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PETROCHEMICALS

Our Petrochemicals business is a major producer of chemicals and plastics through subsidiaries, joint ventures and associated undertakings. The petrochemicals segment is also responsible for the supply, marketing and distribution of chemical products to bulk, wholesale and retail customers. BP has operations principally in the USA and Europe. We are increasing our activities in the Asia-Pacific region.

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Turnover (a)	16,075	13,064	11,515
Total operating profit	623	541	(102)
Total assets	17,649	16,595	15,098
Capital expenditure and acquisitions	775	823	1,926
		($/tonne)	
Chemicals Indicator Margin (b)	112	104	109

(a) Excludes BP s share of joint venture turnover of $434 million in 2003, $511 million in 2002 and $102 million in 2001.

(b) The Chemicals Indicator Margin (CIM) is a weighted average of externally based industry product margins. It is based on market data collected by Nexant in their quarterly market analyses, which we weight based on BP s product portfolio. While it does not cover our entire portfolio, it includes a broad range of products. Among the products and businesses covered in the CIM are the olefins and derivatives, the aromatics and derivatives, linear alpha-olefins (LAOs), acetic acid, vinyl acetate monomers and nitriles. Not included are fabrics and fibres, plastic fabrications, poly alpha-olefins (PAOs), anhydrides, engineering polymers and carbon fibres, speciality intermediates and the remaining parts of the solvents and acetyls businesses. This measure is not BP specific, rather it is an indicator of relative industry profitability and BP s actual margins will differ. While not entirely representative of BP s complete range of products, we believe it does provide investors with useful information about the environment for BP s products.

Our strategy is focused on seven core products, with the aim of providing world-class performance in all aspects of our activities. We are now managing our portfolio in two distinct parts Aromatics and Acetyls (A&A), comprising PTA, PX and acetic acid, and Olefins and Derivatives (O&D) comprising ethylene and related co-products, polypropylene, HDPE and acrylonitrile. On April 27, 2004, we announced our intention to set up a separate corporate entity for the O&D businesses. It is our intention to make a public offering of this new entity at an appropriate time. Based on the estimated lead-time required for such a transaction, and depending on market circumstances, we are aiming to make such an offering in the second half of 2005. We intend to retain and grow the A&A businesses, which will be transferred to the Refining and Marketing segment on January 1, 2005.

Our core products are eventually used in the manufacture of a wide variety of consumer goods, including plastic drinks bottles, computer housings, adhesives, inks, rigid packaging, pipes, food packaging and automobile components, as well as textiles for clothes and carpets. We compete through proprietary technology, leadership positions and value associated with the integration of group hydrocarbons and sites. Our investment and divestment activities are aligned with this strategy.

Significant investment activities during 2003:

- In January, we commissioned a new 350-ktepa PTA plant at Zhuhai in southern China.

- In April, China American Petrochemical Company (CAPCO), a BP associated undertaking in Taiwan, started producing from its new 700-ktepa PTA unit.

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BP increased the investment in our South Korean and Taiwanese joint ventures. BP acquired an incremental 9% interest in CAPCO to obtain a 59% holding and increased our ownership from 35% to 47% in Samsung Petrochemicals Company (SPC).

BP Solvay Polyethylene North America and its joint venture partners started a new and more efficient High Density Polyethylene (HDPE) plant at Cedar Bayou and discontinued BP Solvay Polyethylene North America s higher cost unit at Deer Park, Texas.

The Shanghai Ethylene Cracker Complex (SECCO) (BP 50%) is on schedule to start up during 2005. At the end of 2003, construction was approximately 50% complete.

BP Solvay Polyethylene Europe (BP 50%) commenced full-scale production from the newly constructed HDPE plant at Lillo, Belgium.

Capital expenditure and acquisitions in 2003 was $775 million compared with $823 million in 2002 and $1,926 million in 2001. Excluding acquisitions, capital expenditure was $775 million, $810 million and $1,446 million respectively. Capital expenditure excluding acquisitions is expected to be around $900 million in 2004.

Significant divestment activities during 2003:

During the second quarter, we divested PT Petrokimia Nusantara Interindo (PT Peni) (BP 75%), a polyethylene joint venture in Indonesia.

In March 2003, we announced our intention to sell our wholly owned specialty intermediate chemicals businesses including trimellitic anhydride (TMA), purified isophthalic acid (PIA) and maleic anhydride (MAN). The sale was completed on May 28, 2004.

Businesses outside of our A&A and O&D portfolios, their co-products, and closely related activity have been reviewed for sale, and to this end we announced in late March 2004 our intention to sell our Fabrics and Fibres and our LAO/PAO businesses. The LAO/PAO businesses may be included in the intended public offering of our O&D business.

During 2003, overall BP petrochemicals production capacity grew 2%.

The following table shows BP production capacity in kilotonnes per annum (ktepa) by product and by region at December 31, 2003.

		Rest of		Rest of	
	UK	Europe	USA	World	Total
Capacity by region (a)					
PTA		1,027	2,481	3,363	6,871
PX		482	2,320		2,802
Acetic acid	781		491	926	2,198

Ethylene and related co-products	1,575	4,198	2,246	64	8,083
Polypropylene	270	1,052	1,371		2,693
HDPE	165	618	490	184	1,457
Acrylonitrile/Acetonitrile		300	792		1,092
Other	1,839	4,926	2,221	301	9,287
Total	4,630	12,603	12,412	4,838	34,483

(a) Includes BP share of joint ventures, associated undertakings and other interests in production.

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BP is the world s third largest petrochemicals company in terms of production capacity, and currently manufactures and markets about 28 million tonnes of products each year.

As a result of growth and portfolio management, our seven core products now account for 70% of our capital employed.

The seven core products within our portfolio are:

Aromatics and Acetyls

Purified Terephthalic Acid (PTA)

PTA is important as a raw material for the manufacture of polyester used in textiles, fibres and films. BP is the world s largest producer of PTA, with an interest in approximately 20% of the world s PTA capacity. PTA is manufactured at Cooper River, South Carolina and Decatur, Alabama in the USA, Geel in Belgium, and Kuantan in Malaysia. We also produce PTA through BP Zhuhai (BP 85%), Samsung Petrochemical Company (SPC) in South Korea (BP 47.41%), CAPCO in Taiwan (BP 59.02%), PT AMI in Indonesia (BP 50%) and Rhodiaco in Brazil (BP 49%). The sites in Taiwan, South Korea, Belgium and the USA are among the largest PTA production sites in the world.

Major Activities

In 2003, BP Zhuhai (BP 85%) commissioned a 350-ktepa unit in southern China and CAPCO started up their new 700-ktepa unit in Taichung, Taiwan. Both projects use BP s proprietary PTA technology and were delivered safely, on budget and on time.

BP increased the investment in our Korean and Taiwanese joint ventures. BP acquired an incremental 9% interest in CAPCO to obtain a 59% holding and increased our ownership from 35% to 47% in SPC. As a result, BP s equity PTA capacity in Asia has increased by 14% to around 3 million tonnes a year.

We announced in early June that, due to market factors, we have decided to delay the final sanctioning of the proposed new world-scale PTA plant at Geel in Belgium. We will continue to explore potential options for further developing this project as and when the business environment improves. BP remains committed to the PTA business in Europe.

In May 2004, BP signed a letter of intent to examine the viability of expanding production at the BP Zhuhai (BP 85%) PTA plant from 350,000 tonnes per year to 1.2 million tonnes per year.

Paraxylene (PX)

PX is feedstock for the production of PTA and is manufactured from mixed xylene streams acquired from BP refineries and third-party producers. We are currently one of the world s leading producers of PX in terms of capacity. Our plants are located in Decatur, Alabama and Texas City, Texas in the USA and Geel in Belgium. We engage with Refining and Marketing to optimize sourcing of xylenes feedstock from BP refineries.

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Acetic Acid

We are a major manufacturer and supplier of acetic acid, a versatile chemical used in a variety of products such as foodstuffs, textiles, paints, dyes and pharmaceuticals. Acetic acid is also used in the production of PTA. BP has acetic acid operations at Hull, UK; in the USA through a capacity rights agreement with Sterling Chemicals at Texas City, Texas; in South Korea through Samsung BP Chemicals (BP 51%); in China through Yangtze River Acetyls Company (BP 51%) and in Malaysia through BP Petronas Acetyls Sdn. Bhd. (BP 70%).

Major Activities

The joint venture project to build a 300-ktepa acetic acid plant in Taiwan with Formosa Chemicals and Fibre Corporation (BP 50%) continued to progress in 2003 and is on schedule to start up around mid 2005. Engineering contracts were awarded at the end of 2003.

BP Petronas Acetyls Sdn. Bhd. (BP 70%) completed a debottleneck project in Kertih, Malaysia in the first quarter of 2003 which increased capacity to 500 ktepa.

Expansion of Yangtze River Acetyls Company (Yaraco), China has progressed. The engineering, procurement and construction contract was awarded by BP in early 2004. Target expansion to 350 ktepa is planned to be completed by early 2005.

BP has a 50% interest in a newly proposed 500-ktepa acetic acid plant in Nanjing, China. The heads of agreement was signed in May 2004, and completion of the plant is projected at the end of 2006.

Olefins and Derivatives

Ethylene (and Related Co-products)

We produce and market the basic petrochemical building blocks, known as olefins, that are used primarily as raw material for other chemical products. These olefins are derived from the steam cracking of liquid and gaseous hydrocarbons.

Olefins - ethylene, propylene and butadiene - are produced by crackers at Grangemouth, UK; Lavéra, France (Naphtachimie - BP 50%); Köln, Germany and Chocolate Bayou, Texas in the USA. Olefins are also manufactured by Ethylene Malaysia Sdn. Bhd. (BP 15%) at Kertih, Malaysia and by BP Refining and Petrochemicals (BPRP) at Gelsenkirchen and Munchmunster in Germany. Crackers produce the raw materials for the production of derivative products including polyethylene, polypropylene, acrylonitrile, styrene, ethanol and ethylene oxide, which are also produced at various BP plants.

Major Activities

During 2003, we continued to integrate the former Veba operations into our own. The company changed its name to BP Refining and Petrochemicals (BPRP) from Veba Oel Refining and Petrochemicals (VORP).

The construction of the 900-ktepa cracker complex in Shanghai by SECCO (BP 50%) progresses smoothly. By early 2004, construction was approximately 50% complete and is on schedule to startup in 2005.

In the USA, construction began on a project to increase ethylene capacity at Chocolate Bayou, Texas by 295 ktepa.

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Polypropylene

Polypropylene is used for moulded products, fibres and films. We are the second largest producer of polypropylene in the world, with manufacturing facilities at Chocolate Bayou and Deer Park, Texas and Carson City, California in the USA; Lillo and Geel, Belgium, Lavéra and Sarralbe, France and Grangemouth, UK.

Major Activities

The petrochemicals complex in Shanghai, planned by SECCO (BP 50%), is expected to add 250 ktepa of polypropylene when completed in 2005.

High Density Polyethylene (HDPE)

Polyethylene is used for packaging, pipes and containers. BP Solvay Polyethylene Europe (BP 50%) has HDPE plants at Grangemouth, UK; Lillo, Belgium; Sarralbe and Lavéra, France; and Rosignano, Italy. In addition, BP Solvay Polyethylene North America (BP 49%) has a HDPE plant at Deer Park, Texas and a joint venture plant with Chevron Philips Chemical Company at Cedar Bayou, Texas. We also produce HDPE through Polyethylene Malaysia Sdn. Bhd. (BP 60%) at Kertih, Malaysia.

Major Activities

BP Solvay Polyethylene North America (BP 49%), along with joint venture partner Chevron Philips Chemical Company, started a new 317-ktepa world scale HDPE plant (BP 25%) at Cedar Bayou, Texas. As a result, BP Solvay Polyethylene North America discontinued a 118-ktepa plant of smaller and less efficient capacity at Deer Park, Texas.

The sale of PT Peni (BP 75%), a 450-ktepa polyethylene plant in Merak, Indonesia was completed in April.

Exit of Bataan Polyethylene Company plant (BP 39%) continued to progress in 2003.

The complex in Shanghai, planned by SECCO (BP 50%), is expected to add 600 ktepa of HDPE/linear-low density polyethylene (LLDPE) when completed in 2005.

Acrylonitrile

BP is the world s largest producer and marketer of acrylonitrile, which is used in textiles and plastics for the automobile and consumer goods industries. We operate two acrylonitrile plants at Green Lake, Texas and Lima, Ohio in the USA. Green Lake, with a capacity of 460 ktepa, is the largest acrylonitrile production site in the world. Acrylonitrile is also produced at Köln, Germany and through a capacity rights agreement with Sterling Chemicals at Texas City, Texas. Additionally, BP is the world s largest producer and marketer of the co-product, acetonitrile, primarily sold for pharmaceutical applications.

Major Activities

The planned SECCO complex in Shanghai (BP 50%) is intended to produce 260 ktepa of acrylonitrile when complete in 2005.

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Other Products

In addition to the seven core products, we are involved in a number of other linked products. These include LLDPE and low density polyethylene (LDPE) which are used in a wide range of applications including packaging, as is styrene. Ethylene oxide and ethanol are all used in solvents, coatings and the automotive industry. LAOs are used as comonomers for polyethylenes and to manufacture synthetic lubricants, plasticizers, surfactants and oilfield chemicals. PAOs are used in both synthetic lubricants and surfactants. PIA is used for isopolyester resins and gel coats. Napthalene dicarboxylate (NDC) is used for photographic film and specialized packaging. Polybutene is used in lubricants and fuel additives. TMA is used by the automotive and consumer goods industries. Butanediol (BDO) is used in synthetic materials and engineering plastics. MAN is used in a wide range of plastics and resins. Ethyl acetate and vinyl acetate monomer (VAM) are used in coatings and textile applications. Polypropylene resins are also converted into woven and non-woven fabrics for industrial products, such as, carpet backing, geo-textiles and various packaging materials.

BP operates LLDPE plants at Grangemouth in the UK and Köln in Germany. The complex at Köln also produces LDPE.

We operate styrene monomer plants at Texas City, Texas in the USA and Marl in Germany. Polystyrene plants are operated at Marl in Germany, Wingles in France and Trelleborg in Sweden. Expanded polystyrene plants are operated at Wingles and Marl.

PIA is produced at Joliet, Illinois in the USA and in Geel, Belgium. NDC is produced at our plant in Decatur, Alabama in the USA.

BP manufactures polybutene at Whiting, Indiana in the USA and at Lavéra, France.

LAOs are produced at our facilities in Pasadena, Texas in the USA; Joffre, Canada and Feluy, Belgium. We manufacture PAOs at our facilities in Deer Park, Texas in the USA and Feluy, Belgium.

TMA and MAN are produced at Joliet, Illinois in the USA. We manufacture BDO using our proprietary technology in a world-scale plant at Lima, Ohio in the USA.

In South Korea, the Asian Acetyls Company (BP 34%) operates a 150-ktepa plant producing VAM, a derivative of acetic acid.

Major Activities

We have implemented or announced a number of structural changes that we believe should significantly improve our portfolio. The most significant changes were as follows:

In March 2003 we announced our plan to sell our wholly-owned TMA, PIA and MAN business in Joliet, Illinois in the USA and PIA produced at our integrated aromatics and derivatives complex in Geel, Belgium. The sale was completed on May 28, 2004.

We sold our share in AG International Chemicals Company (BP 50%), a joint venture with Mitsubishi Gas Chemical Company in Japan manufacturing PIA.

We completed the divestment of Burmah Castrol Chemicals with the sale of Fosroc Mining and Sericol in January 2003.

We exited the ethylene vinyl acetate copolymers (EVA) business at Köln, Germany.

In February 2004, we announced the closure of the last manufacturing plant at Baglan Bay, UK. Production of isopropanol ceased in March, 2004.

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In March 2004, we announced our intention to sell our Fabrics and Fibres and our LAO/PAO businesses. The LAO/PAO businesses may be included in the intended public offering of our O&D business.

On April 27, 2004, we announced our intention to set up a separate corporate entity for the O&D businesses. It is our intent to make a public offering of this entity at the appropriate time. Based on the estimated lead time required for such a transaction, and depending on market circumstances, we are aiming to make such an offering in the second half of 2005.

Manufacturing Facilities

BP has large-scale manufacturing facilities in Europe and the USA. The Group s major sites, with our share of their capacities, are: Grangemouth (2,930 ktepa) and Hull (1,595 ktepa) in the UK; Lavéra (1,800 ktepa) in France; Marl (630 ktepa), Gelsenkirchen (1,460 ktepa) and Köln (4,515 ktepa) in Germany; Geel (2,155 ktepa) in Belgium; and Texas City, Texas (2,800 ktepa), Chocolate Bayou, Texas (2,635 ktepa), Decatur, Alabama (2,280 ktepa), and Cooper River, South Carolina (1,330 ktepa) in the USA.

We aim to grow in the Asia-Pacific region, which we believe offers good prospects for demand growth. Our intention is to build further on the positions that the Group now holds in the region through planned investment and commercial relationships, such as joint ventures. Our share of capacity in Asia amounts to 4,450 ktepa, as follows: Indonesia (215 ktepa), South Korea (1,005 ktepa), Malaysia (1,460 ktepa), Taiwan (1,205 ktepa) and China (565 ktepa). When on line in 2005, our share of the complex in Shanghai, planned by SECCO (BP 50%), is expected to add 1,600 ktepa of capacity.

	Years ended December 31,		
Production by region (a)	2003	2002	2001
		(kte)	
UK	3,186	3,221	3,126
Rest of Europe	10,958	10,526	7,925
USA	10,068	10,201	8,943
Rest of World	3,731	3,040	2,722
Total Production (a)	27,943	26,988	22,716

(a) Includes BP share of joint ventures, associated undertakings and other interests in production.

BP s petrochemical products are sold to companies in a number of industries that manufacture components used in a wide range of applications. These include the agriculture, automotive, construction, furniture, household products, insulation, packaging, paint, pharmaceuticals and textile industries. Our products are marketed through a network of sales personnel and agents who also provide technical services.

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OTHER BUSINESSES AND CORPORATE

Other businesses and corporate comprises Finance, the Group s coal asset and aluminium asset, its investments in PetroChina and Sinopec, interest income and costs relating to corporate activities worldwide.

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Turnover	515	510	549
Total operating loss	(904)	(701)	(523)
Total assets	10,231	6,987	7,527
Capital expenditure and acquisitions	409	428	430

Finance coordinates the management of the Group s major financial assets and liabilities. From locations in the UK, Europe, the USA and the Asia Pacific region, it provides the link between BP and the international financial markets and makes available a range of financial services to the Group including supporting the financing of BP s projects around the world.

Coal activity consisted of our 50% interest in PT Kaltim Prima Coal, an Indonesian company which operates an opencast coal mine at Sangatta in Kalimantan, Indonesia. On October 10, 2003 we completed the sale of this interest to PT Bumi Resources.

Aluminium. Our aluminium business is a non-integrated producer and marketer of rolled aluminium products, headquartered in Louisville, Kentucky, USA. Production facilities are located in Logan County, Kentucky and are jointly owned with Alcan Aluminum. The primary activity of our aluminium business is the supply of aluminium coil to the beverage can business.

Investments in China. During 2000 BP made two investments in China, one of the world s fastest growing economies. BP invested $416 million in the China Petroleum and Chemical Corporation (Sinopec) and $578 million in PetroChina in the initial public offerings of both companies, obtaining around 2% in each company. On January 13, 2004 we sold our investment in PetroChina for $1.65 billion. On February 10, 2004 we sold our investment in Sinopec for $742 million. Separately, BP has formed a joint venture with PetroChina in Guangdong province which had 400 service stations at the end of 2003 and has agreed to form a joint venture with Sinopec to acquire, revamp or build 500 service stations in the Zhehang province. PetroChina and Sinopec are two of China s major companies in the oil and chemicals businesses.

Research, technology and engineering activities are carried out by each of the major business segments on the basis of a distributed programme coordinated by the BP Technology Council. This body provides leadership for scientific, technical and engineering activities throughout the Group and in particular promotes cross-business initiatives and the transfer of best practice between businesses. In addition, a group of eminent industrialists and academics form the Technology Advisory Council, which advises senior management on the state of technology within the Group and helps identify current trends and future developments in technology.

Research and development is carried out using a balance of internal and external resources. Involving third parties in the various steps of technology development and application enables a wider range of technology solutions to be considered and implemented, improving the productivity of research and development activities.

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The innovative application of technology and the rapid transfer of this knowledge through the Group make a key contribution to improving BP s business performance, particularly in the areas of the introduction of new products, safety, the environment, cost reduction and efficiency of business operations. We believe that, in addition to improving existing business performance, the use of innovative technology can create new possibilities for the organic growth of our energy- and petrochemical-related businesses.

Across the Group, expenditure on research for 2003 was $349 million, compared with $373 million in 2002 and $385 million in 2001.

Insurance. 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 premia with attendant transaction costs. The position is reviewed from time to time.

REGULATION OF THE GROUP S BUSINESS

BP s exploration and production activities are conducted in many different countries and are therefore subject to a broad range of legislation and regulations. These cover virtually all aspects of exploration and production activities, including matters such as licence acquisition, production rates, royalties, pricing, environmental protection, export, taxes and foreign exchange. The terms and conditions of the leases, licences and contracts under which these oil and gas interests are held vary from country to country. These leases, licences and contracts are generally granted by or entered into with a government entity or state company and are sometimes entered into with private property owners. These arrangements usually take the form of licences or production sharing agreements.

Licences (or concessions) give the holder the right to explore for and exploit a commercial discovery. Under a licence, the holder bears the risk of exploration, development and production activities and provides the financing for these operations. In principle, the licence holder is entitled to all production minus any royalties that are payable in kind. A licence holder is generally required to pay production taxes or royalties, which may be in cash or in kind.

Production sharing agreements entered into with a government entity or state company generally obligate BP to provide all the financing and bear the risk of exploration and production activities in exchange for a share of the production remaining after royalties, if any.

In certain countries, separate licences are required for exploration and production activities and, in certain cases, production licences are limited to a portion of the area covered by the exploration licence. Both exploration and production licences are generally for a specified period of time (except for licences in the United States which remain in effect until production ceases). The term of BP s licences and the extent to which these licences may be renewed vary by area.

In general, BP is required to pay income tax on income generated from production activities (whether under a licence or production sharing agreement). In addition, depending on the area, BP s production activities may be subject to a range of other taxes, levies and assessments, including special petroleum taxes and revenue taxes. The taxes imposed upon oil and gas production profits and activities may be substantially higher than those imposed on other activities, particularly in the UK, Norway, Angola, Canada and Trinidad.

BP s other activities are also subject to a broad range of legislation and regulations in various countries in which it operates.

Health, safety and environmental regulations are discussed in more detail in the Environmental Protection section on page 68.

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ENVIRONMENTAL PROTECTION

Health, Safety and Environmental Regulation

The Group is subject to numerous national and local environmental laws and regulations concerning its products, operations and activities. Current and proposed fuel and product specifications under a number of environmental laws will have a significant effect on the production, sale and profitability of many of our products. Environmental laws and regulations also require the Group to remediate or otherwise redress 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, chemicals plants, natural gas processing plants, oil and natural gas fields, service stations, terminals and waste disposal sites. In addition, the Group may have obligations relating to prior asset sales or closed facilities. Provisions for environmental restoration and remediation are made when a clean-up is probable and the amount is reasonably determinable. Generally, their timing coincides with the commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites. The provisions made are considered by management to be sufficient for known requirements.

The extent and cost of future environmental restoration, remediation and abatement programmes are often inherently difficult to estimate. They depend on the magnitude of any possible contamination, the timing and extent of the corrective actions required and BP s share of liability relative to that of other solvent responsible parties. Though the costs of future restoration and remediation could be significant, and may be material to the results of operations in the period in which they are recognized, it is not expected that such costs will have a material impact on the Group s overall financial position or liquidity. Refer to Item 18 Financial Statements Note 31 on page F-51 for the amounts provided in respect of environmental remediation and decommissioning.

The Group s operations are also subject to environmental and common law claims for personal injury and property damage caused by the release of chemicals, hazardous materials or petroleum substances by the Group or others. Fifteen proceedings instituted by governmental authorities are pending or known to be contemplated against BP and certain of its US subsidiaries under US federal, state or local environmental laws, each of which could result in monetary sanctions in excess of $100,000. No individual proceeding is, nor are the proceedings as a group, expected to have a material adverse effect on BP s consolidated financial position or profitability.

Management cannot predict future developments, such as increasingly strict requirements of environmental laws and the resulting enforcement policies thereunder, that might affect the Group s operations or affect the exploration for new reserves or the products sold by the Group. A risk of increased environmental costs and impacts is inherent in particular operations and products of the Group and there can be no assurance that material liabilities and costs will not be incurred in the future. In general, the Group does not expect that it will be affected differently from other companies with comparable assets engaged in similar businesses. Management believes that the Group s activities are in compliance in all material respects with applicable environmental laws and regulations.

For a discussion of the Group s environmental expenditures see Item 5 Operating and Financial Review and Prospects Environmental Expenditure on page 90.

BP operates in over 100 countries worldwide. In all regions of the world BP has processes to ensure compliance with applicable regulations. In addition, each individual in the Group is required to comply with the BP health, safety and environment policy and associated expectations and standards. Our partners, suppliers and contractors are also encouraged to adopt them. The Group is reviewing impacts of health safety and environment regulations and obligations related to our 50% ownership of TNK-BP. This document focuses primarily on the US and EU, where over 80% of our fixed assets are located, and on two issues of a global nature: climate change programmes and maritime oil spills regulations.

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Climate Change Programmes

Kyoto Protocol

In December 1997, at the Third Conference of the Parties to the United Nations Framework Convention on Climate Change (UNFCCC) in Kyoto, Japan, the participants agreed on a system of differentiated internationally legally binding targets for the first commitment period of 2008 to 2012. Before it can be implemented, the Kyoto protocol to the UNFCCC needs to be ratified by at least 55 nations, representing a minimum of 55% of global anthropogenic greenhouse gas (GHG) emissions. The US has indicated that it will not ratify. Therefore, in order for the treaty to come into force, Russia needs to ratify, in addition to those nations which have either already ratified or indicated that they will ratify. If the Kyoto treaty does enter into force and its targets are to be met, some reduction in the use of fossil fuels would be required within countries which have ratified the Kyoto treaty. The impact of the Kyoto agreements on global energy (and fossil fuel) demand is expected to be small (see International Energy Agency Global Energy Outlook, 2000 Edition).

Since 1997, BP has been actively involved in policy debate, worked with others on mitigating technologies, demonstrated global emissions trading and reduced the emissions from our facilities. In early 2002, we announced that we had succeeded in reducing our direct, equity share, GHG emissions by 10% and set a target to maintain our net emissions at 2001 levels through the next decade, with success being dependent upon the resolution of the various international policy discussions on market mechanisms.

BP is an advocate of market mechanisms to allow optimum utilization of resources to meet national Kyoto targets. Such systems are being considered, developed or implemented by individual countries and also internationally through the European Union. The relative success of these systems will determine the extent to which alternative fiscal or regulatory measures may be applied. Some EU member States have indicated that they require energy product taxes to enable them to meet their Kyoto commitments within the EU burden sharing agreement, and are already implementing national legislation, such as the UK Climate Change Levy.

United Kingdom Emissions Trading Scheme (UKETS)

The UKETS is a voluntary scheme with the UK Government. The Direct Participant section of the scheme provides a financial incentive for organizations that agreed to take on absolute greenhouse gas emissions reduction targets against a 1998-2000 emissions baseline. At present the market is small and any risk from BP s participation in the scheme is low.

European Union Emissions Trading Scheme

In July 2003, final agreement was reached on a Directive establishing a scheme for greenhouse gas emission allowance trading within the EU. Once implemented by member states, they will set limits on CO_2 emissions from qualifying installations and issue a finite number of tradable allowances. Under the Directive each installation will also require a GHG emissions permit, which carries an obligation to report, monitor and verify annual emissions and surrender enough allowances to cover these. Most major BP facilities within Europe will be included in the Directive. BP is currently assessing the likely impact on our business, although we expect this to be small, as we are well prepared following the operation of our own internal emissions trading system from 1999-2001, and in the UK from participation in the UKETS.

Maritime Oil Spill Regulations

Within the United States, the Oil Pollution Act of 1990 significantly increased oil spill prevention requirements. Details of this legislation are provided in the regional review below. Outside the United States, the BP operated fleet of tankers is subject to international spill response and preparedness regulations that are typically promulgated through the International Maritime Organization (IMO) and implemented by the relevant flag state authorities. The International Convention for the Prevention of Pollution From Ships (Marpol 73/78) requires vessels to have detailed shipboard emergency and spill prevention plans. The International Convention on Oil Pollution, Preparedness, Response and Co-Operation (OPRC) requires vessels to have adequate spill response plans and resources for response anywhere the vessel travels to. These conventions and separate Marine Environmental Protection Circulars also stipulate the relevant state authorities around the globe that require engagement in the event of a spill. All of these requirements together are addressed by the vessel owners in Shipboard Oil Pollution Emergency Plans. BP Shipping s liabilities for oil pollution damage under the United States Oil Pollution Act 1990 and outside the United States under the 1969/1992 International Convention on Civil Liability for Oil Pollution Damage are covered by marine liability insurance having a maximum limit of $1 billion for each accident or occurrence. This insurance cover is provided by two mutual insurance associations, The United Kingdom Steam Ship Assurance Association (Bermuda) Limited and The Britannia Steam Ship Insurance Association Limited.

At the end of 2003 our international fleet numbered 28 oil tankers with an average age of three years (25 are double-hulled, three are double-sided) and eight LNG ships with an average age of six years. Our fleet renewal programme will continue into the future and should see 11 modern double-hulled vessels delivered by the end of 2004, with a further 18 confirmed for 2005 to 2007. In addition to its own fleet, BP will continue to charter quality ships; currently these vessels include both single- and double-hulled designs but all are vetted prior to each use to ensure they are operated and maintained to meet BP s standards.

United States Regional Review

The following is a summary of significant US environmental legislation affecting the Group.

The Clean Air Act and its regulations require, among other things, new fuel specifications and sulphur reductions, enhanced monitoring of major sources of specified pollutants; stringent air emission limits and new operating permits for chemical plants, refineries, marine and distribution terminals; and risk management plans for storage of hazardous substances. This law affects BP facilities producing, refining, manufacturing and distributing oil and products as well as the fuels themselves. Federal and state controls on ozone, carbon monoxide, benzene, sulphur, MTBE, nitrogen dioxide, oxygenates and Reid Vapor Pressure impact BP s activities and products in the US. BP is continually adapting its business to these rules and has the know-how to produce quality and competitive products in compliance with their requirements. For example, in 1999 BP introduced a premium grade gasoline in Atlanta, Georgia, meeting stringent future sulphur standards and has expanded this offer in over 40 cities across the US. Beginning January 2006, all gasoline produced by BP will have to meet EPA s stringent low sulphur standards. Furthermore, by June 2006, at least 80% of the highway diesel fuel produced by BP will have to meet a sulphur cap of 15 parts per million (ppm).

In 2001, BP entered into a consent decree with the Environmental Protection Agency (EPA) and several states that settled alleged violations of various Clean Air Act requirements related largely to emissions of sulphur dioxide and nitrogen oxides at BP s refineries. This settlement requires the installation of additional controls at all of BP s US refineries at a cost currently estimated at $400 million, over at least an eight-year period, and the one-time payment of a $10 million penalty which was made in 2001.

In 2003 the South Coast Air Quality Management District filed a complaint against BP West Coast Products LLC and Atlantic Richfield Company in Los Angeles County Superior Court, alleging multiple violations of air quality regulations at the Carson oil refinery in California, USA. Atlantic Richfield Company operated the refinery until it was transferred to BP West Coast Products LLC on January 1, 2002. The complaint seeks penalties for non-compliance now amounting to $415 million. BP believes

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that it has valid defenses to many of the allegations of the complaint, believes that the amount of the penalty sought is disproportionate to any resulting environmental harm and intends to defend the action vigorously.

BP continues to comply with a plea agreement with the US Justice Department to develop, implement and maintain a nationwide environmental management system (EMS) consistent with the best environmental practices at Group facilities engaged in oil exploration, drilling and/or production in the US and its territories. BP fully implemented EMSs in Alaska and Lower 48 exploration and production performance units during 2003. BP has met the requirement to spend at least $15 million on the programme.

The Clean Water Act is designed to protect and enhance the quality of US surface waters by regulating the discharge of wastewater and other pollutants from both onshore and offshore operations. Facilities are required to obtain permits for most surface water discharges, install control equipment and implement operational controls and preventative measures, including spill prevention and control plans. Requirements under the Clean Water Act have become more stringent in recent years, including coverage of storm and surface water discharges at many more facilities and increased control of toxic discharges.

In 1995, a final federal rule was issued regarding protection of the Great Lakes watershed which has had ongoing impacts on water protection requirements. In 2000, a final federal rule was issued regarding use of Total Maximum Daily Load (TMDL) assessments to address pollutants not meeting water quality standards. EPA deferred implementation of the rule to April 2003 and subsequently withdrew the rule in March 2003, which had the effect of requiring more stringent permit limits at affected industrial facilities. In 2003, EPA published a final strategy for water quality standards and criteria. The strategy lays out actions over the next six years to address a broad range of issues with implications for industrial facilities; these include water use designations, antidegradation, TMDLs, mixing zones, water quality protection criteria and contaminated sediments.

In 2003, BP paid approximately $5.6 million in fines and penalties in the US, about half of which was paid for allegations related to underground storage tanks at its retail operations.

The Oil Pollution Act of 1990 (OPA 90) significantly increased oil spill prevention requirements, spill response planning obligations and spill liability for tankers and barges transporting oil and for offshore facilities such as platforms and onshore terminals. To ensure adequate fundings for response to oil spills and compensation for damages, when not fully covered by a responsible party, OPA 90 created a $1-billion fund which is funded by a tax on imported and domestic oil. OPA 90 also provides that all new tank vessels operating in US waters must have double hulls and existing tank vessels without double hulls must be phased out by 2015. In 2002, BP contracted for the construction of four double-hull tankers at a shipyard in San Diego, California. The first of these new vessels is expected to begin service in 2004, demise chartered to and operated by Alaska Tanker Company (ATC). The current ATC fleet consists of nine tankers: two with single hulls, four with double bottoms and three with double hulls. By the end of 2006 all ATC vessels are expected to be double hulled.

BP has a national spill response team, the BP Americas Response Team (BART), consisting of approximately 240 trained emergency responders at company locations throughout North America. The BART is ready to assist in a response to a major incident.

The Resource Conservation and Recovery Act (RCRA) regulates the storage, handling, treatment, transportation and disposal of hazardous and non-hazardous wastes. It also requires the investigation and remediation of certain locations at a facility where such wastes have been handled, released or disposed of. BP facilities generate and handle a number of wastes regulated by RCRA and have units that have been used for the storage, handling or disposal of RCRA wastes that are subject to investigation and corrective action.

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Under the Comprehensive Environmental Response, Compensation, and Liability Act (also known as CERCLA or Superfund), waste generators, site owners, facility operators and certain other parties are strictly liable for part or all of the cost of addressing sites contaminated by spills or waste disposal regardless of fault or the amount of waste sent to a site. Additionally, each state has laws similar to CERCLA.

BP has been identified as a Potentially Responsible Party (PRP) under CERCLA and similar state statutes at approximately 800 sites. A PRP has joint and several liability for site remediation costs under some of these statutes and so BP may be required to assume, among other costs, the share attributed to insolvent, unidentified or other parties. BP has the most significant exposure for remediation costs at 74 of these sites. For the remaining sites, the number of PRPs can range up to 200 or more. BP expects its share of remediation costs at these sites to be small in comparison to the major sites. BP has estimated its potential exposure at all sites where it has been identified as a PRP and has established provisions accordingly. BP does not anticipate that its ultimate exposure at these sites individually, or in aggregate, will be significant except as reported for Atlantic Richfield Company in the matters below.

The State of Montana has pursued claims against Atlantic Richfield Company alleging natural resource damages arising out of Atlantic Richfield Company s predecessors mining and mineral processing activities. In addition, a tribe was allowed to intervene in the lawsuit, Montana vs. Atlantic Richfield Company. These matters were settled in part in 1999, except for the State s claims for $206 million for restoration damages at several sites. In 1989, the EPA filed a CERCLA cost recovery action against Atlantic Richfield Company for oversight costs at several of the Upper Clark Fork River Basin Superfund sites, US vs. Atlantic Richfield Company. Litigation is proceeding on both the EPA s claim, and on Atlantic Richfield Company s counterclaims against various federal agencies seeking contribution from the federal agencies for remediation costs and for any natural resource damage liability it might incur in Montana vs. Atlantic Richfield Company. The settlements in Montana vs. Atlantic Richfield Company, and subsequent settlements resolved the claims and counterclaims in US vs. Atlantic Richfield Company pertaining to four sites and may provide a framework for possible future settlement of the remaining claims. The Group is also subject to other claims for natural resource damage (NRD) under several federal and state laws. This is a developing area under US law which could impact the cost of some cleanups. NRD claims have been asserted by government trustees against several refineries and other company operations.

In the US, many environmental cleanups are the result of strict groundwater protection standards at both the state and federal level. Contamination or the threat of contamination of current or potential drinking water resources can result in stringent cleanup requirements, but some states have addressed contamination of nonpotable water resources using similarly strict standards. BP has encouraged risk-based approaches to these issues and seeks to tailor remedies at its facilities to match the level of risk presented by the contamination.

Other significant legislation includes the Toxic Substances Control Act which regulates the development, testing, import, export and introduction of new chemical products into commerce; the Occupational Safety and Health Act which imposes workplace safety and health, training and process standards to reduce the risks of chemical exposure and injury to employees; the Emergency Planning and Community Right-to-Know Act which requires emergency planning and spill notification as well as public disclosure of chemical usage and emissions. In addition, the US Department of Transportation through agencies such as the Office of Pipeline Safety and the Office of Hazardous Materials Safety regulates in comprehensive manner the transportation of the Company s products such as gasoline and chemicals to protect the health and safety of the public.

BP is subject to Marine Transportation Security Act and Department of Transport Hazmat security compliance regulations in the United States. These regulations require many of our US businesses to conduct Security Vulnerability Assessments, which include requirements such as preparation of security mitigation plans, implementation of upgrades to security measures, appointment and training of a designated security person and submission of plans for approval and inspection.

See also Item 8 Financial Information Legal Proceedings on page 158.

European Union Regional Review

Within the European Union, member states enact regulations to meet the Directives of the European Commission. By joint agreement, European Union Directives may also be applied within countries outside Europe.

A European Commission Directive for a system of Integrated Pollution Prevention and Control (IPPC) was approved in 1996. This system requires permitting through the application of Best Available Techniques (BAT) taking into account the costs and benefits. In the event that the use of BAT is likely to result in the breach of an environmental quality standard, plant emissions must be reduced further. The European Commission has stated that it hopes that all processes to which it applies will be licenced by July 2005. All plants must be permitted according to the requirements of the IPPC Directive by November 2007. The Directive encompasses most activities and processes undertaken by the oil and petrochemical industry within the European Union and requires capital and revenue expenditure across these BP sites. The European Commission is expected to make recommendations for amendments to the IPPC Directive in 2004.

The European Union Large Combustion Plant Directive sets emission limit values for sulphur dioxide, nitrogen oxides and particulates from large combustion plants. It also required phased reductions in emissions from existing large combustion plants at the latest by April 1, 2001. A revised Large Combustion Plant Directive has been agreed and implementation was required by November 27, 2002. Plants will have to comply by 2008. The second important set of air emission regulations affecting BP European operations is the Air Quality Framework Directive and its three daughter Directives on ambient air quality assessment and management, which prescribe, among other things, limit values for sulphur dioxide, oxides of nitrogen, particulate matter, lead, carbon monoxide, benzene and ozone. A fourth daughter Directive may be agreed in 2004 addressing cadmium, nickel, arsenic and polycyclic aromatic hydrocarbons. Measured or modelled exceedences of air quality limit values will require local action to reduce emissions and may impact any BP operations whose emissions contribute to such exceedences.

BP continues to make investments in respect of cleaner fuels at its refineries worldwide. For our European refineries, these investments are important because availability of cleaner fuels is a part of the EU strategy to combat air pollution. In April 1999, the EU adopted a Directive to further reduce the sulphur content of liquid fuels, but excluding marine bunker fuel oil, and marine gas oil used by ships crossing a frontier between a third country and an EU Member State. Sulphur in gas oil is limited to 0.2% from July 2000 and 0.1% from January 2008. From January 2003, sulphur in heavy fuel oil is limited to 1%, except where use of heavy fuel oil up to 3% sulphur can be used in combustion plants without exceeding specific emission limits, and provided that local air quality standards are met.

The EU has set stringent objectives to control exhaust emissions from vehicles, which are being implemented in stages. In 1998, the EU adopted directives to set emission limits for cars and light vehicles to apply from 2000, together with specifications for gasoline and diesel fuel to apply from that date. In 1999, this was followed by emission limits for heavy commercial vehicles. Maximum sulphur levels for gasoline and diesel fuels to apply from 2005 have also been agreed at 50 ppm and 35% maximum aromatic content for gasoline from the same date. Agreement was reached in December 2002 on a further Directive to make petrol and diesel with a maximum sulphur content of 10 ppm mandatory

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throughout the EU from January 2009, and from 2005 member states will also have to supply low-sulphur fuel at enough locations to allow the circulation of new low-emission engines requiring the cleaner fuel.

In Europe there is no overall soil protection regulation, although a draft Directive is expected in 2004. Certain individual member states have soil protection policies, but each has its own contaminated land regulations. There are common principles behind these regulations, including a risk based approach and recognition of costs versus benefits. Much of the technical guidance supporting these regulations is in draft form.

The European Commission adopted an official proposal on October 29, 2003 for a future regulation on European Chemical Policy referred to as REACH; Registration, Evaluation and Authorisation of Chemicals. This proposal will now be discussed by the European Parliament and Council. Dependent on the discussions, entry in force of the regulation could happen by 2007. Although polymers have been temporarily exempted from the process under the current proposal, about 30,000 other chemicals will have to be re-registered and evaluated. For the Group, this will primarily affect petrochemicals, lubricants and refinery products. At present we do not believe this regulation will have a material impact on our business based on the Group s current range of products, although it will require significant management and administration.

The European Commission issued a proposed Directive on Environmental Liability on January 23, 2003, which is currently under consideration within the European Parliament and Council. The proposal seeks to implement a strict liability approach for damage to biodiversity from high-risk operations.

The Commission s Clean Air for Europe Programme aims to conduct a review of the health and environmental effects of air pollution and predicted European Air Quality up to 2020. It will also examine cost-effective solutions to any residual air pollution problems, firstly in a strategy document (expected in 2005) and secondly in legislative proposals (expected between 2005 and 2007) which may include revisions to current regulations on air quality limit values, fuel quality standards, plant emission standards and totally new regulations. BP through various industry bodies is among the various stakeholders contributing to the scientific activities underpinning this work.

Other environment-related existing regulations include: the Major Hazards Directive which requires emergency planning, public disclosure of emergency plans and ensuring that hazards are assessed, and effective emergency management systems; the Water Framework Directive which includes protection of groundwater; and the Framework Directive on Waste to ensure that waste is recovered or disposed without endangering human health and without using processes or methods which could harm the environment.

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PROPERTY, PLANTS AND EQUIPMENT

BP has freehold and leasehold interests in real estate in numerous countries throughout the world, but no one individual property is significant to the Group as a whole. See Exploration and Production under this heading for a description of the Group s significant reserves and sources of crude oil and natural gas. Significant plans to construct, expand or improve specific facilities are described under each of the business headings within this Item.

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ORGANIZATIONAL STRUCTURE

The significant subsidiary undertakings of the Group at December 31, 2003 and the Group percentage of ordinary share capital (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 Company are marked with an asterisk (*), the percentage owned being that of the Group unless otherwise indicated. Refer to Item 18 Financial Statements Note 42 on page F-77 and Note 45 on page F-80 for information on significant joint ventures and associated undertakings of the Group.

Subsidiary undertakings	%	Country of incorporation	Principal activities
International			
BP Chemicals Investments	100	England	Petrochemicals
BP Exploration Operating 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
Europe			
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
France			
BP France	100	France	Refining and marketing and petrochemicals
Germany			
Deutsche BP	100	Germany	Refining and marketing and petrochemicals
Veba Oil	100	Germany	Refining and marketing and petrochemicals
Netherlands			
BP Capital	100	Netherlands	Finance
BP Nederland	100	Netherlands	Refining and marketing
Norway			
BP Norge	100	Norway	Exploration and production
Spain			
BP España	100	Spain	