BP PLC
Form 20-F
March 02, 2011

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 20-F

(Mark One)

REGISTRATION STATEMENT PURSUANT TO SECTION 12(b) or (g)
OF THE SECURITIES EXCHANGE ACT OF 1934
OR
ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended 31 December 2010
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 Byron E Grote
BP p.l.c.
1 St James s Square, London SW1Y 4PD
United Kingdom
Tel +44 (0) 20 7496 4495
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(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 2011	**New York Stock Exchange**
Substitute Floating Rate Guaranteed Note due 2011	**New York Stock Exchange**
1.55% Guaranteed Notes due 2011	**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**
3.875% Guaranteed Notes due 2015	**New York Stock Exchange**
3.125% Guaranteed Notes due 2015	**New York Stock Exchange**
4.75% Guaranteed Notes due 2019	**New York Stock Exchange**
4.5% Guaranteed Notes due 2020	**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	18,796,461,292
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 o

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 o 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 o

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 þ No o

*This requirement does not apply to the registrant until its fiscal year ending December 31, 2011.

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 o Non-accelerated filer o

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

U.S. GAAP o International Financial Reporting Standards as issued by the International Accounting Standards Board þ Other o

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 o Item 18 o

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 o No þ

Annual Report
and Form 20-F
2010
bp.com/annualreport
What s inside?

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Cross reference to Form 20-F

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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.

Annulus
The space between two concentric objects, such as between the wellbore and casing of an oil well or between casing and tubing, where fluid can flow. It allows fluids, such as drilling mud, to circulate in the well.

Atlantic Richfield
Atlantic Richfield Company and its subsidiaries.

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

Barrel
42 US gallons.

b/d
barrels per day.

boe
barrels of oil equivalent.

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

Burmah Castrol
Burmah Castrol PLC and its subsidiaries.

Cent or c
One-hundredth of the US dollar.

The company
BP p.l.c.

Dollar or $

The US dollar.

EU
European Union.

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.

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.

OPEC
Organization of Petroleum Exporting Countries.

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

Pence or p
One-hundredth of a pound sterling.

Pound, sterling or £
The pound sterling.

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

PSA
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.

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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 2010. 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 5-109 and 123-140, 142. The Directors Remuneration Report is on pages 111-121. The consolidated financial statements of the group are on pages 141-248 and the corresponding reports of the auditor are on pages 143-145.

BP Annual Report and Form 20-F 2010 and *BP Summary Review 2010* may be downloaded from *www.bp.com/annualreport.* No material on the BP website, other than the items identified as *BP Annual Report and Form 20-F 2010* or *BP Summary Review 2010,* 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

BP Annual Report and Form 20-F 2010 contains certain forward-looking statements within the meaning of the US Private Securities Litigation Reform Act of 1995 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.

In order to utilize the Safe Harbor provisions of the United States Private Securities Litigation Reform Act of 1995, BP is providing the following cautionary statement. This document contains certain forward-looking statements with respect to the financial condition, results of operations and businesses of BP and certain of the plans and objectives of BP with respect to these items. These statements may generally, but not always, be identified by the use of words such as will , expects , is expected to , aims , should , may , objective , is likely to , intends , believes , plan expressions. In particular, among other statements, (i) certain statements in the Business review (pages 6-82), including under the heading Outlook , with regard to strategy, management aims and objectives, future capital expenditure, the completion of planned and announced divestments and disposals, acquisitions and other transactions, future hydrocarbon production volume and the group s ability to satisfy its long-term sales commitments from future supplies available to the group, date(s) or period(s) in which production is scheduled or expected to come onstream or a project or action is scheduled or expected to begin or be completed, capacity of planned plants or facilities and impact of health, safety and environmental regulations; (ii) the statements in the Business review (pages 6-63 and 68-81) with regard to anticipated energy demand and consumption, global economic recovery, oil and gas prices, global reserves, refining capacity, expected future energy mix and the potential for cleaner and more efficient sources of energy, management aims and objectives, strategy, production, petrochemical and refining margins, anticipated investment in Alternative Energy, anticipated future project developments, growth of the international businesses, Refining and Marketing investments, reserves increases through technological developments, with regard to planned investment or other projects, timing and ability to complete announced transactions and future regulatory actions; (iii) the statements in the Business review (pages 23-26, 63-67 and 73) with regard to the plans of the group, the cost of and provision for future remediation programmes and environmental operating and capital expenditures, taxation, liquidity and costs for providing pension and other post-retirement benefits; and including under Liquidity and capital resources Trend Information , with regard to global economic recovery, oil and gas prices, petrochemical and refining margins, production, demand for petrochemicals, production and production growth, depreciation, underlying average quarterly charge from Other businesses and corporate, costs, foreign exchange and energy costs, capital expenditure, timing and proceeds of divestments, balance of cash inflows and outflows, dividend and optional scrip dividend, cash flows, shareholder distributions, gearing, working capital, guarantees, expected payments under contractual and commercial commitments and purchase obligations; and (iv) certain statements in Chairman s letter (pages 6-7) and Business review (pages 10-11) in relation to an anticipated increase in the level of the dividend; 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; future levels of industry product supply, demand and pricing; operational problems; general economic conditions; political stability and economic growth in relevant areas of the world; changes in laws and governmental regulations; actions by regulators; exchange rate fluctuations; development and use of new technology; the success or otherwise of partnering; the actions of competitors; natural disasters and adverse weather conditions; changes in public expectations and other changes to business conditions; wars and acts of terrorism or sabotage; and other factors discussed elsewhere in this report including under Risk factors (pages 27-32). 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 in the form of ADSs. *(See page 134 for more details.)*

The registered office of BP p.l.c., and our worldwide headquarters, is:
1 St James s Square,
London SW1Y4PD, 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.

Business review
Chairman s
letter

Dear fellow shareholder

2010 was a profoundly painful and testing year. In April, a tragic accident on the Deepwater Horizon rig claimed the lives of 11 men and injured others. Above all else, I want to remember those men, and say that our thoughts remain with their families and friends. BP s priority is to ensure that the people who work for us, and with us, return home safely. The accident should never have happened. We are shocked and saddened that it did.

The spill that resulted caused widespread pollution. Our response has been unprecedented in scale, and we are determined to live up to our commitments in the Gulf. We will also do everything necessary to ensure BP is a company that can be trusted by shareholders and communities around the world.

In the days after the accident in the Gulf of Mexico the company faced a complex and fast-changing crisis. With oil escaping into the ocean, uncertainty grew around our ability to seal the well and restore the areas affected. This was an intense period, with the situation worsening almost daily. Our meeting with President Obama on 16 June 2010 provided reassurance to the US government that BP would do the right thing in the Gulf, and this marked a turning point. Through diligence and invention, our teams stopped the flow of oil in July and completed relief-well operations in September.

During these difficult days your board focused on three critical objectives.

First, we ensured the response team had the resources it required to stop the leak, contain and clean up the damage, and provide financial support to those affected. This was an unprecedented response to an industrial accident, with some 48,000 people involved at the height of the effort. We have set up a $20-billion fund to show our willingness and capacity to pay all legitimate claims for compensation. For the long term, we have committed $500 million to a 10-year independent research programme that will examine the environmental impact of the oil spilled and dispersants used. BP will continue to help restore the environment and economy of the Gulf, however long that takes.

Second, we resolved to understand what happened on and below the Deepwater Horizon, to apply the lessons learned and to make our findings available publicly. BP s comprehensive internal investigation concluded that a sequence of failures involving a number of different parties led to the explosion and fire.

We are implementing the report s recommendations. We have established a powerful safety and operational risk function, and we have enhanced risk management through the restructuring of our upstream business. We are also conducting a wide-ranging review of when and how we outsource operations.

Third, we moved to secure the long-term future of BP and our capacity to meet our financial responsibilities in the Gulf of Mexico. Decisive action was required here because events in the US led to a crisis of confidence in BP within the financial markets. In response, we made the difficult decision to cancel three dividend payments. We do not underestimate the effect of this on small and large shareholders alike. However, there is no doubt in my mind that this action steadied and strengthened our position at a critical point.

I am pleased that we have been able to resume dividend payments promptly. The dividend for the fourth quarter of 2010, to be paid in March 2011, is 7 cents per share (US$0.42 per ADS). The scrip dividend programme approved last year is in operation once again, and this presents an opportunity to take the dividend in shares or ADSs rather than cash. We intend to raise the level of the dividend as the company s circumstances and performance improve.

During the year we further reinforced our financial position. Having taken a total pre-tax charge of $40.9 billion in relation to the accident and spill, we announced our intention to sell up to $30 billion of assets. We have already secured almost $22 billion. We intend to reduce the net debt ratio to within the range of 10-20%, compared with our previously targeted range of 20-30%.

We have made significant changes to the board and I want to acknowledge Tony Hayward and Andy Inglis, who have left the company. Tony stood down as group chief executive on 1 October 2010. The board was saddened to lose someone whose long-term contribution to BP was so widely admired. Andy Inglis stood down on 31 October 2010. Andy was a strong leader of Exploration and Production and a significant contributor to the board.

BP is fortunate to have an exceptional successor to the role of group chief executive. Bob Dudley has spent his working life in the oil industry and has proved himself a robust, successful leader in the toughest circumstances. I am delighted to be working alongside a man of such substance and experience.

Douglas Flint will be standing down at the annual general meeting in April 2011, having taken up a new role as chairman of HSBC Holdings plc. Douglas has chaired our audit committee for the past year. DeAnne Julius will be standing down at the same time, having joined the board in 2001. DeAnne has chaired the remuneration committee since 2005 and is succeeded in that role by Antony Burgmans. Both DeAnne and Douglas have been immensely valuable board members. We thank them and wish them both well.

Boards must evolve if they are to engage effectively with new issues and opportunities. We have acted to strengthen the board of BP to ensure we have the right mix of skills, knowledge and experience as we work to achieve sustainable success in a fast-changing world. In early 2010 we appointed Paul Anderson and Ian Davis as non-executive directors. We have since made three further non-executive appointments. Admiral Frank L Skip Bowman is former head of the US Nuclear Navy and was a member of the Baker Panel that reviewed safety at BP s US refineries. We will benefit from his exceptional experience on safety matters and his knowledge of BP. Brendan Nelson brings vast financial and auditing experience from KPMG, where latterly he was vice chairman. He is eminently well qualified to take over the chair of the audit committee following the annual general meeting. Phuthuma Nhleko will bring deep experience of emerging markets, gained while he was group president and chief executive officer of multinational telephony company MTN Group.

Clearly, after a very troubled and demanding 12 months, BP is a changed company. As a board we have much to do, and we are working with the executive team to ensure successful implementation of a refocused strategy built on the pillars of safety, trust and value creation. Foremost is the need to ensure the right checks and balances are in place across the company. The full board will continue to maintain close oversight of matters related to safety. And we will have even greater engagement on the strategic implications of risk.

Looking ahead, we believe that a growing population and rising levels of prosperity will create strong demand for energy. BP s ability to produce oil and gas from harsh environments means we have a vital contribution to make here. We will also continue to respond to climate change, and to the prospect of fossil fuels becoming a smaller part of the energy mix. For these reasons, BP must continue to be a leader in high-quality hydrocarbons today, while developing the intelligent options we will all rely on tomorrow. Lower-carbon resources remain central to this long-term strategy.

BP is able to help meet the world s growing need for energy, but we can only do this if we have the trust of society. To achieve this, we must ensure that safety and responsibility are at the heart of everything we do. We must show that we can be trusted to understand and manage our risks. And we must demonstrate that we respect the environment and the needs of local communities and society as a whole.

The many strengths of BP are united in our remarkable people, who showed in 2010 that they can rise to the sternest challenge. I thank them for their efforts.

While we face substantial challenges, shareholders must be in no doubt BP has the determination and strength needed to restore its reputation and deliver long-term shareholder value. Through its refocused strategy, the company is working to become more agile and more competitive, with strong emphasis on realizing value rather than building volume and scale. We will not be afraid to develop new and innovative approaches that redefine the model of an international oil company, as our recently announced partnerships with Rosneft and Reliance demonstrate.

I want to end by thanking shareholders for their support. You have been steadfast through one of the most testing periods in BP s long history. We have learned many lessons about ourselves over the past 12 months, and these will never be forgotten. I believe we will emerge a stronger, wiser company with a very important role to play, for many years to come.

Carl-Henric Svanberg
Chairman
2 March 2011

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Board of directors

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Business review
Group chief
executive s letter
Dear fellow shareholder
The tragic events of 2010 will forever be written in the memory of this company and the people who work here. The explosion and fire on the Deepwater Horizon rig shocked everyone within BP, and we feel great sadness that 11 people died. We are deeply sorry for the grief felt by their families and friends. We know nothing can restore the loss of those men.
The accident on 20 April 2010 turned into an unprecedented oil spill with deep consequences for jobs, businesses, communities, the environment and our industry. From this grew a corporate crisis that threatened the very existence of the company. And it all started in a part of the world that s very close to my heart. I grew up in Mississippi, and spent summers with my family swimming and fishing in the Gulf. I know those beaches and waters well. When I heard about the accident I could immediately picture how it might affect the people who live and work along that coast.
Yet, just days before the accident, I had been reflecting on the progress made by BP. The company had put safe and reliable operations at the centre of everything, and we had turned a corner on financial performance. Then came the unthinkable. A subsea blowout in deep water was seen as a very, very low-probability event, by BP and the entire industry but it happened.
Following the accident, a search-and-rescue operation was carried out by the rig s owner, Transocean, together with BP and the US Coast Guard. This continued for four days and covered 5,000 square miles. On 22 April 2010 the Deepwater Horizon sank, and a major oil spill response was activated. At its peak this involved the mobilization of some 48,000 people, the deployment of around 2,500 miles of boom and the co-ordination of more than 6,500 vessels. Field operations brought together experts from key agencies, organizations and BP. Thousands of our people flew in from around the world and stayed and worked for weeks and months. Nearly 500 retirees from BP America called up to say they wanted to help. This was an extraordinary response.
As the response developed, the problems grew in complexity and scale. Tackling the leak on the seabed demanded groundbreaking technical advances and dauntless spirit. We also found ourselves in the midst of intense political and media scrutiny. We received incredible support and faced tremendous criticism, but our priorities remained clear provide support to the families and friends of those 11 men who died, stop the leak, attack the spill, protect the shore, support all the people and places affected. We also committed to carry out an immediate and detailed internal investigation.
As a responsible party, under the Oil Pollution Act, we knew we would face wide-ranging claims and potential fines, but we resolved to go beyond what the law required of us. We made swift payments to support local economies, and gave a total of $138 million in direct state grants during 2010, which included behavioural health programmes. We set up the $20-billion Deepwater Horizon Oil Spill Trust to meet individual, business, government, local and state claims, and natural resource damages. We provided $500 million for the Gulf of Mexico Research Initiative, which is funding independent research to investigate impacts on affected ecosystems. And we contributed to a $100-million fund to support rig workers hit by the drilling moratorium.
To meet our financial commitments, we announced the sale of up to $30 billion in assets and, by the end of 2010, had agreed to $22 billion of disposals. We have also cut back on discretionary capital spending and secured additional credit lines. The sound underlying performance across our business continues to give us a solid foundation, and speaks volumes for the inner strengths of BP and our people.
As part of our response, we took the decision to cancel further dividends in 2010. While we know that many shareholders rely on their regular payments, we also had to protect the company and secure its long-term future. The board of BP took this decision with a heavy heart, but I believe it was the right thing to do in truly exceptional circumstances.
Our investigation report was published on 8 September 2010, and found that no single factor caused the accident. The report stated that decisions made by multiple companies and work teams contributed to the accident, and these arose from a complex and interlinked series of mechanical, human judgement, engineering design, operational implementation and team interface failures.

We have accepted and are implementing the report s recommendations. We are also sharing what we have learned with governments and others in our industry, and we are co-operating with a series of other investigations, inquiries and hearings.

2010 stands as an inflexion point for BP and our industry, and it is right that we should help lead the development of better ways to operate in deep water. Good risk identification and management is integral to becoming safer, and we are working with governments, service contractors and industry peers to take risk management and equipment design to the next level. Within BP, we have introduced more layers of protection and resilience, with our new safety and operational risk function empowered to intervene in any operation. To enhance our specialist expertise and risk management, we have re-organized our upstream business into three divisions Exploration, Developments and Production. To encourage excellence in risk management throughout the organization, we are reviewing how we incentivize and reward people. And to think hard about what was previously unthinkable, we are looking further afield for insight and wisdom. I have spent time with experts from the nuclear and chemicals industries, and I am convinced that we in the energy industry have much to learn from them and others. We must take what we learn and embed it deep in the fabric of our organization.

Part of BP s task right now is to show we can be trusted to handle the industry s most demanding jobs, including exploration and production in deep water. Around 7% of the world s oil supplies come from this source, and we expect this will rise to nearly 10% by 2020. We are one of only a handful of companies with the financial and technological strengths needed to operate in these geographies. Before April 2010, BP had drilled safely in the deep waters of the Gulf of Mexico for 20 years. The governments of Egypt, China, Indonesia, Azerbaijan and the UK have shown confidence in our ability to operate safely at depths, having signed new deepwater drilling agreements with us in the second half of 2010.

It is important to remember why companies such as BP have to take on the risks they do. Around 40 years ago, international oil companies had access to the majority of the world s oil reserves. Today these companies can access a much smaller share. This still provides substantial opportunities for value creation, but reaching many of those reserves requires us to overcome severe physical, technical, intellectual and geopolitical challenges. Global energy demand continues to rise, so the world needs BP and others to meet these challenges in an environmentally sustainable way. In doing this, we can never eliminate every hazard, but we can become an industry leader in understanding and limiting risk. That s our goal.

Clearly, one of the consequences of the events of 2010 was a substantial loss of value and returns for our shareholders. I am pleased that we have been able to resume dividend payments, and our intention is to grow the dividend level in line with the company s improving circumstances. We are now taking action to create and realize greater value. We are increasing our investment in exploration, which is one of our distinctive strengths.

We are gaining access to a wide range of new upstream resource opportunities, and already have 32 project start-ups planned between now and 2016. We are taking an even more active approach to buying, developing and selling upstream assets, with a focus on maximizing returns rather than building volume. And we are divesting roughly half of our US refining capacity, so we can focus downstream investments on refining positions and marketing businesses where we have competitive advantage. This builds on the success BP s Refining and Marketing business has achieved in driving itself back to significantly improved performance and returns over the past few years.

In short, BP is moving swiftly to address its weaknesses and build on its strengths. While doing this we will not hesitate to go beyond the conventional business model of an international oil company. Since 2003 we have had a strong alliance onshore in Russia with TNK-BP. In January 2011 we announced our Arctic alliance with Rosneft, which further shows our strategy in action. Pending completion[a], this is expected to be the first major equity-linked partnership between a national and international oil company, with an agreement with Rosneft to receive 5% of BP s ordinary voting shares in exchange for approximately 9.5% of Rosneft s shares. Under the agreement, Rosneft and BP will seek to form a joint venture to explore and, if successful, develop three licence blocks in the South Kara Sea an area roughly equivalent in size and prospectivity to the UK North Sea. BP and Rosneft have also agreed to establish an Arctic technology centre in Russia, which will work with research institutes, design bureaus and universities to develop technologies and engineering practices for the safe extraction of hydrocarbon resources from the Arctic shelf.

[a] On 1 February 2011 the English High Court granted an interim injunction restraining BP from taking any further steps in relation to the Rosneft transactions pending the outcome of arbitration proceedings. See Note 6 Events after the reporting period.

In February 2011 we announced a second historic agreement. This will, subject to completion, see BP and Reliance work together across the gas value chain in the fast-growing Indian market. This major strategic alliance will combine BP s deepwater capabilities with Reliance s project management and operations expertise.

BP is also partnering with another organization, Husky Energy, to develop a further important resource of energy Canada s oil sands. These represent the second largest reserves in the world after the oilfields of Saudi Arabia. We will work with this resource in a way that fits with our long-term responsibilities and objectives, using steam assisted gravity drainage to extract the oil, and an efficient, integrated system to transport it. Our approach will have a relatively small footprint and should not be confused with opencast mining we will not engage in mining. On a well-to-wheel basis, greenhouse gas emissions from Canadian oil produced this way are expected to be slightly higher than those from conventional crudes imported to North America.

Along with providing the hydrocarbons required over coming years, we are helping to build the sustainable options needed to meet growing demand for lower-carbon energy. Our natural gas operations will help to provide a lower-carbon bridge from oil and coal to renewables. We are building a material business to produce biofuels in Brazil, the US and the UK. We are becoming a leading player in wind energy. We have a long-established solar business. And we have made substantial investments in carbon-capture-and-storage technology. Lower-carbon resources are the fastest-growing sector in the energy market, and BP intends to develop its portfolio in step with this growth.

As to the immediate future, I expect 2011 to be a year of consolidation for BP, as we focus on completing our previously announced divestment programme, meeting our commitments in the US and bringing renewed rigour to the way we manage risk. There will also be an increasing emphasis on value over volume, as we sharpen our strategy and reshape the company for growth.

Looking back over recent days and months, our thoughts return to the men who lost their lives, to those who were injured and to the communities hit hard by the spill. I have heard people ask Does BP get it? Residents of the Gulf, our employees and investors, governments, industry partners and people around the world all want to know whether we understand that a return to business-as-usual is not an option. We may not have communicated it enough at times, but yes, we get it. Our fundamental purpose is to create value for shareholders, but we also see ourselves as part of society, not apart from it. Put simply, our role is to find and turn energy resources into financial returns, but by doing that in the right way we can help create a prosperous and sustainable future for everyone. This is what people rightfully expect of BP. This is what will inspire and drive us over the next 12 months and far into the future.

Bob Dudley
Group Chief Executive
2 March 2011

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Progress in 2010

Safety

Personal safety reported recordable injury frequency

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 2010 our workforce RIF, which includes employees and contractors combined, was 0.61, compared with 0.34 in 2009 and 0.43 in 2008. The nature of the Gulf Coast response effort resulted in personal safety incident rates significantly higher than in other BP operations.

People

Employee satisfaction (%)

The overall Employee Satisfaction Index comprises 10 key questions that provide insight into levels of employee satisfaction across a range of topics, such as pay and trust in management. We use a sample-based approach to achieve a representative view of BP.

Our 2010 employee survey was delayed to allow for organizational changes to be reflected in the survey construction, with the survey expected to be carried out in summer 2011.

Process safety oil spills

We report all 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 2010 there were 261 oil spills of one barrel or more, including the Gulf of Mexico oil spill. We are taking measures to strengthen mandatory safety-related standards and processes, including operational risk and integrity management.

Number of employees[a] (thousands)

Employees include all individuals who have a contract of employment with a BP group entity.

In 2007 we began a process of making BP a simpler, more efficient organization. Since then our total number of employees has reduced by approximately 18,000, including around 9,200 in our non-retail businesses.

Process safety loss of primary containment

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.

BP is progressively moving towards this as one of the key indicators for process safety, as we believe it provides a more comprehensive and better performance indicator of the safety and integrity of our facilities than oil spills alone.

Environment greenhouse gas emissions[a]
(million tonnes of carbon dioxide equivalent)

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. We have not included any emissions from the Gulf of Mexico oil spill and the response effort due to our reluctance to report data that has such a high degree of uncertainty.

We aim to manage our GHG emissions through a focus on operational energy efficiency and reductions in flaring and venting.

Diversity and inclusion (%)

Each year we record the percentage of women and individuals from countries other than the UK and US among BP s top leaders. The number of top leaders in 2010 was 482, compared with 492 in 2009 and 583 in 2008.

BP has maintained the percentage of female leaders in 2010 and remains focused on building a more sustainable pipeline of diverse talent for the future.

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Performance

Production (thousand barrels of oil equivalent per day)

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 2010 was 4% lower than in 2009, due to the effect of entitlement changes in our production-sharing agreements, the effect of acquisitions and disposals, and the impact of events in the Gulf of Mexico.

Replacement cost profit (loss) per ordinary share (cents)

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 23 for the equivalent measure on an IFRS basis.

In 2010 we recorded a replacement cost loss primarily driven by a $40.9-billion pre-tax charge in relation to the Gulf of Mexico incident.

Reserves replacement ratio[a] (%)

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.

Our reserves replacement ratio in 2010 exceeded 100% once again. We continue to drive renewal through new access, exploration, targeted acquisitions and a strategic focus on increasing resources from fields we currently operate.

Dividends paid per ordinary share

This measure shows the total dividend per share paid to ordinary shareholders in the year.

In June 2010 the BP board reviewed its dividend policy in light of the Gulf of Mexico incident, and the agreement to establish a $20-billion trust fund, and decided to cancel ordinary share dividends in respect of the first three quarters of 2010.

Refining availability (%)

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 continued its increasing trend in 2010, with the biggest contributor being the restoration of our Texas City refinery.

Operating cash flow ($ billion)

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.

The reduction in operating cash flow primarily reflected the impacts of the Gulf of Mexico incident.

Total shareholder return (%)

Total shareholder return represents the change in value of a 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.

Total shareholder returns in 2010 were significantly impacted by the cancellation of dividend payments and the fall in share price brought about by the events in the Gulf of Mexico.

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Business review

Group overview

Our organization

BP is one of the world s leading international oil and gas companies[a]. We operate or market our products in more than 80 countries, providing our customers with fuel for transportation, energy for heat and light, retail services and petrochemicals products for everyday items.

As a global group, our interests and activities are held or operated through subsidiaries, jointly controlled entities or associates established in and subject to the laws and regulations of many different jurisdictions. These interests and activities covered two business segments in 2010: Exploration and Production and Refining and Marketing. BP s activities in low-carbon energy are managed through our Alternative Energy business, which is reported within Other businesses and corporate.

Exploration and Production s activities include 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 (LNG), together with power and natural gas liquids (NGLs). During the fourth quarter of 2010, as part of our wider response to the Gulf of Mexico incident, we decided to reorganize our Exploration and Production segment to create three global functional divisions: Exploration, Developments, and Production, integrated through a Strategy and Integration organization. This is designed to fundamentally change the way the segment operates, with a particular

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

focus on managing risk, delivering common standards and processes and building personnel and technological capability for the future. The Exploration division is accountable for renewing our resource base through access, exploration and appraisal activities. The Developments division is accountable for the safe and compliant execution of wells (drilling and completions) and major projects. 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.

Refining and Marketing s activities include the supply and trading, refining, manufacturing, marketing and transportation of crude oil, petroleum and petrochemicals products and related services. The segment comprises a number of strategic performance units (SPUs), which are organized along either geographic or activity-related lines. Each SPU is of a scale that allows for a close focus on performance delivery, starting with safety, and includes the appropriate management of operating and financial parameters.

Our group functions and regions support the work of our segments and businesses. The key objectives of the functions are to establish and monitor fit-for-purpose functional standards across the group; to act as centres of deep functional expertise; to access significant leverage with third-party suppliers; and to establish and maintain capabilities among the functional staff employed within our operating businesses. In addition, the head of each region provides the required cross-segment integration and co-ordination of group activities in a particular geographic area and represents BP to external parties.

In June 2010, following the Gulf of Mexico incident, we established the Gulf Coast Restoration Organization (GCRO) and subsequently equipped it with dedicated resources and capabilities to manage all aspects of our response to the accident. This organization reports directly to the group chief executive and is overseen by a specific new board committee.

Among the changes we have made following the Gulf of Mexico incident, we have redefined and strengthened the scope and accountabilities of the group function for safety and operations, creating an enhanced, independent Safety and Operational Risk (S&OR) function, to oversee and audit the company s operations around the world. The function has its own expert staff embedded in BP s operating units, including exploration projects

and refineries, with defined intervention rights with respect to BP s technical and operational activities. The function reports directly to the group chief executive and aims to provide assurance that BP s operations are carried out to common standards, and audits conformance to those standards.

The significant subsidiaries of the group at 31 December 2010 and the group percentage of ordinary share capital (to the nearest whole number) are set out in Financial statements Note 46 on pages 220-221. See Financial statements Notes 25 and 26 on pages 183 and 184 respectively for information on significant jointly controlled entities and associates of the group.

On 14 January 2011, BP and Rosneft Oil Company (Rosneft) announced that they had agreed a strategic global alliance. BP and Rosneft have agreed to seek to form a joint venture to explore and, if successful, develop three licence blocks on the Russian Arctic continental shelf. BP and Rosneft have entered into a related share swap agreement whereby, upon completion, BP will receive approximately 9.5% of Rosneft s shares in exchange for BP issuing new ordinary shares to Rosneft with an aggregate value of approximately $7.8 billion (as at close of trading in London on 14 January 2011), resulting in Rosneft holding 5% of BP s ordinary voting shares. See Legal proceedings on page 133 for information on an interim injunction, granted by the English High Court on 1 February 2011 restraining BP from taking any further steps in relation to the Rosneft transactions pending the outcome of arbitration proceedings.

On 21 February 2011, Reliance Industries Limited and BP announced that they intend to form an upstream joint venture in which BP will take a 30% stake in 23 oil and gas production-sharing contracts that Reliance operates in India, including the producing KG D6 block, and form a 50:50 joint venture for the sourcing and marketing of gas in India. BP will pay Reliance Industries Limited an aggregate consideration of $7.2 billion, and completion adjustments, for the interests to be acquired in the 23 production-sharing contracts. Future performance payments of up to $1.8 billion could be paid based on exploration success that results in development of commercial discoveries. Reliance will continue to be the operator under the production-sharing contracts. Completion of the transactions is subject to Indian regulatory approvals and other customary conditions.

Where we operate

BP s 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. Currently, around 68% of the group s fixed assets are invested in Organization for Economic Co-operation and Development (OECD) countries, with around 42% of our fixed assets located in the US and around 20% in Europe.

Our Exploration and Production segment included upstream and midstream activities in 29 countries in 2010 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. Our Exploration and Production segment 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.

In Refining and Marketing, we market our products in more than 70 countries, with a particularly strong presence in Europe and North America, and also manufacture and market our products across Australasia, in China and other parts of Asia, Africa and Central and South America. In the US, we own or have a share in five refineries and market fuel primarily under the ARCO and BP brands. See Refining and Marketing (Our strategy) on page 55 for further information on forthcoming portfolio changes in the US. In Europe, we own or have a share in seven refineries and we market extensively across the region, primarily under the Aral and BP fuel brands. Our long-established supply and trading activity is responsible for delivering value across the crude and oil products supply chain. Our petrochemicals business maintains a manufacturing position globally, with an emphasis on growth in Asia. Our lubricants business blends and markets lubricants globally, primarily under the Castrol brand, and is a growing business through market growth and the development of new products. We continue to seek opportunities to broaden our activities in growth markets such as China and India.

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Business review

Our market

Energy markets in 2010 continued to recover from the impact of the global economic recession. Looking ahead, the long-term outlook is one of growing demand for energy[a], particularly in Asia, and of challenges for the industry in meeting this demand. Rising incomes and expanding urban populations are expected to drive demand, while the evolution towards a lower-carbon economy will require technology, innovation and investment.

World oil consumption rebounded in 2010, with continued robust growth in China and other non-OECD countries and the first increase among OECD countries since 2005. Average crude oil prices in 2010 were higher than in the previous year. Average natural gas prices also increased in 2010. Refining margins stabilized as oil product demand recovered.

Economic context

The world economy continued to recover in 2010. We expect slower global growth in 2011, led by emerging economies, with developed countries lagging behind because of the need to deal with their internal imbalances. Energy demand, and in particular oil demand, follows this overall economic pattern, recovering strongly in 2010 but facing more challenging conditions as we move into 2011, especially in OECD markets.

Concerns about the volatility of commodity and financial markets, combined with renewed focus on climate change and the early experiences with efforts to reduce CO_2 emissions in the EU and elsewhere, have led to an increased focus on the appropriate role for markets, government oversight and other policy measures relating to the supply and consumption of energy. We expect regulation and taxation of the energy industry and energy users to increase in many areas over the short to medium term.

Crude oil prices

Dated Brent for the year averaged $79.50 per barrel, about 29% above 2009 s average of $61.67 per barrel. Prices traded in a relatively narrow band of $70-80 per barrel for most of the year before rising in the fourth quarter. Prices exceeded $90 per barrel in December, the highest level since October 2008.

Global oil consumption rebounded sharply, reflecting a recovery in the global economy and several one-time factors, rising by roughly 2.8 million b/d for the year (3.3%)[c], the largest annual increase since 2004. Growth was broadly-based, with the largest (volumetric) increases seen in China and the US. The relative stability in crude oil prices for much of the year reflected the stability of OPEC crude oil supply, as OPEC members sustained the production cuts implemented in late 2008 throughout 2010, with crude production averaging roughly 2 million b/d below the 2008 level. Commercial oil inventories in the OECD remained high for much of the year before falling as the global supply-balance began to tighten and prices began to rise later in the year.

The rebound in oil prices in 2010 followed a decline in 2009 the first since 2001. Global oil consumption in 2009 reflected the economic slowdown, falling by roughly 1.2 million b/d for the year (1.7%)[d], the largest annual decline since 1982. The biggest reductions were early in the year, with OECD countries accounting for the entire global decline. Crude oil prices rose sharply in the second quarter in response to sustained OPEC production cuts and emerging signs of stabilization in the world economy, despite very high commercial oil inventories in the OECD. OPEC members cut crude oil production by roughly 2.5 million b/d[e] in 2009.

We expect oil price movements in 2011 to continue to be driven by the pace of global economic growth and its resulting implications for oil consumption, and by OPEC production decisions.

[a] *BP Energy Outlook 2030.*

[b] See footnote e on page 56.

[c] *Oil Market Report 10 February 2011* © OECD/IEA 2011, page 4, first paragraph.

[d] *BP Statistical Review of World Energy June 2010.*

[e] *Oil Market Report 10 February 2011* © OECD/IEA 2011, Table 1, page 59.

Natural gas prices

Natural gas prices strengthened in 2010, but were volatile. The average US Henry Hub First of Month Index rose to $4.39/mmBtu, a 10% increase on the depressed prices in 2009.

Gas consumption recovered across the world along with the economy. In the US, a cold start in 2010, followed by a hot summer and low temperatures towards the end of the year also contributed to demand strength. Yet domestic production growth of shale gas in particular continued apace and limited price rises. Henry Hub gas prices stayed below coal parity in US power generation from the summer, leading to the displacement of coal by gas. 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 38% to an average of 42.45 pence per therm for 2010. Yet plentiful global LNG supply kept spot gas prices below oil-indexed contract levels for most of the year, causing competition with contract pipeline supplies and marginal European gas production. UK spot gas prices only attained contract price levels in December as cold weather caused rapid inventory draw-downs.

The rise in prices followed sharp declines in 2009. The recession and strong production had caused the average Henry Hub First of Month Index to fall in 2009 by 56% to $3.99/mmBtu the lowest level since 2002. In the UK, National Balancing Point prices averaged 30.85 pence per therm 47% below the record prices of 58.12 pence per therm in 2008.

In 2011, we expect gas markets to continue to be driven by the economy, weather, domestic production trends and significant growth of global LNG supply.

Refining margins

Refining margins were slightly higher in 2010 as demand for oil products recovered strongly in line with the economic bounce-back from recession. Globally, oil demand grew at the fastest rate since 2004. New refining capacity continued to commission, but the strong demand recovery meant that unused refining capacity fell for the first time since 2005. The BP global indicator refining margin (GIM)[a] averaged $4.44 per barrel, up 44 cents per barrel compared with 2009.

Margins in the Far East improved the most but continued to struggle averaging $1.63 per barrel in Singapore as new refining capacity continued to be added in the region. Margins also rose in both the North West Europe and the Mediterranean but European margins overall remained well below 2008 levels. Margins in the US were relatively unchanged, up slightly on the West and Gulf coasts but down in the Midwest.

Refining margins fell sharply in 2009 as demand for oil products collapsed in the wake of the global economic recession and as new refining capacity came onstream. The premium for light products above fuel oils reduced as demand for transport fuels fell along with the reduction in economic activity, compressing margins even for fully upgraded refineries.

Looking ahead, refiners are likely to continue to operate with excess capacity globally, although near-term supply-demand fundamentals appear broadly in balance. From 2011, we will be reporting a new refining indicator margin, replacing the GIM, which we call the refining marker margin (RMM). This adopts a basis that we believe is more closely related to the approach used by many of our competitors. *(See Refining and Marketing on page 55 for further information on RMM.)*

[a] See footnote e on page 56.

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Business review

Long-term outlook

Over the long term, global demand for primary energy is expected to continue to grow, but less rapidly than the global economy. Growing energy demand is underpinned by continuing population growth and by generally rising living standards in the developing world, including the expansion of urban populations. These drivers of energy demand growth are to some extent offset by efforts to improve efficiency in both the conversion and use of energy.

Global energy demand is projected to increase by around 40% between 2010 and 2030[a]. Fossil fuels are expected still to be satisfying as much as 80% of the world s energy needs in 2030. At current rates of consumption, the world has enough proved reserves of fossil fuels to meet these requirements[b] if investment is permitted to turn those reserves into production capacity. For example, in oil alone, there are reserves in place to satisfy approximately 45 years demand at current rates of consumption[b]. However, to meet the potential growth in demand, continued investment in new technology will be required to boost recovery from declining fields and commercialize currently inaccessible resources. To play their part in achieving this, energy companies such as BP will need secure and reliable access to as-yet undeveloped resources. It is estimated that more than 80% of the world s oil reserves are held by Russia, Mexico and members of OPEC[b] areas where international oil companies are frequently limited or prohibited from applying their technology and expertise to produce additional supply. New partnerships will be required to transform potential resources into proved reserves and eventually into production.

A more diverse mix of energy will also be required to meet this increased demand. Such a mix is likely to include both unconventional fossil fuel resources such as oil sands, coalbed methane and natural gas produced from shale formations and renewable energy sources such as biofuels, wind and solar power. Beyond simply meeting growth in overall demand, a diverse mix would also help to provide enhanced national and global energy security while supporting the transition to a lower-carbon economy. Improving the efficiency of energy use will also play a key role in maintaining energy market balance in the future.

Along with increasing supply, we believe the energy industry will be required to make hydrocarbons cleaner and more efficient to use particularly in the critical area of power generation, for which the key hydrocarbons are currently coal and gas. The world has reserves of coal for around 120 years at current consumption rates[b], but coal produces more carbon than any other fossil fuel. Carbon capture and storage (CCS) may help to provide a path to cleaner coal, and BP is investing in this area, but CCS technologies still face significant technical and economic issues and are unlikely to be in operation at scale for at least a decade.

In contrast, we believe that in many countries natural gas has the potential to provide the most significant reductions in carbon emissions from power generation in the shortest time and at the lowest cost. These reductions can be achieved using technology available today. Combined-cycle turbines, fuelled by natural gas, produce around half the CO_2 emissions of coal-fired power, and are cheaper and quicker to build. It is estimated that there are reserves of natural gas in place equivalent to 63 years consumption at current rates[b] and they are rising as new skills and technology unlock new unconventional gas resources. For these reasons, gas is looking to be an increasingly attractive resource in meeting the growing demand for energy, playing a greater role as a key part of the energy future.

At the same time, alternative energies also have the potential to make a substantial contribution to the transition to a lower-carbon economy, but this will require investment, innovation and time. Currently, biofuels, wind, solar, and other modern forms of renewable energy account for less than 2% of total global consumption[a]. Assuming continuing policy support and favourable technology trends, these forms of energy are likely to meet around 6% of total energy demand in 2030[a].

If industry and the market are to meet the world s growing demand for energy in a sustainable way, governments will be required to set a stable and enduring framework. As part of this, governments will need to provide secure access for exploration and development of fossil fuel resources, define mutual benefits for resource owners and development partners, and establish and maintain an appropriate legal and regulatory environment, including a mechanism for recognizing the cost of carbon.

[a] *BP Energy Outlook 2030*.

[b] *BP Statistical Review of World Energy June 2010.* 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 strategy

Delivering stability, restoring trust and value.

2010 has been a very challenging year for BP and there remains much to be done to address the repercussions of the tragic Gulf of Mexico oil spill. BP is committed to the restoration of the Gulf of Mexico coastline and its communities. BP will manage its liabilities arising from this deeply regretted accident and is committed to learn and share the lessons from the incident. Above all, we will work with regulators and industry globally to reduce the risk of this happening again.

BP s immediate priority beyond the Gulf is to regain the trust of our stakeholders by demonstrating that we understand and can manage the inherent risks across our whole portfolio. From there, we seek to rebuild value for our shareholders by re-establishing our competitive position within the sector.

BP believes that we can emerge from the shadow of the Gulf of Mexico incident a safer, more risk-aware business. Our strategy, which will continue to evolve over 2011, will remain focused on creating value for shareholders through safe, responsible exploration, development and production of fossil fuel resources because the world needs them; the manufacture, processing and delivery of better and more advanced products; and participation in the transition to a lower carbon future.

Our intention is to re-establish all necessary permissions to operate in the deepwater Gulf of Mexico and sustain business momentum outside of the Gulf; to restore value and growth through a rigorous focus on our portfolio of high-quality assets; to develop our people to ensure we have the right competencies and behaviours where they are needed; to learn and implement the lessons from the Gulf of Mexico and rigorously focus on the processes that will deliver safe and reliable operations and continuous improvement; and do so within a clear, conservative financial framework.

A safer, more risk-aware business

Our employees, investors, regulators and government partners expect us to put safety and operational integrity above all other concerns. We intend to build on our existing strengths to systematically manage operating risk by improving our understanding of risk exposure and taking the appropriate action to mitigate risk. Wherever we operate, we must embed the disciplined application of standards within BP s operating management system (OMS), as a single framework for all BP operations. *(See Safety on page 68 for further information on our OMS.)* We will demand independent checks and balances at multiple levels to provide better decision making and transparent governance of standards, capability, compliance and risk management. To effect this we have created a more powerful safety and operational risk function, independent of the business line and deployed into each operating entity across the BP portfolio. For further information on our safety priorities and performance, see Corporate responsibility Safety on pages 68-71.

Fulfilling our commitments and earning back trust following the Gulf of Mexico incident

BP has committed to pay all legitimate claims by individuals, businesses and governments and has established a $20-billion trust fund, following consultation with the US government, to provide funds for that purpose. In addition, BP is working with federal and state agencies to assess the nature and extent of the impact on natural resources resulting from the Gulf of Mexico incident. Based on the assessment, federal and state trustees will prepare plans to restore, rehabilitate, replace or acquire the equivalent of injured resources under their trusteeship. The Oil Pollution Act 1990 (OPA 90) provides for restoration to a baseline condition, which is the condition the resources would have been in if the incident had not occurred. The assessment will also be used to identify any compensation that may be required for the loss of the resources, prior to restoration.

Reinstating a dividend in line with the circumstances of the company, as part of a conservative financial framework

BP will continue to invest with the aim of growing the company and shareholder value, sustainably and through the business cycle. We intend to underpin this with a conservative capital structure, which allows the flexibility to execute strategy while remaining resilient to the inherent volatility of the business. We will endeavour to actively manage day-to-day liquidity in order to meet the cash needs of the business, while maintaining the net debt ratio within a lower range of 10% to 20%. On 1 February 2011, we announced that quarterly dividend payments would resume. The quarterly dividend to be paid in March 2011 is 7 cents per share. The board believes this is an affordable and sustainable level which will allow the company to meet its commitments while continuing to invest in the business for growth and value.

Delivering the right high-quality portfolio

As part of the response to the Gulf of Mexico incident, we announced and are progressing disposals that are expected to deliver around $30 billion in proceeds over 2010 and 2011. During 2010, BP has successfully realized premium values for upstream and downstream assets as part of the programme. See Acquisitions and disposals on page 24. The disposal programme has been an opportunity to further upgrade and focus our portfolio and we intend to retain a capacity to reinvest, to acquire assets that enhance strategy and our portfolio on both a planned and an opportunistic basis through 2011.

Business review

The right people, skills, capability and incentivization

It is vital that we develop and deploy people with the skills, capability and determination required to meet our objectives. There remains, in our industry, a continuing shortage of professionals such as petroleum engineers and scientists, driven by changing demographics. Nonetheless, we have thus far been successful in building this capacity and we are committed to building and deploying capability with a strong safety and risk management culture, including revised reward mechanisms to foster professional pride in engineering, health, safety, security, the environment and operations.

The creation of a more powerful S&OR function represents a significant change that will strengthen our processes and capabilities in safety and risk management. In Exploration and Production, we have reorganized the segment into three functional divisions Exploration, Developments and Production each of which reports directly to the group chief executive. The intent is clear, to focus expertise and capability on a more concentrated asset base to reduce operational risk and deliver long-run sustainable improvement. In each division and across the rest of the group we will continue to develop group leadership and senior management teams, and focus recruitment on individuals with strong operational and technical expertise.

Focus on exploration and high-quality earnings

Through our strategy we aim to deliver value growth for shareholders by investing in our Exploration and Production business and safer operations everywhere, while at the same time enhancing efficiency and growing high-quality earnings and returns throughout all our operations.

In Exploration and Production, our 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 enduring positions in the world s key hydrocarbon basins with a focus on deepwater, gas (including unconventional gas) and giant fields. Our strategy is enabled by continuously reducing operating risk, strong relationships built on mutual advantage, deep knowledge of the basins in which we operate, and technology, together with building capability along the value chain in Exploration, Developments and Production.

We are increasing investment in Exploration, a key source of value creation at the front end of the value chain, and we are evolving the nature of our relationships, particularly with national oil companies. We will also continue to actively manage our portfolio, with a focus on value growth.

In Refining and Marketing, our strategy is to hold a portfolio of quality, efficient and integrated manufacturing and marketing positions underpinned by safe operations, leading technologies and strong brands. We will continue to access market growth opportunities in the emerging markets and intend to grow our international businesses. Over time we expect to shift capital employed from mature to high-growth regions.

In Alternative Energy, our strategy is to build material low-carbon energy businesses that are aligned with BP s core capabilities. In biofuels we are building advantaged positions in low-cost sustainable feedstocks such as Brazilian sugar cane, the lignocellulosic conversion of energy grasses in the US and the development of advantaged fuel molecules such as biobutanol. In the low-carbon power business we are building out our US wind portfolio and continue to grow our solar business. We continue to develop our capability in carbon capture and storage.

Leveraging technology as we look further ahead

As discussed under Our market on pages 16-18 of this report, we expect that the world will require a more diverse energy mix as the basis for a secure supply of energy over time. We intend to play a central role in meeting the world s continued need for hydrocarbons, with our Exploration and Production and Refining and Marketing activities remaining at the core of our strategy. We are also creating long-term options for the future in new energy technology and low-carbon energy businesses. We believe that this focused portfolio has the potential to be a material source of value creation for BP (*see pages 61-62*). We are also enhancing our capabilities in natural gas, which may prove to be a vital source of relatively clean energy during the transition to a lower-carbon economy and beyond. We intend to lead, support and shape this transition while working to achieve sector-leading levels of return for shareholders.

Our performance

Performance in 2010 was overshadowed by the well blowout and subsequent oil spill in the Gulf of Mexico. Beyond this tragic event, the ongoing underlying performance of the group was strong.

Safety

In April 2010, following a well blowout in the Gulf of Mexico, an explosion and fire occurred on the semi-submersible rig Deepwater Horizon, resulting in the tragic loss of 11 lives and a major oil spill. There were three other contractor fatalities during 2010. We deeply regret the loss of these lives and the impact from the oil spill. *(See Gulf of Mexico oil spill on page 34 for more information on the Deepwater Horizon accident.)*

Our priority remains to have safe, reliable and compliant operations worldwide. We have set up a more powerful safety and operational risk function. As an immediate step, we have reinforced the link between safety performance and reward in the fourth quarter of 2010. Other programmes are now under way, including a review of contractor management and a fresh look at how we manage risk systematically across BP.

We also continued to embed our OMS within the group, with all of our operating sites transitioning to the system by the end of February 2011.

Recordable injury frequency (RIF, a measure of the number of reported injuries per 200,000 hours worked) was 0.61 in 2010, compared with 0.34 in 2009 and 0.43 in 2008. The increase in 2010 was significantly impacted by the number of incidents arising in the response effort for the Gulf of Mexico oil spill, which resulted in significantly higher personal safety incident rates than for other BP operations.

The number of oil spills greater than one barrel was 261 in 2010 compared with 234 in 2009 and 335 in 2008. The volume spilled was dominated by the Gulf of Mexico incident. See Oil spill and loss of containment in Safety on page 68.

Our greenhouse gas (GHG) emissions[a] were 64.9Mte in 2010, compared with 65.0Mte in 2009. We have not included any emissions from the Gulf of Mexico incident and the response effort due to our reluctance to report data that has such a high degree of uncertainty.

People

During 2010, we continued to focus on increasing the level of specialist skills and expertise across the workforce. The exceptional response to the oil spill was a reassuring example of the capabilities and commitment of our staff.

The total number of non-retail staff was broadly stable in 2010, adjusting for staff reductions associated with asset disposals. Total non-retail recruitment was around 8,000. This was offset by around 7,700 staff leaving the company plus a further 2,300 staff leaving associated with asset disposals. The total number of employees (including retail staff) was 79,700 at the end of 2010.

[a] See footnote a in Environment on page 72.

[b] See Exploration and Production proved reserves replacement on page 42 for more detailed information on reserves replacement for subsidiaries and equity-accounted entities.

[c] 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.

Operating and financial performance

Our results in 2010 were greatly impacted by the charge recorded for the Gulf of Mexico oil spill incident. Steps were taken to strengthen the balance sheet, including a programme of asset disposals, with very good progress made. Cash and cash equivalents at the end of 2010 was $18.6 billion and the net debt ratio was 21%.

Notable achievements in 2010 include:

Exploration and Production

- Replacing more than 100% of our proved reserves, excluding acquisitions and disposals, on a combined basis of subsidiaries and equity-accounted entities[b].

Taking final investment decisions on 15 projects, with an expected total BP net capital investment of $20 billion.

Increasing production for the Rumaila field in Southern Iraq by more than 10% above the rate initially agreed between the Rumaila Operating Organization partners and the Iraqi Ministry of Oil in December 2009. This significant milestone means that BP and its partners became eligible for service fees from the first quarter of 2011.

Accessing new resources across the globe in Azerbaijan, China, the Gulf of Mexico, Indonesia, onshore North America and the UK.

Making the Hodoa discovery in Egypt, the first Oligocene deepwater discovery in the West Nile Delta.

TNK-BP increasing its production by 2.5% in 2010 compared with 2009.

Securing agreements to dispose of almost $22 billion of non-core assets in line with our plans following the Gulf of Mexico oil spill.

Refining and Marketing

Improving overall financial performance delivery, primarily driven by strong operational performance across all of our businesses, the continuation of our programme to deliver further efficiencies and a more favourable refining environment.

Achieving a Solomon refining availability[c] of 95.0%, which is an increase of 1.4 percentage points compared with 2009.

Achieving record volumes in petrochemicals and strong lubricants performance.

Making significant progress in the Whiting refinery modernization project.

Starting commercial production at our new joint venture acetyls plant in Nanjing, China.

Castrol s sponsorship of the 2010 FIFA World Cup in South Africa.

Successfully exiting from our convenience retail business in France.

Completing the divestment of several packages of non-strategic terminals and pipelines in the US East of Rockies and West Coast.

Selling our 15% interest in Ethylene Malaysia Sdn Bhd (EMSB) and 60% interest in Polyethylene Malaysia Sdn Bhd (PEMSB) to Petronas.

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Oil and natural gas production and net proved reserves[a]

	2010	2009	2008	2007	2006
Crude oil production for subsidiaries (thousand barrels per day)	**1,229**	1,400	1,263	1,304	1,351
Crude oil production for equity-accounted entities (thousand barrels per day)	**1,145**	1,135	1,138	1,110	1,124
Natural gas production for subsidiaries (million cubic feet per day)	**7,332**	7,450	7,277	7,222	7,412
Natural gas production for equity-accounted entities (million cubic feet per day)	**1,069**	1,035	1,057	921	1,005
Estimated net proved crude oil reserves for subsidiaries (million barrels)[b]	**5,559**	5,658	5,665	5,492	5,893
Estimated net proved crude oil reserves for equity-accounted entities (million barrels)[c]	**4,971**	4,853	4,688	4,581	3,888
Estimated net proved bitumen reserves for equity-accounted entities (million barrels)	**179**				
Estimated net proved natural gas reserves for subsidiaries (billion cubic feet)[d]	**37,809**	40,388	40,005	41,130	42,168
Estimated net proved natural gas reserves for equity-accounted entities (billion cubic feet)[e]	**4,891**	4,742	5,203	3,770	3,763

[a] Crude oil includes natural gas liquids (NGLs) and condensate. Production and 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.

[b] Includes 22 million barrels (23 million barrels at 31 December 2009 and 21 million barrels at 31 December 2008) in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[c] Includes 254 million barrels (243 million barrels at 31 December 2009 and 216 million barrels at 31 December 2008) in respect of the 7.03% minority interest in TNK-BP (6.86% at 31 December 2009 and 6.80% at 31 December 2008).

[d] Includes 2,921 billion cubic feet of natural gas (3,068 billion cubic feet at 31 December 2009 and 3,108 billion cubic feet at 31 December 2008) in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[e] Includes 137 billion cubic feet (131 billion cubic feet at 31 December 2009 and 2008) in respect of the 5.89% minority interest in TNK-BP (5.79% at 31 December 2009 and 5.92% at 31 December 2008).

During 2010, 1,503 million barrels of oil and natural gas, on an oil equivalent[a] basis (mmboe), were added, excluding purchases and sales, to BP s proved reserves (686mmboe for subsidiaries and 818mmboe for equity-accounted entities). At 31 December 2010, BP s proved reserves were 18,071mmboe (12,077mmboe for subsidiaries and 5,994mmboe for equity-accounted entities). Our proved reserves in subsidiaries are located primarily in the US (44%), South America (15%), the UK (10%), Australasia (9%) and Africa (11%). Our proved reserves in equity-accounted entities are located primarily in Russia (69%), South America (20%), and Rest of Asia (7%).

For a discussion of production, see Exploration and Production on page 43.

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

Selected financial information[a]

					$ million except per share amount
	2010	2009	2008	2007	2006
come statement data					
les and other operating revenues from continuing operations[b]	**297,107**	239,272	361,143	284,365	265,90
placement cost profit (loss) before interest and tax[c]					
business					
ploration and Production	**30,886**	24,800	38,308	27,602	31,02
fining and Marketing	**5,555**	743	4,176	2,621	5,66
her businesses and corporate	**(1,516)**	(2,322)	(1,223)	(1,209)	(84
lf of Mexico oil spill response[d]	**(40,858)**				
nsolidation adjustment unrealized profit in inventory	**447**	(717)	466	(220)	6
placement cost profit (loss) before interest and taxation from ntinuing operations[b]	**(5,486)**	22,504	41,727	28,794	35,91
ventory holding gains (losses)	**1,784**	3,922	(6,488)	3,558	(25
ofit (loss) before interest and taxation from continuing operations[b]	**(3,702)**	26,426	35,239	32,352	35,65
nance costs and net finance expense or income relating to pensions d other post-retirement benefits	**(1,123)**	(1,302)	(956)	(741)	(51
xation	**1,501**	(8,365)	(12,617)	(10,442)	(12,51
ofit (loss) from continuing operations[b]	**(3,324)**	16,759	21,666	21,169	22,62
ofit (loss) for the year	**(3,324)**	16,759	21,666	21,169	22,60
ofit (loss) for the year attributable to BP shareholders	**(3,719)**	16,578	21,157	20,845	22,31
r ordinary share cents					
ofit (loss) for the year attributable to BP shareholders					
sic	**(19.81)**	88.49	112.59	108.76	111.4
luted	**(19.81)**	87.54	111.56	107.84	110.5
ofit (loss) from continuing operations attributable to BP shareholders[b]					
sic	**(19.81)**	88.49	112.59	108.76	111.5
luted	**(19.81)**	87.54	111.56	107.84	110.6
placement cost profit (loss) for the year[c]	**(4,519)**	14,136	26,102	18,694	22,82
placement cost profit (loss) for the year attributable to BP shareholders[c]	**(4,914)**	13,955	25,593	18,370	22,53
r ordinary share cents					
placement cost profit (loss) for the year attributable to BP shareholders[c]	**(26.17)**	74.49	136.20	95.85	112.5
vidends paid per share cents	**14.00**	56.00	55.05	42.30	38.4
pence	**8.679**	36.417	29.387	20.995	21.10
pital expenditure and acquisitions[e]	**23,016**	20,309	30,700	20,641	17,23

dinary share data[f]

erage number outstanding of 25 cent ordinary shares (shares million undiluted)	**18,786**	18,732	18,790	19,163	20,02
erage number outstanding of 25 cent ordinary shares (shares million diluted)	**18,998**	18,936	18,963	19,327	20,19
lance sheet data					
tal assets	**272,262**	235,968	228,238	236,076	217,60
t assets	**95,891**	102,113	92,109	94,652	85,46
are capital	**5,183**	5,179	5,176	5,237	5,38
shareholders equity	**94,987**	101,613	91,303	93,690	84,62
ance debt due after more than one year	**30,710**	25,518	17,464	15,651	11,08
t debt to net debt plus equity[g]	**21 %**	20 %	21 %	22 %	20

[a] This information, insofar as it relates to 2010, has been extracted or derived from the audited consolidated financial statements of the BP group presented on pages 141-227. 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] Excludes Innovene, which was treated as a discontinued operation in accordance with IFRS 5 Non-current Assets Held for Sale and Discontinued Operations in 2006.

[c] 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 81.

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

[e] Excluding acquisitions and asset exchanges, capital expenditure for 2010 was $19,610 million (2009 $20,001 million, 2008 $28,186 million, 2007 $19,194 million and 2006 $16,910 million). All 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. Capital expenditure in 2006 included $1 billion in respect of our investment in Rosneft.

[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 36 on page 198.

* As reported in Annual Report on Form 20-F. There was a $500 million ($315 million post tax) timing difference between the profit reported under IFRS in the Annual Report and Accounts and the profit reported under IFRS in *BP Annual Report on Form 20-F 2006.* For further information see *BP Annual Report and Accounts 2006.*

Business review

Profit or loss for the year

Loss attributable to BP shareholders for the year ended 31 December 2010 was $3,719 million and included inventory holding gains[a], 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. More information on non-operating items and fair value accounting effects can be found on pages 25-26. See Gulf of Mexico oil spill on page 34 and in Financial statements Note 2 on page 158 for further information on the impact of the Gulf of Mexico oil spill on BP s financial results. See Exploration and Production on page 40, Refining and Marketing on page 55 and Other businesses and corporate on page 61 for further information on segment results.

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.

Profit attributable to BP shareholders for the year ended 31 December 2008 included inventory holding losses, net of tax, of $4,436 million and a net charge for non-operating items, after tax, of $796 million. In addition, fair value accounting effects had a favourable impact, net of tax, of $146 million relative to management s measure of performance.

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.

The primary additional factors reflected in profit for 2009, compared with 2008, were lower realizations and refining margins and higher depreciation, partly offset by higher production, stronger operational performance and lower costs.

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 2010 were $1,170 million compared with $1,110 million in 2009 and $1,547 million in 2008. The decrease in 2009, when compared with 2008, is largely attributable to the reduction in interest rates.

Net finance income relating to pensions and other post-retirement benefits in 2010 was $47 million compared with net finance expense of $192 million in 2009 and net finance income of $591 million in 2008. In 2010, compared with 2009, the improvement reflected the additional expected returns on assets following the increases in the pension asset base at the end of 2009 compared with the end of 2008. In 2009, the expected return on assets decreased significantly as the pension asset base reduced, consistent with falls in equity markets during 2008.

[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 7 on page 167 and further information on inventory holding gains and losses is provided on page 81.

Taxation

The credit for corporate taxes in 2010 was $1,501 million, compared with a charge of $8,365 million in 2009 and a charge of $12,617 million in 2008. The effective tax rate was 31% in 2010, 33% in 2009 and 37% in 2008. The group earns income in many countries and, on average, pays taxes at rates higher than the UK statutory rate of 28%. The decrease in the effective tax rate in 2010 compared with 2009 primarily reflects the absence of a one-off disbenefit that featured in 2009 in respect of goodwill impairment, and other factors. The decrease in the effective tax rate in 2009 compared with 2008 primarily reflects a higher proportion of income from associates and jointly controlled entities where tax is included in the pre-tax operating result, foreign exchange effects and changes to the geographical mix of the group s income.

Acquisitions and disposals

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 Azeri-Chirag-Gunashli (ACG) developments in the Caspian Sea, Azerbaijan for $2.9 billion, as part of a $7-billion transaction with Devon Energy. For further information on this transaction, including required government approvals, see Exploration and Production on page 43. As part of the response to the Gulf of Mexico oil spill, the group plans to deliver up to $30 billion of disposal proceeds by the end of 2011. 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 is for the sale of our interest in Pan American Energy to Bridas Corporation, $1 billion for the sale of our upstream 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, the latter completing in January 2011. See Financial statements Note 4 on page 163.

In Refining and Marketing we made disposals totalling $1.8 billion, 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 are receivable in 2011. See Financial statements Note 5 on page 164.

In 2008, we completed an asset exchange with Husky Energy Inc., and asset purchases from Chesapeake Energy Corporation as described on page 23.

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
	2010	2009	2008
Exploration and Production			
Impairment and gain (loss) on sale of businesses and fixed assets	**3,812**	1,574	(1,015)
Environmental and other provisions	**(54)**	3	(12)
Restructuring, integration and rationalization costs	**(137)**	(10)	(57)
Fair value gain (loss) on embedded derivatives	**(309)**	664	(163)
Other	**(113)**	34	257
	3,199	2,265	(990)
Refining and Marketing			
Impairment and gain (loss) on sale of businesses and fixed assets[a]	**877**	(1,604)	801
Environmental and other provisions	**(98)**	(219)	(64)
Restructuring, integration and rationalization costs	**(97)**	(907)	(447)
Fair value gain (loss) on embedded derivatives		(57)	57
Other	**(52)**	184	
	630	(2,603)	347
Other businesses and corporate			
Impairment and gain (loss) on sale of businesses and fixed assets	**5**	(130)	(166)
Environmental and other provisions	**(103)**	(75)	(117)
Restructuring, integration and rationalization costs	**(81)**	(183)	(254)
Fair value gain (loss) on embedded derivatives			(5)
Other	**(21)**	(101)	(91)
	(200)	(489)	(633)
Gulf of Mexico oil spill response	**(40,858)**		
Total before interest and taxation	**(37,229)**	(827)	(1,276)
Finance costs[b]	**(77)**		
Total before taxation	**(37,306)**	(827)	(1,276)
Taxation credit (charge)[c]	**11,857**	(240)	480

Total after taxation	**(25,449)**	(1,067)	(796)

[a] 2009 includes $1,579 million in relation to the impairment of goodwill allocated to the US West Coast fuels value chain.

[b] Finance costs relate to the Gulf of Mexico oil spill. See Financial statements Note 2 on page 158 for further details.

[c] Tax is calculated by applying discrete quarterly effective tax rates (excluding the impact of the Gulf of Mexico oil spill) on group profit or loss, to the non-operating items as they arise each quarter. However, the US statutory tax rate has been used for expenditures relating to the Gulf of Mexico oil spill 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.

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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 82.

			$ million
	2010	2009	2008
Exploration and Production			
Unrecognized gains (losses) brought forward from previous period	**(530)**	389	107
Unrecognized (gains) losses carried forward	**527**	530	(389)
Favourable (unfavourable) impact relative to management s measure of performance	**(3)**	919	(282)
Refining and Marketing			
Unrecognized gains (losses) brought forward from previous period	**179**	(82)	429
Unrecognized (gains) losses carried forward	**(137)**	(179)	82
Favourable (unfavourable) impact relative to management s measure of performance	**42**	(261)	511
	39	658	229
Taxation credit (charge)[a]	**(26)**	(213)	(83)
	13	445	146
By region			
Exploration and Production			
US	**141**	687	(231)
Non-US	**(144)**	232	(51)
	(3)	919	(282)
Refining and Marketing			
US	**19**	16	231
Non-US	**23**	(277)	280
	42	(261)	511

[a] Tax is calculated by applying discrete quarterly effective tax rates (excluding the impact of the Gulf of Mexico oil spill) on group profit or loss, to the fair value accounting effects as they arise each quarter.

Reconciliation of non-GAAP information

			$ million
	2010	2009	2008
Exploration and Production			
Replacement cost profit before interest and tax adjusted for fair value accounting effects	**30,889**	23,881	38,590
Impact of fair value accounting effects	**(3)**	919	(282)
Replacement cost profit before interest and tax	**30,886**	24,800	38,308
Refining and Marketing			
Replacement cost profit before interest and tax adjusted for fair value accounting effects	**5,513**	1,004	3,665
Impact of fair value accounting effects	**42**	(261)	511
Replacement cost profit before interest and tax	**5,555**	743	4,176

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 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 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 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 charges totalling $40.9 billion in 2010 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 determination of BP s negligence), the outcome of litigation, 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. 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 have regained some confidence after the banking crisis of 2008 but are still subject to volatility and 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 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.

Business review

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 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, and could cause us to incur additional costs. In particular, our investments in the US, Russia, Iraq, Egypt, Libya and other countries could be adversely affected by heightened political and economic environment risks. See pages 14-15 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 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 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 have recognized a total charge of $40.9 billion during 2010 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 page 158 and Legal proceedings on pages 130-131. 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.
For more information on financial instruments and financial risk factors see Financial statements Note 27 on page 185.
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.
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 incident.

Compliance and control risks

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

The Gulf of Mexico oil spill is likely to result in 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. For example, in the US, legislation is currently being considered that may impact BP s existing contracts with the US Government or limit its ability to enter into new contracts with the US Government. The US Government imposed a moratorium on certain offshore drilling activities, which was subsequently lifted in October 2010; however, the implications of the moratorium for how quickly the industry will return to drilling remains uncertain. 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.

For more information on environmental regulation, see pages 78-81.

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. 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 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 130-133. For further information on the risks involved in BP s trading activities, see Operational risks Treasury and trading activities on page 31.

Liabilities and provisions BP s potential liabilities resulting from pending and future claims, lawsuits 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 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 any natural resource damages associated with the spill and certain costs incurred 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 page 130.

BP is subject to a number of investigations related to the Incident by numerous federal and State agencies. See Legal proceedings on page 130. 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 their assessment of BP s culpability 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 costs arising out of the spill are recoverable from its partners and other parties responsible under OPA 90, such recovery is not certain and BP has recognized all of the costs incurred in its financial statements (see Financial statements Note 2 on page 158, Note 37 on page 199 and Note 44 on page 218, under Contingent assets relating to the Gulf of Mexico oil spill).

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 our partners and 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 recent 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 are adjudicated by the Gulf Coast Claims Facility (GCCF) headed by Kenneth Feinberg, who was jointly appointed by BP and the US Administration. On 18 February 2011, the GCCF announced its final rules governing payment options, eligibility and substantiation criteria, and final payment methodology. The impact of these rules, or other events related to the adjudication of claims, on future payments by the GCCF is uncertain. Payments could ultimately be significantly higher or lower than the amount we have estimated for individual and business claims under OPA 90 included in the provision BP recognized for litigation and claims. (See Financial statements Note 37 on page 199 under Litigation and claims.)

Business review

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.

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 incident. 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 due to the nature of some of its business relationships on page 32.

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 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 and damage to our reputation or licence to operate.

To help address health, safety, security, environmental and operations risks, and to provide a consistent framework within which the group can analyze the performance of its activities and identify and remediate shortfalls, BP implemented a group-wide operating management system (OMS). The embedding of OMS continues and following the Gulf of Mexico oil spill an enhanced S&OR function is being 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 compliance 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 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 incident 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 the environment and people and given the high volumes 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 31.

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 and breaches of regulations.

The reliability and security of our digital infrastructure are critical to maintaining the availability of our business applications. A breach of our digital security could cause serious damage to business operations and, in some circumstances, could result in injury to people, damage to assets, harm to the environment and breaches of regulations.

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 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.

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Business review

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.

Our systems of control

The board is responsible for the direction and oversight of BP. The board has set an overall goal for BP, which is to maximize long-term shareholder value through the allocation of its resources to activities in the oil, natural gas, petrochemicals and energy businesses. The board delegates authority for achieving this goal to the group chief executive (GCE).

The board maintains five permanent committees that are composed entirely of non-executives. The board and its committees monitor, among other things, the identification and management of the group s risks both financial and non-financial. During the year, the board s committees engage with executive management, the general auditor and other monitoring and assurance providers (such as the group head of safety and operational risks, the group compliance and ethics officer and the external auditor) on a regular basis as part of their oversight of the group s risks. Significant incidents that occur and management s response to them are considered by the appropriate committee and reported to the board. In July the board established a new committee of non-executives, the Gulf of Mexico committee, to monitor the response of the company to the Gulf of Mexico incident through oversight of the new GCRO. The committee engages with GCRO management on a regular basis to monitor the response to the incident and management of the risks arising. (*See Board performance report on pages 90-105.*)

The company maintains a comprehensive system of internal control. This comprises the holistic set of management systems, organizational structures, processes, standards and behaviours that are employed to conduct our business and deliver returns for shareholders. 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. It addresses risks and how we should respond to them as well as the overall control environment. Each component of the system has been designed to respond to a particular type or collection of risks. Material risks are described in the Risk factors section (*see pages 27-32*).

Key elements of our system of internal control are: the control environment; the management of risk and operational performance (including in relation to financial reporting); and the management of people and individual performance. Controls include the BP code of conduct, our operating management system (OMS), our leadership framework and our principles for delegation of authority, which are designed to make sure employees understand what is expected of them.

As part of the control system, the GCE s senior team known as the executive team is supported by sub-committees that are responsible for and monitor specific group risks. These include the group operations risk committee (GORC), the group financial risk committee (GFRC), the resource commitments meeting (RCM), the group people committee (GPC), and the group s disclosure committee (GDC), which reviews the disclosure controls and procedures over reporting.
Operations and investments are conducted and reported in accordance with, and associated risks are thereby managed through, relevant standards and processes. These range from OMS which is the structured set of processes designed to deliver safe, responsible and reliable operating activity, to group standards, which set out processes for major areas such as fraud and misconduct reporting, through to detailed administrative instructions. The GCE conducts regular performance reviews with the segments and key functions to monitor performance and the management of risk and to intervene if necessary. People management is based on performance objectives, through which individuals are accountable for specific activities within agreed boundaries.
Following the Gulf of Mexico oil spill, the company established the GCRO in June to manage the company s response activities, including managing clean-up and restoration costs, claims management and litigation. Lessons learned from the incident and the recommendations of BP s internal investigation are being embedded into all areas of the system of internal control and in particular in OMS.

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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 the first half of 2010, new sanctions against Iran and against companies that make investments that enhance Iran s ability to develop petroleum resources or provide or facilitate the production or import of refined petroleum products into Iran were adopted in the US under the Comprehensive Iran Sanctions Accountability and Divestment Act of 2010. The European Union and the UN also adopted new restrictive measures. The EU sanctions restrict the provision of certain technologies to Iranian entities and also prohibit providing assistance to help develop certain exploration and production, refining, and LNG facilities or operations in Iran.

BP has interests in, and is the operator of, two fields and a pipeline located outside Iran in which Naftiran Intertrade Co. Ltd, NICO SPV Limited (NICO) and Iranian Oil Company (UK) Limited have interests. One of these fields, the North Sea Rhum field, has suspended production pending clarification of the impact of the EU restrictive measures. The Shah Deniz field continues in operation under the EU measures. BP has purchased or shipped quantities of crude oil, refinery and petrochemicals feedstocks, blending components and LPG of Iranian origin or from Iranian counterparties primarily for sale to third parties in Europe and a small portion is used by BP in its own facilities in South Africa and Europe. BP incurs some port costs for cargos loaded in Iran and sometimes charters Iranian-owned vessels outside of Iran. Small quantities of lubricants are sold to non-Iranian third parties for use in Iran. Until recently BP held an equity interest in an Iranian joint venture that has a blending facility and markets lubricants for sale to domestic consumers. In January 2010, BP restructured its interest in the joint venture and currently maintains its involvement through certain contractual arrangements. BP does not seek to obtain from the government of Iran licences or agreements for oil and gas projects in Iran, is not conducting any technical studies in Iran, and does not own or operate any refineries or petrochemicals plants in Iran.

BP sells lubricants in Cuba through a 50:50 joint venture and trades in small quantities of lubricants. In Syria, BP sells lubricants through a distributor and BP obtains crude oil and refinery feedstocks for sale to third parties in Europe and for use in certain of its non-US refineries. In addition, BP sells crude oil and refined products into and from Syria and incurs port costs for vessels utilizing Syrian ports. BP sold small quantities of LPG to an agent on behalf of a Sudanese party for making aerosols in Sudan, but no longer makes such sales. A non-BP operated Malaysian joint venture has sold small quantities of petrochemicals into Burma; these sales have now terminated. A non-controlled and non-operated Brazilian biofuels joint venture in which BP has an interest sold a cargo of sugar cane by-products to Iran and to Syria.

BP supplies to airlines and shipping companies from Sanctioned Countries fuels and lubricants at airports and ports located outside these countries. BP sells to third parties who may re-sell to entities from Sanctioned Countries. A non-controlled, non-operated joint venture in Hamburg, Germany provided fuel delivery services (but did not sell fuel) to Iranian airlines. BP terminated all fuel sales to Iranian airlines as of July 2010 and to Sudanese airlines in December 2010. Sales to Iranian shipping companies have also been terminated. BP has registered, and paid required fees for, patents and trademarks in Sanctioned Countries.

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.

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Business review
Gulf of Mexico oil spill

Incident summary

On 20 April 2010, following a well blowout in the Gulf of Mexico, an explosion and fire occurred on the semi-submersible rig Deepwater Horizon and on 22 April the vessel sank. Tragically, 11 people lost their lives and 17 others were injured. Hydrocarbons continued to flow from the reservoir and up through the casing and the blowout preventer (BOP) for 87 days, causing a very significant oil spill.

The Deepwater Horizon rig was operated by Transocean Holdings LLC and was drilling the Macondo exploration well. The well forms part of the Mississippi Canyon Block 252 (MC252) lease, in respect of which BP Exploration & Production Inc. was the named party and operator with a 65% working interest. The well was in a water depth of 5,000 feet and 43 nautical miles from shore.

BP tackled the leak at its source in multiple, parallel ways, which over time included: attempting to fit caps on the well, using containment systems to pipe oil to vessels on the surface, sealing the well through a static-kill procedure and drilling relief wells. BP recognized early in the incident that drilling relief wells constituted the ultimate means to seal and isolate the well permanently and stop the flow of oil and gas. Two relief wells were drilled, the first of which was started on 2 May; the second was started on 16 May as a contingency.

On 15 July, BP successfully shut in the Macondo well and then commenced a static-kill procedure. On 9 August, BP confirmed that the casing had been successfully sealed with cement. On 16 September, the first relief well intercepted the annulus of the Macondo well. After completing cementing operations on 19 September, BP, the federal government scientific team and the National Incident Commander concluded that the well-kill operations had successfully sealed the annulus.

BP then began the abandonment of the Macondo well, which included removing portions of the casing and setting cement plugs. This work was completed on 8 November. In parallel, operations to plug and abandon (P&A) the relief well that intercepted the Macondo well also took place and were completed on 30 September. P&A of the second relief well is in progress and is expected to complete in early March 2011. All response activities at the Macondo site (with the exception of the final seabed survey and seismic sweep, which are scheduled to take place at the end of first quarter in 2011), were completed on 8 January with the recovery of the buoy and anchor system for the free-standing riser.

The group income statement for the year ended 31 December 2010 includes a pre-tax charge of $40.9 billion in relation to the Gulf of Mexico oil spill. See Financial consequences on page 38 and Financial statements Note 2 on page 158 for more details.

Key statistics

	2010
Total pre-tax cost recognized in income statement ($ million)	**40,935**
Total cash flow expended (pre-tax) ($ million)	**17,658**
Total payments from $20-billion trust fund ($ million)	**3,023**
Total number of claimants to GCCF[a]	**468,869**
Number of people deployed (at peak) (approximately)	**48,000**
Number of active response vessels deployed during the response (approximately)	**6,500**
Barrels of oil collected or flared (approximately)	**827,000**
Barrels of oily liquid skimmed from surface of sea (approximately)	**828,000**
Barrels of oil removed through surface burns (UAC estimate)	**265,450**

[a] Gulf Coast Claims Facility (GCCF).

Gulf Coast Restoration Organization (GCRO)

Following the accident, BP established a separate organizational unit the Gulf Coast Restoration Organization (GCRO) to provide the necessary leadership and dedicated resources to facilitate BP s fulfilment of its clean-up responsibilities and to support the long-term effort to restore the Gulf coast. The GCRO addresses all aspects of the response, including: executing our ongoing clean-up operations and all associated remediation activities; coordinating with government officials; keeping the public informed; and implementing the $20-billion Deepwater Horizon Oil Spill Trust established to meet certain of our financial obligations. At the end of 2010, the GCRO had a permanent staff of 100 employees and about 5,900 contractors including the Gulf Coast incident management team. The majority of the clean-up, maintenance and monitoring is being carried out by contract staff. Since inception, many other BP staff and contractors have been, and will continue to be, temporarily seconded to assist the permanent team and to provide additional resources or specialist skills where required.

Our response

BP immediately took responsibility for responding to the incident, taking steps to remedy the harm that the spill caused to the Gulf of Mexico, the Gulf coast environment, and the livelihoods of the people in the region. The US government formed a Unified Area Command (UAC) to link the organizations responding to the incident and provide a forum for those organizations to make co-ordinated decisions. If consensus could not be reached on a particular matter, the Federal On-Scene Coordinator (FOSC) made the final decision on response-related actions. BP s comprehensive response focused on three strategic fronts: stopping the flow of hydrocarbons at the source; working to capture, contain and remove oil offshore and near the shore; and cleaning and restoring impacted shorelines and beaches along the Gulf coast.

Initially BP mobilized a fleet of 30 vessels and over a million feet of protective boom. Thereafter the scale of activity grew rapidly, and at its peak included more than 6,500 vessels, more than 13 million feet of boom and almost 48,000 personnel.

BP also formed an investigation team charged with gathering the facts surrounding the accident, analysing available information to identify possible causes and making recommendations that would help prevent similar accidents in the future. The team concluded that no single action or inaction caused this accident. Rather, a complex and interlinked series of mechanical failures, human judgments, engineering design, operational implementation and team interfaces came together to allow the accident. Multiple companies, work teams and circumstances were involved over time. See Internal investigation and report on page 37 for further information on the investigation and its findings.

Subsea

Subsea intervention activities were initiated by BP immediately following the explosion. Initial attempts to stop the flow of oil focused on attempting to actuate the failed BOP with remotely operated vehicles (ROVs). At the same time, planning also began for two relief wells. Attempts to stop the flow of oil by activating the various components of the BOP continued until 5 May, while plans and tools for potential containment options were being developed in parallel.

From 5 May BP attempted to contain the flow of oil using a number of different strategies. Firstly, one of the three leak points was plugged with the installation of a drill pipe overshot and pack-off device, reducing the complexity of the seabed situation. Following a failed attempt to contain the flow of oil using a containment dome, a riser insert tube tool was successfully deployed in the end of the riser on 16 May. This allowed roughly 3,000 barrels of oil per day (b/d) to be captured and returned to the surface for processing on the drillship Discoverer Enterprise. An attempt was also made to top kill the well by pumping heavy drilling mud into the well at high rates but this effort was unsuccessful. By shearing and removing a damaged section of riser from the lower marine riser package (LMRP) on top of the BOP stack, it was possible to attach a new containment system (sometimes referred to as a top hat). This system allowed for up to 15,000b/d of oil to be produced through this non-sealing LMRP cap via a riser to the Discoverer Enterprise for processing. Containment capacity was eventually enhanced to over 40,000b/d of oil. In total, approximately 827,000 barrels of crude oil were recovered using the various containment systems. On 10 July, the top-hat containment cap was removed from the LMRP to allow the installation of a three-ram capping stack, which was completed on 12 July.

The flow of oil into the Gulf of Mexico was finally stopped on 15 July. After verifying integrity of the capping stack, a static-kill procedure was executed. Following a series of tests and the pumping of heavy drilling mud, static conditions were achieved in the Macondo well on 3 August and cement was pumped in two days later. On 2 September, after a successful test of the cement plug, the capping stack was removed from the top of the BOP.

On 3 September, the BOP was removed from the Macondo wellhead to be replaced by the BOP stack from the Development Driller II. The Deepwater Horizon BOP was subsequently recovered to surface, preserved and shipped to the NASA Michoud Facility in Louisiana for examination by the US government and other parties.

Progress on the two relief wells continued in parallel with the containment operations outlined above. The first relief well was delayed on several occasions due to adverse weather and while critical testing and operations were conducted on the Macondo well. On 16 September, the first relief well successfully intersected the Macondo wellbore. On 19 September, after cementing operations on the relief well were complete, the Macondo well was officially declared killed.

The P&A of the first relief well was completed by the Development Driller III rig on 30 September. P&A of the Macondo well was concluded on 8 November by the Development Driller II, and the P&A of the second relief well is in progress and is expected to complete in early March 2011.

Work to recover and secure the subsea infrastructure used for the various containment systems commenced following completion of the Macondo well P&A programme and was completed on 8 January 2011.

During the latter stages of the response, work commenced to restore and decontaminate the many vessels involved in the incident. This is largely complete, with the remaining 25 vessels expected to be completed by the end of April 2011.

The only outstanding work associated with the Macondo site is the seabed and seismic surveys of the area. In consideration of, and subject to, the weather conditions, it is anticipated that the seabed and seismic surveys will take place at the end of first quarter of 2011.

Shoreline and surface

The priorities for the shoreline and surface response were removing oil from the surface of the Gulf, preventing oil from reaching the shoreline and cleaning up any oil that did reach the shores. The response strategy included aerial surveillance to understand where concentrations of oil were located, mechanical skimming, controlled surface burning, application of dispersants, and multiple in-water and onshore booming techniques. Onshore, multiple techniques for cleaning and removing oil from marshes, wetlands, and beaches were deployed. BP worked with local

organizations to refine existing area contingency plans to enable the most effective response to the spill.
Extensive surface skimming activities took place, ranging from large-scale offshore skimmers to inland and shallow water equipment. The UAC also leveraged its Vessels of Opportunity (VoO) programme to assist with this and to support the fish and wildlife, Shoreline Clean-up Assessment Team (SCAT), and Rapid Assessment Team.
Controlled in situ burning of oil on the surface of the water was conducted where concentrations of oil with suitable characteristics could be identified. Approximately 400 controlled burns were performed, which in total removed an estimated 265,450 barrels of oil according to the UAC.
Chemical dispersants were deployed under the close supervision of the UAC. Dispersants are mixtures of solvents, surfactants and other additives that break up the surface tension of an oil slick or sheen and make oil more soluble in water. On the surface, dispersants help break oil down into microscopic droplets that can be dispersed through the seawater and more easily degraded by oil-eating bacteria. Subsea application of dispersants was used to break the oil into small particles that disperse throughout the water column, forming a more dilute oil-and-water solution that degrades more easily.
BP worked closely with state and local officials, seeking to prevent shoreline oiling. The effort involved significant deployment of boom. BP worked closely with experts from the US Coast Guard, the US Fish & Wildlife Service, the National Oceanic and Atmospheric Administration (NOAA), the National Park Service, as well as state agencies to identify the most sensitive wildlife habitats and prioritize appropriate spill countermeasures. These measures included booming wildlife refuges and using methods to deter wildlife from entering oiled areas. BP also established animal treatment facilities, with significant capacity to treat birds, mammals and turtles.

Business review

Once oiling of the shoreline had occurred, SCATs assessed the damage and developed clean-up methods for each type and area of impact, including treatment plans designed to optimize oil removal with minimal intrusion and impact to the marsh. Thousands of personnel organized into operating teams were mobilized for the clean-up efforts.

Beach-cleaning operations were undertaken in collaboration with residents from the highest impacted communities, with almost 11,000 community responders being trained in beach clean-up efforts.

Throughout this response, BP met with local officials and organized town halls and information sessions in the coastal communities. As the response continued, BP opened community outreach and claims centres in each of the coastal counties and established telephone call lines for all activities.

BP has committed to pay all legitimate claims to individuals, businesses and governments and to establish a $20-billion trust fund, following consultation with the US government. As part of the US Natural Resource Damage Assessment (NRDA) process, BP is working with federal and state trustees to identify wildlife and habitats that may have been injured; to restore the environment back to an objective baseline condition; to restore access to and use of the natural resources; and to compensate for losses caused by the incident. Finally, BP has provided long-term funding for response projects, research and community support programmes as part of our long-term commitment to the Gulf.

The Food and Drug Administration (FDA), the NOAA, and state agencies also conducted fisheries testing and monitoring throughout the response. These testing and monitoring programmes included smell and edible tissue tests for oil detection. Approximately 89,000 square miles of federal fisheries were closed at the peak of the response; as of 1 February 2011, 99.6% of federal fisheries were open to fishing. To date, BP has committed $127 million for ongoing monitoring, marketing, and tourism support in the Gulf States.

Restoration, research and other donations

In conjunction with the Gulf of Mexico Alliance (a partnership of the states of Alabama, Florida, Louisiana, Mississippi and Texas with the goal of significantly increasing regional collaboration to enhance the ecological and economic health of the Gulf of Mexico), we have established the Gulf of Mexico Research Initiative (GRI) providing $500 million to study and monitor the spill s potential long-term impacts on the environment and local public health. Specifically, the 10-year programme will examine the spread and fate of the oil and other contaminants, the degree of biodegradation, effects of the spill on local ecosystems, and detection, clean-up and mitigation technology. While the details of the programme were being developed, BP awarded a series of fast-track grants to five research groups, totalling $40 million. BP and the Gulf of Mexico Alliance appointed an equal number of research scientists to the governing board of the GRI and, in December, the GRI held its first meeting.

BP has now contributed a total of $260 million under its agreement to fund the $360-million cost of six berms in the Louisiana barrier islands project.

BP has established a $100-million charitable fund to support unemployed rig workers experiencing economic hardship as a result of the moratorium on deepwater drilling imposed by the US federal government. The Rig Worker Assistance Fund will be administered through the Gulf Coast Restoration and Protection Foundation, a supporting organization of The Baton Rouge Area Foundation.

In line with BP s previous commitment to donate its share of the revenue (net of royalties and transportation costs) from the sale of recovered oil to the National Fish and Wildlife Foundation (NFWF), total donations to date have amounted to $22 million.

Claims process and trust fund

BP initially established a claims process in accordance with the requirements of the Oil Pollution Act 1990 (OPA 90), allowing claimants to make a claim against BP as one of the designated responsible parties. BP has endeavoured to promptly pay all legitimate claims including those from individuals, businesses and government entities. BP paid $399 million in claim payments to individuals and businesses before 23 August 2010, when the administration of these claims was transferred to the Gulf Coast Claims Facility (GCCF) headed by Kenneth Feinberg. Mr Feinberg was jointly appointed by BP and the President of the United States to manage the GCCF. According to GCCF statistics, as of 31 December 2010, 468,869 claimants had submitted claims and $2,776 million in payments had been made. BP continues to evaluate and pay claims from government entities. State and local government entities, as at 31 December 2010, had received $550 million through the trust fund (see below) and BP directly to cover claims and response and removal advances and payments.

In support of the settlement of claims BP established the Deepwater Horizon Oil Spill Trust (Trust), and committed $20 billion to the Trust over a period of three-and-a-half years. While funds are building, BP has secured its commitments to the Trust by granting, conveying, and/or assigning to the Trust first priority perfected security interests in production payments pertaining to certain Gulf of Mexico oil and natural gas production. During 2010, BP made payments to the Trust totalling $5 billion and is committed to making additional payments of $1.25 billion, in one or more instalments, during and prior to the end of each calendar quarter commencing with the first calendar quarter of 2011 and continuing until the last calendar quarter of 2013. The trust fund is available to satisfy legitimate individual and business claims administered by the GCCF, state and local government claims resolved by BP, final judgments and settlements, state and local response costs, and natural resource damages and related costs. Fines and penalties will be paid separately and not from the Trust. Payments from the Trust are made as costs are finally determined or claims are adjudicated, whether by the GCCF, or by a court, or as agreed by BP. The GCCF evaluates all individual and business OPA 90 claims, excluding all government claims. The establishment of this Trust does not represent a cap or floor on BP s liabilities, and BP does not admit to a liability of any amount in the Trust. The Trust agreement provides for the term of the Trust to continue until 30 April 2016, subject to the right of the Individual Trustees to extend or expedite this expiry date under certain circumstances. Any amounts left in the Trust once all legitimate claims have been resolved and paid will revert to BP. See Financial statements Note 2 on page 158, Note 37 on page 199 and Note 44 on page 218 for further information on the Trust and on contingent liabilities arising from the incident. See Proceedings and investigations relating to the Gulf of Mexico oil spill on pages 130-131 for information on legal proceedings.

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Internal investigation and report

BP s investigation found that no single factor caused the Macondo well tragedy; rather, it concluded that decisions made by multiple companies and work teams contributed to the accident which arose from a complex and interlinked series of mechanical failures, human judgments, engineering design, operational implementation and team interfaces . The report based on a four-month investigation led by BP s head of Safety and Operations and conducted independently by a team of over 50 technical and other specialists drawn from inside BP and externally found that:

- The annulus cement barrier and in particular the cement slurry that was used at the bottom of the Macondo well failed to contain hydrocarbons within the reservoir, as it was designed to do. The annulus cement probably experienced nitrogen breakout and migration, allowing gas and liquids to enter the wellbore annulus. The investigation team concluded that there were weaknesses in cement design and testing, quality assurance and risk assessment.
- The shoe track barriers at the bottom of the Macondo well failed to contain hydrocarbons as they were designed to do, allowing hydrocarbons to flow up the production casing. The shoe track barriers consisted of two barriers in the shoe track: the cement in the shoe track and the float collar. BP s investigation team identified a number of potential failure modes that could explain how both the shoe track cement and the float collar allowed hydrocarbon ingress into the production casing, but has not determined which of these failure modes occurred.
- The results of the negative pressure test were incorrectly accepted by BP and Transocean, although well integrity had not been established.
- Over a 40-minute period, the Transocean rig crew failed to recognize and act on the influx of hydrocarbons into the well until the hydrocarbons had passed through the BOP and into the riser and were rapidly flowing to the surface.
- Well control response actions failed to regain control of the well. The first well control actions were to close the BOP and diverter, routing the fluids exiting the riser to a mud gas separator rather than to the overboard diverter line. If fluids had been diverted overboard, rather than to the mud gas separator, there may have been more time to respond, and the consequences of the accident may have been reduced.
- Diversion of the hydrocarbons to the mud gas separator resulted in gas venting onto the rig. The design of the mud gas separator system allowed diversion of the riser contents to the mud gas separator vessel although the well was in a high-flow condition. This overwhelmed the mud gas separator system, resulting in gas venting onto the rig. This increased the potential for the gas to reach an ignition source.
- The flow of gas into the engine rooms through the ventilation system created a potential for ignition that the rig s fire and gas system did not prevent.
- Even after the explosion and fire had disabled its crew-operated controls, the rig s BOP on the seabed should have activated automatically to seal the well. But it failed to operate, probably because critical components were not working. Through a review of rig audit findings and maintenance records, the investigation team found indications of potential weaknesses in the testing regime and maintenance management system for the BOP.

The investigation team developed a series of recommendations based on the above findings. These recommendations cover contractor oversight and assurance, risk assessment, well monitoring and well-control practices, integrity testing practices and BOP system maintenance. The report makes the following recommendations, among others:

Procedures and engineering technical practices

- Update and clarify current practices to ensure that a clear and comprehensive set of cementing guidelines and associated Engineering Technical Practices (ETPs) are available as controlled standards.
- Review and update requirements for subsea BOP configuration.
- Update the relevant technical practices to incorporate certain improved design requirements for subsea wellheads.
- Review and update ETPs regarding negative-pressure testing.
- Clarify and strengthen standards for well-control and well-integrity incident reporting and investigation.
- Propose to the American Petroleum Institute the development of a recommended practice for design and testing of foam cement slurries in high-pressure, high-temperature applications.

Review and assess the consistency, rigour and effectiveness of the current risk management and management of change processes practised by Drilling and Completions (D&C).

Capability and competency

Reassess and strengthen the current technical authority s role in the areas of cementing and zonal isolation.

Enhance D&C competency programmes to deepen the capabilities of personnel in key operational and leadership positions and augment existing knowledge and proficiency in managing deepwater drilling and wells.

Develop an advanced deepwater well-control training programme that supplements current industry and regulatory training and embeds lessons learned from the Gulf of Mexico incident.

Establish BP s in-house expertise in the areas of subsea BOPs and BOP control systems through the creation of a central expert team, including a defined segment engineering technical authority role to provide independent assurance of the integrity of drilling contractors BOPs and BOP control systems.

Request that the International Association of Drilling Contractors review and consider the need to develop a programme for formal subsea engineering certification of personnel who are responsible for the maintenance and modification of deepwater BOPs and control systems.

Audit and verification

Strengthen BP s rig audit process to improve the closure and verification of audit findings and actions across BP-owned and BP-contracted drilling rigs.

Process safety performance management

Establish D&C leading and lagging indicators for well integrity, well control and rig safety critical equipment.

Require drilling contractors to implement an auditable integrity monitoring system to continuously assess and improve the integrity performance of well-control equipment against a set of established leading and lagging indicators.

Cementing services assurance

Conduct an immediate review of the quality of the services provided by all cementing service providers. Confirm that adequate oversight and controls are in place within the service provider s organization and BP.

Well-control practices

Assess and confirm that essential well-control and well-monitoring practices, such as well monitoring and shut-in procedures, are clearly defined and rigorously applied on all BP-owned and BP-contracted offshore rigs.

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Business review

Rig process safety

Require hazard and operability reviews of the surface gas and drilling fluid systems for all BP-owned and BP-contracted drilling rigs.

Include in the hazard and operability reviews a study of all surface system hydrocarbon vents, reviewing suitability of location and design.

Blowout preventer design and assurance

Establish minimum levels of redundancy and reliability for BP s BOP systems. Require drilling contractors to implement an auditable risk management process to ensure that their BOP systems are operated above these minimum levels.

Strengthen BP s minimum requirements for drilling contractors BOP testing, including emergency systems.

Strengthen BP s minimum requirements for drilling contractors BOP maintenance management systems.

Define BP s minimum requirements for drilling contractors management of changes for subsea BOPs.

Develop a clear plan for remotely operated vehicle intervention as part of the emergency BOP operations in each of BP s operating regions, including all emergency options for shearing pipe and sealing the wellbore.

Require drilling contractors to implement a qualification process to verify that shearing performance capability of blind shear rams is compatible with the inherent variations in wall thickness, material strength and toughness of the rig drill pipe inventory.

Include testing and verification of these BOP recommendations in the rig audit process.

National Commission report

BP has co-operated fully with the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling (National Commission), which released the full report of its investigation on 11 January 2011. The National Commission acknowledged the complexities and risks inherent to deepwater energy exploration and production; it also concluded that neither industry nor government was fully prepared to assess or manage those risks. The National Commission identified certain missteps and oversights by individuals at BP, Transocean and Halliburton that led to the blowout and concluded that its root cause involved systemic management failures in the industry. These management issues, the National Commission found, extended beyond BP to contractors that serve the entire industry. This included BP s failure to adequately address risks created by late changes to well design and procedures, inadequate testing of the Macondo cement slurry by BP and Halliburton, inadequate communication between BP, Halliburton and Transocean, inadequate communication between Transocean and its crew, and inadequate decision-making processes at the Macondo well. The National Commission also found regulatory failures to be a contributing factor to the Macondo tragedy, in particular the lack of administrative resources and technical expertise at the Minerals Management Service.

The National Commission s report made a number of recommendations in nine distinct areas for addressing the causes and consequences of the spill, including principally the following: improving the safety of offshore operations by enhancing the government s role and by establishing an industry-run, private-sector oversight entity; safeguarding the environment by increasing support for environmental science and regulatory review related to Outer Continental Shelf oil and gas activities; strengthening spill response planning and capacity; advancing well-containment capabilities by increasing government expertise and requiring enhanced containment plans by operators; dedicating funding by the US Congress to Gulf restoration; ensuring financial responsibility by raising the $75-million liability cap for offshore facility accidents; promoting Congressional awareness of the risks of offshore drilling; and developing expertise and research programmes devoted to exploration and spill containment in the Arctic.

Given the emerging consensus that the Gulf of Mexico accident was the result of multiple causes involving multiple parties, we support the National Commission s efforts to strengthen industry-wide safety practices. 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. Even prior to the conclusion of the National Commission s investigation, BP instituted changes designed to further strengthen safety and risk management. These changes include the creation of an enhanced Safety and Operational Risk function, reporting directly to group chief executive Bob Dudley, that maintains an independent view of the implementation of internal

and external requirements and of safety and operational risks.
On 17 February 2011, the Commission s Chief Counsel published a separate report on his investigation about the causes of the incident. The Chief Counsel s investigation concluded that the blowout resulted from a series of engineering and management mistakes by the companies involved in the incident, including BP, Halliburton and Transocean.
Consequences of the accident for BP and its shareholders
Financial consequences
The group income statement for 2010 includes a pre-tax charge of $40.9 billion in relation to the Gulf of Mexico oil spill. This comprises costs incurred up to 31 December 2010, estimated obligations for future costs that can be estimated reliably at this time, and rights and obligations relating to the trust fund, described below.
Costs incurred during the year mainly related to oil spill response activities, which included the drilling of relief wells and other subsea interventions, surface response activities including numerous vessels, and shoreline response involving deployment of boom and beach cleaning activities.
Under US law BP is required to compensate individuals, businesses, government entities and others who have been impacted by the oil spill. Individual and business claims are administered by the GCCF, which is separate from BP. BP has established a trust fund of $20 billion to be funded over the period to the fourth quarter of 2013, which is available to satisfy legitimate individual and business claims administered by the GCCF, state and local government claims resolved by BP, final judgments and settlements, state and local response costs, and natural resource damages and related costs arising as a consequence of the Gulf of Mexico oil spill. In 2010, BP contributed $5 billion to the fund, and further quarterly contributions of $1.25 billion are to be made during the period 2011 to 2013. The income statement charge for 2010 includes $20 billion in relation to the trust fund, adjusted to take account of the time value of money. The establishment of the trust fund does not represent a cap or floor on BP s liabilities and BP does not admit to a liability of this amount.
BP has provided for all liabilities that can be estimated reliably at this time, including fines and penalties under the Clean Water Act (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 natural resource damages claims under the OPA 90, litigation and fines and penalties except for those in relation to the CWA. These items are therefore contingent liabilities.
BP holds a 65% interest in the Macondo well, with the remaining 35% held by two joint venture partners. While BP believes and will assert that it has a contractual right to recover the partners shares of the costs incurred, no recovery amounts have been recognized in the financial statements.
For a full understanding of the impacts and uncertainties relating to the Gulf of Mexico oil spill refer to Financial statements Note 2 on page 158, Note 37 on page 199 and Note 44 on page 218. See also Risk factors on page 27 and Proceedings and investigations relating to the Gulf of Mexico oil spill on pages 130-131.

Share price and dividend consequences
As a result of the incident, BP s board reviewed its dividend policy and decided that no ordinary share dividends would be paid in respect of the first, second and third quarters of 2010. Furthermore, the BP share price suffered a significant fall on the London Stock Exchange, from 655 pence per share on the day of the incident to reach a trading low point of 296 pence per share on 25 June 2010. Although there has since been some recovery in the share price, at 493 pence per share on 18 February 2011, it remained considerably below its level immediately before the incident. (See *Share prices and listings on page 134 for further information on the performance of BP s share price*.)
Other consequences
BP s reputation has been damaged by the incident. For further information, see Risk factors on pages 27-32.
BP s long-term commitment to the Gulf of Mexico region
The Gulf of Mexico incident has had a profound impact on the people and economy of the Gulf coast as well as the offshore energy industry and BP.
From the beginning, BP has worked tirelessly to address the economic and environmental impact of the spill and has a dedicated team working closely with local and state officials to ensure that government claims are paid in a fair and expeditious manner.
BP has also provided funding to promote tourism and seafood safety two cornerstones of the Gulf coast economy and has worked closely with state and local leaders to restore the economic health of the region.
We recognize that environmental and economic restoration means more than just cleaning up the oil and paying for losses experienced across the Gulf coast. We intend to ensure that the long-term impacts of the oil spill are understood and remediated.

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Business review
Exploration and Production

Organizational and governance changes in Exploration and Production

As part of our response to the Gulf of Mexico oil spill, at the beginning of the fourth quarter we decided to reorganize our Exploration and Production segment to create three separate divisions: Exploration, Developments, and Production, integrated through a Strategy and Integration organization. This is designed to change fundamentally the way we operate, with a particular focus on managing risk, delivering common standards and processes and building personnel and technological capability for the future.

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, building on the centralized developments organization established in 2010. 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 group Safety and Operational Risk (S&OR) function is being enhanced to further our objectives in safety, compliance and risk management and demonstrates our commitment to preventing future low-probability, high-impact incidents. It has its own expert staff embedded in the divisions and is responsible for ensuring that all operations are carried out to common standards and for auditing compliance with those standards.

The Strategy and Integration organization is accountable for optimization and integration across the divisions, including delivery of support from finance, procurement and supply chain, human resources and information technology.

Our Exploration and Production segment included upstream and midstream activities in 29 countries in 2010, including Angola, Azerbaijan, Canada, Egypt, Norway, Russia,Trinidad & Tobago (Trinidad), the UK, the US and other locations within Asia, Australasia, South America and Africa, as well as gas marketing and trading activities, primarily in Canada, Europe and the US. Upstream activities involve oil and natural gas exploration and field development and production. Our exploration programme is currently focused on Egypt, the deepwater Gulf of Mexico, Libya, the North Sea, Oman and onshore US. Major development areas include Angola, Azerbaijan, Canada, Egypt, the deepwater Gulf of Mexico, the UK North Sea and Russia. During 2010, production came from 20 countries. The principal areas of production are Angola, Azerbaijan, Egypt, Russia, Trinidad, 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 the US, the UK, Canada and Indonesia. 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 (SCP), which takes gas from Azerbaijan through Georgia to the Turkish border; and the Baku-Tbilisi-Ceyhan pipeline, running through Azerbaijan, Georgia and Turkey. Major LNG activities are located in Trinidad, Indonesia and Australia. 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 gas and power, and generate margins and fees associated with the provision of physical and financial products to third parties and additional 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 Argentina, Bolivia, Chile, Abu Dhabi, Venezuela and Russia, as well as some of our operations in Angola, Canada and Indonesia, are conducted through equity-accounted entities.

Our market

Energy markets recovered in 2010 from the impact of the global economic recession, with crude oil prices in particular bouncing back following a decline in 2009 the first since 2001.

Dated Brent for the year averaged $79.50 per barrel, 29% above 2009 s average of $61.67 per barrel. Prices fluctuated in a relatively narrow band of $70-$80 per barrel for most of the year before rising in the fourth quarter. Prices

exceeded $90 per barrel in December, the highest level since October 2008.
In 2011, 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 strengthened in 2010, but were volatile. The average US Henry Hub First of Month Index rose to $4.39/mmBtu, a 10% increase from the depressed prices in 2009.
Gas consumption recovered across the world along with the economy. In the US, a cold start to 2010 followed by a hot summer and low temperatures towards the end of the year also contributed to demand strength. Yet domestic production growth of shale gas in particular continued apace and limited price rises. Henry Hub gas prices stayed below coal parity in US power generation from the summer, leading to the displacement of coal by gas. 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 38% to an average of 42.45 pence per therm for 2010. Yet plentiful global LNG supply kept spot gas prices below oil-indexed contract levels for most of the year, causing competition with contract pipeline supplies and marginal European gas production. UK spot gas prices only attained contract price levels from the end of November as cold weather caused rapid inventory draw-downs.
In 2011, we expect gas markets to continue to be driven by the economy, weather, domestic production trends and continued significant growth of global LNG supply.

Our strategy

In Exploration and Production, our 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 enduring positions in the world s key hydrocarbon basins with a focus on deepwater, gas (including unconventional gas) and giant fields. Our strategy is enabled by:

- Continuously reducing operating 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.

We are increasing investment in Exploration, a key source of value creation at the front end of the value chain, and we are evolving the nature of our relationships, particularly with National Oil Companies. We will also continue to actively manage our portfolio, with a focus on value growth.

Our performance
Key statistics

	2010	2009	2008
			$ million
Sales and other operating revenues[a]	**66,266**	57,626	86,170
Replacement cost profit before interest and tax[b]	**30,886**	24,800	38,308
Capital expenditure and acquisitions	**17,753**	14,896	22,227
			$ per barrel
Average BP crude oil realizations[c]	**77.54**	59.86	95.43
Average BP NGL realizations[c]	**42.78**	29.60	52.30
Average BP liquids realizations[c d]	**73.41**	56.26	90.20
Average West Texas Intermediate oil price[e]	**79.45**	61.92	100.06
Average Brent oil price[e]	**79.50**	61.67	97.26
			$ per thousand cubic feet
Average BP natural gas realizations[c]	**3.97**	3.25	6.00
Average BP US natural gas realizations[c]	**3.88**	3.07	6.77
			$ per million British thermal units
Average Henry Hub gas price[f]	**4.39**	3.99	9.04
			pence per therm
Average UK National Balancing Point gas price[e]	**42.45**	30.85	58.12
			thousand barrels of oil equivalent per day
Total production for subsidiaries[g h]	**2,492**	2,684	2,517
Total production for equity-accounted entities[g h]	**1,330**	1,314	1,321
Total of subsidiaries and equity-accounted entities[g h]	**3,822**	3,998	3,838
			million barrels of oil equivalent
Net proved reserves for subsidiaries	**12,077**	12,621	12,562
Net proved reserves for equity-accounted entities	**5,994**	5,671	5,585

Total of subsidiaries and equity-accounted entities	**18,071**	18,292	18,147

[a] Includes sales between businesses.

[b] Includes profit after interest and tax of equity-accounted entities.

[c] Realizations are based on sales of consolidated subsidiaries only, which excludes equity-accounted entities.

[d] Crude oil and natural gas liquids.

[e] All traded days average.

[f] Henry Hub First of Month Index.

[g] Net of royalties.

[h] 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.

2010 performance

Safety and operational risk

In Exploration and Production, safety, both process and personal, remains our highest priority. As described above, the organizational and governance changes in Exploration and Production and S&OR have been designed to ensure we achieve our objectives in this area. In addition, BP s operating management system (OMS) provides us with a systematic framework for safe, reliable and efficient operations. By the end of 2010 all of our exploration and production operations had completed their transition to OMS.

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

In 2010, excluding the impact of the Gulf of Mexico oil spill, further information on which can be found on page 34, Exploration and Production had 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 0.32. This is lower than 2009 when it was 0.39 and 2008 when it was 0.43. Our day away from work case frequency (DAFWCF) in 2010 was 0.063. This is higher than 2009 when it was 0.038 and 2008 when it was 0.057. This increase is largely due to day-away-from-work cases resulting from the Gulf of Mexico incident and an aviation incident in Canada.

In 2010, the number of reported Loss of Primary Containment (LOPC) incidents in Exploration and Production was 194, down from 321 in 2009. Excluding the impact of the Gulf of Mexico incident, the number of reported oil spills equal to or larger than 1 barrel during 2010 was 116, up from 112 in 2009. This is the first year since 1999 that the number of reported spills has increased.

Financial and operating performance

We continually seek access to resources and in 2010, in addition to new access resulting from acquisitions as detailed on page 43, this included Azerbaijan, where BP and the State Oil Company of the Republic of Azerbaijan (SOCAR) signed a new 30-year PSA on joint exploration and development of the Shafag-Asiman structure in the Caspian; China, where we farmed into Block 42/05 in the deepwater South China Sea; the Gulf of Mexico, where we were awarded 18 blocks through the Outer Continental Shelf Lease Sale 213, eleven of which have been executed and seven have yet to be executed; Indonesia, where we were awarded the North Arafura PSC onshore Papua; Jordan, where on 3 January 2010, we received approval from the Government of Jordan to join the state-owned National Petroleum Company (NPC) to exploit the onshore Risha concession in the north east of the country; onshore US, with further properties in the Eagle Ford shale gas play; and the UK, where we were awarded seven blocks in the 26th offshore licensing round.

Since the start of 2011, we have been awarded four blocks in the Ceduna Basin, offshore South Australia and, subject to partner and government approval, we have signed a new agreement with the China National Offshore Oil Corporation (CNOOC) to explore Block 43/11 in the South China Sea. We have also announced a strategic global alliance with Rosneft, which includes an agreement to explore and develop three licence blocks in Russia s South Kara Sea. See Legal proceedings on page 133 for information on an interim injunction, granted by the English High Court on 1 February 2011 and effective until 11 March 2011, restraining BP from taking any further steps in relation to the Rosneft transactions pending the outcome of arbitration proceedings.

On 21 February 2011, Reliance Industries Limited and BP announced their intention to form an upstream joint venture in which BP will take a 30% stake in 23 oil and gas production-sharing contracts that Reliance operates in India, and a 50:50 joint venture for the sourcing and marketing of gas in India. See page 43 for further information.

In November 2010, we announced the Hodoa gas discovery in the deepwater West Nile Delta area of Egypt.

Three major projects came onstream in 2010. Production commenced at the In Salah Gas compression project in Algeria, the Great White field in the Gulf of Mexico, and the Noel field in Canada. In 2010 we took final investment decisions on 15 projects.

Production was lower than last year, largely due to the impact of events in the Gulf of Mexico. After adjusting for the effect of entitlement changes in our PSAs and the effect of acquisitions and disposals, underlying production was 2% lower than 2009. In December 2010, we sustained production from the Rumaila field in Iraq at 10% above the initial production rate in 2009 to achieve the Improved Production Target, which is the first significant milestone in the rehabilitation of Rumaila. In 2010, full-year production growth in TNK-BP was 2.5%.

Sales and other operating revenues for 2010 were $66 billion, compared with $58 billion in 2009 and $86 billion in 2008. The increase in 2010 primarily reflected higher oil and gas realizations, partly offset by lower production. The decrease in 2009 primarily reflected lower oil and gas realizations.

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The replacement cost profit before interest and tax for 2010 was $30,886 million, compared with $24,800 million for the previous year. 2010 included net non-operating gains of $3,199 million, primarily gains on disposals that completed during the year partly offset by impairment charges and fair value losses on embedded derivatives. (*See page 25 for further information on non-operating items*.) In addition, fair value accounting effects had an unfavourable impact of $3 million relative to management s measure of performance. (*See page 26 for further information on fair value accounting effects*.)

The primary additional factors contributing to the 25% increase in replacement cost profit before interest and tax were higher realizations, lower depreciation and higher earnings from equity-accounted entities, mainly TNK-BP, partly offset by lower production, a significantly lower contribution from gas marketing and trading and higher production taxes.

Total capital expenditure including acquisitions and asset exchanges in 2010 was $17.8 billion (2009 $14.9 billion and 2008 $22.2 billion). For further information on acquisitions and disposals see pages 43-44.

Development expenditure of subsidiaries incurred in 2010, excluding midstream activities, was $9.7 billion, compared with $10.4 billion in 2009 and $11.8 billion in 2008.

Prior years comparative financial information

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 replacement cost profit before interest and tax for the year ended 31 December 2008 was $38,308 million and included a net charge for non-operating items of $990 million, with the most significant items being net impairment charges and net fair value losses on embedded derivatives, partly offset by the reversal of certain provisions. The impairment charge included a $517 million write-down of our investment in Rosneft based on its quoted market price at the end of the year. In addition, fair value accounting effects had an unfavourable impact of $282 million relative to management s measure of performance.

The primary additional factor contributing to the 35% decrease in the replacement cost profit before interest and tax for the year ended 31 December 2009 compared with the year ended 31 December 2008 was lower realizations. In addition, the result was impacted by lower income from equity-accounted entities and higher depreciation but the result benefited from higher production and lower costs, as a result of our continued focus on cost management.

Outlook

In 2011, we will seek to continuously drive operational risk reduction through the S&OR function. Through the restructuring into divisions, we intend to drive functional excellence across the lifecycle of exploration, developments and production and continue to focus on building our technological and human 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. We will continue to actively manage our portfolio with a focus on value growth.

Upstream activities

Exploration

The group explores for oil and natural gas under a wide range of licensing, joint venture and other contractual agreements. We may do this alone or, more frequently, with partners. BP acts as operator for many of these ventures. Our exploration and appraisal costs, excluding lease acquisitions, in 2010 were $2,706 million, compared with $2,805 million in 2009 and $2,290 million in 2008. 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 80% of 2010 exploration and appraisal costs were directed towards appraisal activity. In 2010, we participated in 479 gross (95.5 net) exploration and appraisal wells in 10 countries. The principal areas of exploration and appraisal activity were Egypt, the deepwater Gulf of Mexico, Libya, the North Sea, Oman and onshore US.

Total exploration expense in 2010 of $843 million (2009 $1,116 million and 2008 $882 million) included the write-off of expenses related to unsuccessful drilling activities in the deepwater Gulf of Mexico ($161 million), the North Sea ($42 million), Libya ($26 million), Angola ($24 million) and others ($4 million). It also included $157 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 18,071mmboe (12,077mmboe for subsidiaries and 5,994mmboe for equity-accounted entities) at 31 December 2010, a decrease of 1% (decrease of 4% for subsidiaries and increase of 6% for equity-accounted entities) compared with the 31 December 2009 reserves of 18,292mmboe (12,621mmboe for subsidiaries and 5,671mmboe for equity-accounted entities). Natural gas represented about 41% (54% for subsidiaries and 14% for equity-accounted entities) of these reserves. The change includes a net decrease from acquisitions and disposals of 307mmboe (303mmboe net decrease for subsidiaries and 4mmboe net decrease for equity-accounted entities). Acquisitions occurred in Azerbaijan, Canada, Norway and the US. Disposals occurred in Canada, Egypt and the US.

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 2010 the proved reserves replacement ratio excluding acquisitions and disposals was 106% (129% in 2009 and 121% in 2008) for subsidiaries and equity-accounted entities, 74% for subsidiaries alone and 166% for equity-accounted entities alone.

In 2010, net additions to the group s proved reserves (excluding production and sales and purchases of reserves-in-place) amounted to 1,503mmboe (686mmboe for subsidiaries and 818mmboe for equity-accounted entities), principally through 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 67% were associated with new projects and were proved undeveloped reserves additions. The remaining additions are in existing developments where they represent a mixture of proved developed and proved undeveloped reserves. Volumes added in 2010 principally relied on the application of conventional technologies. The principal reserves additions in our subsidiaries were in the US (Arkoma, Hawkville, Kuparuk, Mars, Prudhoe Bay,Thunder Horse,Tubular Bells), the UK (Kinnoull, Loyal, Machar, Schiehallion), Egypt (West Nile Delta),Trinidad (Immortelle) and Iraq (Rumaila). The principal reserves additions in our equity-accounted entities were in Argentina (Cerro Dragon), Bolivia (Margarita), Canada (Sunrise) and in Russia (Samotlor, Sorochinsko-Nikolskoye, Talinskoye, Uvat).

Fourteen per cent of our proved reserves are associated with production-sharing agreements (PSAs). The main countries in which we operated under PSAs in 2010 were Algeria, Angola, Azerbaijan, Egypt, Indonesia, Iraq and Vietnam.

Production

Our total hydrocarbon production during 2010 averaged 3,822 thousand barrels of oil equivalent per day (mboe/d). This comprised 2,493mboe/d for subsidiaries and 1,329mboe/d for equity-accounted entities, a decrease of 7% (decreases of 12% for liquids and 2% for gas) and an increase of 1% (increases of 1% for liquids and 3% for gas) respectively compared with 2009. In aggregate, after adjusting for entitlement impacts in our PSAs and the effect of acquisitions and disposals, production was 2% lower than 2009. For subsidiaries, 39% of our production was in the US, 18% in Trinidad and 9% in the UK.

We expect production in 2011 to be lower than in 2010 as a result of disposals, lower production from the Gulf of Mexico and the increased turnaround activity to improve the long-term reliability of the assets. As a result of these factors, reported production in 2011 is expected to be around 3,400mboe/d. The actual outcome will depend on the exact timing of disposals, the pace of getting back to work in the Gulf of Mexico, OPEC quotas and the impact of the oil price on our PSAs. In the Gulf of Mexico, there is industry-wide uncertainty around the pace at which new drilling activity will be restored following the lifting of the drilling moratorium in October 2010. No new permits for the drilling of deepwater wells (except for water injection and side track wells) had been issued to any company until the end of February 2011. BP has clear criteria for safely restarting drilling and completions activity, which include meeting all new regulatory requirements, addressing each of the recommendations of our internal investigation, compliance with our own standards and ensuring we have the right capability in place, along with appropriate contractor management.

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 2010, we continued to grow our portfolio of assets through acquisitions such as the transaction with Devon Energy, which significantly enhanced our position in a number of core strategic areas in Brazil, Azerbaijan and deepwater Gulf of Mexico, and the increase in our equity holding in the Valhall and Hod fields, potentially very significant fields in the North Sea with technological upsides.

We also undertook a number of disposals as part of our previously announced portfolio high-grading review. In total, these transactions generated $17 billion in proceeds during 2010 including prepayments of $6.2 billion for disposals yet to complete. See Financial statements Note 4 on page 163. With regards to proved reserves, 102mmboe were acquired in 2010, all within our subsidiaries while 408mmboe were disposed of (approximately 404mmboe for subsidiaries and approximately 4mmboe for equity-accounted entities).

Acquisitions

In March 2010, BP announced a broad-ranging transaction with Devon Energy to enhance its position in core strategic areas. BP agreed to pay Devon Energy $6.9 billion in cash for assets in Brazil, Azerbaijan and the US deepwater Gulf of Mexico.

In addition, BP sold to Devon Energy a 50% stake in BP s Kirby oil sands interests in Alberta, Canada, for $500 million. The parties have agreed to form a 50:50 joint venture, operated by Devon, to pursue the development of the interest. Devon committed to fund an additional $150 million of capital costs on BP s behalf.

In Brazil, subject to government and regulatory approvals, the transaction will give BP a diverse and broad deepwater exploration acreage position offshore Brazil with interests in eight licence blocks in the Campos and Camamu-Almada basins, as well as two onshore licences in the Parnaiba basin. The Campos basin blocks include three discoveries Xerelete, pre-salt Wahoo and Itaipu and the producing Polvo field.

In the US deepwater Gulf of Mexico, BP gained a high-quality portfolio with interests in some 240 leases, with a particular focus on the emerging Paleogene play in the ultra-deepwater. The addition of Devon s 30% interest in the major Paleogene discovery, Kaskida, gave BP a 100% interest in the project. The assets also included interests in four producing oilfields: Magnolia, Merganser, Nansen, and Zia, and one non-producing asset.

In Azerbaijan, acquisition of Devon s 3.29% (after pre-emption exercised by some of the partners) stake in the BP-operated Azeri-Chirag-Gunashli development increased BP s interest to 37.43%. The undeveloped Kirby oil sands leases are in the south-east of the Athabasca region of Alberta, close to the Devon-operated Jackfish development, which started production in 2007. BP and Devon have agreed an initial appraisal programme to assess the significant potential of the Kirby acreage and to establish a long-term development plan. In addition to forming the joint venture, BP and Devon have agreed to enter into a long-term heavy crude off-take agreement for production from the Kirby development as well as a portion of the production from some of Devon s other oil sands assets.

Also in March 2010, BP announced that it had entered into a partnership in Canada with Value Creation Inc. (VCI) to develop the Terre de Grace (TDG) oil sands lease, one of VCI s large oil sands leases, in the Athabasca region. BP is now the operator and majority partner for the partnership, with VCI and BP together providing strategic direction and guidance. TDG is a large, contiguous 185,000 acres of high-quality oil sands land with substantial delineation of the East Graceland area and further potential in the less-delineated remainder of the leases. In 2010, capital expenditure in relation to the formation of this partnership was $900 million.

On 1 September 2010, BP increased its equity holding in the significant Norwegian Valhall and Hod fields by acquiring 7.9% interest in the Valhall field and 12.5% in the Hod field from Total. The transaction increased the equity holding in Valhall to 35.95% and Hod to 37.5%. The final purchase consideration was $492 million. The acquisition is expected to strengthen BP s existing business in Norway and the North Sea.

In September 2010, BP announced an agreement with Devon Energy in which BP acquired 40.82% of Devon s existing share in Block 42/05 in the South China Sea. The remaining 59.18% of Devon s share was purchased by Chevron, who will be the operator in the exploration phase under the amendment agreements to the production-sharing contract with CNOOC. All pre-development spending will be incurred by BP and Chevron. During the development phase, CNOOC has the right to back-in to a 51% share in the project thus leaving working interest shares as follows: BP 20%, CNOOC 51%, Chevron 29%.

On 24 January 2011, BP exercised a preferential right to acquire Shell s working interest in the Marlin and Dorado producing fields for a total consideration of $257 million. This brings BP s working interest in both fields to 100%.

On 21 February 2011, Reliance Industries Limited and BP announced that they intend to form an upstream joint venture in which BP will take a 30% stake in 23 oil and gas production-sharing contracts that Reliance operates in India, including the producing KG D6 block, and form a 50:50 joint venture for the sourcing and marketing of gas in India. BP will pay Reliance Industries Limited an aggregate consideration of $7.2 billion, and completion adjustments, for the interests to be acquired in the 23 production-sharing contracts. Future performance payments of up to $1.8 billion could be paid based on exploration success that results in development of commercial discoveries. Reliance will continue to be the operator under the production-sharing contracts. Completion of the transactions is subject to Indian regulatory approvals and other customary conditions.

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Disposals

In July 2010, BP announced that it had entered into several agreements to sell upstream assets in the US, Canada and Egypt to Apache Corporation (and an existing partner that exercised pre-emption rights). The deals, together worth a total of $7 billion, comprise BP s Permian Basin assets in Texas and south-east New Mexico, US; its Western Canadian upstream gas assets; and the Western Desert business concessions and East Badr El-din exploration concession in Egypt. These transactions were completed during 2010.

On 3 August 2010, BP announced that it had agreed to sell its oil and gas exploration, production and transportation business in Colombia to a consortium of Ecopetrol, Colombia s national oil company (51%), and Talisman of Canada (49%). The two companies agreed to pay BP a total of $1.9 billion in cash, subject to customary post-completion price adjustments, for 100% of the shares in BP Exploration Company (Colombia) Limited (BPXC), the wholly-owned BP subsidiary company that held BP s oil and gas exploration, production and transportation interests in Colombia. Following the approval of the Colombian authorities, completion occurred on 24 January 2011.

On 31 August 2010, BP completed the sale of its entire interest in the Overthrust assets (Painter Complex Gas Plant, Painter Reservoir Unit and Whitney Canyon field and inlet facility) to Merit Energy Company for $217 million.

On 18 October 2010, BP announced it had reached agreement to sell its upstream businesses and associated interests in Venezuela and Vietnam to TNK-BP for a total of $1.8 billion subject to customary post-completion price adjustments. The agreement includes BP s interests in the Petroperijá, Boquerón and PetroMonagas joint ventures in Venezuela and, in Vietnam, BP s 35% operating interest in the Lan Tay and Lan Do gas fields (Block 6.1) and associated pipeline and power generation interests. Block 6.1 partners, PetroVietnam and ONGC Videsh Ltd, have waived pre-emption rights to purchase BP s Block 6.1 interest. BP will retain an economic interest in these assets through its 50% interest in TNK-BP.

In October 2010, BP announced it had reached an agreement with its partner, Hess Corporation, for the sale of a 20% interest in the Tubular Bells field in the Gulf of Mexico. Hess agreed to acquire the 20% interest from BP for $40 million and became the operator. The increased ownership brought Hess s working interest in Tubular Bells to 40%. Chevron holds a 30% interest and BP retains 30%. Tubular Bells, which was discovered in 2003, is a deepwater field approximately 135 miles south-east of New Orleans, Louisiana.

On 25 October 2010, BP announced that it had reached agreement to sell its recently acquired interests in four mature producing deepwater oil and gas fields in the US Gulf of Mexico to Marubeni Oil and Gas for $650 million. BP acquired the interests in the fields Magnolia, Merganser, Nansen and Zia from Devon Energy earlier in 2010 as part of the wider acquisition of assets in the Gulf of Mexico, Brazil and Azerbaijan, but determined that they did not fit well with the rest of the group s assets in the region and would be of more value to another company.

On 28 November 2010, BP announced that it had entered into an agreement to sell its interests in Pan American Energy (PAE) to Bridas Corporation. PAE is an Argentina-based oil and gas company owned by BP (60%) and Bridas Corporation (40%). Bridas Corporation will pay BP a total of $7.06 billion in cash for BP s interest in PAE. The transaction is expected to be completed in 2011. The transaction excludes the shares of PAE E&P Bolivia Ltd. Completion of the transaction is subject to closing conditions including the receipt of all necessary governmental and regulatory approvals.

On 14 December 2010, BP announced that it had reached agreement to sell its upstream assets in Pakistan to United Energy Group for $775 million. Subject to certain closing conditions, including the receipt of all necessary governmental and regulatory approvals, closing is anticipated to occur by the end of the first quarter of 2011.

During 2010, BP also announced its intention to divest its interest in the Tuscaloosa fields in Louisiana, the Wattenberg plant in Colorado and its NGL business in Canada.

On 22 February 2011, BP announced its intention to sell its interests in a number of operated oil and gas fields in the UK. The assets involved are 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. BP aims to complete the disposals around the end of 2011, subject to receipt of suitable offers and regulatory and third party approvals. 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 these intended transactions.

The following discussion reviews operations in our Exploration and Production business by continent and country, and lists associated significant events that occurred in 2010. Where relevant, 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.

In July 2010, the UK Parliament s Energy and Climate Change Select Committee launched an investigation into the safety of deepwater drilling in the UK, in light of the accident in the Gulf of Mexico. In September, BP provided both written and oral evidence to the Committee, as did a number of other operators and organizations with a stake in the UK Continental Shelf (UKCS).

In the UK, BP has been closely involved in communicating the lessons learned from the Gulf of Mexico oil spill to industry and the regulatory authorities, and has also been widely represented in the Oil Spill Prevention and Response Advisory Group (OSPRAG), a group formed in late May to co-ordinate and lead the UK s response to such incidents. BP has provided support, for example, through the transfer of two containment devices to Oil Spill Response Limited s Southampton depot and by leading the design and procurement of a capping stack for use in the deepwater of the UKCS. The capping stack project is due for completion in mid-2011.

The European Commission published its policy and pre-legislative communication on offshore safety in October 2010. Preparation of a draft legislative package is now with the European Commission services, for expected publication in spring 2011.

BP is scheduled to drill a deepwater exploration well in the west of Shetland during 2011 and, together with its drilling contractor, plans to implement all relevant lessons from the Gulf of Mexico accident during the planning and execution of that well. Much has already been done during 2010 in the North Sea business to further improve the safety of drilling operations.

In October 2010, BP was awarded interests in seven offshore exploration blocks in the 26th round of UK Continental Shelf licensing. Five of these blocks are BP-operated and two are partner-operated. This represents the largest licence award for BP in the UK for more than 10 years.

On 27 October 2010, the European Union followed the UN and US in enacting further restrictive measures against Iran (the EU Regulations). The EU Regulations target, among other things, legal persons, entities or bodies outside of Iran that have direct or indirect Iranian ownership.

On 16 November 2010, production from the Rhum gas field in the central North Sea was suspended pending clarification from the UK government on certain aspects of the EU Regulations. This action was taken to comply with the notification requirements in the EU Regulations. Rhum is owned by BP (50%) and the Iranian Oil Company (50%) under a joint operating agreement dating back to the early 1970s.

Rest of Europe

Our activities in the Rest of Europe are in Norway.

On 9 November 2010, the development of the Norwegian oil and gas field Skarv reached a significant milestone with the naming ceremony of the Skarv Floating Production, Storage and Offloading (FPSO) unit. The ceremony took place in Geoje in South Korea. The vessel will operate in the Norwegian Sea close to the Arctic Circle, 210km off the coast of Nordland. It is due to start production at the Skarv oil and gas field in the autumn of 2011.

In 2010, the Valhall redevelopment project passed a major milestone with the completion of the heavy lift programme. The main deck and living quarters were successfully installed offshore in July 2010. The living quarters are scheduled to be ready for habitation in April 2011, with production start-up from the new facility scheduled for early 2012.

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 impact of the Gulf of Mexico oil spill and BP s response please see pages 34-39. Also see page 43 under Production.

On 31 March 2010, first oil was achieved from the Great White field (BP 33.3%) located in the ultra-deep waters of the Gulf of Mexico. Production is processed by the Perdido Regional Host floating production facility (BP 27.5%), an integrated spar and drilling rig. The development is operated by Shell on behalf of BP and Chevron. Great White marks the first development of a Paleogene (Lower Tertiary) reservoir in the Gulf of Mexico and is expected to represent 80% of the estimated total production through the Perdido Host.

In September 2010, the final investment decision was made for the Mars B (BP 28.5%) deepwater development, located approximately 130 miles south of New Orleans, Louisiana in the Gulf of Mexico. The development will include a second tension-leg platform, named Olympus, to enhance recovery from the Mars field. The Mars B development will draw production from eight Mississippi Canyon blocks 762, 763, 764, 805, 806, 807, 850 and 851.

In March 2010, BP participated in lease sale 213. Following this sale we were awarded 18 leases, 11 of which have now been executed, a further seven leases were awarded but have not yet been executed.

Lower 48 states

Our North America Gas business operates onshore in the Lower 48 states producing natural gas, natural gas liquids and coalbed methane across 14 states. In 2010, we drilled over 200 wells as operator across the US, including start-up operations in the Eagle Ford shale. Shale gas assets are becoming an increasingly important part of our North America Gas business.

We have not included any proved undeveloped reserves expected to commence development beyond five years in our disclosed volumes, although we are committed to development beyond five years in many fields.

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.

Two key aspects of BP s business strategy in Alaska are commercializing the large undeveloped natural gas resource within our 26.4% interest in Prudhoe Bay and unlocking the large undeveloped viscous and heavy oil resources within existing North Slope fields through the application of advanced technology.

In 2010, we progressed the previously announced development activities for the Liberty oilfield, which is located on federal leases about six miles offshore in the Beaufort Sea, and east of the Prudhoe Bay oilfield. The planned development includes up to six ultra-extended reach wells, including four producers and two injectors, to be drilled from existing infrastructure in the BP-operated Endicott field to minimize the onshore and offshore environmental footprint. As part of a continuous evaluation of project design, materials, and systems, we suspended physical construction of the rig on-site in the fourth quarter. Following a review of engineering and design elements, and resolution of any issues, we plan to continue rig construction. As this review moves forward, we will develop a revised project schedule. BP drilled the Liberty discovery well in 1997, and is the operator and sole owner of the field.

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. At the end of 2006, based on the DNR s termination of the Unit, BP wrote off all historical costs associated with the PTU. In January 2009, ExxonMobil was granted permission by the DNR, under a conditional interim decision, to conduct drilling operations on two of the 31 leases comprising the PTU. On 11 January 2010, the Alaska Superior Court reversed the DNR s administrative decision to terminate the unit. The DNR petitioned the State of Alaska Supreme Court for limited review, and the petition was granted in the second quarter of 2010. As of the end of 2010, the case is still pending before the Alaska Supreme Court. ExxonMobil and the State of Alaska have also informed the other unit owners, including BP, that they are negotiating a settlement agreement. BP has asked to participate in the settlement discussions.

Canada

In Canada, BP is focused on one of the world s largest petroleum resource basins, Canada s oil sands, using in-situ technology. In-situ technology is different to mining in that it limits land disturbance and requires no tailing ponds. The in-situ technology that BP Canada plans to use is steam-assisted gravity drainage (SAGD) which 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 and natural gas liquids, markets natural gas, is the largest marketer in Canada of natural gas liquids and has significant exploration interests in the Canadian Beaufort Sea.

In November 2010, phase 1 of the Sunrise oil sands project (BP 50%) was sanctioned. BP and its partner, Husky Energy Inc, have committed funding to build facilities, drill wells and create the operational systems and resources to bring Sunrise phase 1 into production. First production of bitumen is expected in 2014, building to 60,000 barrels per day gross capacity over the subsequent 24 months. Long-term drilling and facility development is planned to continue thereafter in order to maintain that rate for 40 years or more. Future additional phases of Sunrise are being contemplated.

In July 2010, BP signed a joint operating agreement with ExxonMobil Canada Limited and Imperial Oil Resources Ventures Limited, a subsidiary of ExxonMobil, to exchange 50% of BP s working interest in the EL 449 field for 50% working interest in Imperial/Exxon s EL 446 field, both in the Canadian Beaufort Sea. Under this agreement, operatorship was assigned to Imperial with BP remaining actively involved in major exploration decisions.

In 2010, interpretation of the 2009 3D-seismic survey of licences in the Canadian Beaufort Sea commenced and access to seismic data for the EL 446 licence was acquired.

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South America

Trinidad & Tobago

BP holds exploration and production licences covering 904,000 acres offshore of the east coast. Facilities include 13 offshore platforms and one onshore processing facility. Production comprises oil, gas and NGLs.

On 21 April 2010, BP Trinidad & Tobago s (bpTT) Serrette platform was installed in Trinidad waters in bpTT s east coast offshore acreage. The Serrette platform is located 51 kilometres north of bpTT s Mango development. It represents the first development in the northern area of bpTT s Columbus Basin acreage and has been equipped to enable future development opportunities in this area. Serrette, bpTT s thirteenth offshore production platform, is the fifth normally unmanned installation (NUI), designed and constructed in Trinidad &Tobago. The Serrette project was sanctioned in May 2009 and has a design capacity of 1 billion cubic feet per day and will deliver a peak production of 500 million standard cubic feet per day. The platform will tie into the Cassia B platform. Drilling is expected to commence in the first quarter of 2011 and production is planned for the second quarter of 2011.

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% equity in the first Angolan LNG project.

In August 2010, Total, as operator of Block 17 (BP 16.67%), announced the development of the Cravo Lirio Orquidea Violeta (CLOV) project and the award of the principal contracts. This project is the fourth development in Angola s deepwater offshore Block 17, after Girassol, Dalia and Pazflor, and is located approximately 140 kilometres from Luanda and 40 kilometres north-west of Dalia in water depths ranging from 1,100 to 1,400 metres. The CLOV development will lead to four fields coming onstream. Drilling is expected to start in 2012 and first oil is expected in 2014. A total of 34 subsea wells are planned to be tied back to the CLOV FPSO unit, which will have a processing capacity of 160mb/d and a storage capacity of approximately 1.8 million barrels.

Sanctioned in 2008, PSVM comprises the development of the Plutão, Saturno, Vênus and Marte fields, in a water depth of approximately 2,000 metres, some 400 kilometres north-west of Luanda. In 2010, BP commenced the offshore stage of this major project with the arrival of several vessels into Angola waters. Pile installation has been completed and installation of the production flowlines started. Parallel to this, in Singapore the PSVM FPSO was modified to include the new Turret Support Structure. Oil production from PSVM is scheduled to start in 2011.

The remaining discoveries in Block 31 will be developed through hubs similar to the first development, PSVM.

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 2010, the In Salah compressions project successfully achieved first gas.

During 2010, the next phase of the In Amenas development was approved with the award of the engineering primary contracts for compression. The In Salah Southern Fields project is expected to be approved in early 2011 with first gas for both projects expected by 2014.

In September 2010, the Algerian government approved an extension to the second prospecting period for the Bourarhet Sud block.

Libya

In Libya, BP is in partnership with the Libyan Investment Corporation (LIC) 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 net assets in Libya at 31 December 2010 were $212 million.

The first phase of the offshore 3D seismic acquisition was completed in October 2009, fulfilling BP s marine 3D seismic commitment. The programme covered a surface area of 17,000 square kilometres and was the largest offshore 3D proprietary survey ever undertaken by an international energy company. It involved the deployment of the largest and most powerful data-processing facility ever installed on a seismic vessel and included a technology trial of a multi-azimuth (MAZ) seismic technique, the first ever three-azimuth seismic survey in Libyan waters.

The onshore 3D seismic acquisition in BP s Ghadames acreage commenced in November 2008 and is ongoing. This 14,000 square kilometre commitment represents one of the largest single 3D land seismic commitments in the industry.

The programme involves the first at-scale deployment of the ISS seismic acquisition technology, a cutting-edge proprietary BP technique using independent simultaneous sources that is allowing BP to operate one of the most efficient land seismic programmes in the world today. The technology has enabled BP to acquire high-quality, densely-sampled 3D land data for the same cost as 3D marine or 2D land data while minimizing environmental impacts, a major achievement for the industry.

Due to the outbreak of political unrest in Libya, the BP office in Tripoli was closed on 21 February 2011 and our Libyan operations suspended. All BP expatriate staff and their families have been evacuated from Libya. Currently, it is not possible to say what impact the ongoing unrest, potential political changes and international sanctions will have on the now-suspended seismic operations and start-up of the exploration drilling programme which had been scheduled to commence onshore and offshore in 2011.

Egypt

BP has a long-standing history in Egypt, successfully operating there for over 45 years. To date BP has produced almost 40% of Egypt s entire oil production and supplies more than 35% of the domestic gas demand with its partners. In 2010, BP Egypt production was 133mboe/d. Net assets at 31 December 2010 were $6,107 million. BP is working to meet Egypt s domestic market growth by actively exploring in the Nile Delta and investing to add production from existing discoveries.

In July 2010, BP signed a new agreement with the Egyptian Ministry of Petroleum and the Egyptian General Petroleum Corporation to develop the significant hydrocarbon resources in the North Alexandria and West Mediterranean deepwater concessions. Production from the West Nile Delta development, at an estimated investment of $9 billion gross, is projected to reach up to 1 billion cubic feet per day, providing a major new source of gas for the domestic market in Egypt. The first phase will develop gas and associated condensate through subsea development of five offshore fields into a new purpose-built onshore gas plant on Egypt s Mediterranean coast. First gas is expected in late 2014. The new agreement amends the commercial terms and the governance structure for the two concessions located in the West Nile Delta, enabling BP and its partner, RWE Dea, to proceed with the development.

On 24 November 2010, BP announced that it has made a significant gas discovery in the deepwater West Nile Delta area. The Hodoa discovery is located in the West Mediterranean deepwater Nile Delta concession, some 80 kilometres northwest of Alexandria. The WMDW-7 well was drilled to a depth of 6,350 metres and is the first Oligocene deepwater discovery in the West Nile Delta area. Further appraisal is under way. BP operates and holds 80% of the West Mediterranean deepwater concession with RWE Dea holding the remaining 20%. Hodoa was drilled by the Pride North America semi-submersible rig, in a water depth of 1,077 metres.

Due to the recent significant political unrest in Cairo and other major cities in Egypt, the BP Egypt office in Cairo was closed from 28 January for a period of 10 days. Furthermore, BP expatriate staff and their families were evacuated from Egypt. The BP Egypt office was reopened on 7 February, and national staff returned to work. Most expatriate staff and families returned to Egypt during February. Production at BP Egypt s joint ventures (GUPCO and PHP) was not affected by the office closures. The office closure and staff evacuation will have some short-term impacts on project activity. On 11 February, President Mubarak resigned and handed over power to the Supreme Council of the Egyptian Armed Forces. Currently, it is not possible to say what impact, if any, future politicial changes will have on the BP Egypt business.

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.

In June 2010, BP was awarded joint study rights with the Indonesia Directorate General of Oil and Gas on the West Sanga Sanga block immediately adjacent to the Sanga-Sanga PSA. This study involves gathering, processing and interpreting data to evaluate the viability of a coalbed methane (CBM) project in the area. The award of the joint study secures matching rights for BP and its partner over the 3,500-square kilometre area when the area will be tendered for production-sharing contracts (PSC), allowing them to change their bid to match that of the highest bidder at that time.

China

BP s upstream asset in the country is the Yacheng offshore gas field (BP 34.3%) in the South China Sea, one of the biggest offshore gas fields in China. Yacheng supplies the Castle Peak Power Company gas for up to 70% of Hong Kong s gas-fired electricity generation. Additional gas is also sold to the Hainan Holdings Fuel & Chemical Corporation Limited.

On 12 January 2011, BP announced that it had signed a new agreement with the China National Offshore Oil Corporation (CNOOC) for deepwater exploration in Block 43/11 in the South China Sea, subject to partner and government approval.

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.

On 9 March 2010, the steering committee for the development of the ACG field sanctioned investment in the Chirag Oil Project (COP). This is the next major capital investment in the ongoing development of the ACG field in the Azerbaijan sector of the Caspian Sea. The project is planned to increase oil production and recovery from the field through a new offshore facility which is designed to fill a critical gap in the field infrastructure between the existing Deepwater Gunashli and Chirag-1 platforms.

On 7 June 2010, the government of Azerbaijan and the government of Turkey signed a Memorandum of Understanding (MOU) as part of a package of documents that will regulate the sale of Azerbaijani gas to Turkey and transit terms for transportation of the gas to the European markets through the territory of Turkey. This marks a major step forward towards conclusion of required agreements for Shah Deniz Stage 2 gas sales to Turkey and beyond, and is a milestone that underpins the significance of the Stage 2 development plans and paves the way for the project to move forward towards a final investment decision by the Shah Deniz partnership. At this stage, discussions to define the best option for further gas marketing and sales continue and these are led by the Azerbaijani government in conjunction with the Shah Deniz partnership.

On 7 October 2010, BP and the State Oil Company of the Republic of Azerbaijan (SOCAR) signed a new PSA for the joint exploration and development of the Shafag-Asiman structure in the Azerbaijan sector of the Caspian Sea. Under the PSA, which is for 30 years, BP will be the operator with 50% working interest and SOCAR will hold the remaining 50% equity. The block lies some 125 kilometres (78 miles) to the south east of Baku. It covers an area of some 1,100 square kilometres and has never been explored before. It is located in a deepwater section of about 650-800 metres with reservoir depth of about 7,000 metres.

On 24 December 2010, BP and its partners received a five-year PSA extension for Shah Deniz from SOCAR. The PSA extension allows the Shah Deniz partners to negotiate new long-term gas contracts and underpins the economics of the project.

During 2010, the remedial work necessary following the subsurface gas release that occurred beneath the Central Azeri platform in September 2008 was completed. With the exception of two wells that were abandoned, all wells on the Central Azeri platform are online and in service.

Naftiran Intertrade Co (NICO) Ltd is an Iranian company and has a less than 10% non-operating interest in Shah Deniz. NICO was selected as a Shah Deniz project participant by the State of Azerbaijan when the Shah Deniz PSA was awarded in June 1996. 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.

Russia

On 14 January 2011, BP and Rosneft[a] announced a strategic global alliance. Rosneft and BP have agreed to explore and develop three licence blocks in Russia s South Kara Sea covering approximately 125,000 square kilometres. Additionally, BP has agreed to issue 988,694,683 ordinary BP shares to Rosneft (representing 5% of BP) in a swap where Rosneft has agreed to transfer 1,010,158,003 ordinary Rosneft shares to BP (representing 9.5% of Rosneft). Finally, BP and Rosneft have agreed to other joint pursuits including the establishment of an Arctic technology centre in Russia, joint technical studies in the Russian Arctic beyond the South Kara Sea area and the search for additional international collaboration opportunities. The share swap transaction is subject to certain listing approvals and the completion of certain administrative requirements. The share swap agreement is subject to the outcome of arbitration proceedings between BP and Alfa Petroleum Holdings Limited (APH) and OGIP Ventures Limited (OGIP) who have raised issues relating to the share swap agreement and the alliance. APH is a company owned by Alpha Group. APH and OGIP each own 25% of TNK-BP in which BP also has a 50% shareholding. See further information in Legal proceedings on page 133.

TNK-BP

TNK-BP, an associate owned by BP (50%) and Alfa Group and Access-Renova (AAR) (50%), is an integrated oil company operating in Russia and Ukraine. BP s investment in TNK-BP is reported in the Exploration and Production segment. The TNK-BP group s major assets are held in OAO TNK-BP Holding. Other assets include the BP-branded retail sites in the Moscow region and interests in OAO Rusia Petroleum and the OAO Slavneft group. The workforce comprises more than 43,000 people.

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 715 thousand barrels per day. TNK-BP supplies approximately 1,400 branded filling stations in Russia and Ukraine and has more than 25% market share of the Moscow retail market.

[a] BP already holds a 1.3% investment in Rosneft Oil Company with a carrying value of $948 million.

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On 17 February 2010, the TNK-BP board of directors endorsed investment projects totalling more than $1.8 billion to be spent in 2010 2012. Of this amount, $1.7 billion is allocated for two major upstream projects: full field development and creation of regional infrastructure in the eastern part of the Uvat group of fields and further development of the Verkhnechonskoye oilfield in East Siberia. Members of the board also endorsed TNK-BP s participation in a joint venture between National Petroleum Consortium LLP and Petroleos de Venezuela (PDVSA), the state oil company of Venezuela, to appraise and develop the JUNIN 6 block in Venezuela and to release funding of $180 million to support these activities in 2010 2012.

On 28 May 2010, TNK-BP announced completion of a deal to acquire 100% of the Vik Oil group of companies in the Ukraine. Previously Vik Oil owned 118 fuel stations in 13 Ukrainian regions, as well as 8 oil depots, 49 petrol tankers and 122 land plots in various stages of development. TNK-BP paid $302 million for these interests.

On 28 February 2011, TNK-BP announced that it had sold its interest in the Kovykta gas field to Gazprom.

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. During the year, Elvary Neftegaz, via its Russian affiliate, held geological and geophysical studies licences with the Russian Ministry of Natural Resources and Ecology (MNRE) to perform exploration seismic and drilling operations in a licence area off the east coast of Russia. To date, 2D and 3D seismic data has been acquired and four wells have been drilled in the licence area. In 2010, additional electromagnetic surveys were performed in advance of future drilling commitments. In the fourth quarter of 2010, the value of BP s investment in Sakhalin was written-down to reflect the current outlook on the future recoverability of the investment.

Middle East and Pakistan

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.

On 3 January 2010, BP received approval from the government of Jordan to join the state-owned National Petroleum Company to exploit the onshore Risha concession in the north-east of the country. BP established an office in February and has started its exploration and appraisal work programme, including commencement of a 5,000-square kilometre seismic programme.

On 11 October 2010, after 32 years as operator of the Sharjah concession area, BP agreed to transfer its operatorship of the concession to the government of Sharjah. BP will retain its equity ownership of 40% of the concession until expiry in November 2013.

During 2010, major milestones achieved in the Oman Khazzan Makarem gas appraisal programme included the award of the contract for early engineering, design and concept studies for the potential long-term development of hydrocarbon resources in the block, and the commissioning of early well test facilities.

Iraq

Following a successful bid with PetroChina to run the Rumaila oil field in June 2009, the technical service contract (TSC) became effective on 17 December 2009. BP holds a 38% share and is the lead contractor. Rumaila is one of the world s largest oilfields and was discovered by BP in 1953. It currently produces approximately half of Iraq s oil exports and comprises five producing reservoirs. BP together with its partners is actively refurbishing the wells and facilities.

On 1 July 2010, the Rumaila Operating Organization (ROO) was established and began to take over operatorship of the Rumaila oilfield from South Oil Company (SOC), one of the state-owned oil companies in Iraq. The ROO is made up of approximately 4,000 assignees from BP, PetroChina and SOC, and its creation is one of the first steps in the plan to grow Rumaila production to 2.85 million barrels per day over the next few years.

In September 2010, BP and PetroChina, as the international partners in the ROO, signed an agreement with the British Council to fund dedicated English language tuition for approximately 500 employees of the ROO. The British Council teachers will be based in the Rumaila oilfield and provide training for the current English language teachers in SOC and the local North Rumaila Village school. According to the TSC, BP and PetroChina are required to spend $5 million per year on education and this agreement with the British Council is the first major programme funded as part of this commitment.

In December 2010, as a result of increasing activity throughout 2010, production was sustained at 10% above the initial production rate to achieve the improved production target which is the first significant milestone in the rehabilitation of Rumaila. Achievement of IPT was formally agreed with the Government of Iraq on 25 December 2010 and consequently the Contractors (BP and PetroChina) in accordance with the TSC, become eligible for Service Fees during 2011.

Australasia

Australia

BP is one of seven partners in the North West Shelf (NWS) venture. Six partners (including BP) hold an equal 16.67% interest in the infrastructure and oil reserves and an equal 15.78% interest in the gas and condensate reserves, with a seventh partner owning the remaining 5.32% of gas and condensate reserves. 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.

The North Rankin 2 project linking a second platform to the existing North Rankin A platform, sanctioned in 2008, remains on track for start-up in late 2012. On completion, the North Rankin A and North Rankin B platforms will operate as a single integrated facility and recover low-pressure gas from the North Rankin and Perseus gas fields.

The Janz-lo field (BP 5.375%) development, which is part of the Greater Gorgon project, is on track. The Jansz-lo field will be developed as part of the Greater Gorgon project, which will comprise three LNG trains, each with a capacity of 5 million tonnes per annum (mtpa), on Barrow Island, with first gas expected in 2014. As part of this, a unitization and unit operating agreement has been executed with the joint venture partners and sales and purchase agreements for the wellhead sale of raw gas and repurchase of LNG ex-Barrow Island have been executed between BP and Shell.

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.

Eastern Indonesia

On 26 November 2010, BP was awarded a 100% interest in the North Arafura oil and gas PSA in onshore Papua province. The PSA was signed in Jakarta by representatives of the government and BP. The North Arafura PSA is located on the coast of the Arafura Sea, 480 kilometres south east of the BP-operated Tangguh plant, covering an area of just over 5,000 square kilometres. BP expects to commence seismic operations on the block in the near future.

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 2010 by country.

BP s onshore US crude oil and product pipelines and related transportation assets are included under Refining and Marketing *(see page 55).*

[a] An LNG train is a processing facility used to liquefy and purify LNG.

Alaska

BP owns a 46.9% interest in the Trans-Alaska Pipeline System (TAPS), with the balance owned by four other companies. BP also owns a 50% interest in a joint venture company called Denali The Alaska Gas Pipeline (Denali). The remaining 50% of Denali is owned by a subsidiary of ConocoPhillips. The proposed Denali project consists of a gas treatment plant (GTP) on Alaska s North Slope, transmission lines from the Prudhoe Bay and Point Thomson fields to the GTP, an Alaska mainline that would run from the North Slope of Alaska to the Alaska-Yukon border, and a Canada mainline that would transport gas from the Alaska-Yukon border to Alberta. Also included are delivery points along the route to help meet local natural gas demand in Alaska and Canada. Denali s cost estimate for the GTP and pipelines is approximately $35 billion.

Denali conducted concurrent 90-day open season bidding processes for both the US and Canadian portions of the Denali project during the third quarter of 2010, the bidding for each concluded on 4 October 2010. Conditional bids were received for significant capacity from potential shippers. At the end of 2010, Denali is evaluating the bids received, and confidential negotiations with potential shippers continue in an effort to reach binding agreements. If agreements can be concluded for sufficient capacity, Denali will seek certification from the Federal Energy Regulatory Commission (FERC) of the US and the National Energy Board (NEB) of Canada to move forward with project construction. Denali would manage the project, and would own and operate the pipeline when completed. BP may consider other equity participants, including pipeline companies, that can add value to the project and help manage the risks involved.

On 12 January 2010, an agreement to settle challenges to TAPS carrier interstate tariff rate filings for the calendar year 2008 and the first half of 2009 was signed by the TAPS carriers and those challenging the tariffs at the US FERC. The agreement was approved by the US FERC on 1 April 2010. Under the terms of the settlement, in the second quarter of 2010 BP paid additional refunds to third-party shippers, amounting to $0.4 million, representing the $0.12/bbl difference between the $3.45/bbl tariff rate on which the interim refunds paid in 2009 for this period were based, and the $3.33/bbl tariff rate in the approved settlement agreement.

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 2010 of 598mboe/d. BP also operates and has a 29.5% 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 1,700mmcf/d to a natural gas terminal at Teesside in north-east England. CATS offers natural gas transportation and processing services. In addition, BP operates the Dimlington/Easington gas processing terminal (BP 100%) on Humberside and the Sullom Voe oil and gas terminal in Shetland.

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. BP is technical operator of, and holds a 25.5% interest in, the 693-kilometre South Caucasus Pipeline (SCP), which takes gas from Azerbaijan through Georgia to the Turkish border. 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).

On 21 July 2010, the BTC pipeline exceeded a daily average of 1 million barrels per day for the first time, recording a daily export figure of 1.057 million barrels. A Drag Reducing Agent (DRA) was utilized to achieve this milestone.

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 2010 included:

In Trinidad, BP s net share of the capacity of Atlantic LNG Trains[a] 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 LNG 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 and the Far East.

We have a 10% equity shareholding in the Abu Dhabi Gas Liquefaction Company, which in 2010 supplied 5.85 million tonnes (302,231mmscf) of LNG.

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 year 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 17 million tonnes of LNG in 2010.

Also in Indonesia, BP has its first operated LNG plant, Tangguh (BP 37.16%), in Papua Barat. The first phase of Tangguh, which is in its first full year of operations, comprises two offshore platforms, two pipelines and an LNG plant with two production trains with a total capacity of 7.6mtpa. The Tangguh project has six long-term contracts in place to supply LNG to customers in China, South Korea, Mexico and Japan.

In Australia, we are 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 2.7mtpa of LNG.

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 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, support 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 year due to the accessibility of shale gas and increased pipeline builds in North America. This has resulted in limited basis differentials and faster production responses to price. However, new markets are continuing to develop with continental European markets opening up and LNG becoming more liquid. The supply and trading function supported the group through a period of uncertainty in the credit markets concerning BP s financial position during the Gulf of Mexico oil spill.

[a] See footnote a on page 48.

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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 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 27 to the Financial statements on pages 185-190.

The range of contracts that the group enters into is described in Certain definitions commodity trading contracts, on page 82.

Oil and gas disclosures

The following tables provide additional data and disclosures in relation to our oil and gas operations.

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			Russia	Rest of Asia		
Average sales price[b]										
Subsidiaries										
2010										
Liquids[c]	**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[c]	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
2008										
Liquids[c]	89.82	93.77	89.22	64.42	91.61	89.44		97.20	86.33	90.20

Gas	8.41	6.96	6.77	7.87	4.90	4.46		3.63	9.22	6.00
Equity-accounted entities[d]										
2010										
Liquids[c]					**61.60**		**60.39**	**6.72**		**52.81**
Gas					**1.97**		**1.91**	**7.83**		**2.04**
2009										
Liquids[c]					51.01		47.27	5.59		41.93
Gas					1.90		1.51	5.25		1.68
2008										
Liquids[c]					56.39		73.7	4.80		61.39
Gas					1.97		1.68	10.53		1.94

[a] Units of production are barrels for liquids and thousands of cubic feet for gas.

[b] Realizations include transfers between businesses.

[c] Crude oil and natural gas liquids.

[d] 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			Russia	Rest of Asia		
The average production cost per unit of production[a]										
Subsidiaries										
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
2008	12.19	8.74	9.02	15.35	2.34	6.72		5.24	1.74	7.24
Equity-accounted entities										
2010					**6.32**		**5.04**	**0.97**		**4.26**
2009					6.12		4.63	0.94		3.95
2008					5.84		5.97	0.87		4.73

[a] Units of production are barrels for liquids and thousands of cubic feet for gas. Amounts do not include ad valorem and severance taxes.

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Licence expiry

The group holds no 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 recategorized 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.

Contingent resources in a field will only be recategorized 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. There are volumes of proved undeveloped reserves scheduled to commence after five years in Trinidad and Canada that are part of ongoing development activities for which BP has a historical track record of completing comparable projects. In all cases, the volumes are being progressed as part of an adopted development plan, which calls for drilling of wells over an extended period of time given the magnitude of the development.

Total development expenditure in Exploration and Production, excluding midstream activities, was $12,044 million in 2010 ($9,675 million for subsidiaries and $2,369 million for equity-accounted entities). The major areas converted in 2010 were Azerbaijan, Indonesia, Russia, Trinidad and the US.

In 2010, we converted 1,481mmboe of proved undeveloped reserves to proved developed reserves through ongoing investment in our upstream development activities. The table below describes the changes to our proved undeveloped reserves position through the year.

	volumes in mmboe
Proved undeveloped reserves at 1 January 2010	7,952
Revisions of previous estimates	(247)
Improved recovery	1,062
Discoveries and extensions	689
Purchases	74
Sales	(150)
Total in year proved undeveloped reserves changes	9,380
Progressed to proved developed reserves	(1,481)
Proved undeveloped reserves at 31 December 2010	7,899

BP bases its proved reserves estimates on the requirement of reasonable certainty with rigourous 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.

Business review

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. In addition, we are conducting a fundamental review of how the group incentivizes business performance, including reward strategy, with the aim of encouraging excellence in safety, compliance and operational risk management.

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 2010

Seventy-five per cent of our total proved reserves of subsidiaries at 31 December 2010 were held through unincorporated joint ventures (76% in 2009), and 31% of the proved reserves were held through such unincorporated joint ventures where we were not the operator (27% in 2009).

Estimated net proved reserves of liquids at 31 December 2010[a b c]

			million barrels
	Developed	Undeveloped	Total
UK	364	431	795
Rest of Europe	77	221	298
US	1,729	1,190	2,919[d]
Rest of North America			
South America	44	58	102[e]
Africa	371	374	745
Rest of Asia	269	325	594
Australasia	48	58	106

Subsidiaries	2,902	2,657	5,559
Equity-accounted entities	3,166	1,984	5,150[f]
Total	6,068	4,641	10,709

Estimated net proved reserves of natural gas at 31 December 2010[a b]

			billion cubic feet
	Developed	Undeveloped	Total
UK	1,416	829	2,245
Rest of Europe	40	430	470
US	9,495	4,248	13,743
Rest of North America	58		58
South America	3,575	6,575	10,150[g]
Africa	1,329	2,351	3,680
Rest of Asia	1,290	268	1,558
Australasia	3,563	2,342	5,905
Subsidiaries	20,766	17,043	37,809
Equity-accounted entities	3,046	1,845	4,891[h]
Total	23,812	18,888	42,700

Net proved reserves on an oil equivalent basis

			million barrels of oil equivalent
	Developed	Undeveloped	Total
Subsidiaries	6,481	5,596	12,077
Equity-accounted entities	3,691	2,303	5,994
Total	10,172	7,899	18,071

[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 2010 marker prices used were Brent \$79.02/bbl (2009 \$59.91/bbl and 2008 \$36.55/bbl) and Henry Hub \$4.37/mmBtu (2009 \$3.82/mmBtu and 2008 \$5.63/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 78 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 22 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[f] Includes 254 million barrels of crude oil in respect of the 7.03% minority interest in TNK-BP.

[g] Includes 2,921 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[h] Includes 137 billion cubic feet of natural gas in respect of the 5.89% minority interest in TNK-BP.

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BP s net production by major field for 2010, 2009 and 2008.

Liquids

Subsidiaries	Field or area	thousand barrels per day BP net share of production[a] **2010**	2009	2008
UK[b]	ETAP[c]	**28**	34	27
	Foinaven[d]	**24**	29	26
	Other	**85**	105	120
Total UK		**137**	168	173
Norway[b]	Various	**40**	40	43
Total Rest of Europe		**40**	40	43
Total Europe		**177**	208	216
Alaska	Prudhoe Bay[d]	**67**	69	72
	Kuparuk	**42**	45	48
	Milne Point[d]	**23**	24	27
	Other	**34**	43	50
Total Alaska		**166**	181	197
Lower 48 onshore[b]	Various	**90**	97	97
Gulf of Mexico deepwater[b]	Thunder Horse[d]	**120**	133	24
	Atlantis[d]	**49**	54	42
	Mad Dog[d]	**30**	35	31
	Mars	**23**	29	28
	Na Kika[d]	**25**	27	29
	Horn Mountain[d]	**14**	25	18
	King[d]	**21**	22	23
	Other	**56**	62	49
Total Gulf of Mexico deepwater		**338**	387	244
Total US		**594**	665	538
Canada[b]	Various[d]	**7**	8	9
Total Rest of North America		**7**	8	9
Total North America		**601**	673	547
Colombia	Various[d]	**18**	23	24
Trinidad & Tobago	Various[d]	**36**	38	38

Venezuela[b]	Various			4
Total South America		**54**	61	66
Angola	Greater Plutonio[d]	**73**	70	69
	Kizomba C Dev	**31**	43	30
	Dalia	**20**	32	34
	Girassol FPSO	**18**	22	22
	Other	**28**	44	46
Total Angola		**170**	211	201
Egypt[b]	Gupco	**47**	55	41
	Other	**12**	16	16
Total Egypt		**59**	71	57
Algeria	Various	**17**	22	19
Total Africa		**246**	304	277
Azerbaijan[b]	Azeri-Chirag-Gunashli[d]	**94**	94	97
	Other	**9**	7	8
Total Azerbaijan		**103**	101	105
Western Indonesia[b]	Various	**2**	5	7
Other	Various	**14**	17	16
Total Rest of Asia[b]		**119**	123	128
Total Asia		**119**	123	128
Australia	Various	**30**	31	29
Other	Various	**2**		
Total Australasia		**32**	31	29
Total subsidiaries[e]		**1,229**	1,400	1,263
Equity-accounted entities (BP share)				
Russia TNK-BP[b]	Various	**856**	840	826
Total Russia		**856**	840	826
Abu Dhabi[f]	Various	**190**	182	210
Other	Various	**1**	12	10
Total Rest of Asia[b]		**191**	194	220
Total Asia		**1,047**	1,034	1,046

Argentina	Various	**75**	75	70
Venezuela[b]	Various	**23**	25	19
Bolivia[b]	Various		1	3
Total South America		**98**	101	92
Total equity-accounted entities		**1,145**	1,135	1,138
Total subsidiaries and equity-accounted entities		**2,374**	2,535	2,401

[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 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 Tubular Bells and King fields 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. In 2008, BP concluded the migration of the Cerro Negro operations to an incorporated joint venture with PDVSA while retaining its equity position, and TNK-BP disposed of some non-core interests.

[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 29 net mboe/d of NGLs from processing plants in which BP has an interest (2009 26mboe/d and 2008 19mboe/d).

[f] The BP group holds interests, through associates, in onshore and offshore concessions in Abu Dhabi, expiring in 2014 and 2018 respectively.

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Business review
Natural gas

Subsidiaries	Field or area	million cubic feet per day BP net share of production[a] **2010**	2009	2008
UK[b]	Bruce/Rhum[c]	**100**	110	165
	Brae East	**46**	62	71
	Other	**326**	446	523
Total UK		**472**	618	759
Norway[b]	Various	**15**	16	23
Total Rest of Europe		**15**	16	23
Total Europe		**487**	634	782
Lower 48 onshore[b]	San Juan[c]	**629**	659	682
	Jonah[c]	**185**	227	221
	Arkoma Central	**164**	194	240
	Arkoma West	**128**	65	
	Arkoma East	**112**	67	
	Wamsutter[c]	**126**	146	136
	Other	**531**	597	607
Total Lower 48 onshore	Total	**1,875**	1,955	1,886
Gulf of Mexico deepwater[b]	Thunder Horse[c]	**80**	83	11
	Other	**183**	220	219
Total Gulf of Mexico deepwater		**263**	303	230
Alaska	Various	**46**	58	41
Total US		**2,184**	2,316	2,157
Canada[b]	Various	**202**	263	245
Total Rest of North America		**202**	263	245
Total North America		**2,386**	2,579	2,402
Trinidad & Tobago	Mango[c]	**544**	664	471
	Cashima/NEQB[c]	**679**	571	375
	Kapok[c]	**541**	540	619
	Cannonball[c]	**156**	225	336

	Amherstia[c]	**252**	197	288
	Other[c]	**301**	233	357
Total Trinidad		**2,473**	2,430	2,446
Colombia	Various	**71**	62	84
Venezuela[b]	Various			2
Total South America		**2,544**	2,492	2,532
Egypt[b]	Temsah	**90**	118	109
	Happy[c]	**73**	94	94
	Taurt[c]	**75**	73	24
	Other	**192**	177	145
Total Egypt		**430**	462	372
Algeria	Total	**126**	159	112
Total Africa		**556**	621	484
Pakistan[b]	Various[c]	**150**	173	162
Azerbaijan[b]	Various[c]	**132**	126	143
Western Indonesia[b]	Sanga-Sanga	**69**	71	69
	Other	**1**	35	97
Total Western Indonesia		**70**	106	166
China	Yacheng	**95**	83	91
Vietnam	Various[c]	**77**	63	61
Sharjah	Various[c]	**50**	59	73
Total Rest of Asia		**574**	610	696
Total Asia		**574**	610	696
Australia	Perseus/Athena	**165**	142	229
	Goodwyn	**118**	139	74
	Angel	**133**	120	6
	Other	**46**	39	71
Total Australia		**462**	440	380
Eastern Indonesia	Tangguh[c]	**323**	74	1
Total Australasia		**785**	514	381
Total subsidiaries[d]		**7,332**	7,450	7,277

Equity-accounted entities (BP share)

Russia TNK-BP[b]	Various	**640**	601	564
Total Russia		**640**	601	564
Western Indonesia	Various	**30**	31	31
Kazakhstan[b]	Various		11	8
Total Rest of Asia		**30**	42	39
Total Asia		**670**	643	603
Argentina	Various	**379**	378	385
Bolivia[b]	Various	**11**	11	63
Venezuela[b]	Various	**9**	3	6
Total South America		**399**	392	454
Total equity-accounted entities[d]		**1,069**	1,035	1,057
Total subsidiaries and equity-accounted entities		**8,401**	8,485	8,334

[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 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 Tubular Bells and King fields 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 it s interests in LukArco to Lukoil and the Bolivian government nationalized, with compensation payable, Pan American Energy s shares of Chaco. In 2008, BP concluded the migration of the Cerro Negro operations to an incorporated joint venture with PDVSA while retaining its equity position, and TNK-BP disposed of some non-core interests.

[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 business is responsible for the supply and trading, refining, manufacturing, marketing and transportation of crude oil, petroleum, petrochemicals products and related services to wholesale and retail customers. Within Refining and Marketing, BP markets its products in more than 70 countries. We have significant operations in Europe and North America and also manufacture and market our products across Australasia, in China and other parts of Asia, Africa and Central and South America.

Our organization is managed through two main business groupings: fuels value chains (FVCs) and international businesses (IBs). The FVCs integrate the activities of refining, logistics, marketing, supply and trading, on a regional basis, recognizing the geographic nature of the markets in which we compete. This provides the opportunity to optimize our activities from crude oil purchases to end consumer sales through our physical assets (refineries, terminals, pipelines and retail stations). The IBs operate on a global basis and include the manufacturing, supply and marketing of lubricants, petrochemicals, aviation fuels and liquefied petroleum gas (LPG).

Our market

The 2010 operating environment improved overall along with the global economy but was nevertheless still challenging in certain markets. Global oil demand grew by 2.8 million b/d, with growth in the OECD for the first time since 2005. However, aggregate OECD oil demand in 2010 remained 3.8 million b/d below the 2005 peak.

Annual BP global indicator refining margins in 2010 were slightly higher than 2009 levels although the quarterly variation was within a smaller range. Within the year, margins followed the pattern of a typical year, with a peak in the second quarter. However, fourth-quarter margins defied historic trends to exceed third-quarter levels because of early winter weather in the Northern Hemisphere. As a result, the BP global indicator refining margin (GIM), as defined in footnote (e) on page 56, averaged $4.44 per barrel in 2010. From 2011, we will be reporting a new refining indicator margin, replacing the GIM, which we call the refining marker margin (RMM). This adopts a basis that we believe is more closely related to the approach used by many of our competitors. RMMs are simplified regional margin indicators based on product yields and a representative 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. As a result it is numerically larger than the GIM and uses a much smaller product range.

In Europe, where diesel accounts for a large proportion of regional consumption, refining margins increased as demand for commercial transport improved with stronger economic activity. In the US, where refining is more highly upgraded and the transport market is more gasoline oriented, refining margins were slightly ahead of 2009. Refining margins improved the most in Asia Pacific compared to 2009, but still only averaged $1.63/bbl because of continued additions to refining capacity in the region.

Relatively wider fuel oil to crude differentials and light-heavy crude spreads benefited our highly upgraded refineries and had a positive impact on our financial performance in 2010 compared with 2009.

Although oil demand grew, 2010 was also characterized by very low market volatility in the oil markets. A balanced market in crude, together with record inventory levels, led the oil price to remain stable throughout 2010. After reaching record average levels in 2009, the volatility of dated Brent prices declined in 2010 to the lowest average level in percentage terms, since 1995. This contrast in the level of market volatility between early 2009 and 2010, led to a significantly weaker supply and trading contribution to the financial performance of Refining and Marketing.

In our IBs, demand for our petrochemicals products has improved from the low levels in late 2008 and early 2009 caused by the global recession. This has resulted in an improved environment overall, despite increases in industry capacity. In the aviation industry passenger numbers appear to have recovered from the depths of the financial crisis in 2008 and 2009. We have seen a recovery in demand for lubricants from the lows of the past two years in the automotive sector and most strongly in the industrial sector of the market following a marked decline in 2009. Within the context of overall demand, we continue to see a gradual shift towards higher-quality and higher-margin premium and synthetic lubricants. Base oil prices have risen throughout the year.

Our strategy

Refining and Marketing is the product and service-led arm of BP, focused on fuels, lubricants, petrochemicals products and related services. We aim to be excellent in the markets we choose to be in those that allow BP to serve the major energy markets of the world. We are in pursuit of competitive returns and sustainable growth, underpinned by safe manufacturing operations and technology, as we serve customers and promote BP and our brands through quality products.

We believe that key to success in Refining and Marketing is holding a portfolio of quality, integrated and efficient positions. The FVC strategy globally focuses on feedstock-advantaged, upgraded, well-located refineries integrated into advantaged logistics and marketing. In pursuit of this, in the US, we intend to divest our Texas City refinery and southern part of our West Coast FVC, including the Carson refinery, roughly halving our US refining capacity by the end of 2012, subject to all necessary legal and regulatory approvals. BP will ensure the fulfilment of the current regulatory obligations associated with the Texas City refinery is reflected in any transaction.

In our remaining US FVCs, as well as in our non-US FVCs, we believe we have a portfolio of well-located refineries, integrated with strong marketing positions offering the potential for improvement and growth, either through market growth, margin growth or new access.

Within the IBs, our strategy is to continue to grow these businesses, which are materially exposed to growth markets. Over time we expect to shift the balance of participation and capital employed from established to growth regions.

Our objective has been to improve our performance by focusing on achieving safe, reliable and compliant operations, restoring missing revenues and delivering sustainable competitive returns and cash flows. We intend to improve our financial performance[a] by at least $2 billion between 2009 and 2012, primarily underpinned by identified efficiency opportunities. We expect growth to result from the pursuit of further cost efficiencies, improved portfolio quality and capturing integration benefits as well as margin share growth. In addition, post 2012 we plan to grow our margin through the completion of the upgrade to our Whiting refinery, which is already under way.

We believe that these outcomes will enable us to be a leading player in each of the markets in which we choose to participate.

[a] This performance improvement will be measured by comparing Refining and Marketing s replacement cost profit 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 environment, foreign exchange impacts and price-lag effects for crude and product purchases.

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Our performance

Key statistics

			$ million
	2010	2009	2008
Sales and other operating revenues[a]	**266,751**	213,050	320,039
Replacement cost profit before interest and tax[b]	**5,555**	743	4,176
Capital expenditure and acquisitions	**4,029**	4,114	6,634
			thousand barrels per day
Total refinery throughputs	**2,426**	2,287	2,155
Refining availability[c]	**95.0%**	93.6%	88.8%
			thousand tonnes
Total petrochemicals production[d]	**15,594**	12,660	12,835
			$ per barrel
Global indicator refining margin (GIM)[e]			
US West Coast	**6.16**	5.88	7.42
US Gulf Coast	**4.96**	4.63	6.78
US Midwest	**5.19**	5.43	5.17
Northwest Europe	**3.80**	3.26	6.72
Mediterranean	**3.29**	2.11	6.00
Singapore	**1.63**	0.21	6.30
BP Average GIM	**4.44**	4.00	6.50

[a] Includes sales between businesses.

[b] Includes profit after interest and tax of equity-accounted entities.

[c] 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.

[d] A minor amendment has been made to comparative periods.

[e]

The global indicator refining margin (GIM) is the average of regional industry indicator margins weighted for BP s crude refining capacity in each region. Each regional indicator margin is based on a single representative crude with product yields characteristic of the typical level of upgrading complexity. The indicator margin may not be representative of the margins achieved by BP in any period because of BP s particular refining configurations and crude and product slate.

2010 performance

Safety and operational risk

Safety, both process and personal, remains our top priority. During 2010, personal safety in Refining and Marketing as measured by incident frequencies was slightly worse than 2009, and process safety as measured by our severity-weighted process safety incident index improved by 25%.

One of the primary controls to mitigate or minimize safety and operational risk is the effective, sustained implementation and embedding of our operating management system (OMS). OMS also covers robust contractor management processes. All of Refining and Marketing s major operations had transitioned to OMS by the end of 2010, with only one regional logistics operation completing the process by the end of February 2011.

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

During 2010 Refining and Marketing had two workforce fatalities. In our Rotterdam refinery, a contractor was fatally injured during civil construction works and in the Rhine fuels value chain in Germany, a contractor truck driver was fatally injured in a multiple vehicle accident.

The recordable injury frequency (RIF), which measures the number of recordable injuries to the BP workforce per 200,000 hours worked, was 0.35. This is slightly higher than 2009 when it was 0.32, but significantly lower than in 2008 when it was 0.48. Seventy-seven severe vehicle accidents occurred in Refining and Marketing s operations during 2010 (71 in 2009).

In terms of operational integrity, the number of losses of primary containment (LOPC), which measures unplanned or uncontrolled releases of material from primary containment, was 12% higher in 2010 than in 2009, however this was still over 20% lower than in 2008. The process safety incident index (PSII), which is a weighted index to reflect both the number and severity of events per 200,000 hours worked, fell from 0.48 in 2009 to 0.36 in 2010. The average severity of the process safety-related LOPC events has reduced relative to 2009.

The number of oil spills greater than one barrel increased in 2010 (132) compared with 2009 (113), although this was still significantly lower both in number and volume than for 2008.

In our US refineries, we continued to implement the recommendations of the BP US Refineries Independent Safety Review Panel and regulatory bodies and have made significant progress in 2010. See Corporate responsibility, Safety section on page 68 for further information on progress.

To enhance further the focus on safety during 2010, Refining and Marketing established a segment operational risk committee that meets on a quarterly basis, chaired by the segment chief executive. This committee reviews critical risks, conducts an in-depth review of process safety and also aims to ensure appropriate risk management and mitigating actions are in place and prioritized.

Financial and Operating performance

Our 2010 performance continued to benefit from the fundamental improvements we have been making across the business, including improved availability within our refining system, the efficiency of our operations and growing margin share in our marketing businesses.

Replacement cost profit before interest and tax for the year ended 31 December 2010 was $5,555 million, compared with $743 million for the previous year. 2010 included a net gain for non-operating items of $630 million, mainly relating to gains on disposal partly offset by restructuring charges. (*See page 25 for further information on non-operating items.*) In addition, fair value accounting effects had a favourable impact of $42 million relative to management s measure of performance. (See *page 26 for further information on fair value accounting effects.)*

The primary additional factors contributing to the increase in replacement cost profit before interest and tax were improved operational performance in the fuels value chains, continued strong operational performance in the international businesses and further cost efficiencies, as well as a more favourable refining environment. Against this very good operational delivery, the results were impacted by a significantly lower contribution from supply and trading compared with 2009.

Sales and other operating revenues for 2010, analysed in the table below, were $267 billion compared with $213 billion in 2009. This increase was primarily due to increasing prices. The decrease in 2009 compared with 2008 primarily reflected a decrease in prices.

			$ million
	2010	2009	2008
Sale of crude oil through spot and term contracts	**44,290**	35,625	54,901
Marketing, spot and term sales of refined products	**209,221**	166,088	248,561
Other sales and operating revenues	**13,240**	11,337	16,577
	266,751	213,050	320,039

The following tables set out oil sales volumes by type for the past three years and give further details of refined product marketing sales by product type:

		thousand barrels per day	
Refined products	**2010**	2009	2008
US	**1,433**	1,426	1,460
Europe	**1,402**	1,504	1,566
Rest of World	**610**	630	685
Total marketing sales[a]	**3,445**	3,560	3,711
Trading/supply sales[b]	**2,482**	2,327	1,987
Total refined product sales	**5,927**	5,887	5,698
Crude oil[c]	**1,658**	1,824	1,689
Total oil sales	**7,585**	7,711	7,387

[a] Marketing sales are 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] 113 thousand barrels per day of the crude volumes relates to revenues reported by Exploration and Production.

Marketing sales by refined product	2010	2009	2008
		thousand barrels per day	
Aviation fuel	**546**	495	501
Gasolines	**1,326**	1,444	1,500
Middle distillates	**1,012**	1,012	1,055
Fuel oil	**391**	418	460
Other products	**170**	191	195
Total marketing sales	**3,445**	3,560	3,711

Marketing volumes were 3,445mb/d, slightly lower than 2009, principally reflecting the disposal of our retail businesses in Greece and France.

Our 2010 operational performance was strong, with Solomon refining availability at 95.0% for the year and refining throughputs up by 139mb/d for the year. Our refining utilization was well above industry averages. In the international businesses, the petrochemicals business was able to capture the benefit of the demand recovery, and achieve record volumes.

Prior years comparative financial information

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 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 the expected future cash flows. The decrease in profit was also driven by the very significantly weaker environment, where refining margins fell by almost 40%. This was partly offset by significantly stronger operational performance in the FVCs, with 93.6% Solomon refining availability, lower costs and improved performance in the international businesses. In addition, fair value accounting effects had an unfavourable impact of $261 million relative to management s measure of performance.

The replacement cost profit before interest and tax for the year ended 31 December 2008 was $4,176 million and included a net credit for non-operating items of $347 million. The most significant non-operating items were net gains on disposal (primarily in respect of the gain recognized on the contribution of the Toledo refinery to a joint venture with Husky Energy Inc.) partly offset by restructuring charges. In addition, fair value accounting effects had a favourable impact of $511 million relative to management s measure of performance.

Compared with 2008, our 2009 performance was driven by the high level of non-operating items described above and a significantly weaker environment than in 2008, where refining margins fell by almost 40%. This was partly offset by significantly stronger operational performance in the fuels value chains, with 93.6% refining availability, as well as lower costs and improved performance in the international businesses.

Outlook

In 2011, the overall economic environment is expected to continue to recover, albeit at a relatively slow pace globally. The refining marker margin (RMM) in 2011 is expected to remain in a range more reflective of pre-2004 levels and our forward plans are currently based on a RMM range of $8-12 per barrel.

Our priorities in 2011 remain consistent with those in 2010 and we intend to build on the momentum we have established around improving financial performance and operations. We will continue to focus on delivering safe, reliable and compliant operations, improving the performance of our integrated FVCs, in particular in the US, and driving further cost efficiencies across all our businesses. We intend to increase slightly our investment levels in 2011 versus 2010, focused 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 expect the number and cost of refinery turnarounds in 2011 and 2012 to be higher than in 2010.

As explained in Our strategy on page 55, our US refining capacity is expected to halve when we complete the disposal of our Texas City refinery and the southern part of our West Coast FVC.

The following table summarizes the BP group s interests in refineries and average daily crude distillation capacities at 31 December 2010.

					thousand barrels per day
					Crude distillation capacities[a]
	Refinery	Fuels value chain	Group interest[b] %	Total	BP share
Europe					
Germany	Bayernoil	Rhine	22.5%	215	48
	Gelsenkirchen[c]	Rhine	50.0%	265	132
	Karlsruhe	Rhine	12.0%	324	39
	Lingen[c]	Rhine	100.0%	93	93
	Schwedt	Rhine	18.8%	237	45
Netherlands	Rotterdam[c]	Rhine	100.0%	377	377
Spain	Castellón[c]	Iberia	100.0%	110	110
Total Europe				1,621	844
US					
California	Carson[c]	US West Coast	100.0%	266	266
Washington	Cherry Point[c]	US West Coast	100.0%	234	234
Indiana	Whiting[c]	US Mid-West	100.0%	405	405
Ohio	Toledo[c]	US Mid-West	50.0%	160	80
Texas	Texas City[c]		100.0%	475	475
Total US				1,540	1,460
Rest of World					
Australia	Bulwer[c]	ANZ	100.0%	102	102
	Kwinana[c]	ANZ	100.0%	143	143
New Zealand	Whangerei	ANZ	23.7%	118	28
South Africa	Durban	Southern Africa	50.0%	180	90
Total Rest of World				543	363
Total				3,704	2,667

[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 operated by BP.

Business review

Fuels value chains

We have six regionally organized integrated FVCs (see *map on page 15),* each of which optimizes the activities of our assets across the supply chain from crude delivery to the refineries; manufacture of high-quality fuels; pipeline and terminal infrastructure and marketing and sales to our customers.

In addition to the FVCs, the Texas City refinery is operated as a standalone, predominantly merchant, refining business that also supports our marketing operations on the east and Gulf coasts of the US.

As explained in Our strategy on page 55, we intend to divest the Texas City refinery complex and exit the southern part of our US West Coast FVC business, including the Carson refinery, by the end of 2012.

We also have a number of regionally focused fuels marketing businesses that are not integrated into a refinery, covering the UK, Turkey, China and our remaining business-to-business fuels marketing activities in France.

We currently own or have a share in 16 refineries, which produce refined fuel products that we then supply to retail and commercial customers.

Our refining focus is to maintain and improve our competitive position through sustainable, safe, reliable, compliant and efficient operations of the refining system and disciplined investment for integrity management, to achieve competitively advantaged configuration and growth.

For BP, the strategic advantage of a refinery relates to its location, integration, scale and configuration to produce fuels from lower-cost feedstocks in line with the demand of the region. Strategic investments in our refineries are focused on securing the safety and reliability of our assets while improving our competitive position. In addition, we continue to invest to develop the capability to produce the cleaner fuels that meet the requirements of our customers and their communities.

The following table outlines by region the volume of crude oil and feedstock processed by BP for its own account and for third parties. Corresponding BP refinery capacity utilization data is summarized below.

			thousand barrels per day
Refinery throughputs[a]	**2010**	2009	2008
US	**1,350**	1,238	1,121
Europe	**775**	755	739
Rest of World	**301**	294	295
Total	**2,426**	2,287	2,155
Refinery capacity utilization			
Crude distillation capacity at 31 December[b]	**2,667**	2,666	2,678
Refinery utilization[c]	**91%**	86%	81%
US	**93%**	85%	77%
Europe	**91%**	89%	87%
Rest of World	**84%**	83%	80%

[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. The measure was redefined in 2009 to be more consistent with industry standards.

Refinery throughputs increased by 139mb/d in 2010 relative to 2009, driven principally by higher availability, particularly at Texas City and Whiting.

In addition to refined petroleum products we also blend and market biofuels. 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 that we blend and supply.

Our fuels strategy focuses on optimizing the integrated value of each FVC that is responsible for the delivery of ground fuels to the market. We do this by co-ordinating our marketing, refining and trading activities to maximize synergies across the whole value chain. Our priorities are to operate an advantaged infrastructure and logistics network (which includes pipelines, storage terminals and road or rail tankers), drive excellence in operating and transactional processes, and deliver compelling customer offers in the various markets in which we operate. The fuels business markets a comprehensive range of refined oil products primarily focused on the ground fuels sector.

The ground fuels business supplies fuel and related convenience services to retail consumers through company-owned and franchised retail sites, as well as other channels, including wholesalers and jobbers. It also supplies 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, as well as southern and eastern 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).

At 31 December 2010, BP s worldwide network consisted of some 22,100 sites, primarily branded BP, ARCO and Aral. During 2010 we sold around 400 sites in France to Delek Europe B.V. These will continue to be operated under the BP brand through a brand licensing agreement.

Our retail convenience operations offer consumers a range of food, drink and other consumables and services on the fuel forecourt in a convenient and innovative manner. The convenience offer includes brands such as ampm, Wild Bean Café and Petit Bistro.

In the US, our ampm brand is operated as a convenience retail franchise model. Overall in the US, by the end of 2010 there were 11,300 branded retail sites, of which 1,100 were branded ampm, compared with 11,500 and 1,200 respectively at the beginning of 2010.

In Europe, we had approximately 8,400 branded retail sites at the end of 2010. We are also one of the largest forecourt convenience retailers, with about 1,600 convenience retail sites in nine countries. We are growing our food-on-the-go and fresh grocery services through BP-owned brands and partnerships with leading retailers such as Marks & Spencer.

In addition, at the end of 2010, we had approximately 2,400 branded retail sites outside Europe and the US in countries such as Australia, New Zealand and South Africa.

The table below outlines the number of BP-branded retail sites by region.

	Number of retail sites operated under a BP brand		
Retail sites[a b]	**2010**	2009	2008
US	**11,300**	11,500	11,700
Europe	**8,400**	8,600	8,600
Rest of World	**2,400**	2,300	2,300
Total	**22,100**	22,400	22,600

[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.

The group has a long-established integrated supply and trading function 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 business has trading offices in Europe, the US and Asia to enable the function to maintain a presence in the regionally connected global markets.

The oil supply and trading function has operated through a period of challenging trading conditions in 2010 due to lower price volatility, tighter product and sweet vs sour crude oil spreads, and reduced contango (i.e. spot vs future price) opportunities. The weaker trading environment is a result of OPEC crude supply availability, refining and storage spare capacity. The supply and trading function supported the group through a period of uncertainty in the credit markets concerning BP s financial position following the Gulf of Mexico oil spill.

The function 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 for its refineries where this will provide incremental margin.

Along with the supply activity described above, the function seeks to create incremental trading opportunities. It enters into the full range of exchange-traded commodity derivatives, over-the-counter (OTC) contracts and spot and term contracts that are described in Certain definitions commodity trading contracts, on page 82. In order to facilitate the generation of trading margin from arbitrage, blending and storage opportunities, it also both 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, which is described in Financial statements Note 27 on pages 185-190.

In 2010, the FVCs accounted for roughly three-quarters of the operating capital employed[a] in Refining and Marketing and generated just under half of the replacement cost profit.

Significant events in the FVCs in 2010 were as follows:

- The Whiting refinery modernization project made significant progress in 2010 as above ground construction began, including the reactors for the new gasoil hydrotreater, the new towers on the revamped crude distillation unit and the coker s six new drums. Two third-party world-scale hydrogen units were commissioned in 2010 and began providing hydrogen to the refinery. Progress on important pipeline interconnections completed in 2010 will allow Whiting early access to greater crude imports and product export opportunities.

- In the US, BP s reputation suffered as a result of the oil spill in the Gulf of Mexico, which had an adverse impact on our branded fuels marketing, but this had recovered by year end. We offered additional marketing support to our customers in an attempt to mitigate these declines.

- In the Gulf of Mexico region, sales were down year on year by up to 30% in some sites in the second quarter, but regained ground over the second half of 2010.

- In October, BP opened a cutting-edge fuels technology development centre in South Africa, which will focus on quality assurance, technical service and marketing support for the local market.

- The integrated supply and trading function within the FVCs announced that it was reorganizing its internal structure in order to simplify the organization and reduce costs.

- In October, BP sold its French retail business to Delek Europe B.V.

- During 2010, BP also completed the divestment of several packages of non-strategic terminals and pipelines in the US East of Rockies and West Coast. This programme of divestment of non-strategic pipelines and terminals will continue during 2011.

- Following a strategic review of our businesses in southern Africa, we intend to focus our activities within the continent on South Africa and Mozambique. As a result, BP agreed to sell its fuels marketing businesses in Namibia, Zambia and Botswana to Puma Energy and in addition, BP intends to sell its 50% interest in BP Malawi and BP Tanzania to Puma Energy. The sale of BP Tanzania to Puma Energy is subject to the pre-emption rights of its co-shareholders. Only the sale of the Botswana business had been completed as at 31 December 2010, the other sales are expected to be completed in 2011.

During 2010 BP completed the sale of a number of European terminals as part of ongoing asset optimization activities.

International businesses

Our IBs provide quality products and services to customers in more than 70 countries worldwide with a significant focus on Europe, North America and Asia. Our products include aviation fuels, lubricants, LPG and petrochemicals that are sold for use in the manufacture of a range of products, such as fabrics, fibres and various plastics. We believe each of these IBs is competitively advantaged in the markets in which we have chosen to participate. Such advantage is derived from several factors, including location, proximity of manufacturing assets to markets, physical asset quality, operational efficiency, technology advantage and the strength of our brands. Each business has a clear strategy focused on investing in its key assets and market positions in order to deliver value to its customers and outperform its competitors.

In 2010, the IBs accounted for just under a quarter of the segment s operating capital employed[a] and just over half of the replacement cost profit.

Marketing sales in the international businesses include sales of global fuels and lubricants. The following table sets out the detail by business.

			thousand barrels per day
International businesses sales volumes	**2010**	2009	2008
Air BP	**450**	434	478
LPG	**58**	67	64
Lubricants	**50**	49	54
	558	550	596

Lubricants

We manufacture and market lubricants and related products and services to the automotive, industrial, marine and energy markets across the world. We sell products direct to our customers in around 45 countries and use approved local distributors for the remaining locations. Customer focus, distinctive brands, superior technology and relationships remain the cornerstones of our long-term strategy.

BP markets primarily through its major brands of Castrol and BP, and also the Aral brand in some specific markets. Castrol is a recognized brand worldwide and we believe it provides us with a significant competitive advantage.

In the automotive lubricants sector, 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. In 2010, roughly 30% of replacement cost profit before interest and tax was generated from emerging markets, which we believe continue to have the potential for significant long-term growth.

BP s marine lubricants business is one of the largest global suppliers of lubricants to the marine industry, with global presence in over 800 ports. BP s industrial lubricants business is a leading supplier to those sectors of the market involved in the manufacture of automobiles, trucks, machinery components and steel. BP is also a leading supplier of lubricants for the offshore oil and aviation industries.

Petrochemicals

We manufacture and market four main product lines: purified terephthalic acid (PTA), paraxylene (PX), acetic acid, and olefins and derivatives (O&D). Our strategy is to leverage our industry-leading technology in selected markets, to grow the business and to deliver industry-leading returns. New investments are targeted principally in the higher-growth Asian markets.

PTA is a raw material used in the manufacture of polyesters used in fibres, textiles and film, and polyethylene terephthalate (PET) bottles. Acetic acid is a versatile intermediate chemical used in a variety of products such as paints, adhesives and solvents, as well as its use in the production of PTA. We have a strong global market share in the PTA and acetic acid markets, with a major manufacturing presence in Asia, particularly China. PX is a feedstock for PTA production. We also produce a number of other speciality petrochemicals products.

[a] Operating capital employed is total assets (excluding goodwill) less total liabilities, excluding finance debt and current and deferred taxation.

Business review

In O&D, we crack naphtha to produce ethylene and other products and derivatives. Our SECCO joint venture between BP, Sinopec and its subsidiary, Shanghai Petrochemical Company, is the largest olefins cracker in China and is BP s single largest investment in China. BP also co-owns one other naphtha cracker site outside of Asia, which is integrated with our Gelsenkirchen refinery in Germany.

We have a total of 18 manufacturing sites operating in the UK, the US, Belgium, Germany, China, Indonesia, South Korea, Malaysia and Taiwan, including our joint ventures.

The following table summarizes BP s petrochemicals production capacity, at 31 December 2010.

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	1,342
	Decatur	PTA	100.0	1,043
		Paraxylene (PX)	100.0	1,101
		Naphthalene dicarboxylate	100.0	29
	Texas City	Acetic acid	100.0	583[c]
		PX	100.0	1,271
		Metaxylene	100.0	123
				5,492
Europe				
UK	Hull	Acetic acid	100.0	532
		Acetic anhydride	100.0	153
		Ethylidene diacetate	100.0	4
Belgium	Geel	PTA	100.0	1,343
		PX	100.0	631
Germany	Gelsenkirchen	Olefins and derivatives	50.0 to 61.0	1,764[b d]
	Mulheim	Solvents	50.0	130[b]
				4,557
Rest of World				
China	Caojing	Olefins and derivatives	50.0	3,103[b]
	Chongqing	Acetic acid	51.0	215[b]

		Esters	51.0	52[b]
	Nanjing	Acetic acid	50.0	274[b]
	Zhuhai	PTA	85.0	1,549[e]
Indonesia	Merak	PTA	50.0	253[b]
Korea	Ulsan	Acetic acid	51.0	261[b]
		Vinyl acetate monomer	34.0	56[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	471[b]
	Mai Liao	Acetic acid	50.0	179[b]
				8,261
Total BP share of capacity at 31 December 2010				18,310

[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] Sterling Chemicals plant, 100% of the output of which is marketed by BP.

[d] Group interest varies by product.

[e] BP Zhuhai Chemical Company Ltd is a subsidiary of BP, the capacity of which is shown above at 100%.

Global fuels

The supply of aviation fuels and LPG is managed globally in the global fuels SPU.

Air BP is one of the world s largest and best known aviation fuels suppliers, serving many of the major commercial airlines, as well as the general aviation and military sectors.

We have annual marketing sales in excess of 400mb/d. 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.

The LPG business sells bulk, bottled, automotive and wholesale LPG products in 10 countries, with annual sales in excess of 50 thousand barrels per day. During the past few years, we have introduced new consumer offers in established markets, developed opportunities in growth markets and pursued new demand such as the German Autogas market.

Significant events in 2010 were:

Castrol was a sponsor of the 2010 FIFA World Cup in South Africa and used this to deliver a significant programme of brand visibility and customer engagement. Castrol leveraged the sponsorship to support our businesses in all regions. We have seen increased brand awareness for our Castrol master brand and product brands.

In July 2010, Castrol opened a new lubricants technology development centre in China. Employing scientists and engineers from China and abroad, this team will work collaboratively with vehicle manufacturers, distributors and other partners, focusing on cutting-edge lubricant

technology development and support, as well as providing world-class training for customers and distributors.

During 2010, the LPG business further simplified its portfolio. In China, the LPG business decided to focus its in-country operations on core marketing activities and sold its interest in the China Zhuhai cavern complex. This completes the exit from all major China LPG import facilities. In Europe, BP sold its LPG businesses in Spain and Denmark.

The BP YPC Acetyls Company (Nanjing) Limited (BYACO) joint venture between BP and Yangzi Petrochemical Co. Ltd (a subsidiary of Sinopec) successfully commenced commercial production at its 548,000 tonnes per annum (ktepa) acetic acid plant in the fourth quarter of 2010.

The petrochemicals business started a debottleneck project to add a further 200ktepa PTA capacity at the BP Zhuhai Chemical Company Limited site in Guangdong province (China), which is scheduled for completion in the first quarter of 2012. This additional capacity employs BP s latest proprietary technology and will bring the site s total PTA capacity to 1,750ktepa, continuing our growth in China.

During 2010, BP sold its 15% interest in Ethylene Malaysia Sdn Bhd (EMSB) and its 60% interest in Polyethylene Malaysia Sdn Bhd (PEMSB) to Petronas.

Other businesses and corporate

Other businesses and corporate comprises the Alternative Energy business, Shipping, the group s aluminium business,Treasury (which includes interest income on the group s cash and cash equivalents), and corporate activities worldwide.

The replacement cost loss before interest and tax for the year ended 31 December 2010 was $1,516 million, compared with $2,322 million for the previous year. 2010 included a net charge for non-operating items of $200 million. (*See page 25 for further information on non-operating items.*) The primary additional factors affecting 2010 s result compared with that of 2009 were improved business performance, more favourable foreign exchange effects and cost efficiencies.

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 replacement cost loss before interest and tax for the year ended 31 December 2008 included a net charge for non-operating items of $633 million.

The primary additional factors reflected in 2009 s result compared with that of 2008 were a weaker margin environment for Shipping and our BP Solar business and adverse foreign exchange effects.

Key statistics

			$ million
	2010	2009	2008
Sales and other operating revenues[a]	**3,328**	2,843	4,634
Replacement cost profit (loss) before interest and tax[b]	**(1,516)**	(2,322)	(1,223)
Capital expenditure and acquisitions	**1,234**	1,299	1,839

[a] Includes sales between businesses.

[b] Includes profit after interest and tax of equity-accounted entities.

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 solar, along with demonstration projects and technology development in carbon capture and storage (CCS).

Our market

It is well accepted that a more diverse mix of energy will be required to meet 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, wind power has grown rapidly in many countries and is now growing globally at an annual rate of 30%[a], while installed solar photovoltaic capacity is predicted to increase from 15GW in 2008 to 410GW in 2035[b] and between 2010 and 2030, biofuels are expected to contribute 30% of the global growth in supply of liquid fuels[c].

Our performance

Alternative Energy continues to make progress against its commitment to invest $8 billion by 2015. Our investment since 2005 is more than $5 billion[d]. Our wind business has added 125MW of gross capacity during 2010, with the commercial start-up of the Goshen North wind farm. In our solar business, we achieved sales of 325MW and signed several strategic supply deals *(see Solar on page 62)*. Our biofuels business acquired the lignocellulosic assets from Verenium Corporation Inc. for $98 million. In April, we completed the sale of our 35% interest in K-Power, a gas-fired power asset in Gwangyang, South Korea, to SK Holdings Co. Ltd for $316 million.

[a] Global Wind Energy Council *Annex Stats 2009*.

[b] *World Energy Outlook 2010* ©OECD/IEA 2010, page 306.

[c] *BP Energy Outlook 2030*.

[d] The majority of costs have been capitalized, some were expensed under IFRS.

Business review

	2010	2009	2008
Wind net rated capacity at year-end (megawatts)[a]	**774**	711	432
Solar module sales (megawatts)[b]	**325**	203	162

[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 1,362MW in 2010, 1,237MW in 2009 and 785MW in 2008. This includes 32MW of capacity in the Netherlands which is managed by our Refining and Marketing segment.

[b] Solar sales are the total sales of solar modules to third-party customers, expressed in MW. Previously we reported the theoretical cell production capacity of our in-house solar manufacturing facilities. Reporting sales volumes operating data brings us in line with the broader solar industry.

Biofuels

BP believes that it has a key 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. BP has production facilities operating, or in the planning and construction phases, in the US, Brazil and the UK.

In 2010, we acquired Verenium s lignocellulosic biofuels business for $98 million, providing BP with integrated end-to-end capability. This included a pilot plant and a demonstration facility in Jennings, Louisiana, as well as research and development facilities in San Diego, California; lignocellulosic biofuels technology and related intellectual property (IP); and lignocellulosic enzyme technology and related IP.

The blending and distribution of biofuels continues to be carried out by our Refining and Marketing segment, in line with regulation. BP is one of the largest blenders and marketers of biofuels in the world.

Wind

In wind power, BP has focused its business in the US, where we have developed one of the leading wind portfolios. During 2010, full commercial operations commenced at the 125MW Goshen North wind farm (BP 50%) in Bonneville County, Idaho. We also commenced construction at the Cedar Creek 2 wind farm in Colorado and the project is expected to be in commercial operation in 2011 with a capacity of around 250MW.

BP increased its net wind generation capacity to 774MW during 2010, an increase of 9% over the prior year.

Solar

In 2010, we achieved sales of 325MW, an increase of 60% over 2009. BP Solar s organization, with over 900 employees worldwide, is structured to serve the residential, commercial, and utility markets with sales and marketing offices in major markets around the world. Our joint venture manufacturing facilities are located in Xi an, China and Bangalore, India. In March, BP Solar announced the closure of manufacturing at its Frederick facility, in Maryland, US, as it moves its manufacturing to lower-cost locations. BP Solar will maintain its US presence in sales and marketing, research and technology, project development, and key business support activities. In support of our manufacturing restructuring, we have signed a number of strategic cell supply agreements with suppliers, including JA Solar Holdings Co. Ltd and Hareon SolarTechnology, providing BP Solar with access to around 200MW of mono-crystalline and multi-crystalline solar cells in 2011.

Carbon capture and storage

BP has played a leading role in the carbon capture and storage (CCS) industry for more than 10 years, and today focuses on demonstration projects and a continuing programme of research and technology development.

In Algeria, we are moving into Phase 2 of our joint industry project that monitors the CO_2 injection and storage operation at the In Salah gas field. With our partners Sonatrach and Statoil, we have been injecting up to 1 million tonnes of CO_2 a year since 2004, demonstrating secure geological storage through a comprehensive monitoring programme that is subject to independent academic review by a scientific advisory board.

Since 2007, we have been developing the Hydrogen Energy California 250MW power project with CCS with our partner RioTinto. The project is currently in its feasibility engineering design phase.

Separately, the 400MW Hydrogen Power Abu Dhabi project with CCS awaits 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

The size of our managed international fleet has not changed since 2009. At the end of 2010, we had 54 international vessels (37 medium-size crude and product carriers, four 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 have 14 specialist vessels (two double-hulled lubricants oil barges and 12 offshore support vessels).

Time-charter vessels

BP has 84 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.

2010 has seen continuing pirate activity in the Gulf of Aden, extending well into the Indian Ocean (from the east coast of Somalia to approximately 250 miles west of the Maldives) and to the north into the Arabian Sea. Despite an increasing level of piracy activity, the number of vessels actually attacked and/or hijacked has remained roughly the same as 2009, 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 supports the protective measures recommended in the international shipping industry guide *Best Management Practice 3 Piracy off the Coast of Somalia and Arabian Sea Area.*[a]

Aluminium

Our aluminium business is a non-integrated producer and marketer of rolled aluminium products, headquartered in Louisville, Kentucky, US. Production facilities are located in Logan County, Kentucky, and are jointly owned with Novelis. The primary activity of our aluminium business is the supply of aluminium coil to the beverage can business, which it manufactures primarily from recycled aluminium.

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. For information on the role performed by Treasury in managing the group s liquidity in the aftermath of the Gulf of Mexico oil spill, see Liquidity and capital resources on pages 63-64 and Financial statements Note 2 on page 158. Trading activities are underpinned by the compliance, control, and risk management infrastructure common to all BP trading activities.

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 has been reviewed following the Gulf of Mexico oil spill and it has been concluded that the group will continue with its current approach of not generally purchasing insurance cover.

[a] Jointly published by industry bodies, including the Oil Companies International Marine Forum (OCIMF) and supported by military operations in the region.

Liquidity and capital resources

Following the Gulf of Mexico oil spill, the group 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.

In June, Moody s Investors Service and Standard & Poor s (S&P) downgraded the group s long-term credit ratings from Aa1 (stable outlook) and AA (stable outlook) respectively, to A2 (negative watch) and A (negative watch) respectively. Fitch downgraded BP to BBB. All three rating agencies have subsequently removed the group from ratings watch, Moody s and Fitch have currently placed the group s rating on A2 (stable outlook) and A (stable outlook) respectively, and S&P has placed our rating on A (negative outlook).

Following the incident the group was required to make substantial cash payments in connection with the oil spill. Investors in BP s US Industrial Revenue/Municipal bonds and in bonds associated with long-term gas supply contracts largely exercised their option to tender the bonds for repayment. As a result, at 31 December 2010, BP was holding all $1.5 billion of the outstanding bonds associated with long-term gas supply contracts and had repaid $2.5 billion of US

Industrial Revenue/Municipal bonds with BP either holding or retiring the bonds. The group also experienced increased requirements to post letters of credit to collateralize a number of environmental liabilities in the US and the UK totalling $624 million and post further cash collateral under trading agreements totalling $728 million.
In response, BP instigated a programme early in the second quarter of 2010 to increase available liquidity. We secured additional bank lines totalling $12 billion and announced the temporary suspension of quarterly dividend payments beginning with the payment that had been scheduled to occur in June 2010. BP also announced a disposal programme aimed at raising $30 billion to be completed by the end of 2011. Significant deposits were negotiated as part of these transactions. Deposits totalling $5 billion were held at the end of the third quarter and $6.2 billion was held at the end of the year, significantly increasing available liquidity. Including deposits, $17 billion was raised through the disposal programme in 2010. A further $0.7 billion of funds were raised through borrowings which were secured on working capital and other assets. BP also raised $4.6 billion during the third quarter from syndicated bank loans backed by future crude oil sales over a five-year period from BP s interests in specific offshore Angola and Azerbaijan fields. These initiatives and the strength of our underlying cash flows (including forecasting under different stress scenarios) ensured the group had sufficient working capital to meet its requirements at all times.
Early in the fourth quarter of 2010, BP accessed the US and European capital markets with bond issuances totalling $6.25 billion, with maturities of between four and 10 years.

Business review

Financial framework

As part of our response to the Gulf of Mexico oil spill, we revised our financial framework during 2010. The aim of the revised framework is to provide the group with financial flexibility in the medium term, as we complete our $30-billion disposal programme and fulfil our commitment to fund the Deepwater Horizon Oil Spill Trust. See Financial statements Note 2 on page 158.

We intend to invest to grow the company and shareholder value sustainably through the business cycle and we intend to maintain a capital structure that allows the group to execute its strategy and is resilient to inherent volatility.

We also intend to maintain a significant liquidity buffer and to reduce our net debt ratio to within a range of 10-20%, compared with our previously targeted range of 20-30%. For further information on net debt, which is a non-GAAP measure, see Financial statements Note 36 on page 198.

We will seek to maintain shareholder distributions in line with operating performance through the business cycle. On 1 February 2011, we announced the resumption of quarterly dividend payments, at a level we believe is prudent and recognizes our current circumstances. We still face uncertainties as to the amount and timing of future cash flows and we have an obligation to contribute $5 billion per annum to the Deepwater Horizon Oil Spill Trust for each of the next three years. Our intention is to increase the dividend over time, in line with the circumstances of the company.

Dividends and other distributions to shareholders

In June 2010, the BP board reviewed its dividend policy in light of the Gulf of Mexico oil spill and the agreement to establish the $20-billion trust fund, deciding that no ordinary share dividends would be paid in respect of the first three quarters of 2010. On 1 February 2011, BP announced the resumption of quarterly dividend payments, with a fourth-quarter dividend of 7 cents per share.

We believe this level is supported by the success of our disposal programme thus far, and by the improving business environment, but is balanced by the recognition of our continuing obligation to fund the Trust until the end of 2013 and the need to retain financial flexibility. We intend to increase the dividend level over time in line with the circumstances of the company. The total dividend paid to BP shareholders in 2010 was $2.6 billion, compared with $10.5 billion for 2009. The dividend paid per share was 14 cents, a decrease of 75% compared with 2009. In sterling terms, the dividend decreased 76%. We determine the dividend in US dollars, the economic currency of BP.

During 2010 and 2009, the company did not repurchase any of its own shares.

Financing the group s activities

A summary of financing activities during 2010 following the Gulf of Mexico oil spill is included on page 63. 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, or by using currency swaps when funds have been raised in currencies other than US dollars.

The group s finance debt at 31 December 2010 amounted to $45.3 billion (2009 $34.6 billion). Of the total finance debt, $14.6 billion is classified as short term at the end of 2010 (2009 $9.1 billion). Included within short-term debt is $6.2 billion relating to the previously mentioned deposits received for announced disposal transactions still pending legal completion post the balance sheet date (2009 nil). The short-term balance also includes $6.9 billion for amounts repayable within the next 12 months relating to long-term borrowings (2009 $3.9 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 2010, outstanding commercial paper amounted to $1.0 billion (2009 $0.4 billion). Due to the uncertainty of commercial paper markets in times of crisis, we choose not to include our commercial paper balances when conducting stress tests of our liquidity. We do, nonetheless, make use of these markets when they are commercially attractive.

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 2010, the amount drawn down against the DIP was $12.3 billion (2009 $11.4 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 recent capital market bond issuances contained any additional financial covenants compared to the group s capital markets issuances prior to the Gulf of Mexico oil spill.

The maturity profile and fixed/floating rate characteristics of the group s debt are described in Financial statements Note 35 on page 197.

Net debt was $25.9 billion at the end of 2010, a slight reduction from the 2009 year-end net debt position of $26.2 billion. Included in net debt are cash and cash equivalents of $18.6 billion at 31 December 2010 (2009 $8.3 billion). The ratio of net debt to net debt plus equity was 21% at the end of 2010, compared with 20% at the end of 2009.

BP manages its cash position to ensure the group has liquidity as and when required. 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. Further information on the management of liquidity risk and credit risk is provided in Financial statements Note 27 on pages 188-190, and on the cash position in Financial statements Note 31 on page 191.

BP expects to maintain a strong cash position. This, together with our lower net debt ratio target, aims to ensure the group has the flexibility to meet future financial obligations and reflects a prudent approach to managing the balance sheet and the liquidity requirements of the company.

The group also has access to significant sources of liquidity in the form of committed bank facilities. At 31 December 2010, the group had available undrawn committed borrowing facilities of $12.5 billion (2009 $5.0 billion), made up of:

- $5.3 billion of standby facilities, of which $0.4 billion is available to draw and repay by mid-September 2011, $4.6 billion until mid-October 2011, and $0.3 billion until mid-January 2013.

- $7.2 billion of 364-day facilities, of which $4.0 billion can be drawn until late May 2011, $2.0 billion drawn until the end of June 2011, $0.7 billion drawn until early July 2011 and $0.5 billion drawn until late August 2011. Any amounts drawn are repayable up to 364 days from the date of drawing.

With the level of undrawn committed bank facilities increasing since the Gulf of Mexico oil spill incident and with the levels of cash increasing, our overall liquidity levels strengthened over the course of 2010.

BP believes that, taking into account the substantial amounts of undrawn borrowing facilities and 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. There remains significant uncertainty regarding the amount and timing of future expenditures and the implications for future activities. See Risk factors on pages 27-32, and Financial statements Note 2 on page 158, Note 37 on page 199 and Note 44 on page 218 for further information.

Off-balance sheet arrangements

At 31 December 2010, the group s share of third-party finance debt of equity-accounted entities was $6,987 million (2009 $6,483 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 2010 are $404 million (2009 $319 million) in respect of liabilities of jointly controlled entities and associates and $664 million (2009 $667 million) in respect of liabilities of other third parties. Of these amounts, $355 million (2009 $286 million) of the jointly controlled entities and associates guarantees relate to borrowings and for other third-party guarantees, $649 million (2009 $633 million) relates to guarantees of borrowings.

Contractual commitments

The following table summarizes the group s principal contractual obligations at 31 December 2010, 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 35 on page 197 and more information on operating leases is given in Financial statements Note 15 on page 175.

							$ million
							Payments due by period
Expected payments by period under contractual obligations and commercial commitments	Total	2011	2012	2013	2014	2015	2016 and thereafter
Balance sheet obligations							
Borrowings[a]	41,550	9,200	6,439	7,486	6,054	5,443	6,928
Finance lease future minimum lease payments	1,126	153	377	56	51	51	438
Deepwater Horizon Oil Spill Trust funding liability	15,008	5,008	5,000	5,000			
Decommissioning liabilities[b]	14,876	461	453	370	362	413	12,817
Environmental liabilities[b]	3,903	1,763	545	275	189	158	973
Pensions and other post-retirement benefits[c]	25,670	1,916	1,905	1,403	976	983	18,487
Total balance sheet obligations	102,133	18,501	14,719	14,590	7,632	7,048	39,643
Off-balance sheet obligations							
Operating leases[d]	13,973	3,521	2,475	1,878	1,413	1,032	3,654
Unconditional purchase obligations[e]	166,942	97,355	16,330	9,291	6,778	5,634	31,554
Total off-balance sheet obligations	180,915	100,876	18,805	11,169	8,191	6,666	35,208
Total	283,048	119,377	33,524	25,759	15,823	13,714	74,851

[a] Expected payments include interest payments on borrowings totalling $3,221 million ($888 million in 2011, $679 million in 2012, $520 million in 2013, $362 million in 2014, $225 million in 2015 and $547 million thereafter), and exclude disposal deposits of $6,197 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 2011 include purchase commitments existing at 31 December 2010 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 27 on page 186.

The following table summarizes the nature of the group s unconditional purchase obligations.

							$ million
							Payments due by period
Unconditional purchase obligations	Total	2011	2012	2013	2014	2015	2016 and thereafter
Crude oil and oil products	101,671	70,572	7,058	3,582	2,207	1,934	16,318
Natural gas	36,147	19,780	5,117	2,827	2,078	1,450	4,895
Chemicals and other refinery feedstocks	8,912	2,055	1,278	923	888	858	2,910
Power	2,784	1,915	688	162	16	2	1
Utilities	925	156	154	111	98	89	317
Transportation	8,525	1,184	875	796	726	637	4,307
Use of facilities and services	7,978	1,693	1,160	890	765	664	2,806
Total	166,942	97,355	16,330	9,291	6,778	5,634	31,554

The group expects its total capital expenditure, excluding acquisitions and asset exchanges, to be around $20 billion in 2011. The following table summarizes the group s capital expenditure commitments for property, plant and equipment at 31 December 2010 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	2011	2012	2013	2014	2015	2016 and thereafter
Committed on major projects	31,376	15,193	7,205	4,304	2,170	986	1,518
Amounts for which contracts have been placed	11,279	7,239	1,966	1,093	504	316	161

In addition, at 31 December 2010, the group had committed to capital expenditure relating to investments in equity-accounted entities amounting to $1,033 million. Contracts were in place for $517 million of this total.

Business review

Cash flow

The following table summarizes the group s cash flows.

			$ million
	2010	2009	2008
Net cash provided by operating activities	**13,616**	27,716	38,095
Net cash used in investing activities	**(3,960)**	(18,133)	(22,767)
Net cash provided by (used in) financing activities	**840**	(9,551)	(10,509)
Currency translation differences relating to cash and cash equivalents	**(279)**	110	(184)
Increase in cash and cash equivalents	**10,217**	142	4,635
Cash and cash equivalents at beginning of year	**8,339**	8,197	3,562
Cash and cash equivalents at end of year	**18,556**	8,339	8,197

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 provided by operating activities for the year ended 31 December 2009 was $27,716 million compared with $38,095 million for 2008 reflecting a decrease in profit before taxation of $9,159 million, an increase in working capital requirements of $8,944 million and a decrease in dividends from jointly controlled entities and associates of $725 million. These were partly offset by a decrease in income taxes paid of $6,500 million, higher depreciation, depletion, amortization and impairment charges of $1,329 million and an increase in charges for provisions of $948 million.

Net cash used in investing activities was $3,960 million in 2010, compared with $18,133 million and $22,767 million in 2009 and 2008 respectively. The decrease in 2010 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. The decrease in cash used in investing activities in 2009 compared to 2008 reflected a decrease in capital expenditure and acquisitions of $2,356 million and an increase in disposal proceeds of $1,752 million.

Net cash provided by financing activities was $840 million in 2010 compared with $9,551 million net cash used in 2009 and $10,509 million net cash used in 2008. The net increase in cash provided in 2010 reflects 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 decrease in 2009 reflected a $2,774 million decrease in the net repurchase of shares and an increase in net proceeds from long-term financing of $1,406 million; these were partly offset by an increase in net repayments of short-term debt of $3,090 million.

The group has had significant levels of capital investment for many years. Cash flow in respect of capital investment, excluding acquisitions, was $18.9 billion in 2010, $21.4 billion in 2009 and $23.7 billion in 2008. 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 $25.9 billion at the end of 2010, $26.2 billion at the end of 2009 and was $25.0 billion at the end of 2008.

During the period 2008 to 2010, our total sources of cash amounted to $101 billion, whilst our total uses of cash amounted to $93 billion. The net cash provided of $8 billion, along with an increase in finance debt of $7 billion, resulted in an increase in our balance of cash and cash equivalents of $15 billion over the three-year period. During this period, the price of Brent crude oil has averaged $79.48 per barrel. The following table summarizes the three-year sources and uses of cash.

	$ billion
Sources of cash	
Net cash provided by operating activities	79
Disposals	22
	101
Uses of cash	
Capital expenditure	64
Acquisitions	3
Net repurchase of shares	2
Dividends paid to BP shareholders	23
Dividends paid to minority interests	1
	93
Net source of cash	8
Increase in finance debt	7
Increase in cash and cash equivalents	15

Disposal proceeds received during the three-year period were significantly higher than cash used for acquisitions, as a result in particular of our disposal programme started in 2010. Net investment (capital expenditure and acquisitions less disposal proceeds) during this period averaged $15 billion per year. Dividends paid to BP shareholders totalled $23 billion during the three-year period, with no ordinary share dividends being paid in respect of the first three quarters of 2010. Net repurchase of shares was $2 billion, which included $3 billion in 2008 in respect of our share buyback programme less net proceeds from shares issued in connection with employee share schemes over the three years. Finally, cash was used to strengthen the financial condition of certain of our pension plans. In the past three years, $3 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.

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Trend information

For information on external market trends, see Our market on pages 16-18.

We expect production in 2011 to be lower than in 2010 as a result of divestments, lower production from the Gulf of Mexico and increased turnaround activity to improve the long-term reliability of the assets. As a result of these factors, reported production in 2011 is expected to be around 3,400mboe/d. The actual outcome will depend on the exact timing of divestments, the pace of resumption of operations in the Gulf of Mexico, OPEC quotas and the impact of the oil price on our PSAs.

In Refining and Marketing, refiners are likely to continue to operate with excess capacity globally, although near-term supply-demand fundamentals appear broadly in balance. We expect the number and cost of our refinery turnarounds in 2011 and 2012 to be higher than in 2010.

In Other businesses and corporate, the underlying average quarterly charge for 2011 is expected to be around $400 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 be around $20 billion in 2011, an increase compared with 2010.

Having received a total of $17 billion for disposal proceeds and disposal deposits in 2010, we are targeting around a further $13 billion in 2011.

The discussion above contains forward-looking statements, particularly those regarding global economic recovery and outlook for oil and gas markets, oil and gas prices, refining margins, production, demand for petrochemicals products, effective tax rate, operating and capital expenditure, timing and proceeds of divestments, contractual commitments, balance of cash inflows and outflows, net debt ratio, and dividend and optional scrip dividend. 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 are urged to read the cautionary statement on page 4 and Risk factors on pages 27-32, 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.

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Corporate responsibility

The Deepwater Horizon explosion and subsequent spill had major human and environmental consequences, demonstrating the importance of safe and responsible operations. We deeply regret the loss of lives and injuries suffered, and the impact to the environment and livelihoods of local people.

We are committed to understanding and applying the lessons from the accident. Already, we are making some fundamental changes in the way we operate.

These measures include:

- The creation of an enhanced safety and operational risk function that is independent of the business line and is represented in every BP operation.

- The reorganization of our upstream business to create three functional divisions, each reporting directly to the group chief executive. (*See Exploration and Production on pages 40-41 for further details.*)

- A review of employee reward frameworks to increase the focus on performance in safety, compliance, and operational risk management. (*See Employees on page 74 for further details.*)

- An examination of how we can strengthen the oversight of contractors. Strengthening these core areas will require some profound changes in how we operate and will take several years to fully embed.

In 2010, the company reported 14 workforce fatalities, including the 11 workers on the Deepwater Horizon in the US and three other work-related fatalities in the Netherlands, Germany and Canada. All 14 individuals were contractors. We deeply regret the loss of these lives and recognize the tremendous loss felt by their families, friends and co-workers.

Safety

Gulf of Mexico oil spill investigations and recommendations

In the immediate aftermath of the Deepwater Horizon explosion, 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 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. See Gulf of Mexico oil spill on pages 34-39.

As a result, the investigation team made 26 recommendations specific to drilling, which we accepted and are implementing 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 and verification, and personnel competence.

Several external investigations into the Deepwater Horizon accident and response are under way in the US, including those by the Marine Board, the National Academy of Engineering, the Chemical Safety Board, the US Congress, the Department of Justice and the Securities and Exchange Commission (SEC). In addition, the Presidential Commission issued its report on 11 January 2011. See page 38 in Gulf of Mexico oil spill for a summary of the findings. As the findings of these investigations are made public, we will make them available on *www.bp.com/gulfofmexico*.

Subsequent actions to date to strengthen BP s safety management

Following the accident, BP immediately undertook a variety of activities to further strengthen its oil spill prevention, containment and response capability. These include:

- BOPs used on BP-operated projects, along with other well-control equipment, were checked to confirm that they had been properly maintained and are capable of shutting in the well in an emergency.

Remotely operated vehicles were confirmed to be capable of activating BOPs in emergency situations.

New decision matrix, designed to aid key decisions on well design and operations, was developed and distributed to our operations globally.

Two containment hats were delivered to the UK to aid North Sea containment capability.

We updated our oil spill response plan, and submitted it to the US Department of the Interior.

Meanwhile, our upstream teams are working to implement the 26 recommendations made by BP s internal investigation team. These will be tracked in the quarterly HSE and operations integrity report supplied to the executive team.

Safety and operational risk

Safety and operational risk management requirements, encapsulated by our operating management system (OMS), are set by a central, dedicated function, with periodic reviews by the board and executive committees. The operational delivery of these requirements is the responsibility of the businesses.

As a result of the Gulf of Mexico incident, BP has redefined and strengthened the scope and accountabilities of the group function for safety and operations, creating a new independent function, Safety and Operational Risk (S&OR). We are deploying S&OR professionals, many of whom were previously reporting to local business leaders, in all of BP s operations throughout 2011.

The core responsibilities of S&OR are to:

Provide checks and balances independent of the business line.

Strengthen mandatory safety-related standards and processes, including operational risk management.

Provide an independent view on operational risk.

Assess and enhance the competency and capability of our workforce in matters related to safety.

The head of S&OR is a member of BP s most senior executive team along with the heads of Refining and Marketing, and Exploration and Production. S&OR oversees and audits the company s operations around the world, assuring that all operations are carried out in line with the group s OMS. While the business line continues to be accountable for operational delivery, S&OR holds the authority to intervene in safety and operational risk aspects of BP s technical and operational activities.

Governance processes

The board s safety, ethics and environment assurance committee (SEEAC) receives updates from the executive team s group operations risk committee (GORC), which is chaired by the group chief executive. These updates include quarterly reports monitoring major incidents, near-misses and performance in both process and personal safety across the group. The group chief executive and the head of S&OR attend SEEAC meetings and report on the group s safety performance; this is measured through developing leading and lagging safety indicators. SEEAC also receives information directly from S&OR, other parts of the business and external sources, including the independent expert appointed to monitor the implementation of recommendations made by the BP US Refineries Independent Safety Review Panel following the 2005 incident at our Texas City refinery.

See Board performance report on pages 90-105 for further information on the activities of the board s committees, including the Gulf of Mexico committee established to oversee the work of the Gulf Coast Restoration Organization (GCRO).

Operating management system

In 2008, we launched OMS, our group-wide framework to drive a rigourous and systematic approach to safety, risk management, and operational integrity across the company. OMS integrates all requirements regarding health, safety, security, environment and operational reliability, as well as related issues such as maintenance, contractor relations and organizational learning, into a common system.

The principles and standards of OMS are supported by detailed company practices, as well as other technical guidance materials. OMS mandates that certain standards, group-defined practices and group engineering technical practices be implemented company-wide; these include, among others, the assessment, prioritization and management of risk; incident investigation; integrity management; and environmental and social requirements for major new projects.

The OMS includes these essential requirements, specifically addressing crisis and continuity management and emergency response:

- Identify crisis and continuity management scenarios utilising the entity risk register, the output of the entity s major accident risk assessment and other information.

- Implement and maintain crisis and continuity management plans to manage the scenarios identified. These will include procedures from initiation to response and recovery. At site level these plans shall include arrangements for evacuation and, where needed, for initial shelter-in-place.

- Validate the plans through exercising them at defined intervals. Review the plans at least annually to reflect changes in hazards, risks, organization or contact details, and implement identified improvements.

- Provide access to trained personnel, resources, medical emergency and other facilities needed to implement and execute the crisis and continuity management plans.

- Implement, maintain and exercise a documented process for accounting for personnel during and after an emergency evacuation.

OMS defines the process for BP business units to implement the system and continuously improve their operational performance in all areas, including safety. The embedding of a comprehensive management system such as OMS across a global company is a multi-year process.

The transition to OMS requires each operation to develop a local OMS (LOMS) that describes how the operation addresses site-specific local operating risks to meet group standards and practices and comply with applicable HSSE legal requirements, while focusing on their specific activities. As an essential step in developing its LOMS, the business unit conducts an assessment of the gaps between the standards and practices contained in OMS and the business unit s local processes and procedures, and then develops a gap-closure plan. Every year, after the initial gap assessment, each business unit conducts another assessment to identify the additional steps to be taken to improve performance.

To formally transition to OMS, an operation issues a handbook for the workforce to follow, completes a management-of-change document that details the changes involved, and obtains formal sign-off by the segment operating authority and business unit leader. All of BP s major operations had transitioned to OMS by the end of 2010, with the remaining one regional logistics operation completing the process by the end of February 2011.

BP will continue to evolve OMS, incorporating implementation experience as well as learnings from incident investigations, audits and risk assessments, and by strengthening mandatory practices.

Gulf of Mexico incident and the OMS

The Gulf of Mexico operations completed their transition to OMS in December 2009 and now continue to work towards full conformance to the OMS. Recommendations from BP s internal investigation into the Deepwater Horizon incident will be implemented within our group-wide OMS framework where appropriate; this includes updates around contractor management and oil spill preparedness and response. Once the external investigations have produced their findings, we will carry out a review on the OMS framework; this is expected to be completed in the third quarter of

2011. See Subsequent actions to date on page 68 for
information about our immediate activities to further strengthen our oil spill prevention, containment and response capability.

Process safety management

Process safety involves applying good design principles, along with robust engineering, operating and maintenance practices, to managing operations safely. For BP, this means ensuring the plant is designed, maintained and operated properly to avoid failures such as spills or explosions that can result in injuries and impacts to the environment.

In September 2010, BP published *Deepwater Horizon Containment and Response: Harnessing Capabilities and Lessons Learned,* a report shared with the US Bureau of Ocean Energy Management, Regulation and Enforcement. These learnings are intended to benefit our own operations and potentially those of our peers, in case of a future incident.

The report identifies four broad lessons from the Deepwater Horizon incident:

Collaboration: a broad range of stakeholders came together in the wake of the Deepwater Horizon incident to provide effective solutions and build new capabilities. It would have been extremely difficult for any one company alone to address challenges on the scale of the Deepwater Horizon incident. The response benefited from close collaboration with and the capabilities of the US Coast Guard, Bureau of Ocean Energy Management, Regulation and Enforcement and dozens of other partners and stakeholders from government, industry, academia and the affected communities, as well as around the globe.

Systemization: the response to the incident required the development of extensive systems, procedures and organizational capabilities to adapt to changing and unique conditions. As the Deepwater Horizon spill continued despite efforts at the wellhead, the response effort progressed, expanded, and took on not just new tasks and directions but new personnel and resources. As a result, from source to shore, existing systems were evolved and expanded and new ones developed to advance work flow, improve co-ordination, focus efforts and manage risks. The adoption of these systems will ensure the ability to respond to future spills more rapidly at scale with a clear direction as to personnel, resource and organizational needs.

Information: timely and reliable information was essential across both the containment and response operations to achieve better decision-making, ensure safe operations and inform stakeholders and the public.

Innovation: the urgency in containing the spill and dealing with its effects drove innovations in tools, equipment, processes and know-how, ranging from incremental enhancements to step changes in technologies and techniques, that have advanced the state of the art and laid the foundation for future refinements as part of an enhanced regime for any type of source-to-shore response.

BP joined the Marine Well Containment Company (MWCC), a non-profit initiative with ExxonMobil, Shell, ConocoPhillips and Chevron designed to quickly deploy effective equipment in case of another underwater blowout in the US Gulf of Mexico. The well containment equipment used in the Deepwater Horizon response will preserve existing capability for use by the oil and gas industry in the US Gulf of Mexico while the MWCC member companies build a system that exceeds current response capabilities. BP has also offered to make available to the MWCC BP technical personnel with experience from the Deepwater Horizon response.

Oil spills and loss of containment

We strive to prevent future oil spills by weaving process safety into every stage of the design, operation and management of our operations. We monitor the integrity of all our operations, vessels and pipelines used to produce, process and transport oil and other hydrocarbons with the aim of preventing any loss of hydrocarbons from their primary containment. Accordingly, we record all losses of containment, losses of hydrocarbons from our assets (which we monitor as an enduring indicator of process safety), and losses or spills that reach land or water.

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

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Although there are several third-party estimates of the flow rate or total volume of oil spilled from the Deepwater Horizon incident, we believe that the total volume of oil spilled cannot be finalized until further information is collected and the analysis, such as the condition of the blowout preventer, is completed. Once such determination has been made, we will report on the spill volume as appropriate. See Financial statements Note 37 on page 199 for information about the volume used to determine the estimated liabilities.

Loss of primary containment and oil spills (excluding Gulf of Mexico oil spill in respect of volume)

	2010	2009	2008
Loss of primary containment number of all incidents[a]	**418**	537	658
Loss of primary containment number of oil spills[b]	**261**	234	335
Number of oil spills to land and water	**142**	122	170
Volume of oil spilled (thousand litres)	**1,719**	1,191	3,440
Volume of oil unrecovered (thousand litres)	**758**	222	911

[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).

Reports of the US refineries Independent Expert

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.

During 2010, Mr Wilson kept the committee updated on his work activities and BP s progress in implementing the recommendations, including the outcome of his visits to each of BP s five US refining sites. In March 2010 he published his third annual report (the Third Report) that assessed BP s progress against the 10 Panel recommendations and associated commentary. In that report, which was published in full on BP s website, he found that, in the three years since the Panel issued its report in January 2007, BP had made significant improvements in response to all 10 Panel recommendations. He found measureable improvement across nearly all the common indicators used by BP to track process safety performance; although results varied from refinery to refinery for individual indicators, he found that the composite of these indicators, both at individual refineries and across all BP s US refineries, reflected improvement over time.

Mr Wilson also found, however, that, while significant gaps had been closed and most of the new systems, processes, standards, and practices required for continued process safety improvements had been developed, much work remained to be done to fully implement them. The Third Report stated that BP must demonstrate improved capability for systematic management of these systems, processes, standards, and practices so it can accelerate the overall pace of implementing the 10 Panel recommendations. It also identified the following areas at BP s US refineries in which more focused attention was required:

- addressing overtime issues, and in particular high individual overtime rates;
- the development and implementation of management systems for safety instrumented systems (SIS), required by BP s internal standards, to address areas such as documentation, training for personnel competency, and auditing (collectively, SIS life cycle issues);
- taking advantage of certain additional opportunities to further strengthen the process safety culture at BP s US refineries and increasing the pace to achieve this desired culture change; and

addressing issues of non-conformance with standards and practices and ensuring that installed equipment continues to meet applicable standards and practices.

On 23 February 2011, Mr Wilson presented his fourth annual report (the Fourth Report) to the committee. He found that, throughout 2010, BP s executive management continued to emphasize the importance of safe, reliable, and compliant operations. Even though the year was particularly challenging for BP following the Gulf of Mexico incident, he noted that, during and after the incident response, process safety and personal safety performance continued to be a major focus for executive management. The Fourth Report stated that, during the year, group-level activities continued to focus on the development and enhancement of competency and capability programs, effective audits, and ongoing maintenance and support for the OMS. The five US refineries continued to demonstrate good progress in a number of key areas, and they successfully accelerated the pace of implementation in several other key areas. However, some areas require special emphasis going forward, and the US refineries are addressing these needs through interventions or renewed commitments to accelerated implementation plans.

The Fourth Report assessed the company s progress against the areas identified in the Third Report as requiring more focused attention and found that:

in relation to reduction of overtime rates, the US refineries had reduced their average overtime rates to levels that are perceived to be at or near industry norms for both operations and maintenance personnel in 2010, and significant reductions in overtime rates for individuals had also been achieved, with only a few people exceeding BP s individual overtime target at the end of 2010;

in relation to SIS management systems, the US refineries had made accelerated progress in 2010 in addressing SIS life-cycle requirements; the Fourth Report noted that rigourous implementation of these new SIS life-cycle policies and procedures for all existing and newly installed SISs will be a challenging task;

in relation to process safety culture, the US refineries had developed a common safety culture vision in 2010 and progress was being made in communicating the new vision; the Fourth Report also noted that progress is being made toward improved communication, co-operation and sharing between the refineries and commented on some improvements with respect to individuals adopting a more proactive and self-critical approach towards identifying and addressing risks. The Fourth Report noted that input from Mr Wilson was still sometimes required to catalyze the identification of and timely response to process safety issues; and

in relation to implementing internal and external standards and practices, BP had clearly identified those standards and practices that apply to the US refineries and is implementing them through risk-prioritized plans. The Fourth Report noted that, although progress is being made in the implementation of standards and practices, special emphasis will be required to address certain remaining issues in a timely manner, including: the time required to implement some new standards; the need to identify requirements in standards that apply retroactively to existing equipment; and the need for a process to ensure that existing equipment remains in conformance with applicable standards.

The Fourth Report also identified three additional areas that warrant special emphasis in order to implement selected Panel recommendations effectively:

additional sustained efforts, building on sincere messages from executive management to date, may be required to ensure that executive management effectively stimulates and supports a process safety culture within BP s US refineries that promotes industry-leading process safety performance;

with the exception of action items resulting from audits and incident investigations, overdue process safety action items were not being reported to executive management and to the board, as recommended by the Panel; in addition, Mr Wilson recommended that BP consider ways to systematically gather information sufficient to ensure completion of identified process safety action items within reasonable time periods; and

in the second half of 2010, the quality of some aspects of incident investigations and reports did not maintain the levels achieved in 2009. In response, a Continuous Improvement Team was chartered that developed a number of process improvements to be implemented in early 2011.

The Fourth Report is expected to be published in full in March 2011 and will be made available on our website.

Capability development
BP strives to equip its staff with the skills needed to apply the systems and processes to strengthen our management of risk and process safety. We have provided extensive and focused training programmes for our operations personnel at all levels.
This training provision 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 defined by our OMS. To date, approximately 11,800 managers, supervisors and technicians have attended at least one workshop within the Operations Essentials programme; additionally, more than 35,000 eLearning modules have been completed.
We communicate our expectations for qualified, competent and experienced contractor personnel through our procurement process. These become obligations within the formal contract. We further manage capability development of our strategic suppliers through a formalized performance review process at operational and strategic levels that is informed with performance data around agreed key metrics. The result of these performance review meetings is agreed joint plans to deliver the performance outcomes required.
The challenges of the Gulf of Mexico incident accelerated learning and capability development for both BP and those who worked with us on the response and for the oil industry. It is hoped that by sharing these lessons, the wider industry will be able to respond more effectively and efficiently to any similar incidents.
BP and third-party responders learned valuable lessons in collaboration, systemization, information-sharing, command and protocol. Some of the most valuable capability advancements were technical, with particularly valuable experiences in the areas of subsea containment systems, remotely operated vehicles, reservoir visualization, hydrate inhibition, rapid retrofitting, and application of dispersants. The shoreline response effort has built an expanded resource of trained responders, and the vessels of opportunity programme has built a base of trained, vetted and locally knowledgeable responders.
Safety performance
BP reports publicly on its personal safety performance according to standard industry metrics. In 2010, our overall reported recordable injury frequency (RIF) was 0.61, compared with 0.34 in 2009 and 0.43 in 2008. The nature of the Gulf Coast response effort has resulted in personal safety incident rates significantly higher than other BP operations. Injuries occurred primarily during boom deployment and the beach clean-up activities, and relate to a working population rapidly recruited to work in new roles, in unfamiliar environments.
Our reported day away from work case frequency (DAFWCF) in 2010 was 0.193, compared with 0.069 in 2009 and 0.080 in 2008. This increase is due in large part to the response effort, but also reflects a substantial increase in the rest of BP. There were nine day away from work cases resulting from the Deepwater Horizon accident and nine as a result of the air crash in Canada.
We apply a formal process designed to ensure that adequate controls to mitigate our internal risks are in place, while constantly looking for ways to strengthen these systems. BP reviews risks at all levels of the organization and, following the Gulf of Mexico incident, our group chief executive challenged our operations to ensure that all risk reviews correctly identify and mitigate lower-probability but higher-impact events.
BP takes major incidents and high-potential incidents very seriously; the more significant incidents are scrutinized by GORC, who has the option to require operations leaders to provide assurance that corrective measures are being taken.
BP has learned important lessons from major incidents at our Texas City refinery in 2005 and the Prudhoe Bay field in Alaska in 2006. We implemented our six-point plan, designed to address the immediate risks and priorities, and then began the roll-out of our OMS underpinned by our capability programmes, and strengthened our global audit team.
In the Gulf of Mexico, our internal investigation and resultant report form only a starting point for what is expected to be an extended process to fully analyse the Gulf of Mexico accident and implement the appropriate measures designed to prevent recurrence.
Contractor management

BP s OMS formalizes standards and recommended practices for selecting and working with contractors. This includes assessing the contractor s safety performance as part of the selection process, and defining safety requirements in contracts.
As a result of the Gulf of Mexico accident, which involved multiple contracting partners, we are reviewing how best to provide consistent and effective contractor oversight. This process began in late 2010 and will be focusing on the way we work with contractors for all onshore and offshore rig activities, particularly in regard to safety and operational risk.
Environment
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 present challenges around their environmental sensitivity and managing our impact on the areas where we operate is at the core of our activities.
We strive to minimize our impacts, whether to land, air, water or wildlife, through a systematic approach, supported by rigorous risk assessment and management, preventive measures and training.
Environmental management
We work to understand the sensitivities of the environments in which we operate and our responsibilities from beginning to end of our projects. By adopting a full project cycle approach to environmental management, we strive to identify the potential environmental impacts of our new projects, in the planning stage and during operations. We continue this approach after operations have ended, through our remediation strategy.
Our environmental and social group defined practices (E&S GDP), launched in April 2010, detail the requirements to help us identify and manage the environmental and social risks of major new projects, projects in new access locations and those that could affect an international protected area. Our E&S GDP is aligned with environmental and social standards and practices generally accepted in the oil and gas industry.
These group defined practices include environmental and social requirements for nine key issues: international protected areas; water management; drilling wastes and discharges; greenhouse gas (GHG) emissions (including energy efficiency and flaring); ozone depleting substances; indigenous people; physical resettlement; security and human rights; and impact assessment.
All our major operating sites are certified under the international environmental management system standard ISO 14001, with the

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Texas City plant and Tangguh LNG facility successfully receiving certification in 2010.

No new projects entered an international protected area in 2010. Our international protected areas classification includes the International Union for the Conservation of Nature (IUCN) I-IV, Ramsar and World Heritage designations.

Oil spill response plans

We continue to develop and assimilate lessons from the response to the Gulf of Mexico oil spill, which we plan to incorporate into our OMS specifically on oil spill preparedness and response.

All of BP s operations are required to comply with all applicable laws, including those requirements relating to dealing with the environmental impact of oil spills or leaks, in all regions where we operate. Within OMS, BP has a control document on crisis and continuity management that covers recommendations and approved good practice. OMS also requires environmental risks and hazards to be identified and managed, including those related to unplanned events e.g. oil spills. Country-specific regulators require such plans to be in place and approved as part of our licence to operate.

We complete environmental impact assessments (EIAs) for many of our projects, which include information on the potential environmental impact that might occur in the event of a spill, and use modelling and predictive assessments of where and how oil might impact identified environmentally sensitive sites, species or commercially vulnerable sites.

We then formulate crisis management and oil spill plans, building off the information in the EIA. Environmentally sensitive areas are mapped, preventative response plans agreed, and clean-up and remediation procedures established to determine clean-up end points. These plans address potential scenarios and response strategies, including how we would work with designated regulatory bodies in the event of a spill and what personnel and equipment would be needed.

The response techniques with the least environmental impact are usually agreed based on the sensitivity of the relevant environment. In many countries where BP operates, the regulator will determine and agree on the procedures to deal with the environmental impact.

Acute response plans are often focused on the physical containment and recovery of the spilled oil, though they will 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.

The potential actions during the acute stages of an offshore spill response include:

- Booms can be placed around the spill to gather the oil. A curtain is attached to its underside to prevent the oil from sliding out underneath it and spreading further.

- Sorbents can absorb the oil.

- In situ burning can be used to reduce the amount of oil on the water.

- Skimming equipment can be placed around the area to scoop it from the water s surface.

- Chemical dispersants can help the oil break up more quickly and mix more easily with the water column. Specific dispersants have been developed for different oils. The net environmental benefit of using chemical dispersants should always be considered and assessed before use.

For onshore operations, BP s refineries each have detailed spill response plans that include passive and active containment measures that are appropriate for their specific location and type of operation.

In conjunction with the US authorities, BP has gained significant experience in combating and mitigating a major oil release. The learnings from our spill response experience will be incorporated into the current remediation plans and procedures and also shared with governments, regulators and the industry world-wide.

In the unlikely event of multiple concurrent spills, 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 would be a challenge for the group, our response plans are not interdependent. Further, the plans do not contain physical or financial constraints BP is committed to devoting such resources as are necessary to mitigate the consequences of any spill to people and the environment.

BP has also joined the Marine Well Containment Company (MWCC) and will make our underwater well containment equipment available to all oil and gas companies operating in the Gulf of Mexico. The well containment equipment used in the Gulf of Mexico oil spill response will preserve existing capability for use by the oil and gas industry in the US Gulf of Mexico, while the MWCC member companies build a system that exceeds current response capabilities. BP has also offered to make available to the MWCC BP technical personnel with experience from the Gulf of Mexico oil spill response. BP considers that the deepwater intervention experience and specialized equipment will be important to the industry as a whole as well as the MWCC. In addition to the MWCC, we work with all of the other seven major international spill response organizations in the world.

See Gulf of Mexico oil spill on pages 34-39 for further information on BP s response to the incident.

Gulf of Mexico environmental impact and long-term commitments

The Gulf of Mexico oil spill affected water, shores, marshlands and wildlife. Immediately following the accident, BP and personnel from the US National Oceanic and Atmospheric Association, the US Environmental Protection Agency (EPA), and many other governmental agencies began patrolling the waters of the Gulf, sampling the waters looking for residual oil, or injured birds and marine life. BP has worked to support testing and sampling throughout the region.

BP is committed to understanding the long-term environmental impacts of the oil spill. In June 2010, we established the GCRO to manage all aspects of the immediate response to the incident and our long-term efforts to restore the regional environment.

In partnership with the Gulf of Mexico Alliance, we have set up the Gulf of Mexico Research Initiative (GRI), pledging to provide $500 million to study and monitor the spill s potential impacts on the environment and local public health.

See Gulf of Mexico oil spill on pages 34-39 for further information on BP s response to the incident.

Canadian oil sands

Canada s oil sands are believed to hold one of the world s largest untapped supplies of oil, second in size only to the resources in Saudi Arabia. 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 expected to start in 2014. The other two proposed projects, Pike and Terre de Grace, are still in the early stages of development.

We reviewed and approved the decision to invest in Canadian oil sands projects, taking into consideration 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 we plan to use, in-situ steam-assisted gravity drainage technology, involves the injection of steam underground. The steam liquefies the bitumen, allowing it to flow to the surface through production wells. Unlike mining, in-situ development creates a smaller physical footprint and does not involve tailing ponds.

Climate change

Climate change is a major global issue one that justifies precautionary action and represents a significant challenge for society, the energy industry, and BP.

Our GHG emissions were 64.9Mte in 2010, compared with 65.0Mte in 2009[a]. We have not included any emissions from the Gulf of Mexico incident and the response effort due to our reluctance to report data that has such a high degree of uncertainty.

[a] We report 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.

We aim to manage our GHG emissions through a focus on operational energy efficiency and reductions in flaring and venting. Also, we expect that additional regulation of GHG emissions in the future and international accords aimed at addressing climate change will have an increasing impact on our businesses, operating costs and strategic planning, but may also offer opportunities in the development of low-carbon technologies and businesses. See Regulation of the group s business Greenhouse gas regulation on page 78.

To help address this expectation, we factor a carbon cost into our investment appraisals and the engineering design of new projects. We do this by requiring larger projects, and those for which emissions costs would be a material part of the project, to make realistic assumptions about the likely carbon price during the lifetime of the project. In industrialized countries, this assumption is currently $40 per tonne of CO_2. This is used as a basis for assessing the economic value of the investment and for optimizing the way the project is engineered and the consequences for emissions. This helps to ensure our investments are competitive under scenarios in which the price of carbon is higher than it is today.

Adaptation to climate change impacts

For several years BP has sponsored research, including climate modelling, into the impacts of climate change on both existing operations and new projects. Introduced in 2010, the E&S GDP now requires screening for potential climate change impacts in major new projects, projects in new access locations and those that could affect an internationally protected area.

For larger projects where climate impacts are identified as a risk, we put a mitigation programme in place. Our current engineering practices address climate impacts in the same way as any other physical and ecological impacts. These practices are periodically reviewed and updated.

For many climate-related impacts, the appropriate engineering solutions are already known, because somewhere in our operations we already have experience and design facilities to withstand weather extremes, such as hurricanes, monsoons and Arctic conditions.

Water

To improve our understanding and act upon the growing global issue of water scarcity, BP is taking a more strategic approach to water management. We are currently developing our plans in regards to water management, which include increasing our capability to manage emerging water risks and engaging with external organizations to develop sustainable water management practices.

Environmental expenditure

			$ million
	2010	2009	2008
Environmental expenditure relating to the Gulf of Mexico oil spill			
Spill response	**13,628**		
Additions to environmental remediation provision	**929**		
Other environmental expenditure			
Operating expenditure	**716**	701	755
Capital expenditure	**911**	955	1,104
Clean-ups	**55**	70	64
Additions to environmental remediation provision	**361**	588	270
Additions to decommissioning provision	**1,800**	169	327

BP incurred significant costs in 2010 in response to the Gulf of Mexico oil spill. The spill response cost of $13,628 million includes amounts provided during 2010 of $10,883 million, of which $9,840 million has been expended during 2010, and $1,043 million remains as a provision at 31 December 2010. The majority of this remaining amount is expected to be expended during 2011. In addition, a further $2,745 million of clean-up costs were incurred in the year that were not provided for.

Additions to environmental provisions in 2010 in respect of the Gulf of Mexico oil spill relate to BP s commitment to fund the $500-million Gulf of Mexico Research Initiative, a research programme to study the impact of the incident on the marine and shoreline environment of the Gulf coast, and the estimated costs of assessing injury to natural resources. BP faces claims under the Oil Pollution Act of 1990 for natural resource damages, but the amount of such claims cannot be estimated reliably until the size, location and duration of the impact is assessed.

For further information relating to the Gulf of Mexico oil spill see Financial statements Note 2 on page 158, Note 37 on page 199 and Note 44 on page 218.

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 $716 million in 2010 was at a similar level to 2009, while in 2008, it was lower due to a reduction in new projects undertaken. In addition, there was a significant reduction in the sulphur oil premium paid due to a greater use of low-sulphur fuel.

Similar levels of operating and capital expenditures are expected in the foreseeable future. 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. The charge for environmental remediation provisions in 2010 included $307 million resulting from a reassessment of existing site obligations and $54 million in respect of provisions for new sites. The charge for environmental remediation provisions in 2009 included $582 million resulting from a reassessment of existing site obligations and $6 million in respect of provisions for new sites.

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.

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. On 15 October 2010, the Bureau of Ocean Energy Management, Regulation and Enforcement

Business review

(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 during the year.

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 37 on page 199.

Employees

Number of employees at 31 December	US	Non-US	Total
2010			
Exploration and Production	**7,900**	**13,200**	**21,100**
Refining and Marketing[a]	**12,400**	**39,900**	**52,300**
Other businesses 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 businesses and corporate	2,100	5,100	7,200
	22,800	57,500	80,300
2008			
Exploration and Production	7,700	13,700	21,400
Refining and Marketing[a]	19,000	42,500	61,500
Other businesses and corporate	2,600	6,500	9,100
	29,300	62,700	92,000

[a] Includes 15,200 (2009 13,900 and 2008 21,200) service station staff.

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 are reviewing the way we express BP s values and the content of our leadership framework with a goal of ensuring they support our aspirations for the future, align explicitly with our code of conduct and translate into responsible behaviours in the work we do every day. In 2011, we expect to carry out a programme to renew employee and contractor awareness of our values and the behaviours everyone in BP needs to exhibit as we work to reset our

priorities as a company.
We had approximately 79,700 employees at 31 December 2010, compared with approximately 80,300 a year ago. Since 2007, when we began a process of making BP a simpler, more efficient organization, our total number of employees has reduced by approximately 18,000, including around 9,200 in our non-retail businesses.
BP announced significant changes to our organization in 2010 designed to strengthen safety and risk management across the group, including the creation of an enhanced S&OR function and the re-organization of the upstream segment into three divisions: Exploration, Developments and Production, integrated through a Strategy and Integration function.
The group people committee, chaired by the group chief executive continues to take overall responsibility for policy decisions relating to employees. In 2010, this included senior-level talent reviews and succession planning, new hire and promotion assessments, leadership training and reward strategy, including the structure and operation of incentive programmes.
In 2011, our focus will be on rebuilding trust with all our stakeholders, including our employees. Our people priorities continue to be to ensure the right employees are in the right roles, while building a sustainable talent pipeline; to build capability and embed our required leadership behaviours; and to manage and reward performance while ensuring a focus on diversity and inclusion (D&l) in everything we do.
Sustainable talent pipeline
In managing our people, we seek to attract, develop and retain highly talented individuals who can contribute to BP s delivery of its strategy and plans. We place significant emphasis on developing our leaders internally, although we recruit outside the group when we do not have specialist skills in-house or when exceptional people are available. In 2010, we appointed 47 people to group leadership positions, 33 of which were internal candidates.
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. In 2010, we extended these assessments to cover new hires into middle and junior management roles, carrying out over 900 external assessments for new hires and promotions during the year. In 2011, we will be launching a new technical assessment process to complement these existing processes with more focus on detailed technical capability.
Our ongoing three-year graduate development programme continued in 2010. It currently has about 1,400 participants from all over the world.
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 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 incident, BP has been seeking the same or comparable pay and benefits for employees transferring to other companies.

Building capability and developing leaders

The group chief executive and each member of the executive team held review meetings to ensure a rigorous and consistent talent and succession process is followed for all group leadership roles.

We continue to work to embed appropriate leadership behaviours throughout our organization. In 2010, we piloted a new group leader development programme with leaders in the US. All group leaders will be expected to participate in the programme from 2011 onwards.

Our group-wide suite of management development programmes, Managing Essentials, has now run in 42 countries, with more than 21,000 participants. This includes new modules introduced in 2010, such as a mandatory D&I training programme for leaders that has had over 3,000 participants so far.

Managing and rewarding performance

We are conducting a fundamental review of how the group incentivizes business performance, including reward strategy, with the aim of encouraging excellence in safety, compliance and operational risk management. This review is closely linked to the refresh of our values and behaviours and to our work in embedding leadership behaviours throughout the group. We expect to deliver a revised individual performance management framework in 2011.

In the final quarter of 2010, individual performance bonuses were based solely on the achievement of safety targets.

We encourage employee share ownership. For example, through the ShareMatch plan run in around 60 countries, we match BP shares purchased by our employees.

Diversity and inclusion

Diversity and inclusion (D&I) involves acknowledging, valuing and leveraging our similarities and differences for business success, and is central to our employee processes in BP. The group chief executive chairs the global D&I council, which is supported by a North American regional council and segment councils. Each of our businesses has a D&I plan against which progress is measured. We are also incorporating detailed D&I 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. For example, in Azerbaijan, national employees now make up around 88% of BP s team. 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 2010, 14% of our top 482 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.

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

At our annual leadership forum in late 2010, our group chief executive and other senior leaders reinforced BP s commitment to achieving excellence in safety, compliance and risk management. 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.

Our 2010 employee survey was delayed to allow for organizational changes to be reflected in the survey construction, with the survey expected to be carried out in the third quarter of 2011.

The code of conduct

We have a code of conduct designed to ensure that all employees comply with legal requirements and our own standards. The code defines what BP expects of its people in key areas such as safety, workplace behaviour, bribery and corruption and financial integrity. Our employee concerns programme, OpenTalk, enables employees to raise

questions, receive guidance on the code of conduct and report suspected breaches of compliance or other concerns. The number of cases raised through OpenTalk in 2010 was 742, compared with 874 in 2009.
In the US, former US 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 2010, 552 dismissals were reported by BP s businesses for non-adherence to the code of conduct or unethical behaviour compared to 524 in 2009. This number excludes dismissals of staff employed at our retail service station sites for more minor incidents.
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.
Social and community issues
We strive to make our impact on society and communities a positive one by running our operations responsibly and by investing in communities in ways that benefit both local populations and BP.
Managing our impact
We believe each BP project has the potential to benefit local communities by creating jobs, tax revenues and opportunities for local suppliers. A positive impact also means making sure that human rights are respected, that we engage openly with people who could be affected by our projects and that local cultural heritage is preserved.
Our OMS lays out the steps and safeguards we believe are necessary to maintain socially responsible operations at our projects and operations.
For major new projects, projects in new locations and those that could affect an internationally protected area, detailed group practices apply. These include guidance on how the project should go about identifying groups that could be affected by the project, consulting with them to understand their needs and concerns and carrying out an impact assessment to evaluate the potential negative and positive community impacts. These are often carried out along with assessments of health, safety, environmental and other impacts.
Following the impact assessment, we review the project plans with a view to avoiding, mitigating or minimizing any negative impacts, such as noise, odour or other forms of community disturbance, and making the most of positive impacts.
Socio-economic investments
We invest in development programmes that we believe will 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 b