BP PLC
Form 20-F
March 06, 2012

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

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended 31 December 2011

OR

.. **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
OR

.. **SHELL COMPANY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
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

United Kingdom

(Address of principal executive offices)

Dr Brian Gilvary

BP p.l.c.

1 St James s Square, London SW1Y 4PD

United Kingdom

Tel +44 (0) 20 7496 5311

Fax +44 (0) 20 7496 4573

(Name, Telephone, E-mail and/or Facsimile number and Address of Company Contact Person)

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	**New York Stock Exchange***
Floating Rate Guaranteed Notes due June 2013	**New York Stock Exchange**
Floating Rate Guaranteed Notes due December 2013	**New York Stock Exchange**
Floating Rate Guaranteed Notes due 2014	**New York Stock Exchange**
3.125% Guaranteed Notes due 2012	**New York Stock Exchange**
5.25% Guaranteed Notes due 2013	**New York Stock Exchange**
3.625% Guaranteed Notes due 2014	**New York Stock Exchange**
1.7% Guaranteed Notes due 2014	**New York Stock Exchange**
3.875% Guaranteed Notes due 2015	**New York Stock Exchange**
3.125% Guaranteed Notes due 2015	**New York Stock Exchange**
2.248% Guaranteed Notes due 2016	**New York Stock Exchange**
3.2% Guaranteed Notes due 2016	**New York Stock Exchange**
4.75% Guaranteed Notes due 2019	**New York Stock Exchange**
4.5% Guaranteed Notes due 2020	**New York Stock Exchange**
4.742% Guaranteed Notes due 2021	**New York Stock Exchange**
3.561% Guaranteed Notes due 2021	**New York Stock Exchange**

*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	18,975,902,659
Cumulative First Preference Shares of £1 each	7,232,838
Cumulative Second Preference Shares of £1 each	5,473,414

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes þ No ¨

If this report is an annual or transition report, indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.

Yes ¨ No þ

Note Checking the box above will not relieve any registrant required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 from their obligations under those Sections.

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 þ No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).*

Yes ¨ No ¨

*This requirement does not apply to the registrant in respect of this filing.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ Accelerated filer ¨ Non-accelerated filer ¨

Indicate by check mark which basis of accounting the registrant has used to prepare the financial statements included in this filing:

International Financial Reporting

Standards as issued by the

U.S. GAAP ¨ International Accounting Standards Board þ Other ¨

If Other has been checked in response to the previous question, indicate by check mark which financial statement item the registrant has elected to follow.

Item 17 ¨ Item 18 ¨

If this is an annual report, indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes ¨ No þ

Cross reference to Form 20-F

Contents

Additional information for shareholders

Financial statements

Miscellaneous terms

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

ADR

American depositary receipt.

ADS

American depositary share.

AGM

Annual general meeting.

Amoco

The former Amoco Corporation and its subsidiaries.

Atlantic Richfield

Atlantic Richfield Company and its subsidiaries.

Associate

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

Barrel (bbl)

159 litres, 42 US gallons.

b/d

barrels per day.

boe

barrels of oil equivalent.

BP, BP group or the group

BP p.l.c. and its subsidiaries.

Burmah Castrol

Burmah Castrol PLC and its subsidiaries.

Cent or c

One-hundredth of the US dollar.

The company

BP p.l.c.

Dollar or $

The US dollar.

EU

European Union.

GAAP

Generally accepted accounting practice.

Gas

Natural gas.

GCRO

Gulf Coast Restoration Organization.

Hydrocarbons

Crude oil and natural gas.

IFRS

International Financial Reporting Standards.

Joint control

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

Joint venture

A contractual arrangement whereby two or more parties undertake an economic activity that is subject to joint control.

Jointly controlled asset

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

Jointly controlled entity

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

Liquids

Crude oil, condensate and natural gas liquids.

LNG

Liquefied natural gas.

London Stock Exchange or LSE

London Stock Exchange plc.

LPG

Liquefied petroleum gas.

MDL 2179

Multi-District Litigation proceedings pending in New Orleans.

MDL 2185

Multi-District Litigation proceedings pending in Houston.

mb/d

thousand barrels per day.

mboe/d

thousand barrels of oil equivalent per day.

mmBtu

million British thermal units.

mmboe

million barrels of oil equivalent.

mmcf

million cubic feet.

mmcf/d

million cubic feet per day.

MW

Megawatt.

NGLs

Natural gas liquids.

OECD

Organization for Economic Co-operation and Development.

OPEC

Organization of Petroleum Exporting Countries.

Ordinary shares

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

Pence or p

One-hundredth of a pound sterling.

Pound, sterling or £

The pound sterling.

Preference shares

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

PSA

A production-sharing agreement (PSA) is an arrangement through which an oil company bears the risks and costs of exploration, development and production. In return, if exploration is successful, the oil company receives entitlement to variable physical volumes of hydrocarbons, representing recovery of the costs incurred and a stipulated share of the production remaining after such cost recovery.

SEC

The United States Securities and Exchange Commission.

Subsidiary

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

Tonne

2,204.6 pounds.

Trust

Deepwater Horizon Oil Spill Trust.

UK

United Kingdom of Great Britain and Northern Ireland.

US

United States of America.

Information about this report

This document constitutes the Annual Report and Accounts in accordance with UK requirements and the Annual Report on Form 20-F in accordance with the US Securities Exchange Act of 1934, for BP p.l.c. for the year ended 31 December 2011. A cross reference to Form 20-F requirements is on page 2.

This document contains the Directors Report, including the Business Review and Management Report, on pages 7-138 and 153-172. The Directors Remuneration Report is on pages 139-151. The consolidated financial statements of the group are on pages 173-281 and the corresponding reports of the auditor are on pages 176-177.

BP Annual Report and Form 20-F 2011 and *BP Summary Review 2011* may be downloaded from *bp.com/annualreport.* No material on the BP website, other than the items identified as *BP Annual Report and Form 20-F 2011* or *BP Summary Review 2011,* forms any part of those documents.

BP p.l.c. is the parent company of the BP group of companies. Unless otherwise stated, the text does not distinguish between the activities and operations of the parent company and those of its subsidiaries.

The term shareholder in this report means, unless the context otherwise requires, investors in the equity capital of BP p.l.c., both direct and indirect. As BP shares, in the form of ADSs, are listed on the New York Stock Exchange (NYSE), an Annual Report on Form 20-F is filed with the US Securities and Exchange Commission (SEC).

Cautionary statement

In order to utilize the Safe Harbor provisions of the United States Private Securities Litigation Reform Act of 1995 (the PSLRA), BP is providing the following cautionary statement. This document contains certain forward looking statements within the meaning of the PSLRA with respect to the financial condition, results of operations and businesses of BP and certain of the plans and objectives of BP with respect to these items. These statements may generally, but not always, be identified by the use of words such as will , expects , is expected to , aims , should , may , objective , is likely to , intends , believes , anticipates , p expressions. In particular, among other statements, (i) certain statements in the Chairman s letter (pages 8-11), the Group chief executive s letter (pages 14-17) and the Business review (pages 18-111), including but not limited to statements under the headings Our Strategy , Outlook and Looking Ahead , with regard to strategy and strategic priorities, plans to deliver shareholder value, expectations regarding the 10-point plan , expectations regarding future dividend payments, BP s outlook on global energy trends to 2030 and beyond, the intention to make $38 billion of disposals, anticipated increase in operating cash flow and margins, future capital expenditure, expected level of investments, the anticipated timing for completion of and final proceeds from the disposition of certain BP assets, future production levels including expectations for an increase in high-margin production, the timing and composition of future projects including expected start up, completion, timing of production, level of production and margins, expectations for drilling and rig activity in the Gulf of Mexico, the timing and quantum of and timing for completion of contributions to and payments from the $20-billion Trust fund, the expected terms of the proposed settlement agreement with the Plaintiffs Steering Committee in MDL 2179 and the expected timing of the fairness hearing and court approvals in respect thereof, the expected amount, source and timing of payments under any settlements, expectations regarding regulation and taxation of the energy industry and energy users, future global refinery capacity and utilization, the timing for completion of the Whiting refinery upgrade, plans regarding the implementation of enhancements to BP s risk management system, expectations regarding the reduction of net debt and the net debt ratio, the expected future level of depreciation, depletion and amortization, the expected level of the refining marker margin, the completion of planned and announced divestments, including the planned disposals of the Texas City refinery and the southern part of the US West Coast FVC, dates or periods in which production is scheduled or expected to come onstream or a project or action is scheduled or expected to begin or be completed, and the level of future turnaround activity; (ii) the statements in the Business review (pages 18-111), Corporate governance (pages 119-138), the Directors remuneration report (pages 139-151) and Additional information for shareholders (pages 153-172) with regard to plans to continue the ongoing process of embedding OMS, the timing for the implementation of the Bly report recommendations, intentions to implement group-wide practices for oil spill preparedness

and response and crisis management, plans to spend $700 million on certain refinery-related safety measures, plans to implement enhanced and standardized technical practices across the refining business, the timing for the completion of the Shoreline Clean-up, the timing of, cost of, source of payment and provision for future remediation and restoration programmes and environmental operating and capital expenditures, the anticipated future level of time for conversion of proved undeveloped reserves to proved reserves, expectations regarding Refining and Marketing s intentions to achieve $2 billion in performance improvement by the end of 2012, plans to halve US refining capacity by the end of 2012, the timing for the completion of construction at the Cherry Point refinery, anticipated investment in Alternative Energy, expectations regarding greater regulation and increased operating costs in the Gulf of Mexico in the future, and costs for providing pension and other post-retirement benefits; (iii) the statements in the Business review (pages 103-106) with regard to future dividend and optional scrip dividend payments, future capital expenditures and capital expenditure commitments, taxation, intentions to maintain a significant liquidity buffer, future working capital and cash flows, gearing and the net debt ratio, expected payments under contractual and commercial commitments and purchase obligations, and including under Liquidity and capital resources Trend information , with regard to production excluding TNK-BP, the expected level of turnarounds, the marketing environment in fuels, lubricants and petrochemicals, underlying average quarterly charge from Other businesses and corporate, and expectations regarding future disposals; and (iv) certain statements in the Business review (page 84) and Additional information for shareholders (pages 160-166) regarding the anticipated timing of trial proceedings, court decisions and potential investigations and civil or criminal actions by US state and/or local governments; 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 onstream; the timing of certain disposals; future levels of industry product supply, demand and pricing; OPEC quota restrictions; PSA effects; operational problems; general economic conditions; political stability and economic growth in relevant areas of the world; changes in laws and governmental regulations; regulatory or legal actions including the types of enforcement action pursued and the nature of remedies sought; the actions of prosecutors, regulatory authorities and courts; the actions of all parties to the Deepwater Horizon oil spill-related litigation at various phases of the litigation; exchange rate fluctuations; development and use of new technology; the success or otherwise of partnering; the actions of competitors; the actions of contractors; natural disasters and adverse weather conditions; changes in public expectations and other changes to business conditions; wars and acts of terrorism or sabotage; and other factors discussed elsewhere in this report including under Risk factors (pages 59-63). In addition to factors set forth elsewhere in this report, those set out above are important factors, although not exhaustive, that may cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements.

Statements regarding competitive position

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

Unless otherwise indicated, information in this document reflects 100% of the assets and operations of the company and its subsidiaries that were consolidated at the date or for the periods indicated, including minority interests. The company was incorporated in 1909 in England and Wales and changed its name to BP p.l.c. in 2001. BP s primary share listing is the London Stock Exchange. Ordinary shares are also traded on the Frankfurt Stock Exchange in Germany and, in the US, the company s securities are traded on the New York Stock Exchange in the form of ADSs *(see page 167 for more details).*

The registered office of BP p.l.c., and our worldwide headquarters, is:

1 St James s Square,

London SW1Y 4PD, UK.

Tel +44 (0)20 7496 4000.

Registered in England and Wales No. 102498. Stock exchange symbol BP .

Our agent in the US is BP America Inc.,

501 Westlake Park Boulevard, Houston, Texas 77079.

Tel +1 281 366 2000.

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Group overview

2011 was a year of recovery, consolidation and change. We laid strong foundations, reshaped the portfolio and recovered momentum.

Chairman s letter

Carl-Henric Svanberg

Chairman

Dear fellow shareholder,

In 2011 we re-laid the foundations of BP. Our objective was to ensure your company is able to deliver sustainable shareholder value in the months and years ahead. Above all else, this is dependent on BP having the trust of the societies in which it works today and over the long term.

During the year the board oversaw a major reorganization designed to establish a stronger, safer BP. The progress made demonstrates that the company can and will recover from the consequences of the Deepwater Horizon accident. We remained mindful of the tragic events seen in 2010 and the need to ensure such an accident never happens again.

I thank you for the patience you have shown as we work to rebuild your company.

The board set three priorities for BP. Safety must be enhanced and embedded. Trust must be regained. Value must be created through a clear strategic plan. While these priorities are simple to express, substantial activity is required to turn them into tangible and lasting change.

On safety, the board supported and challenged Bob Dudley and his executive team as they restructured and enhanced BP s processes, systems and culture. Furthermore, the board initiated a review of the way BP manages, reports and acts on risk, including board oversight.

On trust, we ensured that BP continued to meet its commitments in the Gulf of Mexico. We co-operated with every official investigation and prepared for litigation. We worked closely with governments and regulators, and we communicated openly with shareholders and the wider world.

On value, the board set a 10-point plan focused on growing operating cash flow and increasing shareholder returns. The company will play to its greatest strengths and prioritize value over volume. Relentless execution of this strategy is now needed so we deliver value to our shareholders.

BP s financial and operating performance in 2011 has created a springboard for growth. In the upstream, we secured 55 new exploration licences in nine countries, and our Refining and Marketing segment delivered very strong earnings. Our $38-billion divestment programme is strengthening the group s financial position and focusing our portfolio.

In 2011 we restored your dividend, and I am pleased to report that we increased the dividend by 14% in February 2012, in accordance with our policy.

The wider world did not stand still in 2011. We saw rapid and sometimes unpredictable change. This included escalation of the European debt crisis and political upheaval in countries where BP has significant operations, such as Libya and Egypt. We kept a close watch on these developments and acted where required. Our international advisory board assisted us in this task.

The company continually looks for ways to form new relationships and enhance its partnerships around the world. Our new alliance with Reliance Industries in India is a significant venture in a fast-growing market. Russia is particularly important for BP. Our TNK-BP alliance is hugely successful. Since acquiring 50% of the company for around $8 billion, BP has received around $19 billion in dividends - which equates to around $2 billion per year. In 2011, we saw new opportunities in Russia, but these did not progress. This region still has excellent potential for BP and we remain committed to it. The nature of our industry is rarely straightforward, and BP will never shrink from pursuing opportunities simply because they involve challenges.

In my letter last year, I commented on the evolution of the board. This has continued. My goal is to ensure that the board combines a broad set of skills and experience. BP s board should be diverse in the widest sense. It should have the best blend of the best people from our industry and from other sectors. BP remains committed to meritocracy as well as diversity.

Andrew Shilston and Professor Dame Ann Dowling have joined the board as non-executive directors and Brian Gilvary has joined as an executive director.

Left BP s LNG activities are focused on building competitively advantaged liquefaction projects.

Chairman s letter

Andrew, a former finance director at Rolls-Royce, brings substantial experience in the oil and gas industry through previous roles at Enterprise Oil and Cairn Energy. Ann is Head of the Department of Engineering at the University of Cambridge, where she is Professor of Mechanical Engineering. She brings exceptional academic and engineering expertise to BP.

Brian Gilvary is now our chief financial officer. His broad experience of BP, gained over 25 years in influential roles such as the chief executive of integrated supply and trading and as deputy group CFO, makes him a valuable addition. Our previous CFO Byron Grote takes up a new role as the director responsible for corporate business activities. Byron has made a substantial contribution over his lengthy BP career and I am pleased we have retained his services as a board member.

Left The East Azeri platform in the Caspian Sea in Azerbaijan. BP is the largest foreign investor in the country.

Right In 2011, the chairman visited the Alberta oil sands in Canada including the Sunrise Energy Project BP s joint venture with Husky Energy.

In detail

For more information

on the board and its

committees, see

Corporate governance

report.

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Bill Castell has decided not to seek re-election at the forthcoming AGM. Bill has made a substantial contribution to the board, not least as chair of the safety, ethics and environment assurance committee. Bill has devoted all the time that was asked of him and more in the service of the board and the company. I speak for the whole board when I thank him sincerely for all he has done. Bill s role as senior independent director will be taken by Andrew Shilston, who will be supported on internal matters by Antony Burgmans.

The board committees have always played an important oversight role, freeing the main board to concentrate on strategic matters. All of our committees have been heavily involved this year. Each committee has dealt with different challenges, and all of the directors have been unstinting in the time they have given.

The Gulf of Mexico committee, formed in 2010 and chaired by Ian Davis, has been invaluable in allowing the board to prioritize its work during the restoration of the Gulf of Mexico and the ensuing litigation. During the year, Antony Burgmans became chair of the remuneration committee and Brendan Nelson became chair of the audit committee. Paul Anderson took over the chair of the safety, ethics and environmental assurance committee in December.

During the year, the remuneration committee has worked with Bob Dudley and his team to remodel the reward system within the group. The system below the board is now clearly focused on the long term and is similar to that used for executive directors. I believe our approach to rewarding directors balances the company s priorities of driving financial performance, meeting our responsibilities as a corporate citizen and providing value for our shareholders.

Against all of this background, I have been keen to see how the board could work more effectively. During the year, a working group of

non-executive directors reviewed board tasks, roles and processes. This work, coupled with our board evaluation, has led to a number of changes in the way in which the board operates. These are set out in the board performance section of this annual report.

2011 was a testing year for everyone at the company. The board was impressed by the way in which Bob and his executive team tackled a range of considerable issues. We were also struck by the tenacity and dedication of BP s employees. On behalf of the board, I thank everyone for their efforts.

In 2012 we must execute our 10-point plan and continue to meet our commitments in the Gulf of Mexico. While many of the investigations into the causes of the accident have been completed, we still face major litigation in the US during 2012. This must run its course, although we are pleased with the continuing progress that we are making with settling some of these claims.

As part of its strategic role, the board must be mindful of the long-term developments in our industry. *BP Energy Outlook 2030* tells us that rising populations, increasing levels of life expectancy and improving standards of living will continue to generate growing demand for energy. The challenges in terms of supply are immense. I expect these dynamics to provide BP with opportunities for decades to come. The report projects that fossil fuels will be providing around 80% of the world s energy in 2030. This will require companies such as ours to overcome substantial technical and physical challenges. Lower carbon resources and energy efficiency technologies are required to play their part in addressing both demand and emissions. BP must understand and adapt to these changes in order to remain sustainable in this changing world.

I believe BP ended the year stronger and safer, with increasing forward momentum and a clear strategy matched to the world we see ahead. This is a great company, with a strong board and excellent people. I thank you for your continued support. I will report back to you on BP s progress at this point next year.

Carl-Henric Svanberg

Chairman

6 March 2012

Group chief executive s letter

Bob Dudley

Group Chief Executive

Dear fellow shareholder,

Following the tragic Deepwater Horizon accident of 2010, BP entered 2011 facing a range of uncertainties. These included concerns about our ability to operate safely in deep water, meet our financial commitments in the Gulf of Mexico, and recover the trust and value we had lost. We were also subject to intense speculation around the future and direction of the company.

By the end of the year we had successfully resolved some significant uncertainties facing the company. We set new standards for safety, led by our safety and operational risk organization, and we reshaped our upstream business. We strengthened the group s financial position by progressing our divestment programme. We worked to earn back trust through co-operation with the official investigations and actively sharing the lessons learned. We set a clear strategic direction through a 10-point plan focused on building value for shareholders. We also received permission to resume operations in the Gulf of Mexico a significant milestone.

During the year more clarity also emerged over the 2010 accident as official investigation reports were published. Their central conclusions supported that of our own investigation namely that what happened in the Gulf of Mexico was a complex accident involving multiple causes and multiple parties. I am pleased that we were able to reach settlements with Mitsui, Weatherford, Anadarko and Cameron during 2011. On 3 March 2012 we announced a settlement with the Plaintiffs Steering Committee, subject to final written agreement and court approvals, to resolve the substantial majority of legitimate economic loss and medical claims made by individual and business plaintiffs in the Multi-District Litigation proceedings pending in New Orleans (MDL 2179). The legal process continues with other parties.

We recognize there is a great deal more to do, but I can report that BP finished its year of consolidation in robust shape.

Through the year, BP s employees worked with great determination to enhance what we do and how we do it. This work will continue. I want to make it absolutely clear that we are not seeking a return to business as usual. The events of 2010 demand more than that. As we move ahead, our job is to make BP a stronger, safer company by further embedding safety at the heart of the company, continuing to earn back trust, and creating long-term value for shareholders once again. In this letter, I outline in more detail the actions taken in 2011 to achieve these objectives.

Above During the

year BP gained its first

US exploration drilling

permit since the 2010

Deepwater Horizon oil

spill - for the Kaskida

field, Gulf of Mexico.

Safety

During the year, we reorganized our upstream segment to improve clarity and accountability. We introduced new systems and technologies to further enhance oversight of operations. We continued to increase the capacity of our independent safety and operational risk organization, and recruited experts from other high-hazard industries to add new expertise and perspectives. We also renewed the company s performance and reward systems, values and code of conduct, which require whoever works for BP to put safety first.

At the front line, we shut down platforms and operations to make necessary upgrades. We set new, voluntary standards for blowout preventers, which shut off the flow of oil in an emergency. We also designed a new type of capping stack, which now stands ready for deployment anywhere in the world in the event of a leak in deep water.

Trust

Looking back over events in the Gulf of Mexico, I am proud of how BP responded. Just in financial terms, during 2010 and 2011 combined we made a pre-tax cash outlay of more than $26 billion to cover oil spill response costs, meet claims and litigation expenses, support research, promote tourism and help restore the environment. The test of corporate responsibility is whether a company follows up its words with actions. I believe we have. And we will continue to do so.

During the year we were invited to 25 countries to share what we have learned in the Gulf. In turn, we have gone out to gain insights from organizations in other high-hazard sectors, including NASA, the UK Atomic Energy Authority and various naval bodies. We will keep listening to others and applying what we learn.

Value

As I write this letter, the market value of the company remains significantly lower than it was before the incident. Our 10-point plan shows our belief that the company can realize improved returns for shareholders. The plan sets out what you can expect from us, and what you will be able to measure, over the next three years.

- First and foremost, you will see a continuing, relentless focus on safety and risk management.
- You will see the company play to its strengths exploration; managing deepwater activity; giant fields; gas supply chains; our world-class downstream business; and our capabilities in developing technology and building relationships.
- You will see a company that is simpler and more focused as a result of a major divestment programme.
- You will see a company that is organized effectively and applies its standards consistently.
- You will see more visibility from us on our individual businesses.

You will be able to measure the effects of active portfolio management, as we invest more in our areas of strength and generate cash through further divestments.

You will be able to measure the contribution of new upstream projects with higher margins, as they come onstream over the next three years.

You will be able to measure operating cash flow, which we expect to be around 50% higher by 2014.[a]

[a] See footnote c on page 39.

Group chief executive s letter

In detail

For more on the

strategic priorities set

out in the 10-point plan,

see Our strategy.

Pages 37-41

We plan to use around half of the increased cash flow for investment and half for other uses including increased distributions to shareholders.

And finally, you will be able to measure balance sheet strength.

The plan makes a greater priority of creating value for the shareholder, rather than simply increasing production volume. We will sell assets earlier in their lifecycle following discovery if we spot opportunities to reinvest in higher growth areas. We are also being selective in where we invest along the supply chain. For example, we are selling certain mature fields that hold more value for others, and we are selling a number of refining and marketing assets that do not match our aspirations.

I want to say a little more about the areas of strength at the heart of our strategy.

Exploration is our lifeblood. We had a record year for new access in 2011, gaining 55 exploration licences in nine countries. This opened up around 315,000km^2 for exploration. We intend to more than double exploration investment over the next three years.

In deep water, we are confident in our ability to design, engineer and operate large installations safely. 2012 will be a busy year for us in the deepwater regions of Angola, Brazil and the Gulf of Mexico.

Left New investment

announced in 2011 may

extend production at the

Clair field of the UK North

Sea to 2050.

Right February 2011

saw BP announce a

partnership with Reliance Industries spanning the

gas value chain in India,

from exploration to

marketing.

In giant fields, work with our partners has increased output at Iraq s Rumaila field by more than 10%. BP was the first supermajor to exceed its production target in Iraq. During the year we also announced we will be investing approximately $14 billion with our partners in the UK North Sea.

Natural gas is set to be the fastest-growing fossil fuel globally to 2030. Here, we are forging new partnerships, such as the strategic alliance created in 2011 with Reliance Industries in India. We continue to have a significant focus on developing unconventional resources around the world. Taking technology and skills developed in North America, we are working with the governments of Oman and Algeria to develop their large tight gas reservoirs, and we also continue to work in Indonesia to develop their onshore coalbed methane fields.

We also have exceptional expertise in building supply chains. For example, we move gas from 6,000 metres below the Shah Deniz field in Azerbaijan to markets in Western Europe, 3,000 kilometres away.

In Refining and Marketing, our world-class fuels, lubricants and petrochemicals businesses are shifting the balance of their activity towards higher growth markets, including China and India. We are moving forward with our plans to sell around half of our refining capacity in the US, and we have made good progress on the modernization of the Whiting refinery. Looking ahead, we expect our downstream operations to be a material contributor to the cash flow we anticipate over the next few years.

These strengths are supported by our long-standing track record in developing and applying leading technology, and the deep and enduring relationships we form. We were disappointed that our exploration plans with Rosneft did not progress, but we remain committed to our TNK-BP investment in Russia, which continues to be successful.

A well-balanced business

As the *BP Energy Outlook 2030* shows, the world is now in a long wavelength transition to a lower-carbon energy mix. For BP, that means helping to meet current demand through the supply of oil and gas including unconventional resources while developing a number of the lower-carbon options needed at scale tomorrow.

During 2011, we invested a further $1.6 billion in our Alternative Energy business, which takes total investment since 2005 to $6.6 billion. We have a growing biofuels business in Brazil and we added 401MW[a] of wind generation capacity during the year, with interests in more than 1,000 wind turbines now turning across the US. In contrast, solar has evolved into a low-margin commodity market, and in 2011 we began winding down our remaining solar operations as we prepare to exit the business.

Looking ahead

BP is meeting its commitments and moving forward with increasing momentum. 2012 will be a year of milestone delivery, with financial momentum building in 2013 and 2014. In 2012, you can expect high-margin production coming back on stream, major project start-ups and new exploration wells, further progress on our divestment programme, continued improvement in downstream financial performance and completion of payments into the Deepwater Horizon Oil Spill Trust fund.

The company has a strong leadership team and non-executive directors who provide rigorous oversight challenging and supporting executives as circumstances dictate. I want to thank BP s employees for their resilience. They were again tested hard this year. The character of BP s people was evident wherever we operate, not least in Egypt and Libya, where our teams evacuated colleagues and their families safely during the upheavals in the region.

I thank investors for their continued patience through a tough time. One by one, we are addressing the uncertainties facing our company. The days ahead may bring further challenges, but we are in a much stronger position than this time last year. There is a great deal more to do, but we are building a stronger, safer BP that can play an important role in the world for many years to come.

Bob Dudley

Group Chief Executive

6 March 2012

[a] On a gross joint-venture basis (which includes 100% of the capacity of equity-accounted entities where BP has partial ownership). Including BP s share of joint ventures on a net basis, the capacity added was 274MW.

Our market

In 2011, energy markets proved resilient, with continued growth despite volatile conditions in the global economy.

Left Modernization work at BP's Whiting refinery, Indiana, made significant progress in 2011, with the completion of a new pipeline to Canada.

Right Operations at our East Azeri platform. BP production in Azerbaijan is an important source of natural gas for markets in Western Europe.

The growth in world oil consumption slowed in 2011, albeit with continued robust growth in China and certain other non-OECD countries partially offsetting an overall decline in OECD countries. However, despite the slowdown in demand, average crude oil prices in 2011 were significantly higher than in the previous year, exceeding $100 per barrel for the first time (in nominal terms). Natural gas prices diverged globally in 2011. Globally, refining margins improved on average as oil product demand continued to grow.

Economic context

After a very strong 2010, world economic growth slowed in 2011 and we expect subdued global growth to continue in 2012. Emerging economies with stronger productivity and rising populations led by China and India are set to drive growth, while developed countries may lag behind as they seek to address their internal fiscal imbalances.

Energy demand, and in particular oil demand, has followed overall economic trends in recent years, recovering strongly in 2010 but facing more challenging conditions in 2011, especially in OECD markets.

Concerns about the volatility of commodity and financial markets, energy security and climate change have led to continued debate over the appropriate role of markets, government regulation and other policy measures that affect the supply and consumption of energy. Given the pressures in the sector, we expect regulation and taxation of the energy industry and energy users to increase in many areas in the future.

Below Work at BP's

Castellón refinery,

Spain. Refining

margins in Europe

increased in 2011,

as demand for

commercial transport

improved.

Crude oil prices

Crude oil prices, as demonstrated by the industry benchmark of dated Brent for the year, averaged $111.26 per barrel in 2011, about 40% above 2010 s average of $79.50 per barrel. This represents the highest annual average ever (in nominal terms), as well as the largest one-year increase ever.

Prices rose early in 2011 and then increased further following the loss of Libyan supplies, which drove prices briefly above $125 per barrel in April. Thereafter, weakening global economic growth, increased production by other OPEC producers and the release of International Energy Agency (IEA) strategic stocks helped to cushion the disruption. While oil prices eased over the remainder of the year, they still ended the year above $100 per barrel.

These record prices prevailed despite the fact that the growth in global oil consumption slowed in 2011 with demand rising by roughly 0.7 million barrels per day for the year (0.8%)[a] in the face of slower economic growth and higher prices. Growth in 2011 was concentrated in non-OECD countries, led by China. There was relatively little change in non-OPEC production and, with the loss of Libyan supplies beginning in February, OPEC crude oil production did not return to its January peak until November. As a result, by mid-year OECD commercial oil inventories were consistently below average for the first time since 2008.

By comparison, global oil consumption in 2010 grew by roughly 2.7 million barrels per day (3.1%)[b], the strongest growth in annual consumption since 2004, driven by a renewed global economy. Crude oil prices in 2010 remained stable in a range of $70-80 per barrel before beginning to increase in the fourth quarter due to rising consumption and continuing OPEC production.

We expect oil price movements in 2012 to continue to be driven by the pace of global economic growth and its resulting implications for oil consumption, and by OPEC production decisions, especially in reaction to the recovery of Libyan supplies and the EU embargo on Iranian crude.

[a] From *Oil Market Report February 2012©,* OECD/IEA 2012, page 5.
[b] *BP Statistical Review of World Energy June 2011.*

Our market

Left Operations at BP s Na Kika field in deepwater Gulf of Mexico. BP is one of the largest producers of hydrocarbons in the region.

Natural gas prices

Natural gas prices diverged globally in 2011, reflecting different regional dynamics. The average US Henry Hub First of Month Index fell to $4.04/mmBtu, 8% lower than the prices in 2010, while in Europe prices increased.

After a record increase in 2010, global gas consumption growth moderated in 2011. In the US, economic momentum supported gas use in the first half of the year and a hot summer raised demand. Yet domestic production outpaced consumption growth due to further increases in the availability of shale gas. Henry Hub gas prices fell and traded below coal parity in US power generation throughout the year, leading to the displacement of coal by gas. Unusually mild winter weather weakened prices at the end of year. The differentials of production area prices to Henry Hub prices continued to narrow as pipeline bottlenecks were reduced.

In Europe, spot gas prices at the UK National Balancing Point increased by 33% to an average of 56.33 pence per therm for 2011 the highest level since 2008. The loss of Libyan gas supply raised continental European demand for Russian gas in early 2011, but LNG supply and weak general demand kept spot gas prices below oil-indexed contract levels. Competition between spot and contract pipeline supplies continued. High volumes of LNG were available to Europe, despite the Japanese earthquake and tsunami in March 2011, which caused major nuclear outages and significantly increased LNG purchases in Japan. This contributed to a tightening global LNG market over the year.

The economic rebound had led the average Henry Hub First of Month Index to recover in 2010 from eight-year lows, rising by 10% to $4.39/mmBtu. In the UK, National Balancing Point prices averaged 42.45 pence per therm in 2010 - 38% above the depressed prices in 2009.

In 2012, we expect gas markets to continue to be driven by the economy, weather, domestic production, LNG supply and reductions in nuclear power generation following the Fukushima disaster in Japan in March 2011.

In detail

For more information, see

Refining and Marketing.

Page 94

Refining margins

In 2011, demand for oil products continued to grow, albeit more slowly than a year ago, with all of the demand increase occurring in non-OECD markets and with overall demand in the OECD resuming its structural decline. As new refining capacity continued to be commissioned in Asia and the Far East, global refinery utilization rates fell in 2011. Despite this, a number of factors supported an increase in refining margins across all regions for a second consecutive year. The BP refining marker margin (RMM)[a] averaged $11.64 per barrel in 2011, compared with $10.02 per barrel in 2010 and $9.19 per barrel in 2009.

In 2011, diesel prices relative to crude reached highs not seen since 2008 as the trend to lower-sulphur fuels continued and demand grew. Gasoline prices were volatile in 2011. In the US, short-term supply issues supported gasoline prices in the middle of the year despite a reduction in demand compared with last year. By the fourth quarter, US gasoline prices relative to crude had fallen to the lowest levels seen for at least 23 years. Refining margins improved in Asia Pacific, due to continuing oil demand growth and the disruption to Japanese refining operations caused by the earthquake and tsunami.

US mid-continent crude oils (including the key marker grade of West Texas Intermediate) were heavily discounted throughout the year because of increasing production in the US Lower 48 states and in Canada, coupled with constrained logistics. This allowed refiners that are able to access these crudes to capture additional margins.

The loss of Libyan crude oil supply in the first quarter of 2011 and production problems in the North Sea during the summer resulted in record high prices for low-sulphur grades of crude oil. This adversely impacted the margin for refiners configured to process these grades, particularly in Europe, the US East Coast and Asia.

By contrast, in 2010 the RMM increase compared with 2009 was due to strongly-improved demand for oil products, in line with the economic bounce-back from recession, despite unused refining capacity.

Looking ahead, the overall economic environment is expected to result in limited demand growth such that refinery utilization levels are likely to remain low, despite the announced shutdown of capacity in Europe and the US.

[a] See page 94 for further information on RMM.

Left In 2011, we

received local

government approval

for a 1.25mtpa PTA

plant to be added to existing BP petrochemicals facilities in Zhuhai, China.

Our market: Longer-term outlook

The long-term outlook is one of growing demand for energy and increasing challenges for our industry in meeting the world s needs.

The facts and figures used

in our longer-term outlook commentary in this section

are derived from *BP Energy Outlook 2030,* published in

January 2012, unless otherwise indicated, and represent a 'base case' or most likely projection.

Long-term growth in energy demand

Energy demand is linked to economic growth, development and population. The world s population is projected to increase by 1.4 billion over the next 20 years, while its real income is likely to grow by 100% over the same period. This combination of factors is expected to increase world primary energy consumption by approximately 40% over the next 20 years, with non-OECD energy consumption as much as 70% higher by 2030. Energy and climate policies, efficiency gains and a long-term structural shift in fast-growing economies away from industry towards less energy-intensive activities may act to restrain consumption, but the overall trend is likely to be one of strong growth in energy demand.

Oil and gas are still expected to play a significant part in meeting this demand and we project they will represent 53% of total energy consumption in 2030 (compared with 57% in 2010). Even under the IEA s most challenging climate policy scenario (450 Scenario) that might with difficulty still be achievable, oil and gas together still makes up 49% of the energy mix in 2030, with combined demand projected to exceed current levels.[a] The 450 Scenario assumes governments adopt commitments to limit the long-term concentration of greenhouse gases in the atmosphere to 450 parts-per-million of CO_2 equivalent. We believe the political, technological, logistical, infrastructure and cost challenges presented by the 450 Scenario make it increasingly unlikely to occur, meaning that demand for fossil fuels would remain at a higher level for longer.

We also expect advances in technology to lead to new and more efficient ways to transform base hydrocarbons (including natural gas and coal) into usable forms of energy, petrochemicals and lubricants.

Beyond 2030, we believe it is currently very difficult to provide meaningful projections. We expect that growing population and per-capita incomes will continue to drive growing demand for the services that energy provides including mobility, heat and light. The way those services are provided will be shaped by future technology developments, changes in tastes, and future policy choices all of which are inherently uncertain. Concerns about affordability, energy security and environmental impacts in particular climate change are all likely to be important considerations for the future. These factors may accelerate the trend towards more diverse sources of energy supply, a lower average carbon footprint, increased efficiency of energy provision and use, and demand management.

We actively monitor developments and continually assess a range of potential outcomes and their implications for our long-term strategy.

[a] From *World Energy Outlook 2011*©, OECD/IEA 2011, page 545.

Above An engineer on board the BP oil tanker British Gannet. At the end of 2011, we had 53 international vessels.

Below The control room at BP's Atlantic LNG facility in Trinidad, where BP has been operating since 1961.

Meeting the energy challenge

We estimate that there are enough energy resources available to meet the increases in demand. As a measure of this availability, today's oil reserves could meet more than 45 years of demand at current consumption rates; while known supplies of natural gas could meet demand for nearly 60 years; and coal could meet demand for up to 120 years.[a] Meanwhile, new technologies are improving the availability and affordability of unconventional fossil resources such as shale gas, oil sands and coalbed methane. And emerging renewable resources have the potential for significant growth as their markets mature and technological advances make them more affordable and efficient.

While energy is available to meet demand, action is also required to limit the volumes of carbon dioxide and other greenhouse gases being emitted through energy use. Global economic challenges have reduced the focus of some governments on climate policy, at least in the short term. But the position set out at the UN's 2010 climate change conference in Cancun that deep cuts are required to hold global temperature rises to 2°C, and the commitment by both developed and developing countries in Durban in 2011 to negotiate an agreement by 2015 that requires action from all countries, suggests that in the medium to long term an emphasis on carbon policy will return and grow. We project that under known and probable policy and technology, global CO_2 emissions may be 28% higher in 2030 than they are today, partly as a consequence of coal use in rapidly-growing economies. More aggressive, but still plausible, energy policy and technology deployment could lead to slower growth in CO_2 emissions than expected, with emissions from energy use falling after 2020, but probably not to the extent of putting the world on a global warming trajectory that does not exceed 2°C. And even these policies would require concerted multilateral action from policymakers and a willingness by society to bear a significant cost.

Energy security also represents a major challenge. More than half of the world's natural gas is in just three countries, and more than 80% of global oil reserves are in 10 countries, most of which are located well away from the hubs of energy consumption. The ability and willingness of OPEC members to expand capacity and production is one of the main factors determining the dynamics of the oil market.

[a] *BP Statistical Review of World Energy June 2011*. These reserve estimates are compiled from official sources and other third-party data, which may not be based on proved reserves as defined by SEC rules.

Our market: Longer-term outlook

The dual challenges of emissions and energy security underline the value of energy efficiency. Increases in efficiency have the potential to reduce emissions without inhibiting economic growth, and they can help energy-importing countries to reduce their dependency on others. For these reasons, we expect efficiency to remain high on the agenda through to 2030.

A diverse energy mix

We believe the global energy challenge can only be met through a diverse mix of fuels and technologies. This is why BP's portfolio includes oil sands, shale gas, deepwater production, and alternative energies such as biofuels and wind power, in addition to conventional oil and gas. As well as simply meeting growth in overall demand, a diverse mix can help to provide enhanced national and global energy security while supporting the transition to a lower-carbon economy.

Within the energy mix, we see a key strategic role for natural gas as a lower-carbon fuel that is increasingly secure and affordable. Used in place of coal for power, it can reduce CO_2 emissions by half.

Renewables will be essential in addressing the challenges of climate change and energy security over the long term. Renewable energy is already the fastest-growing fuel and is projected to grow 8.2% per annum to 2030 a rate similar to the emergence of nuclear power in the 1970s and 1980s. Renewable energies are starting from a low base however, and we project that they are only likely to meet around 6% of total energy demand by 2030. With a few exceptions, renewables are not yet competitive with conventional power and transportation fuels. Sufficient policy support is required to help the commercialization of effective options and technologies, but renewables must ultimately become free from subsidy and commercially self-sustaining. *See Risk factors climate change and carbon pricing on page 60.*

The future for hydrocarbons

Given the vital role oil will continue to play in meeting demand, substantial investment in new technology will be required to boost recovery from declining fields and commercialize currently inaccessible resources. The industry's ability to increase recovery from mature assets will be profoundly important, particularly in the world's giant fields. Over time, it will become increasingly difficult to reach, extract and manage oil resources, and companies such as BP may be required to move yet further into technically challenging areas. Greater energy intensity could be required to extract these resources; operating costs and greenhouse gas emissions from operations are likely to increase. Along with increasing supply, we believe the energy industry will be required to make hydrocarbons cleaner and more efficient to use.

Carbon capture and storage (CCS) may help to provide a path to cleaner coal and gas, but CCS technologies still face significant technical and economic issues and are unlikely to be in operation at scale in the near future.

Policy and access

If industry and the market are to meet the world's growing demand for energy in a sustainable way, governments must set a stable and enduring framework. As part of this, governments will need to provide secure access for exploration and development of energy resources, define mutual benefits for resource owners and development partners, and establish and maintain an appropriate legal and regulatory environment. Within this framework, we believe that the most effective means of finding, producing and distributing diverse forms of energy is to foster the use of markets that are open and competitive, and in which carbon has a price.

Our organization: Business model

BP's business model is to create value across the entire hydrocarbon value chain. This starts with exploration and ends with the supply of energy and other products that are fundamental to everyday life.

BP is one of the world's leading integrated oil and gas companies.[a] Our objective is to create value for shareholders and supplies of energy for the world in a safe and responsible way. We strive to be a safety leader in our industry, a world-class operator, a responsible corporate citizen and a good employer.

Above When completed in the second half of 2013, modernization work at our Whiting refinery should enable BP to capture additional margins.

At each stage of the hydrocarbon value chain there are opportunities for us to create value both through the successful execution of activities that are core to our industry, and through the application of our own distinctive strengths and capabilities in performing those activities.

We have two main business segments: Exploration and Production, and Refining and Marketing. Through these, our activities are focused on finding, developing and producing essential sources of energy, and turning these sources into products that people need. We provide our customers with fuel for transportation, energy for heat and light, lubricants to keep engines moving, and the petrochemicals products used to make everyday items like plastic bottles.

We also invest in renewable energy sources, which we believe will be an increasing source of value for BP. Our activities are focused on biofuels and wind. These are managed through our Alternative Energy business, which is reported in Other businesses and corporate.

In detail

For more information about Alternative Energy, see Other businesses and corporate.

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Our projects and operations help to generate employment, investment and tax revenues in countries and communities around the world. The relationships we form with governments, partners, contractors, customers, franchisees and suppliers are very important to the success of our business. We are committed to being responsible, meeting our obligations, and building long-lasting relationships.

As a global group, our interests and activities are held or operated through subsidiaries, branches, joint ventures or associates established in and subject to the laws and regulations of many different jurisdictions. Our worldwide headquarters is in London. The UK is a centre for trading, legal, finance and other business functions as well as three of BP's major global research and technology groups. We have well-established operations in Europe, the US, Canada, Russia, South America, Australasia, Asia and parts of Africa. Around 61% of the group's fixed assets are located in OECD countries, including around 37% in the US and around 18% in Europe.

In detail

For definitions of subsidiaries, joint ventures and associates, see Miscellaneous terms.

Page 4

The significant subsidiaries of the group at 31 December 2011 and the group percentage of ordinary share capital (to the nearest whole number) are set out in Financial statements Note 45 on page 251. For information on significant jointly controlled entities and associates of the group, see Financial statements Notes 24 and 25 on pages 215 and 216 respectively.

[a] On the basis of market capitalization, proved reserves and production.

Our organization: Business model

Value creation in our industry

BP's core activities are similar to those carried out by other global, integrated, oil and gas companies.

First, we acquire the rights to explore for oil and gas. When we are successful in finding hydrocarbon resources, we create value by seeking to develop them into proved reserves or by selling them on if they do not fit with our strategic objectives. We often work with partners to mitigate risk or gain from complementary skills. Through disciplined execution of capital projects we then develop, extract and sell the resources. The benefits are shared with governments and other partners.

We move oil and gas through pipelines and by ship, truck and rail. We use our skills and knowledge to find the best routes to deliver supplies to the most attractive markets.

We manufacture fuels and products, creating value by seeking to operate a high-quality portfolio of well-located assets safely, reliably and efficiently. We use our sales and marketing skills to add value to our fuels and other products.

And we also invest in renewable energy sources, with a focus on biofuels and wind.

Integrated model

BP's distinctive capabilities and sources of value

By operating across the full hydrocarbon value chain we believe we can create more value for shareholders, as benefits and costs can often be shared by our two segments. We can develop shared functional excellence more efficiently in areas such as safety and operational risk, environmental and social practices, procurement, technology and treasury management.

We have a distinctive integrated supply and trading function, which aims to maximize the value of our production while ensuring our refineries are fully supplied. We buy and sell at each stage in the value chain to optimize value for the group, often selling our own production and buying from elsewhere to satisfy demand from our refineries and customers. The function also creates value through entrepreneurial trading, where our presence across the major energy trading hubs of the world provides access to vital information on the fundamentals of markets that are increasingly connected.

We consider our ability to build a wide range of strong, long-term relationships to be both a key strength and crucial to our success. We form partnerships with national oil companies and our international oil company peers. We partner with universities and governments in pursuit of improving the technologies available to us, in order to enhance our operations and develop new products. We also actively participate in industry bodies such as the American Petroleum Institute and the Marine Well Containment Company in the US and the Oil Spill Preventions and Response Advisory Group in the UK. Regular review and audit processes enable us to maintain strong links with contractors and suppliers. We work with our partners through the management frameworks embedded in our joint venture and shareholder agreements to ensure safe and reliable operations, and for our mutual commercial benefit.

Left Employees at Prudhoe Bay one of the 15 North Slope oilfields that BP operates in Alaska.

Right During 2011, full commercial operations started at Cedar Creek 2 wind farm in Colorado.

In detail

For more information,

see Technology.

Page 74

We believe our development and application of technology represents a distinctive capability that is central to our reputation and competitive advantage. For us, technology is the practical application of scientific knowledge to manage risks, capture business value and inform strategy development. This includes the research, development, demonstration and acquisition of new technical capabilities and support for the deployment of BP's know-how.

We monitor the potential opportunities and risks presented by emerging science, interdisciplinary innovation and new players; natural resource issues and climate concerns; and evolving policy concerns, including the current emphasis on energy security and efficiency.

Our technology advisory council, which is comprised of eminent technology leaders from business and academia, advises the board and executive management on research and technology matters.

Our organization: Business model

In detail

For more information on

Exploration and Production,

see BP in more depth.

Page 80

Upstream and midstream playing to our strengths

Our Exploration and Production segment is responsible for our activities in oil and natural gas exploration, field development and production; midstream transportation, storage and processing; and the marketing and trading of natural gas, including liquefied natural gas, together with power and natural gas liquids.

Our exploration division obtains access to and finds resources at scale in the world's key hydrocarbon basins. We are an industry leader in seismic imaging, a key technology in the identification of potential hydrocarbon resources. Our developments division develops our hydrocarbon resources, applying effective project execution and capital efficiency. Our production division then extracts resources efficiently and maximizes their recovery.

We focus on areas that play to our strengths deepwater, gas value chains (including the infrastructure required from field to market) and giant fields. We are increasing investment with a particular focus on exploration. We actively manage our portfolio, including divesting assets when we believe they may be more valuable to others than to ourselves. This allows us to focus our leadership, technical resources, and organizational capability on the resources we believe are most likely to flourish in our portfolio.

In 2011, our upstream and midstream activities took place in 30 countries including Angola, Azerbaijan, Canada, Egypt, Norway, Russia, Trinidad & Tobago (Trinidad), the UK, the US and other locations within Asia, Australasia, South America, North Africa and the Middle East. Exploration and Production also includes gas marketing and trading activities, primarily in Canada, Europe and the US. In Russia, we have an important associate through our 50% shareholding in TNK-BP, a major oil company with exploration assets, refineries and other downstream infrastructure.

Upstream technology flagships

In detail

For more information on

Refining and Marketing,

see BP in more depth.

Page 94

Technology will continue to play a critical role in our upstream activities, as the upstream technology flagships diagram demonstrates. In addition, our Project 20K is a significant new initiative that illustrates how new advances have the potential to deliver material value. Through this, we are investing in technology to enable exploration, development and production of reservoirs that were previously beyond reach due to high reservoir pressures, including those at a pressure between 15,000 and 20,000 pounds per square inch. Successful deployment of these technologies would enable us to further develop a number of our existing resources substantially, and we also see opportunities to develop new onshore and offshore resources both as BP and in partnership with national oil companies.

Downstream working across our value chains

Our Refining and Marketing segment is responsible for the refining, manufacturing, marketing, transportation, and supply and trading of crude oil, petroleum, petrochemicals products and related services to wholesale and retail customers.

We have significant operations in Europe, North America and Asia, and we also manufacture and market our products across Australasia, southern Africa and Central and South America. In total we market our products in more than 70 countries.

The segment comprises three main businesses: fuels, lubricants and petrochemicals. All of our businesses operate as value chains. Previously we discussed the segment under the headings of fuels value chains and international businesses, but we now report the value chains by business.

The fuels businesses sell refined petroleum products including gasoline, diesel and aviation fuel. Within this, the fuels value chains (FVCs) integrate the

Downstream technology

Our organization: Business model

activities of refining, logistics, marketing, and supply and trading on a regional basis. This recognizes the geographic nature of the markets in which we compete, providing the opportunity to optimize our activities from crude oil purchases to end-consumer sales through our physical assets (refineries, terminals, pipelines and retail stations). In addition, we operate a global aviation fuels business and an LPG marketing business, from which we intend to divest the bulk and bottled LPG marketing operations.

We own or have a share in 16 refineries including five in the US and seven in Europe. Our focus is on complex, upgraded refineries that are able to process cheaper feedstocks yet yield more valuable products. We also market fuels through around 21,800 retail sites, principally in the US, Europe, Australia and southern Africa. Many of our retail sites are now operated by franchisees with whom we work in close partnership as we seek to ensure our standards and brand are consistently applied. We divest assets and businesses when we believe they will be of greater value to others. In 2011, we announced that we are seeking buyers for our Texas City refinery; and for our Carson refinery near Los Angeles, together with its associated integrated marketing business in southern California, Arizona and Nevada.

Our lubricants business is involved in manufacturing and marketing lubricants and related services to markets around the world. In 2011, approximately 45% of our profit from lubricants was generated from non-OECD markets, and we see good opportunities for further growth in these areas. We market lubricants to the automotive, industrial, marine, aviation and energy markets. The business blends and markets lubricants globally through our key brands of Castrol, BP and Aral. Our strategic relationships with our original equipment manufacturing partners provide the ongoing collaboration needed to develop the next generation of high-performance lubricants, such as Castrol EDGE.

Our petrochemicals business operates on a global basis and includes the manufacture and marketing of petrochemicals that are used in many everyday products, such as plastic bottles and textiles for clothing. Future growth in our business is focused on the demand centres of Asia, where our relationships with joint venture partners are key to our strategy in these increasingly important markets. From 2012 we plan to create a new revenue stream in petrochemicals through licensing some of our leading technology.

Above BP is working with Mendel Biotechnology to develop and commercialize seed products with high resistance to environmental stresses, such as water and nutrient limitation.

Left Developed with Imperial College London, new Permasense sensors are helping BP corrosion engineers to see what is happening inside pipes.

Our organization: People and governance

The people of BP are united by a common code of conduct and values, and share an aspiration to make BP a stronger, safer company that makes a positive difference to the world.

Our board

In detail

For more information, see Corporate governance.

Page 119

The board is responsible for the direction and oversight of BP on behalf of shareholders. As at 31 December 2011, it comprised the chairman, nine non-executive directors together with the group chief executive; the chief financial officer and the chief executive of BP's Refining and Marketing segment.

The executive directors have responsibility for the day-to-day running of BP, while the non-executive directors bring independent viewpoints and a breadth of experience, along with insights into how other companies manage key issues. Five of our current non-executive directors have been appointed since 2010.

Above In 2011, BP announced the start of natural gas production from the Serrette field, offshore Trinidad.

Below A team at work in East Texas. As operator, BP drilled 148 wells across the US Lower 48 states in 2011.

Board committees play an increasingly important role. The committees are: the Gulf of Mexico committee; the safety, ethics and environment assurance committee; the audit committee; the remuneration committee; the nomination committee; and the chairman's committee. In addition, an independent international advisory board advises our chairman, group chief executive and board on strategic and geopolitical issues relating to the long-term development of the group.

In 2011, an internal review of risk management systems and processes was undertaken to enhance clarity, simplicity and the consistency of our risk management system, from front-line operations through to the boardroom. *See Our management of risk on page 42 for further information.* Also in 2011, a new board steering group completed a review of board governance. The review looked at the structure, roles, tools and processes involved in board and board committee work. The findings of the review will inform a new set of board governance principles, which will be published later in 2012. *See Board performance report on pages 120-133 for further information.*

Our employees

In detail

For more information on employees, see BP in more depth.

Page 73

We employ approximately 83,400 people (including 14,600 service station staff), the majority of whom are located in the US and Europe. The Deepwater Horizon oil spill in 2010 had a profound effect on our employees, and to strengthen and standardize what we do, we launched a range of internal change projects in 2011. See *How BP is changing on page 36 for more information.*

In addition, we are working hard to address a critical issue facing everyone in our industry a growing skills gap. This, alongside the increasing demand for energy products and complexity of projects, means that attracting and retaining skilled and talented people is vital.

Our leadership has focused on ensuring that appropriate development opportunities and succession plans are in place to build capability. To supplement our existing internal capability, we also target experienced and skilled professionals in the external market and are continuing to increase our intake of graduates to create a strong internal talent pipeline for the future.

We provide a range of professional development programmes and training to build capabilities in our people and are committed to creating an inclusive work environment where everyone is treated fairly, with dignity, respect and without discrimination.

Our organization: **People and governance**

In detail

For more information on contractors, see Working with partners and contractors.

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Contractors and suppliers

Like our peers, BP rarely works in isolation. In 2011, for example, 55% of the 374 million hours worked were carried out by contractors. These individuals play an important role for BP. During the year we initiated a far-reaching review of the way we work with third parties, particularly those involved in potential high-consequence activities. We are now implementing a range of measures based on our findings, with a focus on six key themes: consistent standards and priorities; fewer suppliers to enable deeper, longer-term relationships; detailed and systematic selection of contractors; clear and specific contracts; intensive oversight and verification; and assurance that supplier personnel are competent.

Our values

Our approach is built on respect, being consistent and having the courage to do the right thing. We believe success comes from the energy of our people. We have a determination to learn and to do things better. We depend upon developing and deploying the best technology, and building long-lasting relationships. We are committed to making a real difference in providing the energy the world needs today, and in the changing world of tomorrow. We are one team a group of diverse individuals from around the world united by shared values and a drive to rebuild BP.

These words, taken from the BP code of conduct, capture what we strive to stand for as a company our renewed values. They are an expression of work done across BP in 2011 to define and renew our principles and values. This work was carried out in response to the events of recent years, which have caused us to reflect on what is important and how we do what we do.

We launched our renewed values in 2011. They represent the qualities and actions we wish to see in BP, and those that BP already demonstrates when it is at its best. The values are aligned with our code of conduct and are there to guide the way we do business and the decisions we take, every day. Safety has been re-emphasized as our number one priority.

Left In 2011, we purchased 10 blocks in Brazil from Devon Energy. Here, a worker on the Deep Ocean Clarion moves drilling pipes on to the rig.

Above Technicians on board the *Jack Ryan* drilling ship, Angola. In 2011, BP gained access to five new deepwater blocks, offshore Angola.

In detail

Find out more online

bp.com/values

The values are much more than words we are actively seeking to embed these values at the heart of the systems and processes we are introducing to unify and strengthen our business. We are both enforcing and incentivizing values-led behaviour. For example, our updated performance and reward system, which came into effect on 1 January 2012, now creates an explicit link between our values and the way individuals are judged and rewarded within BP.

Our values

This statement of our values expresses our aspirations and intentions for BP, as we work together to strengthen safety and risk management, earn back trust and create value. Our values are aligned with, and an extension of, our code of conduct.

Safety

Safety is good business. Everything we do relies upon the safety of our workforce and the communities around us. We care about the safe management of the environment. We are committed to safely delivering energy to the world.

Respect

We respect the world in which we operate. It begins with compliance with laws and regulations. We hold ourselves to the highest ethical standards and behave in ways that earn the trust of others. We depend on the relationships we have and respect each other and those we work with. We value diversity of people and thought. We care about the consequences of our decisions, large and small, on those around us.

Excellence

We are in a hazardous business, and are committed to excellence through the systematic and disciplined management of our operations. We follow and uphold the rules and standards we set for our company. We commit to quality outcomes, have a thirst to learn, and to improve. If something is not right, we correct it.

Courage

What we do is rarely easy. Achieving the best outcomes often requires the courage to face difficulty, to speak up and stand by what we believe. We always strive to do the right thing. We explore new ways of thinking and are unafraid to ask for help. We are honest with ourselves, and actively seek feedback from others. We aim for an enduring legacy, despite the short-term priorities of our world.

One Team

Whatever the strength of the individual, we will accomplish more together. We put the team ahead of our personal success and commit to building its capability. We trust each other to deliver on our respective obligations.

Our code

The BP code of conduct sets the standard that we all work to. It is aligned with our values, group standards and legal requirements, and it clarifies the ethics and compliance expectations for everyone who works at BP. The code was updated in 2011 and now puts greater emphasis on a values-based approach. Where rules are not stated explicitly, our everyday business decisions will be guided by our values.

Our organization: Where we operate

2011 saw BP streamline its operational footprint through divestments while increasing new access to resources. The map below shows the group's key operating sites in 2011.

Our organization: How BP is changing

Following the tragic events in the Gulf of Mexico in 2010, we initiated a wide-ranging programme designed to enhance safety and risk management within the group, earn back trust and restore value. Much was achieved in 2011, but there is a great deal more to do.

Safety and operational risk

We are strengthening our group-wide application of enhanced, consistent standards driven by our safety and operational risk function, which is independent from the business segments.

In detail See Safety, *page 65*

Risk management review

We are enhancing the clarity, consistency and quality of the way risks are understood, reported and acted upon, from front-line operations to the boardroom.

In detail See Our management of risk, *page 42*

Upstream restructuring

We restructured to create three global divisions exploration, developments and production. These constitute the biggest changes in BP s upstream business for 20 years.

In detail See Exploration and Production, *page 80*

Values and behaviours

We have refreshed our values and behaviours and continue embedding these into how we work together.

In detail See Our values, *page 32*

Individual performance and reward

We have aligned performance and reward with our values and introduced safety and taking

Contractor management

We are driving consistent global standards, strengthening verification and assurance, and

Technology

Through technology, we are strengthening our capability to manage risks, capture business

Joint ventures not operated by BP

We initiated a review into our approach to the management of our relationships with significant

long-term perspective as key indicators.	developing longer-term relationships with contractors.	value and inform strategy development.	non-operated joint venture operators and partners. This work includes safety and operational risk as well as bribery and corruption risk.
In detail See Our values, *page 32*	**In detail** See Working with partners and contractors, *page 69*	**In detail** See Technology, *page 74*	**In detail** See Our partners in joint ventures, *page 69*

Our strategy

Below BP has a significant presence in Trinidad & Tobago, operating 13 offshore platforms and holding an interest in Atlantic LNG.

In 2011, we put forward a clear 10-point plan that defines what you can expect from us, and what you will be able to measure, through to 2014.

Following the tragic Deepwater Horizon oil spill, we set out a strategy designed to deliver stability, and restore trust and value. Our first priority was to work to make BP a safer, more risk-aware business. We pursued that strategy with purpose through 2011 and have now laid out a 10-point plan for BP s future.

Our renewed strategy is designed to make BP a simpler, stronger company that plays to its strengths. It concentrates our distinctive talents on high value, advantaged assets, with new and enhanced structures, process and discipline serving to support and sustain our businesses and operations. Our goal is to grow operating cash flows to enable us to both invest for future growth and increase distributions to shareholders.

Our upstream strategic focus is aligned with what we see as the five key drivers of value growth in our operations. These are: managing risk; increasing investment, with a particular focus on exploration; managing our portfolio actively; growing operating cash faster than production; and focusing on the major growth engines that capitalize on our strengths deepwater, gas value chains and giant fields.

In the downstream, we are in the business of hydrocarbon value chains, and with an intense focus on safe and reliable operations, we believe we now have the platform to sustain and grow a world-class business capable of generating leading returns and cash flow growth.

Above Having achieved our improved production target in 2010, BP and partners are working to refurbish the wells and facilities at the Rumaila field in Iraq.

Our strategy: Strategic priorities

Our 10-point plan

Our 10-point plan is how we intend to build a stronger, safer BP. The first five points are things you can expect from us; the second five are things you can measure.

What you can expect from us

We will keep a relentless focus on safety and managing risk

We are determined that BP will deliver world-class performance in safety, risk management and operational discipline. We will be a company that systematically applies our global standards as a single team.

We will play to our strengths

We have had major successes at finding oil and gas at scale. We are also among the real pioneers of deepwater exploration. We have decades of experience managing giant fields and developing valuable gas value chains. We have built a world-class downstream business. Underpinning these strengths are deep capabilities in building relationships and in developing technologies.

Left BP moves gas from 6,000 metres below the Shah Deniz field in Azerbaijan to markets in Western Europe, 3,000 kilometres away.

Right As part of a $1.2 billion investment announced in 2011, the Kinnoull reservoir, UK North Sea, will be connected to BP's Andrew platform.

We will be stronger and more focused

We intend to be a stronger and more focused BP, with a base of assets that is high graded and high performing.

We will be simpler and more standardized

Our organization is already much more standardized than it was before the Deepwater Horizon oil spill. The transformation of our Exploration and Production segment from a regional business to one that is managed along lines of functional expertise is an example of this. Our footprint is smaller, with fewer assets and operations in fewer countries. Our internal reward and performance processes are more streamlined. This should drive better and more sustainable performance in safety, quality and efficiency, with less variation.

We will improve transparency through our reporting

We will improve transparency in the reporting of our business segments. We now break out the numbers of certain parts of our businesses, such as lubricants and petrochemicals in the downstream. From the first quarter of 2012, the group s investment in TNK-BP will be reported as a separate operating segment.

What you can measure

Active portfolio management

We want to focus our portfolio further on our areas of strength, and deliver increased financial flexibility. By the end of 2013, we expect to have completed $38 billion of disposals since the start of 2010.

New projects with higher margins

We have a strong list of upstream projects due to come onstream over the next three years. By 2014, unit cash margins[a] on production from this new wave of projects are expected to be around double our existing average.[b]

Operating cash flow growth

We are aiming to generate an increase of around 50% net cash provided by additional operating activities by 2014 compared with 2011[C] approximately half from ending Deepwater Horizon Oil Spill Trust fund payments and around half from operations.

Use of cash flow for reinvestment and distributions

We will use additional operating cash prudently. We want to use around half for increased investment in our project inventory for growth, and around half for other purposes. This may include increased distributions to shareholders through dividends or share buybacks or repayment of debt.

Strong balance sheet

We intend to enhance the strength of our balance sheet by targeting our level of gearing[d] at the lower half of the 10-20% range over time.

[a] Unit cash margin is net cash provided by operating activities for the relevant projects in our Exploration and Production segment, divided by the total number of barrels of oil and gas equivalent produced for the relevant projects. It excludes dividends and production for TNK-BP.

[b] Assuming a constant oil price of $100 per barrel.

[c] Assuming an oil price of $100 per barrel in 2014. The projection reflects our expectation that all required payments into the $20-billion trust fund will have been completed by the end of 2012. It does not reflect any cash flows relating to other liabilities, contingent liabilities, settlements or contingent assets arising from the Gulf of Mexico oil spill which may or may not arise at that time. We are not able to reliably estimate the amount or timing of a number of contingent liabilities. See Financial statements Note 43 on page 249 for further information.

[d] Gearing refers to the ratio of the group s net debt to net debt plus equity and is a non-GAAP measure. See Financial statements Note 35 on page 230 for further information including a reconciliation to gross debt, which is the nearest equivalent measure on an IFRS basis.

Left Lingen refinery in

Germany is one of Europe s

most complex refineries due

to its ability to fully upgrade

crude during processing.

Our management of risk

Putting safety and risk management at the heart of the company is the foundation for building trust and creating value. In 2011 we began a process to review, refresh and enhance our management of risk.

The role of the board

The board is responsible for the direction and oversight of BP as set out in its governance principles, which include that it will satisfy itself that the material risks to BP are identified and understood and that systems of risk management, compliance and control are in place to mitigate such risks. The board, through its governance principles, requires the group chief executive to operate with a comprehensive system of controls and internal audit to identify and manage the risks that are material to BP. *See Risk management: from operations to the board on page 122.*

Our system of internal control

The system of internal control comprises the holistic set of management systems, organizational structures, processes, standards and behaviours that are employed to conduct the business of BP. The system is designed to meet the expectations of internal control of the Corporate Governance Code in the UK and of COSO (Committee of Sponsoring Organizations of the Treadway Commission) in the US.

Key elements of the system include: the control environment; the management of risk and operational performance; and the management of people and individual performance. As such, BP s risk management system is an integral part of our system of internal control, and is designed to be a simple, consistent and clear framework for managing and reporting all risk from the group's operations to the board.

Review of risk management

In 2011, we initiated a review of our risk management system. The review considered the group s existing risk management system, along with good practices in risk management from outside the company, with a view to identifying what might be done to enhance the clarity, simplicity and consistency of our risk management system.

Using the findings of this review, we have begun implementing enhancements to the way we manage and report risks. This has involved the development of common language, concepts and templates for consistent reporting on risks and risk management; designing enhancements to board and executive processes; and greater alignment of risk management activities and business processes. These improvements build from our existing management systems, standards and practices and we will continue to embed these in 2012. *See the information on Safety and operational risk on page 65 for examples of enhancements to the S&OR function and management of safety and operational risks.*

Our risk management system

Our enhanced risk management system focuses on three levels of activity:

First, the system helps facilitate day-to-day risk management in the group s operations and functions, with the approach varying according to the types of risk we face. Risks are to be identified and managed, and actions to improve the management of risk are to be put in place where necessary. Our aim is to address each different type of risk as well as we can promoting safe, compliant and reliable operations.

Second, for our businesses and functions, risks arising are to be collated periodically, risk management activities are to be assessed, and any necessary further improvements or actions are to be planned. The system is designed to facilitate this by incorporating a standardized form that we call the risk management report (RMR) for businesses and functions to report consistently the risks they face for management consideration, challenge, resource allocation and intervention.

Left Operations at BP's Shah Deniz platform, Azerbaijan. Located offshore, 40 miles south east of Baku, Shah Deniz is thought to hold 1 trillion cubic metres of gas.

Right BP's state-of-the-art Houston monitoring centre provides real-time communications between rigs in the Gulf of Mexico and experts based onshore.

Third, the system facilitates executive and board oversight and governance over the management of significant risks. It requires executive team level involvement in the finalization of risk management activities and improvement plans for the group s most significant individual risks. Using the consistent bottom-up risk identification and assessment process, coupled with top-down executive overview, the system requires that the most significant risks requiring oversight are identified. Oversight of the management of these risks is to be provided through regular review by the board or one of its committees.

Drawing on this input, our enhanced risk management system assists us in our:

Understanding of the risk environment for input into our strategy.

Understanding of which risk types we operate with, given our strategy.

Identification and assessment of actual specific risks and the potential exposure they may represent.

Decision-making on how best to deal with those risks to manage our overall potential exposure.

Active management of identified risks.

Reporting to management and the board about how those risks are managed, and monitoring of our potential exposure.

Obtaining of assurance over the effectiveness of the management of those risks.

Interventions for improvements in the management of those risks where necessary.

Consideration of the effect of the external environment and our business activities on the principal activities of our risk management system.

Our management of risk

Above BP's Cooper River petrochemicals plant in South Carolina operates two PTA units. PTA is used in the production of plastic bottles.

Below Working with Falex Corporation, Air BP has developed a faster and more reliable way to test aviation lubricants.

During 2011, functions, strategic performance units, divisions and segments within BP were requested to prepare RMRs using the new, common approach. This helped provide an overall data set of the key risks identified, an assessment of their potential impact and likelihood on a consistent basis, information on how they are being managed and any actions planned or in progress to improve the management of risk. Based on these RMRs, together with additional executive overview, a single group RMR has been prepared. Those risks identified on the group RMR as requiring particular group-level oversight in the coming year have been allocated to specific board and executive committees for oversight and monitoring. These are discussed below. *Also see Risk factors on pages 59-63 for a description of the material risks we face in our business.*

Risk management can also be a foundation for creating value. The willingness to take and appropriately manage certain risk is fundamental to the success of any commercial enterprise. For example, in our upstream business we consciously place significant amounts of capital at risk in exploring for new hydrocarbon resources. Where this exploration is successful, we would generally expect it to lead to future increases in our proved reserves and future cash flows. However, exploration expenditure may not yield adequate returns, for example in the case of unproductive wells or discoveries that prove uneconomic to develop.

Safety and operational risk function

We have redefined and strengthened the scope and accountabilities of the group function for safety and operational risk (S&OR), creating a new team independent of business line management to drive safe, compliant and reliable operations in BP. The S&OR function, which continues to build towards its full staffing complement, includes S&OR teams which have been formed to work alongside line management but are independent of them. In pursuit of safe, compliant and reliable operations, S&OR personnel can assist, challenge and escalate or intervene as necessary to promote and assure the operating businesses' systematic and disciplined application of global standards on safety and operational risk. The function helps provide assurance as to whether line operations are carried out in accordance with the group's operating management system, and seeks to facilitate more comprehensive and assured S&OR risk action plans for operational units, more incisive interventions on emerging risk situations, and improved investigations and learning from significant incidents.

How we seek to manage our risks

The following is a summary of how we seek to manage the risks we have identified as having a high priority in 2012. There can be no guarantee that our risk management activities will mitigate or prevent these, or other, risks from occurring.

Strategic risks

In response to risks associated with the general macroeconomic outlook and changes in prices and markets, we monitor early warnings from our treasury team and customer-facing businesses. To manage our liquidity, financial capacity and financial exposure risks, we apply our financial framework (see *Liquidity and capital resources on page 103)* and we conduct liquidity stress testing and scenario-planning interventions.

Our current strategic priorities are set out in our 10-point plan (see *pages 38-39).* Among other things, this aims to target investments and disposals efficiently, renew and reposition our portfolio and deliver our major projects to plan. As part of managing the risks to delivery of the 10-point plan we conduct regular planning and performance-monitoring activity, including the planning of disposals; we focus on the delivery of major projects; and we pursue the development of continued technological advances and innovation.

The diverse locations of our operations around the world exposes us to a wide range of political developments and consequent changes to the economic and operating environment. For example, our investments in Russia could be adversely affected by heightened political and other environment risks. As such, we try to actively manage our relationships in Russia, including with the Russian federal government and with TNK-BP. We also seek to manage the group's exposure in Russia through our development of BP's overall portfolio.

Many of our major projects and operations are conducted through joint ventures or associates and through contracting and sub-contracting arrangements where BP may not have full operational control. We seek to manage such joint venture and contractor relationships actively, and this may include monitoring compliance with applicable standards.

As a result of the Deepwater Horizon oil spill there is significant uncertainty regarding the extent and timing of costs and liabilities relating to the incident, the impact of the incident on our reputation and the resulting possible impact on our licence to operate including, among other things, our ability to access new opportunities. In addressing these risks we seek to co-operate with investigators and we encourage the application of responsible and objective scientific analysis in determining outcomes. We always seek to comply with local regulations and, in some cases, our required practices will exceed regulations if our assessment of the operating risk indicates it would be beneficial to do so. We seek to engage with local communities in order to foster improved relationships and reputation.

Left Bernard Looney, BP's Executive Vice President, Developments, on board the Deep Ocean Clarion rig in Brazil.

Above Work at BP's Tangguh facility, West Papua, Indonesia; where gas is collected and distributed to energy markets via ship.

Our management of risk

In detail

For more information

on OMS, see Safety.

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Safety and operational risk

The nature of the group's operations exposes us to a wide range of significant health, safety and environmental risks such as incidents associated with the drilling of wells, operation of facilities, transportation of hydrocarbons and product quality. In addressing these risks we seek to apply our operating management system (OMS) including group and engineering technical practices as applicable. We seek to conduct maintenance and equipment testing and to apply product quality control and testing procedures. We also provide our staff with training and competency development. To better manage the risks inherent in drilling wells where we are the operator, we conduct activity through a global wells organization that is accountable for systems and processes for designing, constructing and managing wells. See *Safety on page 66 for information on the recommendations of BP's internal investigation into the Deepwater Horizon oil spill and the actions we are pursuing to address them.*

Security threats require continuous oversight and control as hostile actions against our staff, our activities and our digital infrastructure (cyber security) could cause harm to people and could disrupt our operations. We have procedures that are intended to monitor for threats and vulnerabilities. We also maintain business continuity plans.

Crisis-management plans are developed to help us to respond effectively to emergencies and to avoid a potentially severe disruption in our business and operations. For deepwater drilling, interim requirements for oil spill preparedness and response, including crisis management response capability, were introduced in 2011 in the Gulf of Mexico. The intention is to build on these interim requirements to put in place group-wide practices for both oil spill preparedness and response and crisis management.

Successful recruitment and development of staff is central to our plans. We have programmes to recruit both graduates and experienced staff and we maintain succession plans for key roles. We also operate training and development programmes, including relating to leadership, and we engage all employees in regular performance-management processes.

Compliance and control risk

Ethical misconduct or breaches of applicable laws or regulations could be damaging to our reputation, results of operations and shareholder value and could affect our licence to operate. Central to managing these risks is our code of conduct (see *page 31),* the requirements of which apply to all employees, supported by our various group standards covering issues such as anti-bribery and corruption, anti-money laundering and competition/anti-trust law compliance. We seek to monitor for new regulations and legislation and plan our response to them. We also operate a range of compliance training and monitoring programmes for our employees.

In the normal course of business, we are subject to risks around our treasury and trading activities, which could arise from shortcomings or failures in our systems, risk management methodology, internal control processes or employees. In addressing these risks, we have adopted specific operating standards and control processes, including guidelines in relation to trading, and seek to monitor compliance through dedicated compliance and risk organizations. We also seek to maintain a positive and collaborative relationship with regulators and the industry at large.

Our performance

2011 was a year of further stern tests for BP. Our challenge was to stabilize the company and meet our commitments in the Gulf of Mexico while laying firm foundations for the future.

We went into 2011 with a clear set of strategic priorities and determination to rebuild the company. Our employees have worked to make BP a safer business and to earn back trust. We also pushed forward on the journey to grow value over the short, medium and long term. The key measures in this section show our progress in numbers, and here you can also read about some of the significant actions and events that defined our year.

Left The BP-Husky refinery in Toledo, Ohio   in operation since 1919.

Right Azeri-Chirag-Guneshli is the largest oilfield under development in the Azerbaijan sector of the Caspian basin.

In detail

For more information, see Safer drilling.

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Safety

Our safety and operational risk function (S&OR) is driving the systematic and disciplined application of global standards in safety and operational risk across the company. We recruited 87 new employees into S&OR during the year, taking its total headcount to around 600 against a target headcount of 800.

During the year, as part of our enhanced focus on safety and operational risk management, we completed a programme of 47 major upstream turnarounds.

We set enhanced voluntary standards for how we drill in the Gulf of Mexico, and implemented new global standards in our operations worldwide. For example, in deepwater drilling, where we use drill rigs that are maintained in position by computer-controlled systems rather than fixed moorings, we require BP-contracted drill rigs to have no fewer than two blind shear rams and a casing shear ram[a] in order to provide additional assurance.

We initiated a review of the way we work with contractors and other industry partners. Guided by our findings, we have implemented a range of new measures, starting with our offshore rigs. We also reviewed and updated our system of risk management see *Our management of risk on pages 42-46.* And we reviewed and updated our values and behaviours, linked them explicitly to an enhanced code of conduct and embedded them in our approach to safety, performance management and reward.

[a] Shear rams are devices within a blowout preventer designed to cut the drill pipe and seal the well in the event of a blowout or other operational emergency.

Our performance

In detail

For more information on the Gulf of Mexico oil spill, see BP in more depth.

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Our upstream business is now reorganized into three divisions exploration, developments and production. We have also reorganized our drilling operations into a single global wells organization (GWO), which forms part of the developments division and takes a consistent, global approach to managing risk. GWO has implemented a number of standard processes since its formation, covering activities such as rig start-up and well cementing.

Trust

Released in January 2011, the report of the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling identified certain failures of management and decision-making within BP and its contractors, as well as regulatory failures, to be contributing factors to the accident. *See Safety on page 65 and Legal proceedings on pages 160-166 for information on other investigations and reports.* We are committed to working with government officials and other operators and contractors to identify and implement operational and regulatory changes that will enhance safety practices throughout the oil and gas industry. BP teams have travelled to 25 countries to share the lessons learned from events in the Gulf of Mexico with our industry, regulators and governments. We also shared equipment and technology developed during the response with the Marine Well Containment Company in the US.

On the ground, the focus of our work in the Gulf of Mexico shifted from response to recovery. The majority of the clean-up work required along the shoreline has now been completed. We are encouraged by local and state reports that indicate tourism in many areas of the region is rebounding. And all federal commercial fishing areas had been reopened by April 2011. We are still at work on the recovery and remain committed to meeting our responsibilities in the region.

By the end of 2011, we had paid $15.1 billion into the $20-billion Deepwater Horizon Oil Spill Trust fund (Trust) set up to meet the costs of the spill. In total, the Trust and BP had paid a total of $7.8 billion in claims, advances and other payments by the end of 2011.

Value

Our profit in 2011 was $25.7 billion compared with a loss of $3.7 billion in 2010. After adjusting for inventory holding gains, our replacement cost profit[a] in 2011 was $23.9 billion compared with a loss of $4.9 billion in 2010. Cash and cash equivalents at the end of 2011 totalled $14.1 billion and our net debt ratio[b] was 20.5%. *See Financial review on pages 56-58 for further information on the group s financial results.*

During 2010 and 2011 combined, we strengthened the group s financial position by completing asset sales totalling almost $20 billion and we have announced our intention to make further disposals that would bring the total to $38 billion by the end of 2013. Previously this disposal target had been set at $45 billion, however it was reduced in November 2011 when we received notice of termination from Bridas Corporation of the agreement for their purchase of BP s 60% interest in Pan American Energy LLC. We intend to reduce our net debt ratio to the lower half of the 10-20% range over time. During 2011 we reached settlements with MOEX USA Corporation (MOEX), Weatherford U.S., L.P. (Weatherford), Anadarko Petroleum Corporation (Anadarko) and Cameron International Corporation (Cameron) totalling $5.5 billion related to the Deepwater Horizon oil spill. All cash received has been paid to the Trust.

[a] Replacement cost profit or loss for the group is not a recognized GAAP measure. The equivalent measure on an IFRS basis is Profit (loss) for the year attributable to BP shareholders . See *footnote b on page 56 and page 110 for further information.*

[b] Net debt ratio is a non-GAAP measure. See Note 35 on page 230 for the equivalent measure on an IFRS basis.

Left BP employees at work in Prudhoe Bay, Alaska the largest oilfield in North America and among the 20 largest fields ever discovered.

Right Operations on the BP-operated Atlantis PQ, Gulf of Mexico - the deepest moored semi-submersible platform in the world when it was installed in 2007.

[a] See Financial statements Note 6 on page 200.

[b] Based on sales of consolidated subsidiaries only this excludes equity-accounted entities.

On 3 March 2012, we announced we had reached a settlement with the Plaintiffs Steering Committee (PSC), subject to final written agreement and court approvals, to resolve the substantial majority of legitimate economic loss and medical claims stemming from the Deepwater Horizon accident and oil spill. The PSC acts on behalf of individual and business plaintiffs in the Multi-District Litigation proceedings pending in New Orleans (MDL 2179). We estimate that the cost of the proposed settlement would be approximately $7.8 billion, but with no net impact on either the income or cash flow statements, since the proposed settlement is expected to be payable from the $20-billion Trust. While this is BP s reliable best estimate of the cost of the proposed settlement, it is possible that the actual cost could be higher or lower than this estimate depending on the outcomes of the court-supervised claims processes. See *Legal proceedings on page 162 for further information.*

Exploration and Production

[a] Combined basis of subsidiaries and equity-accounted entities, on a basis consistent with general industry practice.

[b] Liquids comprise crude oil, condensate, natural gas liquids and bitumen and include totals of 5,153 million barrels for subsidiaries and 5,412 million barrels for equity-accounted entities.

[c] Natural gas is converted to oil equivalent at 5.8 billion cubic feet (bcf) = 1 million barrels and includes 6,273 million barrels of oil equivalent for subsidiaries and 910 million barrels of oil equivalent for equity-accounted entities.

The replacement cost profit before interest and tax for 2011 was $30,500 million, compared with $30,886 million for the previous year. See *Exploration and Production on page 80 for further information on the segment s financial results.*

Our production was lower than in 2010 due to divestments, the suspension of drilling in the Gulf of Mexico and the high number of turnarounds and maintenance projects undertaken during the year. However, production began to increase from the fourth quarter with the completion of turnarounds in the North Sea, Angola and the Gulf of Mexico. Also, two new major projects were brought onstream during the year the BP-operated Serrette field in Trinidad and the Pazflor field in Angola, operated by Total.

We had our best year for a decade in terms of access to new upstream opportunities, with awards for a total of 55 new exploration licences. We also gained approval for our exploration plan for the Kaskida field in the Gulf of Mexico our first drilling permit for an exploration well in the US since the Deepwater Horizon oil spill.

In India, we completed a transaction that brings us into a unique relationship with Reliance Industries and access to 21 oil and gas blocks which covered approximately 83,000 square miles (216,000 square kilometres). In November 2011 we formed a 50:50 gas marketing joint venture to source and market gas.

In Russia, our plans to form a strategic alliance with Rosneft did not reach fruition. Nonetheless, we remain committed to Russia and the ongoing success of TNK-BP, which comprises 27% of our reserves and 29% of our production.

In Brazil, we acquired assets from Devon Energy, giving us a material position in one of the great deepwater provinces of the world. We started upstream operations during the year.

Our performance

[a] See Financial statements Note 6 on page 200. See also Financial and operating performance on page 94.

In the UK North Sea, we announced plans for investments totalling approximately $14 billion with our partners in major new project developments.

In Iraq, working with our partners in the Rumaila Operating Organization, we met a major milestone in reaching initial production targets agreed for the Rumaila field.

Refining and Marketing

Replacement cost profit before interest and tax for 2011 was $5,474 million compared with $5,555 million in 2010. Strong refinery operations enabled us to capture the benefits of BP s location advantage in accessing WTI-based crude grades and, compared with 2010, the result also benefited from a higher refining margin environment and a stronger supply and trading contribution. These benefits were partly offset by a significantly higher level of turnarounds in 2011 than 2010 and negative impacts from the increased relative sweet crude prices in Europe and Australia, primarily caused by the loss of Libyan production, and the weather-related power outages in the second quarter. *See Refining and Marketing on page 94 for further information on the segment s financial results.*

Operating performance was strong, with Solomon refining availability of 94.8% and utilization rates above the industry average. We made significant progress on the modernization of our Whiting refinery in the US, which is expected to come onstream in the second half of 2013. This project will significantly increase the capability of the refinery to process heavy crude and provide it with access to crude from the Gulf of Mexico, the mid-continent US and Canada.

We achieved strong performance in our lubricants business, despite a difficult marketing environment and increasing base oil prices. In our petrochemicals business we received local government approval for our proposed 1.25 million tonnes per annum purified terephthalic acid (PTA) plant in Zhuhai, China, and are now seeking final central governmental approval.

Left Air BP is one of the world's largest and best-known aviation fuels suppliers.

Above The SECCO facility is BP's single largest investment in China and has a capacity of 3.2 million tonnes of petrochemicals per year.

We continued to sell non-core assets, and we are progressing with our intention to divest about half of our US refining capacity. We completed the divestment of non-strategic terminals and pipelines in the US East of Rockies and West Coast, and of our fuels marketing businesses in several African countries.

In addition, in February 2012 we announced our intent to sell our bulk and bottled LPG marketing businesses in nine countries.

Looking ahead

We believe our actions and achievements in 2011 brought BP to a turning point. As we move into 2012, our operations are regaining momentum and we have a clear strategy for value creation. Maintaining our absolute commitment to safety, our intention is to build on our strengths so we can grow operating cash flows, invest for future growth and increase returns to shareholders.

Our performance

We track performance against key financial and non-financial indicators. This year, in alignment with our 10-point strategic plan, we have introduced gearing as a key measure.

Replacement cost profit (loss) reflects the replacement cost of supplies. It is arrived at by excluding from profit inventory holding gains and losses and their associated tax effect. Replacement cost profit for the group is the profitability measure used by management. It is a non-GAAP measure. See page 56 for the equivalent measure on an IFRS basis.

In 2011, we returned to profitability following the financial impact of the Deepwater Horizon oil spill in 2010.

Proved reserves replacement ratio (also known as the production replacement ratio) is the extent to which production is replaced by proved reserves additions. The ratio is expressed in oil equivalent terms and includes changes resulting from revisions to previous estimates, improved recovery and extensions, and discoveries. The measure reflects both subsidiaries and equity-accounted entities, but excludes acquisitions and disposals.

The 2011 reserves additions for TNK-BP include the effect of moving from life-of-licence measurement to life-of-field measurement, reflecting TNK-BP s track record of successful licence renewal. Excluding this effect, BP s 2011 reserves replacement ratio would have been 83%.

Operating cash flow is net cash flow provided by operating activities, from the group cash flow statement. Operating activities are the principal revenue-generating activities of the group and other activities that are not investing or financing activities.

In 2011, operating cash flow recovered, primarily due to a reduction in cash outflow in respect of the Deepwater Horizon oil spill.

We report crude oil, natural gas liquids (NGLs) and natural gas produced from subsidiaries and equity-accounted entities. These are converted to barrels of oil equivalent (boe) at 1 barrel of NGL = 1boe and 5,800 standard cubic feet of natural gas = 1boe.

Reported production in 2011 was 10% lower than in 2010, due to higher turnaround and maintenance activity, and the impact of the drilling moratorium in the Gulf of Mexico.

Gearing enables investors to see how significant net debt is relative to equity from shareholders. Net debt is equal to gross finance debt, plus associated derivatives, less cash and cash equivalents. Net debt and net debt ratio are non-GAAP measures. See Financial statements Note 35 on page 230 for the nearest equivalent measure on an IFRS basis and for further information.

In 2011, gearing decreased slightly and we expect it to reduce to the lower half of the 10-20% range over time.

Refining availability represents Solomon Associates operational availability, which is defined as the percentage of the year that a unit is available for processing after subtracting the annualized time lost due to turnaround activity and all planned mechanical, process and regulatory maintenance downtime.

Refining availability decreased slightly in 2011 principally due to the second quarter weather-related power outage at Texas City.

Total shareholder return represents the change in value of a BP shareholding over a calendar year, assuming that dividends are re-invested to purchase additional shares at the closing price applicable on the ex-dividend date.

In 2011, shareholder return improved with the resumption of dividends.

Reported recordable injury frequency (RIF) measures the number of reported work-related incidents that result in a fatality or injury (apart from minor first aid cases) per 200,000 hours worked.

In 2011, our workforce RIF, which includes employees and contractors combined, was 0.36, compared with 0.61 in 2010 and 0.34 in 2009. The 2010 group RIF was affected by the Gulf Coast response effort.

a This represents reported incidents occurring within BP s operational HSSE reporting boundary. That boundary includes BP s own operated facilities and certain other locations or situations.

The employee satisfaction index comprises 10 questions that provide insight into levels of employee satisfaction across topics such as pay and trust in management.

Our 2010 survey was delayed to allow for organizational changes to be reflected in the survey construction. This was completed and the 2011 survey showed improvements in the level of employee recognition, with the opportunity for clarity about the organization s priorities highlighted as an area for improvement.

b Relates to BP employees.

Loss of primary containment is the number of unplanned or uncontrolled releases of material, excluding non-hazardous releases, such as water from a tank, vessel, pipe, railcar or other equipment used for containment or transfer.

In 2011, there were 361 losses of primary containment compared to 418 in 2010. Tracking losses of integrity is a way of measuring safety performance and helping drive improvements.

Each year we record the percentage of women and individuals from countries other than the UK and US among BP s group leaders. The number of group leaders in 2011 was 516, compared with 482 in 2010 and 492 in 2009.

BP has increased the percentage of female leaders in 2011 and remains focused on building a more sustainable pipeline of diverse talent for the future.

We report the number of spills of hydrocarbons greater than or equal to one barrel (159 litres, 42 US gallons). We include spills that were contained, as well as those that reached land or water.

In 2011, there were 228 oil spills of one barrel or more. We are taking measures to strengthen mandatory safety-related standards and processes, including operational risk and integrity management.

We report greenhouse gas (GHG) emissions on a CO_2-equivalent basis, including CO_2 and methane. This represents all consolidated entities and BP s share of equity-accounted entities, except TNK-BP. In 2010 we did not report on GHG emissions associated with the Deepwater Horizon incident or response (see page 70).

The decrease of 3.1Mte in 2011 is primarily explained by temporary reduction in activity in some of our businesses as a result of maintenance work and also by the sale of assets as part of our disposal programme.

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Financial review

Selected financial information[a]

$ million except per share amounts

	2011	2010	2009	2008	2007
Income statement data					
Sales and other operating revenues	**375,517**	297,107	239,272	361,143	284,365
Replacement cost profit (loss) before interest and tax[b]					
By business					
Exploration and Production	**30,500**	30,886	24,800	38,308	27,602
Refining and Marketing	**5,474**	5,555	743	4,176	2,621
Other businesses and corporate	**(2,478)**	(1,516)	(2,322)	(1,223)	(1,209)
Gulf of Mexico oil spill response[c]	**3,800**	(40,858)			
Consolidation adjustment	**(113)**	447	(717)	466	(220)
Replacement cost profit (loss) before interest and taxation[b]	**37,183**	(5,486)	22,504	41,727	28,794
Inventory holding gains (losses)	**2,634**	1,784	3,922	(6,488)	3,558
Profit (loss) before interest and taxation	**39,817**	(3,702)	26,426	35,239	32,352
Finance costs and net finance expense/income relating to pensions and other post-retirement benefits	**(983)**	(1,123)	(1,302)	(956)	(741)
Taxation	**(12,737)**	1,501	(8,365)	(12,617)	(10,442)
Profit (loss) for the year	**26,097**	(3,324)	16,759	21,666	21,169
Profit (loss) for the year attributable to BP shareholders	**25,700**	(3,719)	16,578	21,157	20,845
Inventory holding (gains) losses, net of tax	**(1,800)**	(1,195)	(2,623)	4,436	(2,475)
Replacement cost profit (loss) for the year attributable to BP shareholders[b]	**23,900**	(4,914)	13,955	25,593	18,370
Per ordinary share cents					
Profit (loss) for the year attributable to BP shareholders					
Basic	**135.93**	(19.81)	88.49	112.59	108.76
Diluted	**134.29**	(19.81)	87.54	111.56	107.84
Replacement cost profit (loss) for the year attributable to BP shareholders[b] (basic)	**126.41**	(26.17)	74.49	136.20	95.85
Dividends paid per share cents	**28.00**	14.00	56.00	55.05	42.30
pence	**17.4035**	8.679	36.417	29.387	20.995
Capital expenditure and acquisitions[d]	**31,518**	23,016	20,309	30,700	20,641
Capital expenditure, excluding acquisitions and asset exchanges[e]	**20,235**	19,610	20,001	28,186	19,194
Ordinary share data[f]					
Average number outstanding of 25 cent ordinary shares (shares million undiluted)	**18,905**	18,786	18,732	18,790	19,163
Average number outstanding of 25 cent ordinary shares (shares million diluted)	**19,136**	18,998	18,936	18,963	19,327
Balance sheet data (at 31 December)					
Total assets	**293,068**	272,262	235,968	228,238	236,076
Net assets	**112,482**	95,891	102,113	92,109	94,652
Share capital	**5,224**	5,183	5,179	5,176	5,237
BP shareholders equity	**111,465**	94,987	101,613	91,303	93,690
Finance debt due after more than one year	**35,169**	30,710	25,518	17,464	15,651
Net debt to net debt plus equity[g]	**20.5%**	21.2%	20.4%	21.4%	22.1%

a This information, insofar as it relates to 2011, has been extracted or derived from the audited consolidated financial statements of the BP group presented on pages 173-258. Note 1 to the financial statements includes details on the basis of preparation of these financial statements. The selected information should be read in conjunction with the audited financial statements and related notes elsewhere herein.

b Replacement cost profit or loss reflects the replacement cost of supplies. The replacement cost profit or loss for the year is arrived at by excluding from profit inventory holding gains and losses and their associated tax effect. Replacement cost profit or loss for the group is not a recognized GAAP measure. The equivalent measure on an IFRS basis is Profit (loss) for the year attributable to BP shareholders . Further information on inventory holding gains and losses is provided on page 110.

c Under IFRS these costs are presented as a reconciling item between the sum of the results of the reportable segments and the group results.

d AII capital expenditure and acquisitions during the past five years have been financed from cash flow from operations, disposal proceeds and external financing. 2008 included capital expenditure of $2,822 million and an asset exchange of $1,909 million, both in respect of our transaction with Husky Energy Inc., as well as capital expenditure of $3,667 million in respect of our purchase of all of Chesapeake Energy Corporation s interest in the Arkoma Basin Woodford shale assets and the purchase of a 25% interest in Chesapeake s Fayetteville shale assets. 2007 included $1,132 million for the acquisition of Chevron s Netherlands manufacturing company.

e 2011 included $1,096 million associated with deepening our natural gas asset base. 2010 included capital expenditure of $900 million relating to the formation of a partnership with Value Creation Inc.

f The number of ordinary shares shown has been used to calculate per share amounts.

g Net debt and the ratio of net debt to net debt plus equity are non-GAAP measures. We believe that these measures provide useful information to investors. Further information on net debt is given in Financial statements Note 35 on page 230.

Profit or loss for the year

Profit attributable to BP shareholders for the year ended 31 December 2011 was $25,700 million and included inventory holding gains[a], net of tax, of $1,800 million and a net credit for non-operating items, after tax, of $2,195 million. In addition, fair value accounting effects had a favourable impact, net of tax, of $47 million relative to management s measure of performance. Non-operating items in 2011 included a $3.7 billion pre-tax credit relating to the Gulf of Mexico oil spill. More information on non-operating items and fair value accounting effects can be found on page 58. *See Gulf of Mexico oil spill on page 76 and in Financial statements Note 2 on page 190 for further information on the impact of the Gulf of Mexico oil spill on BP s financial results.*

Loss attributable to BP shareholders for the year ended 31 December 2010 included inventory holding gains, net of tax, of $1,195 million and a net charge for non-operating items, after tax, of $25,449 million. In addition, fair value accounting effects had a favourable impact, net of tax, of $13 million relative to management s measure of performance. Non-operating items in 2010 included a $40.9 billion pre-tax charge relating to the Gulf of Mexico oil spill.

Profit attributable to BP shareholders for the year ended 31 December 2009 included inventory holding gains, net of tax, of $2,623 million and a net charge for non-operating items, after tax, of $1,067 million. In addition, fair value accounting effects had a favourable impact, net of tax, of $445 million relative to management s measure of performance.

The primary additional factors affecting the financial results for 2011, compared with 2010, were higher realizations, higher earnings from equity-accounted entities, a higher refining margin environment and a stronger supply and trading contribution, partly offset by lower production volumes, rig standby costs in the Gulf of Mexico, higher costs related to turnarounds, higher exploration write-offs, and negative impacts of increased relative sweet crude prices in Europe and Australia, primarily caused by the loss of Libya production and the weather-related power outages in the US.

The primary additional factors affecting the financial results for 2010, compared with 2009, were higher realizations, lower depreciation, higher earnings from equity-accounted entities, improved operational performance, further cost efficiencies and a more favourable refining environment in Refining and Marketing, partly offset by lower production, a significantly lower contribution from supply and trading (including gas marketing) and higher production taxes.

See Exploration and Production on page 80, Refining and Marketing on page 94 and Other businesses and corporate on page 101 for further information on segment results.

a Inventory holding gains and losses represent the difference between the cost of sales calculated using the average cost to BP of supplies acquired during the year and the cost of sales calculated on the first-in first-out (FIFO) method, after adjusting for any changes in provisions where the net realizable value of the inventory is lower than its cost. BP s management believes it is helpful to disclose this information. An analysis of inventory holding gains and losses by business is shown in Financial statements Note 6 on page 200 and further information on inventory holding gains and losses is provided on page 110.

Finance costs and net finance expense relating to pensions and other post-retirement benefits

Finance costs comprise interest payable less amounts capitalized, and interest accretion on provisions and long-term other payables. Finance costs in 2011 were $1,246 million compared with $1,170 million in 2010 and $1,110 million in 2009.

Net finance income relating to pensions and other post-retirement benefits in 2011 was $263 million compared with net finance income of $47 million in 2010 and net finance expense of $192 million in 2009. In 2011, compared with 2010, the improvement largely reflected the additional expected returns on assets following the increases in the pension asset base at the end of 2010 compared with the end of 2009.

During 2011 the value of our pension assets declined and this, combined with changes to assumptions used to value benefit obligations, most notably lower discount rates, meant that the deficit relating to pension and other post-retirement benefits increased to $12.0 billion at the end of the year (2010 $7.7 billion).

Taxation

The charge for corporate taxes in 2011 was $12,737 million, compared with a credit of $1,501 million in 2010 and a charge of $8,365 million in 2009. The effective tax rate was 33% in 2011, 31% in 2010 and 33% in 2009. The group earns income in many countries and, on average, pays taxes at rates higher than the UK statutory rate of 26%. The increase in the effective tax rate in 2011 compared with 2010 primarily reflects a higher level of income earned in jurisdictions with a higher tax rate. The decrease in the effective tax rate in 2010 compared with 2009 primarily reflected the absence of a one-off disbenefit that featured in 2009 in respect of goodwill impairment, and other factors.

Acquisitions and disposals

In 2011, BP acquired from Reliance Industries Limited (Reliance) a 30% interest in each of 21 oil and gas production-sharing agreements operated by Reliance in India for $7.0 billion. We completed the purchase, for $3.6 billion, of 10 exploration and production blocks in Brazil, which was the final part of a $7-billion transaction with Devon Energy that had been announced in March 2010, and our Alternative Energy business acquired the Brazilian sugar and ethanol producer Companhia Nacional de Açúcar e Álcool (CNAA) for $0.7 billion. *See Financial statements Note 3 on page 194 for further details of the business combinations undertaken during the year.*

Total disposal proceeds received during 2011, including the repayment of the disposal deposit relating to Pan American Energy LLC (PAE) (see *below),* were $2.7 billion.

In Exploration and Production, disposal proceeds included $0.6 billion from the sale of our upstream assets in Pakistan to United Energy Pakistan Limited, a subsidiary of United Energy Group (UEG), $0.5 billion from the sale of half of the 3.29% interest in the Azeri-Chirag-Gunashli (ACG) development in the Caspian Sea which we had acquired from Devon Energy in 2010 to Azerbaijan (ACG) Limited and $0.5 billion from the sale of our interests in the Wytch Farm, Wareham, Beacon and Kimmeridge fields to Perenco UK Ltd. In addition, further payments of $1.1 billion were received on completion of the sales of our upstream and certain midstream interests in Venezuela and Vietnam and our oil and gas exploration, production and transportation business in Colombia, for which we had received $2.3 billion in 2010 as deposits. In November 2011, BP received from Bridas Corporation (Bridas) a notice of termination of the agreement for their purchase of BP s 60% interest in PAE. As a result, the deposit of $3.5 billion relating to the sale of PAE which had been received by BP in 2010 was repaid to Bridas.

In Refining and Marketing we made disposals totalling $0.7 billion, which included completion of the divestment of non-strategic pipelines and terminals in the US, announced in 2009, for $0.3 billion and the disposal of our fuels marketing businesses in several African countries (see *Refining and Marketing on page 97 for more details)* for $0.2 billion.

Within Other businesses and corporate, we completed the sale of BP s wholly-owned subsidiary, ARCO Aluminum Inc., to a consortium of Japanese companies for $0.7 billion.

In 2010, BP acquired a major portfolio of deepwater exploration acreage and prospects in the US Gulf of Mexico and an additional interest in the BP-operated ACG developments in the Caspian Sea, Azerbaijan for $2.9 billion, as part of a $7-billion transaction with Devon Energy. Total disposal proceeds during 2010 were $17 billion, which included $7 billion from the sale of US Permian Basin, Western Canadian gas assets, and Western Desert exploration concessions in Egypt to Apache Corporation (and an existing partner that exercised pre-emption rights), and $6.2 billion of deposits received in advance of disposal transactions expected to complete in 2011. Of these deposits received, $3.5 billion was for the sale of our interest in PAE to Bridas, however, this was subsequently repaid to Bridas at the end of 2011 following the termination of the sale agreement. See *above and Financial statements Note 4 on page 196 for further information.* The deposits received also included $1 billion for the sale of our upstream and midstream interests in Venezuela and Vietnam to TNK-BP, and $1.3 billion for the sale of our oil and gas exploration, production and transportation business in Colombia to a consortium of Ecopetrol and Talisman.

In Refining and Marketing we made disposals totalling $1.8 billion in 2010, which included our French retail fuels and convenience business to Delek Europe, the fuels marketing business in Botswana to Puma Energy, certain non-strategic pipelines and terminals in the US, our interests in ethylene and polyethylene production in Malaysia to Petronas and our interest in a futures exchange.

There were no significant acquisitions in 2009. Disposal proceeds in 2009 were $2.7 billion, principally from the sale of our interests in BP West Java Limited, Kazakhstan Pipeline Ventures LLC and LukArco, and the sale of our ground fuels marketing business in Greece and retail churn in the US, Europe and Australasia. Further proceeds from the sale of LukArco were received in 2011.

Non-operating items

Non-operating items are charges and credits arising in consolidated entities that BP discloses separately because it considers such disclosures to be meaningful and relevant to investors. They are provided in order to enable investors to better understand and evaluate the group s financial performance. An analysis of non-operating items is shown in the table below.

$ million

	2011	2010	2009
Exploration and Production			
Impairment and gain (loss) on sale of businesses and fixed assets	**2,131**	3,812	1,574
Environmental and other provisions	**(27)**	(54)	3
Restructuring, integration and rationalization costs		(137)	(10)
Fair value gain (loss) on embedded derivatives	**191**	(309)	664
Other[a]	**(1,165)**	(113)	34
	1,130	3,199	2,265
Refining and Marketing			
Impairment and gain (loss) on sale of businesses and fixed assets[b]	**(334)**	877	(1,604)
Environmental and other provisions	**(219)**	(98)	(219)
Restructuring, integration and rationalization costs	**(4)**	(97)	(907)
Fair value gain (loss) on embedded derivatives			(57)
Other	**(45)**	(52)	184
	(602)	630	(2,603)
By business			
Fuels[b]	**(703)**	339	(2,394)
Lubricants	**100**	(47)	(171)
Petrochemicals	**1**	338	(38)
	(602)	630	(2,603)
Other businesses and corporate			
Impairment and gain (loss) on sale of businesses and fixed assets	**275**	5	(130)
Environmental and other provisions	**(220)**	(103)	(75)
Restructuring, integration and rationalization costs	**(39)**	(81)	(183)
Fair value gain (loss) on embedded derivatives[c]	**(123)**		
Other[d]	**(715)**	(21)	(101)
	(822)	(200)	(489)
Gulf of Mexico oil spill response	**3,800**	(40,858)	
Total before interest and taxation	**3,506**	(37,229)	(827)
Finance costs[e]	**(58)**	(77)	
Total before taxation	**3,448**	(37,306)	(827)
Taxation credit (charge)[f]	**(1,253)**	11,857	(240)
Total after taxation	**2,195**	(25,449)	(1,067)

a 2011 included a charge of $700 million associated with the termination of the agreement to sell our 60% interest in Pan American Energy LLC to Bridas Corporation *(see page 85).*

b 2009 included $1,579 million in relation to the impairment of goodwill allocated to the US West Coast fuels value chain.

c Relates to an embedded derivative arising from a financing arrangement.

d 2011 included charges of $687 million in relation to raw materials purchase contracts associated with our exit from the solar business.

e Finance costs relate to the Gulf of Mexico oil spill. *See Financial statements Note 2 on page 190 for further details.*

f Tax is calculated by applying discrete quarterly effective tax rates (excluding the impact of the Gulf of Mexico oil spill and, for 2011, the impact of a $683-million one-off deferred tax adjustment in respect of an increase in the supplementary charge on UK oil and gas production) on group profit or loss. However, the US statutory tax rate has been used for recoveries relating to the Gulf of Mexico oil spill and expenditures that qualify for tax relief. In 2009, no tax credit was calculated on the goodwill impairment in Refining and Marketing because the charge is not tax deductible.

Non-GAAP information on fair value accounting effects

The impacts of fair value accounting effects, relative to management s internal measure of performance, and a reconciliation to GAAP information is also set out below. Further information on fair value accounting effects is provided on page 110.

			$ million
	2011	2010	2009
Exploration and Production			
Unrecognized gains (losses) brought forward from previous period	**(527)**	(530)	389
Unrecognized (gains) losses carried forward	**538**	527	530
Favourable (unfavourable) impact relative to management s measure of performance	**11**	(3)	919
Refining and Marketing[a]			
Unrecognized gains (losses) brought forward from previous period	**137**	179	(82)
Unrecognized (gains) losses carried forward	**(74)**	(137)	(179)
Favourable (unfavourable) impact relative to management s measure of performance	**63**	42	(261)
	74	39	658
Taxation credit (charge)[b]	**(27)**	(26)	(213)
	47	13	445
By region			
Exploration and Production			
US	**15**	141	687
Non-US	**(4)**	(144)	232
	11	(3)	919
Refining and Marketing[a]			
US		19	16
Non-US	**63**	23	(277)
	63	42	(261)

a Fair value accounting effects arise solely in the fuels business.

b Tax is calculated by applying discrete quarterly effective tax rates (excluding the impact of the Gulf of Mexico oil spill and, for 2011, the impact of a $683-million one-off deferred tax adjustment in respect of an increase in the supplementary charge on UK oil and gas production) on group profit or loss.

Reconciliation of non-GAAP information

			$ million
	2011	2010	2009
Exploration and Production			
Replacement cost profit before interest and tax adjusted for fair value accounting effects	**30,489**	30,889	23,881
Impact of fair value accounting effects	**11**	(3)	919
Replacement cost profit before interest and tax	**30,500**	30,886	24,800
Refining and Marketing			
Replacement cost profit before interest and tax adjusted for fair value accounting effects	**5,411**	5,513	1,004
Impact of fair value accounting effects	**63**	42	(261)
Replacement cost profit before interest and tax	**5,474**	5,555	743
Total group			
Profit (loss) before interest and tax adjusted for fair value accounting effects	**39,743**	(3,741)	25,768
Impact of fair value accounting effects	**74**	39	658
Profit (loss) before interest and tax	**39,817**	(3,702)	26,426

Risk factors

We urge you to consider carefully the risks described below. The potential impact of their occurrence could be for our business, financial condition and results of operations to suffer (including through the failure to achieve our current strategic priorities (see *10-point plan pages 38-39))* and the trading price and liquidity of our securities to decline.

Our system of risk management identifies and provides the response to risks of group significance through the establishment of standards and other controls. Any failure of this system could lead to the occurrence, or re-occurrence, of any of the risks described below and a consequent material adverse effect on BP s business, financial position, results of operations, competitive position, cash flows, prospects, liquidity, shareholder returns and/or implementation of its strategic agenda.

The risks are categorized against the following areas: strategic; compliance and control; and safety and operational. In addition, we have also set out two further risks for your attention those resulting from the 2010 Gulf of Mexico oil spill (the Incident) and those related to the general macroeconomic outlook.

The Gulf of Mexico oil spill has had and could continue to have a material adverse impact on BP.

There is significant uncertainty in the extent and timing of costs and liabilities relating to the Incident, the impact of the Incident on our reputation and the resulting possible impact on our licence to operate including our ability to access new opportunities. There is also significant uncertainty regarding potential changes in applicable regulations and the operating environment that may result from the Incident. These increase the risks to which the group is exposed and may cause our costs to increase. These uncertainties are likely to continue for a significant period. Thus, the Incident has had, and could continue to have, a material adverse impact on the group s business, competitive position, financial performance, cash flows, prospects, liquidity, shareholder returns and/or implementation of its strategic agenda, particularly in the US.

We recognized a pre-tax charge of $40.9 billion in 2010 and a pre-tax credit of $3.7 billion in 2011 as a result of the Incident. The total amounts that will ultimately be paid by BP in relation to all obligations relating to the Incident are subject to significant uncertainty and the ultimate exposure and cost to BP will be dependent on many factors. Furthermore, the amount of claims that become payable by BP, the amount of fines ultimately levied on BP (including any potential determination of BP s negligence or gross negligence), the outcome of litigation, the amount and timing of payments under any settlements, and any costs arising from any longer-term environmental consequences of the oil spill, will also impact upon the ultimate cost for BP. Although the provision recognized is the current best estimate of expenditures required to settle certain present obligations at the end of the reporting period, there are future expenditures for which it is not possible to measure the obligation reliably. The risks associated with the Incident could also heighten the impact of the other risks to which the group is exposed as further described below.

The general macroeconomic outlook can affect BP s results given the nature of our business.

In the continuing uncertain financial and economic environment, certain risks may gain more prominence either individually or when taken together. Oil and gas prices can be very volatile, with average prices and margins influenced by changes in supply and demand. This is likely to exacerbate competition in all businesses, which may impact costs and margins. At the same time, governments are facing greater pressure on public finances, which may increase their motivation to intervene in the fiscal and regulatory frameworks of the oil and gas industry, including the risk of increased taxation, nationalization and expropriation. The global financial and economic situation may have a negative impact on third parties with whom we do, or may do, business. In particular, ongoing instability in or a collapse of the eurozone could trigger a new wave of financial crises and push the world back into recession, leading to lower demand and lower oil and gas prices. Any of these factors may affect our results of operations, financial condition, business prospects and liquidity and may result in a decline in the trading price and liquidity of our securities.

Capital markets are subject to volatility amid concerns over the European sovereign debt crisis and the slow-down of the global economy. If there are extended periods of constraints in these markets, or if we are unable to access the markets, including due to our financial position or market sentiment as to our prospects, at a time when cash flows from our business operations may be under pressure, our ability to maintain our long-term investment programme may be impacted with a consequent effect on our growth rate, and may impact shareholder returns, including dividends and share buybacks, or share price. Decreases in the funded levels of our pension plans may also increase our pension funding requirements.

Strategic risks

Access and renewal BP s future hydrocarbon production depends on our ability to renew and reposition our portfolio. Increasing competition for access to investment opportunities, the effects of the Gulf of Mexico oil spill on our reputation and cash flows, and more stringent regulation could result in decreased access to opportunities globally.

Successful execution of our group strategy depends on implementing activities to renew and reposition our portfolio. The challenges to renewal of our upstream portfolio are growing due to increasing competition for access to opportunities globally among both national and international oil companies, and heightened political and economic risks in certain countries where significant hydrocarbon basins are located. Lack of material positions in new markets could impact our future hydrocarbon production.

Moreover, the Gulf of Mexico oil spill has damaged BP s reputation, which may have a long-term impact on the group s ability to access new opportunities, both in the US and elsewhere. Adverse public, political and industry sentiment towards BP, and towards oil and gas drilling activities generally, could damage or impair our existing commercial relationships with counterparties, partners and host governments and could impair our access to new investment opportunities, exploration properties, operatorships or other essential commercial arrangements with potential partners and host governments, particularly in the US. In addition, responding to the Incident has placed, and will continue to place, a significant burden on our cash flow over the next several years, which could also impede our ability to invest in new opportunities and deliver long-term growth.

More stringent regulation of the oil and gas industry generally, and of BP s activities specifically, arising from the Incident, could increase this risk.

Prices and markets BP s financial performance is subject to the fluctuating prices of crude oil and gas as well as the volatile prices of refined products and the profitability of our refining and petrochemicals operations.

Oil, gas and product prices are subject to international supply and demand. Political developments and the outcome of meetings of OPEC can particularly affect world supply and oil prices. Previous oil price increases have resulted in increased fiscal take, cost inflation and more onerous terms for access to resources. As a result, increased oil prices may not improve margin performance. In addition to the adverse effect on revenues, margins and profitability from any fall in oil and natural gas prices, a prolonged period of low prices or other indicators would lead to further reviews for impairment of the group s oil and natural gas properties. Such reviews would reflect management s view of long-term oil and natural gas prices and could result in a charge for impairment that could have a significant effect on the group s results of operations in the period in which it occurs. Rapid material or sustained change in oil, gas and product prices can impact the validity of the assumptions on which strategic decisions are based and, as a result, the ensuing actions derived from those decisions may no longer be appropriate. A prolonged period of low oil prices may impact our ability to maintain our long-term investment programme with a consequent effect on our growth rate and may impact shareholder returns, including dividends and share buybacks, or share price. Periods of global recession could impact the demand for our products, the prices at which they can be sold and affect the viability of the markets in which we operate.

Refining profitability can be volatile, with both periodic over-supply and supply tightness in various regional markets, coupled with fluctuations in demand. Sectors of the petrochemicals industry are also subject to fluctuations in supply and demand, with a consequent effect on prices and profitability.

Climate change and carbon pricing climate change and carbon pricing policies could result in higher costs and reduction in future revenue and strategic growth opportunities.

Compliance with changes in laws, regulations and obligations relating to climate change could result in substantial capital expenditure, taxes, reduced profitability from changes in operating costs, and revenue generation and strategic growth opportunities being impacted. Our commitment to the transition to a lower-carbon economy may create expectations for our activities, and the level of participation in alternative energies carries reputational, economic and technology risks.

Socio-political the diverse nature of our operations around the world exposes us to a wide range of political developments and consequent changes to the operating environment, regulatory environment and law.

We have operations, and are seeking new opportunities, in countries where political, economic and social transition is taking place. Some countries have experienced, or may experience in the future, political instability, changes to the regulatory environment, changes in taxation, 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, could limit our ability to pursue new opportunities and could cause us to incur additional costs. In particular, our investments in the US, Russia, Iraq, Egypt, Libya, Bolivia, Argentina and other countries could be adversely affected by heightened political and economic environment risks. *See pages 34-35 for information on the locations of our major assets and activities.*

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. If it is perceived that we are not respecting or advancing the economic and social progress of the communities in which we operate, our reputation and shareholder value could be damaged.

Competition BP s group strategy depends upon continuous innovation in a highly competitive market.

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, while ensuring safety and operational risk is not compromised. The implementation of group strategy requires continued technological advances and innovation including advances in exploration, production, refining, petrochemicals manufacturing technology and advances in technology related to energy usage. Our performance could be impeded if competitors developed or acquired intellectual property rights to technology that we required or if our innovation lagged the industry.

Investment efficiency poor investment decisions could negatively impact our business.

Our organic growth is dependent on creating a portfolio of quality options and investing in the best options. Ineffective investment selection and development could lead to loss of value and higher capital expenditure.

Reserves replacement inability to progress upstream resources in a timely manner could adversely affect our long-term replacement of reserves and negatively impact our business.

Successful execution of our group strategy depends critically on sustaining long-term reserves replacement. If upstream resources are not progressed in a timely and efficient manner, we will be unable to sustain long-term replacement of reserves.

Liquidity, financial capacity and financial exposure failure to operate within our financial framework could impact our ability to operate and result in financial loss. Exchange rate fluctuations can impact our underlying costs and revenues.

The group seeks to maintain a financial framework to ensure that it is able to maintain an appropriate level of liquidity and financial capacity. This framework constrains the level of assessed capital at risk for the purposes of positions taken in financial instruments. Failure to accurately forecast or maintain sufficient liquidity and credit to meet these needs could impact our ability to operate and result in a financial loss. Commercial credit risk is measured and controlled to determine the group s total credit risk. Inability to determine adequately our credit exposure could lead to financial loss. A credit crisis affecting banks and other sectors of the economy could impact the ability of counterparties to meet their financial obligations to the group. It could also affect our ability to raise capital to fund growth and to meet our obligations. The change in the group s financial framework during 2010 to make it more prudent may not be sufficient to avoid a substantial and unexpected cash call.

BP s clean-up costs and potential liabilities resulting from pending and future claims, lawsuits, settlements and enforcement actions relating to the Gulf of Mexico oil spill, together with the potential cost of implementing remedies sought in the various proceedings, cannot be fully estimated at this time but they have had, and could continue to have, a material adverse impact on the group s business, competitive position, financial performance, cash flows, prospects, liquidity, shareholder returns and/or implementation of its strategic agenda, particularly in the US. Furthermore, we recognized a pre-tax charge of $40.9 billion in 2010 and a pre-tax credit of $3.7 billion in 2011, and further potential liabilities may continue to have a material adverse effect on the group s results of operations and financial condition. *See Financial statements Note 2 on pages 190-194 and Legal proceedings on pages 160-166.* More stringent regulation of the oil and gas industry arising from the Incident, and of BP s activities specifically, could increase this risk.

Crude oil prices are generally set in US dollars, while sales of refined products may be in a variety of currencies. Fluctuations in exchange rates can therefore give rise to foreign exchange exposures, with a consequent impact on underlying costs and revenues.

See Financial statements Note 26 on page 217 for more information on financial instruments and financial risk factors.

Insurance BP s insurance strategy means that the group could, from time to time, be exposed to material uninsured losses which could have a material adverse effect on BP s financial condition and results of operations.

In the context of the limited capacity of the insurance market, many significant risks are retained by BP. The group generally restricts its purchase of insurance to situations where this is required for legal or contractual reasons. This means that the group could be exposed to material uninsured losses, which could have a material adverse effect on its financial condition and results of operations. In particular, these uninsured costs could arise at a time when BP is facing material costs arising out of some other event which could put pressure on BP s liquidity and cash flows. For example, BP has borne and will continue to bear the entire burden of its share of any property damage, well control, pollution clean-up and third-party liability expenses arising out of the Gulf of Mexico oil spill.

Compliance and control risks

Regulatory the oil industry in general, and in particular the US industry following the Gulf of Mexico oil spill, faces increased regulation that could increase the cost of regulatory compliance and limit our access to new exploration properties.

After the Gulf of Mexico oil spill, it is likely that there will be more stringent regulation of oil and gas activities in the US and elsewhere, particularly relating to environmental, health and safety controls and oversight of drilling operations, as well as access to new drilling areas. Regulatory or legislative action may impact the industry as a whole and could be directed specifically towards BP. The US government imposed a moratorium on certain offshore drilling activities, which was subsequently lifted in October

2010. Similar actions may be taken by governments elsewhere in the world. New regulations and legislation, as well as evolving practices, could increase the cost of compliance and may require changes to our drilling operations, exploration, development and decommissioning plans, and could impact our ability to capitalize on our assets and limit our access to new exploration properties or operatorships, particularly in the deepwater Gulf of Mexico. In addition, increases in taxes, royalties and other amounts payable to governments or governmental agencies, or restrictions on availability of tax relief, could also be imposed as a response to the Incident.

In addition, 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, health and safety controls, controls over the development and decommissioning of a field (including restrictions on production) and, possibly, nationalization, expropriation, cancellation or non-renewal of contract rights. We buy, sell and trade oil and gas products in certain regulated commodity markets. Failure to respond to changes in trading regulations could result in regulatory action and damage to our reputation. 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, and operates in certain tax jurisdictions that have a degree of uncertainty relating to the interpretation of, and changes to, tax law. As a result of new laws and regulations or other factors, we could be required to curtail or cease certain operations, or we could incur additional costs.

See pages 107-110 for more information on environmental regulation.

Ethical misconduct and non-compliance ethical misconduct or breaches of applicable laws by our employees could be damaging to our reputation and shareholder value.

Our code of conduct, which applies to all employees, defines our commitment to integrity, compliance with all applicable legal requirements, high ethical standards and the behaviours and actions we expect of our businesses and people wherever we operate. Our renewed values, which were launched in 2011, are intended to guide the way we and our employees behave and do business. Incidents of ethical misconduct or non-compliance with applicable laws and regulations, including non-compliance with anti-bribery, anti-corruption and other applicable laws could be damaging to our reputation and shareholder value. Multiple events of non-compliance could call into question the integrity of our operations. For example, in our trading businesses, there is the risk that a determined individual could operate as a rogue trader , acting outside BP s delegations, controls or code of conduct and in contravention of our renewed values in pursuit of personal objectives that could be to the detriment of BP and its shareholders.

For certain legal proceedings involving the group, see Legal proceedings on pages 160-166. For further information on the risks involved in BP s trading activities, see Operational risks Treasury and trading activities on page 63.

Liabilities and provisions BP s potential liabilities resulting from pending and future claims, lawsuits, settlements and enforcement actions relating to the Gulf of Mexico oil spill, together with the potential cost and burdens of implementing remedies sought in the various proceedings, cannot be fully estimated at this time but they have had, and are expected to continue to have, a material adverse impact on the group s business.

Under the Oil Pollution Act of 1990 (OPA 90), BP Exploration & Production Inc. is one of the parties financially responsible for the clean-up of the Gulf of Mexico oil spill and for certain economic damages as provided for in OPA 90, as well as certain natural resource damages associated with the spill and certain costs determined by federal and state trustees engaged in a joint assessment of such natural resource damages.

BP and certain of its subsidiaries have also been named as defendants in numerous lawsuits in the US arising out of the Incident, including actions for personal injury and wrongful death, purported class actions for commercial or economic injury, actions for breach of contract,

violations of statutes, property and other environmental damage, securities law claims and various other claims. *See Legal proceedings on pages 160-166.*

BP is subject to a number of investigations related to the Incident by numerous federal and State agencies. *See Legal proceedings on pages 160-166.* The types of enforcement action pursued and the nature of the remedies sought will depend on the discretion of the prosecutors and regulatory authorities and, in some circumstances, their assessment of BP s culpability, if any, following their investigations. Such enforcement actions could include criminal proceedings against BP and/or employees of the group. In addition to fines and penalties, such enforcement actions could result in the suspension of operating licences and debarment from government contracts. Debarment of BP Exploration & Production Inc. would prevent it from bidding on or entering into new federal contracts or other federal transactions, and from obtaining new orders or extensions to existing federal contracts, including federal procurement contracts or leases. Dependent on the circumstances, debarment or suspension may also be sought against affiliated entities of BP Exploration & Production Inc. Although BP believes that there are costs arising out of the spill that are recoverable from its partners and other parties responsible under OPA 90, and although settlements have been agreed during 2011 with both partners, one contractor, and the manufacturer of the blowout preventer at the Macondo well, further recoveries are not certain and so have not been recognized in the financial statements (*see Financial statements Note 2 on pages 190-194*).

Any finding of gross negligence for purposes of penalties sought against the group under the Clean Water Act would also have a material adverse impact on the group s reputation, would affect our ability to recover costs relating to the Incident from other parties responsible under OPA 90 and could affect the fines and penalties payable by the group with respect to the Incident under enforcement actions outside the Clean Water Act context.

The Gulf of Mexico oil spill has damaged BP s reputation. This, combined with other past events in the US (including the 2005 explosion at the Texas City refinery and the 2006 pipeline leaks in Alaska), may lead to an increase in the number of citations and/or the level of fines imposed in relation to the Gulf of Mexico oil spill and any future alleged breaches of safety or environmental regulations.

Claims by individuals and businesses under OPA 90 s claims process have been administered by the Gulf Coast Claims Facility (GCCF) headed by Kenneth Feinberg, who was appointed jointly by BP and the US Administration. The proposed economic loss settlement reached with the Plaintiffs Steering Committee (PSC), acting on behalf of individual and business plaintiffs in MDL 2179, provides for a transition from the GCCF. A court-supervised transitional claims process for economic loss claims will be in operation while the infrastructure for the new settlement claims process is put in place. During this transitional period, the processing of claims that have been submitted to the GCCF will continue, and new claimants may submit their claims.

The proposed settlement is subject to final written agreement and court approvals and payments under the proposed settlement, and any other payments that may be made by BP in respect of any other individual and business claims under OPA 90, could ultimately be higher than the amount for which we have recognized a provision. *See Legal proceedings on pages 160-164 and Financial statements Note 36 on pages 231-234.*

Changes in external factors could affect our results of operations and the adequacy of our provisions.

We remain exposed to changes in the external environment, such as new laws and regulations (whether imposed by international treaty or by national or local governments in the jurisdictions in which we operate), changes in tax or royalty regimes, price controls, government actions to cancel or renegotiate contracts, market volatility or other factors. Such factors could reduce our profitability from operations in certain jurisdictions, limit our opportunities for new access, require us to divest or write-down certain assets or affect the adequacy of our provisions for pensions, tax, environmental and legal liabilities. Potential changes to pension or financial market regulation could also impact funding requirements of the group.

Business review

Reporting failure to accurately report our data could lead to regulatory action, legal liability and reputational damage.

External reporting of financial and non-financial data is reliant on the integrity of systems and people. Failure to report data accurately and in compliance with external standards could result in regulatory action, legal liability and damage to our reputation.

Safety and operational risks

The risks inherent in our operations include a number of hazards that, although many may have a low probability of occurrence, can have extremely serious consequences if they do occur, such as the Gulf of Mexico oil spill. The occurrence of any such risks could have a consequent material adverse impact on the group s business, competitive position, cash flows, results of operations, financial position, prospects, liquidity, shareholder returns and/or implementation of the group s strategic goals.

Process safety, personal safety and environmental risks the nature of our operations exposes us to a wide range of significant health, safety, security and environmental risks, the occurrence of which could result in regulatory action, legal liability and increased costs and damage to our reputation.

The nature of the group s operations exposes us to a wide range of significant health, safety, security and environmental risks. The scope of these risks is influenced by the geographic range, operational diversity and technical complexity of our activities. In addition, in many of our major projects and operations, risk allocation and management is shared with third parties, such as contractors, sub-contractors, joint venture partners and associates. *See Joint ventures and other contractual arrangements BP may not have full operational control and may have exposure to counterparty credit risk and disruptions to our operations and strategic objectives due to the nature of some of its business relationships on page 63.*

There are risks of technical integrity failure as well as risk of natural disasters and other adverse conditions in many of the areas in which we operate, which could lead to loss of containment of hydrocarbons and other hazardous material, as well as the risk of fires, explosions or other incidents.

In addition, inability to provide safe environments for our workforce and the public could lead to injuries or loss of life and could result in regulatory action, legal liability and damage to our reputation.

Our operations are often conducted in difficult or environmentally sensitive locations, in which the consequences of a spill, explosion, fire or other incident could be greater than in other locations. These operations are subject to various environmental and safety laws, regulations and permits and the consequences of failure to comply with these requirements can include remediation obligations, penalties, loss of operating permits and other sanctions. Accordingly, inherent in our operations is the risk that if we fail to abide by environmental and safety and protection standards, such failure could lead to damage to the environment and could result in regulatory action, legal liability, material costs, damage to our reputation or denial of our licence to operate.

To help address health, safety, security, environmental and operations risks, and to provide a consistent framework within which the group can analyse the performance of its activities and identify and remediate shortfalls, BP has introduced a group-wide operating management system (OMS). Work on the application of OMS in individual operating businesses continues and following the Gulf of Mexico oil spill an enhanced safety and operational risk (S&OR) function was established, reporting directly to the group chief executive. There can be no assurance that OMS will adequately identify all process safety, personal safety and environmental risk or provide the correct mitigations, or that all operations will be in conformance with OMS at all times.

Security hostile activities against our staff and activities could cause harm to people and disrupt our operations.

Security threats require continuous oversight and control. Acts of terrorism, piracy, sabotage, cyber-attacks and similar activities directed against our operations and offices, pipelines, transportation or computer systems could cause harm to people and could severely disrupt business and operations.

Our business activities could also be severely disrupted by civil strife and political unrest in areas where we operate.

Product quality failure to meet product quality standards could lead to harm to people and the environment and loss of customers.

Supplying customers with on-specification products is critical to maintaining our licence to operate and our reputation in the marketplace. Failure to meet product quality standards throughout the value chain could lead to harm to people and the environment and loss of customers.

Drilling and production these activities require high levels of investment and are subject to natural hazards and other uncertainties. Activities in challenging environments heighten many of the drilling and production risks including those of integrity failures, which could lead to curtailment, delay or cancellation of drilling operations, or inadequate returns from exploration expenditure.

Exploration and production require high levels of investment and are subject to natural hazards and other uncertainties, including those relating to the physical characteristics of an oil or natural gas field. Our exploration and production activities are often conducted in extremely challenging environments, which heighten the risks of technical integrity failure and natural disasters discussed above. 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. In addition, exploration expenditure may not yield adequate returns, for example in the case of unproductive wells or discoveries that prove uneconomic to develop. The Gulf of Mexico oil spill illustrates the risks we face in our drilling and production activities.

Transportation all modes of transportation of hydrocarbons involve inherent and significant risks.

All modes of transportation of hydrocarbons involve inherent risks. An explosion or fire or loss of containment of hydrocarbons or other hazardous material could occur during transportation by road, rail, sea or pipeline. This is a significant risk due to the potential impact of a release on people and the environment and given the high volumes potentially involved.

Major project delivery our group plan depends upon successful delivery of major projects, and failure to deliver major projects successfully could adversely affect our financial performance.

Successful execution of our group plan depends critically on implementing the activities to deliver the major projects over the plan period. Poor delivery of any major project that underpins production or production growth, including maintenance turnaround programmes, and/or a major programme designed to enhance shareholder value could adversely affect our financial performance. Successful project delivery requires, among other things, adequate engineering and other capabilities and therefore successful recruitment and development of staff is central to our plans. *See People and capability successful recruitment and development of staff is central to our plans on page 63.*

Digital infrastructure is an important part of maintaining our operations, and a breach of our digital security could result in serious damage to business operations, personal injury, damage to assets, harm to the environment, breaches of regulations, litigation, legal liabilities and reparation costs.

The reliability and security of our digital infrastructure are critical to maintaining the availability of our business applications, including the reliable operation of technology in our various business operations and the collection and processing of financial and operational data, as well as the confidentiality of certain third-party information. A breach of our digital security, either due to intentional actions or due to negligence, could cause serious damage to business operations and, in some circumstances, could result in injury to people, damage to assets, harm to the environment, breaches of regulations, litigation, legal liabilities and reparation costs.

Business continuity and disaster recovery the group must be able to recover quickly and effectively from any disruption or incident, as failure to do so could adversely affect our business and operations.

Contingency plans are required to continue or recover operations following a disruption or incident. Inability to restore or replace critical capacity to an agreed level within an agreed timeframe would prolong the impact of any disruption and could severely affect our business and operations.

Crisis management crisis management plans are essential to respond effectively to emergencies and to avoid a potentially severe disruption in our business and operations.

Crisis management plans and capability are essential to deal with emergencies at every level of our operations. If we do not respond, or are perceived not to respond, in an appropriate manner to either an external or internal crisis, our business and operations could be severely disrupted.

People and capability successful recruitment and development of staff is central to our plans.

Successful recruitment of new staff, employee training, development and long-term renewal of skills, in particular technical capabilities such as petroleum engineers and scientists, are key to implementing our plans. Inability to develop human capacity and capability, both across the organization and in specific operating locations, could jeopardize performance delivery.

In addition, significant management focus is required in responding to the Gulf of Mexico oil spill Incident. Although BP set up the Gulf Coast Restoration Organization to manage the group s long-term response, key management and operating personnel will need to continue to devote substantial attention to responding to the Incident and to address the associated consequences for the group. The group relies on recruiting and retaining high-quality employees to execute its strategic plans and to operate its business. The Incident response has placed significant demands on our employees, and the reputational damage suffered by the group as a result of the Incident and any consequent adverse impact on our performance could affect employee recruitment and retention.

Treasury and trading activities control of these activities depends on our ability to process, manage and monitor a large number of transactions. Failure to do this effectively could lead to business disruption, financial loss, regulatory intervention or damage to our reputation.

In the normal course of business, we are subject to operational risk around our treasury and trading activities. Control of these activities is highly dependent on our ability to process, manage and monitor a large number of complex transactions across many markets and currencies. Shortcomings or failures in our systems, risk management methodology, internal control processes or people could lead to disruption of our business, financial loss, regulatory intervention or damage to our reputation.

Following the Gulf of Mexico oil spill, Moody s Investors Service, Standard and Poor s and Fitch Ratings downgraded the group s long-term credit ratings. Since that time, the group s credit ratings have improved somewhat but are still lower than they were immediately before the Gulf of Mexico oil spill. The impact that a significant operational incident can have on the group s credit ratings, taken together with the reputational consequences of any such incident, the ratings and assessments published by analysts and investors concerns about the group s costs arising from any such incident, ongoing contingencies, liquidity, financial performance and volatile credit spreads, could increase the group s financing costs and limit the group s access to financing. The group s ability to engage in its trading activities could also be impacted due to counterparty concerns about the group s financial and business risk profile in such circumstances. Such counterparties could require that the group provide collateral or other forms of financial security for its obligations, particularly if the group s credit ratings are downgraded. Certain counterparties for the group s non-trading businesses could also require that the group provide collateral for certain of its contractual obligations, particularly if the group s credit ratings were downgraded below investment grade or where a counterparty had concerns about the group s financial and business risk profile following a significant operational incident. In addition, BP may be

unable to make a drawdown under certain of its committed borrowing facilities in the event we are aware that there are pending or threatened legal, arbitration or administrative proceedings which, if determined adversely, might reasonably be expected to have a material adverse effect on our ability to meet the payment obligations under any of these facilities. Credit rating downgrades could trigger a requirement for the company to review its funding arrangements with the BP pension trustees. Extended constraints on the group s ability to obtain financing and to engage in its trading activities on acceptable terms (or at all) would put pressure on the group s liquidity. In addition, this could occur at a time when cash flows from our business operations would be constrained following a significant operational incident, and the group could be required to reduce planned capital expenditures and/or increase asset disposals in order to provide additional liquidity, as the group did following the Gulf of Mexico oil spill.

Joint ventures and other contractual arrangements BP may not have full operational control and may have exposure to counterparty credit risk and disruptions to our operations and strategic objectives due to the nature of some of its business relationships.

Many of our major projects and operations are conducted through joint ventures or associates and through contracting and sub-contracting arrangements. These arrangements often involve complex risk allocation, decision-making processes and indemnification arrangements. In certain cases, we may have less control of such activities than we would have if BP had full operational control. Our partners may have economic or business interests or objectives that are inconsistent with or opposed to, those of BP, and may exercise veto rights to block certain key decisions or actions that BP believes are in its or the joint venture s or associate s best interests, or approve such matters without our consent. Additionally, our joint venture partners or associates or contractual counterparties are primarily responsible for the adequacy of the human or technical competencies and capabilities which they bring to bear on the joint project, and in the event these are found to be lacking, our joint venture partners or associates may not be able to meet their financial or other obligations to their counterparties or to the relevant project, potentially threatening the viability of such projects. Furthermore, should accidents or incidents occur in operations in which BP participates, whether as operator or otherwise, and where it is held that our sub-contractors or joint-venture partners are legally liable to share any aspects of the cost of responding to such incidents, the financial capacity of these third parties may prove inadequate to fully indemnify BP against the costs we incur on behalf of the joint venture or contractual arrangement. Should a key sub-contractor, such as a lessor of drilling rigs, be no longer able to make these assets available to BP, this could result in serious disruption to our operations. Where BP does not have operational control of a venture, BP may nonetheless still be pursued by regulators or claimants in the event of an incident.

Further note on certain activities

During the period covered by this report, non-US subsidiaries or other non-US entities of BP conducted limited activities in, or with persons from, certain countries identified by the US Department of State as State Sponsors of Terrorism or otherwise subject to US sanctions (Sanctioned Countries). These activities continue to be insignificant to the group s financial condition and results of operations. In 2011, the US enacted additional sanctions against Iran which included lower monetary thresholds for certain investments in Iran for the development or refining of petroleum resources, new restrictions on the petrochemicals industry and restrictions on transactions with the Iran Central Bank, including financial transactions for the purchase of Iranian-origin crude oil. Further legislation is pending in the US Congress which may enact additional sanctions against Iran. The UK adopted sanctions prohibiting UK persons from engaging in any financial transactions with the Iran Central Bank or other financial institutions incorporated in Iran. Both the US and the EU enacted strong sanctions against Syria including a prohibition on the purchase of Syrian-origin crude and a US prohibition on the provision of services by US persons. (Libya sanctions were enacted in early 2011 and largely lifted by the end of the year.) In January 2012, the EU imposed an embargo on Iranian crude, among other measures, to be phased in over a period of months. The EU also adopted more stringent sanctions against Syria including a prohibition on supplying certain equipment used in the production, refining, or liquefaction of petroleum resources as well as restrictions on dealing with the Central Bank of Syria and numerous other Syrian financial institutions. BP monitors its activities with Sanctioned Countries and keeps them under review to ensure compliance with applicable laws and regulations of the US, the EU and other countries where BP operates.

BP has interests in, and is the operator of, two fields (the North Sea Rhum field and the Azerbaijan Shah Deniz field) and, serving the Shah Deniz field, a gas marketing entity and an entity that owns a gas pipeline (both entities and related assets located outside Iran), in which Naftiran Intertrade Co. Ltd (NICO) and NICO SPV Limited (collectively NICO) or Iranian Oil Company (UK) Limited (IOC UK) have interests. Production was suspended at the North Sea Rhum field (in which IOC UK has a 50% interest) in November 2010 and Rhum remains shut-in. It is presently unclear when it may be possible to resume production. The Shah Deniz field, its gas marketing entity and the entity that owns a pipeline (in which NICO has a 10% or less non-operating interest) continues in operation in full compliance with current US and EU sanctions. BP has no operations in Iran and does not purchase or ship crude oil or other products of Iranian origin. Joint venture participants in non-BP controlled or operated joint ventures may purchase Iranian-origin crude oil or other components as feedstock for facilities located outside the EU and US. BP does not sell crude oil or other products into Iran, except that small quantities of lubricants are sold to non-Iranian third parties for resale or use in Iran. Until January 2010, BP held an equity interest in an Iranian joint venture that blended and marketed lubricants for sale to domestic consumers in Iran. BP sold its equity interest but continues to sell small quantities of lubricant components to the current owner. Transactions with Iranian shipping companies have been terminated.

Following the imposition in 2011 of further US and EU sanctions against Syria, BP terminated all sales of crude oil and petroleum products into Syria, though continues to supply aviation fuel to non-governmental Syrian resellers outside of Syria. Prior to the imposition of Syrian sanctions in 2011, BP sold lubricants through third parties and obtained crude oil and refinery feedstocks for sale to third parties in Europe and for use in certain of its non-US refineries. BP also bought and sold crude oil and refined products into and from Syria and incurred port costs for vessels utilizing Syrian ports. Sales and purchases to and from Syrian shipping companies have been terminated.

BP sells lubricants in Cuba through a 50:50 joint venture and trades in small quantities of lubricants. BP sold small quantities of lubricants to third parties that were resold in Sudan; BP has terminated these sales.

BP has equity interests in non-operated joint ventures with air fuel sellers, re-sellers, and fuel delivery services around the world. From time to time, the joint venture operator may sell or deliver fuel to airlines from Sanctioned Countries or flights to Sanctioned Countries without BP s knowledge or consent. BP has registered and paid required fees for patents and trademarks in Sanctioned Countries.

Safety

Over the past year, we have been developing and implementing a wide-ranging programme to further enhance safety, risk management and compliance across BP. This programme was initiated in response to the Deepwater Horizon incident in the Gulf of Mexico in April 2010.

The programme emphasizes the continuing importance of personal and process safety within BP. Process safety involves applying good design principles, along with robust engineering, operating and maintenance practices, to managing operations safely. For BP, this means the plant is designed, maintained and operated properly to avoid failures such as spills or explosions that can result in injuries to people and impacts to the environment. It also means that employees and contractors have the appropriate training and competencies to carry out work, as well as observing applicable procedures and policies that help to prevent personal injury.

In 2011, BP reported two workforce fatalities, and we regret the loss of these lives. One was a rail-related fatality in the US, the other died as a result of an unauthorized transfer of fuel in South Africa.

Safety and operational risk

Safety management

Our safety and risk management approach is built on deep experience in the oil and gas industry. This includes learning from the recommendations of investigations into the Deepwater Horizon oil spill in 2010 and the Texas City refinery explosion in 2005, as well as operations audits, annual risk reviews, other incident investigations and from industry practice of sharing experience.

There are three key principles which we intend to be at the heart of our approach:

- Leadership fostering a culture where everyone is focused on safety, on managing and reducing risk and on safe, reliable and compliant operations.
- Our operating management system (OMS) being the way BP seeks to operate.
- Effective checks and balances independent of the business line and self-verification being carried out at all levels of the organization.

While we maintain our focus on processes, practices and protocols, we also place great emphasis on how our workforce applies them, thereby working to strengthen safety culture and workforce capability.

A dedicated function

We established the safety and operational risk (S&OR) function in early 2011. S&OR supports the business line in delivering safe, reliable and compliant operations across the group s operated businesses. It does this in four ways:

- It sets and updates the requirements, including those in OMS, that are used across the business for safety and operational risk management.
- It provides expert scrutiny of safety and operational risk, independent of line managers advising, examining and providing assurance about what our operations do.
- It provides deep technical expertise to the operations.
- It has the authority to intervene and escalate issues to cause corrective action to be taken.

S&OR, as of the end of 2011, was made up of a central team of around 300, as well as nearly 300 more who are deployed in BP s businesses, providing guidance and scrutiny and examining how safety and operating risks are being assessed and managed on oil and gas production and drilling rigs, at refineries and across all our operations. The head of S&OR reports directly to the group chief executive.

The central team serves as the custodian of group requirements, runs safety and operational risk audit and capability programmes and endorses the appointment of individuals for designated safety-critical roles. The central team includes some of BP s top engineers and safety specialists, several of whom have experience of other industries where major hazards have to be managed, including the military, nuclear energy and space exploration.

Our deployed S&OR teams work with our operating businesses ranging from upstream oil and gas development and production to refineries, petrochemicals plants and retail networks. They help the businesses apply our standards to their operations and they help provide assurance to the group on how operational risks are being managed, business by business.

Operating businesses remain accountable for delivering safe, reliable and compliant operations. They have the responsibility of managing risks and bringing together people with the right skills and competencies. Working in collaboration with deployed S&OR subject specialists for guidance, they are subject to new levels of independent scrutiny and assurance.

Governance

BP reviews risks at all levels of the organization, with our S&OR function providing an independent view of safety and operational risk. While line managers are responsible for identifying and managing risks, we place strong emphasis on checks and balances, including both enhanced self-verification by individual BP operations such as drilling rigs or refineries and independent assurance by the S&OR function.

The board s safety, ethics and environment assurance committee (SEEAC) receives updates from the group chief executive and the head of S&OR on the work of the group operations risk committee (GORC), on BP s performance in process and personal safety, and our monitoring of major incidents and near misses across the group. Where appropriate other senior managers will attend to provide briefings on safety, environmental and operational integrity in their areas of responsibility. SEEAC also receives information from the Independent Expert appointed to monitor the implementation of recommendations made by the BP US Refineries Independent Safety Review Panel following the 2005 explosion at our Texas City refinery. *See Board performance report on pages* 120-133 *for further information on the activities of the board s committees, including SEEAC and the Gulf of Mexico committee.*

Lessons learned from major incidents are being incorporated into our operating management system and capability development programmes.

Operating management system

Launched in 2008, our operating management system (OMS) serves as our group-wide framework designed to drive a rigorous and systematic approach to safety, risk management, and operational integrity across the group. OMS integrates requirements regarding health, safety, security, environment, social responsibility and operational reliability, as well as related issues such as maintenance, contractor management and organizational learning, into a common system.

The principles and standards of OMS are supported by detailed group-wide practices, as well as other technical guidance materials. The goal of OMS is to apply certain standards, group-defined practices and group engineering technical practices on a group-wide basis in our operations; these include, among others, the practices on assessment, prioritization and management of risk; incident investigation; integrity management; and environmental and social requirements for major new projects.

Following the principle of continuous improvement, our OMS evolves over time, for example to reflect implementation experience as well as learnings from incident investigations, audits and risk assessments, and by strengthening mandatory practices.

Transitioning to OMS

The transition to OMS requires operations to develop a local OMS that describes how the operation addresses site-specific local operating risks, applies group standards and practices and manages compliance with applicable health, safety, security and environment legal requirements. As part of the transition, operations conduct a gap assessment against defined aspects of OMS and their local processes and procedures, and then develop a prioritized gap-closure plan. To formally transition to the system, operations issue a local OMS handbook for the workforce to follow, and complete a management-of-change document that details the changes involved.

Business review

All of our operations, with the exception of those recently acquired, are now applying our OMS to govern their BP operations and have begun working to achieve conformance to standards and practices required by OMS through the performance improvement cycle process. This includes our global wells organization and global projects organization which were set up in 2011. *See page 69 for information about joint ventures.*

Conformance and continuous improvement

The application of a comprehensive management system such as OMS across a global company is an ongoing process. OMS defines the process for BP operations to apply and conform to required standards and practices on an ongoing basis, as well as to continuously improve their operational performance. Every year, after the initial gap assessment, as part of the annual performance improvement cycle each operating unit for example, a region like the Gulf of Mexico in our upstream business, or a refinery in our downstream business is required to conduct another gap assessment and to develop a further prioritized gap closure plan. These actions are risk-prioritized and form an integral part of each operation's annual and three-year planning cycle. Where appropriate, actions are aggregated to provide common solutions. The results of these annual assessments are subject to review by S&OR.

Capability development

BP strives to equip its staff with the skills needed to apply the systems and processes to strengthen further our management of risk and process safety. We have provided extensive and focused training programmes for our operations personnel at all levels.

Training provision for operations personnel includes our operations academy programmes for senior management, delivered in partnership with the Massachusetts Institute of Technology, US; specialized operational and technical management programmes, for example courses in engineering and project management at the University of Manchester, UK; and process safety and management training for our front-line leaders, delivered under our Operations Essentials programme, which seeks to embed the BP way of operating as represented by our OMS. To date, approximately 24,000 managers, supervisors and technicians have attended at least one workshop within the operations essentials programme since 2008; additionally, more than 180,000 eLearning modules have been completed.

We communicate our expectations for qualified, competent and experienced contractor personnel through our procurement process and contractual provisions.

Safer drilling

Since the beginning of 2011, all BP-operated drilling and wells activity in the world has been conducted through a single global wells organization (GWO). By bringing functional wells expertise into a single organization with common global standards, we are working to standardize BP drilling and wells operations with the intent of delivering safe and compliant wells. GWO works with our safety and operational risk function with a view to reducing risk in drilling and so reduce the likelihood of an oil spill or incident occurring through prevention efforts. We also aim to reduce the consequences should an incident occur by focusing on containment, spill response, relief wells and crisis management. *See Exploration and Production on page 80 for information about the upstream reorganization.*

Oil spill prevention

We are implementing enhanced drilling safety standards across the organization.

Blowout preventers

We have issued standards for the maintenance, testing, verification and use of subsea blowout preventers (BOPs). For example, we require dynamically positioned drill rigs contracted by BP to have no fewer than two blind shear rams and a casing shear ram sitting within the blowout preventer to enhance its reliability in cutting the drill pipe and sealing the well in the event of a blowout or other operational emergency. We require third-party verification that testing and maintenance of our subsea BOPs are performed

in accordance with industry recommended practice. In addition, BP requires that remotely operated vehicles can activate these BOPs in an emergency.

Cementing

We are enhancing oversight of cementing services by implementing new standards in cement design and testing. We have also strengthened the technical approval process for critical cementing operations, and have brought additional expertise into BP to oversee this. We are implementing quality audits of our cementing contractors' laboratories.

Well start-up procedure

We have introduced a new well start-up procedure. The checklist covers a range of operational areas and verification of conformance is required by leaders from the business line and S&OR before operations can begin on certain wells and on new rigs. In one case, as a result of this process, BP rejected a contractor rig put forward by another operator due to it not meeting BP's standards.

These requirements are designed to help identify and mitigate risks prior to contractors' drilling rigs being put into service for BP. Interventions to date have included repairs to safety systems, additional training of personnel, modifications to equipment, verification of quality and inspection records, revised and clarified roles and responsibilities, enhanced training requirements, and enhanced risk management techniques.

See Environment and social responsibility section on pages 69-73 for further information on BP s approach to oil spill contingency planning and response.

Bly Report internal investigation recommendations and actions taken

In the immediate aftermath of the Deepwater Horizon oil spill, BP launched an internal investigation, drawing on the expertise of more than 50 technical and other specialists within BP and the industry. The investigation team was led by BP's head of safety and operations, and worked independently from BP's other spill response activities and organizations.

The BP investigation (the Bly Report) concluded that no single cause was responsible for the accident. The investigation instead found that a complex, inter-linked series of mechanical failures, human judgements, engineering design, operational implementation and team interfaces, involving several companies including BP, contributed to the accident.

The recommendations

As a result, the investigation team made 26 recommendations specific to drilling, which we accepted and are working to implement across our worldwide drilling operations. The recommendations include measures to improve contractor management, as well as to strengthen design and assurance on blowout preventers (BOPs), well control, pressure-testing for well integrity, emergency systems, cement testing, rig audit, verification, and personnel competence.

Interim measures

Shortly following the publication of the Bly Report, BP developed interim measures to immediately address the eight key findings contained within the report. An interim guidance document was issued to each of our 14 operating regions in December 2010 which contained specific requirements, including the well start-up check list. This guidance continues to be in effect across all BP drilling and completions operations. We continue to progress implementation of the recommendations from the Deepwater Horizon investigation report and that work will ultimately replace the interim guidance.

Implementing the recommendations

Implementing the 26 recommendations across the group requires detailed work and many activities from creating new practices and guidance, training and testing appropriate staff, changing requirements and expectations of our contractors, and establishing verification processes to assure the changes are sustainably embedded. We have a team of around 85 people working full-time on this.

A project of this scale takes time; we must work to assure that all actions are delivered to a high standard across all of our well operations, and independently verified by our S&OR audit or internal audit function.

We have estimated and communicated delivery timelines for each of the recommendations and will continue to provide periodic updates of our progress. These timelines are based on existing facts and circumstances and can shift due to complexity, resource availability and evolving regulatory requirements.

The BP board has identified an independent expert to provide further oversight and assurance regarding the implementation of the Bly Report recommendations. The independent expert's engagement is expected to commence in the latter half of May 2012.

Progress update

At the end of 2011, four of the Bly Report recommendations have been completed. These were:

- Recommendation 6: to propose a recommended practice for foam cementing to the American Petroleum Institute.
- Recommendation 8: to strengthen the technical authority's role in cementing and zonal isolation.
- Recommendation 13: to strengthen our rig audit process to improve closure and verification of audit findings across the rigs we own and contract.
- Recommendation 14: to establish key performance indicators for well integrity, well control, and rig safety-critical equipment.

We continue to make progress on all of the remaining recommendations largely in line with our planned schedule, with a further 12 recommendations expected to be completed in 2012. Progress is tracked in the quarterly HSE and operations integrity report supplied to the executive team. *See bp.com/internalinvestigation for the full report and quarterly updates on progress.*

External investigations

In addition, there have been a number of external investigations, including those of the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling *(oilspillcommission.gov)* and the Joint Investigation Team of the Bureau of Ocean Energy Management, Regulation and Enforcement and the United States Coast Guard *(boemre.gov/ooc/press/2011/press0914.htm).* These reports were consistent in their conclusions that the accident resulted from multiple causes and was due to the actions of multiple parties. We are committed to understanding the causes, impacts and implications of the Deepwater Horizon incident and to learn and act on lessons from it. As part of this commitment, BP is reviewing the recommendations from government and industry reports.

Capping and containment

We have developed a mobile deepwater well capping package that includes about 250 pieces of speciality equipment. Maintained in a constant state of readiness in Houston, it is designed to be deployed by air freight and arrive wherever it is needed in just a few days.

We also share capping and containment equipment with other operators in the Gulf of Mexico, through the Marine Well Containment Company, as well as with operators in the UK North Sea. Further, BP provided project management for the Oil and Gas UK Oil Spill Prevention and Response Advisory Group to develop a next generation well capping system, now available in Europe, and is one of nine companies working in the Subsea Well Response Project to enhance the industry's capability to respond globally to subsea well control events.

Relief wells

In responding to the Gulf of Mexico oil spill, we drilled two relief wells. Prior to drilling a deepwater well, BP operations now have relief well plans in place with equipment identified that can be moved to the site if needed. This is of particular benefit in areas that do not have the same infrastructure and support as more active basins such as the Gulf of Mexico.

Oil spill preparedness

We continue to develop and assimilate lessons from the response to the Gulf of Mexico oil spill. In 2011, as a priority we incorporated many of these lessons into new technical requirements for BP operations that drill

in deepwater. Conformance with these requirements is mandatory for all operations drilling in water deeper than 1,000 feet and is subject to a formal assessment and sign-off by technical experts, S&OR and senior leaders. During 2011, we began implementing these requirements in Angola, the North Sea, Brazil, the US and Egypt, where we have deepwater drilling active or planned for 2012.

Crisis management

Crisis management planning is essential to respond effectively to emergencies and to avoid a potentially severe disruption in our business and operations. The intention is to build on interim requirements introduced in 2011 for deepwater drilling to put in place group-wide practices for both oil spill preparedness and response and crisis management.

During the response, we updated our incident action plan an operational crisis planning tool every 12-24 hours, which allowed us to have recent information to aid decision making. This was made possible by developing a common operating picture (COP) which helped us collect and present information in a way that enabled faster, better-informed decisions. The COP created an integrated view across more than 200 different data types. It provided an instant, interactive picture of the spill status and the activities of all responders.

See Environmental and social responsibility on pages 69-73 for further information on BP's approach to oil spill contingency planning and response.

Safer refining

We have been working hard to apply the lessons learned from the tragic accident in our Texas City refinery in 2005 and are committed to implementing the recommendations of the BP US Refineries Independent Safety Review Panel.

Systematic management

The core business of our refineries is the safe storage, handling and processing of hydrocarbons which involves systematic management of the associated operating risks. In seeking to manage these risks, measures are taken by our refineries to:

- Prevent loss of hydrocarbon containment, such as oil spills, through well-designed, maintained and operated equipment.
- Reduce the likelihood of ignition of any hydrocarbon releases which may occur through controlling ignition sources.
- Provide safe locations, emergency procedures and other mitigation measures in the event of a fire or explosion occurring.

For example, across our refining business we are spending more than $700 million to install safety shelters for individuals, move people further away from hydrocarbon containing equipment and reduce the number of vehicles in our sites.

In 2011, we enhanced and standardized a number of technical practices that we intend to implement across our refining business in 2012 and 2013, including practices pertaining to:

- Control of work practices including rules for what work is done, who it is done by, where it is done, when it is done and how it is done.
- Isolation of equipment from hydrocarbon and other energy sources to safely allow maintenance.
- Design, operation, maintenance for instrumented systems throughout their lifecycle to reliably achieve or maintain a safe operating state if unacceptable or dangerous process conditions are detected.
- Procedures and equipment requirements to assure safe handling of hydrogen sulphide containing streams.
- Design and operation of existing fired heaters.
- Identifying operating limits for our processes and equipment.

Risk assessment, prioritization and management

In 2011, all refineries used a consistent methodology to identify risks and prioritize mitigation actions, including addressing low probability, high consequence scenarios. Action plans have been developed for each risk and reviewed by authorized line and S&OR leaders. A multi-year risk profile reduction plan has been approved for each refinery and, learning from our review of all the plans, we are introducing additional requirements to enhance the mitigation of similar risks across our refining business.

Operational planning and controls

Each BP-operated entity develops an annual plan drawing on the output from the performance improvement cycle including the risk management process. The plan is prioritized with the aim of continually driving reductions in the level of risk at the sites. We plan our work taking account of the capacity needed to deliver the safety-related activities required.

Control of work has been an area of major focus in our refining business since 2008. We continue to see improvement in the execution of our maintenance planning, scheduling and work activities across our refining sites as the overall control of work process is better understood, learning shared and efficiency opportunities identified.

Competence and capability

Refinery leaders are experienced operations professionals with many years' experience within the industry and have typically attended the BP Operations Academy. Each refinery, with S&OR direction and expertise, is developing a consistent competency framework against which safety critical roles are assessed. The US refineries completed process safety competency assessments of over 3,500 employees in safety-critical roles and developed gap closure plans in 2011.

A key element within this competency development plan is the development of high fidelity process simulators. These will be used to train operators via simulations to respond to low probability, high consequence scenarios, similar to methods used with airline pilots.

Measurement, evaluation and corrective action

Regional vice presidents conduct performance reviews at each refinery. We now use a set of common safety metrics that are standard across all sites to help us proactively identify opportunities for improvement.

A quarterly assurance process has been introduced to enable S&OR to develop an ongoing, independent view of OMS conformance by the sites. Each site is assessed on their OMS self-assessment processes, the strength of existing risk mitigations and progress on risk reduction plans. Periodic S&OR audits against OMS requirements provide valuable insights from experts outside the site and result in actions to close identified gaps.

In 2011, we strengthened and standardized our approach to incident learning in our refining business, issuing briefings and alerts on lessons learned from incidents and near misses and requiring each refinery to assure that similar risks are assessed and appropriate actions completed.

Reports of the US refineries' Independent Expert

L. Duane Wilson was appointed in 2007 by the board as an Independent Expert to provide an objective assessment of BP's progress in implementing the recommendations of the BP US Refineries Independent Safety Review Panel (the Panel) aimed at improving process safety performance at BP's five US refineries. Mr Wilson is expected to deliver his fifth annual report in April 2012, and BP will publish it at *bp.com/independentexpert.* As in prior years, BP will have an opportunity to review and comment on Mr Wilson's draft report for factual accuracy, but he is solely responsible for the report's ultimate content.

The Independent Expert conducts his assessment of BP's implementation of the Panel's recommendations both through sampling and in-depth monitoring, evaluation and confirmation. Mr Wilson visited each BP US refinery at least twice in 2011 and interviewed personnel at many levels in the organization. He also engaged regularly with senior and executive management, both within Refining and Marketing and our safety and operational risk function, to gauge implementation progress. Mr Wilson also reviews progress reports and other documentation from BP. These include implementation status reports, process safety performance reports, overtime reports (to monitor the potential for worker fatigue), open and overdue process safety action item reports, incident investigations reports and safety audit reports.

Mr Wilson reports to the board through the chairman of BP's safety, ethics and environment assurance committee. In addition to an annual written report, he makes periodic oral reports of his observations to the committee, in which he gives status updates on BP's progress in implementing the Panel's recommendations.

Safety performance

Oil spills and loss of primary containment

We monitor the integrity of our operations, tanks, vessels and pipelines used to produce, process and transport oil and other hydrocarbons with the aim of preventing the loss of material from its primary containment. Accordingly, we record losses of material, including hydrocarbons, from our assets, and losses or spills that reach land or water.

The loss of primary containment metric below includes unplanned or uncontrolled releases from a tank, vessel, pipe, rail car or equipment used for containment or transfer within our operational boundary, excluding non-hazardous releases such as water.

The US government and third parties have announced various estimates of the flow rate or total volume of oil spilled from the Deepwater Horizon incident. The multi-district litigation beginning in 2012 in New Orleans will address the amount of oil spilled. *See Financial statements Note 36 on page 233 for information about the volume used to determine the estimated liabilities.*

Loss of primary containment and oil spills (excluding Deepwater Horizon oil spill in respect of 2010 volume)

	2011	2010	2009
Loss of primary containment number of all incidents[a]	**361**	418	537
Loss of primary containment number of oil spills[b]	**228**	261	234
Number of oil spills to land and water	**102**	142	122
Volume of oil spilled (thousand litres)	**556**	1,719	1,191
Volume of oil unrecovered (thousand litres)	**281**	758	222

a Does not include either small or non-hazardous releases.

b Number of spills greater than or equal to one barrel (159 litres, 42 US gallons).

Process safety

BP uses a disciplined framework for managing the integrity of hazardous operating systems and processes. We apply a combination of good design principles, engineering, and operating and maintenance practices to help deliver process safety performance and we monitor the number of process safety events occurring across our operations. The recently introduced American Petroleum Institute RP-754 standard, which sets out leading and lagging process safety indicators, organized into different tiers is used as the basis for our internal process safety-related reporting. API tier 1 process safety events are the losses of primary containment of greatest consequence causing harm to a member of the workforce or costly damage to equipment, or exceeding defined quantities. Seventy-four tier 1 process safety events were reported in BP in 2011.

Personal safety

BP reports publicly on its personal safety performance according to standard industry metrics. In 2011, our overall reported recordable injury frequency (RIF) was 0.36, compared with 0.61 in 2010 and 0.34 in 2009. Our reported day away from work case frequency (DAFWCF) in 2011 was 0.090, compared with 0.193 in 2010 and 0.069 in 2009. The 2010 group personal safety data was affected by the Gulf Coast response effort.

Working with partners and contractors

BP, like our industry peers, rarely works in isolation we need to work with suppliers, contractors and partners to carry out our operations. In 2011, more than 55% of the 374 million hours worked by BP were carried out by contractors.

Our ability to fulfil our corporate responsibility depends in part on the conduct of our suppliers, contractors and partners. We address this in a variety of ways, from training and dialogue to confirming operational standards through legally binding agreements. When we select contractors, our due diligence is designed to identify safety, bribery and corruption, money laundering and trade sanctions risks. We expect our suppliers, contractors and partners to comply with legal requirements and operate consistently with the principles of our code of conduct when they work on our behalf.

Within our operating management system we have group-wide and business-specific requirements and practices for working with contractors. The objective is to provide assurance that goods, equipment and services provided by third parties meet contractual and BP requirements and that there is a consistent, shared understanding of responsibilities. For example, in our drilling operations, where we have evaluated differences between our own standards and those of contractors, we require bridging documents to be put in place. These define how two or more safety management systems co-exist to allow co-operation and co-ordination between BP and the contractor.

Contractor management review

Following the Deepwater Horizon oil spill, we began an in-depth review of contractor management practices, with the aim of documenting and learning from best practice throughout BP and across a number of sectors and industries that use contractors in potentially dangerous activities. We studied 21 major organizations in six different sectors airlines, mining, construction, pharmaceuticals and chemicals, nuclear and space.

We found that these organizations working in potentially high-risk arenas tended to have fewer and longer-lasting relationships with contractors, supported by shared structures and practices. Clearly defined responsibilities and decision rights at every stage of each process are needed to make contractor relationships work - including training, monitoring and auditing. Rigorous qualification of suppliers, including competency assessments for critical roles, is also important.

The findings of this review are informing our contractor management approach, with initial work focusing on contracts in our upstream supply chain that involve potentially high-consequence activities.

Our partners in joint ventures

We seek to work in partnership with companies that share our commitment to ethical and sustainable working practices. However, in some of our joint ventures, we do not directly control how our partners and their employees approach these issues.

Typically, our level of influence or control over a project or operation is linked to the size of our financial stake compared to other participants. In some joint ventures we act as the operator. Where we are the operator, and where legal and contractual arrangements allow, our policies, standards and operating systems apply.

In other cases, for example where one of our partners is the designated operator or where the operator is a joint venture company owned by BP and other partners, we are not the day-to-day operator. In those cases our OMS provides for our businesses to consider whether the management system used by the operator provides similar levels of risk and performance management to our own. We seek to influence our partners through dialogue and constructive engagement.

In 2011, BP initiated a review into our approach to the management of our relationships with non-operated joint venture operators and partners. This work includes safety and operational risk as well as bribery and corruption risk.

Environmental and social responsibility

The world's demand for energy is increasing and our business of finding and producing some of that energy means we operate in increasingly diverse locations globally. Many of these locations have environmental and social sensitivities.

To BP, working responsibly means managing our impacts on the areas where we operate, and making this a core principle in all of our activities. From the initial planning stages of a new project through to its eventual decommissioning and any remediation work that follows, our operating management system (OMS) lays out the standards and processes required for environmentally and socially responsible operations.

Wherever we work, we strive to minimize our impact on the environment whether to land, air, water or wildlife and to ensure that local people are engaged, human rights are respected and cultural heritage is conserved.

Our environmental and social practices

We are taking an increasingly systematic approach to the management of the environmental and social impacts of our projects. Our environmental and social practices, which form part of our OMS, set out how the major projects to which they apply should identify and manage environmental and social impacts. The practices also apply to projects that involve new access, projects that could affect an international protected area and some BP acquisition negotiations.

The practices help us deliver on the intent of the relevant sections of the OMS, the BP code of conduct and on our external commitments. They include several key requirements on impact assessment, security and human rights, indigenous people, international protected areas, greenhouse gas emissions, energy management, water management, ozone depleting substances, drilling wastes, and moving communities.

Early in the planning stage, applicable projects complete a screening process to identify environmental and social impacts that could arise from their activities. Between implementation in April 2010 and the end of 2011, nearly 60 projects had completed the screening process with the support of a trained and independent screening facilitator.

More information about our approach to environmental and social issues may be found in the BP Sustainability Review and on bp.com/sustainability.

Working in internationally protected areas

Our environmental and social practices require the projects to which they apply to understand the potential to affect international protected areas. The UNEP World Conservation Monitoring Centre's World Database on Protected Areas is used to inform this screening process. Our international protected areas classification includes areas designated as protected by the International Union for the Conservation of Nature (categories I-IV), Ramsar and World Heritage sites, as well as areas proposed for protected status.

Where screening indicates that a proposed BP project may potentially affect an international protected area a high-level risk assessment is carried out. Our safety and operational risk function provides an independent review to inform the risk assessment, and before any physical activity begins permission is sought from senior management, together with appropriate mitigation measures. The Great Australian Bight Project completed this process in 2011.

Oil spill contingency planning and response

Applicable laws generally include requirements for dealing with the environmental and socio-economic impacts of oil spills or leaks. In some countries, regulators require as part of our licences to operate that plans are in place for responding to accidents and unplanned events such as oil spills.

The Deepwater Horizon oil spill demanded a response at an order of magnitude never required before. We learned a great deal and made advances in response technology and systems. As a result we are updating our group requirements and are sharing our knowledge with the industry and regulators.

In 2012, we will be working on the development of enhanced oil spill preparedness and response requirements for all BP entities that handle oil in a way that gives rise to a risk of an oil spill. Once these requirements are incorporated into OMS, they will require relevant businesses to follow a planning process to predict how the spilled oil will behave; identify, assess and understand the environmental and social sensitivities at risk; define effective response strategies and confirm that appropriate response capabilities are in place. This practice will incorporate our deepwater technical requirements, further enabling a single, consistent process across BP.

Sensitivity mapping

Understanding the environmental and socio-economic sensitivities where we operate is an important part of planning for an effective response. We obtain sensitivity information from many sources, including environmental and social impact assessments (ESIAs) for many of our projects. These ESIAs include information about the potential environmental and socio-economic impacts of planned activities and also the potential impacts that might occur in the event of an unplanned event, such as an oil spill. In 2011, we have used high resolution satellite imagery to enhance our sensitivity mapping across thousands of miles of coastlines, and submersibles to characterize the deep ocean. This has helped us better understand our environmental risks in regions like Angola, Brazil and the US.

Contingency planning

Identifying and assessing environmentally and socio-economically sensitive areas helps us to develop appropriate oil spill response and crisis management plans. The objective is to use response techniques to avoid or minimize the environmental and socio-economic impact of a spill to the extent feasible based upon an assessment of the sensitivity of the local environment. These plans are backed up by robust response 'capability', the tools and people required to mount an effective response to an incident.

How we work with designated government regulatory bodies in the event of a spill is critical. Sharing lessons learned and maintaining a dialogue with regulators in the regions where we operate is an important part of our approach. In many countries where BP operates, the regulator will ultimately determine the procedures to deal with the environmental and socio-economic impact.

Acute response plans are often focused on the physical containment and recovery of the spilled oil, though they also recognize that components in dispersed oil will be subject to processes of biodegradation, which may be facilitated and accelerated by the application of chemical dispersants.

For onshore operations, for example, BP refineries' spill response plans include passive and active containment measures that are designed for the specific location and types of operations.

In the event of concurrent spills at multiple locations, each affected facility would activate its independent oil spill response plan and respond accordingly. Although responding to multiple spills of the same magnitude and complexity as occurred in the Gulf of Mexico in 2010 would be a challenge for the group, our response plans are not interdependent.

See Safety on pages 65-69 for further information on BP's approach to oil spill prevention and preparedness.

Gulf of Mexico our long-term commitments

See Gulf of Mexico oil spill on pages 76-79 for further information on BP's response to the incident and environment and economic restoration efforts.

Canadian oil sands

Canada s oil sands are believed to hold one of the world s largest untapped supplies of oil, third in size to the resources in Saudi Arabia and Venezuela. BP is involved in three oil sands projects, all of which are located in the province of Alberta. Development of the Sunrise project, our joint venture operated by Husky Energy, is under way, with production from Phase 1 expected to start in 2014. The other two proposed projects Pike, which will be operated by Devon, and Terre de Grace, which will be BP-operated are still in the early stages of development.

We reviewed and approved the decision to invest in Canadian oil sands projects, taking into consideration greenhouse gas (GHG) emissions, impacts on land, water use and local communities, and commercial viability. As with all joint ventures in which we are not the operator, we will monitor the progress of these projects and the mitigation of risk.

The extraction process to be used, in situ steam-assisted gravity drainage (SAGD) technology, involves the injection of steam underground. The steam liquefies the bitumen, allowing it to flow to the surface through production wells. This production technique reduces land disturbance and aligns to our strengths, particularly to our expertise with wells and improving large-scale reservoir performance. Unlike mining, in situ processes create a smaller physical footprint and do not involve tailing ponds.

A key concern around oil sands operations using SAGD is the amount of greenhouse gas emissions produced for steam generation and the processing of the produced bitumen. A well-to-wheels study conducted in 2009, which measured total GHG emissions from production through to consumption, found the lifecycle emissions for oil sands-based products to be 5-15% higher than those from products from average crude oils consumed in the US.

Climate change

Climate change represents a significant challenge for society, the energy industry and BP. In response to the challenges and opportunities, BP is taking a number of practical steps, including investing in lower-carbon energy products such as biofuels and wind, and ventures focused on sustainable energy solutions; and seeking to manage our own GHG emissions through a focus on operational energy efficiency, reductions in flaring and venting and the engineering design for new projects. We see natural gas playing a key strategic role as a lower-carbon fuel that is increasingly secure and affordable. We also consider the potential impacts of a changing climate on our operations.

Greenhouse gas emissions

Our direct GHG emissions[a] were 61.8 million tonnes (Mte) in 2011, compared with 64.9 Mte in 2010. This decrease of 3.1 Mte is primarily explained by the temporary reduction in activity in some of our businesses as a result of maintenance work and also by the sale of assets as part of our disposal programme. We achieved 0.2 Mte of sustainable emissions reductions in 2011.

Over the long-term it is likely that the carbon intensity of parts of our business will increase. In our upstream operations this is because we expect to move further into technically difficult and potentially more energy intensive areas. The intensity of certain refining operations may also increase with the trend towards processing heavier crudes which requires more energy.

In 2010 we did not report on GHG emissions associated with the Deepwater Horizon incident or response. We have since estimated the CO_2 equivalent emissions from response activities in 2010 to be approximately 481,000 metric tonnes, which includes major vessels deployed. This figure does not include emissions associated with the 'vessels of opportunity programme', the onshore vehicles and equipment and the incident itself, which are estimated to be minor.

a We report GHG emissions on a CO2-equivalent basis, including CO2 and methane. This represents all consolidated entities and BP's share of equity-accounted entities except TNK-BP.

Greenhouse gas regulation

In the future, we expect that additional regulation of GHG emissions aimed at addressing climate change will have an increasing impact on our businesses, operating costs and strategic planning, but may also offer opportunities for the development of low-carbon technologies and businesses. *See Regulation of the group's business Greenhouse gas regulation on page* 109.

To help address potential future regulation, we factor a carbon cost into our investment appraisals and engineering designs for new projects. We do this by requiring larger projects, and those for which emissions costs would be a material part of the project, to apply a standard carbon cost to the projected GHG emissions over the life of the project. The standard cost is based on our estimate of the carbon price that might realistically be expected in particular parts of the world. In industrialized countries, this standard cost assumption is currently $40 per tonne of CO_2 equivalent. We use this as a basis for assessing the economic value of the investment and as one consideration in optimizing the way the project is engineered with respect to emissions. This helps to assess our investments under scenarios in which the price of carbon emissions is higher than the current market price.

Adaptation to impacts resulting from a changing climate

We have funded research into the impacts of climate change on our operations for many years, to better understand the possible types of climate change impacts, potential effects on the environment and on our facilities and to develop potential responses to these impacts.

In the Beaufort Sea in Canada, for example, where BP is in the early stages of an oil exploration project, we have collaborated with ArcticNet, a local research organization devoted to understanding climate change impacts in the Arctic, on a two-year environmental baseline study. For ArcticNet the information gleaned will provide valuable data for analysis, while for BP the data will provide a useful baseline with which to compare future research, helping us to understand and chart the effects of climate change in this deepwater ocean environment.

Projects implementing our environmental and social practices are required to assess the potential impacts to the project from the changing climate. Any significant potential impacts identified are managed via the project's risk management process. To support this risk assessment process, we continually update and improve our climate impact modelling tools. In the Caspian region, for example, we are working with meteorology and oceanology consultants to enhance the existing modelling capability and develop a regional climate model to provide long-term forecasts and trends of wind speed, wave height and sea level.

We also have a guide on adapting to a changing climate which is available for all projects and operations. This document sets out guidance to help businesses across BP make appropriate allowance for the potential effects of climate change.

For projects where climate change impacts are identified as a risk, our engineers typically seek to address them like any other physical and ecological hazard, rather than as a discrete category. We periodically review and adjust existing design criteria and engineering technology practices. For example, we adapt our drainage design practices based on the frequency and severity of storms as well as rainfall and runoff amounts; if storms are anticipated to become more frequent, or heavier, the engineering design will accommodate this.

Water

We are taking a more strategic approach to water use and assessing water-related risks within our businesses, including those associated with the growing global issue of water scarcity. Our focus is on increasing our ability to forecast, measure and manage emerging water risks and engaging with external organizations to better understand these risks and develop sustainable water management practices, particularly where water is scarce.

With our industry association IPIECA, BP has also participated in the development of a new customized oil and gas version of the World Business Council for Sustainable Development's Global Water Tool, which helps oil and gas companies map their water use and assess risks of freshwater scarcity and related biodiversity impacts, across their portfolio of sites. BP has also invested in a water risk management tool, which is currently being piloted at a number of BP's operations, to investigate the risks of water use and availability at a local level.

In the future, these tools will provide BP with a means of consistently defining water risks and opportunities across a number of our operations, enabling us to establish a more consistent approach to managing water issues throughout the group.

Hydraulic fracturing

Technology helps to make it possible for BP to extract unconventional gas resources safely and responsibly to help meet the growing global demand for gas. Unconventional gas can be classified into three categories: tight gas, coalbed methane and shale gas. BP is pursuing unconventional gas in the US and in other countries such as Algeria, Oman and Indonesia.

Hydraulic fracturing, or 'fracking', is a process of pumping water mixed with a small proportion of sand and chemicals underground at high pressure to fracture the rock and release gas that would otherwise not be accessible. Some stakeholders have expressed concerns about the potential environmental impacts. BP recognizes these concerns and seeks to apply responsible well design and construction, surface operation and fluid handling practices and engages constructively with government and industry to promote sound policies and regulation that protect water resources and the environment. We expect that many of the jurisdictions in which we operate will adopt stricter regulations governing 'fracking' and other unconventional gas extraction technologies in the future which could adversely affect our operations and profitability in our unconventional gas business.

Environmental expenditure

			$ million
	2011	2010	2009
Environmental expenditure relating to the Gulf of Mexico oil spill			
Spill response	**586**	13,628	
Additions to environmental remediation provision	**1,167**	929	
Other environmental expenditure			
Operating expenditure	**704**	716	701
Capital expenditure	**819**	911	955
Clean-ups	**53**	55	70
Additions to environmental remediation provision	**510**	361	588
Additions to decommissioning provision	**4,596**	1,800	169

BP continues to incur significant costs related to the 2010 Gulf of Mexico oil spill. Of the spill response cost of $586 million incurred in the year (2010 $13,628 million) $336 million (2010 $1,043 million) remains as a provision at 31 December 2011.

The environmental remediation provision includes amounts for BP's commitment to fund the Gulf of Mexico Research Initiative, natural resource damage (NRD) assessment costs and emergency NRD restoration projects. In addition, during the year BP entered a framework agreement with natural resource trustees for the United States and five Gulf Coast states, providing for up to $1 billion to be spent on early restoration projects to address natural resource injuries resulting from the Gulf of Mexico oil spill. Further amounts for spill response costs were provided during the year primarily to recognize increased costs of shoreline clean-up, patrolling and maintenance and vessel decontamination. The majority of the active clean-up of the shorelines had been completed by the end of the year.

See Financial statements Note 2 on page 190, Note 36 on page 231 and Note 43 on page 249 for further information relating to the Gulf of Mexico oil spill.

Operating and capital expenditure on the prevention, control, abatement or elimination of air, water and solid waste pollution is often not incurred as a separately identifiable transaction. Instead, it forms part of a larger transaction that includes, for example, normal maintenance expenditure. The figures for environmental operating and capital expenditure in the table are therefore estimates, based on the definitions and guidelines of the American Petroleum Institute.

Environmental operating expenditure of $704 million in 2011 was at a similar level to 2009 and 2010.

Similar levels of operating and capital expenditures are expected in the foreseeable future. 2011 capital expenditure was lower than in 2010 due to the completion of various capital projects in our US refineries.

In addition to operating and capital expenditures, we also create provisions for future environmental remediation. Expenditure against such provisions normally occurs in subsequent periods and is not included in environmental operating expenditure reported for such periods.

Provisions for environmental remediation are made when a clean-up is probable and the amount of the obligation can be reliably estimated. Generally, this coincides with the commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites.

The extent and cost of future environmental restoration, remediation and abatement programmes are inherently difficult to estimate. They often depend on the extent of contamination, and the associated impact and timing of the corrective actions required, technological feasibility and BP's share of liability. Though the costs of future programmes could be significant and may be material to the results of operations in the period in which they are recognized, it is not expected that such costs will be material to the group's overall results of operations or financial position.

Additions to our environmental remediation provision increased in 2011 largely due to changes in scope reassessments of the remediation plans of a number of our US retail sites. The charge for environmental remediation provisions in 2011 included $12 million in respect of provisions for new sites (2010 $54 million and 2009 $6 million).

In addition, we make provisions on installation of our oil- and gas-producing assets and related pipelines to meet the cost of eventual decommissioning. On installation of an oil or natural gas production facility a provision is established that represents the discounted value of the expected future cost of decommissioning the asset.

The level of increase in the decommissioning provision varies with the number of new fields coming onstream in a particular year and the outcome of the periodic reviews. There was a significant increase in 2010, driven by activity in the Gulf of Mexico and this trend has continued in 2011 as a result of changes in estimation and detailed reviews of expected future costs; the majority of the increase related to our sites in Trinidad, the Gulf of Mexico and the North Sea.

On 15 October 2010, the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) issued Notice to Lessees (NTL) 2010-G05, which requires that idle infrastructure on active leases is decommissioned earlier than previously was required and establishes guidelines to determine the future utility of idle infrastructure on active leases. As a consequence, the timing and methodology of well abandonment have changed, reflected in an increase to the decommissioning provision.

Additionally, we undertake periodic reviews of existing provisions. These reviews take account of revised cost assumptions, changes in decommissioning requirements and any technological developments.

Provisions for environmental remediation and decommissioning are usually set up on a discounted basis, as required by IAS 37 'Provisions, Contingent Liabilities and Contingent Assets'.

Further details of decommissioning and environmental provisions appear in Financial statements Note 36 on page 231.

Respecting human rights

BP supports the Universal Declaration of Human Rights, which lays out the rights to which all human beings are entitled. We have also supported recent multi-stakeholder efforts to establish clear, universally-applicable guidelines on the responsibilities of businesses in relation to human rights issues.

We are a signatory to two voluntary agreements with implications for specific aspects of human rights: the UN Global Compact, which helps businesses align their operations and strategies with 10 principles, including some that are related to human rights, and the Voluntary Principles on Security and Human Rights, which define good practice for security operations in extractive industry companies. We have contributed to the work of oil and gas industry organization IPIECA's human rights task force, which works on human rights issues and develops good practice guidance for companies in our industry.

In 2011 the UN Human Rights Council unanimously endorsed the Guiding Principles on Business and Human Rights. These outline specific responsibilities for businesses in relation to human rights. We participated in discussions on the development of the Guiding Principles, and in 2011 we completed a comparison between our current policies and practices and the expectations in the Guiding Principles, to help us identify what work will be needed to achieve alignment with the principles.

BP's code of conduct makes it clear that certain provisions, such as BP's stance on the rights and dignity of communities, relate directly to human rights. *See page 31 for further information about our code of conduct.*

Revenue transparency and business ethics

As a member of the Extractive Industries Transparency Initiative (EITI), we work with governments, non-governmental organizations and international agencies to improve transparency in this area. In several countries that are in the process of becoming EITI compliant, BP is supporting the process; for example, BP is an active member of the Trinidad & Tobago EITI steering committee. In countries that have achieved EITI compliance, including Azerbaijan and Norway, BP submits an annual report on payments to their governments.

We have taken part in consultations in relation to new or proposed revenue transparency reporting requirements in the US and Europe for companies in the extractive industries. BP will fully comply with the appropriate mandatory regulations when they come into effect.

We are working to respond effectively to the standards flowing from the UK Bribery Act as well as other anti-corruption legislation such as the Foreign Corrupt Practices Act in the US. Bribery and corruption are serious risks in the oil and gas industry. Our code of conduct requires that our employees or others working on behalf of BP do not engage in bribery or corruption in any form in both the public and private sectors.

In 2011, we issued a group-wide anti-bribery and corruption standard, which applies to all BP employees and contractors. The standard requires annual bribery and corruption risk assessments; due diligence on all parties with whom BP does business; appropriate anti-bribery and corruption clauses in contracts and the training of personnel in anti-bribery and corruption measures.

Socio-economic development

We believe each BP project has the potential to benefit local communities by creating jobs, generating tax revenues and providing opportunities for local suppliers. Our presence in a location also has the potential to bring indirect economic benefits.

We run a range of programmes to build the skills of businesses in places where we work and to develop the local supply chain. These range from financing to sharing global standards and practice in areas such as health and safety. The programmes can benefit local companies by empowering them to reach the standards needed to supply BP and other clients. At the same time BP benefits from the local sourcing of goods and services.

BP's social investments the contributions we make to social and community programmes in locations where we operate aim to support development programmes that we believe will seek to create a meaningful and sustainable impact one that is relevant to local needs, aligned with BP's business and undertaken in partnership with local organizations.

The programmes we support fall into three broad categories: building business skills and developing enterprise, supporting education and other community needs and sharing technical expertise with local governments. In some developing economies we also support community infrastructure programmes that help people improve their access to basic resources such as drinking water and public health improvements. We work with local authorities, community groups and specialists to deliver these community programmes.

We use our technical knowledge and global reach where relevant to support national and regional governments in their efforts to develop their economies sustainably and provide public resources such as education and health. As well as country-specific projects, we support more general initiatives, including the Oxford Centre for the Analysis of Resource-Rich Economies, which studies how countries that are rich in natural resources such as oil and gas can use their resources for successful development rather than falling prey to mismanagement, corruption or other pitfalls.

Our direct spending on community programmes in 2011 was $103.7 million, which included contributions of $37.5 million in the US, $27.0 million in the UK (including $7.2 million to UK charities, of which $2.5 million for arts and culture, $2.8 million for enterprise development, $1.6 million for education), $2.6 million in other European countries and $36.6 million in the rest of the world. These reported amounts exclude social bonuses paid by BP to governments as part of licence acquisition costs and which have been capitalised as intangible assets on the group balance sheet. In such cases the group has no direct oversight of the expenditure. Contributions relating to economic recovery following the Deepwater Horizon oil spill are also excluded, *see page 77 for details of these contributions.*

Employees

Number of employees at 31 December	US	Non-US	Total
2011			
Exploration and Production	**8,900**	**13,300**	**22,200**
Refining and Marketing[a]	**12,000**	**39,000**	**51,000**
Other business and corporate	**1,900**	**8,200**	**10,100**
Gulf Coast Restoration Organization	**100**		**100**
	22,900	**60,500**	**83,400**
2010			
Exploration and Production	7,900	13,200	21,100
Refining and Marketing[a]	12,400	39,900	52,300
Other business and corporate	1,700	4,500	6,200
Gulf Coast Restoration Organization	100		100
	22,100	57,600	79,700
2009			
Exploration and Production	8,000	13,500	21,500
Refining and Marketing[a]	12,700	38,900	51,600
Other business and corporate	2,100	5,100	7,200
	22,800	57,500	80,300

a Includes 14,600 (2010 15,200 and 2009 13,900) service station staff, all of whom are non-US.

To be sustainable as a business, BP needs employees who have the right skills for their roles and who understand the values and expected behaviours that guide everything we do as a group.

We have reviewed the way we express BP's values and required behaviours with the goal of ensuring they support our aspirations for the future, align explicitly with our code of conduct and translate into responsible actions in the work we do every day. We conducted a programme in 2011 to renew employee awareness of our values and the behaviours as we work to reset our priorities as a company. *See bp.com/values for more information.*

We had approximately 83,400 employees at 31 December 2011, compared with approximately 79,700 a year ago. During 2011, our headcount has been most significantly affected by both external hiring in order to build capability and acquisition and divestment activity as part of the strategy to re-shape the business.

The group people committee, chaired by the group chief executive, continues to take overall responsibility for key policy decisions relating to employees. In 2011, some of the key subjects discussed were longer-term people priorities; the design and implementation of a new reward model;

our ambition on diversity and inclusion and a review of the governance of our learning programmes.

Our priorities for managing our people focus on ensuring the safety of our employees, strengthening capability, developing the potential of our own people, increasing diversity and inclusion and retaining the best people by motivating and engaging them.

Strengthening capability

The increasing demand for energy products and the complexity of our projects means that attracting and retaining skilled and talented people is vital to BP's delivery of its strategy and plans.

In support of this, the group chief executive and each member of the executive team hold regular review meetings to ensure that appropriate plans to build capability are in place and that a rigorous and consistent succession process is followed for all group leadership roles.

To supplement our existing internal capability, we also target experienced and skilled professionals in the external market and are continuing to increase our intake of graduates to create a strong internal talent pipeline for the future.

We conduct external assessments for all new hires into BP at senior levels and for internal promotions to senior level and group leader level roles. These assessments ensure rigour and objectivity in our hiring and talent processes. They give an in-depth analysis of leadership behaviours, intellectual capacity and the required experience and skills for the role in question.

Our ongoing three-year graduate development programme continued in 2011. It currently has about 1,600 participants from all over the world.

Developing our people

We provide development opportunities for all our employees, including external and on-the-job training, international assignments, mentoring, team development days, workshops, seminars and online learning. We encourage all employees to take at least five training days per year.

We continue to work to embed appropriate leadership behaviours throughout our organization. In 2011, we delivered a new group leader development programme, designed to help our most senior leaders apply BP's required leadership behaviours in their work. The first phase of the programme has now been completed with about half the group leader population having undertaken eight days of intensive training. We are refreshing the content and will start the next phase in 2012.

Our group-wide suite of management development programmes, Managing Essentials, has now run in 41 countries, with around 32,400 participants.

Meeting the expectations of our people

We have reviewed our reward strategy, including how the group incentivizes business performance, with the aim of encouraging excellence in safety, compliance and operational risk management. Our revised performance management framework was implemented in 2011.

We encourage employee share ownership. For example, through the ShareMatch plan run in around 50 countries, we match BP shares purchased by our employees.

We aim to treat employees affected by mergers, acquisitions and joint ventures fairly and with respect, through open and regular communication. As part of the divestment programme following the Gulf of Mexico oil spill, BP has been seeking the same or comparable pay and benefits for employees transferring to other companies.

Diversity and inclusion

We are a global company and aim for a workforce that is representative of the societies in which we operate. We work to attract, motivate, develop and retain the best talent from the diversity the world offers our ability to be competitive and to thrive globally depends on it. We believe success comes from the energy of our people.

Through living our values of safety, respect, excellence, courage and one team, we create an inclusive working environment where everyone can make a difference and give their best. Our work on diversity and inclusion is overseen by the group people committee who review performance on a quarterly basis. They agree strategic direction and group standards which are then implemented through business specific diversity and inclusion plans. We supported the UK government-commissioned Lord Davies review in 2011, which made recommendations on increasing gender diversity on the boards of listed companies.

We are also incorporating detailed diversity and inclusion analysis into talent reviews, with processes to identify actions where any issues are found. We continue to increase the number of local leaders and employees in our operations so that they reflect the communities in which we operate.

By 2020, more than half our operations are expected to be in non-OECD countries and we see this as an opportunity to develop a new generation of experts and skilled employees. At the end of 2011, 15% of our group leaders were female and 19% came from countries other than the UK and the US. When we started tracking the composition of our group leadership in 2000, these percentages were 9% and 14% respectively. BP has increased the percentage of female leaders in 2011 and remains focused on building a more sustainable pipeline of diverse talent for the future.

We aim to ensure equal opportunity in recruitment, career development, promotion, training and reward for all employees, including those with disabilities. Where existing employees become disabled, our policy is to provide continuing employment and training wherever practicable.

Employee engagement

Executive team members hold regular town halls and webcasts to communicate with our employees around the world.

Team meetings and one-to-one meetings are the core of our employee engagement, complemented by formal processes through works councils in parts of Europe. These communications, along with training programmes, are designed to contribute to employee development and motivation by raising awareness of financial, economic, ethical, social and environmental factors affecting our performance. The group seeks to maintain constructive relationships with labour unions.

We conduct an employee engagement survey to monitor employee attitudes and identify areas for improvement. Our 2010 employee survey was delayed to allow for organizational changes to be reflected in the survey construction. This was completed and we carried out an employee engagement survey in 2011. The 2011 survey found that employees are committed and understand BP procedures and standards. The results show that there are a number of areas that can be improved. These include increasing transparency of the promotion process and being clear about the organization s priorities. Business leadership teams reviewed the results of the survey and have agreed actions to address the identified issues.

The survey includes 10 questions which make up the employee satisfaction index. The overall employee satisfaction index score for 2011 (62%) was below the score from 2009 (65%) but above that of 2008 (59%).

The code of conduct

The BP code of conduct sets the standard that all BP employees are required to work to. It is aligned with our values, group standards and legal requirements, and it clarifies the ethics and compliance expectations for everyone who works at BP. The code was updated in 2011 and now puts greater emphasis on a values-based approach.

The code defines what BP expects of its people in key areas such as safety, workplace behaviour, bribery and corruption and financial integrity.

Employees, contractors or other third parties who have questions or concerns that laws, regulations or the code of conduct may be breached, can get help through OpenTalk, an independent confidential helpline. The number of cases raised through OpenTalk in 2011 was 796, compared with 742 in 2010. In the US, former district court Judge Stanley Sporkin acts as an ombudsperson. Employees and contractors can contact him confidentially to report any suspected breach of compliance, ethics or the code of conduct, including safety concerns.

We take steps to identify and correct areas of non-compliance and take disciplinary action where appropriate. In 2011, 529 dismissals were reported by BP s businesses for non-adherence to the code of conduct or unethical behaviour compared to 552 in 2010.

BP continues to apply a policy that the group will not participate directly in party political activity or make any political contributions, whether in cash or in kind. We review employees rights to political activity in each

country where we operate. For example, in the US, BP facilitates staff participation in the political process by providing staff support to ensure BP employee political action committee contributions are publicly disclosed and comply with the law.

Technology

Technology in BP

We define technology in BP as the practical application of science to manage risks, capture business value and inform strategy development. This includes the research, development, demonstration and acquisition of new technical capabilities and support for the deployment of BP s know-how.

BP s model continues to be one of selective technology leadership, under which we focus on major technology programmes that best support our business priorities and competitive performance.

External assurance is achieved through the technology advisory council, which advises the board and executive management on the state of technology within BP. The council is comprised of eminent business and academic technology leaders.

In 2011 we invested $636 million (of which $12 million related to the response to the Deepwater Horizon incident) in research and development (R&D). This compares with $780 million in 2010 (of which $211 million related to the response to the Deepwater Horizon incident), and $587 million in 2009. The increase in the underlying R&D spend is related to our major technology programmes. *See Financial statements Note 13 on page 208.*

Our innovation ecosystem

BP has hundreds of scientists and technologists across the group, with seven major technology centres in the US, UK and Germany. We access external expertise through various forms of partnership and collaboration, from joint research agreements to venturing. We have a strategic approach to university relationships across our portfolio for the purposes of research, recruitment, policy insights and education.

BP has long-term research programmes with major universities and research institutions around the world, exploring areas from reservoir fluid flow to energy biosciences. These include the following programmes:

- The Energy Biosciences Institute (EBI) is BP s largest external R&D investment, being a $500-million 10-year commitment to a multi-disciplinary research partnership with the University of California Berkeley, the Lawrence Berkeley National Laboratory, and the University of Illinois. Now in its fourth year, the EBI is generating multiple innovations, particularly in the field of cellulosic conversion, that give our biofuels business viable opportunities for commercial application.
- BP s energy sustainability challenge (ESC) is a research programme with 13 leading universities to establish trusted peer-reviewed data on the relationships between natural resource usage and different energy pathways. The aim is to better understand the implications of energy production and consumption on potentially-constrained land, water and materials resources, and assess corresponding technology and policy opportunities. One of the early publications resulting from this research is the University of Augsburg s handbook, *Materials critical to the energy industry.*
- In September 2011, BP opened the BP energy innovation laboratory at the Dalian Institute for Chemical Physics (DICP) in China as part of a 10-year extension to our research agreements with DICP.
- In January 2011, BP started a new three-year policy programme at Harvard University s Kennedy School focused on examining current and future potential policies on energy, security and climate change.

BP is a founding member of the UK s Energy Technologies Institute (ETI) a public/private partnership established in 2008 to accelerate low-carbon technology development. As at 31 December 2011, the ETI has commissioned over $200 million of work covering over 30 projects across a wide range of technologies. The ETI has also developed an integrated model of the UK energy system which projects potential pathways out to 2050 to meet the UK s emissions targets.

Exploration and Production

In the upstream, our technology investment directly supports business strategy by focusing on safety and operational risk management; operational efficiency; increased recovery and reserves; and winning new access. Our strengths in exploration, deepwater, giant fields and gas are underpinned by flagship technology programmes that conduct scientific research in proprietary laboratories and in partnership with world-class research institutes and universities, to develop industry-leading technologies in imaging, facilities, well design and completions, and field recovery. These technologies are applied in the field, often in combination with real-time data acquisition and visualization, to drive risk reduction and excellence in exploration, developments and production.

- We are applying many of the lessons learned from the Deepwater Horizon incident and response throughout our global deepwater operations. The response required rapid innovation of new technologies to cap the well and contain the spill and in partnership with industry partners, government agencies and leading universities we have continued to develop and deploy new equipment and standards. Among many new developments in BP, we have built a global deepwater well cap and tooling package, now available for global deployment. This new capability includes a containment cap, remote operating vehicle (ROV) intervention system, subsea dispersant injection system, subsea debris removal equipment, and other tools.
- BP continues to develop and apply innovative exploration technologies. BP has applied two novel seismic acquisition methods developed in-house. Our distance separated simultaneous sources (DS3) and independent simultaneous sources (ISS®) methods were used to complete ultra-large, high density land seismic surveys in the Middle East and North Africa. BP also has field trials under way to extend these acquisition methods to the offshore.
- Through our Field of the Future® flagship technology programme, BP has deployed a range of digital, sensing and control technologies in its operations and is using the data to enhance real-time operating efficiency and recovery. Field of the Future tools are enabling more effective monitoring of production, multiple well components, and well characteristics such as temperature, which help to optimize hydrocarbon production. In addition, improved monitoring of facilities is helping to reduce risk, reducing downtime and saving tens of millions of dollars.
- In 2011, we successfully completed BP well advisor module field trials in Azerbaijan, a technology designed to aid decision making, enhance safety, reduce cost and bring wells on line more quickly. Through well advisor, we can harness real-time drilling data from sensors that see ahead of the drill, enabling us to deploy technologies such as early kick detection, which allow adjustments that can minimize down time during this critical phase of development. Rolling field trials will continue throughout 2012 to accelerate deployment.
- Enhanced oil recovery (EOR) technologies continue to push recovery factors to new limits. We believe that by increasing the overall recovery factor from our fields by 1%, we could be able to add 2 billion boe to our estimated ultimate recovery from existing fields. As at the end of 2011, BP, using its Designer Water® EOR technology, has treated 78 wells with Bright Water particles (a BP idea) in Alaska, Argentina, Azerbaijan, Pakistan and Russia. These applications have delivered more than 20 million barrels of additional gross recoverable volumes at a development cost of less than $6 per barrel, and with an 80% success rate: BP has pumped almost 90% of all Bright Water treatments in the industry. Bright Water treatments involve the design and deployment of this sweep-improving component with regular injection water over a period of several days. These particles are activated deep in the reservoir to form a waterflood sweep improving diversion at a point between the injection and production wells.
- The $7.6 billion Clair Ridge project in the UK North Sea will be the first offshore project to use BP s LoSal® EOR technology to increase the recovery of oil by modifying the salinity of the water injected into the reservoir. (LoSal EOR is part of BP s suite of Designer Water technologies.) Earlier in 2011, BP and its partners also announced plans for the $5 billion redevelopment of the Schiehallion and Loyal fields,

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west of Shetland. The floating production, storage and offloading unit (FPSO) is to be built with full polymer EOR application capability.

Refining and Marketing

Our Refining and Marketing technology focus is both operational and customer facing. In our refineries and petrochemicals assets, we develop and apply technology to monitor operational integrity, to optimize product yields as a function of feedstock changes, to ensure quality attainment, and to improve energy efficiency. We also apply our expertise to create quality brand fuel and lubricant products for customers in on-road, off-road, air, sea and industrial applications globally.

For example:

- We continued to expand our integrity monitoring systems, with the deployment of over 1,000 wireless Permasense sensors in 2011, now spanning all of our BP-operated refineries worldwide. These wireless corrosion sensors are the product of collaborative research and development between BP and Imperial College London. The sensors enable frequent, repeatable wall-thickness monitoring and provide previously unavailable insights into the condition of oil and gas assets.
- In fuels and lubricants, our technology focus is on creating sustainable, differentiated and competitive products that enable advances in transport and industry. We continue to support our partners and customers in delivering greater energy efficiency and reduced CO_2 emissions in both established and emerging markets. In 2011, BP developed a new range of industrial metalworking fluids that are both safer for workers and less harmful to the environment, a new gear lubricant for maximizing the efficiency of wind turbines, and co-engineered passenger car lubricants for optimizing engine fuel efficiency. We are also working on new fuels and lubricants that deliver improved fuel economy and compatibility with the latest engine technology and with biofuel components. In 2011, we launched our latest generation BP Ultimate gasoline and diesel fuels, and BP s first differentiated-performance heavy duty diesel offer.
- In July, we opened a new industrial technology centre in Turin, Italy. It will serve customers across Europe and analyse about 30,000 oil samples a year.
- In petrochemicals, our proprietary processing technologies and operational experience continue to reduce the manufacturing costs and environmental impact of our plants, helping to maintain competitive advantage in purified terephthalic acid (PTA), paraxylene and acetic acid. A third PTA plant is currently being

engineered for Zhuhai, China. With a capacity of 1.25 million tonnes per year it will be the first to employ BP s latest PTA technology, enabling scale and cost efficiencies which significantly reduce both capital and conversion costs to a lower level than any other PTA technology.

In the field of unconventional feedstocks, we collaborate with KBR to promote, market, and license the slurry-bed residue and coal-upgrading Veba combi-cracking (VCC) technology. VCC is a hydrogen-addition technology suitable for processing crude oil residuum into high-quality distillates or synthetic crude oil in the refining, upstream-field upgrading and coal-to-liquids sectors.

Alternative Energy

In Alternative Energy, we are aligning technology capability with future growth platforms, particularly biofuels.

- In addition to our expanding biofuel production business in Brazil, we are developing advanced technologies that will unlock the commercial potential of next generation biofuels. At our technology centre in San Diego, bioscientists are advancing the technology to commercialize cellulosic biofuels and utilizing our large scale demonstration facility in Louisiana to prove the scale-up of proprietary cellulosic technology. In the UK, BP and its partners have constructed a demonstration plant to accelerate commercial-scale production of biobutanol, a highly-efficient fuel molecule.
- Our portfolio of strategic venturing investments aims at putting BP at the forefront in terms of innovation, particularly in developing sustainable energy solutions. Our emerging business and ventures unit brings together BP s venturing and carbon markets expertise with extensive carbon capture and storage capability and through this unit, we have more than 29 separate investments spanning three broad areas: bioenergy, electrification and carbon solutions.

The investments create insights and develop options to grow value for BP, for both its oil and gas assets as well as its low-carbon businesses. They cover a range of specialized innovations and technologies, such as waste-heat recovery, energy storage, carbon funds and land-carbon projects, new solar and bio-energy technologies. For example, we have an investment stake in GMZ Energy, based in the US, which is commercializing materials that allow the efficient conversion of heat to electricity with a thermoelectric device a building block for a new generation of energy-efficient products. The investment gives us insights into the ability of thermoelectric technology to recover low-grade waste heat sources cost-effectively across the group.

Gulf of Mexico oil spill

From response to restoration - summary

Building on the efforts of 2010, BP has continued to demonstrate its commitment to the US federal, state and local governments and communities of the Gulf Coast following the Deepwater Horizon oil spill. BP s efforts in 2011 included:

- Continuing the clean-up of the waters and shorelines impacted across the Gulf of Mexico and the ongoing protection of fish and wildlife.
- Supporting the economic restoration of impacted sectors of the Gulf Coast economy through targeted support to the tourism and seafood industries.
- Continuing the funding of the $20-billion Deepwater Horizon Oil Spill Trust for the purposes of paying all legitimate individual, business, state and local government claims and funding of settlements and Natural Resource Damages (NRD) assessment and restoration activities.
- Progressing the NRD activities in collaboration with the federal and state trustee agencies and progressing both emergency and early restoration activities, including our voluntary commitment of up to $1 billion in early restoration projects.
- Continuing the support of independent long-term research through the Gulf of Mexico Research Initiative (GoMRI) to improve knowledge of the Gulf ecosystem and to better understand and mitigate the potential impacts of oil spills in the region and elsewhere.

Proposed settlement with the Plaintiffs Steering Committee

On 3 March 2012, BP announced that it had reached a settlement with the Plaintiffs Steering Committee (PSC), subject to final written agreement and court approvals, to resolve the substantial majority of legitimate economic loss and medical claims stemming from the Deepwater Horizon accident and oil spill. The PSC acts on behalf of individual and business plaintiffs in the Multi-District Litigation proceedings pending in New Orleans (MDL 2179).

The proposed settlement is comprised of two separate agreements, one to resolve economic loss claims and another to resolve medical claims. Each proposed agreement provides that class members would be compensated for their claims on a claims-made basis, according to agreed compensation protocols in separate court-supervised claims processes. The proposed agreement to resolve economic loss claims includes a BP commitment of $2.3 billion to help resolve economic loss claims related to the Gulf seafood industry and a fund to support continued advertising that promotes Gulf Coast tourism.

BP estimates that the cost of the proposed settlement, expected to be paid from the $20 billion Trust, would be approximately $7.8 billion. This includes the financial commitment for the Gulf seafood industry.

The proposed economic loss settlement provides for a transition from the Gulf Coast Claims Facility (GCCF). A court-supervised transitional claims process for economic loss claims will be in operation while the infrastructure for the new settlement claims process is put in place. During this transitional period, the processing of claims that have been submitted to the GCCF will continue, and new claimants may submit their claims. BP has agreed not to wait for final approval of the economic loss settlement before claims are paid. The economic loss claims process will continue under court supervision before final approval of the settlement, first under the transitional claims process, and then through the settlement claims process established by the proposed economic loss agreement.

This proposed settlement does not include claims against BP made by the United States Department of Justice or other federal agencies (including under the Clean Water Act and for Natural Resource Damages under the Oil Pollution Act) or by the states and local governments. The proposed settlement also excludes certain other claims against BP, such as securities and shareholder claims pending in MDL 2185, and claims based solely on the deepwater drilling moratorium and/or the related permitting process.

For further details, see the Legal proceedings section on pages 160-164.

Completing the response

Throughout 2011, BP, working under the direction of the US Coast Guard s Federal On-Scene Coordinator (FOSC), and collaboratively with individual federal and state entities, continued to complete the Deepwater Horizon operational response activities as described below.

Source control and site remediation

During the first half of 2011, BP completed the decommissioning of all source control equipment including all vessels used in the response. We also completed plugging and abandonment (P&A) of the second relief well and conducted a seabed survey. BP conducted a further site survey of the Macondo wellhead and the two relief wells during the third quarter of 2011. Following these surveys it was determined that no further activity is necessary at the well site.

During the year we continued our efforts to recover and recycle waste material in order to minimize impacts. We also continued or completed the site remediation of multiple locations that were used during the response.

Residual clean-up in the Gulf of Mexico

Since the beginning of the Deepwater Horizon response multi-party Shoreline Clean-up Assessment Technique (SCAT) teams have continuously and systematically surveyed the shoreline to assess oiling conditions and develop shoreline treatment recommendations (STRs), which are implemented at the direction of the FOSC. Over 110,000 miles of aerial reconnaissance flights were conducted across the 11,000 miles of Gulf Coast shoreline. From this surveillance information, the SCAT teams identified more than 4,300 miles for further, ground-based survey. Of the Gulf Coast shoreline, 635 miles required some measure of mechanical or manual cleaning.

During 2011, mechanical or manual cleaning of the majority of the segments was completed. Patrolling and maintenance activities were initiated and will continue until the shoreline segments meet the applicable clean-up standards for the FOSC to determine that operational removal activity is complete. In November 2011, the FOSC also approved the Shoreline Clean-up Completion plan. This plan describes the process whereby the various shoreline segments included in the area of response operations can be surveyed, verified as meeting the applicable clean-up standards, and moved out of operational activity. It is expected that the majority of the 4,300 miles of the Gulf Coast shoreline within the area of response will be deemed operationally complete within 2012.

Environmentally sensitive areas were often hand cleaned. In some areas cleaning was paused at the direction of, or in consultation with, wildlife scientists, to minimize interference with migration patterns or breeding cycles.

The Coast Guard has indicated that if oil is discovered in a segment that has been deemed operationally complete, the Coast Guard will follow long-standing response protocols established under the law and contact whoever it believes is the responsible party or parties.

Response efforts guided by science

At the direction of the FOSC, scientific studies were conducted to study the status of oil and dispersants in the water and sediments of the Gulf. These studies are being used to guide continuing response activities in the near shore environment and to better understand the potential impacts of residual oil. These results have been published in Operational Scientific Advisory Team (OSAT) reports (OSAT-1 and OSAT-2 reports, and a toxicity addendum) and Net Environmental Benefits Analysis reports (NEBAs).

These reports confirmed the appropriateness of the steps taken to remove oil and mitigate the impact on the environment. The OSAT-2 report determined that further efforts, beyond guidelines established by the FOSC to remove the residual oil from the shoreline, could potentially pose a greater risk to the environment than allowing the residual oil to degrade naturally.

To assess the potential impacts on fauna, the FOSC directed the OSAT scientists to conduct a comprehensive toxicity study. The report, which was an addendum to the OSAT-1 report, was issued on 8 July 2011. Of the approximately 3,500 toxicity tests conducted, 90% showed no statistically significant effects on wildlife.

At the request of the FOSC, several NEBA studies and specialized activities were carried out, including an effort to detect anchors that had been deployed during the response to keep containment boom in place. Based on the NEBA results, the NEBA team recommended that the FOSC let the anchors remain in place to allow them to degrade through natural processes.

Economic restoration

BP continued to support economic recovery in local communities through a variety of actions and programmes in 2011.

Deepwater Horizon Trust activity

BP has established the Deepwater Horizon Oil Spill Trust (the Trust) in the amount of $20 billion to be used in compensating individuals, businesses, government entities and others who have been impacted by the oil spill. The Trust provides funds to satisfy legitimate state and local government claims resolved by BP, final judgments and settlements, legitimate state and local response costs, natural resource damages and related costs, and legitimate individual and business claims administered by the GCCF, which has been managed by Kenneth Feinberg. The proposed economic loss settlement announced on 3 March 2012 with the Plaintiffs Steering Committee on MDL 2179 provides for a transition from the GCCF. A court-supervised transitional claims process for economic loss claims will be in operation while the infrastructure for the new settlement claims process is put in place. During this transitional period, the processing of claims that have been submitted to the GCCF will continue and new claimants may submit their claims. The establishment of the Trust does not represent a cap or floor on BP s liabilities and BP does not admit to a liability of this amount.

In 2011, $1 billion was voluntarily set aside in the Trust for NRD early restoration projects. BP is working with federal and state trustees to select appropriate projects that will enhance habitats, wildlife and access for recreational use.

As at 31 December 2011, BP s cumulative contributions to the Trust amounted to $15.1 billion since its inception, including our second-year commitment of $5 billion and a total of $5.1 billion cash settlements received during 2011 from MOEX USA Corporation (MOEX), Weatherford US., L.P. (Weatherford), and Anadarko Petroleum Corporation (Anadarko). The remaining committed contributions as at 31 December 2011 totalling $4.9 billion are scheduled to be made by the end of 2012. In January 2012, we contributed to the Trust the $250 million settlement received from Cameron International Corporation (Cameron). The Trust disbursed $3.7 billion in 2011 and the total paid out since its establishment amounted to $6.7 billion by the end of 2011.

Claims payments

All payments that were made in 2011 for legitimate claims by individuals, businesses and government entities were paid from the Trust. During the year, individuals and businesses received $3.1 billion in payments through the GCCF. More than 189,000 individual and business claimants accepted full and final settlements, while about 33,000 received interim payments. Since May 2010, more than $6.2 billion has been paid to individuals and businesses through the claims process, with the Trust paying $5.8 billion of this and BP paying the remainder prior to the establishment of the Trust.

Government entities received more than $40 million in claims payments during 2011. Nearly 60 loss-of-revenue claims have been paid to government entities since May 2010. By the end of 2011, BP had resolved over 90% of government claims filed.

During 2011, BP paid a total of $7.7 million to vessel owners whose vessels were involved in clean-up and protection activities as part of the Vessels of Opportunity (VoO) programme. In an effort to ensure fairness, BP instructed the external adjusters to broaden the original compensation guidelines. Once the new guidelines were established, adjusters have and are continuing to re-examine property damage claims from about 1,200 vessel owners, whose property-damage claims had previously been denied or partially paid to ensure that property damages reported by claimants have been adequately addressed.

Promoting tourism along the Gulf Coast

To support economic restoration in the impacted Gulf Coast communities, BP entered into three-year agreements with the states of Alabama, Florida, Louisiana and Mississippi to promote tourism, monitor seafood safety and promote Gulf seafood.

During 2011, BP made commitments of $92 million in total over three years to support tourism promotion within the four affected states. This is in addition to $87 million in tourism grants provided by BP in 2010. Each state is using its tourism funds to develop specific marketing programmes.

The proposed settlement announced on 3 March 2012 with the Plaintiffs Steering Committee in MDL 2179 includes a fund to support continued advertising that promotes Gulf Coast tourism.

Seafood testing, monitoring and promotion

Federal and state officials continue to collect and test seafood from the Gulf of Mexico, and the results of these tests have indicated that Gulf of Mexico seafood meets the US Food and Drug Administration (FDA) safety guidelines. The National Oceanic and Atmospheric Administration (NOAA) and the FDA are conducting widespread scientific evaluation of seafood samples to protect and reassure consumers. Since May 2010, more than 6,000 seafood samples have been collected by the FDA, NOAA, and state agencies in Louisiana, Mississippi, Alabama, and Florida. The FDA has also visited over 100 seafood processors and wholesalers across the Gulf Coast, collecting seafood samples and inspecting processing plants for biological, chemical, and physical hazards. Levels of residues of oil contamination in seafood have consistently tested between 100 and 1,000 times lower than the safety thresholds established by the FDA. Test results from NOAA, the FDA, and the Gulf of Mexico states are publicly available.

Recreational fishing showed signs of recovery in 2011. To raise public awareness of Gulf of Mexico seafood, BP has committed $34 million for Gulf of Mexico states to conduct seafood testing and $48 million to market Gulf of Mexico seafood.

Rig Worker Assistance Fund

BP established a $100-million Rig Worker Assistance Fund through the Baton Rouge Area Foundation (the Foundation) to support unemployed rig workers experiencing economic hardship as a result of the moratorium on deepwater drilling imposed by the US federal government. In 2011, the Foundation awarded $5.8 million to an expanded pool of applicants, after awarding $5.6 million to nearly 350 rig workers in 2010. With less than 2,000 applying for funds, the Foundation granted $18 million of the BP contribution to community-based organizations through its Future for the Gulf Fund. At the end of 2011, the Foundation was assessing additional funding requests from organizations assisting those impacted by the spill, and has said it hopes to complete the distribution of the BP contribution by the end of 2012.

Environmental restoration

We made progress during 2011 on multiple fronts as part of the ongoing efforts to assess and address injury to natural resources in the Gulf of Mexico.

We continued to support and participate in the Natural Resource Damages (NRD) process. Work has been completed or is under way on more than 150 cooperative studies with federal and state agencies to gather data on potential impacts and injuries to birds, turtles and mammals; fish and shell fish; near shore and shoreline habitats; and the Gulf of Mexico water column and sediment.

We also worked with the Natural Resource Damage Assessment (NRDA) trustees to begin assessing the potential lost human use of these Gulf Coast natural resources. Additional studies focused on the potential impacts on historical and archaeological resources and endangered species.

During the year we also supported two emergency restoration projects and made a major commitment to fund early restoration projects. In addition, the National Fish and Wildlife Foundation funded several projects during 2011 using funds provided by BP in 2010 from the sale of oil recovered from the spill.

We are working with NOAA to prepare and provide access to summaries of the studies completed and data gathered during the cooperative assessment process. We also prepared and participated

in a variety of scientific publications and seminars as part of our efforts to share learnings from the oil spill as broadly as possible.

NRD process under way

In 2011, we continued to work with scientists and trustee agencies through the NRD process to identify natural resources that may have been exposed to oil or otherwise impacted by the incident, and to look for evidence of injury.

As part of the NRD process, trustees from each state and the federal government held a series of public meetings during 2011 in each of the five states affected by the Deepwater Horizon oil spill. These focused on the status of potential injury assessments and of potential restoration process. To date, BP has paid over $600 million for NRD assessment efforts.

Public comments were collected as part of the Programmatic Environmental Impact Statement (PEIS) process, which will inform one of the core planning documents for restoration. A final PEIS is scheduled to be released by the trustees in late 2012.

Emergency restoration projects

Emergency restoration projects are defined under the Oil Pollution Act of 1990 (OPA 90) as preventative measures or actions undertaken to stop continuing injuries to resources and to mitigate potential effects of the spill. During 2011, two emergency restoration projects were completed along the Gulf Coast in support of birds and turtles. A third project is in the planning phase for submerged aquatic vegetation and is scheduled to be implemented in 2012.

Early restoration projects

Under an agreement signed with federal and state trustees in April 2011, BP voluntarily committed to provide up to $1 billion to fund projects that will accelerate restoration efforts in Gulf Coast areas that were impacted by the Deepwater Horizon oil spill.

The agreement enables work on restoration projects to begin at the earliest opportunity, before all of the studies under the NRDA process are complete, and before funding is required by OPA 90. Priority will be assigned to projects aimed at improving areas that offer the greatest benefits to wildlife, habitat, and recreational use that were impacted as a result of the incident.

In December 2011, state and federal trustees unveiled the first set of early environmental restoration projects that are proposed for funding under the agreement. The eight proposed projects are located in Alabama, Florida, Louisiana and Mississippi. Collectively, the projects will restore and enhance wildlife, habitats, the ecosystem services provided by those habitats, and provide additional access for fishing, boating and related recreational uses. More early restoration projects are anticipated in the future.

Funding for the early restoration projects will come from the $20-billion Trust. Additional information about the projects, projected costs and proposed credits can be found on the NOAA website.

Environmental studies and reports

BP is committed to sharing and providing access to the numerous studies and reports generated during the course of the response. In total, since May 2010, more than 150 NRDA studies have been completed or are in progress throughout the Gulf. As the studies are completed, summaries are expected to be published as appropriate either on BP s website or on government websites. Our website also contains numerous technical reports and documentation on a variety of environmental and health-related topics.

National Fish and Wildlife Foundation projects

In 2010, BP donated $22 million from the net revenue of the sale of oil recovered from the spill to the US National Fish and Wildlife Foundation (NFWF) which used the funds to quickly implement several conservation projects along the Gulf Coast.

In 2011, the NFWF announced that it issued $6.9 million in grants from the Recovered Oil Fund for Wildlife for 22 new projects. The grants, which were supplemented by a further $3.3 million from other contributors, were awarded for projects designed to:

- Improve sea turtle hatchling success across 56 miles of priority Florida beaches.
- Increase the capacity of marine mammal and sea turtle treatment facilities.
- Restore a combined 3.5 miles of oyster reefs, which in turn protect sensitive coastal habitat.
- Reduce the incidence of sea turtles being caught in the course of recreational and commercial fishing.

Commitment to long-term oil spill research

In 2010, BP committed $500 million over 10 years to fund independent scientific research through the Gulf of Mexico Research Initiative (GoMRI). The research will improve knowledge of the Gulf ecosystem and help the industry and others to better understand and mitigate the impact of oil spills in the region and elsewhere.

In June 2011, the GoMRI Research Board awarded 17 grants totalling $1.5 million to support scientists as they continue time-sensitive data collection. In August 2011, the Research Board awarded a total of $112.5 million over three years to eight consortia comprised of over 70 research institutions. All eight consortia are led by Gulf Coast institutions. Research recipients will use the grants to investigate the fate of oil released by the spill, and for the development of new tools and technology for responding to future spills and improving mitigation and restoration.

In December 2011, the GoMRI Research Board also issued a request for proposals (RFP) for approximately $7.5 million per year for three years, in smaller grants to individual or small teams of researchers.

Rebuilding trust through effective communications

During 2011, we worked to engage, inform and communicate with a wide range of stakeholders throughout the region. We supported community events and we shared information on a variety of issues and concerns with individuals, community organizations, business leaders, elected officials, non-governmental organizations and the news media.

Financial update

Profit before tax for the group includes a pre-tax credit of $3.8 billion and finance costs of $0.1 billion in relation to the Gulf of Mexico oil spill. The pre-tax credit reflects $5.5 billion in relation to settlements reached with MOEX, Weatherford, Anadarko and Cameron, partially offset by further costs associated with the ongoing spill response, adjustments to provisions, and an increase in the amount provided for legal fees, as well as functional expenses of BP s Gulf Coast Restoration Organization (GCRO).

Provisions were established during 2010 for the environmental expenditure, spill response costs, litigation and claims, and Clean Water Act (CWA) penalties. Most of the costs incurred in 2011 were covered by these existing provisions. Pre-tax charges were recorded in 2011 of $0.4 billion for the functional expenses of the GCRO, $1.1 billion for increases in the amounts provided, primarily related to spill response costs and legal fees, a $0.1 billion finance charge for unwinding of discount on provisions, and $0.1 billion for spill response costs charged directly to the income statement. These charges partially offset the $5.5 billion credit for settlements reached during the year.

As at 31 December 2011, the cumulative charges for provisions to be paid from the Trust and the associated reimbursement asset recognized amounted to $16.6 billion. This represented an increase of $4.0 billion in the provisioned amounts during 2011, primarily for the $2.1 billion expected impact of the proposed settlement announced on 3 March 2012 with the Plaintiffs Steering Committee in MDL 2179, the $1-billion commitment to NRD early restoration and new provisions for personal injury and death claims and Vessel of Opportunity programme claims. A further $3.4 billion could be provided in subsequent periods for items covered by the Trust, with no net impact on the income statement.

BP has provided for all potential liabilities that can be estimated reliably at this time, including fines and penalties under the CWA. The total amounts that will ultimately be paid by BP in relation to all obligations relating to the incident are subject to significant uncertainty.

BP considers that it is not possible to estimate reliably any obligation in relation to NRD claims under OPA 90 (other than the estimated costs of the assessment phase and the costs relating to emergency restoration and the $1 billion agreement for early restoration), any amounts in relation to fines and penalties except for those relating to the CWA and litigation arising from alleged violations of OPA 90. These items are therefore contingent liabilities.

BP holds a 100% interest in the Macondo well, with the lease interests previously held by MOEX and Anadarko now assigned to BP as part of the settlement agreements. MOEX paid BP $1.1 billion in cash and Anadarko paid BP $4 billion in cash to settle all outstanding claims between the companies related to the incident and to the prospect.

For details regarding the impacts and uncertainties relating to the Gulf of Mexico oil spill refer to Financial statements Note 2 on page 190, Note 36 on page 231 and Note 43 on page 249. See also Risk factors on page 59 and Proceedings and investigations relating to the Gulf of Mexico oil spill on pages 160-164.

Legal proceedings and investigations

See Legal proceedings on pages 160-164 for a full discussion of legal proceedings and investigations relating to the incident.

Exploration and Production

At the end of 2010, as part of our response to the Deepwater Horizon oil spill, we announced the decision to reorganize the Exploration and Production segment to create three separate divisions: Exploration, Developments and Production, integrated through a Strategy and Integration organization. This structure was established in March 2011 and each of the four parts is led by an executive vice president reporting directly to the group chief executive. The new organization is designed to change the way we operate, with a particular focus on managing risk, delivering common standards and processes and building technical capability. The new organization has not changed the way we report our operating segments under IFRS.

The Exploration division is accountable for renewing our resource base through access, exploration and appraisal. The Developments division is accountable for the safe and compliant execution of wells (drilling and completions) and major projects and comprises the global wells organization and the global projects organization, which were established in 2011. The Production division is accountable for safe and compliant operations, including upstream production assets, midstream transportation and processing activities, and the development of our resource base. Divisional activities are integrated on a regional basis by a regional president reporting to the Production division. The Strategy and Integration organization is accountable for optimization and integration across the divisions, including the delivery of support from the group s finance, procurement and supply chain, human resources, technology and information technology functions.

From 1 January 2012, the group s investment in TNK-BP will be reported as a separate operating segment, rather than within the Exploration and Production segment, reflecting the way in which the investment is now managed.

The group safety and operational risk (S&OR) function maintains our global safety standards. S&OR staff are deployed at the operating level within the Exploration and Production segment to support the systematic and disciplined application of those standards. This creates an independent reporting line, working alongside line management while having the power to intervene.

Our Exploration and Production segment included upstream and midstream activities in 30 countries in 2011, including Angola, Azerbaijan, Brazil, Canada, Egypt, India, Iraq, Norway, Russia, Trinidad & Tobago (Trinidad), the UK, the US and other locations within Africa, Asia, Australasia and South America, as well as gas marketing and trading activities, primarily in Canada, Europe and the US. Upstream activities involve oil and natural gas exploration, field development and production. Our exploration and appraisal programme is currently focused on Angola, Australia, Azerbaijan, Brazil, Canada, Egypt, the deepwater Gulf of Mexico, the UK North Sea, Oman and onshore US. Major development areas include Angola, Australia, Azerbaijan, Canada, Egypt, the deepwater Gulf of Mexico, North Africa, and the UK North Sea. During 2011, production came from 24 countries. The principal areas of production are Angola, Argentina, Azerbaijan, Egypt, Russia, Trinidad, the UAE, the UK and the US.

Midstream activities involve the ownership and management of crude oil and natural gas pipelines, processing facilities and export terminals, LNG processing facilities and transportation, and our NGL extraction businesses in Canada, Indonesia, the US and the UK. Our most significant midstream pipeline interests are the Trans-Alaska Pipeline System in the US; the Forties Pipeline System and the Central Area Transmission System pipeline, both in the UK sector of the North Sea; the South Caucasus Pipeline, which runs from Azerbaijan through Georgia to the Turkish border; and the Baku-Tbilisi-Ceyhan pipeline, which runs through Azerbaijan, Georgia and Turkey. Major LNG activities are located in Australia, Indonesia and Trinidad. BP is also investing in the LNG business in Angola.

Additionally, our activities include the marketing and trading of natural gas, power and natural gas liquids. These activities provide routes into liquid markets for BP s produced gas, and generate margins and fees associated with the provision of physical products and derivatives to third parties and income from asset optimization and trading.

Our oil and natural gas production assets are located onshore and offshore and include wells, gathering centres, in-field flow lines, processing facilities, storage facilities, offshore platforms, export systems (e.g. transit lines), pipelines and LNG plant facilities.

Upstream operations in Abu Dhabi, Argentina, Bolivia, Chile, Russia, Venezuela and Vietnam as well as some of our operations in Angola, Canada, Indonesia and Trinidad are conducted through equity-accounted entities.

Our market

Energy demand, and in particular oil demand, has followed overall economic trends in recent years, recovering strongly in 2010 but facing more challenging conditions in 2011.

Dated Brent for the year averaged $111.26 per barrel, 40% above 2010 s average of $79.50 per barrel. In 2012, we expect oil price movements to continue to be driven by the pace of global economic growth and its resulting implications for oil consumption, and by OPEC production decisions.

Natural gas prices diverged globally in 2011, reflecting different regional dynamics. The average US Henry Hub First of Month Index fell to $4.04/mmBtu, an 8% decrease from 2010, while in Europe prices increased. Spot gas prices at the UK National Balancing Point increased by 33% to an average of $56.33 pence per therm for 2011.

After a record increase in 2010, global gas consumption growth moderated in 2011. In the US, economic momentum supported gas use in the first half of the year and a hot summer raised demand. Yet domestic production outpaced consumption growth due to further increases in the availability of shale gas.

In 2012, we expect gas markets to continue to be driven by the economy, weather, domestic production, LNG supply and reductions in nuclear power generation following the Fukushima disaster in Japan in March 2011.

Our strategy

In Exploration and Production, our highest priority is to ensure safe, reliable and compliant operations worldwide. Our strategy is to invest to grow long-term value by continuing to build a portfolio of material, enduring positions in the world s key hydrocarbon basins with a focus on deepwater, gas value chains and giant fields. Our strategy is enabled by:

- A continued focus on safety and managing risk.
- Strong relationships built on mutual advantage, deep knowledge of the basins in which we operate, and technology.
- Building capability along the value chain in Exploration, Developments and Production.
- Actively managing our portfolio.

We intend to increase investment with a focus on Exploration, a key source of value creation, and evolve the nature of our relationships, particularly with national oil companies.

Our performance

Key statistics

			$ million
	2011	2010	2009
Sales and other operating revenues[a]	**75,475**	66,266	57,626
Replacement cost profit before interest and tax	**30,500**	30,886	24,800
Capital expenditure and acquisitions	**25,535**	17,753	14,896
			$ per barrel
Average BP crude oil realizations[b]	**107.91**	77.54	59.86
Average BP NGL realizations[b]	**51.18**	42.78	29.60
Average BP liquids realizations[b c]	**101.29**	73.41	56.26
Average West Texas Intermediate oil price[d]	**95.04**	79.45	61.92
Average Brent oil price[d]	**111.26**	79.50	61.67
			$ per thousand cubic feet
Average BP natural gas realizations[b]	**4.69**	3.97	3.25
Average BP US natural gas realizations[b]	**3.34**	3.88	3.07
			$ per million British thermal units
Average Henry Hub gas price[e]	**4.04**	4.39	3.99
			pence per therm
Average UK National Balancing Point gas price[d]	**56.33**	42.45	30.85
			thousand barrels per day
Liquids production for subsidiaries[c f]	**992**	1,229	1,400
Liquids production for equity-accounted entities[c f]	**1,165**	1,145	1,135
Total of subsidiaries and equity-accounted entities[c f]	**2,157**	2,374	2,535
			million cubic feet per day
Natural gas production for subsidiaries[f]	**6,393**	7,332	7,450
Natural gas production for equity-accounted entities[f]	**1,125**	1,069	1,035
Total of subsidiaries and equity-accounted entities[f]	**7,518**	8,401	8,485
			thousand barrels of oil equivalent per day
Total production for subsidiaries[f g]	**2,094**	2,492	2,684
Total production for equity-accounted entities[f g]	**1,360**	1,330	1,314
Total of subsidiaries and equity-accounted entities[f g]	**3,454**	3,822	3,998
			million barrels
Estimated net proved crude oil reserves for subsidiaries[c h]	**5,153**	5,559	5,658
Estimated net proved crude oil reserves for equity-accounted entities[c i]	**5,234**	4,971	4,853
Estimated net proved bitumen reserves for equity-accounted entities	**178**	179	
Total of subsidiaries and equity-accounted entities[c h i]	**10,565**	10,709	10,511
			billion cubic feet
Estimated net proved natural gas reserves for subsidiaries[j]	**36,381**	37,809	40,388
Estimated net proved natural gas reserves for equity-accounted entities[k]	**5,278**	4,891	4,742
Total of subsidiaries and equity-accounted entities[j k]	**41,659**	42,700	45,130
			million barrels of oil equivalent
Estimated net proved reserves for subsidiaries[h j]	**11,426**	12,077	12,621
Estimated net proved reserves for equity-accounted entities[i k]	**6,322**	5,994	5,671
Total of subsidiaries and equity-accounted entities[h i j k]	**17,748**	18,071	18,292

a Includes sales between businesses.
b Realizations are based on sales of consolidated subsidiaries only, which excludes equity-accounted entities.
c Crude oil and natural gas liquids.
d All traded days average.
e Henry Hub First of Month Index.
f Net of royalties.
g Expressed in thousands of barrels of oil equivalent per day (mboe/d). Natural gas is converted to oil equivalent at 5.8 billion cubic feet = 1 million barrels.
h Includes 20 million barrels (22 million barrels at 31 December 2010 and 23 million barrels at 31 December 2009) in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

i Includes 310 million barrels (254 million barrels at 31 December 2010 and 243 million barrels at 31 December 2009) in respect of the 7.37% minority interest in TNK-BP (7.03% at 31 December 2010 and 6.86% at 31 December 2009).

j Includes 2,759 billion cubic feet of natural gas (2,921 billion cubic feet at 31 December 2010 and 3,068 billion cubic feet at 31 December 2009) in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

k Includes 174 billion cubic feet (137 billion cubic feet at 31 December 2010 and 131 billion cubic feet at 31 December 2009) in respect of the 6.27% minority interest in TNK-BP (7.03% at 31 December 2010 and 6.86% at 31 December 2009).

2011 performance

Safety and operational risk

In Exploration and Production, ensuring safe, reliable and compliant operations remains our highest priority. The organizational and governance changes in Exploration and Production and S&OR have been designed to ensure we achieve this, supported by a systematic framework provided by BP s operating management system (OMS). All Exploration and Production operated businesses, with the exception of those recently acquired, are now applying our OMS to govern their BP operations and have begun working to achieve conformance to standards and practices required by OMS through the performance improvement cycle process. We continue to work to enhance local systems and processes at all our sites. *See Safety on pages 65-66 for more information on OMS.*

Safety performance is monitored by a suite of input and output metrics which focus on personal and process safety including operational integrity, occupational health and all aspects of compliance.

In 2011, there were no workforce fatalities in Exploration and Production. In 2010, there was one workforce fatality.

The recordable injury frequency (RIF), which measures the number of recordable injuries to the BP workforce per 200,000 hours worked, was 0.30. This is lower than 2010 when it was 0.32 and 2009 when it was 0.39. Our day away from work case frequency (DAFWCF) in 2011 was 0.060. This is lower than 2010 when it was 0.063 but higher than 2009 when it was 0.038.

In 2011, the number of reported loss of primary containment (LOPC) incidents in Exploration and Production was 152, down from 194 in 2010. The number of reported oil spills equal to or larger than 1 barrel during 2011 was 71, down from 117 in 2010.

Financial and operating performance

We continually seek access to resources and in 2011, in addition to new access resulting from acquisitions as detailed on page 83, this included Angola, where BP gained access to five new deepwater exploration and production blocks covering 24,200km^2; Australia, where BP was awarded four blocks covering 24,500km^2 in the Ceduna Sub Basin off the coast of South Australia; Azerbaijan, where the republic of Azerbaijan ratified the Shafag-Asiman production-sharing agreement (PSA) covering 1,100km^2 in the Caspian Sea; China, where BP was awarded access to a 9,700km^2 block in the South China Sea; deepwater Gulf of Mexico, where 12 leases from the March 2010 Outer Continental Shelf Lease Sale 213 covering 280km^2 were executed; Indonesia, where BP was awarded four coalbed methane PSAs covering 4,800km^2 in the Barito basin of South Kalimantan and two oil and gas PSAs covering 16,400km^2 offshore in the Arafura Sea; and Trinidad, where BP was awarded two deepwater blocks covering 3,600km^2, subject to government approval.

In September 2011, we announced the Moccasin oil discovery in the deepwater Gulf of Mexico (not BP-operated). In October 2011, we announced the Salmon gas discovery in Egypt s Nile Delta. In 2011, we took final investment decisions on three projects and two major projects came onstream: Serrette in Trinidad and Pazflor in Angola.

Production for 2011 was lower than last year. After adjusting for the effect of entitlement changes in our PSAs and the effect of acquisitions and disposals, underlying production was 7% lower than 2010. This primarily reflects lower Gulf of Mexico production as a result of the impact of the drilling moratorium as well as the impact of turnaround maintenance activities. In 2011, full-year production growth in TNK-BP was 2.8%.

Sales and other operating revenues for 2011 were $75 billion, compared with $66 billion in 2010 and $58 billion in 2009. The increase in 2011, compared with 2010, primarily reflected higher oil and gas realizations, partly offset by lower production. The increase in 2010, compared with 2009, primarily reflected higher oil and gas realizations, partly offset by lower production.

The replacement cost profit before interest and tax for 2011 was $30,500 million, compared with $30,886 million for the previous year. 2011 included net non-operating gains of $1,130 million, primarily a result of gains on disposals being partly offset by impairments, a charge associated with the termination of our agreement to sell our 60% interest in Pan American Energy LLC (PAE) to Bridas Corporation and other non-operating items. (*See page 58 for further information on non-operating items.*) In addition, fair value accounting effects had a favourable impact of $11 million relative to management s measure of performance. (*See page 58 for further information on fair value accounting effects.*)

The primary additional factors contributing to the 1% decrease in replacement cost profit before interest and tax were higher realizations partially offset by lower production volumes (including in higher margin areas), rig standby costs in the Gulf of Mexico, higher costs related to turnarounds, certain one-off costs and higher exploration write-offs.

Total capital expenditure including acquisitions and asset exchanges in 2011 was $25.5 billion (2010 $17.8 billion and 2009 $14.9 billion). (*See page 83 for further information on acquisitions.*)

Development expenditure of subsidiaries incurred in 2011, excluding midstream activities, was $10.2 billion, compared with $9.7 billion in 2010 and $10.4 billion in 2009.

Provisions for decommissioning increased from $10.5 billion at the end of 2010 to $17.2 billion at the end of 2011. The increase reflects higher cost estimates, which are in part driven by new requirements in the Gulf of Mexico. Decommissioning costs are initially capitalized within fixed assets and are subsequently depreciated as part of the asset.

Prior years comparative financial information

The replacement cost profit before interest and tax for the year ended 31 December 2010 of $30,886 million included net non-operating gains of $3,199 million, comprised primarily of gains on disposals that completed during the year partly offset by impairment charges and fair value losses on embedded derivatives. In addition, fair value accounting effects had an unfavourable impact of $3 million relative to management s measure of performance.

The replacement cost profit before interest and tax for the year ended 31 December 2009 of $24,800 million included a net credit for non-operating items of $2,265 million, with the most significant items being gains on the sale of operations (primarily from the disposal of our 46% stake in LukArco, the sale of our 49.9% interest in Kazakhstan Pipeline Ventures LLC and the sale of BP West Java Limited in Indonesia) and fair value gains on embedded derivatives. In addition, fair value accounting effects had a favourable impact of $919 million relative to management s measure of performance.

The primary additional factor contributing to the 25% increase in the replacement cost profit before interest and tax for the year ended 31 December 2010 compared with the year ended 31 December 2009 were higher realizations, lower depreciation and higher earnings from equity-accounted entities, partly offset by lower production, a significantly lower contribution from gas marketing and trading and higher production taxes.

Outlook

In 2012, we will continue to drive operational risk reduction through the new Exploration and Production segment structure, supported by the S&OR function. Our divisions will work to manage risk and deliver common standards, driving functional excellence across the lifecycle of exploration, development and production, while continuing to focus on building our technical capability for the future. We believe that our portfolio of assets remains well positioned to compete and grow value in a range of external conditions and we continue to increase both investment and operating cash. We expect production in 2012 to be broadly flat, normalizing for divestments and price effects, and excluding TNK-BP. This is the net effect of growth from new projects and new production from India and Brazil being offset by normal base decline. In 2012, we intend to drill 12 exploration wells, start up six major projects, and increase our activity in the Gulf of Mexico to eight operational rigs, subject to approvals by US regulators.

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.

In 2011, our exploration and appraisal costs, excluding lease acquisitions, were $2,398 million, compared with $2,706 million in 2010 and $2,805 million in 2009. These costs included exploration and appraisal drilling expenditures, which were capitalized within intangible fixed assets, and geological and geophysical exploration costs, which were charged to income as incurred. Approximately 76% of 2011 exploration and appraisal costs were directed towards appraisal activity. In 2011, we participated in 308 gross (73.33 net) exploration and appraisal wells in nine countries. The principal areas of exploration and appraisal activity were Angola, Australia, Azerbaijan, Brazil, Canada, Egypt, the deepwater Gulf of Mexico, the UK North Sea, Oman and onshore US.

Total exploration expense in 2011 of $1,520 million (2010 $843 million and 2009 $1,116 million) included the write-off of expenses related to unsuccessful drilling activities in the deepwater Gulf of Mexico ($284 million), Asia Pacific ($61 million) and others ($5 million). It also included $14 million related to decommissioning of idle infrastructure, as required by the Bureau of Ocean Energy Management Regulation and Enforcement s Notice of Lessees 2010 G05 issued in October 2010.

Reserves booking from new discoveries will depend on the results of ongoing technical and commercial evaluations, including appraisal drilling.

Proved reserves replacement

Total hydrocarbon proved reserves, on an oil equivalent basis including equity-accounted entities, comprised 17,748mmboe (11,426mmboe for subsidiaries and 6,322mmboe for equity-accounted entities) at 31 December 2011, a decrease of 2% (decrease of 5% for subsidiaries and increase of 5% for equity-accounted entities) compared with the 31 December 2010 reserves of 18,071mmboe (12,077mmboe for subsidiaries and 5,994mmboe for equity-accounted entities). Natural gas represented about 40% (55% for subsidiaries and 14% for equity-accounted entities) of these reserves. The change includes a net decrease from acquisitions and disposals of 361mmboe (218mmboe net decrease for subsidiaries and 143mmboe net decrease for equity-accounted entities). Acquisitions occurred in Brazil, Canada, India, the UK, the US, Venezuela and Vietnam. Divestments occurred in Algeria, Azerbaijan, Canada, Colombia, Pakistan, Trinidad, the US, the UK, Venezuela and Vietnam.

The proved reserves replacement ratio is the extent to which production is replaced by proved reserves additions. This ratio is expressed in oil equivalent terms and includes changes resulting from revisions to previous estimates, improved recovery and extensions and discoveries. For 2011, the proved reserves replacement ratio excluding acquisitions and disposals was 103% (106% in 2010 and 129% in 2009) for subsidiaries and equity-accounted entities, 45% for subsidiaries alone and 194% for equity-accounted entities alone. The 2011 reserves additions for TNK-BP include the effect of moving from life-of-licence measurement to life-of-field measurement, reflecting TNK-BP s track record of successful licence renewal. Excluding this effect, our 2011 reserves replacement ratio excluding acquisitions and disposals would have been 83%.

In 2011, net additions to the group s proved reserves (excluding production and sales and purchases of reserves-in-place) amounted to 1,320mmboe (348mmboe for subsidiaries and 972mmboe for equity-accounted entities), through revisions to previous estimates, improved recovery from, and extensions to, existing fields and discoveries of new fields. Of our subsidiary reserves additions through improved recovery from, and extensions to, existing fields and discoveries of new fields, approximately 26% were associated with new projects and were proved undeveloped reserves additions. The remaining additions were in existing developments where they represented a mixture of proved developed and proved undeveloped reserves. Volumes added in 2011 principally relied on the application of conventional technologies. The principal reserves additions in our subsidiaries were in the US (San Juan North, Mad Dog, Ursa, Prudhoe Bay, Hawkville), Trinidad (Cashima, Juniper) and Indonesia (Tangguh). The principal reserves additions in our equity-accounted entities were in Russia (Orenburg, Slavneft, Verkhnechonskoye, Uvat, Talinskoye), Venezuela (Petromonagas) and Argentina (Cerro Dragon).

Twelve per cent of our proved reserves are associated with PSAs. The countries in which we operated under PSAs in 2011 were Algeria, Angola, Azerbaijan, Egypt, India, Indonesia, Oman, Trinidad and Vietnam. In addition, the technical service contract (TSC) under which we operate in Iraq functions as a PSA.

Production

Our total hydrocarbon production during 2011 averaged 3,454 thousand barrels of oil equivalent per day (mboe/d). This comprised 2,094mboe/d for subsidiaries and 1,360mboe/d for equity-accounted entities, a decrease of 16% (decreases of 19% for liquids and 13% for gas) and an increase of 2% (increases of 2% for liquids and 5% for gas) respectively compared with 2010. In aggregate, after adjusting for entitlement impacts in our PSAs and the effect of acquisitions and disposals, production was 7% lower than 2010. For subsidiaries, 37% of our production was in the US, 20% in Trinidad and 8% in the UK.

The group and its equity-accounted entities have numerous long-term sales commitments in their various business activities, all of which are expected to be sourced from supplies available to the group that are not subject to priorities, curtailments or other restrictions. No single contract or group of related contracts is material to the group.

Acquisitions and disposals

During 2011, we undertook a number of acquisitions and disposals. In total, disposal transactions generated $1.1 billion in proceeds during 2011 including repayment of the $3.5 billion disposal deposit relating to Pan American Energy. *See Financial statements Note 5 on page 197*. With regards to proved reserves, 211mmboe were acquired in 2011 (approximately 94mmboe for subsidiaries and approximately 117mmboe for equity-accounted entities), while 572mmboe were disposed of (approximately 312mmboe for subsidiaries and approximately 260mmboe for equity-accounted entities).

Acquisitions

- On 24 January 2011, BP exercised a preferential right to acquire Shell s working interest in the Marlin and Dorado producing fields in the Gulf of Mexico for a total consideration of $257 million. This brought BP s working interest in both fields to 100%.
- On 12 May 2011, BP completed the purchase of 10 exploration and production blocks in Brazil from Devon Energy, concluding the agreement announced in 2010.
- On 30 August 2011, BP completed its acquisition from Reliance Industries Limited (RIL) of a 30% stake in 21 oil and gas PSAs that RIL operates in India for an aggregate consideration of $7.0 billion. In November 2011, the two companies formed a 50:50 joint venture for the sourcing and marketing of gas in India. *See India for further information on page 87.*

Disposals

- On 24 January 2011, following the approval of the Colombian authorities, BP completed the sale of its oil and gas exploration, production and transportation business in Colombia to a consortium of Ecopetrol, Colombia s national oil company, and Talisman of Canada. The sale had been announced in August 2010.
- On 22 February 2011, BP announced its intention to sell its interests in a number of operated oil and gas fields in the UK including the Wytch Farm onshore oilfield in Dorset and all of BP s operated gas fields in the southern North Sea, including associated pipeline infrastructure and the Dimlington terminal. The sale of Wytch Farm to Perenco UK Limited completed on 14 December 2011 for consideration of up to $610 million in cash, which includes $55 million contingent on Perenco s future development of the Beacon field and on oil prices in 2011-2013. A sale of the southern North Sea assets has yet to be concluded. The assets do not yet meet the criteria to be reclassified as non-current assets held for sale and it is not yet possible to estimate the financial effect of the intended disposal of these assets.
- In April 2011, the Wattenberg Plant in Colorado was divested to Anadarko for $575 million.
- In April 2011, an exchange agreement was signed with Bluestone Natural Resources, LLC for the divestment of a mature gas field in South Texas in exchange for acreage in a non-operated property in Eagle Ford.
- In June 2011, BP completed the sale of its upstream businesses in Venezuela to TNK-BP.
- On 5 July 2011, BP sold half of the 3.29% interest in the Azeri-Chirag-Gunashli development in the Caspian Sea which had been acquired from Devon Energy in 2010 to Azerbaijan (ACG) Limited, an affiliate wholly owned and controlled by the State Oil Company of the Republic of Azerbaijan (SOCAR) for $485 million.
- On 16 September 2011, the sale of BP s upstream assets in Pakistan to United Energy Group (UEG) was completed. UEG has now assumed control of the upstream assets. The sale, for $775 million, had been announced at the end of 2010.
- In October 2011, BP completed the sale of Tuscaloosa assets in Louisiana to Hilcorp Energy I LLC for $110 million.
- Also in October 2011, BP completed the sale of its 35% interest in the Lan Tay and Lan Do gas fields in Vietnam to TNK-BP. The sale of BP s interests in the associated pipeline completed in November 2011. The sale of BP s interest in the Phu My 3 power generation plant is expected to complete in 2012. As at 31 December 2011, this was classified as assets held for sale.
- On 5 November 2011, BP received a notice from Bridas Corporation of termination of the agreement for their purchase of BP s 60% interest in PAE. As a result of their decision and action, the share purchase agreement governing this transaction, originally agreed on 28 November 2010, has been terminated. BP has repaid the deposit for the transaction of $3.5 billion received at the end of 2010. *For details of payments in respect of the termination of restrictive covenants see page 85.*

On 1 December 2011, BP announced the sale of its Canadian Natural Gas Liquid (NGL) business to Plains All American Pipeline L.P. for $1.67 billion subject to closing adjustments. BP s Canadian NGL business owns, operates and has contractual rights to assets involved in the extraction, gathering, fractionation, storage, distribution and wholesale marketing of NGLs across Canada and in the Midwest US. As at 31 December 2011 these assets were held as assets held for sale, awaiting completion of the sale.

On 28 December 2011, BP completed the sale of its interests in the Pompano and Mica fields in the deepwater Gulf of Mexico to Stone Energy Corporation for $204 million. The sale includes BP s 75% operated working interest in the Pompano field and assets and 50% non-operated working interest in the Mica field, together with a 51% operated working interest in Mississippi Canyon block 29 and interests in certain leases located in the vicinity of the Pompano field.

On 28 February 2012, BP announced it had agreed terms with LINN Energy to sell BP s Hugoton basin assets (including the Jayhawk NGL Plant). Under the agreement, LINN Energy has agreed to pay BP $1.2 billion in cash. Completion of the agreement is subject to closing conditions including the receipt of all necessary governmental and regulatory approvals. The sale is currently expected to complete on 30 March 2012.

The following discussion reviews operations in our Exploration and Production business by continent and country, and lists associated significant events that occurred in 2011. BP s percentage working interest in oil and gas assets is shown in brackets. Working interest is the cost-bearing ownership share of an oil or gas lease. Consequently, the percentages disclosed for certain agreements do not necessarily reflect the percentage interests in reserves and production.

Europe

United Kingdom

BP is the largest producer of hydrocarbons in the UK. Key aspects of our activities in the North Sea include a focus on in-field drilling and selected new field developments.

On 16 November 2010, production from the Rhum gas field in the central North Sea was suspended in relation to certain aspects of the EU sanctions. This action was taken to comply with the notification requirements in the relevant EU Regulation. Rhum is owned by BP (50%) and the Iranian Oil Company (50%) under a joint operating agreement dating back to the early 1970s. Rhum remains shut-in. The restart and safe operation of Rhum remains contingent on the availability of third parties to provide services to Rhum. Such services are not as yet all available and it is presently unclear when resumption of production may be possible.

On 13 July 2011, BP and its co-venturers announced an agreement to progress a major redevelopment of the Schiehallion and Loyal oilfields to the west of the Shetland Islands. The investment of circa $5 billion in the redevelopment of the fields is expected to extend the field life to 2035. The project involves replacing the existing Schiehallion Floating, Production, Storage and Offloading (FPSO) vessel with a new FPSO which is scheduled to be installed in 2015. BP will have a 36.3% ownership interest in the new FPSO. There will also be a major investment in the upgrading and replacement of the subsea facilities to enable full development of the reserves. Production is scheduled to commence from the new facilities in 2016.

On 6 September 2011, BP and its co-venturers announced an agreement to invest up to $1.2 billion to progress a project to develop the Kinnoull reservoir in the central UK North Sea (BP 77.06%). The reservoir will be connected to BP s Andrew platform, enabling production from the Andrew area to extend to 2021.

On 13 October 2011, BP announced that a major milestone had been reached on the Devenick gas project (BP 88.7%) with the installation of a 600-tonne module to receive gas and condensate from the Devenick reservoir. Production from the field is due to commence in 2012.

On 13 October 2011, BP announced the successful completion of a well drilled to establish a southwest extension of the Clair field, west of Shetland in the UK North Sea. This well confirmed recoverable oil from a new portion of the field, and also discovered oil in a new, shallower reservoir horizon. During 2012, a further seismic survey of the field is planned, to understand the reservoir structure in more detail.

Also on 13 October 2011, BP announced that the UK government had granted BP and its partners Shell, ConocoPhillips and Chevron, approval to proceed with the $7.6 billion Clair Ridge project (BP 28.6%), the second phase of development of the Clair field.

Rest of Europe

Our activities in the Rest of Europe are in Norway.

In 2011, the Valhall redevelopment project continued, with production switch-over to the new facility scheduled for 2012. The redevelopment consists of a new processing platform required as a result of the existing platform suffering subsidence from extraction of hydrocarbons and includes a power from shore system eliminating all gas-fired equipment offshore.

On 14 August 2011, the FPSO vessel for the Skarv field arrived on location in the Norwegian Sea. Hook up of risers and commissioning work is ongoing and production is due to commence at the Skarv field in 2012.

On 6 October 2011, the Ula field on the Norwegian Continental Shelf celebrated 25 years of production.

North America

United States

Our activities within the US take place in three main areas: deepwater Gulf of Mexico, Lower 48 states and Alaska.

Deepwater Gulf of Mexico

For further information on the activities of BP s Gulf Coast Restoration Organization established following the Deepwater Horizon oil spill, *see pages 76-79.*

BP is the largest producer of hydrocarbons and the largest acreage holder in the deepwater Gulf of Mexico, operating seven production hubs.

Following BP s success in lease sale 213 in March 2010, seven of the leases awarded in 2010 were executed in 2011 and a further five leases from the sale were awarded and executed in 2011.

During 2011, preparations for safely restarting drilling operations in the Gulf of Mexico were progressed. In July 2011, BP announced the implementation of a new set of voluntary drilling standards for its operations in the Gulf of Mexico. The standards go beyond existing regulatory obligations and have been developed through lessons learned following the Deepwater Horizon oil spill in 2010. By the end of 2011 there were five BP-operated deepwater rigs engaged in abandonment and appraisal activities in the Gulf of Mexico. A permit to drill an appraisal well at Kaskida was approved and drilling operations commenced in October. Looking forward to 2012, plans include the drilling of exploration, appraisal and development wells and the start-up of additional three rigs, subject to receiving approvals from the US regulators.

On 7 September 2011, BP announced the drilling of a successful appraisal well in a previously untested northern segment of the Mad Dog field in the Gulf of Mexico. The well, located on Green Canyon Block 738, approximately 140 miles south of Grand Isle, Louisiana, confirms a significant resource extension for the Mad Dog field complex, which includes the existing field, in production since 2005, and appraisal drilling of the Mad Dog South field in 2008 and 2009. Due to the materiality of the Mad Dog South finds, BP has been advancing development options to increase production from Mad Dog and has now sanctioned the final investment decision on Mad Dog Phase 2. This will be the first BP-operated, standalone facility in a decade and will develop significant additional resources through the addition of subsea water injection and installation of a new production host.

On 14 December 2011, the Bureau of Ocean Energy Management held its first western Gulf of Mexico lease sale since August 2009. BP bid on leases for 15 blocks and expects to be awarded leases for 11 blocks in early 2012.

Lower 48 states

The North America Gas business operates onshore in the Lower 48 states producing natural gas, natural gas liquids and coalbed methane across nine states. In 2011, BP drilled 148 wells as operator across the US, including the Wyoming, San Juan, Anadarko, Arkoma and East Texas basins. BP also continues to participate in Eagle Ford, Fayetteville and other non-operated positions. *For further information on the use of fracking in our shale gas assets see page 71.*

Alaska

BP operates 15 North Slope oilfields (including Prudhoe Bay, Endicott, Northstar, and Milne Point) and four North Slope pipelines, and owns a significant interest in six other producing fields.

The Point Thomson Unit (PTU) was terminated by administrative decision of the State of Alaska Department of Natural Resources (DNR) in November 2006 (BP 32%). ExxonMobil, the operator, and the other unit owners, including BP, appealed the unit termination in the Alaska Superior Court. On 11 January 2010, the Alaska Superior Court reversed the DNR s administrative decision to terminate the unit, and in the second quarter of 2010, the State of Alaska Supreme Court granted the DNR s petition for a limited review. Briefs have been submitted to the Alaska Supreme Court, and a decision is expected in 2012. In the meantime, ExxonMobil and the State of Alaska have also informed the other unit owners, including BP, that they have reached a preliminary settlement agreement. BP and the other owners asked to participate in the settlement discussions but were precluded. We are currently analysing the agreement.

In light of the closure of the Denali operations *(see page 88 for further details)* BP continues to explore ways to commercialize its North Slope gas resources.

On 29 November 2007, BP Exploration (Alaska) Inc. (BPXA) pled guilty to a misdemeanour violation under the US Water Pollution Control Act to settle the criminal allegations by the state and federal government related to leaks in 2006 from oil transit lines in the Prudhoe Bay unit. The penalty included payment of $20 million with three years probation that was due to expire on 29 November 2010. On 29 November 2009, a spill of approximately 360 barrels of crude oil and produced water was discovered beneath a ruptured frozen three-phase flow line running from a well pad to the Lisburne Processing Center. On 17 November 2010, the US Probation Officer filed a petition in federal district court to revoke BPXA s probation based on an allegation that the Lisburne spill was a criminal violation of state or federal law. In November 2011, a hearing was held in federal court in Anchorage. On 27 December 2011, the court issued a final decision denying the government s petition and releasing BPXA from probation. *See page 165 in Legal proceedings for further details.*

Canada

In Canada, BP is focused on oil sands, and will use in situ steam-assisted gravity drainage (SAGD) technology. This uses the injection of steam into the reservoir to warm the bitumen so that it can flow to the surface through recovery wells. BP holds an interest in several oil sands leases through the Sunrise oil sands and Terre de Grace oil sands partnerships and the Pike Oil Sands joint venture. BP also develops and produces natural gas, markets natural gas and has significant exploration interests in the Canadian Beaufort Sea.

The Pike Oil Sands joint venture and the Terre de Grace partnership successfully completed winter drilling programmes in 2011, which were conducted to further appraise in situ oil sands resources. In late 2011, Pike Phase 1 moved to project appraisal status.

The Sunrise operator, Husky Energy Inc., commenced building facilities, drilling wells and creating operational systems to bring Phase 1 into production. First production of Phase 1 bitumen is expected in 2014, potentially building to 60,000 barrels per day gross capacity over the subsequent 24 months.

Interpretation of the 3D seismic survey acquired in 2009 and the seismic data for the EL446 field acquired in 2010 in the Canadian Beaufort Sea continued in 2011 and is nearing completion.

South America

Brazil

On 12 May 2011, after receiving approval from the Brazilian National Petroleum, Natural Gas and Biofuels Agency (ANP), BP concluded the purchase of Devon Energy do Brasil (later renamed BP Energy do Brasil), adding 10 exploration and production blocks to its portfolio. The acquired blocks give BP a diverse and broad deepwater exploration acreage position offshore Brazil, with interests in seven licence blocks in the Campos basin, one in the Camamu-Almada basin in water depths ranging from 330 to 9,100 feet (100 to 2,780 metres), as well as two onshore licences in the Parnaíba basin. The Campos basin blocks include three discoveries Xerelete, Pre-Salt Wahoo, and Itaipú and the Polvo Field in shallow water, which is currently producing around 19,000boe/d net. BP completed the drilling of ltaipú-2, the first appraisal well in the Itaipú deepwater discovery in November 2011 and is in the process of finishing a second appraisal well.

Argentina, Bolivia and Chile

BP conducts activity in the Southern Cone region of South America (Argentina, Bolivia and Chile) through PAE, an equity-accounted joint venture with Bridas Corporation in which BP has a 60% interest.

Following the announcement in November 2011 of the termination of the sale of BP s interest in PAE to Bridas, BP no longer classifies these assets as assets held for sale. Under the share purchase agreement BP was required to make a payment of $700 million to Bridas upon termination in full settlement of any and all past claims between the two companies and also as consideration for amendments to the PAE agreement which terminate certain legacy restrictive covenants among BP, PAE and Bridas. Subsequent to payment of this amount by BP in November 2011, Bridas returned this $700 million to BP claiming that the share purchase agreement was void; BP disputes this claim by Bridas and maintains that the share purchase agreement and its terms which survive termination (including the settlement and termination of legacy restrictive covenants) remain valid and binding. The $700 million returned to BP is shown in the balance sheet at 31 December 2011 within cash and cash equivalents and within current trade and other payables.

On 24 January 2012, the Republic of Bolivia issued a press statement declaring its intent to nationalize PAE s interests in the Caipipendi Operations Contract. No formal nationalization process has yet commenced. PAE and its shareholders BP and Bridas intend to vigorously defend their legal interests under the Caipipendi Operations Contract and available Bilateral Investment Treaties.

Trinidad & Tobago

BP holds exploration and production licences covering 917,000 acres offshore of the east coast. Facilities include 13 offshore platforms and one onshore processing facility. Production is comprised of oil, gas and natural gas liquids (NGLs).

On 25 July 2011, BP announced that it had been awarded two deepwater exploration and production blocks by the government of the Republic of Trinidad & Tobago. The award was for a 100% interest in blocks 23(a) and TTDAA 14 offshore Trinidad s east coast, both under PSAs. Government approval is expected in early 2012. These blocks will increase the acreage in the region by 889,000 acres.

On 26 August 2011, BP announced that first gas had been achieved from the Serrette platform. Serrette, sanctioned in May 2009, has a design capacity of 1 billion cubic feet per day and may deliver a peak production of up to 500 million standard cubic feet per day. It is the fifth normally unmanned installation (NUI) to be designed and constructed in Trinidad & Tobago. The platform will tie into the Cassia B platform.

Africa

Angola

BP is present in four major deepwater licences offshore Angola (Blocks 15, 17, 18 and 31) and is operator in Blocks 18 and 31. In addition, BP holds a 13.6% interest in the first Angolan LNG project.

During the second quarter of 2011, a 40-day planned maintenance shutdown was conducted on the Greater Plutonio field. Corrosion in the high pressure gas cooling systems had restricted operations from September 2010, necessitating a complex replacement project that was safely completed in June 2011.

The Pazflor deepwater development, located in block 17 (BP 16.67%), came onstream on 24 August 2011, ahead of schedule. It encompasses a new build FPSO, 49 subsea wells, 180 kilometres of flowlines and 10,000 tonnes of equipment on the seabed. Pazflor is expected to have a plateau production rate of 220,000boe/d gross which will come from the Perpetua, Hortensia, Acacia and Zinia fields. The FPSO has topside facilities to process both Oligocene and Miocene age oils.

In December 2011, BP gained access to five new deepwater exploration and production blocks offshore Angola. These gave BP a leading position in Angola, with interests in nine blocks accounting for a total acreage of 30,842km^2. BP was awarded operatorship of Blocks 19 and 24 with 50% interest, and additional non-operating interests in Blocks 20 (20%) and 25 (15%) covering 19,400km^2 in the Kwanza and Benguela basins. BP has also taken a 40% stake in the 4,840km^2 Block 26 in the Benguela basin, by agreeing a farm-in deal with Brazilian national oil company, Petrobras, which operates the block. The five new blocks, including block 26, cover a total area of 24,000km^2 in water depths from 200 to 2,500 metres, and increase BP s total Angolan acreage by 275%.

Algeria

BP is a partner with Sonatrach and Statoil in the In Salah (BP 33.15%) and In Amenas (BP 45.89%) projects, which supply gas to the domestic and European markets. BP is also in a joint venture with Sonatrach in the Rhourde El Baguel (REB) oilfield (BP 60%), an enhanced oil recovery project 75 kilometres east of the Hassi Messaoud oilfield. In addition, BP is in a joint venture with Sonatrach in the Bourarhet Sud block, located to the south west of In Amenas.

In 2011, development of the In Salah Southern Fields was approved and the primary engineering contracts awarded. First gas is expected in 2014.

On 22 December 2011, BP and Sonatrach reached an agreement for BP to withdraw from the REB PSA at the end of 2011.

Libya

In Libya, BP is in partnership with the Libyan Investment Authority (LIA) to explore acreage in the onshore Ghadames and offshore Sirt basins, covered under the exploration and production-sharing agreement ratified in December 2007 (BP 85%). BP s total assets in Libya at 31 December 2011 were $437 million. To date, all of the 3D seismic commitment has been completed but no exploration wells have yet been drilled.

Due to the outbreak of civil unrest leading to the regime change in Libya, the BP office in Tripoli was closed on 21 February 2011 and our Libyan operations suspended. BP declared force majeure the contractual mechanism which flows from the suspension of our activities in Libya and the imposition of sanctions. We intend to resume exploration activities with agreement of the new authorities, and when we are sure it is safe to do so. We are currently assessing how long it will take to re-establish exploration operations.

Business review

Egypt

BP has a long-standing history in Egypt, successfully operating there for close to 50 years. To date BP with its partners has produced almost 40% of Egypt s entire oil production and supplies more than 35% of the domestic gas demand. BP s total assets in Egypt at 31 December 2011 were $8,784 million ($4,768 non-current and $4,016 current).

The 25 January 2011 civil uprising resulted in the BP office in Cairo closing for a period of 10 days, reopening on 7 February. Production and operations were, and continue to be, unaffected. Parliamentary elections started in late November 2011 and are expected to run until mid-March 2012. We continue to closely monitor the developing situation in the country and its potential impact on the business and our people.

In October 2011, BP announced the Salmon gas discovery in the North El Burg (BP 50% and operator) offshore concession in the Nile Delta. Salmon is the third discovery in the concession, following the Satis 1 and Satis 3 gas discoveries. Further appraisal work to evaluate the resources is under way.

Asia

Western Indonesia

BP has a joint interest in Virginia Indonesia Company LLC (VICO), the operator of the Sanga-Sanga PSA (BP 38%) supplying gas to Indonesia s largest LNG export facility, the Bontang LNG plant in Kalimantan. BP also participates in the Sanga-Sanga coalbed methane (CBM) PSA (BP 38%), a brownfield, unconventional development overlaying the conventional PSA. Sanga-Sanga CBM is the cornerstone of the BP Asia Pacific CBM growth strategy.

In March 2011, the first CBM long-term production test well was tied into the system that supplies Bontang LNG plant.

On 1 April 2011, BP signed four new CBM PSAs Tanjung IV, Kapuas I, II, and III in the Barito Basin of Central Kalimantan, covering a contiguous area of approximately 4,800km^2. BP holds a 44% interest in the Pertamina-operated Tanjung IV PSA, and a 45% operating interest in each of the Kapuas I, II, and III PSAs. Subsurface evaluation of the areas covered by the new PSAs is under way.

China

BP s upstream activities in the country include production from the China National Offshore Oil Corporation (CNOOC) operated Yacheng offshore gas field (BP 34.3%) as well as deepwater exploration in the South China Sea s Block 42/05 (BP 40.82%). Yacheng supplies gas to the Castle Peak Power Company for up to 70% of Hong Kong s gas-fired electricity generation. Additional gas is sold to the Hainan Holdings Fuel & Chemical Corporation Limited.

On 10 January 2011, BP announced that it had signed a new agreement with CNOOC for deepwater exploration in Block 43/11 in the South China Sea and government approval was received on 30 January 2012.

Azerbaijan

BP is the largest foreign investor in the country. BP operates two PSAs, Azeri-Chirag-Gunashli (ACG) and Shah Deniz, and also holds other exploration leases.

In June 1996, when the Shah Deniz PSA was awarded, Oil Industries Engineering and Construction, an affiliate of the National Iranian Oil Company and assignor to the current Iranian interest holder, Naftiran Intertrade Co. Ltd (NICO), was selected as a Shah Deniz project participant by the State of Azerbaijan, and has a 10% non-operating interest under the Shah Deniz PSA. NICO also has a 10% or less, non- operating, interest in both the Shah Deniz project gas marketing entity and its gas transportation entity, both of which were incorporated in 2002 and derive from the award of the Shah Deniz PSA. Under article 30 of the new EU Regulations concerning restrictive measures against Iran, any body, entity or holder of rights derived from an award of a PSA before the entry into force of the EU Regulations by a sovereign government other than Iran, shall not be considered an Iranian person, entity or body for the purposes of the main operative provisions of the EU Regulations. As such, the restrictive measures do not apply to NICO and Shah Deniz continues to operate in full compliance with EU and US law.

On 6 May 2011, the Parliament of the Republic of Azerbaijan ratified the new PSA between BP and the State Oil Company of Azerbaijan (SOCAR) on joint exploration and development of the Shafag-Asiman structure in the Azerbaijan sector of the Caspian Sea. The ratification follows the signing of the PSA in Baku in October 2010. Under the PSA, which has a 30-year term, BP will be the operator with 50% interest while SOCAR will hold the remaining 50% interest.

Following the Memorandum of Understanding signed in June 2010 between Turkey and Azerbaijan for gas sales and transportation of gas from the new Shah Deniz full field development to be sold to consumers in Turkey and across Europe, on 25 October 2011, Azerbaijan and Turkey signed a number of key gas export related agreements to enable Turkey to buy gas from Azerbaijan and to transit gas from Azerbaijan through Turkey to Europe. The documents signed included an intergovernmental agreement between the government of Azerbaijan and the government of Turkey, gas sales agreements between SOCAR and BOTAS and also between the Azerbaijan Gas Supply Company (AGSC) and BOTAS International Limited (BIL), a gas transit agreement between SOCAR and BIL and a framework agreement setting the general terms and conditions for transit of gas sourced from Azerbaijan through the territory of Turkey. The agreements provide a legal framework to regulate the sale of Shah Deniz gas to Turkey and its transportation to European markets through Turkey.

Russia

In May 2011, BP announced that both the Rosneft[a] share swap agreement and the Arctic Opportunity, originally announced on 14 January 2011, had terminated. This termination was a result of the deadline for the satisfaction of conditions precedent having expired following delays resulting from interim orders granted by the English High Court and a UNCITRAL arbitration tribunal. This followed applications brought by Alfa Petroleum Holdings Limited

(Alfa) and OGIP Ventures Limited (OGIP) against BP International Limited (BPIL) and BP Russian Investments Limited (BPRIL) alleging breach of the TNK-BP shareholders agreement (SHA). These interim orders did not address the question of whether or not BP breached the SHA. The UNCITRAL arbitration proceedings with Alfa, Access and Renova (AAR) which are subject to strict confidentiality obligations are ongoing. *See Legal proceedings on page 166 for further information.*

TNK-BP

TNK-BP, an associate owned by BP (50%) and AAR (50%), is an integrated oil company operating in Brazil, Russia, Ukraine, Venezuela and Vietnam. TNK-BP s strategic goal is to become an international oil and gas company with a leading position in the Russian oil and gas industry. BP s investment in TNK-BP is reported in the Exploration and Production segment. From 2012 onward TNK-BP will be reported as a separate operating segment, as explained more fully on page 80. The TNK-BP group s major assets are held in OAO TNK-BP Holding. Other assets include OAO Slavneft, an equity-accounted joint venture. The workforce is comprised of more than 50,000 people. TNK-BP s main board is currently comprised of four BP, four AAR, and one independent director, with two vacancies for independent directors. The boards of key TNK-BP subsidiaries have both BP and AAR directors. In December 2011, two independent non-executive directors of TNK-BP Limited, Gerhard Schroeder and James Leng, announced that they would be stepping down from their positions on the board at the end of 2011.

Upstream, TNK-BP operates either directly, or through equity-accounted joint ventures, a number of oil and gas fields in Russia, Vietnam and Venezuela which produced approximately 1.99mboe/d in 2011.

Downstream, TNK-BP has interests in six refineries in Russia and Ukraine (including Ryazan and Lisichansk and Slavneft s Yaroslavl refinery), with throughput of approximately 711 thousand barrels per day in 2011. TNK-BP has over 1,400 branded retail stations in Russia and Ukraine.

a BP already holds a 1.3% investment in Rosneft Oil Company with a carrying value of $873 million.

In March 2011, TNK-BP completed the acquisition of 74.9% of CJSC Toplivozapravochny kompleks Sheremetyevo , the operator of jet fuel storage and into-wing fuelling services at Sheremetyevo International Airport in Moscow.

In June 2011, TNK-BP completed the acquisition from BP of stakes in three upstream assets in Venezuela. Acquisition of these assets was announced in October 2010.

In October 2011, TNK-BP entered into an agreement with HRT Oil & Gas for the acquisition of a 45% stake in 21 blocks in the Brazilian Solimoes Basin. These oil and gas exploration blocks are operated by HRT Oil & Gas, and cover an area of approximately 48,000km^2.

Also in October 2011, TNK-BP announced that the Vietnamese Ministry of Investment and Trade granted TNK Vietnam, a Vietnam-based subsidiary of TNK-BP, the investment licence to operate offshore gas Block 6.1. TNK-BP acquired BP s 35% stake in Block 6.1, an integrated gas to power project which contains the Lan Tay and Lan Do gas condensate fields. As part of the deal, TNK-BP also acquired BP s 32.7% interest in the Nam Con Son Pipeline. Acquisition of these assets was announced in October 2010.

Five minority shareholders of OAO TNK-BP Holding (TBH) filed a civil action in Tyumen, Siberia, against BP Russia Investments Limited and BP p.I.c. seeking to recover alleged losses of $13 billion relating to BP s attempt to form a strategic alliance with Rosneft in January 2011. The action was dismissed by the Tyumen court fully on its merits. The Omsk Appellate court confirmed the Tyumen court of first instance s dismissal of the minority suits. *See Legal proceedings on page 166 for further information.*

On 9 February 2012, BP reached agreement with its Russian partners in TNK-BP on temporary amendments to the memorandum and articles of association of TNK-BP Limited and the SHA that reduce quorum requirements to require presence of directors nominated by BP and AAR only. The amendments are aimed at enabling the continuing functioning of the board of directors of TNK-BP (board of directors) while two independent directors who recently resigned are being replaced. This change is currently set to expire on 31 March 2012, unless both independent directors are appointed earlier.

On 9 February 2012, BP also reached agreement with its Russian partners in TNK-BP regarding certain changes to the management board of its main management company in Russia OAO TNK-BP Management (management board). The changes were aimed at restructuring and optimizing the management board, following the elimination of the deputy TNK-BP group chief executive officer role. The restructured management board will now consist of six people. BP will have the right to nominate the chairman of the management board, as well as two executive directors in charge of upstream and downstream respectively (the BP members). AAR will have the right to nominate two other executive directors (the AAR members). The sixth member the chief financial officer will be nominated by the chairman of the management board. The chairman of the management board will in time also have the right to nominate the executive directors, subject to prior concurrence by the respective shareholder. All of the aforementioned nominations will require approval by the board of directors as a majority matter, except for the chairman of the management board whose appointment will require approval as a unanimous reserved matter. As part of the agreement, BP and AAR agreed to approve the continued appointment of the chief executive officer and the appointment of their respective executive directors, with such appointments to expire no later than 31 December 2013.

All other provisions of the SHA (including those related to the review of new business opportunities, the board of directors and dispute resolution) remain unchanged.

Sakhalin

BP has interests in Sakhalin through a joint venture company, Elvary Neftegaz, in which BP holds a 49% equity interest, and its partner, Rosneft, holds the remaining 51% interest. In 2011, the process to exit the licence areas held by Elvary Neftegaz and liquidate the joint venture commenced. This follows the write-down of BP s investment at the end of 2010 following an unsuccessful exploration programme.

Middle East

Production in the Middle East consists principally of the production entitlement of associates in Abu Dhabi, where we have equity interests of 9.5% and 14.67% in onshore and offshore concessions respectively. The Abu Dhabi onshore concession expires in January 2014 with a consequent reduction in production of approximately 140mb/d.

In the first quarter of 2011, extended well test production began in Oman.

In August 2011, the seismic survey of the Risha concession in Jordan was successfully completed.

India

On 30 August 2011, BP and Reliance Industries Limited (RIL) announced the completion of BP s acquisition of a 30% stake in 21 oil and gas PSAs that RIL operates in India, including the producing KG D6 block. BP paid RIL an aggregate consideration of $7.0 billion for the interests acquired in the 21 PSAs. Further performance payments of up to $1.8 billion could be paid in case of exploration success in certain blocks that result in the development of commercial discoveries. This step commenced the planned alliance which will operate across the gas value chain in India, from exploration and production to distribution and marketing.

On 17 November 2011, the two companies formed a 50:50 joint venture for the sourcing and marketing of gas in India.

Iraq

Following a successful bid with PetroChina to run the Rumaila oilfield in June 2009, the technical service contract (TSC) became effective on 17 December 2009. BP holds a 38% working interest and is the lead contractor. Rumaila is one of the world s largest oilfields and was discovered by BP in 1953 and comprises five producing reservoirs. BP together with its partners is actively refurbishing the wells and facilities. With the achievement of the improved production target on 25 December 2010, BP and PetroChina became eligible for service fees pursuant to the TSC. In 2011 both companies lifted cargoes from the Basra terminal as payment for service fees due.

Australasia

Australia

BP is one of seven partners in the North West Shelf (NWS) venture which has been producing LNG, pipeline gas, condensate, LPG and oil since the 1980s. Six partners (including BP) hold an equal 16.67% interest in the gas infrastructure and an equal 15.78% interest in the gas and condensate reserves, with a seventh partner owning the remaining 5.32%. BP also has a 16.67% interest in the NWS oil reserves and related infrastructure. The NWS venture is currently the principal supplier to the domestic market in Western Australia and one of the largest LNG export projects in Asia with five LNG trains[a] in operation. BP also holds a 5.375% interest in the Jansz-lo field which is part of the Greater Gorgon project (Chevron, ExxonMobil and Shell) and is currently being developed.

In January 2011, BP announced that it had been awarded four deepwater offshore exploration blocks in the Ceduna Sub Basin within the Great Australian Bight, off the coast of South Australia. The exploration work is to be phased over six years with a 3D seismic survey covering approximately 12,500km^2 commenced in November 2011 and continuing into 2012. Following interpretation of the seismic survey, BP will drill four deepwater wells in this frontier exploration basin.

Eastern Indonesia

BP has a 100% interest in an exploration asset, the North Arafura PSA, located on the coast of the Arafura Sea, 480 kilometres south east of our Tangguh LNG plant (BP 37.16% and operator) and covering an area of just over 5,000km^2. In addition, BP owns a 32% interest in Chevron s operated West Papua I and III PSAs, located circa 120 kilometres to the south of the Tangguh LNG plant (see *Liquefied natural gas on page 88).*

In December 2011, BP signed contracts with the Government of Indonesia for two deepwater PSAs; West Aru I and II. The PSAs are located 500 kilometres south west of the North Arafura PSA and 200 kilometres west of the Aru island group, covering areas of 8,100km^2 and 8,300km^2 respectively. BP holds 100% interest in the PSAs and expects to commence seismic operations in the near future.

a An LNG train is a processing facility used to liquefy and purify LNG.

Midstream activities

Oil and natural gas transportation

The group has direct or indirect interests in certain crude oil and natural gas transportation systems. The following narrative details the significant events that occurred during 2011 by country.

BP s onshore US crude oil and product pipelines and related transportation assets are included under Refining and Marketing (see *page 94).*

Alaska

BP owns a 46.9% interest in the Trans-Alaska Pipeline System (TAPS), with the balance owned by four other companies. The TAPS transports crude oil from Prudhoe Bay on the Alaska North Slope to the port of Valdez in south-east Alaska. BP also owns a 50% interest in a joint venture company called Denali -The Alaska Gas Pipeline (Denali).

On 16 May 2011, Denali announced that its open season efforts did not result in the commitments necessary to continue work on the Alaska North Slope gas pipeline project. Denali also indicated that it planned to close out its operations over the remainder of 2011. As a 50% owner in Denali, BP, along with co-owner ConocoPhillips, was directly involved in the decision to terminate Denali s activities. BP s focus as an owner in Denali was to create a viable alternative for the owners of the North Slope gas resource to commercialize their gas. BP has determined that the North American natural gas market does not support the project at this time. The Denali effort marked an important step in advancing the industry understanding of the gas pipeline opportunity in Alaska. BP will continue to pursue ways to commercialize our Alaskan gas resource.

North Sea

In the UK sector of the North Sea, BP operates the Forties Pipeline System (FPS) (BP 100%), an integrated oil and NGLs transportation and processing system that handles production from more than 50 fields in the central North Sea. The system has a capacity of more than 1 million barrels per day, with average throughput in 2011 of 473mboe/d. BP also operates and has a 36% interest in the Central Area Transmission System (CATS), a 400-kilometre natural gas pipeline system in the central UK sector of the North Sea. The pipeline has a transportation capacity of 293mboe/d to a natural gas terminal at Teesside in north-east England. Average throughput in 2011 was 39mboe/d. CATS offers natural gas transportation and processing services. In addition, BP operates the Sullom Voe oil and gas terminal in Shetland and the Dimlington/Easington Terminals in Humberside. Dimlington and Easington form part of the southern gas assets that BP announced its intention to sell in February 2011 (see *Disposals on page 83).*

Asia

BP, as operator, holds a 30.1% interest in and manages the Baku-Tbilisi-Ceyhan (BTC) oil pipeline. The 1,768-kilometre pipeline transports oil from the BP-operated ACG oilfield in the Caspian Sea to the eastern Mediterranean port of Ceyhan and has a capacity of 1.2 million barrels per day. BP is technical operator of, and holds a 25.5% interest in, the 693-kilometre South Caucasus Pipeline, which takes gas from Azerbaijan through Georgia to the Turkish border and has a capacity of 780mmscf/d. In addition, BP operates the Azerbaijan section of the Western Export Route Pipeline between Azerbaijan and the Black Sea coast of Georgia (as operator of Azerbaijan International Operating Company).

Liquefied natural gas

Our LNG activities are focused on building competitively advantaged liquefaction projects, establishing diversified market positions to create maximum value for our upstream natural gas resources and capturing third-party LNG supply to complement our equity flows. Assets and significant events in 2011 included:

In Trinidad, BP s net share of the capacity of Atlantic LNG trains 1, 2, 3 and 4 is 6 million tonnes of LNG per year (292 billion cubic feet equivalent regasified). All of the LNG from Atlantic train 1 and most of the LNG from trains 2 and 3 is sold to third parties in the US and Spain under long-term contracts. All of BP s LNG entitlement from Atlantic LNG train 4 and some of its entitlement from trains 2 and 3 is marketed via BP s LNG marketing and trading business to a variety of markets including the US, the Dominican Republic, Spain, the UK, Japan, India and South Korea.

We have a 10% equity shareholding in the Abu Dhabi Gas Liquefaction Company, which in 2011 supplied 5.76 million tonnes of LNG (297 billion cubic feet equivalent regasified).

BP has a 13.6% share in the Angola LNG project, which is expected to receive approximately 1 billion cubic feet of associated gas per day from offshore producing blocks and to produce 5.2 million tonnes per annum of LNG (gross), as well as related gas liquids products. Construction and implementation of the project is proceeding and the plant is expected to start up in 2012.

In Indonesia, BP is involved in two of the three LNG centres in the country. BP participates in Indonesia s LNG exports through its holdings in the Sanga-Sanga PSA (BP 38%). Sanga-Sanga currently delivers around 13% of the total gas feed to Bontang, one of the world s largest LNG plants. The Bontang plant produced more than 15 million tonnes of LNG in 2011.

Also in Indonesia, BP has its first operated LNG plant, Tangguh (BP 37.16%), in Papua Barat. The asset comprises of 14 producing wells, two offshore platforms, two pipelines and an LNG plant with two production trains with a total capacity of 7.6 million tonnes per annum. Tangguh supplies LNG to customers in China, South Korea, Mexico and Japan through long-term contracts. BP is currently progressing options to expand the Tangguh facilities.

In Australia, BP is one of seven partners in the NWS venture. The joint venture operation covers offshore production platforms, trunklines, onshore gas and LNG processing plants and LNG carriers. BP s net share of the capacity of NWS LNG trains 1-5 is 2.7 million tonnes per annum of LNG. BP is one of five partners in the Browse LNG venture (operated by Woodside) and holds approximately a 17% interest. A greenfield LNG development at a proposed state government LNG precinct in the Kimberley region is currently in the early design stage and remains subject to regulatory, company and partner approvals.

BP has a 30% equity stake in the 7mtpa capacity Guangdong LNG regasification and pipeline project in south-east China, making it the only foreign partner in China s LNG import business. The terminal is also supplied under a long-term contract with Australia s NWS project in which BP has an interest.

In both the Atlantic and Asian regions, BP is marketing LNG using BP LNG shipping and contractual rights to access import terminal capacity in the liquid markets of the US (via Cove Point and Elba Island), the UK (via the Isle of Grain) and Italy (Rovigo), and is supplying Asian customers in Japan, South Korea and Taiwan.

Gas marketing and trading activities

Gas and power marketing and trading activity is undertaken primarily in the US, Canada and Europe to market both BP production and third-party natural gas, to support group LNG activities and manage market price risk, as well as to create incremental trading opportunities through the use of commodity derivative contracts. Additionally, this activity generates fee income and enhances margins from sources such as the management of price risk on behalf of third-party customers. These markets are large, liquid and volatile. Market conditions have become more challenging over the past few years due to the availability of shale gas and increased pipeline builds in North America. This has resulted in limited basis differentials and faster changes in production volumes in response to price movements. However, new markets are continuing to develop with continental European markets opening up and LNG becoming more liquid. The business (including support functions) operates primarily from offices in Houston and London and employs around 1,500 people.

In connection with its trading activities, the group uses a range of commodity derivative contracts and storage and transport contracts. These include commodity derivatives such as futures, swaps and options to manage price risk and forward contracts used to buy and sell gas and power in the marketplace. Using these contracts, in combination with rights to access storage and transportation capacity, allows the group to

a See footnote a on page 87.

access advantageous pricing differences between locations, time periods and arbitrage between markets. Natural gas futures and options are traded through exchanges, while over-the-counter (OTC) options and swaps are used for both gas and power transactions through bilateral and/or centrally-cleared arrangements. Futures and options are primarily used to trade the key index prices, such as Henry Hub, while swaps can be tailored to price with reference to specific delivery locations where gas and power can be bought and sold. OTC forward contracts have evolved in both the US and UK markets, enabling gas and power to be sold forward in a variety of locations and future periods. These contracts are used both to

sell production into the wholesale markets and as trading instruments to buy and sell gas and power in future periods. Storage and transportation contracts allow the group to store and transport gas, and transmit power between these locations. The group has developed a risk governance framework to manage and oversee the financial risks associated with this trading activity, which is described in Note 26 to the Financial statements on pages 217-222. The group s trading activities in natural gas are managed by the integrated supply and trading function.

The range of contracts that the group enters into is described in Certain definitions commodity trading contracts, on page 111.

Oil and gas disclosures

The following tables provide additional data and disclosures in relation to our oil and gas operations.

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Average sales price per unit of production

$ per unit of production[a]

	Europe		North America		South America	Africa	Asia		Australasia	Total group average
	UK	Rest of Europe	US	Rest of North America[b]			Russia	Rest of Asia		
Average sales price[c]										
Subsidiaries										
2011										
Liquids[d]	**107.83**	**106.89**	**96.34**		**86.60**	**104.37**		**111.10**	**101.22**	**101.29**
Gas	**7.91**	**13.15**	**3.34**		**3.60**	**5.24**		**4.73**	**9.13**	**4.69**
2010										
Liquids[d]	76.33	81.09	70.79	48.26	71.01	74.87		78.80	75.81	73.41
Gas	5.44	7.16	3.88	4.20	2.80	4.11		4.05	7.01	3.97
2009										
Liquids[d]	62.19	60.73	53.68	30.77	52.48	57.40		61.27	57.22	56.26
Gas	4.68	7.62	3.07	3.53	2.50	3.61		3.30	5.25	3.25
Equity-accounted entities[e]										
2011										
Liquids[d]					**73.51**		**84.39**	**8.11**		**71.35**
Gas					**2.31**		**2.23**	**12.21**		**2.40**
2010										
Liquids[d]					61.60		60.39	6.72		52.81
Gas					1.97		1.91	7.83		2.04
2009										

Liquids[d]	–	–	–	–	51.01	–	47.27	5.59	–	41.93
Gas					1.90		1.51	5.25		1.68

a Units of production are barrels for liquids and thousands of cubic feet for gas.
b Producing assets now largely divested.
c Realizations include transfers between businesses.
d Crude oil and natural gas liquids.
e It is common for equity-accounted entities agreements to include pricing clauses that require selling a significant portion of the entitled production to local governments or markets at discounted prices.

Average production cost per unit of production

$ per unit of production[a]

	Europe		North America		South America	Africa	Asia		Australasia	Total group average
	UK	Rest of Europe	US	Rest of North America[b]			Russia	Rest of Asia		
The average production cost per unit of production[a]										
Subsidiaries										
2011	**21.59**	**18.23**	**12.09**		**3.20**	**10.82**		**8.65**	**3.05**	**10.08**
2010	12.79	9.76	8.10	15.78	2.48	7.52		4.59	2.03	6.77
2009	12.38	10.72	7.26	14.45	2.20	6.05		4.35	1.60	6.39
Equity-accounted entities										
2011					**9.04**		**5.68**	**2.70**		**5.58**
2010					6.32		5.04	2.61[c]		4.83[c]
2009					6.12		4.63	2.52[c]		4.50[c]

a Units of production are barrels for liquids and thousands of cubic feet for gas. Amounts do not include ad valorem and severance taxes.
b Producing assets now largely divested.
c A minor amendment has been made to comparative periods.

Business review

Licence expiry

The Abu Dhabi onshore concession expires in January 2014 with a consequent reduction in production of approximately 140mb/d. The group holds no other licences due to expire within the next three years that would have a significant impact on BP s reserves or production.

Resource progression

BP manages its hydrocarbon resources in three major categories: prospect inventory, contingent resources and proved reserves. When a discovery is made, volumes usually transfer from the prospect inventory to the contingent resources category. The contingent resources move through various sub-categories as their technical and commercial maturity increases through appraisal activity.

At the point of final investment decision, most proved reserves will be categorized as proved undeveloped (PUD). Volumes will subsequently be re-categorized from PUD to proved developed (PD) as a consequence of development activity. When part of a well s proved reserves depends on a later phase of activity, only that portion of proved reserves associated with existing, available facilities and infrastructure moves to PD. The first PD bookings will typically occur at the point of first oil or gas production. Major development projects typically take one to four years from the time of initial booking of proved reserves to the start of production. Changes to proved reserves bookings may be made due to analysis of new or existing data concerning production, reservoir performance, commercial factors, acquisition and disposal activity and additional reservoir development activity.

Volumes can also be added or removed from our portfolio through acquisition or divestment of properties and projects. When we dispose of an interest in a property or project, the volumes associated with our adopted plan of development for which we have a final investment decision will be removed from our proved reserves upon completion. When we acquire an interest in a property or project, the volumes associated with the existing development and any committed projects will be added to our proved reserves if BP has made a final investment decision and they satisfy the SEC s criteria for attribution of proved status. Following the acquisition, additional volumes may be progressed to proved reserves from contingent.

Contingent resources in a field will only be re-categorized as proved reserves when all the criteria for attribution of proved status have been met and the proved reserves are included in the business plan and scheduled for development, typically within five years. The group will only book proved reserves where development is scheduled to commence after five years, if these proved reserves satisfy the SEC s criteria for attribution of proved status and BP management has reasonable certainty that these proved reserves will be produced.

At the end of 2011, BP had material volumes of proved undeveloped reserves held for more than five years in Trinidad, as well as non-material volumes in Australia, Azerbaijan, Norway, the UK and the US, that are part of ongoing development activities for which BP has a historical track record of completing comparable projects in these countries. The volumes are being progressed as part of an adopted development plan where there are physical limits to the development timing such as infrastructure limitations, contractual limits including gas delivery commitments, late life compression and the complex nature of working in remote locations.

BP has a three year average track record (since the adoption of the modernised rules for reporting) of converting 20% of our proved undeveloped reserves (excluding disposals) to proved developed reserves. This equates to a turnover time of five years. We expect the turnover time to remain at or below five years and anticipate no increase in the volume of proved undeveloped reserves held for more than five years.

In 2011, we converted 1,062mmboe of proved undeveloped reserves to proved developed reserves through ongoing investment in our upstream development activities. Total development expenditure in Exploration and Production, excluding midstream activities, was $13,329 million in 2011 ($10,194 million for subsidiaries and $3,135 million for equity-accounted entities). The major areas converted in 2011 were Argentina, Indonesia, Russia, Trinidad and the US. Revisions of previous estimates for proved undeveloped reserves are due to the impact of

year-end price (net of 1%) and changes relating to field performance or well results (99%). The table below describes the changes to our proved undeveloped reserves position through the year.

	volumes in mmboe
Proved undeveloped reserves at 1 January 2011	7,899
Revisions of previous estimates	693
Improved recovery	522
Discoveries and extensions	92
Purchases	77
Sales	(302)

Total in year proved undeveloped reserves changes	8,981
Progressed to proved developed reserves	(1,062)
Proved undeveloped reserves at 31 December 2011	7,919

BP bases its proved reserves estimates on the requirement of reasonable certainty with rigorous technical and commercial assessments based on conventional industry practice. BP only applies technologies that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. BP applies high-resolution seismic data for the identification of reservoir extent and fluid contacts only where there is an overwhelming track record of success in its local application. In certain deepwater fields BP has booked proved reserves before production flow tests are conducted, in part because of the significant safety, cost and environmental implications of conducting these tests. The industry has made substantial technological improvements in understanding, measuring and delineating reservoir properties without the need for flow tests. To determine reasonable certainty of commercial recovery, BP employs a general method of reserves assessment that relies on the integration of three types of data: (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 analogous fields. Well data includes appraisal wells or sidetrack holes, full logging suites, core data and fluid samples. BP considers the integration of this data in certain cases to be superior to a flow test in providing understanding of overall reservoir performance. The collection of data from logs, cores, wireline formation testers, pressures and fluid samples calibrated to each other and to the seismic data can allow reservoir properties to be determined over a greater volume than the localized volume of investigation associated with a short-term flow test. There is a strong track record of proved reserves recorded using these methods, validated by actual production levels.

Governance

BP s centrally controlled process for proved reserves estimation approval forms part of a holistic and integrated system of internal control. It consists of the following elements:

- Accountabilities of certain officers of the group to ensure that there is review and approval of proved reserves bookings independent of the operating business and that there are effective controls in the approval process and verification that the proved reserves estimates and the related financial impacts are reported in a timely manner.
- Capital allocation processes, whereby delegated authority is exercised to commit to capital projects that are consistent with the delivery of the group s business plan. A formal review process exists to ensure that both technical and commercial criteria are met prior to the commitment of capital to projects.
- Internal audit, whose role is to consider whether the group s system of internal control is adequately designed and operating effectively to respond appropriately to the risks that are significant to BP.
- Approval hierarchy, whereby proved reserves changes above certain threshold volumes require central authorization and periodic reviews. The frequency of review is determined according to field size and ensures that more than 80% of the BP proved reserves base undergoes central review every two years, and more than 90% is reviewed centrally every four years.

BP s vice president of segment reserves is the petroleum engineer primarily responsible for overseeing the preparation of the reserves estimate. He has over 25 years of diversified industry experience with the past eight spent managing the governance and compliance of BP s reserves estimation. He is a past member of the Society of Petroleum Engineers Oil and Gas Reserves Committee, a sitting member of the American Association of Petroleum Geologists Committee on Resource Evaluation and vice chair of the bureau of the United Nations Economic Commission for Europe Expert Group on Resource Classification.

For the executive directors and senior management, no specific portion of compensation bonuses is directly related to proved reserves targets. Additions to proved reserves is one of several indicators by which the performance of the Exploration and Production segment is assessed by the remuneration committee for the purposes of determining compensation bonuses for the executive directors. Other indicators include a number of financial and operational measures.

BP s variable pay programme for the other senior managers in the Exploration and Production segment is based on individual performance contracts. Individual performance contracts are based on agreed items from the business performance plan, one of which, if chosen, could relate to proved reserves.

Compliance

International Financial Reporting Standards (IFRSs) do not provide specific guidance on reserves disclosures. BP estimates proved reserves in accordance with SEC Rule 4-10 (a) of Regulation S-X and relevant Compliance and Disclosure Interpretations (C&DI) and Staff Accounting Bulletins as issued by the SEC staff.

By their nature, there is always some risk involved in the ultimate development and production of proved reserves, including, but not limited to, final regulatory approval, the installation of new or additional infrastructure, as well as changes in oil and gas prices, changes in operating and development costs and the continued availability of additional development capital. All the group s proved reserves held in subsidiaries and equity-accounted entities are estimated by the group s petroleum engineers.

Our proved reserves are associated with both concessions (tax and royalty arrangements) and agreements where the group is exposed to the upstream risks and rewards of ownership, but where our entitlement to the hydrocarbons is calculated using a more complex formula, such as PSAs. In a concession, the consortium of which we are a part is entitled to the proved reserves that can be produced over the licence period, which may be the life of the field. In a PSA, we are entitled to recover volumes that equate to costs incurred to develop and produce the proved reserves and an agreed share of the remaining volumes or the economic equivalent. As part of our entitlement is driven by the monetary amount of costs to be recovered, price fluctuations will have an impact on both production volumes and reserves.

We disclose our share of proved reserves held in equity-accounted entities (jointly controlled entities and associates), although we do not control these entities or the assets held by such entities.

BP s estimated net proved reserves as at 31 December 2011

Seventy-five per cent of our total proved reserves of subsidiaries at 31 December 2011 were held through unincorporated joint ventures (75% in 2010), and 33% of the proved reserves were held through such unincorporated joint ventures where we were not the operator (31% in 2010).

Estimated net proved reserves of liquids at 31 December 2011[a b c]

million barrels

	Developed	Undeveloped	Total
UK	288	445	733
Rest of Europe	69	230	299
US	1,685	1,173	2,858[d]
Rest of North America			
South America	27	48	75[e]
Africa	311	315	626
Rest of Asia	177	279	456
Australasia	59	47	106
Subsidiaries	2,616	2,537	5,153
Equity-accounted entities	3,201	2,211	5,412[f]
Total	5,817	4,748	10,565

Estimated net proved reserves of natural gas at 31 December 2011[a b]

billion cubic feet

	Developed	Undeveloped	Total
UK	1,411	909	2,320
Rest of Europe	43	450	493
US	9,721	3,831	13,552
Rest of North America	28		28
South America	2,869	6,529	9,398[g]
Africa	1,224	2,033	3,257
Rest of Asia	1,034	364	1,398
Australasia	3,570	2,365	5,935
Subsidiaries	19,900	16,481	36,381
Equity-accounted entities	3,367	1,911	5,278[h]
Total	23,267	18,392	41,659

Net proved reserves on an oil equivalent basis

million barrels of oil equivalent

	Developed	Undeveloped	Total
Subsidiaries	6,048	5,378	11,426
Equity-accounted entities	3,781	2,541	6,322[i]
Total	9,829	7,919	17,748

a Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently, and include minority interests in consolidated operations. We disclose our share of reserves held in jointly controlled entities and associates that are accounted for by the equity method although we do not control these entities or the assets held by such entities.

b The 2011 marker prices used were Brent $110.96/bbl (2010 $79.02/bbl and 2009 $59.91/bbl) and Henry Hub $4.12/mmBtu (2010 $4.37/mmBtu and 2009 $3.82/mmBtu).

c Liquids include crude oil, condensate, natural gas liquids and bitumen.

d Proved reserves in the Prudhoe Bay field in Alaska include an estimated 82 million barrels on which a net profits royalty will be payable over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.

e Includes 20 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

f Includes 310 million barrels of crude oil in respect of the 7.37% minority interest in TNK-BP.

g Includes 2,759 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

h Includes 174 billion cubic feet of natural gas in respect of the 6.27% minority interest in TNK-BP.

i Total proved reserves held as part of our equity interest in TNK-BP is 4,802mmboe comprising 100 million barrels in Venezuela, 14mmboe in Vietnam and 4,688mmboe in Russia. In 2011 BP aligned its reporting with TNK-BP by moving to a life of field reporting basis. Reasonable certainty of licence renewals is demonstrated by evidence of Russian subsoil law, track record of renewals within the industry and track record of success in obtaining renewals by TNK-BP. This has resulted in a 253mmboe increase in proved reserves.

BP s net production by major field for 2011, 2010 and 2009.

Liquids

Subsidiaries	Field or area	BP net share of productiona 2011	2010	2009
				thousand barrels per day
UK[b]	ETAP[c]	**22**	28	34
	Foinaven[d]	**26**	24	29
	Other	**65**	85	105
Total UK		**113**	137	168
Norway[b]	Various	**32**	40	40
Total Rest of Europe		**32**	40	40
Total Europe		**145**	177	208
Alaska	Prudhoe Bay[d]	**64**	67	69
	Kuparuk	**39**	42	45
	Milne Point[d]	**19**	23	24
	Other	**31**	34	43
Total Alaska		**153**	166	181
Lower 48 onshore[b]	Various	**69**	90	97
Gulf of Mexico deepwater[b]	Thunder Horse[d]	**77**	120	133
	Atlantis[d]	**34**	49	54
	Mad Dog[d]	**8**	30	35
	Mars	**19**	23	29
	Na Kika[d]	**14**	25	27
	Horn Mountain[d]	**8**	14	25
	King[d]	**15**	21	22
	Other	**56**	56	62
Total Gulf of Mexico deepwater		**231**	338	387
Total US		**453**	594	665
Canada[b]	Various[d]	**2**	7	8
Total Rest of North America		**2**	7	8
Total North America		**455**	601	673
Colombia[b]	Various[d]	**1**	18	23
Trinidad & Tobago	Various[d]	**31**	36	38
Brazil[b]	Various	**7**		
Total South America		**39**	54	61
Angola	Greater Plutonio[d]	**51**	73	70
	Kizomba C Dev	**21**	31	43
	Dalia	**12**	20	32
	Girassol FPSO	**12**	18	22
	Other	**27**	28	44
Total Angola		**123**	170	211
Egypt[b]	Gupco	**34**	47	55
	Other	**11**	12	16
Total Egypt		**45**	59	71
Algeria[b]	Various	**22**	17	22
Total Africa		**190**	246	304
Azerbaijan[b]	Azeri-Chirag-Gunashli[d]	**86**	94	94
	Other	**8**	9	7
Total Azerbaijan		**94**	103	101
Western Indonesia[b]	Various	**2**	2	5
Iraq	Rumaila	**31**		
Other	Various	**11**	14	17
Total Rest of Asia[b]		**138**	119	123
Total Asia		**138**	119	123
Australia	Various	**23**	30	31
Other	Various	**2**	2	
Total Australasia		**25**	32	31
Total subsidiaries[e]		**992**	1,229	1,400
Equity-accounted entities (BP share)				
Russia TNK-BP[f]	Various	**865**	856	840

Total Russia		**865**	856	840
Abu Dhabi[f]	Various	**209**	190	182
Other	Various	**1**	1	12
Total Rest of Asia[b]		**210**	191	194
Total Asia		**1,075**	1,047	1,034
Argentina	Various	**74**	75	75
Venezuela[b]	Various	**16**	23	25
Bolivia[b]	Various			1
Total South America		**90**	98	101
Total equity-accounted entities		**1,165**	1,145	1,135
Total subsidiaries and equity-accounted entities		**2,157**	2,374	2,535

a Production excludes royalties due to others whether payable in cash or in kind where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

b In 2011, BP sold its holdings in Venezuela and Vietnam to TNK-BP. It also made acquisitions in India through a joint venture with Reliance, Brazil and additional volumes in the US Gulf of Mexico and UK North Sea. BP divested its holdings in Pompano along with other interests in the US Gulf of Mexico, Tuscaloosa and interests in South Texas in the US onshore, a portion of our interest in the Azeri-Chirag-Gunashli development in Azerbaijan, Wytch Farm in the UK, our interests in the REB field in Algeria, and the remainder of our interests in Colombia and Pakistan. In 2010, BP divested its Permian Basin assets in Texas and south-east New Mexico, the East Badr El-Din and Western Desert concession in Egypt, its Canada gas assets and reduced its interest in the King field in the Gulf of Mexico. It also acquired an increased holding in the Azeri-Chirag-Gunashli development in Azerbaijan and the Valhall and Hod fields in the Norwegian North Sea. Four other producing fields in the Gulf of Mexico that were acquired during 2010 were subsequently disposed of in early 2011. In 2009, BP assumed operatorship of the Mirpurkhas and Khipro blocks in Pakistan, swapped a number of assets with BG Group plc. in the UK sector of the North Sea, divested some minor interests in the US Lower 48, divested its holdings in Indonesia s Offshore Northwest Java to Pertamina, divested its interests in LukArco to Lukoil and the Bolivian government nationalized, with compensation payable, Pan American Energy s shares of Chaco.

c Volumes relate to six BP-operated fields within ETAP. BP has no interests in the remaining three ETAP fields, which are operated by Shell.

d BP-operated.

e Includes 28 net mboe/d of NGLs from processing plants in which BP has an interest (2010 29mboe/d and 2009 28mboe/d).

f The BP group holds interests, through associates, in onshore and offshore concessions in Abu Dhabi, expiring in 2014 and 2018 respectively.

Natural gas

Subsidiaries	Field or area	BP net share of production[a] (million cubic feet per day) 2011	2010	2009
UK[b]	Bruce/Rhum[c]	**20**	100	110
	Other	**335**	372	508
Total UK		**355**	472	618
Norway[b]	Various	**13**	15	16
Total Rest of Europe		**13**	15	16
Total Europe		**368**	487	634
Lower 48 onshore[b]	San Juan[c]	**603**	629	659
	Jonah[c]	**145**	185	227
	Anadarko	**141**	137	146
	Arkoma Central	**136**	164	194
	Wamsutter[c]	**122**	126	146
	Arkoma East	**115**	112	67
	Arkoma West	**109**	128	65
	Other	**274**	394	451
Total Lower 48 onshore	Total	**1,645**	1,875	1,955
Gulf of Mexico deepwater[b]	Various	**176**	263	303
Alaska	Various	**22**	46	58
Total US		**1,843**	2,184	2,316
Canada[b]	Various	**14**	202	263
Total Rest of North America		**14**	202	263
Total North America		**1,857**	2,386	2,579
Trinidad & Tobago	Mango[c]	**308**	544	664
	Cashima/NEQB[c]	**570**	679	571
	Kapok[c]	**464**	541	540
	Cannonball[c]	**99**	156	225
	Amherstia[c]	**296**	252	197
	Other[c]	**456**	301	233
Total Trinidad		**2,193**	2,473	2,430
Colombia[b]	Various	**4**	71	62
Total South America		**2,197**	2,544	2,492
Egypt[b]	Temsah	**74**	90	118
	Ha py[c]	**99**	73	94
	Taurt[c]	**61**	75	73
	Other	**210**	192	177
Total Egypt		**444**	430	462
Algeria	Total	**114**	126	159
Total Africa		**558**	556	621
Pakistan[b]	Various[c]	**73**	150	173
Azerbaijan	Various[c]	**140**	132	126
Western Indonesia[b]		**59**	70	106
India[b]	KGD6	**121**	–	–
	Other	**25**		
Total India		**146**		
Vietnam[b]	Various[c]	**69**	77	63
China	Yacheng	**70**	95	83
Oman		**20**		
Sharjah	Various[c]	**41**	50	59
Total Rest of Asia		**618**	574	610
Total Asia		**618**	574	610
Australia	Perseus/Athena	**170**	165	142
	Goodwyn	**72**	118	139
	Angel	**126**	133	120
	Other	**87**	46	39
Total Australia		**455**	462	440
Eastern Indonesia	Tangguh[c]	**340**	323	74

Total Australasia		**795**	785	514
Total subsidiaries[d]		**6,393**	7,332	7,450
Equity-accounted entities (BP share)				
Russia TNK-BP[b]	Various	**699**	640	601
Total Russia		**699**	640	601
Western Indonesia	Various	**26**	30	31
Vietnam[b]		**8**	–	–
Kazakhstan[b]	Various			11
Total Rest of Asia		**34**	30	42
Total Asia		**733**	670	643
Argentina	Various	**371**	379	378
Bolivia[b]	Various	**14**	11	11
Venezuela[b]	Various	**7**	9	3
Total South America		**392**	399	392
Total equity-accounted entities[d]		**1,125**	1,069	1,035
Total subsidiaries and equity-accounted entities		**7,518**	8,401	8,485

a Production excludes royalties due to others whether payable in cash or in kind where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

b In 2011, BP sold its holdings in Venezuela and Vietnam to TNK-BP. It also made acquisitions in India through a joint venture with Reliance, in the Eagle Ford shale in North America and additional volumes in the US Gulf of Mexico. BP divested its holdings in Pompano along with other interests in the US Gulf of Mexico, Tuscaloosa and interests in South Texas in the US onshore, Wytch Farm in the UK, minor volumes in Canada and the remainder of our interests in Colombia and Pakistan. In 2010, BP divested its Permian Basin assets in Texas and south-east New Mexico, the East Badr El-Din concession in Egypt, its Canada gas assets and reduced its interest in the King field in the Gulf of Mexico. It also acquired an increased holding in the Valhall and Hod fields in the Norwegian North Sea. Four other producing fields in the Gulf of Mexico that were acquired during 2010 were subsequently disposed of in early 2011. In 2009, BP assumed operatorship of the Mirpurkhas and Khipro blocks in Pakistan, swapped a number of assets with BG Group plc. in the UK sector of the North Sea, divested some minor interests in the US Lower 48, divested its holdings in Indonesia s Offshore Northwest Java to Pertamina, divested its interests in LukArco to Lukoil and the Bolivian government nationalized, with compensation payable, Pan American Energy s shares of Chaco.

c BP-operated.

d Natural gas production volumes exclude gas consumed in operations within the lease boundaries of the producing field, but the related reserves are included in the group s reserves.

Refining and Marketing

Our Refining and Marketing segment is responsible for the refining, manufacturing, marketing, transportation, and supply and trading of crude oil, petroleum, petrochemicals products and related services to wholesale and retail customers. We have significant operations in Europe, North America and Asia, and we also manufacture and market our products across Australasia, southern Africa and Central and South America; in total we market our products in more than 70 countries.

The segment operates hydrocarbon value chains covering three main businesses: fuels, lubricants and petrochemicals. Previously we referred to lubricants and petrochemicals as international businesses, but to provide greater transparency of the performance of these businesses we are now providing our financial information separately for fuels, lubricants and petrochemicals.

The fuels businesses sell refined petroleum products including gasoline, diesel, aviation fuel and liquefied petroleum gas (LPG). Within this, the fuels value chains (FVCs) integrate the activities of refining, logistics, marketing, and supply and trading on a regional basis. This recognizes the geographic nature of the markets in which we compete, providing the opportunity to optimize our activities from crude oil purchases to end-consumer sales through our physical assets (refineries, terminals, pipelines and retail stations). In addition, we operate a global aviation fuels marketing business and an LPG marketing business.

Our lubricants business is involved in manufacturing and marketing lubricants and related services to markets around the world. We market lubricants to the automotive, industrial, marine, aviation and energy markets through our key brands of Castrol, BP and Aral. Our Castrol brand is a highly recognized and popular lubricant brand worldwide. Distinctive brands, cutting-edge technology and building and sustaining customer relationships are cornerstones to our approach to market and underpin our success. We are particularly strong in Europe and key Asia Pacific markets including India.

Our petrochemicals business operates on a global basis and includes the manufacture and marketing of petrochemicals that are used in many everyday products, such as plastic bottles and textiles for clothing. Technology is at the heart of our business and we own proprietary world class technology for each of our main products. Our technological advantage, operational experience and project execution track record has made us an attractive partner which leads to material and distinctive growth opportunities. Petrochemicals growth is focused on the demand centre of Asia.

Our market

Overall world economic growth slowed in 2011, as did growth in world oil consumption. Global oil demand grew by 0.7 million b/d, but in the OECD, demand contracted again after growing for the first time in five years in 2010. By contrast, there was demand growth in Australia and Japan, where oil partially replaced nuclear power after the earthquake and tsunami. Aggregate OECD oil demand in 2011 was 4.3 million b/d below the 2005 peak.

The annual average BP refining marker margin (RMM) in 2011 was 16% higher than in 2010, averaging $11.64 per barrel. Margins followed a typical seasonal pattern, with a peak in the second quarter in the run-up to the summer driving season. The RMM is an environmental indicator, similar to those used by many of our competitors, and is weighted regionally based on our refining capacity in that part of the world. Each regional marker margin is based upon product yields and a marker crude oil deemed appropriate for the region.

The RMM uses regional crack spreads to calculate the margin indicator, and does not include estimates of fuel costs and other variable costs. The RMMs may not be representative of the margins achieved by BP in any period because of BP s particular refinery configurations and crude and product slate. However, the RMM is useful for understanding the indicative refining margin environment that is available to refiners in each region.

$ per barrel

	Crude marker	**2011**	2010	2009
Refining marker margin (RMM)				
US West Coast	ANS	**13.63**	13.09	13.40
US Gulf Coast	Mars	**11.87**	10.17	9.16
US Midwest	LLS	**7.46**	6.00	6.02
Northwest Europe	Brent	**11.85**	10.36	8.95
Mediterranean	Azeri Light	**9.03**	8.82	7.93
Singapore	Dubai/Tapis blend	**14.57**	10.69	8.51
BP Average RMM		**11.64**	10.02	9.19

In 2011, refining margins increased in all the main US regions, despite a contraction in domestic gasoline demand, with reduced gasoline import volumes compensated for by higher domestic crude runs.

In Europe, where diesel accounts for a large proportion of regional consumption, refining margins increased for a second year running despite the loss of Libyan sweet crude supplies for much of the year, as demand for commercial transport improved.

Refining margins also improved in Asia Pacific, averaging $14.57 per barrel due to continuing oil demand growth and the disruption to Japanese refining operations caused by the earthquake and tsunami.

US mid-continent crude oils (including West Texas Intermediate (WTI)) were heavily discounted throughout the year because of increasing production in the US mid-continent and Canada, coupled with constrained infrastructure for crude transportation. This particularly benefited BP s location-advantaged refineries of Toledo and Whiting in the US Midwest. In addition, fuel oil price discounts versus crude oil widened in 2011, benefiting our highly upgraded refineries that produce relatively little fuel oil.

In oil markets in 2011, supply was hampered by geo-political issues and a series of technical problems in non-OPEC crude production. This supply deficit brought OECD stocks down from historical highs to near-average levels within the first nine months of the year. After very low volatility levels in the second half of 2009 and in 2010, 2011 saw a return towards more average volatility.

In lubricants, we saw modest improvement in demand for the automotive and industrial sectors early in the year, but this came under increasing pressure as the year progressed and by the fourth quarter demand was declining in many geographies. Base oil prices rose markedly in the first half of the year, increasing our input costs. We continued to see a gradual shift towards higher-quality and higher-margin premium and synthetic lubricants.

In the first half of 2011, the petrochemicals margin environment was markedly different from the second half, due to strong demand for purified terephthalic acid (PTA) coupled with supply interruptions in both PTA and paraxylene (PX) leading to robust margins. In contrast the second half of the year saw the installed capacity run normally along with significant new capacity coming onstream. In addition concerns over the global economy affected demand, leading to a rapid reduction in margins. Acetic acid had a similar margin profile to PTA with supply interruptions in the first half leading to higher margins followed by weaker margins in the second half of the year as additional capacity came onstream.

Our strategy

Refining and Marketing is the product and service-led arm of BP, focused on fuels, lubricants and petrochemicals products and related services. We aim to be excellent in the markets in which we choose to participate those that allow BP to serve the major energy markets of the world. We pursue competitive returns and sustainable growth, underpinned by safe manufacturing operations and technology, as we serve customers and promote BP and our brands through high-quality products.

We are focused on a consistent set of priorities executed in a systematic and disciplined way. These priorities begin with safety and include excellence of execution, portfolio quality and integration and growing margin share via exposure to growth. This is all underpinned by a disciplined financial framework. We believe that we now have a platform to sustain a world-class downstream business, which will enable us to be a leader in each of our chosen markets. Over time, we expect to shift the balance of participation and capital employed from established to growth regions.

In March 2010, we set a target to shareholders to deliver a performance improvement of at least $2 billion by 2012 relative to a 2009 baseline and we believe we are on track to deliver this by the end of 2012[a]. In addition, post-2012, we plan to grow our margin further through our focus on growth markets and expansion of our margin capture capability, which we expect to achieve through projects such as those described below.

In our fuels business, as previously announced, we are planning to dispose of our Texas City refinery and the southern part of the US West Coast FVC before the end of 2012. We are investing in our existing operations to sustain safe, compliant standards and selectively investing in cash margin capture projects. The largest of these projects is the repositioning of the Whiting refinery towards heavy feedstock advantage, which is already under way and scheduled to come onstream in the second half of 2013. In addition to the repositioning of the Whiting refinery, margin capture projects include the Cherry Point refinery clean diesel project, Toledo refinery continuous catalytic reforming project, Gelsenkirchen refinery margin improvement programme and the recently announced Brazil aviation acquisition (see *Acquisitions and disposals section on page 97).*

We are also well positioned for growth in our lubricants and petrochemicals businesses. In our lubricants business, around half of our profit growth in recent years has come from the emerging economies in non-OECD countries as we have expanded in these markets. We have a material presence in the Indian automotive lubricant market. These positions provide a strong base to capture further long-term growth. In petrochemicals around 45% of our capacity is in the demand centre of Asia. Growth options are enabled by our distinctive technology, operational capability and access through key strategic relationships. During 2011 the latest example of our strategy deployment was the signing of a memorandum of understanding with IndianOil Corp (IOC) to explore the potential for establishing a 50:50 joint venture to invest in a 1 million tonne per annum (mtpa) acetic acid plant in Gujarat, India. The joint venture will use BP s latest Cativa® catalyst and technology, while the associated gasification facilities would utilize petroleum coke feedstock from IOC. Additionally, in 2011 BP received local government approval for a 1.25mtpa PTA plant in Zhuhai, China, and is now seeking final central governmental approval.

From 2012 we plan to create a new revenue stream in petrochemicals through licencing our technology, beginning with our aromatics products of PX and PTA.

As part of our drive towards more efficient operations, we have been transforming our back office. In 2011, we made further progress on our global SAP implementation within the fuels and lubricants businesses. We also continued to expand the scale of our business service centres (BSCs). BSCs are regional centres for certain finance, operational procurement and IT services for the BP group.

a This performance improvement will be measured by comparing Refining and Marketing s replacement cost profit before interest and tax for 2009 with that of 2012, after adjusting for non-operating items, fair value accounting effects and the impact of changes in the refining margin and petrochemicals environment (including energy costs), foreign exchange impacts and price-lag effects for crude and product purchases. This adjusted measure of replacement cost profit before interest and tax is non-GAAP. We believe the measure is useful to investors because it is one that is viewed and closely tracked by management as an important indicator of segment performance.

Our performance

2011 performance

Safety and operational risk

Safety remains the top priority across BP, and we are committed to leadership in process safety and to ensuring that our operations are safe, compliant and reliable with regard to both personal and process safety.

Refining and Marketing utilizes the group s operating management system (OMS). OMS provides a set of group-wide requirements and a systematic way of working to continuously improve the way we operate. *(OMS is explained in more detail on page 65).* While all Refining and Marketing entities have transitioned on to OMS, we continue to work to enhance local systems and processes at all our sites.

All our major manufacturing entities (refineries and petrochemicals sites) have been through two performance improvement cycles (PIC) of OMS, and all other entities across our FVCs will have completed their second PIC by the end of 2012. The PIC is a management review carried out within each entity of their local operating management system, which identifies areas where further actions can be taken to enhance our systems and processes. These actions are risk-prioritized and form an integral part of each entity s annual and longer-term planning. Where appropriate, actions are aggregated to provide common solutions.

Direction and oversight of safety in Refining and Marketing is provided by the segment operating risk committee (SORC) chaired by the chief executive officer of Refining and Marketing. Monitoring of safety and compliance in our operations is conducted by the newly-formed safety and operational risk function, for which there is a Refining and Marketing segment team independent of the segment CEO.

As outlined on page 65, BP has further strengthened its risk review process, and this process was applied to Refining and Marketing to ensure that appropriate risk management and mitigating actions were prioritized throughout the segment.

We measure our personal safety performance through the employment of a recordable injury frequency (RIF) rate and a days away from work case frequency (DAFWCF) rate, as well as a severe vehicle accident rate.

In 2011, our RIF (measured by the number of recordable injuries to the BP workforce per 200,000 hours worked) was 0.37, slightly higher than the 2010 rate of 0.35. The 2011 DAFWCF (a subset of the RIF that measures the number of cases where an employee misses one or more days from work) was 0.108, compared with 0.114 in 2010. There was a significant improvement in the severe vehicle accident rate (SVAR) in 2011 with 61 severe vehicle accidents compared with 77 in 2010.

While progress has been made in the area of personal safety, there were two workplace fatalities in 2011. These tragic events have been fully investigated, and the learnings shared and actioned.

Process safety is measured by the process safety incident index (PSII), a weighted index which reflects both the number and severity of events per 200,000 hours worked. The PSII for 2011 was 0.36, equal to the 2010 rate, and better than the 2009 rate of 0.48. While the number of PSII events has increased from 2010, the overall severity of the events has reduced.

In terms of operational integrity, the number of losses of primary containment (LOPC), a measure of unplanned or uncontrolled releases of material from primary containment, was 5% lower in 2011 than in 2010. The number of oil spills greater than one barrel was slightly higher in 2011 (145) than 2010 (132) however the volumes of oil spills were significantly lower in 2011 than in 2010 at 0.4 million litres compared with 1.3 million litres respectively.

In our US refineries, we continue to implement the recommendations of the BP US Refineries Independent Safety Review Panel and regulatory bodies. *See the Safety section on page 67 for further information on progress.*

Financial and operating performance

			$ million
	2011	2010	2009
Replacement cost profit (loss) before interest and tax[a]			
Fuels[b]	**3,003**	2,628	(914)
Lubricants	**1,350**	1,357	1,059
Petrochemicals[c]	**1,121**	1,570	598
	5,474	5,555	743
Sales and other operating revenues[d]	**344,116**	266,751	213,050
Capital expenditure and acquisitions	**4,130**	4,029	4,114
			thousand barrels per day
Total refinery throughputs[e]	**2,352**	2,426	2,287
			%
Refining availability[f]	**94.8**	95.0	93.6
			thousand tonnes
Total petrochemicals production[g]	**14,866**	15,594	12,660

a Income from petrochemicals produced at our Gelsenkirchen and Mulheim sites is reported within the fuels business. Segment level overhead expenses are included within the fuels business.

b 2009 includes a $1.6 billion impairment of goodwill in the US West Coast FVC.

c 2010 includes $338 million gain from non-operating items.

d Includes sales between businesses.

e Refinery throughputs reflect crude oil and other feedstock volumes.

f Refining availability represents Solomon Associates operational availability, which is defined as the percentage of the year that a unit is available for processing after subtracting the annualized time lost due to turnaround activity and all planned mechanical, process and regulatory maintenance downtime.

g Petrochemicals production includes 1,699kte of petrochemicals produced at our Gelsenkirchen and Mulheim sites in Germany for which the income is reported in our fuels business.

Replacement cost profit before interest and tax for the year ended 31 December 2011 was $5,474 million, compared with $5,555 million for the previous year. The full-year results included a net loss for non-operating items of $602 million, compared with a gain of $630 million in 2010. The non-operating items in 2011 mainly related to impairment charges relating to our disposal programme, partially offset by gains on disposal. (*See page 58 for further information on non-operating items).* In addition, fair value accounting effects had a favourable impact of $63 million, compared to a favourable impact of $42 million in 2010. (*See page 58 for further information on fair value accounting effects.)*

After adjusting for non-operating items and fair value accounting effects, Refining and Marketing reported record earnings in 2011[a].

Strong refinery operations enabled us to capture the benefits available in 2011 from BP s location advantage in accessing WTI-based crude grades. Compared with 2010, the result also benefited from a higher refining margin environment and a stronger supply and trading contribution. These benefits were partly offset by a significantly higher level of turnarounds in 2011 than 2010 and negative impacts from increased relative sweet crude prices in Europe and Australia and the weather-related power outages in the second quarter.

In the fuels business, financial performance for the full year was impacted by the factors noted above. Operational performance was strong with Solomon refining availability at 94.8% and refinery utilisation at 88% for the year.

Performance in our lubricants business in 2011 was impacted by an increasingly difficult marketing environment characterized by significant base oil price increases and weaker demand. These impacts were partly offset by supply chain efficiencies, and the strength of our products and brands, which has allowed the increased cost of goods to be largely recovered in the market.

In our petrochemicals business, compared with 2010, the 2011 result was negatively impacted by weakening market conditions as the year progressed, as additional Asian capacity came onstream during the year at a time of weaker demand. This was somewhat offset by the strength in aromatics margins and volumes in the first half of the year.

a In 2011, there was a charge of $602 million for non-operating items and a favourable impact of $63 million for fair value accounting effects. After adjusting for these impacts, replacement cost profit before interest and tax was $6,013 million. This is a non-GAAP measure, which management believes is useful to investors because it is viewed and closely tracked by management as an important indicator of segment performance.

Sales and other operating revenues for 2011, analysed in the table below, were $344 billion, compared with $267 billion in 2010 and $213 billion in 2009. These increases were primarily due to increasing oil prices.

Sales and other operating revenues[a]	2011	2010	2009
			$ million
Sale of crude oil through spot and term contracts	**57,055**	44,290	35,625
Marketing, spot and term sales of refined products	**273,940**	209,221	166,088
Other sales and operating revenues	**13,121**	13,240	11,337
	344,116	266,751	213,050

a Includes sales between businesses.

The following table sets out oil sales volumes by type for the past three years. Marketing sales volumes were 3,311mb/d, slightly lower than 2010, principally reflecting reduced demand in some OECD markets and simplification of our portfolio.

Refined products volumes	2011	2010	2009
			thousand barrels per day
Marketing sales[a]	**3,311**	3,445	3,560
Trading/supply sales[b]	**2,465**	2,482	2,327
Total refined product marketing sales	**5,776**	5,927	5,887
Crude oil[c]	**1,532**	1,658	1,824
Total oil sales	**7,308**	7,585	7,711

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

b Trading/supply sales are sales to large unbranded resellers and other oil companies.

c Crude oil sales relate to transactions executed by our integrated supply and trading function, primarily for optimizing crude oil supplies to our refineries and in other trading. 79 thousand barrels per day relate to revenues reported by Exploration and Production.

Prior years comparative financial information

The replacement cost profit before interest and tax for the year ended 31 December 2010 of $5,555 million included a net gain for non-operating items of $630 million, mainly relating to gains on disposal, partly offset by restructuring charges. Almost half of this gain related to our petrochemicals business, mainly relating to the disposal of our share of BP s interests in ethylene and polyethylene production in Malaysia to Petronas. In addition, fair value accounting effects had a favourable impact of $42 million relative to management s measure of performance. The primary additional factors contributing to the increase in replacement cost profit before interest and tax compared with 2009 were improved operational performance in the FVCs, continued strong operational performance in lubricants and petrochemicals, and further cost efficiencies, as well as a more favourable refining environment. Against very good operational delivery, the results were impacted by a significantly lower contribution from supply and trading compared with 2009.

The replacement cost profit before interest and tax for the year ended 31 December 2009 of $743 million included a net charge for non-operating items of $2,603 million. The most significant non-operating items were restructuring charges and a $1.6 billion one-off non-cash loss to impair all of the segment s goodwill in the US West Coast FVC relating to our 2000 ARCO acquisition. This resulted from our annual review of goodwill as required under IFRS and reflected the prevailing weak refining environment that, together with a review of future margin expectations in the FVC, led to a reduction in expected future cash flows.

Acquisitions and disposals

We have been managing our portfolio actively, investing in businesses where we have strengths in terms of location, configuration, integration, technology and brand, while divesting assets that do not display these strategic characteristics.

- We completed the divestment programme of non-strategic pipelines and terminals in the US East of Rockies and West Coast, announced in 2009.
- We completed the disposal of our fuels marketing businesses in Malawi, Namibia, Tanzania, Zambia and Zimbabwe following the 2010 disposal of the business in Botswana. This portfolio rationalization now allows us to focus our activities within the continent on South Africa and Mozambique.
- We also announced our intention to divest the Texas City refinery and the southern part of the US West Coast FVC, including the Carson refinery, roughly halving our US refining capacity. BP is aiming to complete the sales by the end of 2012 subject to signing definitive agreements for the sales and subsequent satisfaction of any legal, regulatory or other conditions. BP will ensure that the fulfilment of current regulatory obligations associated with the Texas City refinery is reflected in any transaction. These assets are classified as held for sale in the group balance sheet as at 31 December 2011.
- In December 2011, Air BP announced the purchase of aviation fuels assets at seven Brazilian airports from Shell Brasil Holding B.V. and Cosan S.A. Industria e Commercio for approximately $100 million. The acquisition will give Air BP access to several new airports in Brazil as well as increasing capacity at existing Air BP operations. This deal is expected to be completed in the first quarter of 2012 subject to regulatory approvals.
- In February 2012, we announced our intent to sell our bulk and bottled LPG marketing businesses in nine countries.

Fuels

Our fuels business is made up of six regionally organized integrated FVCs (as shown in the refineries table below), the Texas City refinery, our global aviation fuel and LPG marketing businesses, and a number of regionally-focused fuels marketing businesses notably the UK, Turkey, China and France. At the end of 2011, the operating capital employed relating to the fuels business was approximately $44 billion.

Fuels value chains

The six FVCs seek to optimize the activities of our assets across the supply chain: crude delivery to the refineries; manufacture of high-quality fuels; distribution through pipeline and terminal infrastructure; and marketing and sales to our customers on a regional basis (*see map on pages 34-35*). This integration, together with a focus on excellent execution and cost management as well as a strong brand, market presence and customer base, are key to our financial performance.

The FVC strategy focuses on feedstock-advantaged, upgraded, well-located refineries integrated into advantaged logistics and marketing. Consequently, in the US we intend to roughly halve our US refining capacity by the end of 2012 (subject to all necessary legal and regulatory approvals) (see *also the Acquisitions and disposals section on this page).*

In our remaining FVCs, we believe that we have a portfolio of well-located refineries, integrated with strong marketing positions offering the potential for improvement and growth. We currently own or have a share in 16 refineries, which refine crude oil and produce refined fuel products which we supply to retail and commercial customers. Strategic investments in our refineries are focused on securing the safety and reliability of our assets while improving our competitive position.

Key to our future refining capability is the Whiting refinery modernization project (WRMP), which will allow the capture of additional margin through the processing of heavy Canadian crudes. The project continued to make significant progress in 2011. The coker s six new drums are now set in place, and the Southern Lights pipeline to Canada, and Whiting s interconnection to it, are in operation. This new pipeline capability allows transport of diluent streams back to Canada which are used to dilute heavy Canadian oils to facilitate their flow back to the US. WRMP is expected to come onstream in the second half of 2013.

The following tables summarize the BP group s interests in refineries and average daily crude distillation capacities as at 31 December 2011.

	thousand barrels per day
	Crude distillation capacitiesa

	Refinery	Fuels value chain	Group interest[b] %	Total	BP share
US					
California	Carson	US West Coast	100.0	266	266
Washington	Cherry Point	US West Coast	100.0	234	234
Indiana	Whiting	US East of Rockies	100.0	413	413
Ohio	Toledo	US East of Rockies	50.0	160	80
Texas	Texas City		100.0	475	475
Total US				1,548	1,468
Europe					
Germany	Bayernoil[c]	Rhine	22.5	217	49
	Gelsenkirchen	Rhine	50.0	265	132
	Karlsruhe[c]	Rhine	12.0	322	39
	Lingen	Rhine	100.0	93	93
	Schwedt[c]	Rhine	18.8	239	45
Netherlands	Rotterdam	Rhine	100.0	377	377
Spain	Castellón	Iberia	100.0	110	110
Total Europe				1,623	845
Rest of World					
Australia	Bulwer	ANZ	100.0	102	102
	Kwinana	ANZ	100.0	146	146
New Zealand	Whangerei[c]	ANZ	23.7	118	28
South Africa	Durban[c]	Southern Africa	50.0	180	90
Total Rest of World				546	366
Total				3,717	2,679

a Crude distillation capacity is gross rated capacity, which is defined as the highest average sustained unit rate for a consecutive 30-day period.
b BP share of equity, which is not necessarily the same as BP share of processing entitlements.

c Indicates refineries not operated by BP.

Business review

The table below summarizes the volume, by region, of crude oil and feedstock processed by BP for its own account and for third parties. Utilization data is also summarized below.

			thousand barrels per day
Refinery throughputs[a]	**2011**	2010	2009
US	**1,277**	1,350	1,238
Europe	**771**	775	755
Rest of World	**304**	301	294
Total	**2,352**	2,426	2,287
Refinery capacity utilization			
Crude distillation capacity at 31 December[b]	**2,679**	2,667	2,666
Refinery utilization[c]	**88%**	91%	86%
US	**87%**	93%	85%
Europe	**91%**	91%	89%
Rest of World	**84%**	84%	83%

a Refinery throughputs reflect crude oil and other feedstock volumes.

b Crude distillation capacity is gross rated capacity, which is defined as the highest average sustained unit rate for a consecutive 30-day period.

c Refinery utilization is annual throughput divided by crude distillation capacity, expressed as a percentage.

Overall refinery throughputs decreased by 74mb/d in 2011 relative to 2010, mainly due to the second quarter weather-related power outages in the US.

We continue to invest to develop the capability of producing cleaner fuels to meet the requirements of our customers and their communities. For example, in April 2011, BP announced a major investment in a new hydrotreater unit and hydrogen plant at our Cherry Point refinery, called the clean diesel project. This project will allow the refinery to produce fuels that meet ultra-low sulphur diesel (ULSD) standards for rail and marine diesel customers. In addition, the new hydrogen plant will allow improved operation of naphtha reforming units at the refinery.

In addition to refined petroleum products, we also blend and market biofuels at our refineries. Biogasoline (bioethanol) and biodiesel (hydrogenated vegetable oils and fatty acid methyl esters) continue to grow in volume, primarily in Europe and the US, as regulatory requirements demand heavier blending levels. Our response is to continue to develop blend capabilities and to work with regulators, biofuels supply chains and other stakeholders to improve the sustainability of the biofuels we blend and supply.

Downstream of our refineries, our priorities are to operate an advantaged infrastructure and logistics network (which includes pipelines, storage terminals and road or rail tankers), drive excellence in operational and transactional processes, and deliver compelling customer offers in the various markets in which we operate.

We supply fuel and related convenience services to retail consumers through company-owned and franchised retail sites, as well as other channels, including wholesalers and jobbers. We also supply commercial customers within the transport and industrial sectors.

Our retail network is largely concentrated in Europe and the US, but also has established operations in Australasia, and southern Africa. We have developed networks in China in two separate joint ventures, one with PetroChina and the other with China Petroleum and Chemical Corporation (Sinopec) and these joint ventures in China operate around 700 dual branded sites.

As at 31 December 2011, BP s worldwide retail network consisted of some 21,800 sites across the US, Europe, Australia, New Zealand and southern Africa. This is a reduction of 300 since 2010, primarily due to a focus on fewer higher throughput sites and portfolio changes such as the southern African disposals. These retail sites are primarily branded BP, ARCO and Aral. We expect the number of sites to fall in 2012 as we dispose of the southern part of our US West Coast FVC. In 2011, branded fuels sales in the US continued to recover from the oil effects of the Deepwater Horizon oil spill, and market share stabilized but remained lower than before the oil spill, partly caused by the slowdown in US gasoline demand. We continue to invest in our fuels marketing in growing markets, for example in 2011, we piloted a new convenience retail offer in Poland with Carrefour.

The table below shows the number of BP-branded retail sites by region.

			Number of retail sites operated under a BP brand
Retail sites[a b]	**2011**	2010	2009
US	**11,300**	11,300	11,500
Europe	**8,200**	8,400	8,600
Rest of World	**2,300**	2,400	2,300
Total	**21,800**	22,100	22,400

a The number of retail sites includes sites not operated by BP but instead operated by dealers, jobbers, franchisees or brand licensees that operate under a BP brand. These may move to or from the BP brand as their fuel supply or brand licence agreements expire and are renegotiated in the normal course of business. Retail sites are primarily branded BP, ARCO and Aral.
b Excludes our interest in equity-accounted entities which are dual-branded.

Some of these retail sites include a convenience store which offers consumers a range of food, drink and other consumables and services in a convenient and innovative manner. The convenience offer includes brands such as *ampm,* Wild Bean Café and Petit Bistro and includes partnerships with leading retailers such as Marks & Spencer in the UK and Carrefour in Poland.

BP s integrated supply and trading function is responsible for delivering value across the overall crude and oil products supply chain. This structure enables the optimization of BP s FVCs to maintain a single interface with the oil trading markets and to operate with a single set of trading compliance processes, systems and controls. The oil trading business (including support functions) has trading offices in Europe, the US and Asia and employs around 1,500 people. This enables the function to maintain a presence in the more actively traded regions of the global oil markets in order to gain an overall understanding of the supply and demand forces across this market. It has a two-fold strategic purpose in our business.

First, it seeks to identify the best markets and prices for our crude oil, source optimal feedstocks for our refineries, and provide competitive supply for our marketing businesses. In addition, where refinery production is surplus to marketing requirements or can be sourced more competitively, it is sold into the market. Wherever possible, the group will look to optimize value across the supply chain. For example, BP will often sell its own crude and purchase alternative crudes from third parties for its refineries where this will provide incremental margin.

Second, the function seeks to create and capture incremental trading opportunities. It enters into the full range of exchange-traded commodity derivatives, over-the-counter (OTC) contracts and spot and term contracts *(described in Certain definitions commodity trading contracts on page 111*). In order to facilitate the generation of trading margin from arbitrage, blending and storage opportunities, it also owns and contracts for storage and transport capacity. The group has developed a risk governance framework to manage and oversee the financial risks associated with this trading activity, *see Financial statements Note 26 on pages 217-222.*

The group s trading activities in oil are managed by the integrated supply and trading function. In order to carry out the unique delegations from the BP group, the integrated supply and trading function operates and enforces a robust system of internal control. The internal control systems operated by the regional business leads are augmented by internal support functions that provide independent oversight, including product control, risk, trade completion and accounting and reporting. They are further supported by regional and group ethics and compliance and group internal audit.

Aviation

Our global aviation business, Air BP, is one of the world s largest and best known aviation fuels suppliers, serving many major commercial airlines as well as the general aviation and military sectors. We have marketing sales in excess of 450 thousand barrels per day. Air BP s strategic aim is to grow its position in the core locations of Europe, the US, Australasia and the Middle East, while focusing its portfolio towards airports that offer long-term competitive advantage.

LPG

Our global LPG marketing business sells bulk, bottled, automotive and wholesale LPG products in 10 countries, with sales of over 50 thousand barrels per day. As noted in the Acquisitions and disposals section, BP announced in February 2012 its intent to sell the bulk and bottled LPG businesses in nine countries, and will retain the autogas and wholesale LPG sales from refineries which will be integrated into the fuels value chains.

Lubricants

Our lubricants business manufactures and markets lubricants and related products and services to the automotive, industrial, marine, aviation and energy markets across the world. At the end of 2011, the operating capital employed relating to the lubricants business was approximately $5 billion including goodwill of around $3 billion (*see Financial statements Note 10 on pages 206-207*).

We organize our lubricants business into customer sectors. The automotive sector serves the needs of land-based vehicles including cars, trucks, motorbikes, buses, tractors, earth movers and other vehicles. Our industrial sector serves customers who run or maintain plant and equipment; our marine sector serves users of river and sea-going vessels; aviation serves aircraft operators and maintenance industries; and our energy sector serves the oil and gas and power industries.

In the automotive lubricants sector, which accounts for more than two-thirds of our lubricants sales, we supply lubricants and other related products and services to intermediate customers such as retailers and workshops. These, in turn, serve end-consumers such as car, truck and motorcycle owners.

BP s marine lubricants business is one of the largest global suppliers of lubricants to the marine industry, with a global presence in over 800 ports. BP s industrial lubricants business is a leading supplier to those sectors of the market involved in the manufacturing of automobiles, trucks, machinery components and steel. We are also a leading supplier of lubricants for the oil, gas and aviation industries. In the oil and gas industry we supply some of world s largest production and drilling companies, and we estimate that we supply over 30% of the world s subsea control fluids. In the aviation industry, we are the lubricants supplier for around 40% of the jet engines of the world s commercial airlines.

We look to market and sell our products across the world. We sell products direct to our customers in around 45 countries and use approved local distributors for other geographies. Approximately 40% of our employees are located in non-OECD markets and around 20% of staff are located in China and India alone. We are particularly strong in Europe and key Asia Pacific markets including India.

Our lubricants business markets primarily through our major brands of Castrol and BP, and through the Aral brand in specific European markets, notably Germany. Castrol is a recognized brand worldwide and we believe it provides us with a significant competitive advantage.

Distinctive brands, superior technology and building and sustaining customer relationships remain the cornerstones of our long-term strategy.

Our participation in the value chain is focused on areas of competitive differentiation and strength. These fall into three main areas: the development of formulations and the application of cutting-edge technology; developing product brands and communicating the benefits that our products provide to our customers; and building and extending our relationships with customers so that our products and services are delivered in a manner which best meets their needs.

We have chosen not to participate at scale in base oil or additives manufacturing. We are, however, one of the largest purchasers of base oil in the market.

We participate in blending in locations where scale and competitive advantage can be sustained, or where customer service or security of supply are of critical importance and otherwise difficult to secure. We have a network of 27 wholly-owned and operated blending plants worldwide and joint ownership in five others operated by third parties.

Our focus is on developing premium products, and we often work alongside original equipment manufacturers (OEMs) in doing this. The new Castrol EDGE professional range was launched in 2011 to the franchised workshop market in Europe and Africa.

In 2011, approximately 45% of the lubricants replacement cost profit before interest and tax was generated from non-OECD markets.

Petrochemicals

Our petrochemicals business is global, with operations in the US, Europe and Asia. The business buys a range of feedstocks for input into our manufacturing units, the majority of which have been built and operate utilizing our proprietary technology. We manufacture and market four main product lines: purified terephthalic acid (PTA), paraxylene (PX), acetic acid, and, through joint ventures, olefins and derivatives (O&D). We also produce a number of other speciality petrochemicals products. At the end of 2011, the operating capital employed relating to the petrochemicals business was approximately $5 billion.

Our strategy is to leverage our industry-leading technology in the markets in which we choose to participate, to grow the business, and to deliver industry-leading returns. New investments are targeted principally in the higher-growth Asian markets. We both own and operate 100%-owned assets, and have also invested in a number of joint ventures in Asia, where our partners are leading companies within their domestic market.

PTA is a raw material used in the manufacture of polyesters used in fibres, textiles and film, and polyethylene terephthalate (PET) bottles. PTA production requires PX as a feedstock, which we produce in the US and Europe and buy in Asia. PTA is then reacted with glycol to produce polyester chips or fibres, which are in turn used to produce PET bottles, polyester fibres and various speciality products, including protective screens for computers and TVs. PX production is primarily from the mixed xylene stream produced in a reformer within a refinery.

Acetic acid is a versatile intermediate chemical used in a variety of products such as paints, adhesives and solvents, as well as in the production of PTA. In producing acetic acid, we purchase methanol and either make or buy carbon monoxide (CO). CO can be produced from a variety of hydrocarbon feedstocks, including natural gas, naphtha, fuel oil and coal.

Our O&D business is based in China and is focused on serving the Chinese and Asian markets. The SECCO joint venture between BP, Sinopec and its subsidiary, Shanghai Petrochemical Company, is our main O&D site and is BP s single largest investment in China. BP also co-owns one other naphtha cracker site outside Asia, which is integrated with our Gelsenkirchen refinery in Germany.

The petrochemicals business runs 16 manufacturing sites in the UK, the US, Belgium, Germany, China, Indonesia, South Korea, Malaysia and Taiwan, including our joint ventures, and we also have two petrochemicals plants which are managed by the fuels business as they utilize feedstock from our Gelsenkirchen refinery.

Business review

The table below summarizes BP s petrochemicals production capacity, at 31 December 2011.

Petrochemicals production capacity[a b]

Geographical area	Site	Product	Group interest %	BP share of capacity thousand tonnes per year
US				
	Cooper River	Purified terephthalic acid (PTA)	100.0	1,345
	Decatur	PTA	100.0	1,026
		Paraxylene (PX)	100.0	1,101
		Naphthalene dicarboxylate	100.0	29
	Texas City	Acetic acid	100.0[c]	583[c]
		PX	100.0	1,271
		Metaxylene	100.0	123
				5,478
Europe				
UK	Hull	Acetic acid	100.0	544
		Acetic anhydride	100.0	157
		Ethylidene diacetate	100.0	4
Belgium	Geel	PTA	100.0	1,330
		PX	100.0	631
Germany[d]			50.0 to	
	Gelsenkirchen	Olefins and derivatives	61.0	1,837[b e]
	Mülheim	Solvents	50.0	130[b]
				4,633
Rest of World				
China	Caojing	Olefins and derivatives	50.0	3,230[b]
	Chongqing	Acetic acid	51.0	217 [b]
		Esters	51.0	52[b]
	Nanjing	Acetic acid	50.0	274[b]
	Zhuhai	PTA	85.0	1,564[f]
Indonesia	Merak	PTA	50.0	253[b]
South Korea	Ulsan	Acetic acid	51.0	267[b]
		Vinyl acetate monomer	34.0	65[b]
Malaysia	Kertih	Acetic acid	70.0	391 [b]
	Kuantan	PTA	100.0	610
Taiwan	Kaohsiung	PTA	61.4	847[b]
	Taichung	PTA	61.4	474[b]
	Mai Liao	Acetic acid	50.0	181[b]
				8,425
Total BP share of capacity at 31 December 2011				18,536

a Petrochemicals production capacity is the proven maximum sustainable daily rate (MSDR) multiplied by the number of days in the respective period, where MSDR is the highest average daily rate ever achieved over a sustained period.
b Includes BP share of equity-accounted entities, as indicated.
c Group interest is quoted at 100%, reflecting the capacity entitlement which is marketed by BP.
d Due to the integrated nature of these plants with our Gelsenkirchen refinery, the income and expenditure of these plants is managed and reported through the fuels business.
e Group interest varies by product.
f BP Zhuhai Chemical Company Ltd is a subsidiary of BP, the capacity of which is shown above at 100%.

Outlook

In 2012, we expect the overall economic environment to be challenging, with below-average growth. Emerging economies are likely to drive growth, while developing countries are expected to lag behind. We expect that refiners will continue to operate with excess capacity globally, despite the announced shutdown of refineries in the US East Coast and Europe. The RMM in 2012 is expected to remain in a range of $8-12 per barrel. We expect the differential between WTI and Brent crude to eventually return to lower levels as additional US pipeline capacity is brought online. The level of BP s refinery turnaround activity is expected to be broadly similar in 2012 compared with 2011.

We expect the marketing environment for lubricants to remain challenging given the outlook for global economic growth. Longer term however, we expect to see growth in global lubricants demand through to 2020 as a result of continued growth in the number of vehicles, continuing industrialization in emerging markets, and expanding world trade. This growth is expected to be concentrated in non-OECD markets. Lubricants demand is also expected to continue to shift towards higher quality, premium products as new vehicles adopt advanced, smaller, more efficient engines placing greater demands on lubricant performance.

In the petrochemicals industry, we expect significant new capacity to come onstream in acetic acid and PTA in 2012, 7% and 15% of global capacity respectively. Demand is expected to remain robust in 2012, but not sufficient to absorb the additional capacity, hence we expect the margin environment to be weaker in 2012 than in 2011.

Our priorities in 2012 remain consistent with those in 2011 and 2010. We will continue to focus on delivering safe, reliable and compliant operations, improving the performance of our integrated FVCs, and driving further cost efficiencies across all our businesses. We intend to increase our investment levels slightly in 2012 versus 2011 and 2010, focusing on key safety and operational integrity priorities, maintaining our quality manufacturing and marketing portfolio, strengthening our US East of Rockies FVC business through the Whiting refinery modernization project, and continuing to grow our advantaged petrochemicals business in China. We intend to continue to upgrade our portfolio through investments in advantaged assets and the completion of our divestment programme, including the US southern west coast FVC and the Texas City refinery, announced in February 2011.

Other businesses and corporate

Other businesses and corporate comprises the Alternative Energy business, Shipping, Treasury (which includes interest income on the group s cash and cash equivalents), and corporate activities worldwide. It also included the group s aluminium business until its disposal in 2011.

The replacement cost loss before interest and tax for the year ended 31 December 2011 was $2,478 million, compared with $1,516 million for the previous year. 2011 included a net charge for non-operating items of $822 million. *(See page 58 for further information on non-operating items.)* The primary additional factors affecting 2011 s result compared with that of 2010 were significantly higher functional and corporate costs; loss of aluminium contribution following disposal of the group s aluminium business in 2011; impacts of restructuring in the Alternative Energy business; higher Shipping losses, partly offset by improved foreign exchange hedging results.

The replacement cost loss before interest and tax for the year ended 31 December 2010 included a net charge for non-operating items of $200 million.

The replacement cost loss before interest and tax for the year ended 31 December 2009 included a net charge for non-operating items of $489 million.

The primary additional factors reflected in 2010 s result compared with that of 2009 were improved business performance, more favourable foreign exchange effects and cost efficiencies.

Key statistics

			$ million
	2011	2010	2009
Sales and other operating revenues[a]	**2,957**	3,328	2,843
Replacement cost (loss) before interest and tax	**(2,478)**	(1,516)	(2,322)
Capital expenditure and acquisitions	**1,853**	1,234	1,299

[a] Includes sales between businesses.

Alternative Energy

Alternative Energy comprises BP s low-carbon businesses and future growth options outside oil and gas, which we believe have the potential to be a material source of low-carbon energy and are aligned with BP s core capabilities. These are biofuels, wind and a range of strategic investments.

Our market

A more diverse mix of energy will be required to meet long-term future demand. BP s own estimates suggest that global primary energy demand will increase by around 40% between 2010 and 2030. Supported by government policies, renewables global share of power generation, is expected to be 11% by 2030. Between 2010 and 2030, biofuels are expected to account for 23% of transport energy demand growth[a].

Our performance

In 2011, our biofuels business acquired the Brazilian sugar and ethanol producer Companhia Nacional de Açúcar e Álcool (CNAA) for $705 million. Our wind business added 401MW of gross generation capacity during 2011 (274MW net), with the commercial start-up of the Cedar Creek 2 and Sherbino 2 wind farms. At the end of 2011, BP began winding down its remaining solar operations as it prepares to exit the solar business.

Alternative Energy continues to make progress against its commitment to invest $8 billion in low-carbon businesses by 2015. Our investment since 2005 is $6.6 billion[b].

a *BP Energy Outlook 2030.*

b The majority of costs have been capitalized, some were expensed under IFRS.

Biofuels

BP believes that it has a key technological role to play in enabling the transport sector to respond to the dual challenges of energy security and climate change. We have embarked on a focused programme of biofuels development based around the most efficient transformation of sustainable and low-cost sugars into a range of fuel molecules. BP continues to invest throughout the entire biofuels value chain, from sustainable feedstocks that minimize pressure on food supplies through to the development of the advantaged fuel molecule biobutanol, which has a higher energy content than ethanol and delivers improved fuel economy. *See Technology Alternative Energy on page 76 for further information.*

BP has production facilities operating, or in the planning and construction phases, in the US, Brazil and the UK.

The 2011 CNAA acquisition included mills located in Goiás and Minas Gerais states that supply both Brazilian and international markets with ethanol. We have also increased our share in the Brazilian biofuels company, Tropical BioEnergia S.A., to 100%, by acquiring the remaining 50% for cash consideration of approximately $71 million. The acquisition included an operating ethanol mill, located in Goiás state. BP now owns and operates three producing ethanol mills in Brazil, with a total crush capacity[a] of 7.2 million tonnes per annum. The blending and distribution of biofuels continues to be carried out by our Refining and Marketing segment, in line with regulation.

a Crush capacity represents a maximum capacity to process biofuels feedstock.

Wind

In wind power, BP has focused its business in the US, where we have developed one of the leading wind portfolios.

During 2011, full commercial operations commenced at the Cedar Creek 2 wind farm in Colorado with a gross capacity of 251MW (BP 50%) and in Texas at the 150MW Sherbino 2 wind farm. Construction is nearly complete at a further Texas wind farm, the 225MW Trinity Hills facility, and construction has commenced at the 141MW Mehoopany wind farm in Pennsylvania, and at the 470MW Flat Ridge wind farm in Kansas.

BP increased its net wind generation capacity to 1,048MW during 2011, an increase of 35% over the prior year.

	2011	2010	2009
Wind net rated capacity at year-end (megawatts)[a]	**1,048**	774	711

a Net wind capacity is the sum of the rated capacities of the assets/turbines that have entered into commercial operation, including BP s share of equity-accounted entities. The equivalent capacities on a gross-JV basis (which includes 100% of the capacity of equity-accounted entities where BP has partial ownership) were 1,763MW in 2011, 1,362MW in 2010 and 1,237MW in 2009. This includes 32MW of capacity in the Netherlands which is managed by our Refining and Marketing segment.

Solar

BP has been involved in solar for more than 35 years and in the last two years the industry has changed radically into a low margin commodity market. At the end of 2011, BP began winding down its remaining solar operations as it prepares to exit the solar business. BP will take the necessary steps to transfer its obligations and assets to its affiliates or to third parties.

Emerging business and ventures

Our emerging business and ventures unit brings together BP s venturing and carbon markets expertise with extensive carbon capture and storage capability. Through venturing we have 29 separate venturing investments spanning three broad areas: bioenergy, electrification and carbon solutions. We are able to deploy specialist carbon capture and storage capabilities on our own operations and to monitor CO_2 storage opportunities, such as the In Salah gas field where we have injected almost 4 million tonnes of CO_2 since 2004.

In September 2011, SCS Energy, an independent power producer involved in clean power projects, acquired the Hydrogen Energy California joint venture project from BP and Rio Tinto.

Separately, the 400MW Hydrogen Power Abu Dhabi project with CCS is awaiting further decisions, including arrangements for CO_2

transportation and storage. The project is a joint venture between BP (40%) and Masdar (60%).

Shipping

We transport our products across oceans, around coastlines and along waterways, using a combination of BP-operated, time-chartered and spot-chartered vessels. All vessels conducting BP activities are subject to our health, safety, security and environmental requirements. The primary purpose of our shipping and chartering activities is the transportation of our hydrocarbon products. In addition, we may use surplus capacity to transport third-party products.

International fleet

At the end of 2011, we had 53 international vessels (37 medium-size crude and product carriers, three very large crude carriers, one North Sea shuttle tanker, eight LNG carriers and four LPG carriers). All these ships are double-hulled. Of the eight LNG carriers, BP manages one on behalf of a joint venture in which it is a participant.

Regional and specialist vessels

In Alaska, we retain a fleet of four double-hulled vessels. Outside the US, we had 14 specialist vessels (two double-hulled lubricants oil barges and 12 offshore support vessels).

Time-charter vessels

At the end of 2011 BP had 93 hydrocarbon-carrying vessels above 600 deadweight tonnes on time-charter, all of which are double-hulled. All these vessels participate in BP s time-charter assurance programme.

Spot-charter vessels

BP spot-charters vessels, typically for single voyages. These vessels are always vetted for safety assurance prior to each use.

Other vessels

BP uses various craft such as tugs, crew boats and seismic vessels in support of the group s business. We also use sub-600 deadweight tonne barges to carry hydrocarbons on inland waterways.

Maritime security issues

At a strategic level, BP avoids known areas of pirate attack or armed robbery; where this is not possible for trading reasons and we consider it safe to do so, we will continue to trade vessels through these areas, subject to the adoption of heightened security measures.

2011 has seen continuing pirate activity in the Gulf of Aden, Indian Ocean (up to approximately 200 miles west of the Indian coast) and the Arabian Sea. Activity has further extended into the north Arabian Sea (approximately 200 miles south of Pakistan) and the southern Red Sea. Despite an increasing level of piracy activity the number of vessels actually attacked and/or hijacked has remained roughly the same as in 2010, and the percentage success rate of the pirates has reduced. This is as a result of stronger naval intervention off the Somali coast, heightened awareness of the threat, and protective measures adopted by transiting ships.

At present, we follow available military and government agency advice and are participating in protective group transits through the Gulf of Aden Internationally Recommended Transit Corridor. BP uses the protective measures recommended in the international shipping industry guide *BMP 4 Best Management Practices for Protection against Somalia Based Piracy,* jointly published by industry bodies, including Oil Companies International Marine Forum and supported by military operations in the region.

We continue to monitor other areas where piracy is known to occur e.g. West Africa and the South China Sea.

Aluminium

During 2011, we terminated our interest in this business with the disposal of our wholly-owned subsidiary, ARCO Aluminum Inc., to a consortium of Japanese companies for cash consideration of $680 million.

Treasury

Treasury manages the financing of the group centrally, ensuring liquidity sufficient to meet group requirements and manages key financial risks including interest rate, foreign exchange, pension and financial institution credit risk. From locations in the UK, the US and the Asia-Pacific region, Treasury provides the interface between BP and the international financial markets and supports the financing of BP s projects around the world. Treasury trades foreign exchange and interest rate products in the financial markets, hedging group exposures and generating incremental value through optimizing and managing cash flows. Trading activities are underpinned by the compliance, control, and risk management infrastructure common to all BP trading activities. For further information, *see Financial statements Note 26 on page 217.*

Insurance

The group generally restricts its purchase of insurance to situations where this is required for legal or contractual reasons. Losses are borne as they arise, rather than being spread over time through insurance premiums with attendant transaction costs. This approach was reviewed following the Deepwater Horizon oil spill but the group concluded that it will continue with its current approach of not generally purchasing insurance cover.

Liquidity and capital resources

Following the Deepwater Horizon oil spill in 2010, the group initially faced significant costs relating to the immediate response activities as well as significant uncertainty regarding the ultimate magnitude of its liabilities and timing of cash outflows. During 2011 the impact on the group s liquidity and capital resources has stabilized, allowing steps to be taken to enhance the strength of the balance sheet.

The group s long-term credit ratings are A (stable outlook) from Standard & Poor s, strengthened from A (negative outlook) in July 2011, and A2 (stable outlook) from Moody s Investor Services.

BP renegotiated its committed bank facilities during 2011 putting in place $6.9 billion of facilities with 25 international banking counterparties, mostly for a term of three years. In addition the group has increased its access to commercial bank letters of credit (LC) by putting in place committed LC facilities of $5.1 billion and secured LC arrangements of $2.2 billion, to supplement its uncommitted and unsecured LC lines.

The disposal programme of $30 billion initially announced in 2010 has been increased to $38 billion, for completion by the end of 2013. By the end of 2011 agreements had been signed for more than $21 billion, with cash receipts totalling $17 billion in 2010 and $2.7 billion in 2011.

BP accessed US and European capital markets throughout the year with bond issuances amounting to $10.7 billion in 2011.

A further $0.8 billion of US Industrial Revenue/Municipal bonds were re-issued in term-out mode of between three to 10 years during the year.

During 2011 BP repaid $2.9 billion of the $5.3 billion of borrowings raised in 2010 that were secured against working capital and other assets, or backed by future crude oil sales from BP s interests in specific offshore Angola and Azerbaijan fields.

Financial framework

BP continues to refine its financial framework to support the pursuit of value growth for shareholders, while maintaining a secure financial base. BP intends to increase operating cash flow[a] by 50% in 2014 compared to 2011[b]. Half of the increase will arise as the remaining payments into the Deepwater Horizon Oil Spill Trust fund complete by the end of 2012, and half from operations. BP plans to use half of the expected additional cash flows to increase investments and half for other purposes.

We intend to maintain a significant liquidity buffer and to reduce our net debt ratio to the lower half of the 10-20% gearing range over time. *See Financial statements Note 35 on page 230 for gross debt, which is the nearest equivalent measure to net debt on an IFRS basis, and for further information on net debt and net debt ratio.*

a Operating cash flow is net cash provided by (used in) operating activities, as stated in the group cash flow statement on page 181.
b Assuming an oil price of $100 per barrel in 2014. The projection reflects our expectation that all required payments into the $20-billion trust fund will have been completed by the end of 2012. It does not reflect any cash flows relating to other liabilities, contingent liabilities, settlements or contingent assets arising from the Gulf of Mexico oil spill which may or may not arise at that time. See Financial statements Note 43 on page 249, for further information on contingent liabilities.

Dividends and other distributions to shareholders

On 1 February 2011, BP announced the resumption of quarterly dividend payments, with a fourth-quarter 2010 dividend of 7 cents per share. The resumption followed the suspension of dividend payments for the first three quarters of 2010 announced in June 2010 in light of the Deepwater Horizon oil spill and commitments to fund the $20-billion Trust. The same level of dividend was maintained for the first three quarters of 2011.

The total dividend paid to BP shareholders in 2011 was $4.1 billion with shareholders also having the option to receive a scrip dividend, compared with $2.6 billion paid in 2010. The dividend is determined in US dollars, the economic currency of BP.

On 7 February 2012, BP announced a dividend of 8 cents per share in respect of the fourth quarter 2011.

During 2011 and 2010, the company did not repurchase any of its own shares. Details of purchases to satisfy requirements of certain employee share-based payment plans are set out on page 170.

Financing the group s activities

The group s principal commodity, oil, is priced internationally in US dollars. Group policy has generally been to minimize economic exposure to currency movements by financing operations with US dollar debt. Where debt is issued in other currencies, including euros, it is generally swapped back to US dollars using derivative contracts, or else hedged by maintaining offsetting cash positions in the same currency. The overall cash balances of the group are mainly held in US dollars or swapped to US dollars and holdings are well-diversified to reduce concentration risk. The group is not therefore exposed to significant currency risk, such as in relation to the euro, regarding its borrowings. Also *see Risk factors on page 59 for further information on risks associated with the general macroeconomic outlook, including the stability of the eurozone and Financial statements Note 26 on page 217.*

The group s finance debt at 31 December 2011 amounted to $44.2 billion (2010 $45.3 billion). Of the total finance debt, $9.0 billion is classified as short term at the end of 2011 (2010 $14.6 billion). The short-term balance includes $4.9 billion for amounts repayable within the next 12 months relating to long-term borrowings (2010 $6.9 billion). Commercial paper markets in the US and Europe are a further source of short-term liquidity for the group to provide timing flexibility. At 31 December 2011, outstanding commercial paper amounted to $3.6 billion (2010 $1.0 billion). Also included within short-term debt at the end of 2010 was $6.2 billion relating to deposits received for announced disposal transactions still pending legal completion post the balance sheet date. At the end of 2011 the balance was de minimis at $30 million.

We have in place a European Debt Issuance Programme (DIP) under which the group may raise up to $20 billion of debt for maturities of one month or longer. At 31 December 2011, the amount drawn down against the DIP was $11.6 billion (2010 $12.3 billion). In addition, the group has in place an unlimited US shelf registration statement under which it may raise debt with maturities of one month or longer. None of the capital market bond issuances since the Deepwater Horizon oil spill contain any additional financial covenants compared with the group s capital markets issuances prior to the incident.

The maturity profile and fixed/floating rate characteristics of the group s debt are described in Financial statements Note 34 on page 229.

Net debt was $29.0 billion at the end of 2011, an increase of $3.1 billion from the 2010 year-end position of $25.9 billion. The ratio of net debt to net debt plus equity was 20.5% at the end of 2011 (2010 21.2%). Net debt and the ratio of net debt to net debt plus equity are non-GAAP measures. We believe that these measures provide useful information to investors. Net debt enables investors to see the economic effect of gross debt, related hedges and cash and cash equivalents in total. The net debt ratio enables investors to see how significant net debt is relative to equity from shareholders. *See Financial statements Note 35 on page 230 for gross debt, which is the nearest equivalent measure on an IFRS basis, and for further information on net debt.*

Included in net debt are cash and cash equivalents of $14.1 billion at 31 December 2011 (2010 $18.6 billion). BP manages its cash position to ensure the group has adequate cover to respond to potential short-term market illiquidity, and expects to maintain a strong cash position. Cash balances are pooled centrally where permissible, and deployed globally as required. Cash surpluses are deposited with creditworthy banks and money market funds with short maturities to ensure availability. The group holds $1.2 billion of cash outside the UK and it is not expected that any significant tax will arise on repatriation. Further information on the management of liquidity risk and credit risk is provided in Financial statements Note 26 on pages 217-222, and on the cash position in Financial statements Note 30 on page 223.

The group also has access to significant sources of liquidity in the form of committed bank facilities. At 31 December 2011, the group had available undrawn committed standby borrowing facilities of $6.9 billion (2010 $12.5 billion), made up of:

- $6.8 billion of standby facilities available to draw and repay by mid-March 2014.
- 625 million Chinese yuan ($0.1 billion) of 365-day standby facilities available to draw and repay until the second half of 2012.

During 2011 $7.2 billion of 364-day facilities expired and were not renewed.

BP believes that, taking into account the amounts of undrawn borrowing facilities and increased levels of cash and cash equivalents, and the ongoing ability to generate cash, including further disposal proceeds, the group has sufficient working capital for foreseeable requirements.

Uncertainty remains regarding the amount and timing of future expenditures relating to the Deepwater Horizon oil spill and the implications for future activities. *See Risk factors on pages 59-63, and Financial statements Note 2 on page 190, Note 36 on page 231 and Note 43 on page 249 for further information.*

Off-balance sheet arrangements

At 31 December 2011, the group s share of third-party finance debt of equity-accounted entities was $7,003 million (2010 $6,987 million). These amounts are not reflected in the group s debt on the balance sheet. The group has issued third-party guarantees under which amounts outstanding at 31 December 2011 are $415 million (2010 $404 million) in respect of liabilities of jointly controlled entities and associates and $1,430 million (2010 $1,339 million) in respect of liabilities of other third parties. Of these amounts, $220 million (2010 $355 million) of the jointly controlled entities and associates guarantees relate to borrowings and for other third-party guarantees, $1,267 million (2010 $1,324 million) relates to guarantees of borrowings. Details of operating lease commitments, which are not recognized on the balance sheet, are shown in the table below and in Note 14 on page 208.

Contractual commitments

The following table summarizes the group s principal contractual obligations at 31 December 2011, distinguishing between those for which a liability is recognized on the balance sheet and those for which no liability is recognized. Further information on borrowings and finance leases is given in Financial statements Note 34 on page 229 and more information on operating leases is given in Financial statements Note 14 on page 208.

							$ million
Expected payments by period under contractual							Payments due by period
obligations and commercial commitments	Total	2012	2013	2014	2015	2016	2017 and thereafter
Balance sheet obligations							
Borrowings[a]	47,242	9,570	7,812	7,262	5,438	4,586	12,574
Finance lease future minimum lease payments	1,034	454	54	49	49	48	380
Deepwater Horizon Oil Spill Trust funding liability	4,884	4,884					
Decommissioning liabilities[b]	19,693	610	546	433	305	346	17,453
Environmental liabilities[b]	3,646	1,665	588	232	187	192	782
Pensions and other post-retirement benefits[c]	29,171	1,945	1,933	1,944	1,938	1,921	19,490
Total balance sheet obligations	105,670	19,128	10,933	9,920	7,917	7,093	50,679
Off-balance sheet obligations							
Operating leases[d]	16,072	4,182	3,286	2,207	1,630	1,223	3,544
Unconditional purchase obligations[e]	197,404	115,679	18,155	12,388	8,311	7,168	35,703
Total off-balance sheet obligations	213,476	119,861	21,441	14,595	9,941	8,391	39,247
Total	319,146	138,989	32,374	24,515	17,858	15,484	89,926

a Expected payments include interest payments on borrowings totalling $3,751 million ($896 million in 2012, $746 million in 2013, $582 million in 2014, $443 million in 2015, $333 million in 2016 and $751 million thereafter), and exclude disposal deposits of $30 million included in current finance debt on the balance sheet.

b The amounts are undiscounted. Environmental liabilities include those relating to the Gulf of Mexico oil spill, including liabilities for spill response costs.

c Represents the expected future contributions to funded pension plans and payments by the group for unfunded pension plans and the expected future payments for other post-retirement benefits.

d The future minimum lease payments are before deducting related rental income from operating sub-leases. In the case of an operating lease entered into solely by BP as the operator of a jointly controlled asset, the amounts shown in the table represent the net future minimum lease payments, after deducting amounts reimbursed, or to be reimbursed, by joint venture partners. Where BP is not the operator of a jointly controlled asset BP s share of the future minimum lease payments are included in the amounts shown, whether BP has co-signed the lease or not. Where operating lease costs are incurred in relation to the hire of equipment used in connection with a capital project, some or all of the cost may be capitalized as part of the capital cost of the project.

e Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms. The amounts shown include arrangements to secure long-term access to supplies of crude oil, natural gas, feedstocks and pipeline systems. In addition, the amounts shown for 2012 include purchase commitments existing at 31 December 2011 entered into principally to meet the group s short-term manufacturing and marketing requirements. The price risk associated with these crude oil, natural gas and power contracts is discussed in Financial statements - Note 26 on page 217.

The following table summarizes the nature of the group s unconditional purchase obligations.

$ million

Unconditional purchase obligations	Total	2012	2013	2014	2015	2016	2017 and thereafter
	Payments due by period						
Crude oil and oil products	130,824	90,690	9,095	5,684	3,344	2,853	19,158
Natural gas	38,370	17,591	5,258	3,589	2,516	2,087	7,329
Chemicals and other refinery feedstocks	9,962	2,573	1,129	1,115	1,028	979	3,138
Power	3,038	2,169	644	212	11	2	
Utilities	892	181	154	106	97	75	279
Transportation	8,061	1,183	957	926	731	661	3,603
Use of facilities and services	6,257	1,292	918	756	584	511	2,196
Total	197,404	115,679	18,155	12,388	8,311	7,168	35,703

The group expects its total capital expenditure, excluding acquisitions and asset exchanges, to be around $22 billion in 2012. The following table summarizes the group s capital expenditure commitments for property, plant and equipment at 31 December 2011 and the proportion of that expenditure for which contracts have been placed. Capital expenditure is considered to be committed when the project has received the appropriate level of internal management approval. For jointly controlled assets, the net BP share is included in the amounts shown. Where operating lease costs are incurred in connection with a capital project, some or all of the cost may be capitalized as part of the capital cost of the project. Such costs are included in the amounts shown.

$ million

Capital expenditure commitments	Total	2012	2013	2014	2015	2016	2017 and thereafter
Committed on major projects	32,951	15,113	7,443	4,268	2,828	1,535	1,764
Amounts for which contracts have been placed	12,517	7,689	2,789	1,094	511	315	119

In addition, at 31 December 2011, the group had committed to capital expenditure relating to investments in equity-accounted entities amounting to $610 million. Contracts were in place for $332 million of this total.

Cash flow

The following table summarizes the group s cash flows.

$ million

	2011	2010	2009
Net cash provided by operating activities	22,154	13,616	27,716
Net cash (used in) investing activities	(26,633)	(3,960)	(18,133)
Net cash provided by (used in) financing activities	482	840	(9,551)
Currency translation differences relating to cash and cash equivalents	(492)	(279)	110
Increase (decrease) in cash and cash equivalents	(4,489)	10,217	142
Cash and cash equivalents at beginning of year	18,556	8,339	8,197
Cash and cash equivalents at end of year	14,067	18,556	8,339

Net cash provided by operating activities for the year ended 31 December 2011 was $22,154 million compared with $13,616 million for 2010, the increase primarily reflecting a reduction in the cash outflow in respect of the Gulf of Mexico oil spill from $16,019 million in 2010 to $6,813 million in 2011. Excluding the impacts of the Gulf of Mexico oil spill, net cash provided by operating activities was $28,967 million for 2011, compared to $29,635 million for 2010, a decrease of $668 million. Profit before taxation decreased by $1,018 million, working capital requirements increased by $1,509 million and income taxes paid increased by $1,879 million. These impacts were partially offset by a decrease of $2,622 million in the net impairment, gains and losses on sale of businesses and fixed assets, and an increase in dividends received from jointly controlled entities and associates of $2,104 million.

Net cash provided by operating activities for the year ended 31 December 2010 was $13,616 million compared with $27,716 million for 2009, the reduction primarily reflecting a net cash outflow of $16,019 million in respect of the Gulf of Mexico oil spill. Excluding the impacts of the Gulf of Mexico oil spill, profit before taxation increased by $10,986 million and a decrease in working capital requirements contributed $842 million. This higher profit before tax did not result in an equivalent net increase in operating cash flow because it included $4,854 million in net gains on disposals, net of impairments, a decrease of $1,160 million in depreciation, depletion, amortization and exploration expense, and a decrease of $787 million in the net charge for provisions, less payments, all of which are non-cash items.

Net cash used in investing activities was $26,633 million in 2011, compared with $3,960 million and $18,133 million in 2010 and 2009 respectively. The increase in cash used in 2011 reflected a decrease of $14,222 million in disposal proceeds, including the impact of the repayment in 2011 of a $3,530 million disposal deposit received in 2010, following the termination of the Pan American Energy LLC sale agreement, and an increase of $8,441 million in acquisitions, net of cash acquired; of which $7.0 billion was for the Reliance transaction. The decrease in 2010 compared with 2009 reflected an increase of $14,273 million in disposal proceeds and a decrease in capital expenditure and investments of $2,445 million, partly offset by an increase in acquisitions of $2,469 million.

Net cash provided by financing activities was $482 million in 2011 compared with $840 million net cash provided in 2010 and $9,551 million net cash used in 2009. The decrease in net cash provided in 2011 primarily reflected a decrease in net proceeds from long-term financing of $4,734 million, and an increase in dividends paid of $1,445 million partly offset by a net increase in short-term debt of $5,846 million. The net increase in cash provided in 2010 compared with 2009 reflected a decrease in dividends paid of $7,957 million, an increase in net proceeds from long-term financing of $1,686 million and a decrease in net repayments of short-term debt of $786 million.

The group has had significant levels of capital investment for many years. Cash flow in respect of capital investment, excluding acquisitions, was $18.8 billion in 2011, $18.9 billion in 2010 and $21.4 billion in 2009. Sources of funding are completely fungible, but the majority of the group s funding requirements for new investment come from cash generated by existing operations. The group s level of net debt, that is debt less cash and cash equivalents, was $29.0 billion at the end of 2011, $25.9 billion at the end of 2010 and $26.2 billion at the end of 2009.

During the period 2009 to 2011, our total sources of cash amounted to $87 billion, while our total uses of cash amounted to $90 billion. The net cash usage of $3 billion, and the increase in cash and cash equivalents held of $6 billion, were financed by an increase in finance debt of $9 billion over the three-year period. During this period, the price of Brent crude oil has averaged $84.14 per barrel. The following table summarizes the three-year sources and uses of cash.

	$ billion
Sources of cash	
Net cash provided by operating activities	63
Disposals	24
	87
Uses of cash	
Capital expenditure	59
Acquisitions	13
Net repurchase of shares	
Dividends paid to BP shareholders	17
Dividends paid to minority interests	1
	90
Net use of cash	(3)
Increase in finance debt	9
Increase in cash and cash equivalents	6

Disposal proceeds received during the three-year period exceeded cash used for acquisitions, as a result in particular of our ongoing disposal programme started in 2010. Net investment (capital expenditure and acquisitions less disposal proceeds) during this period averaged $16 billion per year. Dividends paid to BP shareholders totalled $17 billion during the three-year period, with no ordinary share dividends being paid in respect of the first three quarters of 2010. In the past three years, $4 billion has been contributed to funded pension plans. This is reflected in net cash provided by operating activities in the table above. The balance of cash and cash equivalents held has been increased in light of the group s current circumstances, as noted above.

Trend information

For information on external market trends, see Our market on pages 18-24.

We expect production excluding TNK-BP in 2012 to be broadly flat compared with 2011, after adjusting for divestments and at an oil price of $100 per barrel.

In Refining and Marketing, the level of BP s refinery turnaround activity is expected to be broadly similar in 2012 compared with 2011. We also expect the marketing environment in fuels, lubricants and petrochemicals to remain subdued given the outlook for global demand.

In 2012, we expect the quarterly loss, excluding non-operating items, for Other businesses and corporate to average around $500 million. As in previous years, this is likely to be volatile on an individual quarterly basis.

We expect capital expenditure, excluding acquisitions and asset exchanges, to increase to around $22 billion in 2012, as we invest to grow in our Exploration and Production segment.

Having completed disposals of almost $20 billion during 2010 and 2011 combined, we expect to make further disposals that would bring the total to $38 billion by the end of 2013.

We intend to reduce the net debt ratio to the lower half of the 10-20% range over time. Net debt is a non-GAAP measure.

Depreciation, depletion and amortization in 2012 is expected to be around $1.0 billion higher than in 2011.

The discussion above contains forward-looking statements, particularly those regarding external market trends, the future level of production excluding TNK-BP, the expected level of turnarounds, the marketing environment in fuels, lubricants and petrochemicals, the expected quarterly loss for Other businesses and corporate, the expected level of capital expenditures, expectations regarding future disposals, net debt and net debt ratio, and future levels of depreciation, depletion and amortization. These forward-looking statements are based on assumptions that management believes to be reasonable in the light of the group s operational and financial experience. However, no assurance can be given that the forward-looking statements will be realized. You should not rely on past performance as an indicator of future performance. You are urged to read the cautionary statement on page 5 and Risk factors on pages 59-63, which describe the risks and uncertainties that may cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements. The company provides no commitment to update the forward-looking statements or to publish financial projections for forward-looking statements in the future.

Regulation of the group s business

BP s activities, including its oil and gas exploration and production, pipelines and transportation, refining and marketing, petrochemicals production, trading, alternative energy and shipping activities, are conducted in many different countries and are subject to a broad range of EU, US, international, regional and local legislation and regulations, including legislation that implements international conventions and protocols. These cover virtually all aspects of our activities and include matters such as licence acquisition, production rates, royalties, environmental, health and safety protection, fuel specifications and transportation, trading, pricing, anti-trust, export, taxes and foreign exchange.

The terms and conditions of the leases, licences and contracts under which our oil and gas interests are held vary from country to country. These leases, licences and contracts are generally granted by or entered into with a government entity or state owned or controlled company and are sometimes entered into with private property owners. These arrangements with governmental or state entities usually take the form of licences or production-sharing agreements (PSAs), although arrangements with the US government can be by lease. Arrangements with private property owners are usually in the form of leases.

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. Less typically, BP may explore for and exploit hydrocarbons under a service agreement with the host entity in exchange for reimbursement of costs and/or a fee paid in cash rather than production.

PSAs entered into with a government entity or state owned or controlled company generally require 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 only a portion of the area covered by the original exploration licence. Both exploration and production licences are generally for a specified period of time. In the US, leases from the US government typically remain in effect for a specified term, but may be extended beyond that term as long as there is production in paying quantities. The term of BP s licences and the extent to which these licences may be renewed vary from country to country.

Frequently, BP conducts its exploration and production activities in joint ventures or co-ownership arrangements with other international oil companies, state owned or controlled companies and/or private companies. These joint ventures may be incorporated or unincorporated ventures, while the co-ownerships are typically unincorporated. Whether incorporated or unincorporated, relevant agreements will set out each party s level of participation or ownership interest in the joint venture or co-ownership. Conventionally, all costs, benefits, rights, obligations, liabilities and risks incurred in carrying out joint venture or co-ownership operations under a lease or licence are shared among the joint venture or co-owning parties according to these agreed ownership interests. Ownership of joint venture or co-owned property and hydrocarbons to which the joint venture or co-ownership is entitled is also shared in these proportions. To the extent that any liabilities arise, whether to governments or third parties, or as between the joint venture parties or co-owners themselves, each joint venture party or co-owner will generally be liable to meet these in proportion to its ownership interest (*see Financial statements Note 2 in relation to the Gulf of Mexico oil spill).* In many upstream operations, a party (known as the operator) will be appointed (pursuant to a joint operating agreement (JOA)) to carry out day-to-day operations on behalf of the joint venture or co-ownership. The operator is typically one of the joint venture parties or a co-owner and will carry out its duties either through its own staff, or by contracting out various elements to third-party contractors or service providers. BP acts as operator on behalf of joint ventures and co-ownerships in a number of countries where we have exploration and production activities.

Frequently, work (including drilling and related activities) will be contracted out to third-party service providers who have the relevant expertise and equipment not available within the joint venture or the co-owning operator s organization. The relevant contract will specify the work to be done and the remuneration to be paid and typically will set out how major risks will be allocated between the joint venture or co-ownership and the service provider. Generally, the joint venture or co-owner and the contractor would respectively allocate responsibility for and provide reciprocal indemnities to each other for harm caused to their respective staff and property. Depending on the service to be provided, an oil and gas industry service contract may also contain provisions allocating risks and liabilities associated with pollution and environmental damage, damage to a well or hydrocarbon reservoir and for claims from third parties or other losses. The allocation of those risks vary among contracts and are determined through negotiation between the parties.

In general, BP is required to pay income tax on income generated from production activities (whether under a licence or PSAs). In addition, depending on the area, BP s production activities may be subject to a range of other taxes, levies and assessments, including special petroleum taxes and revenue taxes. The taxes imposed on oil and gas production profits and activities may be substantially higher than those imposed on other activities, for example in Abu Dhabi, Angola, Egypt, Norway, the UK, the US, Russia and Trinidad & Tobago.

Environmental regulation

BP operates in more than 80 countries and is subject to a wide variety of environmental regulations concerning our products, operations and activities. Current and proposed fuel and product specifications, emission controls and climate change programmes under a number of environmental laws may have a significant effect on the production, sale and profitability of many of our products.

There are also environmental laws that require us to remediate and restore areas damaged by the accidental or unauthorized release of hazardous substances or petroleum associated with our operations. These laws may apply to sites that BP currently owns or operates, sites that it previously owned or operated, or sites used for the disposal of its and other parties waste. Provisions for environmental restoration and remediation are made when a clean-up is probable and the amount of BP s legal obligation can be reliably estimated. The cost of future environmental remediation obligations is often inherently difficult to estimate. Uncertainties can include the extent of contamination, the appropriate corrective actions, technological feasibility and BP s share of liability. *See Financial statements Note 36 on page* 231 *for the amounts provided in respect of environmental remediation and decommissioning.*

A number of pending or anticipated governmental proceedings against BP and certain subsidiaries under environmental laws could result in monetary sanctions. We are also subject to environmental claims for personal injury and property damage alleging the release of or exposure to hazardous substances. The costs associated with such future environmental remediation obligations, governmental proceedings and claims could be significant and may be material to the results of operations in the period in which they are recognized. We cannot accurately predict the effects of future developments on the group, such as stricter environmental laws or enforcement policies, or future events at our facilities, and there can be no assurance that material liabilities and costs will not be incurred in the future. *For a discussion of the group s environmental expenditure see page 71.*

Approximately 56% of our fixed assets are located in the US and the EU. US and EU environmental, health and safety regulations significantly affect BP s exploration and production, refining and marketing, transportation and shipping operations. Significant legislation and regulation in the US and the EU affecting our businesses and profitability includes the following:

United States

- The Clean Air Act (CAA) regulates air emissions, permitting, fuel specifications and other aspects of our production, distribution and marketing activities. Stricter limits on sulphur and benzene in fuels will affect us in future, as will actions on greenhouse gas (GHG) emissions and other air pollutants. Additionally, states may have separate, stricter air emission laws in addition to the CAA.
- The Energy Policy Act of 2005 and the Energy Independence and Security Act of 2007 affect our US fuel markets by, among other things, imposing renewable fuel mandates and imposing GHG emissions thresholds for certain renewable fuels. States such as California also impose additional fuel carbon standards.
- The Clean Water Act regulates wastewater and other effluent discharges from BP s facilities, and BP is required to obtain discharge permits, install control equipment and implement operational controls and preventative measures.
- The Resource Conservation and Recovery Act regulates the generation, storage, transportation and disposal of wastes associated with our operations and can require corrective action at locations where such wastes have been released.
- The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) can, in certain circumstances, impose the entire cost of investigation and remediation on a party who owned or operated a site contaminated with a hazardous substance, or arranged for disposal of a hazardous substance at the site. BP has incurred, or expects to incur, liability under the CERCLA or similar state laws, including costs attributed to insolvent or unidentified parties. BP is also subject to claims for remediation costs under other federal and state laws, and to claims for natural resource damages under the CERCLA, the Oil Pollution Act of 1990 (OPA 90) (discussed below) and other federal and state laws. CERCLA also requires hazardous substance release notification.
- The Toxic Substances Control Act regulates BP s import, export and sale of new chemical products.
- The Occupational Safety and Health Act imposes workplace safety and health requirements on our operations along with significant process safety management obligations.
- The Emergency Planning and Community Right-to-Know Act requires emergency planning and hazardous substance release notification as well as public disclosure of our chemical usage and emissions.

- The US Department of Transportation (DOT) regulates the transport of BP s petroleum products such as crude oil, gasoline, and petrochemicals, and other hydrocarbon liquids.
- The Marine Transportation Security Act (MTSA), the DOT Hazardous Materials (HAZMAT) and the Chemical Facility Anti-Terrorism Standard (CFATS) regulations impose security compliance regulations on around 50 BP facilities. These regulations require security vulnerability assessments, security risk mitigation plans and security upgrades, increasing our cost of operations.

OPA 90 is implemented through regulation issued by the US Environmental Protection Agency (EPA), the US Coast Guard, the DOT, the Occupational Safety and Health Administration and various states, Alaska and the west coast states currently have the most demanding state requirements although regulation in the Gulf of Mexico has increased following the 2010 Deepwater Horizon oil spill. There is an expectation that OPA 90 and its regulations will become more stringent in the future. The impact will likely be more rigorous preparedness requirements (the ability to respond over a longer period to larger spills), including the demonstration of that preparedness. There will be additional costs associated with this increased regulation. In 2012, we expect more unannounced exercises and potential penalties for any failure to demonstrate required preparedness even without any OPA 90 amendments.

As a consequence of the Deepwater Horizon oil spill we have become subject to claims under OPA 90 and other laws and have established a $20-billion trust fund for legitimate state and local government response claims, final judgments and settlement claims, legitimate state and local response costs, natural resource damages and related costs and legitimate individual and business claims. We are also subject to Natural Resource Damages claims and numerous civil lawsuits by individuals, corporations and governmental entities. The ultimate costs for these claims cannot be determined at this time. We also expect the industry in general, and BP in particular, to become subject to greater regulation and increased operating costs in the Gulf of Mexico in the future. *For further disclosures relating to the consequences of the 2010 Deepwater Horizon oil spill, see Legal proceedings on page 160.*

On 31 March 2009, the United States filed a complaint seeking civil penalties and damages relating to oil leaks from oil transit lines operated by BP Exploration (Alaska) Inc. (BPXA) at the Prudhoe Bay unit on the North Slope of Alaska. *(See Legal proceedings on page 165.)* The complaint also involved claims related to asbestos handling, allegations of non-compliance at multiple facilities for failure to comply with EPA s spill prevention plan regulations, and for non-compliance with US Department of Transportation orders and regulations. The parties settled the dispute and on 13 July 2011 the Court entered a Consent Agreement in which BPXA agreed to pay a $25-million penalty and to perform certain injunctive measures over the next three years with respect to pipeline inspection and maintenance.

Various environmental groups and the EPA have challenged certain aspects of the air permits issued by the Indiana Department of Environmental Management (IDEM) for upgrades to the Whiting refinery. In response to these challenges, the IDEM has reviewed the permits and responded formally to the EPA. BP is in discussions with EPA, the IDEM and certain environmental groups over these and other CAA issues relating to the Whiting refinery. BP has also been in settlement discussions with EPA to resolve alleged CAA violations at the Toledo, Carson and Cherry Point refineries.

European Union

BP s operations in the EU are subject to a number of current and proposed regulatory requirements that affect or could affect our operations and profitability. These include:

- The EU Climate and Energy Package and the Emissions Trading Scheme (ETS) Directive (see *Greenhouse gas regulation on page 109).*
- The EU Industrial Emissions Directive (IED) (revising and replacing the Integrated Pollution Prevention and Control Directive (IPPC) and several other industrial directives including the Large Combustion Plant Directive (LCPD)) are in the process of transposition by the EU Member States. The IED provides the framework for setting permits for major industrial sites. Relative to IPPC and LCPD, the IED imposes tighter emission standards for some large combustion plants and is more prescriptive regarding the setting of emission of limit values based on use of Best Available Techniques (BAT) in permits for other discharges to air and water. The emission limit values are informed by the Sector specific and cross-Sector BAT Reference documents (BREFs) which are reviewed periodically. The outcome of the review of several BREFs key to our major sites is expected in 2012/2013. The IED transposition and output from the BREF revisions may result in requirements for further emission reductions at our EU sites.
- The European Commission Thematic Strategy on Air Pollution and the related work on revisions to the Gothenburg Protocol and National Emissions Ceiling Directive (NECD) will establish national ceilings for emissions of a variety of air pollutants in order to achieve EU-wide health and environmental improvement targets. This may result in requirements for further emission reductions at our EU sites.
- The EU Regulation on ozone depleting substances (ODS), which implements the Montreal Protocol (Protocol) on ODS was most recently revised in 2009. It requires BP to reduce the use of ODS and phase out use of certain ODS substances. BP continues to replace ODS in refrigerants and/or equipment, in the EU and elsewhere, in accordance with the Protocol and related legislation. Methyl bromide (an ODS) is a minor by-product in the production of purified terephthalic acid in our petrochemicals operations. The progressive phase-out of methyl bromide uses may result in future pressure to reduce our emissions of methyl bromide.
- The EU Fuels Quality Directive affects our production and marketing of transport fuels. Revisions adopted in 2009 mandate reductions in the life cycle GHG emissions per unit of energy as described in Greenhouse gas regulation above, and tighter environmental fuel quality standards for petrol and diesel (for example see *Greenhouse gas regulation on page 109).*
- The EU Registration, Evaluation and Authorization of Chemicals (REACH) Regulation requires registration of chemical substances, manufactured in, or imported into, the EU in quantities greater than 1 tonne per annum per legal entity, together with the submission of relevant hazard and risk data. REACH affects our refining, petrochemicals, exploration and production, biofuels, lubricants and other manufacturing or trading/import operations.
- Having completed registration of all the substances that we were required to submit by the regulatory deadline of 1 December 2010, we are now preparing registration dossiers for those substances (manufactured or imported in amounts in the range 100-1,000 tonnes per annum/legal entity) that are due to be submitted before 1 June 2013. Substances registered in 2010 are subject to evaluation and/ or authorization/restriction procedures by the authorities and this may impact activities, product sales and their profitability.
- In addition, Europe has adopted the UN Global Harmonization System for hazard classification and labelling of chemicals and products through the Classification Labelling and Packaging (CLP) Regulation. This requires us to assess the hazards of all of our chemicals and products against new criteria and will, over time, result in significant changes to warning labels and material safety data sheets. All our European Material Safety Data Sheets will need to be updated to include both REACH and CLP information. We have completed updates for all chemicals substances we manufacture and market in the EU by the compliance deadline of 3 January 2011, and have implemented a process to maintain compliance in our European operations. We have also notified the European Chemicals Agency of hazard classifications for our manufactured and imported chemicals, for inclusion in a publicly available inventory of hazardous chemicals. CLP will also apply to mixtures (e.g. lubricants) by 2015. Activities covered by both CLP and REACH are subject to possible enforcement activity by national regulatory authorities.
- In the UK, significant health and safety legislation affecting BP includes the Health and Safety at Work Act and regulations and the Control of Major Accident Hazards Regulations.

The EU Commission has proposed the adoption of a regulation on safety of offshore oil and gas prospection, exploration and production activities. The proposed regulation aims to introduce harmonized regulation of the potential environmental, health and safety impacts of the offshore oil and gas industry throughout EU waters. Although it is at an early stage in the legislative process, as published the proposal is not entirely aligned with the regime operating in the UK and could also, if adopted, have the effect of extending liability for clean-up and compensation of environmental damage to marine waters.

Environmental maritime regulations

BP s shipping operations are subject to extensive national and international regulations governing liability, operations, training, spill prevention and insurance. These include:

- In US waters, OPA 90 imposes liability and spill prevention and planning requirements governing, among others, tankers, barges and offshore facilities. It also mandates a levy on imported and domestically produced oil to fund the oil spill response. Some states, including Alaska, Washington, Oregon and California, impose additional liability for oil spills.
- Outside US territorial waters, BP Shipping tankers are subject to international liability, spill response and preparedness regulations under the UN s International Maritime Organization, including the International Convention on Civil Liability for Oil Pollution, the MARPOL, the International Convention on Oil Pollution, Preparedness, Response and Co-operation and the International Convention on Civil Liability for Bunker Oil Pollution Damage. In April 2010, a new protocol, the

Hazardous and Noxious Substance (HNS) Convention 2010 was adopted to address issues that have inhibited ratification of the International Convention on Liability and Compensation for Damage in Connection with the Carriage of Hazardous and Noxious Substances by Sea 1996 (the HNS Convention). This protocol will enter into force when at least 12 states have agreed to be bound by it (four of the states must have at least 2 million gross tonnes of shipping) and contributing parties in the consenting states have received at least 40 million tonnes of contributing cargoes in the preceding year.

International marine fuel regulations under International Maritime Organization (IMO) and International Convention for the Prevention of Pollution from Ships (MARPOL) regimes impose stricter sulphur emission restrictions on ships in EU ports and inland waterways and the North and Baltic seas since 2010 and with a stricter global cap on marine sulphur emissions beginning in 2012. Further reductions are to be phased in thereafter. These restrictions require the use of compliant heavy fuel oil (HFO) or distillate, or the installation of abatement technologies on ships. These regulations will place additional costs on refineries producing marine fuel, including costs to dispose of sulphur, as well as increased GHG emissions and energy costs for additional refining.

To meet its financial responsibility requirements, BP Shipping maintains marine liability pollution insurance to a maximum limit of $1 billion for each occurrence through mutual insurance associations (P&I Clubs) but there can be no assurance that a spill will necessarily be adequately covered by insurance or that liabilities will not exceed insurance recoveries.

Greenhouse gas regulation

Increasing concerns about climate change have led to a number of international climate agreements and negotiations are ongoing.

The Kyoto Protocol commits the parties and other entities to meet emissions targets in the first commitment period from 2008 to 2012.

The UN summit in Cancun in December 2010 where parties to the UN Framework Convention on Climate Change (UNFCCC) reached formal agreement on a balanced package of measures to 2020. The Cancun Agreement recognizes that deep cuts in global GHG emissions are required to hold the increase in global temperature to below 2°C. Signatories formally commit to carbon reduction targets or actions by 2020. Around 114 countries, including all the major economies and many developing countries, have made such commitments supplemented currently by an additional 27 parties that have agreed to be listed as agreeing to the accord. Supporting those efforts, principles were agreed for monitoring, verifying and reporting emissions reductions; establishment of a green fund to help developing countries limit and adapt to climate change; and measures to protect forests and transfer low-carbon technology to poorer nations.

In November 2011, parties to the UNFCCC conference in Durban (COP 17) agreed several measures. One was a roadmap for negotiating a legal framework by 2015 for action on climate change involving all countries by 2020, to close the ambition gap between existing GHG reduction pledges and what is required to achieve the goal of limiting global temperature rise to 2°C. Another was a second commitment period for the Kyoto Protocol, to begin immediately after the first period and run for five or eight years. However, it will not include the US, Canada, Japan and Russia, and quantitative targets and the rules for carry-over of allowances from the first commitment will not be agreed until the end of 2012.

These international concerns and agreements are reflected in national and regional measures to limit GHG emissions. Additional stricter measures can be expected in the future. These measures can increase our production costs for certain products, increase demand for competing energy alternatives or products with lower-carbon intensity and affect the sales and specifications of many of our products. Current measures and developments potentially affecting our businesses include the following:

The European Union (EU) has agreed an overall GHG reduction target of 20% by 2020. To meet this, a Climate and Energy Package of regulatory measures has been adopted including: national reduction
targets for emissions not covered by the EU Emissions Trading Scheme (ETS); binding national renewable energy targets to double renewable energy in the EU including at least a 10% share of final energy in transport; a legal framework to promote carbon capture and storage (CCS); and a revised EU ETS Phase 3. EU ETS revisions include a GHG reduction of 21% from 2005 levels, a significant increase in allowance auctioning, an expanded scope (sectors and gases), no free allocations for electricity production but free allocations for energy-intense and trade exposed industrial sectors. The EU ETS regulates approximately one-fifth of our reported 2011 global GHG emissions and can be expected to require additional expenditure from 2013 when Phase 3 comes into effect. Finally, EU energy efficiency policy is currently addressed via national energy efficiency action plans.

Article 7a of the revised EU Fuels Quality Directive requires fuel suppliers to reduce the life cycle GHG emissions per unit of fuel and energy supplied in certain transport markets.

Australia has committed to reduce its GHG emissions by at least 5% below 2000 levels by 2020. In support of this, a Clean Energy legislative package of 19 bills was passed in November 2011 which includes imposing a carbon price on the top 500 emitting entities meeting the thresholds in the bill. The carbon price is scheduled to take effect from 1 July 2012 with a fixed price of $23 Australian dollar (indexed to forecast inflation) until 1 July 2015, an international linked price (trading) with floor and ceiling prices from 1 July 2015 through to 1 July 2018, and a market based price (trading) forward. A certain portion of allowances will be distributed to emission intensive trade exposed businesses for no cost; this transitional support decreases with time. The majority of our Australia business emissions will be subject to the pricing scheme and will require additional expenditures for compliance.

New Zealand has agreed to cut GHG emissions by 10-20% below 1990 levels by 2020, subject to a comprehensive global agreement for emissions reductions coming into force. New Zealand s emission trading scheme (NZ ETS) commenced on 1 July 2010 for transport fuels, industrial processes, and stationary energy. The agriculture sector (45% of New Zealand s GHG emissions) has been proposed to join the NZ ETS in January 2015. New Zealand also employs a portfolio of mandatory and voluntary complementary measures aimed at GHG reductions. A September 2011 review of the scheme recommended effective delays to near-term emissions reductions targets, citing a lack of international action on cutting emissions.

In the US, with no current potential for passing comprehensive climate legislation, the US Environmental Protection Agency (EPA) continues to pursue regulatory measures to address GHGs under the Clean Air Act (CAA).

In late 2009, the EPA released a GHG endangerment finding to establish its authority to regulate GHG emissions under the CAA.

Subsequent to this, the EPA finalized regulations imposing light duty vehicle emissions standards for GHGs.

The EPA finalized the initial GHG mandatory reporting rule (GHGRR) in 2009 and continues to make amendments to the rule. The first reports under the GHGRR were due on or before 30 September 2011. The majority of BP s US businesses were affected by the GHGRR and submitted their first GHG emissions reports to the EPA under the GHGRR on or before the 30 September 2011 deadline. In addition to direct emissions from affected facilities, producers and importers/ exporters of petroleum products, certain natural gas liquids, and GHG s were required to report product volumes and notional GHG emissions should these products be fully combusted. The EPA released direct emission data and a small subset of product supplier data on 11 January 2012, with certain confidential business information protections, in a tool enabled database which allows transparency to the individual facility/entity level. Release of the balance of the product supply data is expected soon along with release of additional non-confidential information which will enable aggregation of reported emissions to the highest level US parent company.

The EPA finalized permitting requirements for new or modified large GHG emission sources in 2010, with these regulations taking effect in January 2011 and the second phase taking effect on 1 July 2011. The EPA has committed to additional actions, beginning in 2012, relating to smaller sources of GHG emissions.

In a legal settlement with environmental advocacy groups the EPA committed to propose regulations under their New Source Performance Standards (NSPS) for GHG emissions from refineries by December 2011 and to finalize these by November 2012; the EPA was unable to meet the December deadline, which may delay final rulemaking. The EPA has communicated that they are considering three options for these standards, energy management, command and control (source specific emission limits) and benchmarking (e.g. a Solomon-type GHG intensity index or variation).

Legal challenges to the EPA s efforts to regulate GHG emissions through the CAA continue along with active political debate with the final content and scope of GHG regulation in the US remaining uncertain.

A number of additional state and regional initiatives in the US will affect our operations. Of particular significance, California is seeking to reduce GHG emissions to 1990 levels by 2020 and to reduce the carbon intensity of transport fuel sold in the state. California implemented a low-carbon fuel standard in 2010 although a preliminary injunction filed in late December 2011 is preventing its implementation. California issued final rules for its cap and trade programme in December 2011, with the scheduled start of the scheme to begin January 2012, with obligations commencing in 2013.

Canada has established an action plan to reduce emissions to 17% below 2005 levels by 2020 and the national government continues to seek a co-ordinated approach with the US on environmental and energy objectives. Additionally, Canada s highest emitting province, Alberta, has been running a market mechanism to reduce GHG since 2007. Controversy, partially driven by perceived GHG intensity regarding Canadian oil sand produced crude, continues with some jurisdictions contemplating policies to restrict or penalize its use.

China has committed to reducing carbon intensity of GDP 40-45% below 2005 levels by 2020 and increasing the share of non-fossil fuels in total energy consumption from 7.5% in 2005 to 15% by 2020. The country s 12th (2011-2015) Development Programme has set the target to reduce carbon intensity by 17% within five years, and this national target has been deconstructed into provincial ones for local actions. Meanwhile, five provinces and eight cities were selected as pilots for low carbon development, and seven provinces/cities were formally given instruction to start emission trading trials. As part of the country s energy saving programme, the government also requires any operating entity with annual energy consumption of 10 thousand tonnes of coal equivalent (7ktoe/a) to have an energy saving target for the next five years. A number of BP joint venture companies in China will be required to participate in this initiative.

Certain definitions

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

Replacement cost profit

Replacement cost profit or loss reflects the replacement cost of supplies. The replacement cost profit or loss for the year is arrived at by excluding from profit or loss inventory holding gains and losses and their associated tax effect. Replacement cost profit or loss for the group is not a recognized GAAP measure.

BP believes that replacement cost profit before interest and taxation for the group is a useful measure for investors because it is the profitability measure used by management. *See Selected financial information on page 56 for the nearest equivalent measure on an IFRS basis, which is Profit (loss) for the year attributable to BP shareholders .*

Inventory holding gains and losses

Inventory holding gains and losses represent the difference between the cost of sales calculated using the average cost to BP of supplies acquired during the period and the cost of sales calculated on the first-in first-out (FIFO) method after adjusting for any changes in provisions where the net realizable value of the inventory is lower than its cost. Under the FIFO method, which we use for IFRS reporting, the cost of inventory charged to the income statement is based on its historic cost of purchase, or manufacture, rather than its replacement cost. In volatile energy markets, this can have a significant distorting effect on reported income. The amounts disclosed represent the difference between the charge (to the income statement) for inventory on a FIFO basis (after adjusting for any related movements in net realizable value provisions) and the charge that would have arisen if an average cost of supplies was used for the period. For this purpose, the average cost of supplies during the period is principally calculated on a monthly basis by dividing the total cost of inventory acquired in the period by the number of barrels acquired. The amounts disclosed are not separately reflected in the financial statements as a gain or loss. No adjustment is made in respect of the cost of inventories held as part of a trading position and certain other temporary inventory positions.

Management believes this information is useful to illustrate to investors the fact that crude oil and product prices can vary significantly from period to period and that the impact on our reported result under IFRS can be significant. Inventory holding gains and losses vary from period to period due principally to changes in oil prices as well as changes to underlying inventory levels. In order for investors to understand the operating performance of the group excluding the impact of oil price changes on the replacement of inventories, and to make comparisons of operating performance between reporting periods, BP s management believes it is helpful to disclose this information.

Non-GAAP information on fair value accounting effects

BP uses derivative instruments to manage the economic exposure relating to inventories above normal operating requirements of crude oil, natural gas and petroleum products. Under IFRS, these inventories are recorded at historic cost. The related derivative instruments, however, are required to be recorded at fair value with gains and losses recognized in income because hedge accounting is either not permitted or not followed, principally due to the impracticality of effectiveness testing requirements. Therefore, measurement differences in relation to recognition of gains and losses occur. Gains and losses on these inventories are not recognized until the commodity is sold in a subsequent accounting period. Gains and losses on the related derivative commodity contracts are recognized in the income statement from the time the derivative commodity contract is entered into on a fair value basis using forward prices consistent with the contract maturity.

BP enters into commodity contracts to meet certain business requirements, such as the purchase of crude for a refinery or the sale of BP s gas production. Under IFRS these contracts are treated as derivatives and are required to be fair valued when they are managed as part of a larger portfolio of similar transactions. Gains and losses arising are recognized in the income statement from the time the derivative commodity contract is entered into.

IFRS requires that inventory held for trading be recorded at its fair value using period end spot prices whereas any related derivative commodity instruments are required to be recorded at values based on forward prices consistent with the contract maturity. Depending on market conditions, these forward prices can be either higher or lower than spot prices resulting in measurement differences.

BP enters into contracts for pipelines and storage capacity, oil and gas processing and liquefied natural gas (LNG) that, under IFRS, are recorded on an accruals basis. These contracts are risk-managed using a variety of derivative instruments, which are fair valued under IFRS. This results in measurement differences in relation to recognition of gains and losses.

The way that BP manages the economic exposures described above, and measures performance internally, differs from the way these activities are measured under IFRS. BP calculates this difference for consolidated entities by comparing the IFRS result with management s internal measure of performance. Under management s internal measure of performance the inventory, capacity, oil and gas processing and LNG contracts in question are valued based on fair value using relevant forward prices prevailing at the end of the period and the commodity contracts for business requirements are accounted for on an accruals basis. We believe that disclosing management s estimate of this difference provides useful information for investors because it enables investors to see the economic effect of these activities as a whole. The impacts of fair value accounting effects, relative to management s internal measure of performance and a reconciliation to GAAP information is shown on page 58.

Commodity trading contracts

BP s Exploration and Production and Refining and Marketing segments both participate in regional and global commodity trading markets in order to manage, transact and hedge the crude oil, refined products and natural gas that the group either produces or consumes in its manufacturing operations. These physical trading activities, together with associated incremental trading opportunities, are discussed further in Exploration and Production on pages 88-89 and in Refining and Marketing on page 98. The range of contracts the group enters into in its commodity trading operations is as follows.

Exchange-traded commodity derivatives

These contracts are typically in the form of futures and options traded on a recognized exchange, such as Nymex, SGX and ICE. Such contracts are traded in standard specifications for the main marker crude oils, such as Brent and West Texas Intermediate, the main product grades, such as gasoline and gasoil, and for natural gas and power. Gains and losses, otherwise referred to as variation margins, are settled on a daily basis with the relevant exchange. These contracts are used for the trading and risk management of crude oil, refined products, natural gas and power. Realized and unrealized gains and losses on exchange-traded commodity derivatives are included in sales and other operating revenues for accounting purposes.

Over-the-counter contracts

These contracts are typically in the form of forwards, swaps and options. Some of these contracts are traded bilaterally between counterparties; others may be cleared by a central clearing counterparty. These contracts can be used both for trading and risk management activities. Realized and unrealized gains and losses on OTC contracts are included in sales and other operating revenues for accounting purposes.

The main grades of crude oil bought and sold forward using standard contracts are West Texas Intermediate and a standard North Sea crude blend (Brent, Forties and Oseberg or BFO). Although the contracts specify physical delivery terms for each crude blend, a significant number are not settled physically. The contracts typically contain standard delivery, pricing and settlement terms. Additionally, the BFO contract specifies a standard volume and tolerance given that the physically settled transactions are delivered by cargo.

Gas and power OTC markets are highly developed in North America and the UK, where the commodities can be bought and sold for delivery in future periods. These contracts are negotiated between two parties to purchase and sell gas and power at a specified price, with delivery and settlement at a future date. Typically, these contracts specify delivery terms for the underlying commodity. Certain of these transactions are not settled physically, which can be achieved by transacting offsetting sale or purchase contracts for the same location and delivery period that are offset during the scheduling of delivery or dispatch. The contracts contain standard terms such as delivery point, pricing mechanism, settlement terms and specification of the commodity. Typically, volume and price are the main variable terms.

Swaps are often contractual obligations to exchange cash flows between two parties: a typical swap transaction usually references a floating price and a fixed price with the net difference of the cash flows being settled. Options give the holder the right, but not the obligation, to buy or sell crude, oil products, natural gas or power at a specified price on or before a specific future date. Amounts under these derivative financial instruments are settled at expiry. Typically, netting agreements are used to limit credit exposure and support liquidity.

Spot and term contracts

Spot contracts are contracts to purchase or sell a commodity at the market price prevailing on or around the delivery date when title to the inventory is taken. Term contracts are contracts to purchase or sell a commodity at regular intervals over an agreed term. Though spot and term contracts may have a standard form, there is no offsetting mechanism in place. These transactions result in physical delivery with operational and price risk. Spot and term contracts typically relate to purchases of crude for a refinery, purchases of products for marketing, purchases of third-party natural gas, sales of the group s oil production, sales of the group s oil products and sales of the group s gas production to third parties. For accounting purposes, spot and term sales are included in sales and other operating revenues, when title passes. Similarly, spot and term purchases are included in purchases for accounting purposes.

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Directors and senior management

Directors and senior management

The following lists the company s directors and senior management as at 28 February 2012.

Directors		Initially elected or appointed
C-H Svanberg	Chairman	Chairman since January 2010 Director since September 2009
R W Dudley	Executive Director (Group Chief Executive)	Group chief executive since October 2010 Director since April 2009
P M Anderson	Non-Executive Director	February 2010
F L Bowman	Non-Executive Director	November 2010
A Burgmans	Non-Executive Director	February 2004
C B Carroll	Non-Executive Director	June 2007
Sir William Castell	Non-Executive Director (Senior Independent Director)	July 2006
I C Conn	Executive Director (Chief Executive, Refining and Marketing)	July 2004
G David	Non-Executive Director	February 2008
I E L Davis	Non-Executive Director	April 2010
Professor Dame Ann Dowling	Non-Executive Director	February 2012
Dr B Gilvary	Executive Director (Chief Financial Officer)	January 2012
Dr B E Grote	Executive Director (Executive Vice President, Corporate Business Activities)	August 2000
B R Nelson	Non-Executive Director	November 2010
F P Nhleko	Non-Executive Director	February 2011
A Shilston	Non-Executive Director	January 2012
Senior management		**Initially elected or appointed**
M Bly	Executive Vice President (Safety and Operational Risk)	October 2010
R Bondy	Group General Counsel	May 2008
Dr M C Daly	Executive Vice President (Exploration)	October 2010
R Fryar	Executive Vice President (Production)	October 2010
A Hopwood	Executive Vice President (Strategy and Integration)	October 2010
B Looney	Executive Vice President (Developments)	October 2010
H L McKay	Executive Vice President (Chairman and President of BP America Inc.)	June 2008
D Sanyal	Executive Vice President and Group Chief of Staff	January 2012
Dr H Schuster	Executive Vice President (Human Resources)	March 2011

Mr F P Nhleko was appointed as a director on 1 February 2011, Dr B Gilvary and Mr A Shilston were appointed as directors on 1 January 2012 and Professor Dame Ann Dowling was appointed as a director on 3 February 2012. Dr H Schuster was appointed as executive vice president, human resources on 1 March 2011 and Mr D Sanyal was appointed as executive vice president and group chief of staff on 1 January 2012.

Mr D J Flint and Dr D S Julius retired as directors on 14 April 2011. Mr S Westwell retired as executive vice president, strategy and integration on 31 December 2011.

At the company s 2011 annual general meeting (AGM), the following directors retired, offered themselves for election/re-election and were duly elected/re-elected: Mr P M Anderson, Mr F L Bowman, Mr A Burgmans, Mrs C B Carroll, Sir William Castell, Mr I C Conn, Mr G David, Mr I E L Davis, Mr R W Dudley, Dr B E Grote, Mr B R Nelson, Mr F P Nhleko and Mr C-H Svanberg.

Sir William Castell will retire at the conclusion of the 2012 AGM. His role as senior independent director will be taken by Andrew Shilston upon his retirement. All of the other directors will offer themselves for election/re-election at the company s 2012 AGM.

David Jackson (59) was appointed company secretary in 2003. A solicitor, he is a director of BP Pension Trustees Limited.

Directors

C-H Svanberg

Chairman of the chairman s and nomination committees and attends meetings of the Gulf of Mexico and remuneration committees

Carl-Henric Svanberg (59) joined BP s board in September 2009 and became chairman of BP on 1 January 2010. From 2003 until December 2009, he was president and chief executive officer of Ericsson, also serving as the chairman of Sony Ericsson Mobile Communications AB. He continues to be a non-executive director of Ericsson.

R W Dudley

Robert Dudley (56) joined the Amoco Corporation in 1979 for whom he worked until its merger with BP in 1998. Following a variety of posts in the US, the UK, the South China Sea and Moscow, in 2001 he became group vice president responsible for BP s upstream businesses in Russia, the Caspian Region, Angola, Algeria and Egypt. From 2003 to 2008, he was president and chief executive officer of TNK-BP in Moscow. He was appointed an executive director in April 2009 and oversaw the group s activities in the Americas and Asia. Between 23 June and 30 September 2010, he served as the president and chief executive officer of BP s Gulf Coast Restoration Organization in the US. On 1 October 2010 he became BP s group chief executive.

P M Anderson

Member of the chairman s and Gulf of Mexico committees and chairman of the safety, ethics and environment assurance committee

Paul Anderson (66) was appointed a non-executive director of BP on 1 February 2010. He is a non-executive director of BAE Systems PLC and of Spectra Energy Corp. He was formerly chief executive at Duke Energy where he also served as chairman of the board. Having previously been chief executive officer and managing director of BHP Limited and then BHP Billiton Limited and BHP Billiton Plc, he re-joined these latter boards in 2006 as a non-executive director, retiring on 31 January 2010. Previously he served as a non-executive director on numerous boards in the US and Australia.

F L Bowman

Member of the chairman s, Gulf of Mexico and safety, ethics and environment assurance committees

Frank Bowman (67) joined BP s board on 8 November 2010. He served for over 38 years in the United States Navy, during which time he served as commander of the nuclear submarine *USS City of Corpus Christi and* commander of the submarine tender *USS Holland,* director of political-military affairs on the joint staff and chief of naval personnel. He was director of the naval nuclear propulsion programme in the Department of Navy and Department of Energy. After retiring from the Navy as an admiral, he became president and chief executive officer of the Nuclear Energy Institute. He served on the BP Independent Safety Review Panel and on the BP America Advisory Panel. He is president of Strategic Decisions, LLC and a director of Morgan Stanley Mutual Funds.

A Burgmans, KBE

Member of the chairman s, nomination and safety, ethics and environment assurance committees and chairman of the remuneration committee

Antony Burgmans (65) joined BP s board in 2004. He was appointed to the board of Unilever in 1991. In 1999, he became chairman of Unilever NV and vice chairman of Unilever PLC. In 2005, he became non-executive chairman of Unilever PLC and Unilever NV, retiring from these appointments in 2007. He is also a member of the supervisory boards of Akzo Nobel N.V., Aegon N.V. and SHV Holdings N.V.

C B Carroll

Member of the chairman s, nomination and safety, ethics and environment assurance committees

Cynthia Carroll (55) joined BP s board in 2007. She started her career at Amoco and in 1989 she joined Alcan, where in 2002 she was appointed president and chief executive officer of Alcan s primary metals group and an officer of Alcan, Inc. She was appointed as chief executive of Anglo American plc, the global mining group, in 2007. She is also a director of De Beers s.a. and chairman of Anglo Platinum Ltd.

Sir William Castell, LVO

Member of the chairman s, Gulf of Mexico, nomination and safety, ethics and environment assurance committees

Sir William (64) joined BP s board in 2006 and is the senior independent director. From 1990 to 2004, he was chief executive of Amersham plc and subsequently president and chief executive officer of GE Healthcare. He was appointed as a vice chairman of the board of GE in 2004, stepping down from this post in 2006 when he became chairman of the Wellcome Trust. He remains a non-executive director of GE. He will retire from the BP board at the conclusion of the 2012 AGM.

I C Conn

lain Conn (49) joined BP in 1986. Following a variety of roles in oil trading, commercial refining, retail and commercial marketing operations, and exploration and production, in 2000 he became group vice president of BP s refining and marketing business. From 2002 to 2004, he was chief executive of petrochemicals. He was appointed group executive officer with a range of regional and functional responsibilities and an executive director in 2004. He was appointed chief executive of Refining and Marketing in 2007. He is a non-executive director and senior independent director of Rolls-Royce Holdings plc, chairman of The Advisory Board of Imperial College Business School and a member of The Council of The Imperial College.

G David

Member of the chairman s, audit, Gulf of Mexico and remuneration committees

George David (69) began his career in The Boston Consulting Group before joining the Otis Elevator Company in 1975. He held various roles in Otis and later in United Technologies Corporation (UTC), following Otis s merger with UTC in 1977. In 1992, he became UTC s chief operating officer. He served as UTC s chief executive officer from 1994 until 2008 and as chairman from 1997 until his retirement in 2009.

I E L Davis

Member of the chairman s, nomination and remuneration committees and chairman of the Gulf of Mexico committee

Ian Davis (60) joined BP s board on 2 April 2010. He spent his early career at Bowater, moving to McKinsey & Company in 1979. He was managing partner of McKinsey s practice in the UK and Ireland from 1996 to 2003. In 2003, he was appointed as chairman and worldwide managing director of McKinsey, serving in this capacity until 2009. He retired as senior partner of McKinsey & Company in July 2010. He is a non-executive director of Johnson & Johnson, Inc and a senior adviser to Apax Partners. He is also a non-executive member of the UK s Cabinet Office.

Professor Dame Ann Dowling

Member of the chairman s and safety, ethics and environment assurance committees

Dame Ann (59) joined BP s board on 3 February 2012. She was appointed a Professor of Mechanical Engineering in the Department of Engineering at the University of Cambridge in 1993. Between 1999 and 2000 she was the Jerome C Hunsaker Visiting Professor of Aerospace Systems at MIT subsequently becoming a Moore distinguished scholar at Caltech in 2001. When she returned to the University of Cambridge, she became Head of the Division of Energy, Fluid Mechanics and Turbomachinery in the Department of Engineering, becoming UK lead of the Silent Aircraft Initiative in 2003 and Head of the Department of Engineering at the University of Cambridge in 2009. She is chair of the Physical Sciences, Engineering and Mathematics Panel in the Research Excellence Framework the UK government s review of research in universities.

She was appointed Director of the University Gas Turbine Partnership with Rolls-Royce in 2001 and chairman in 2009. Between 2003 and 2008 she chaired the Rolls-Royce Propulsion and Power Advisory Board. She chaired the Royal Society/Royal Academy of Engineering study on Nanotechnology.

Directors and senior management

Dr B Gilvary

Brian Gilvary (50) joined BP in 1986. Following a variety of roles in exploration and production, downstream and trading, in 2000 he became chief of staff of BP s refining and marketing business and held a number of executive roles in the business, including chief financial officer and commercial director from 2002 to 2005. In 2003 he was appointed director of TNK-BP, retiring from the board in 2005 and re-joining in 2010. From 2005 to 2010 he was chief executive of integrated supply and trading, BP s commodity trading arm. In 2010 he was appointed deputy group chief financial officer with responsibility for the finance function. On 1 January 2012 he was appointed to the board of BP p.l.c. and became chief financial officer.

Dr B E Grote

Byron Grote (63) joined BP in 1987 following the acquisition of the Standard Oil Company of Ohio, where he had worked since 1979. He became group treasurer in 1992 and in 1994 regional chief executive in Latin America. In 1999, he was appointed an executive vice president of Exploration and Production, and chief executive of chemicals in 2000. He was appointed an executive director of BP in 2000. Between 2002 and 31 December 2011 he was BP s chief financial officer. In January 2012 he became executive vice president, corporate business activities. He is a non-executive director of Unilever NV and Unilever PLC.

B R Nelson

Member of the chairman's committee and chairman of the audit committee

Brendan Nelson (62) joined BP s board on 8 November 2010. He is a chartered accountant and was admitted as a partner of KPMG in London in 1984. He served as a member of the UK Board of KPMG from 2000 to 2006 subsequently being appointed vice chairman until his retirement in 2010. At KPMG International he held a number of senior positions including global chairman, banking and global chairman, financial services. He is a non-executive director of The Royal Bank of Scotland Group plc where he is chairman of the group audit committee. He is Vice President of the Institute of Chartered Accountants of Scotland, a member of the Financial Reporting Review Panel and a director of the Financial Skills Partnership.

F P Nhleko

Member of the chairman s and audit committees

Phuthuma Nhleko (51) joined BP s board on 1 February 2011. He began his career as a civil engineer in the United States and as a project manager for infrastructure developments in Southern Africa. Following this, he became a senior executive of the Standard Corporate and Merchant Bank in South Africa. He later held a succession of directorships before joining MTN Group, a pan-African and Middle Eastern telephony group, as group president and chief executive officer in 2002. He stepped down as group chief executive of MTN Group at the end of March 2011 and became vice-chairman of the MTN Group and chairman of MTN International. He is a non-executive director of Anglo American plc.

A Shilston

Member of the chairman s and audit committees

Andrew Shilston (56) trained as a chartered accountant before joining BP as a management accountant. He subsequently joined Abbott Laboratories before moving to Enterprise Oil plc in 1984 at the time of flotation. In 1989 he became treasurer of Enterprise Oil and was appointed finance director in 1993. After the sale of Enterprise Oil to Shell in 2002, in 2003 he became finance director of Rolls-Royce plc until his retirement on 31 December 2011. Andrew has served as a non-executive director on the boards of AEA Technology plc and Cairn Energy plc where he chaired the remuneration and audit committees. He recently joined the board of Circle Holdings plc as a non-executive director. He will become senior independent director at the conclusion of the 2012 AGM.

Senior management

M Bly

Mark Bly (52) joined BP in 1984. Following various engineering and commercial leadership assignments he held business unit leader posts in Alaska and the North Sea and was strategic performance unit leader for BP's North America Gas business. In 2007, he became group vice president, Exploration and Production and a member of the exploration and production operating committee. In 2008, he became group head of safety and operations and in October 2010 he was appointed executive vice president of safety and operational risk.

R Bondy

Rupert Bondy (50) joined BP as group general counsel in 2008. In 1989, he joined US law firm Morrison & Foerster, working in San Francisco and London. From 1994 to 1995, he worked for UK law firm Lovells in London. In 1995, he joined SmithKline Beecham as senior counsel for mergers and acquisitions and other corporate matters. He subsequently held positions of increasing responsibility and, following the merger of SmithKline Beecham and GlaxoWellcome, he was appointed senior vice president and general counsel of GlaxoSmithKline in 2001.

Dr M C Daly

Mike Daly (58) joined BP in 1986 as a technical specialist in structural geology, subsequently joining BP s global basin analysis group. After a series of exploration business and functional roles in South America, the North Sea and new business development, in 2000 he became president of BP s Middle East and South Asia businesses. In 2006, he was appointed BP's head of exploration and new business development and in October 2010 he was appointed executive vice president, exploration.

R Fryar

Bob Fryar (48) joined Amoco Production Company in 1985, serving in a variety of engineering and management positions in the onshore US and deepwater Gulf of Mexico. In 2003, he was appointed vice president of operations performance unit for BP Trinidad and later, in 2009, he became chief executive officer for BP Angola. In October 2010, he was appointed executive vice president, production.

A Hopwood

Andy Hopwood (54) joined BP in 1980 as a petroleum engineer. Following a series of operational and corporate planning roles, in 1999 he was appointed business unit leader in Azerbaijan, returning to London in 2001 as the upstream chief of staff. He became strategic performance unit leader for BP s North America Gas business in 2004, returning to London in 2009 as head of portfolio and technology for BP's upstream businesses. In October 2010, he was appointed executive vice president of strategy and integration.

B Looney

Bernard Looney (41) joined BP in 1991 as a drilling engineer, working in a variety of roles in the North Sea, Vietnam and the Gulf of Mexico and later in the exploration and technology group. In 2005, he became senior vice president for BP Alaska, before moving to be head of the group chief executive s office. He was appointed vice president for Norway and infrastructure in 2008 and then, in 2009, he became managing director of BP s North Sea business. In October 2010, he was appointed executive vice president, developments.

H L McKay

Lamar McKay (53) was appointed chairman and president of BP America, Inc. in 2009. He joined Amoco Production Company as a petroleum engineer in 1980. He held a variety of roles before becoming group vice president for Russia and Kazakhstan in 2003, also being appointed to the board of TNK-BP in 2004. In 2007, he was appointed senior group vice president of BP and executive vice president of BP America. In early 2008, he became executive vice president of BP p.l.c. special projects, focusing on Russia, subsequently joining the group executive management team. In October 2010, in addition to his current duties, he was appointed president and chief executive officer of the Gulf Coast Restoration Organization.

D Sanyal

Dev Sanyal (46) joined BP in 1989 and has held a variety of international roles in London, Athens, Istanbul, Vienna and Dubai. He was appointed chief executive, BP Eastern Mediterranean Fuels in 1999. In 2002, he moved to London as chief of staff of BP s worldwide downstream businesses. In 2003, he was appointed chief executive officer of Air BP following which in 2006, he became head of the group chief executive s office. He was appointed group vice president and group treasurer in 2007. During this period, he was also chairman of BP Investment Management Ltd and accountable for the Group s aluminium interests. He was appointed an executive vice president and group chief of staff with effect from 1 January 2012.

Dr H Schuster

Helmut Schuster (51) joined BP in 1989. He held a number of roles working in most parts of refining, marketing, trading and gas and power in the US, UK and Continental Europe. In 2007 he became vice president, human resources for Refining and Marketing in BP and in 2010 he added corporate and functions to his portfolio. On 1 March 2011 he became group human resources director and a member of BP s executive team.

Directors interests

The figures below indicate and include all the beneficial and non-beneficial interests of each director of the company in shares of the company (or calculated equivalents) that have been disclosed to the company under the Disclosure and Transparency Rules as at the applicable dates.

Current directors	At 31 Dec 2011	At 1 Jan 2011	Change from 31 Dec 2011 to 1 Mar 2012
C-H Svanberg	933,971	925,000	
R W Dudley	287,945[a]	280,799[a]	49,356
P M Anderson	6,000[a]	6,000[a]	
F L Bowman	12,720[a]	2,520[a]	
A Burgmans	10,156	10,156	
C B Carroll	10,500[a]	10,500[a]	
Sir William Castell	82,500	82,500	
I C Conn	425,169[b]	339,637[b]	72,332
G David	579,000[a]	159,000[a]	
I E L Davis	10,391	10,000	
Dr B E Grote	1,394,819[c]	1,372,643[c]	89,784
B R Nelson	11,040		
Directors leaving the board	**At resignation/ retirement**	**At 1 Jan 2011**	
D J Flint	15,000[d]	15,000	
Dr D S Julius	15,000[d]	15,000	
Directors joining the board	**At 31 Dec 2011**	**On appointment**	**Change from 31 Dec 2011 to 1 Mar 2012**

Professor Dame		
Ann Dowling	[e]	
Dr B Gilvary	236,029[f]	95,059
F P Nhleko	[g]	
A Shilston	[f]	

a Held as ADSs.
b Includes 48,024 shares held as ADSs at 1 January 2011 and at 31 December 2011.
c Held as ADSs, except for 94 shares held as ordinary shares.
d On retirement at 14 April 2011.
e On appointment at 3 February 2012.
f On appointment at 1 January 2012.
g On appointment at 1 February 2011.

The following performance shares were awarded on 9 March 2011 under the BP Executive Directors Incentive Plan (EDIP). These figures represent the maximum possible vesting levels. The actual number of shares/ADSs that vest will depend on the extent to which performance conditions have been satisfied over a three-year period.

Director	Potential maximum performance shares 2011 EDIP awards
R W Dudley[a]	1,330,332
I C Conn	623,025
Dr B E Grote[a]	785,394

a Held as ADSs.

Additional details regarding performance shares awarded can be found in the Directors remuneration report on page 149.

Executive directors are also deemed to have an interest in such shares of the company held from time to time by the BP Employee Share Ownership Plan (No. 2) to facilitate the operation of the company s option schemes.

No director has any interest in the preference shares or debentures of the company or in the shares or loan stock of any subsidiary company.

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Corporate governance

Over this coming year we will maintain focus, discipline and follow through at the board as we continue to deal with a volume of issues.

Board performance report

Dear shareholder,

In my letter to shareholders earlier in this report I have endeavoured to give an overview of the challenges which the company has faced in 2011 and the work of the board in meeting those challenges.

In this letter, and in the report which follows, my aim is to give shareholders, and indeed all those with whom the company interacts, a deeper insight into the evolution of the BP board, the review which it has undertaken and the changes that have been made, and which are continuing to be made, to govern your company at the highest standard.

BP has a clear system of governance based upon the BP board governance principles. This serves BP and its board well. It is vital that the system of governance, what the board does, evolves with the company and with the thinking of those charged with its governance.

The tragic events in the Gulf of Mexico require that the board consider how it operates; however the substantial change in directors has meant there have been new views on the role of the board. This has resulted in the evolution that I have mentioned. In undertaking strong governance of the company, I believe that the board should provide leadership and challenge, but also support to executive management. In its activities this year, the board has strived to achieve this role.

The tasks of the board set out later in this report have not and will not change. It was clear though that a board which governs a company of the scale and scope of BP needs to have a clear view of its role and the steps it can take to support or challenge and the information which it needs.

The board is initiating modifications in all of these areas and will keep those changes under review. The actions from this work are important as we operate a system of governance throughout the company. The framework for how the board works is articulated in our board governance principles, available on our website at *bp.com/governance.*

Over this coming year we will maintain focus, discipline and follow through at the board as we continue to deal with a volume of issues. Looking forward into 2012, one of our aims is to get back into a steady rhythm of board meetings. We hope to do this through strengthening our forward agenda and board planning processes. We will also maintain our focus on the skills and experience of our directors, the composition of our board and succession planning.

Diversity within UK boards was a topic of debate in 2011 and will remain so going forward. BP is a company with global reach and we believe that it is important to have a board that is diverse in the widest sense; the company remains committed to meritocracy as well as to diversity. As part of the update of our board governance principles we have included a policy on board diversity. At the time of writing we have 12.5% female representation on the board. Our goal is to increase the number of women on the board to three by 2013 and to work towards 25% representation by 2015.

In the governance report which follows we have outlined key elements of the activities of the board and its committees during the year.

Carl-Henric Svanberg

Chairman

How the board works

BP s governance framework

BP s system of governance begins with the board and continues into our subsidiaries. The governance framework is outlined in the BP board governance principles which sets out the role of the board, its processes and its relationship with executive management.

The board s core activities include:

- The active consideration of long-term strategy.
- The monitoring of executive action and the performance of BP.
- Obtaining assurance that the material risks to BP are identified and that systems of risk management and control are in place to mitigate such risks.
- Ongoing board and executive management succession.

In all its work the board sets the tone from the top for the organization by considering specific issues, including health, safety, the environment and BP s reputation and working with management to set the values of the company.

During 2011 the board undertook a review of its corporate governance model. A working group consisting of the chairman and three non-executive directors (Paul Anderson, Antony Burgmans and Cynthia Carroll) examined key aspects of BP s system of governance, including the system of delegation, board processes, information, risk and the tasks and role of the committees. During the review, input was sought from board members and from executive management, both through board and working group discussions and individually through our board evaluation process.

The review concluded that BP s system of governance is robust but that further clarity on board processes would help reinforce the board s delegation to the group chief executive and strengthen the board s monitoring and assurance role.

Who s on the BP board?

The composition of the board and the mix of knowledge, skills and experience that our directors bring to the company is a key area of focus for the nomination committee. The committee keeps this mix under review and regularly maps the skillset of our existing board membership against the likely tenure of individual directors. This is viewed against the potential demands placed on the board due to developments in our strategy and business activities. Further detail of the current skillset of the board and the skills/competencies that the nomination committee has prioritized for future non-executive director appointments is outlined in the report of the nomination committee later in this section.

Full biographies of our board members can be found on our website.

Succession: board and committee membership

Since the beginning of 2011, the following changes have taken place to the composition of the board:

- Phuthuma Nhleko joined the board as a non-executive director on 1 February 2011.
- Dr DeAnne Julius and Douglas Flint retired from the board at the AGM in April 2011.
- Dr Brian Gilvary joined the board as an executive director and chief financial officer (CFO) on 1 January 2012.
- Andrew Shilston joined the board as a non-executive director on 1 January 2012.
- Professor Dame Ann Dowling joined the board as a non-executive director on 3 February 2012.

Dr Byron Grote stepped down as CFO at the end of 2011 but will remain on the board as an executive director during 2012, with responsibility for BP s integrated supply and trading operations, Alternative Energy, shipping, technology and remediation activities.

Sir William Castell has decided not to seek re-election at this year s AGM and will retire from the board at the meeting. Andrew Shilston will succeed Sir William as the senior independent director from the 2012 AGM and will be available to shareholders who have concerns that cannot be addressed through normal channels. He will work closely with

Antony Burgmans who, given his length of service on the board, will respond to any internal board matters, act as a sounding board for the chairman and serve as an intermediary for other directors if necessary.

Sir William stepped down as chairman of the safety, ethics and environment assurance committee (SEEAC) and Paul Anderson became its chairman from 9 December 2011.

Ian Davis stepped down as a member of the audit committee on 3 February 2012 and Frank Bowman joined the Gulf of Mexico committee on the same date.

Neither the chairman nor the senior independent director are employed as executives of the group. The board maintains a succession plan for the chairman and senior independent director, in addition to the group chief executive and senior management.

Appointment and tenure

The chairman and our non-executive directors (NEDs) serve on the basis of letters of appointment. BP does not place a term limit on director s service as we propose all directors for annual re-election by shareholders (a practice we have followed since 2004).

The governance principles require our non-executive directors to be independent in character and judgement and free from any business or other relationship which could materially interfere with the exercise of their judgement. The board has determined that those non-executive directors who served during 2011 fulfilled this requirement and were independent.

The board also satisfied itself that there is no compromise to the independence of, or existence of conflicts of interest for, those directors who serve together as directors on the boards of outside entities or who have other appointments in outside entities. These issues are considered on a regular basis at board meetings. The nomination committee keeps under review the nature of non-executive directors other interests to ensure that the effectiveness of the board is not compromised. The

committee may make recommendations to the board if it concludes that a director s other commitments are inconsistent with those required by BP.

Time commitment and outside appointments

Letters of appointment for non-executive directors do not set out a fixed time commitment for board duties as we believe that the time required by directors may fluctuate depending on demands of the business and other events. However, it is expected that directors will allocate sufficient time to the company to perform their duties effectively. The chairman s appointment letter sets out the time commitment expected of him.

Following an approach from the Volvo Group, the chairman discussed with the board, through the chairman s committee, whether to take an additional post as a part-time non-executive chairman of Volvo. During this process, our senior independent director led a discussion of non-executive directors without the chairman present to hear their views. The board concluded that Mr Svanberg has sufficient time to carry out both commitments and supported the chairman taking on this additional role. The chairman will step down from his existing non-executive directorship at Ericsson before assuming the chairmanship of Volvo in April 2012; he also confirmed to the board that he does not intend to seek any additional roles outside those at BP and Volvo.

Executive directors are permitted to take up one external board appointment, subject to the agreement of the chairman and provided such external appointment is reported to the BP board. Fees received for an external appointment may be retained by the executive director and are reported in the Directors remuneration report.

Diversity

BP recognizes the importance of diversity, including gender, at all levels of the company as well as the board. The company is committed to increasing diversity across our operations and has in place a wide range of activities to support the development and promotion of talented individuals, including women.

During the year, the board responded to Lord Davies report on gender diversity and confirmed its goal to increase the number of women on the BP board to three by 2013 and work towards the recommendation of 25% female representation by 2015. With the appointment of Professor

Dame Ann Dowling, BP currently has two female board members, equating to 12.5% of our directors.

The board has agreed a board diversity policy which will be included in our board governance principles. The policy states that when considering the composition of the board, directors will be mindful of diversity, inclusiveness and meritocracy. As part of its workplan for this year, the nomination committee will develop and agree a set of measurable objectives for implementing this policy and report back on these to shareholders.

Induction and board learning

On joining BP non-executive directors are given a tailored induction programme. This programme includes one-to-one meetings with senior management, our auditors and site visits to our operations. The induction will also cover the board committees that a director will join. An example of the initial induction programme for one of our recently joined non-executive directors is set out below.

Director induction programme

Board and governance

BP s board governance model, directors duties, interests and potential conflicts.

Committee induction.

Strategy and planning.

Group investor event on governance and board activities.

BP s business

History of the integrated oil company and BP.

Upstream (exploration, development, production, overview of our operations).

Refining and Marketing.

Alternative Energy.

Functional input

Controls, external auditors and internal audit.

Finance and corporate reporting.

HR.

Legal.

Ethics and compliance.

Safety and operational risk (S&OR), BP s operating management system (OMS) and environmental performance.

Research and technology.

Engineering.

We continue the board s learning through board and committee events. At our May 2011 board meeting in Houston, we ran a day-long event to give our non-executive directors an insight into how BP manages its learning and capability development, including briefings on seismic interpretation, the company s technical education programme and trading. Non-executive directors are expected to attend at least one site visit per year. During 2011, such visits included Texas City and Whiting refineries with the independent expert, L. Duane Wilson, an offshore visit to the Gulf of Mexico, visits to global wells organization leadership teams in the Gulf of Mexico and the North America gas business, our business centre in Budapest and BP s offices in Houston and Canary Wharf. During the year our chairman visited BP s operations in Alaska and our oil sands projects in Canada.

Board effectiveness

Board evaluation

We undertake an annual review of the board, its committees and individual directors. The chairman undertakes the evaluation of individual directors, with the chairman s own performance evaluated by the chairman s committee (led by the senior independent director).

In 2009 and 2010, we undertook an external review of the board s performance. In 2011, we decided to continue external facilitation as a

way of building on the past year s results and providing a robust, third-party insight into the board s effectiveness. To enable continuity and comparability of results over the two year period, we used the same external facilitator as for the 2010 review.

Evaluation process for 2011

- Each director (with the exception of those appointed in 2012) was sent a questionnaire and a list of discussion topics.
- The facilitator held one-to-one reviews with each participating director, using the questionnaire and discussion topics as a starting point.
- Each committee held its own review using online questionnaires that were developed by us using an externally generated question bank. The results from these questionnaires were then discussed with the external facilitator by each committee (these are outlined in the reports of our committees).
- A paper on the key themes and views from the one-to-one reviews and the evaluation of the committees were sent to the board to review.
- The board held a discussion with the external facilitator to assess these views and the issues raised.
- The board agreed on actions for the forthcoming year based on this discussion.

Key conclusions of the 2011 evaluation

The review concluded the board had operated well in 2011. It had been an eventful year and the board continues to deal with events from the Gulf of Mexico. There was a strong view that the board had an open and transparent style of discussion, with good engagement and contribution from all members, particularly around strategic planning and risk management. The board also considered that its focus, discipline and follow through had strengthened over the year, which was seen as important given the events of the previous 18 months and the volume of issues dealt with by the board. It hoped to continue this trend in 2012.

The review also found that there was potential for continuous improvement in areas such as board materials (including the length of papers) and agendas, and that as the board endeavours to move back into a steady state of operation, it would need to revisit its collective expectation around governance processes and style.

Tracking issues from our previous evaluation

Over 2011, the board acted upon the recommendations from the 2010 board evaluation. The board determined to conduct additional site visits and participate in detailed briefings in order to gain further insight into the company s operations and activities which it achieved through an active programme over the year attended by individual or groups of directors. The board set up a working group to review and revise the company s board governance principles to ensure that BP s governance processes were effective. The board also reviewed BP s crisis and continuity plan, including specific focus on the process through which board involvement is triggered as part of its action to clarify the board s role in the crisis planning process. Finally, the board had extensive engagement with executive management in forward-looking strategy discussions and an overview of BP s risk management systems.

Risk management: from operations to the board

One of the board s tasks is to satisfy itself that the material risks to BP are identified and understood and that systems of risk management, compliance and control are in place to mitigate such risks. The board, through its governance principles, requires the group chief executive to operate with a comprehensive system of controls and internal audit to identify and manage the risks that are material to BP. Authority for the design and implementation of this system of internal control is delegated by the board to the group chief executive. Components of our system of internal control (which includes the risk management system) are management systems, organizational structures, processes, standards and behaviours employed to conduct the business of BP.

Risk management in BP is a top-down and bottom-up process. The bottom-up process starts at the day-to-day level with businesses and functions identifying and managing their risks using existing company standards and practices, e.g. OMS. The most significant risks are organized into common categories strategic risks, safety and operational risks and compliance and controls risks so they can be reported up the line in a standardized form.

During the year a review of BP s risk management system was initiated which has built on our current system of risk management. Using the findings of this review, BP has started to implement enhancements to drive consistency and clarity in how risks are reported and understood in all levels of our organization from operations to the board. *See Our management of risk on page 42* for further discussion of the risk management system and 2011 review.

Within BP s risk management system, functions set standards, provide guidance and provide a view of group risks in their functional area of expertise, independent of line management. Certain functions also deliver assurance that the activities to manage the risks are working as intended in the businesses.

Group risks are allocated to one of the committees established by the group chief executive for management and monitoring. These executive level committees are sub-committees of our senior management team and their role includes setting policy, making decisions and overseeing the management of risks and performance. The executive committees are:

- Group operations risk committee (GORC) for risks of a safety, environment or operations nature.
- Group financial risk committee (GFRC) for finance and trading risks.
- Group disclosure committee (GDC) for financial reporting risks.
- Group people committee (GPC) for people risks.
- Resource commitments meeting (RCM) for risks related to investment decisions.

At the group level, risk is examined by the board to apply a top-down perspective. The group risks identified as requiring particular oversight in the coming year are selected for discussion with the board. These are then allocated for review by the board or one of its committees. A common agenda for the review is established to enable the board or committee to discuss risk in a consistent manner with executive management.

The board examines group risks both on a periodic basis and as part of its review of the annual plan. The board also conducts an annual review of the risk management and internal control systems as required by the UK Corporate Governance Code. During the year there is flexibility to change which risks have been identified as requiring particular oversight and which have been allocated to the board and its committees, in the event there are any changes to the internal or external environments or events arising.

Following its review of the 2012 annual plan, the risks described above have been allocated for review by the board and its committees as follows:

- The board has been allocated several strategic and safety and operational group risks, including risks associated with the macroeconomic outlook, the delivery of the 10-point plan, the group s exposure to Russia, crisis management, reputational impact and the recruitment and development of staff.
- The audit committee has been allocated a number of compliance and control and safety and operational risks, including risks associated with treasury and trading activities, compliance with applicable laws and regulations and security threats against our digital infrastructure.
- The safety, ethics and environment assurance committee has been allocated several safety and operational and strategic risks, including risks associated with conducting our operations through joint ventures or associates and through contracting and sub-contracting arrangements where BP may not have full operational control. Other safety and operational risks the committee have been allocated include the health, safety and environmental risks of incidents associated with the drilling of wells, operation of facilities and transportation of hydrocarbons.
- The Gulf of Mexico committee has been allocated a number of strategic risks, including risks associated with the extent and timing of costs and liabilities relating to the incident and the possible impact on our licence to operate.

Board activities during 2011

2011 was another active year for the board, which met 15 times. The board s focus remained on the incident in the Gulf of Mexico both to understand what happened and how the company can apply the lessons learned. Within the board and its committees, debate and assurance has been ongoing with management on key aspects such as the impact on the group s reputation, accounting treatment and provisioning, implementation of the recommendations of the Bly Report and the legal and communication strategy for litigation arising from the incident. The challenge has remained for the board to ensure that it devoted enough time to the ongoing business of the company whilst holding these important discussions. Periodic meetings throughout the year of the non-executive directors comprising the chairman s committee, together with liaison between the chairman and the chairs of the board committees, have assisted in managing this challenge. Areas discussed by the board included the following:

Strategy

The board is engaged at the early stages of discussion on strategy and the annual plan in order to provide constructive challenge. During the year two day-long meetings were held for strategic discussions. After the February 2011 update to the market the board continued to develop the company s strategy with respect to milestones and deliverables, resulting in a further market update in October on the company s 10-point-plan . Over the year, the board considered key strategic elements, including biofuels, Canadian heavy oil and the company s disposal programme. The board also spent considerable time discussing strategic opportunities and implications of the strategic alliance that had been proposed with Rosneft and the new relationship with Reliance.