STRATEGIC REPORT
CHAIRMAN'S MESSAGE

There is no doubt that 2015 was a turbulent year, with low oil and gas prices having a far-reaching impact on the energy industry.

We have taken the opportunity to strengthen our business by reducing our operating expenses and capital investment, while continuing to divest assets that are not central to our long-term strategy.

Our acquisition of BG Group plc (BG) – one of the largest takeovers in UK corporate history – in February 2016 will help sharpen our focus on liquefied natural gas (LNG) and deep-water exploration and production. Combined, we are stronger, more competitive and better-equipped financially to continue to play an important role in meeting global energy demand for decades to come. It underscores our role as one of the largest independent oil and gas producers. Increased cash flows from our newly acquired assets will also help to support dividend payments and future investment.

A major challenge facing society is how to meet the needs of a growing global population, while limiting the amount of carbon dioxide (CO_2) in our atmosphere. This requires a mix of urgent action, realism and long-term planning by governments and industry alike. It will also require unprecedented co-operation, investment and innovation.

It was encouraging to see governments reach a global climate agreement in Paris in December. The agreement should now encourage countries to develop policies that balance environmental concerns with enabling a decent quality of life for more people.

Delivering the energy essential for economic development and the wellbeing of billions of people will require huge and sustained investment. Limiting the amount of CO_2 in our atmosphere also requires major investments in advanced technologies, such as carbon capture and storage (CCS). Oil and gas, which make up over 50% of global energy supplies today, will need to continue to provide a large part of the world's energy for decades to come.

The International Energy Agency estimates that over $25 trillion of investment will be needed in oil and gas supply alone from 2015 to 2040. So the long-term investment case for oil and gas remains strong, despite the fall in oil prices over the last 18 months. The concern is that prices seen in late 2015 and early 2016 may be too low to spur investment in projects that are needed to ensure long-term supplies. Without sufficient investment, the risk of demand exceeding supply will increase.

We know that understanding the world's future energy needs will help us improve our competitiveness.

We have evolved over the last few decades from a company focused almost entirely on oil to one of the world's leading suppliers of gas, the cleanest-burning hydrocarbon. Gas is already playing a role in tackling carbon emissions. Switching from coal to gas for power generation is one way to reduce emissions of CO_2, while increasing energy supply to a growing global population, including more than 1 billion people who lack access to electricity today.

We are working on multiple fronts to play our part in the energy transition. For example, we are now one of the world's largest suppliers of low-carbon biofuel through our Raízen joint venture in Brazil, which produces ethanol from sugar cane. We are in the early stages of developing biofuels that could further reduce the environmental impact of the transport sector. Our high-performance lubricants can already contribute to improved energy efficiency for motorists and we are working with vehicle manufacturers to improve them further. We are also increasingly offering LNG as a transport fuel and are exploring the potential of hydrogen.

CCS is an especially important technology for reducing CO_2 emissions from a range of industries. Quest, which we opened in 2015, captures and safely stores around one-third of the annual CO_2 emissions from an oil sands bitumen processing facility in Canada. We are sharing information on its design and processes so that it can serve as a blueprint for others. Strong government support is needed to encourage many more businesses around the world to invest in CCS.

The Paris climate agreement provided a promising platform for society to develop a solution to climate change. Governments now need to implement policies that will stimulate investment in all technologies that can contribute to a lower-carbon future.

Despite some of the toughest operating conditions that our industry has seen, we are in a stronger position to weather current market volatility and play our part in the energy transition.

Let me take this opportunity to thank our shareholders for supporting the BG acquisition at a very challenging time for the industry. Your Board of Directors is committed to delivering the value from this important investment.

Chad Holliday
Chairman

CHIEF EXECUTIVE OFFICER'S REVIEW

It was a highly challenging year for the industry, but our integrated business and improved operational performance helped soften the impact of lower energy prices.

In these difficult economic times, our acquisition of BG Group plc (BG), which came into effect on February 15, 2016, will make us stronger.

The global portfolio we acquired is a good complement to our own. The combination will help us concentrate on more profitable pillars of our business, particularly deep water and liquefied natural gas (LNG). We are entering an exciting new era for Shell.

We continued our focus on safety. However, sadly seven people working for Shell in 2015 lost their lives. A fire at our Bukom refinery in Singapore also led to six workers being injured. Such tragic events underscore the importance of unwavering vigilance.

RESULTS

Earnings on a current cost of supplies basis attributable to Royal Dutch Shell plc shareholders were $3.8 billion in 2015, compared with $19.0 billion in 2014.

Lower oil prices and charges related to our exit from Alaska and decision to stop work on the Carmon Creek project in Canada contributed to our Upstream business making a loss in 2015. Strong performances by our Integrated Gas and Downstream businesses helped offset some of the impact of low energy prices. This is a reminder of the importance of remaining an integrated energy company.

Responding to the changing industry landscape, we reduced our operating expenses and capital investment by a combined $12.5 billion in 2015 compared with 2014. We distributed $12.0 billion to shareholders in dividends in 2015, including those taken as shares under our Scrip Dividend Programme.

Divestments amounted to $5.5 billion in 2015, and to more than $20 billion for 2014-2015. This exceeded our target of $15 billion for the period. The asset sales are part of our ongoing strategy of reducing costs and concentrating on markets where we can be most competitive.

Our oil and gas production averaged around 3 million barrels of oil equivalent per day in 2015. We started production at a major project off the coast of Nigeria which, combined with increased output from existing projects, helped partially offset the impact on production from naturally declining fields and divestments.

RENEWED FOCUS

We continue to lower our costs and take tough decisions on projects that, in the current oil-price environment, may be uncompetitive or unaffordable. For example, we stopped construction of the Carmon Creek in-situ oil project in 2015 and exited the development of the Bab sour gas project in the United Arab Emirates in early 2016. We are also postponing final investment decisions on the Bonga South West project off the coast of Nigeria and the LNG Canada facility.

Despite the current market uncertainty, it is important that we continue to invest wisely to achieve the most competitive portfolio we can. For example, we have decided to expand capacity at our Pernis refinery in the Netherlands and embark on a major expansion at our Geismar plant in the USA, reflecting the strong growth potential in chemicals for Shell.

In 2015, we announced the final investment decision to go ahead with the Appomattox deep-water project in the Gulf of Mexico.

We are prepared to reduce investments further, if evolving market conditions call for that. But we want to protect our growth prospects in a world where long-term demand for energy will continue to rise.

Greater energy efficiency and cleaner technologies are needed to help keep pace with energy demand growth, while limiting carbon dioxide (CO_2) emissions in the fight against climate change.

Meeting the energy needs of a growing world population means oil and gas are expected to continue to play vital roles in global energy supply into the latter half of the century.

Carbon capture and storage (CCS) systems that safely trap CO_2 deep underground can play an important part in the energy future. Shell started its first major CCS facility, Quest, in Canada in 2015. Government-led carbon pricing mechanisms can provide impartial and long-term incentives to invest in effective lower-carbon technologies, such as CCS.

Natural gas, the cleanest-burning hydrocarbon, can play a role in limiting emissions if more of it is used instead of coal for power generation. Gas is also making a growing contribution as a transport fuel.

As a whole, the oil and gas industry is going through a difficult period. However, our financial fortitude before the downturn and our sound strategy are helping us through the rough weather.

The acquisition of BG reinforces and reinvigorates us, and I am confident that our combined strength greatly improves our ability to thrive in a challenging business environment.

Ben van Beurden
Chief Executive Officer

RISK FACTORS

The risks discussed below could have a material adverse effect separately, or in combination, on our operational performance, earnings, cash flows and financial condition. Accordingly, investors should carefully consider these risks.

Measures that we use to manage or mitigate our various risks are set out in the relevant sections of this Report. The Board's responsibility for identifying, evaluating and managing our significant risks is discussed in "Corporate governance" on page 74.

We are exposed to fluctuating prices of crude oil, natural gas, oil products and chemicals.
The prices of crude oil, natural gas, oil products and chemicals are affected by supply and demand, both globally and regionally. Moreover, prices for oil and gas can move independently of each other. Factors that influence supply and demand include operational issues, natural disasters, weather, political instability, conflicts, economic conditions and actions by major oil and gas producing countries. Price fluctuations could have a material adverse effect on our business, including on our cash flows and earnings. For example, in a low oil and gas price environment, we would generate less revenue from our Upstream production, and, as a result, some long-term projects would become less profitable, or could incur losses. In this regard, if oil and gas prices remain at the levels observed in early 2016, there is the potential for our Upstream and Integrated Gas segments to incur a loss. Additionally, low oil and gas prices have resulted, and could continue to result, in the debooking of proved oil or gas reserves, if they become uneconomic in this type of price environment. Prolonged periods of low oil and gas prices, or rising costs, have resulted, and could continue to result, in projects being delayed or cancelled. In addition, assets have been impaired in the past, and there could be impairments in the future. Low oil and gas prices could also affect our ability to maintain our long-term capital investment programme and dividend payments. In a high oil and gas price environment, we could experience sharp increases in costs, and, under some production-sharing contracts, our entitlement to proved reserves would be reduced. Higher prices could also reduce demand for our products, which could result in lower profitability, particularly in our Downstream business. See "Market overview" on page 16.

Our ability to deliver competitive returns and pursue commercial opportunities depends in part on the robustness and, ultimately, the accuracy of our price assumptions.
We use oil and gas price assumptions, which we review on a periodic basis, to evaluate project decisions and commercial opportunities. While we believe our current long-term price assumptions are prudent, if our assumptions prove to be incorrect, it could have a material adverse effect on our earnings, cash flows and financial condition. See "Market overview" on page 17.

Our ability to achieve strategic objectives depends on how we react to competitive forces.
We face competition in each of our businesses. We seek to differentiate our products, however many of them are competing in commodity-type markets. Accordingly, failure to manage our costs as well as our operational performance could result in a material adverse effect on our earnings, cash flows and financial condition.

Increasingly, we compete with state-owned oil and gas entities, particularly in seeking access to oil and gas resources. These entities control vastly greater quantities of oil and gas resources than the major independent oil and gas companies. State-owned entities have access to significant resources and could be motivated by political or other factors in their business decisions, which could harm our competitive position or reduce our access to desirable projects. See "Strategy and outlook" on page 15.

The acquisition of BG Group plc exposes us to integration risks and other challenges.
Our future prospects will, in part, be dependent upon our ability to integrate BG Group plc (BG) successfully and completely, without disruption to our existing business. Value delivery from a number of key jurisdictions, including BG's assets in Australia and Brazil, as well as the integration of its LNG shipping and marketing business and trading activities and the successful execution of the substantial disposals that we expect to make following the acquisition are, in particular, critical to overall success. The BG acquisition was premised on a number of factors, including expected benefits from synergies, but also our expectation of future oil and gas prices. If these synergies do not materialise or oil and gas prices remain low for a prolonged period, this could result in future impairments and further pressure on our financial framework. We will face challenges when integrating the businesses, including standardisation of ways of working, policies and procedures, processes and systems. No assurance can be given that the integration process will deliver all the expected benefits within the assumed time frame or that the expected disposals will be made as planned. Unanticipated events, liabilities, tax impacts or unknown pre-existing issues could arise and result in the costs of integration being higher and the realisable benefits being lower than expected, with a material adverse effect on our operational performance, earnings, cash flows and financial condition. See "Strategy and outlook" on page 15.

Following the acquisition of BG, we seek to execute divestments in the pursuit of our strategy. We may not be able to successfully divest these assets in line with our strategy.
We may not be able to successfully divest assets at acceptable prices or within the timeline envisaged in view of market conditions or credit risk, resulting in increased pressure on our cash position. We may be held liable for past acts, failures to act or liabilities that are different from those foreseen. We may also face liabilities if a purchaser fails to honour all of its commitments. See "Strategy and outlook" on page 15.

Our future hydrocarbon production depends on the delivery of large and complex projects, as well as on our ability to replace proved oil and gas reserves.
We face numerous challenges in developing capital projects, especially those which are large and complex. Challenges include uncertain geology, frontier conditions, the existence and availability of necessary technology and engineering resources, the availability of skilled labour, the existence of transportation infrastructure, project delays, the expiration of licences and potential cost overruns, as well as technical, fiscal, regulatory, political and other conditions. These challenges are particularly relevant in certain developing and emerging-market countries, such as Iraq and Kazakhstan, in frontier areas and in deep-water fields, such as in Brazil. We may fail to assess or manage these and other risks properly. Such potential obstacles could impair our delivery of these projects, our ability to fulfil the value potential at the time of the project investment approval, and our ability to fulfil related contractual commitments. These could lead to impairments and could have a material adverse effect on our operational performance, earnings, cash flows and financial condition.

Future oil and gas production will depend on our access to new proved reserves through exploration, negotiations with governments and other owners of proved reserves and acquisitions, as well as on developing and applying new technologies and recovery processes to existing fields and mines. Failure to replace proved reserves could result in lower future production, earnings and cash flows.

See "Business overview" on page 14.

OIL AND GAS PRODUCTION AVAILABLE FOR SALE			MILLION BOE [A]
	2015	2014	2013
Shell subsidiaries	880	895	850
Shell share of joint ventures and associates	198	229	318
Total	1,078	1,124	1,168

[A] Natural gas volumes are converted into oil equivalent using a factor of 5,800 scf per barrel.

PROVED DEVELOPED AND UNDEVELOPED OIL AND GAS RESERVES [A][B] (AT DECEMBER 31)			MILLION BOE [C]
	2015	2014	2013
Shell subsidiaries	9,117	10,181	10,835
Shell share of joint ventures and associates	2,630	2,900	3,109
Total	11,747	13,081	13,944

[A] We manage our total proved reserves base without distinguishing between proved reserves from subsidiaries and those from joint ventures and associates.
[B] Includes proved reserves associated with future production that will be consumed in operations.
[C] Natural gas volumes are converted into oil equivalent using a factor of 5,800 scf per barrel.

The estimation of proved oil and gas reserves involves subjective judgements based on available information and the application of complex rules, so subsequent downward adjustments are possible.

The estimation of proved oil and gas reserves involves subjective judgements and determinations based on available geological, technical, contractual and economic information. Estimates could change because of new information from production or drilling activities, or changes in economic factors, including changes in the price of oil or gas and changes in the regulatory policies of host governments or other events. Estimates could also be altered by acquisitions and divestments, new discoveries, and extensions of existing fields and mines, as well as the application of improved recovery techniques. Published proved oil and gas reserves estimates could also be subject to correction due to errors in the application of published rules and changes in guidance. Downward adjustments could indicate lower future production volumes and could also lead to impairment of some assets. This could have a material adverse effect on our operational performance, earnings, cash flows and financial condition. See "Supplementary information – oil and gas (unaudited)" on page 153.

We operate in more than 70 countries that have differing degrees of political, legal and fiscal stability. This exposes us to a wide range of political developments that could result in changes to contractual terms, laws and regulations. In addition, we and our joint arrangements and associates face the risk of litigation and disputes worldwide.

Developments in politics, laws and regulations can and do affect our operations. Potential developments include: forced divestment of assets; expropriation of property; cancellation or forced renegotiation of contract rights; additional taxes including windfall taxes, restrictions on deductions and retroactive tax claims; trade controls; price controls; local content requirements; foreign exchange controls; changing environmental regulations; and disclosure requirements. A prolonged period of lower oil and gas prices could affect the financial, fiscal, legal, political and social stability of countries that rely significantly on oil and gas revenue. This could, in turn, have a material adverse effect on us.

From time to time, cultural and political factors play a role in unprecedented and unanticipated judicial outcomes that could adversely affect Shell. Non-compliance with policies and regulations could result in regulatory investigations, litigation and ultimately sanctions. Certain governments and regulatory bodies have, in the opinion of Shell, exceeded their constitutional authority by: attempting unilaterally to amend or cancel existing agreements or arrangements; failing to honour existing contractual commitments; and seeking to adjudicate disputes between private litigants. Additionally, certain governments have adopted laws and regulations that could potentially force us to violate other countries' laws and regulations, therefore potentially subjecting us to both criminal and civil sanctions. Such developments and outcomes could have a material adverse effect on our operational performance, earnings, cash flows and financial condition.

See "Corporate governance" on page 74.

Our operations expose us to social instability, civil unrest, terrorism, piracy, acts of war and risks of pandemic diseases that could have a material adverse effect on our business.

As seen in recent years in Nigeria, North Africa and the Middle East, social and civil unrest, both in the countries in which we operate and elsewhere, can and do affect us. Such potential developments that could have a material adverse effect on us include: acts of political or economic terrorism; acts of maritime piracy; conflicts including war and civil unrest (including disruptions by non-governmental and political organisations); and local security concerns that threaten the safe operation of our facilities and transport of our products. Pandemic diseases, such as Ebola, can affect our operations directly and indirectly. If such risks materialise, they could result in injuries, loss of life, environmental harm and disruption to business activities. See "Environment and society" on page 59.

A further erosion of the business and operating environment in Nigeria could have a material adverse effect on us.

In our Nigerian operations, we face various risks and adverse conditions which could have a material adverse effect on our operational performance, earnings, cash flows and financial condition. These risks and conditions include: security issues surrounding the safety of our people, host communities and operations; sabotage and theft; our ability to enforce existing contractual rights; litigation; limited infrastructure; potential legislation that could increase our taxes or costs of operations; the effect of lower oil and gas prices on the government budget; and regional instability created by militant activities. In addition, the Nigerian government is contemplating new legislation to govern the petroleum industry which, if passed into law, could have a material adverse effect on our existing and future activities in that country. See "Upstream" on page 29.

Rising climate change concerns have led and could lead to additional legal and/or regulatory measures which could result in project delays or cancellations, a decrease in demand for fossil fuels and additional compliance obligations, and therefore could adversely impact our costs and/or revenue.

There is continued and increased attention to climate change from all sectors of society. This attention has led, and we expect it to continue to lead, to additional regulations designed to reduce greenhouse gas (GHG) emissions and potential demand for fossil fuels. Furthermore, we expect that a growing share of our GHG emissions will be subject to regulation, resulting in increased compliance costs and operational restrictions. If our GHG emissions rise alongside our ambitions to increase the scale of our business, our regulatory burden will increase proportionally.

We also expect that GHG regulation will focus more on suppressing demand for fossil fuels. This could result in lower revenue. In addition, we expect that GHG emissions from flaring will rise where no gas-gathering systems are in place. We intend to continue to work with our partners to find ways to capture the gas that is flared. However, governmental support is fundamental to ensure the success of individual initiatives. There is no assurance that we will be able to obtain government support.

If we are unable to find economically viable, as well as publicly acceptable, solutions that reduce our GHG emissions and/or GHG intensity for new and existing projects or products, we could experience additional costs or financial penalties, delayed or cancelled projects,

RISK FACTORS CONTINUED

and/or reduced production and reduced demand for hydrocarbons, which could have a material adverse effect on our operational performance, earnings, cash flows and financial condition.

See "Environment and society" on pages 54-56.

The nature of our operations exposes us, and the communities in which we work, to a wide range of health, safety, security and environment risks.
The health, safety, security and environment (HSSE) risks to which we, and the communities in which we work, are potentially exposed cover a wide spectrum, given the geographic range, operational diversity and technical complexity of our operations. These risks include the effects of natural disasters (including weather events), earth tremors, social unrest, personal health and safety lapses, and crime. If a major HSSE risk materialises, such as an explosion or hydrocarbon spill, this could result in injuries, loss of life, environmental harm, disruption of business activities, and loss or suspension of our licence to operate or ability to bid on mineral rights. Accordingly, this would have a material adverse effect on our operational performance, earnings, cash flows and financial condition.

Our operations are subject to extensive HSSE regulatory requirements that often change and are likely to become more stringent over time. Operators could be asked to adjust their future production plans, as the government of the Netherlands has done, affecting production and costs. We could incur significant additional costs in the future due to compliance with HSSE requirements or as a result of violations of, or liabilities under, laws and regulations, such as fines, penalties, clean-up costs and third-party claims. Therefore, HSSE risks, should they materialise, could have a material adverse effect on us.

See "Environment and society" on page 53.

The operation of the Groningen asset in the Netherlands continues to expose communities to earth tremor risks.
Production from the Groningen asset has resulted in earth tremors in the past and tremors are expected to continue. This has resulted in damage to buildings and complaints from local communities. The Dutch government, local authorities and the operator are implementing measures to address the concerns of the local communities. The government has ordered a cap on production and a further reduction of production is possible. If the government decides not to develop the full field as currently planned, it could have a material adverse effect on our earnings, cash flows, proved reserves and financial condition. See "Environment and society" on pages 58-59 and "Upstream" on page 27.

Our future performance depends on the successful development and deployment of new technologies and new products.
Technology and innovation are essential to our efforts to meet the world's energy demands in a competitive way. If we do not develop the right technology and products, do not have access to it or do not deploy these effectively, there could be a material adverse effect on the delivery of our strategy and our licence to operate. We operate in environments where advanced technologies are utilised. While we take measures to ensure that such technologies and products are safe for the environment and public health based on today's knowledge, there is always the possibility of unknown or unforeseeable technological failures or environmental and health effects that could harm our reputation and licence to operate or expose us to litigation or sanctions. We seek to benefit financially from developing and deploying advanced technology. The associated costs are sometimes underestimated or delays occur. Any of these occurrences could have a material adverse effect on our operational performance, earnings, cash flows and financial condition. See "Business overview" on page 14.

We are exposed to treasury and trading risks, including liquidity risk, interest rate risk, foreign exchange risk, commodity price risk and credit risk. We are affected by the global macroeconomic environment as well as financial and commodity market conditions.
Our subsidiaries, joint arrangements and associates are subject to differing economic and financial market conditions around the world. Political or economic instability affects such markets. If the associated risks set out below materialise, they could have a material adverse effect on our earnings, cash flows and financial condition.

We use debt instruments, such as bonds and commercial paper, to raise significant amounts of capital. Should our access to debt markets become more difficult, the potential impact on our liquidity could have a material adverse effect on our operations. Our financing costs could also be affected by interest rate fluctuations or any credit rating deterioration.

We are exposed to changes in currency values and to exchange controls as a result of our substantial international operations. Our reporting currency is the dollar. However, to a material extent, we hold assets and are exposed to liabilities in other currencies. We have significant financial exposure to the eurozone and could be materially affected by a significant change in the euro's value or any structural changes to the European Union (EU) or the European Economic and Monetary Union affecting the euro. Commodity trading is an important component of our Upstream and Downstream businesses and is integrated with our supply business. While we undertake some foreign exchange and commodity hedging, we do not do so for all of our activities. Furthermore, even where hedging is in place, it may not function as expected.

We are exposed to credit risk; our counterparties could fail or could be unable to meet their payment and/or performance obligations under contractual arrangements. Although we do not have significant direct exposure to sovereign debt, it is possible that our partners and customers may have exposure which could impair their ability to meet their obligations, thereby having a material adverse effect on us. In addition, our pension funds may invest in government bonds. Therefore, a sovereign debt downgrade or other default could have a material adverse effect on us.

See "Liquidity and capital resources" on page 50.

We have substantial pension commitments, whose funding is subject to capital market risks.
Liabilities associated with defined benefit plans can be significant, as can the cash funding requirement of such plans; both depend on various assumptions. Volatility in capital markets, and the resulting consequences for investment performance and interest rates, could result in significant changes to the funding level of future liabilities, and could also increase balance sheet liabilities. We operate a number of defined benefit pension plans and, in case of a shortfall, we could be required to make substantial cash contributions (depending on the applicable local regulations) resulting in a material adverse effect on our business, earnings and financial condition.
See "Liquidity and capital resources" on page 50.

We mainly self-insure our risk exposure. We could incur significant losses from different types of risks that are not covered by insurance from third-party insurers.
Our insurance subsidiaries provide hazard insurance coverage to other Shell entities and only reinsure a portion of their risk exposures. Such reinsurance would not provide any material coverage in the event of an incident like BP Deepwater Horizon. Similarly, in the event of a material environmental incident, there would be no material proceeds available from

third-party insurance companies to meet our obligations. Therefore, we may incur significant losses from different types of risks that are not covered by insurance from third-party insurers, potentially resulting in a material adverse effect on our operational performance, earnings, cash flows and financial condition. See "Corporate" on page 48.

An erosion of our business reputation could have a material adverse effect on our brand, our ability to secure new resources and our licence to operate.
Our reputation is an important asset. The Shell General Business Principles (Principles) govern how Shell and its individual companies conduct their affairs, and the Shell Code of Conduct (Code) instructs employees and contractors on how to behave in line with the Principles. Our challenge is to ensure that all employees and contractors, more than 100,000 in total, comply with these Principles and Code. Real or perceived failures of governance or regulatory compliance could harm our reputation. This could impact our licence to operate, damage our brand, reduce consumer demand for our branded products, harm our ability to secure new resources and contracts and limit our ability to access capital markets. Many other factors, including the materialisation of the risks discussed in several of the other risk factors, may impact our reputation and could have a material adverse effect on our operational performance, earnings, cash flows and financial condition. See "Corporate governance" on page 70.

Many of our major projects and operations are conducted in joint arrangements or associates. This could reduce our degree of control, as well as our ability to identify and manage risks.
In cases where we are not the operator, we have limited influence over, and control of, the behaviour, performance and costs of operation of such joint arrangements or associates. Despite not having control, we could still be exposed to the risks associated with these operations, including reputational, litigation (where joint and several liability could apply) and government sanction risks, which could have a material adverse effect on our operational performance, earnings, cash flows and financial condition. For example, our partners or members of a joint arrangement or an associate (particularly local partners in developing countries) may not be able to meet their financial or other obligations to the projects, threatening the viability of a given project. Where we are the operator of a joint arrangement, the other partner(s) could still be able to veto or block certain decisions, which could be to our overall detriment. See "Corporate governance" on page 74.

We rely heavily on information technology systems for our operations.
The operation of many of our business processes depends on information technology (IT) systems. Our IT systems are increasingly concentrated in terms of geography, number of systems, and key contractors supporting the delivery of IT services. Shell, like many other multinational companies, is the target of attempts to gain unauthorised access to our IT systems through the internet, including more sophisticated and coordinated attempts often referred to as advanced persistent threats. We seek to detect and investigate all such security incidents, aiming to prevent their recurrence. Disruption of critical IT services, or breaches of information security, could harm our reputation and have a material adverse effect on our operational performance, earnings and financial condition. See "Corporate" on page 48.

Violations of antitrust and competition laws carry fines and expose us and/or our employees to criminal sanctions and civil suits.
Antitrust and competition laws apply to Shell and its joint ventures and associates in the vast majority of countries in which we do business. Any violation of these laws could have a material adverse effect on our operational performance, earnings, cash flows and financial condition. Shell and its joint ventures and associates have been fined for violations of antitrust and competition laws. These include a number of fines in the past by the European Commission Directorate-General for Competition (DG COMP). Due to the DG COMP's fining guidelines, any future conviction of Shell and its joint ventures or associates for violation of EU competition law could result in significantly larger fines and have a material adverse effect on us. Violation of antitrust laws is a criminal offence in many countries, and individuals can be either imprisoned or fined. Furthermore, it is now common for persons or corporations allegedly injured by antitrust violations to sue for damages. See "Corporate governance" on page 70.

Violations of anti-bribery and corruption laws and anti-money laundering laws carry fines and expose us and/or our employees to criminal sanctions and civil suits.
In 2010, we agreed to a Deferred Prosecution Agreement (DPA) with the US Department of Justice (DOJ) for violations of the Foreign Corrupt Practices Act (FCPA), which arose in connection with our use of the freight-forwarding firm Panalpina. In 2013, following our fulfilment of the terms of the DPA, the criminal charges filed in connection with the DPA were dismissed. Our ethics and compliance programme was enhanced during the DPA and remains in full force and effect. The authorities in various countries are investigating our investment in Nigerian oil block OPL 245 and the 2011 settlement of litigation pertaining to that block. Any violation of the FCPA or other relevant anti-bribery and corruption legislation or anti-money laundering legislation could have a material adverse effect on our operational performance, earnings, cash flows and financial condition. See "Corporate governance" on page 70.

Violations of data protection laws carry fines and expose us and/or our employees to criminal sanctions and civil suits.
Data protection laws apply to Shell and its joint ventures and associates in the vast majority of countries in which we do business. Over 100 countries have data protection laws and regulations. Additionally, the impending EU Data Privacy Regulation proposes to increase penalties up to a maximum of 5% of global annual turnover for breach of the regulation. Non-compliance with data protection laws could expose us to regulatory investigations, which could result in fines and penalties. We could also be subject to litigation from persons or corporations allegedly affected by data protection violations. Violation of data protection laws is a criminal offence in some countries, and individuals can be either imprisoned or fined. Any violation could have a material adverse effect on our operational performance, earnings, cash flows and financial condition. See "Corporate governance" on page 70.

Violations of trade controls, including sanctions, carry fines and expose us and our employees to criminal sanctions and civil suits.
We use "trade controls" as an umbrella term for various national and international laws designed to regulate the movement of items across national boundaries and restrict or prohibit trade and other dealings with certain parties. The number and breadth of trade controls which we face continues to expand. For example, the EU and the USA continue to impose restrictions and prohibitions on certain transactions involving Syria. Additional trade controls directed at defined oil and gas activities in Russia were imposed by the EU and the USA in 2014. In addition to the significant trade-control programmes administered by the EU and the USA, many other nations are also adopting such programmes. Any violation of one or more trade-control regimes could lead to significant penalties or prosecution of Shell or its employees, and could have a material adverse effect on our operational performance, earnings, cash flows and financial condition. See "Corporate governance" on page 70.

RISK FACTORS CONTINUED

Investors should also consider the following, which could limit shareholder remedies.

The Company's Articles of Association determine the jurisdiction for shareholder disputes. This could limit shareholder remedies.
Our Articles of Association generally require that all disputes between our shareholders in such capacity and the Company or our subsidiaries (or our Directors or former Directors), or between the Company and our Directors or former Directors, be exclusively resolved by arbitration in The Hague, the Netherlands, under the Rules of Arbitration of the International Chamber of Commerce. Our Articles of Association also provide that, if this provision is to be determined invalid or unenforceable for any reason, the dispute could only be brought to the courts of England and Wales. Accordingly, the ability of shareholders to obtain monetary or other relief, including in respect of securities law claims, could be determined in accordance with these provisions.

BUSINESS OVERVIEW

HISTORY

From 1907 until 2005, Royal Dutch Petroleum Company and The "Shell" Transport and Trading Company, p.l.c. were the two public parent companies of a group of companies known collectively as the "Royal Dutch/Shell Group". Operating activities were conducted through the subsidiaries of these parent companies. In 2005, Royal Dutch Shell plc became the single parent company of Royal Dutch Petroleum Company and of The "Shell" Transport and Trading Company, p.l.c., now The Shell Transport and Trading Company Limited.

Royal Dutch Shell plc (the Company) is a public limited company registered in England and Wales and headquartered in The Hague, the Netherlands.

ACTIVITIES

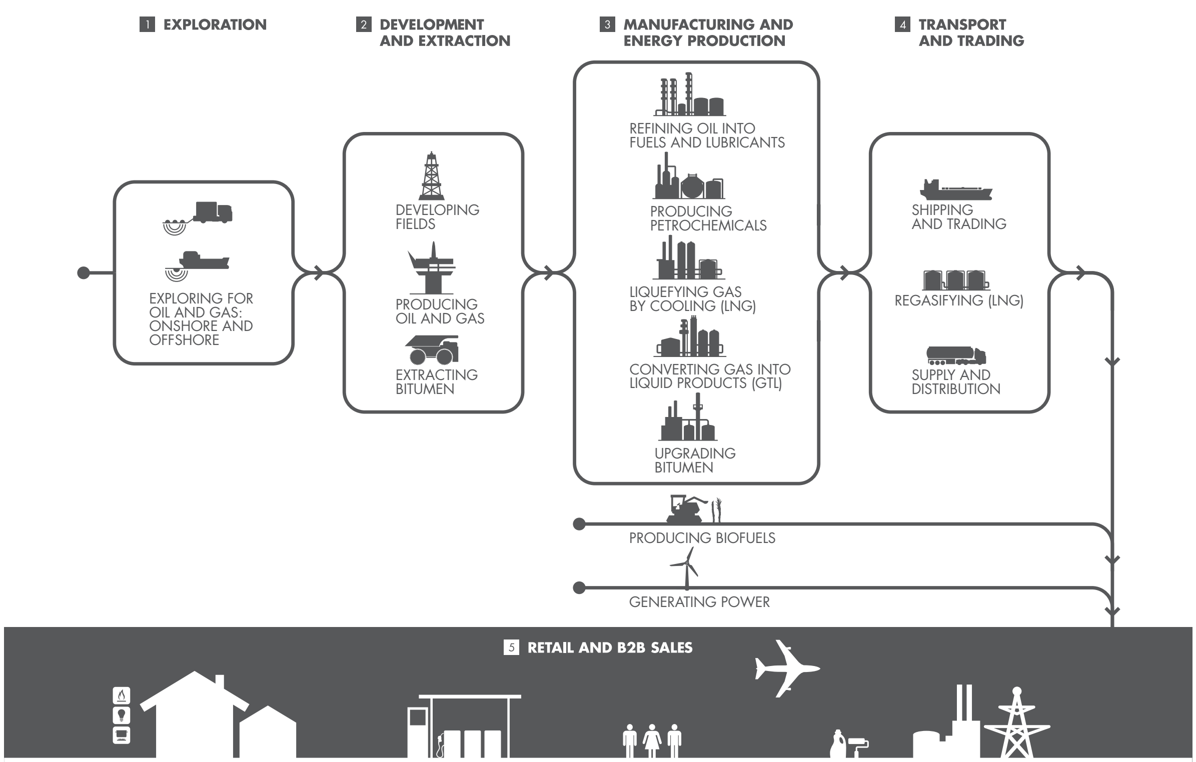
Shell is one of the world's largest independent oil and gas companies in terms of market capitalisation, operating cash flow and production.

We explore for crude oil and natural gas worldwide, both in conventional fields and from sources such as tight rock, shale and coal formations. We work to develop new crude oil and natural gas supplies from major fields. For example, in 2015, production began from the Bonga Phase 3 and Erha North Phase 2 projects in Nigeria, and the Corrib gas field in Ireland. We also extract bitumen from oil sands, which we convert into synthetic crude oil.

We cool natural gas to provide liquefied natural gas (LNG) that can be safely shipped to markets around the world, and we convert gas to liquids (GTL).

Our portfolio of refineries and chemical plants enables us to capture value from the oil and gas that we produce, turning them into a range of refined and petrochemical products, which are moved and marketed around the world for domestic, industrial and transport use. The products we sell include gasoline, diesel, heating oil, aviation fuel, marine fuel, LNG for transport, lubricants, bitumen and sulphur. We also produce and sell ethanol from sugar cane in Brazil, through our Raízen joint venture.

The distinctive Shell pecten, (a trademark in use since the early part of the 20th century), and trademarks in which the word Shell appears, help raise the profile of our brand globally. A strong patent portfolio underlies the technology that we employ in our various businesses. In total, we have about 12,000 granted patents and pending patent applications.



BUSINESS OVERVIEW CONTINUED

BUSINESSES AND ORGANISATION

In 2016, the Upstream International and Upstream Americas businesses were reorganised into Integrated Gas and Upstream. Our businesses and organisations described below were in place until December 31, 2015, and are consistent with the discussion of our performance in 2015 and position at December 31, 2015, in this Report.

Upstream International

Our Upstream International business manages Shell's Upstream activities outside the Americas. It explores for and extracts crude oil, natural gas and natural gas liquids, transports oil and gas, and operates the upstream and midstream infrastructure necessary to deliver oil and gas to market. Upstream International also manages the LNG and GTL businesses outside the Americas, and markets and trades natural gas, including LNG, outside the Americas. It manages its operations primarily by line of business, with this structure overlaying country organisations. This organisation is supported by activities such as Exploration and New Business Development. See "Upstream" on pages 23-40.

Upstream Americas

Our Upstream Americas business manages Shell's Upstream activities in North and South America. It explores for and extracts crude oil, natural gas and natural gas liquids, transports oil and gas, and operates the upstream and midstream infrastructure necessary to deliver oil and gas to market. Upstream Americas also extracts bitumen from oil sands that is converted into synthetic crude oil. It manages the LNG business in the Americas, and markets and trades natural gas in the Americas. Additionally, it manages the US-based wind business. It manages its operations by line of business, supported by activities such as Exploration and New Business Development. See "Upstream" on pages 23-40.

Downstream

Our Downstream business manages Shell's Oil Products activities, comprising Refining, Trading and Supply, Pipelines and Marketing, and Chemicals activities. See "Downstream" on pages 41-47.

Projects & Technology

Our Projects & Technology organisation manages the delivery of our major projects and drives research and innovation to develop new technology solutions. It provides technical services and technology capability covering both Upstream and Downstream activities. It is also responsible for providing functional leadership across Shell in the areas of safety and environment, contracting and procurement, wells activities and CO_2 management.

Our future hydrocarbon production depends on the delivery of large and complex projects (see "Risk factors" on page 08). Systematic management of lifecycle technical and non-technical risks is in place for each opportunity, with assurance and control activities embedded throughout the project lifecycle. We focus on the cost-effective delivery of projects through quality commercial agreements, supply-chain management and construction and engineering productivity through effective planning and simplification of delivery processes. Development of our employees' project management competencies is underpinned by project principles, standards and processes. A dedicated competence framework, training, standards and processes exist for exploration and appraisal activities. In addition, we provide governance support for our non-operated ventures or projects.

SEGMENTAL REPORTING

Our reporting segments at December 31, 2015, were Upstream, Downstream and Corporate. Upstream combines the operating segments Upstream International and Upstream Americas. Upstream and Downstream earnings include their respective elements of Projects & Technology and of trading and supply activities. Corporate comprises Shell's holdings and treasury organisation, including its self-insurance activities as well as its headquarters and central functions. See Note 4 to the "Consolidated Financial Statements" on page 126.

REVENUE BY BUSINESS SEGMENT (INCLUDING INTER-SEGMENT SALES) $ MILLION

	2015	2014	2013
Upstream			
Third parties	28,480	45,240	47,357
Inter-segment	25,447	47,059	45,512
Total	53,927	92,299	92,869
Downstream			
Third parties	236,384	375,752	403,725
Inter-segment	1,362	2,294	702
Total	237,746	378,046	404,427
Corporate			
Third parties	96	113	153
Total	96	113	153

REVENUE BY GEOGRAPHICAL AREA (EXCLUDING INTER-SEGMENT SALES) $ MILLION

	2015	2014	2013
Europe	95,223	154,709	175,584
Asia, Oceania, Africa	95,892	149,869	157,673
USA	50,666	80,133[A]	79,581[A]
Other Americas	23,179	36,394[A]	38,397[A]
Total	264,960	421,105	451,235

[A] Revised following a reassessment of geographical allocation, resulting in an increase in the USA and a corresponding decrease in Other Americas of $9,320 million in 2014 and $7,029 million in 2013.

With effect from 2016, our reporting segments were amended to align with the reorganisation of the Upstream business and consist of Integrated Gas, Upstream, Downstream and Corporate.

RESEARCH AND DEVELOPMENT

In 2015, research and development expenses were $1,093 million, compared with $1,222 million in 2014, and $1,318 million in 2013. Our main technology centres are in India, the Netherlands and the USA, with other centres in Canada, China, Germany, Norway, Oman and Qatar.

Technology and innovation are essential to our efforts to meet the world's energy demands in a competitive way. If we do not develop the right technology, do not have access to it or do not deploy it effectively, this could have a material adverse effect on the delivery of our strategy and our licence to operate (see "Risk factors" on page 10). We continuously scan the external environment for technologies and innovations of potential relevance to our business. Our Chief Technology Officer oversees the development and deployment of new and differentiating technologies and innovations across Shell, seeking to align business requirements and technology requirements throughout our technology maturation process.

STRATEGY AND OUTLOOK

STRATEGY

Our strategy seeks to reinforce our position as a leader in the oil and gas industry, while helping to meet global energy demand in a responsible way. We aim to balance growth with returns, by growing our cash flow and delivering competitive returns through economic cycles, to finance a competitive dividend and fund investment for future growth. Safety and environmental and social responsibility are at the heart of our activities.

Meeting the growing demand for energy worldwide in ways that minimise environmental and social impact is a major challenge for the global energy industry. We aim to improve energy efficiency in our own operations, support customers in managing their energy demands and continue to research and develop technologies that increase efficiency and reduce emissions from liquids and natural gas production.

Intense competition exists for access to upstream resources and to new downstream markets. But we believe that our technology, project delivery capability and operational excellence will remain key differentiators for our businesses.

In April 2015, we announced a recommended cash and share offer for BG Group plc (BG), and the transaction was completed on February 15, 2016. It should add significant scale and profitability, particularly in LNG worldwide and deep-water oil and gas in Brazil. It presents an opportunity to accelerate portfolio refocusing through asset sales and reduced spending, resulting in a simpler, more focused company.

With effect from 2016, we have a new upstream organisation that reflects recent changes in our portfolio. This is the platform for integration with BG and will help speed up the streamlining of the portfolio.

In Integrated Gas, we focus on liquefying natural gas (LNG) so that it can be safely shipped to markets around the world, and we convert gas to liquids (GTL).

In Upstream, we focus on exploration for new crude oil and natural gas reserves and on developing major new projects where our technology and know-how add value to the resources holders.

In Downstream, we focus on turning crude oil into a range of refined products, which are moved and marketed around the world for domestic, industrial and transport use. In addition, we produce and sell petrochemicals for industrial use worldwide.

We focus on a series of strategic themes, each requiring distinctive technologies and risk management:

- Our Downstream businesses in Oil Products and Chemicals are strongly cash-generative with high returns. Our distinctive product offering is underpinned by a strong manufacturing base, and offers growth potential in selective markets, particularly in petrochemicals.
- Our conventional oil and gas business has strong cash flow and returns potential, typically in mature hydrocarbon provinces. We only make investments in selective growth positions and apply our distinctive technology and operating performance to extend the productive lives of our assets and to enhance their profitability.
- In deep water, we have leading positions in the Gulf of Mexico, Brazil, Nigeria and Malaysia. Our deep-water operations have significant growth potential from our large undeveloped resource base, and deployment of our technology and capabilities.
- In Integrated Gas, covering LNG worldwide, and in GTL in Qatar and Malaysia, we have leadership positions in profitable and growing markets. We are making selective investments in new LNG capacity, and continuing to develop new markets for gas.
- We have substantial positions in both heavy oil and oil and gas plays. These reserves are in production today, with substantial longer-term growth potential.
- Reflecting the long-term trend in demand growth for lower-carbon energy, we intend to make investments in large-scale and commercial forms of lower-carbon technology and energy, such as natural gas, carbon capture and storage, biofuels, wind and solar energy.

Our commitment to technology and innovation continues to be at the core of our strategy. As energy projects become more complex and more technically demanding, we believe our engineering expertise will be a deciding factor in the growth of our businesses. Our key strengths include the development and application of technology, the financial and project-management skills that allow us to deliver large field-development projects, and the management of integrated value chains.

We aim to leverage our diverse and global business portfolio and customer-focused businesses built around the strength of the Shell brand.

Our ability to achieve strategic objectives depends on how we respond to competitive forces (see "Risk factors" on page 08). We continuously assess the external environment – the markets as well as the underlying economic, political, social and environmental drivers that shape them – to anticipate changes in competitive forces and business models. We undertake regular reviews of the markets we operate in, and analyses of our competitors' strengths and weaknesses to understand our competitive position. We maintain business strategies and plans that focus on actions and capabilities to create and sustain competitive advantage.

OUTLOOK FOR 2016 AND BEYOND

We continuously seek to improve our operating performance, with an emphasis on health, safety, security and environment, asset performance and operating costs.

In 2016, we expect organic capital investment to be around $33 billion in the current environment. We have options to further reduce capital investment, should the evolving market outlook warrant that step. We are being highly selective on new investment decisions. We are leveraging our Projects & Technology organisation's capabilities and taking opportunities presented by the downturn to reduce both our own costs and costs in the supply chain. Asset sales are a key element of our strategy, improving our capital efficiency by focusing our investments on the most attractive growth opportunities. Divestments of non-strategic assets in 2014-15 totalled over $20 billion, successfully completing our divestment programme for that period. We expect divestments to increase to $30 billion for 2016-2018.

In addition, we expect the combination with BG to generate pre-tax synergies of $3.5 billion in operating and exploration expenses in 2018, with further upside potential. A transition organisation is in place to track the delivery of the integration plans, including the expected synergies, identification of further value upside, and move to standardised operating arrangements (see "Risk factors" on page 08).

The statements in this "Strategy and outlook" section, including those related to our growth strategies and our expected or potential future cash flow from operations, capital investment, divestments and production, are based on management's current expectations and certain material assumptions and, accordingly, involve risks and uncertainties that could cause actual results, performance or events to differ materially from those expressed or implied herein. See "About this Report" on page 05 and "Risk factors" on pages 08-12. Forward-looking information includes the impact of the BG acquisition.

MARKET OVERVIEW

We maintain a large business portfolio across a fully-integrated value chain and are therefore exposed to oil, gas and product prices as well as refining, chemicals and marketing margins (see "Risk factors" on page 08). This diversified portfolio helps us mitigate the impact of price volatility. Our annual planning cycle and periodic portfolio reviews aim to ensure that our levels of capital investment and operating expenses are affordable in the context of a volatile price environment. We test the resilience of our projects and other opportunities against a range of oil and gas prices. We also maintain a strong balance sheet to provide resilience in times of fluctuating oil and gas prices.

GLOBAL ECONOMIC GROWTH

According to the International Monetary Fund's (IMF) January 2016 *World Economic Outlook*, global economic growth was 3.1% in 2015. This fell short of the IMF's forecast of 3.5% made at the beginning of 2015. Lower than expected economic growth in the USA and China, together with recessions in Brazil and Russia, contributed to lower global economic growth than forecast.

The IMF estimated that the eurozone economy grew by 1.5% in 2015, compared with 0.9% in 2014, US economic growth was 2.5%, compared with 2.4% in 2014, while Chinese economic growth slowed from 7.3% in 2014 to 6.9%. The average economic growth rate for emerging markets and developing economies was 4.0%, compared with 4.6% in 2014.

The IMF expects global economic growth to rise to 3.4% in 2016, but that would still be less than the annual average of 3.7% for the previous 10 years.

GLOBAL OIL AND GAS DEMAND AND SUPPLY

Reflecting the combination of the economic conditions described above and of low crude oil prices during the year, global oil demand rose by 1.8% (1.7 million barrels per day (b/d)) in 2015, according to the International Energy Agency's (IEA) January 2016 *Oil Market Report*. This annual oil demand growth was the highest since 2005. Lower crude oil prices are thought to have triggered additional demand not only from end-consumers, for example in the USA, but also strategic petroleum reserves building in Asia, particularly China. Demand grew in emerging and advanced economies.

The Brent crude oil price, an international crude-oil benchmark, averaged $52/b, the lowest level since 2005. As in 2014, oil supply continued to grow faster than demand. On the non-OPEC supply side, the US Energy Information Administration reported another year of continued supply growth albeit at a slower pace. Daily production in the USA declined in the second half of 2015, as light tight oil producers drilled fewer wells in response to lower prices. However, ongoing technical improvements and increased focus on the most productive areas helped increase recovery per well. OPEC oil production grew by 1 million b/d year-on-year driven primarily by Saudi Arabia and Iraq. At the June and December OPEC meetings, it was decided not to reduce production in support of oil prices. The market interpreted these decisions as an increased risk of oversupply: crude oil prices remained low and ended the year at around $36/b for Brent compared with $54/b at the start of the year.

We estimate that global gas demand grew by less than 1% in 2015, which is much lower than the average annual growth rate of about 2.3% in the past decade. A combination of mild weather and continued moderate global economic growth led to a lower rate of demand growth in most regions. We believe that most of the growth in demand was in the USA with an estimated 10% increase over 2014, driven by its power generation and industrial sectors. Asian gas demand growth weakened in the key markets of China, Japan and Korea. Chinese demand in the first nine months of 2015 grew by only 3% year-on-year, compared with the average 15% growth seen in previous years. Gas demand across the European Union is expected to have increased by about 7% in 2015 compared with 2014, according to the latest forecast from gas industry association Eurogas. The first half of 2015 saw a significant increase of approximately 9% in gas demand, compared with the same period in 2014.

CRUDE OIL AND NATURAL GAS PRICES

The following table provides an overview of the main crude oil and natural gas price markers that we are exposed to:

OIL AND GAS AVERAGE INDUSTRY PRICES [A]

	2015	2014	2013
Brent ($/b)	52	99	109
West Texas Intermediate ($/b)	49	93	98
Henry Hub ($/MMBtu)	2.6	4.3	3.7
UK National Balancing Point (pence/therm)	43	50	68
Japan Customs-cleared Crude ($/b)	55	105	110

[A] Yearly average prices are based on daily spot prices. The 2015 average price for Japan Customs-cleared Crude excludes December data.

The Brent crude oil price traded in a range of $35-67/b in 2015, ending the year at about $36/b. Both the Brent and the West Texas Intermediate (WTI) average crude oil prices for 2015 were lower than in 2014, as a result of demand growth being outpaced by continued supply growth, which has resulted in crude oil and oil products inventory levels well above their historical five-year averages.

On a yearly average basis, WTI traded at a $3/b discount to Brent in 2015, compared with $6/b in 2014. The discount widened during the spring US refinery maintenance season to about $13/b as a consequence of reduced refinery crude oil intake and therefore higher crude oil inventory levels in the landlocked Cushing, Oklahoma, trading hub. Towards the end of the year, Brent and WTI crude oil prices were nearly equal.

Looking ahead, significant price volatility can be expected in the short to medium term. Crude oil prices may strengthen if the global economy accelerates, or if supply tightens as a result of a further deceleration in non-OPEC production growth due to the current price weakness, if OPEC countries reduce their production levels, or if supply disruptions occur in major producing countries. Alternatively, crude oil prices may weaken further if economic growth slows or production continues to rise, for example from Iran after the lifting of sanctions.

Unlike crude oil pricing, which is global in nature, natural gas prices vary significantly from region to region. In the USA, the natural gas price at the Henry Hub averaged $2.6 per million British thermal units (MMBtu) in 2015, 40% lower than in 2014, and traded in a range of $1.5-3.3/MMBtu. The year 2015 began with normal winter weather and gas at the Henry Hub traded between $2 and 3.3/MMBtu through the first half of the year. But robust growth in gas production and normal weather in the summer led to a gradual decline in prices during the second half as gas in storage reached a record high of some 4 trillion cubic feet by November 2015. A relatively very warm start of the 2015-2016 winter season led to a steep decline in Henry Hub prices which then remained below $2/MMBtu for prolonged periods. In the longer term, the US market may tighten due to exports of liquefied natural gas (LNG).

In Europe, natural gas prices fell during 2015. The average natural gas price at the UK National Balancing Point was 14% lower than in 2014. At the main continental European gas trading hubs – in the Netherlands, Belgium and Germany – prices were similarly weak. Lower prices reflected ample supply which was in part driven by lower oil-indexed contract prices.

Weather, a key driver for gas demand, was mixed during the year with unusually mild temperatures in the fourth quarter.

We also produce and sell natural gas in regions where supply, demand and regulatory circumstances differ markedly from those in the USA or Europe. Long-term contracted LNG prices in Asia-Pacific generally fell in 2015 as they are predominantly indexed to the price of Japan Customs-cleared Crude (JCC), which has fallen as global crude oil prices have weakened.

CRUDE OIL AND NATURAL GAS PRICE ASSUMPTIONS

Our ability to deliver competitive returns and pursue commercial opportunities depends in part on the robustness and, ultimately, the accuracy of our price assumptions (see "Risk factors" on page 08). The range of possible future crude oil and natural gas prices used in project and portfolio evaluations is determined after a rigorous assessment of short, medium and long-term market drivers. Historical analyses, trends and statistical volatility are considered in this assessment, as are analyses of market fundamentals such as possible future economic conditions, geopolitics, actions by OPEC and other major resource holders, production costs and the balance of supply and demand. Sensitivity analyses are used to test the impact of low-price drivers, such as economic weakness, and high-price drivers, such as strong economic growth and low investment in new production capacity. Short-term events, such as relatively warm winters or cool summers, affect demand. Supply disruptions, due to weather or political instability, contribute to price volatility.

REFINING AND PETROCHEMICAL MARGINS

REFINING MARKER AVERAGE INDUSTRY GROSS MARGINS			($/B)
	2015	2014	2013
US West Coast	19.4	9.5	8.7
US Gulf Coast Coking	10.6	5.5	3.9
Rotterdam Complex	4.7	1.3	1.4
Singapore	4.7	(0.1)	(1.0)

Industry gross refining margins were higher on average in 2015 than in 2014 in each of the key refining hubs in Europe, Singapore and the USA. Oil products demand growth was stronger globally, driven in part by the sustained lower crude oil price environment compared with 2014. The refining industry has seen a period of generally tightening capacity, reducing the overcapacity that has been observed for several years. However, the improved gross margins have probably delayed some further capacity rationalisation, especially in Europe.

In 2016, demand for gasoline is expected to be a key driver of gross refining margins, especially in the middle of the year, supported by demand for middle distillates. The overall outlook remains unclear because of continuing economic uncertainty, geopolitical tensions in some regions that could lead to supply disruptions, and continued overcapacity in the global refining market.

CRACKER INDUSTRY MARGINS			($/TONNE)
	2015	2014	2013
North East/South East Asia naphtha	463	296	132
Western Europe naphtha	617	613	548
US ethane	498	798	770

In Chemicals, Asian naphtha cracker margins increased in 2015 compared with 2014 due to periods of reduced cracker availability. European naphtha cracker margins remained high in 2015, supported by periods of low cracker availability. US ethane cracker margins were significantly lower due to a narrower differential between crude oil prices and US natural gas prices.

The outlook for petrochemicals in 2016 will depend on economic growth, especially in Asia, and developments in relative raw material prices which will be influenced by crude oil prices.

SUMMARY OF RESULTS

KEY STATISTICS	$ MILLION, EXCEPT WHERE OTHERWISE INDICATED		
	2015	2014	2013
Earnings by segment [A]			
Upstream	(5,663)	15,841	12,638
Downstream	10,243	3,411	3,869
Corporate	(425)	(156)	372
Total segment earnings [A][B]	4,155	19,096	16,879
Attributable to non-controlling interest	(313)	(55)	(134)
Earnings on a current cost of supplies basis attributable to Royal Dutch Shell plc shareholders [B]	3,842	19,041	16,745
Capital investment [B]	28,861	37,339	46,041
Divestments [B]	5,540	15,019	1,738
Operating expenses [B]	41,144	45,225	44,379
Return on average capital employed [B]	1.9%	7.1%	7.9%
Gearing at December 31 [C]	14.0%	12.2%	16.1%
Proved oil and gas reserves at December 31 (million boe)	11,747	13,081	13,944

[A] Segment earnings are presented on a current cost of supplies basis. See Note 4 to the "Consolidated Financial Statements" on pages 127-128.
[B] See "Non-GAAP measures reconciliations and other definitions" on pages 198-199.
[C] See Note 14 to the "Consolidated Financial Statements" on page 134.

EARNINGS 2015-2014

Global realised liquids prices in 2015 were 48% lower than in 2014. Global realised natural gas prices were 27% lower than in 2014. Oil and gas production available for sale in 2015 was 2,954 thousand barrels of oil equivalent per day (boe/d) compared with 3,080 thousand boe/d in 2014. Liquids production increased by 2% and natural gas production decreased by 9% compared with 2014.

Realised refining margins were significantly higher in 2015 than in 2014, driven by stronger industry gross margins and improved availability early in 2015, which allowed our refineries to capitalise on the strong margin environment.

Earnings on a current cost of supplies basis (CCS earnings) exclude the effect of changes in the oil price on inventory valuation, as the purchase price of the volumes sold during a period is based on the current cost of supplies during the same period, after making allowance for the tax effect. Accordingly, when oil prices increase during the period, CCS earnings are likely to be lower than earnings calculated on a first-in first-out (FIFO) basis. Similarly, in a period with declining oil prices, CCS earnings are likely to be higher than earnings calculated on a FIFO basis. This explains why 2015 CCS earnings attributable to shareholders were higher than income attributable to shareholders calculated on a FIFO basis, as shown in "Non-GAAP measures and other definitions" on page 198.

CSS earnings attributable to Royal Dutch Shell plc shareholders were $3,842 million in 2015 compared with $19,041 million in 2014.

Upstream earnings in 2015 were a loss of $5,663 million, compared with an income of $15,841 million in 2014. Lower earnings in 2015 reflected the significant decline in oil and gas prices, charges associated with management's decision to cease Alaska drilling activities for the foreseeable future and the Carmon Creek project in Canada, higher impairment charges, lower divestment gains and the weakening of the Australian dollar and Brazilian real on deferred tax positions, partly offset by lower operating expenses and depreciation, depletion and amortisation. See "Upstream" on page 23.

Downstream earnings in 2015 were $10,243 million compared with $3,411 million in 2014. The increase was principally driven by lower operating expenses, as a result of favourable exchange rates and divestments, higher realised refining margins, and a lower effective tax rate, together with lower impairment charges and higher divestment gains. See "Downstream" on pages 41-42.

Corporate earnings in 2015 were a loss of $425 million, compared with a loss of $156 million in 2014. See "Corporate" on page 48.

As set out in Note 4 to the "Consolidated Financial Statements" on page 127, earnings included a taxation charge of $493 million in 2015, compared with $15,038 million in 2014. This reduction was due to the significant tax credits associated with the impairment charges, and other charges related to ceasing activities in Alaska and the Carmon Creek project, and to the overall reduction in Upstream earnings before taxation as a result of lower oil and gas prices.

EARNINGS 2014-2013

CCS earnings attributable to shareholders in 2014 were 14% higher than in 2013.

Upstream earnings in 2014 were $15,841 million, compared with $12,638 million in 2013. The increase was mainly driven by increased contributions from liquids production volumes, higher divestment gains, lower exploration expenses, increased contributions from Trading and Supply and lower impairment charges. These effects were partially offset by the impact of declining oil prices and higher depreciation (excluding impairments).

Downstream earnings in 2014 were $3,411 million compared with $3,869 million in 2013, reflecting significantly higher charges for impairment which were partially offset by higher realised refining margins, higher earnings from Trading and Supply and lower operating expenses.

Corporate earnings in 2014 were a loss of $156 million, compared with a gain of $372 million in 2013.

CAPITAL INVESTMENT AND OTHER INFORMATION

Capital investment was $28.9 billion in 2015, compared with $37.3 billion in 2014, reflecting our decision to curtail spending. See "Upstream" on page 24 and "Downstream" on page 42.

Divestments were $5.5 billion in 2015, compared with $15.0 billion in 2014. See "Upstream" on page 24 and "Downstream" on page 42.

The decrease in operating expenses from $45.2 billion in 2015 to $41.1 billion in 2014 included favourable exchange rate effects and the impact of divestments. See "Upstream" on page 23 and "Downstream" on page 41.

Our return on average capital employed (ROACE) decreased to 1.9% compared with 7.1% in 2014, due to lower earnings. In 2015, 31% of our average capital employed was not generating any revenue, which reduced our ROACE by 1%. These assets included projects being developed and exploration acreage.

Gearing was 14.0% at the end of 2015, compared with 12.2% at the end of 2014. Debt and cash increased by $12.8 billion and $10.1 billion respectively, and total equity decreased by $8.7 billion. See "Liquidity and capital resources" on page 50.

PROVED RESERVES AND PRODUCTION

Shell subsidiaries' and the Shell share of joint ventures and associates' estimated net proved oil and gas reserves are summarised in "Upstream" on pages 25-26 and set out in more detail in "Supplementary information – oil and gas (unaudited)" on pages 153-161.

In 2015, proved reserves before taking production into account decreased by 220 million boe, of which 157 million boe came from Shell subsidiaries and 63 million boe from the Shell share of joint ventures and associates, including a net reduction from sales and purchases of 84 million boe. The proved reserves changes in 2015 included an addition of 600 million boe as a result of an increased entitlement share due to the lower yearly average price applied to production-sharing contracts (PSC) and tax/variable royalty contracts.

In 2015, total oil and gas production was 1,114 million boe, of which 1,078 million boe was available for sale and 36 million boe was consumed in operations. Production available for sale from subsidiaries was 880 million boe and 27 million boe was consumed in operations. The Shell share of the production available for sale of joint ventures and associates was 198 million boe and 9 million boe was consumed in operations.

Accordingly, after taking production into account, our proved reserves decreased in 2015 by 1,334 million boe to 11,747 million boe at December 31, 2015, with a decrease of 1,064 million boe from subsidiaries and a decrease of 270 million boe from the Shell share of joint ventures and associates.

KEY ACCOUNTING ESTIMATES AND JUDGEMENTS

See Note 2 to the "Consolidated Financial Statements" on pages 120-125.

LEGAL PROCEEDINGS

See Note 25 to the "Consolidated Financial Statements" on page 151.

PUBLICATION OF PROFIT ESTIMATES

In our update on fourth quarter 2015 and full year 2015 unaudited results published on January 20, 2016, we made the following profit estimates for the full year 2015:

- Earnings on a CCS basis were expected to be in the region of $10.4-10.7 billion excluding "identified items".
- Income attributable to Royal Dutch Shell plc shareholders was expected to be in the region of $1.6-2.0 billion.

The actual results for the full year 2015, in respect of the above profit estimates, were within the ranges stated above, and were as follows:

- Earnings on a CCS basis were $10,676 million, excluding a net charge in Upstream of $7,443 million (see "Upstream" on page 23), a net gain of $495 million in Downstream (see "Downstream" on pages 41-42) and a net gain in Corporate of $114 million.
- Income attributable to Royal Dutch Shell plc shareholders was $1,939 million. See "Non-GAAP measures reconciliations and other definitions" on page 198.

PERFORMANCE INDICATORS

KEY PERFORMANCE INDICATORS

Total shareholder return

2015 -29.9% 2014 -3.0%

Total shareholder return (TSR) is the difference between the share price at the beginning of the year and the share price at the end of the year (each averaged over 30 days), plus gross dividends delivered during the calendar year (reinvested quarterly), expressed as a percentage of the share price at the beginning of the year (averaged over 30 days). The data used are a weighted average in dollars for A and B shares. The TSRs of major publicly-traded oil and gas companies can be compared directly, providing a way to determine how we are performing in relation to our industry peers.

Net cash from operating activities ($ billion)

2015 30 2014 45

Net cash from operating activities is the total of all cash receipts and payments associated with our sales of oil, gas, chemicals and other products. The components that provide a reconciliation from income for the period are listed in the "Consolidated Statement of Cash Flows". This indicator reflects our ability to generate cash for both distributions to shareholders and investments. See "Liquidity and capital resources" on page 49.

Project delivery

2015 82% 2014 83%

Project delivery reflects our capability to complete major projects on time and within budget on the basis of targets set in our annual Business Plan. The set of projects consists of at least 20 Shell-operated capital projects that are in the execution phase (post final investment decision) and are reflected in the above index.

Production available for sale (thousand boe/d)

2015 2,954 2014 3,080

Production is the sum of all average daily volumes of unrefined oil and natural gas produced for sale by Shell subsidiaries and Shell's share of those produced for sale by joint ventures and associates. The unrefined oil comprises crude oil, natural gas liquids, synthetic crude oil and bitumen. The gas volume is converted into equivalent barrels of oil to make the summation possible. Changes in production have a significant impact on our cash flow. See "Upstream" on page 24.

Equity sales of liquefied natural gas (million tonnes)

2015 22.6 2014 24.0

Equity sales of liquefied natural gas (LNG) is a measure of the operational performance of our Upstream business and LNG market demand. See "Upstream" on page 24.

Refinery and chemical plant availability

2015 89.3% 2014 92.1%

Refinery and chemical plant availability is the weighted average of the actual uptime of plants as a percentage of their maximum possible uptime. The weighting is based on the capital employed, adjusted for cash and non-current liabilities. It excludes downtime due to uncontrollable factors, such as hurricanes. This indicator is a measure of the operational excellence of our Downstream manufacturing facilities. See "Downstream" on page 42.

Total recordable case frequency (injuries per million working hours)

2015 0.94 2014 0.99

Total recordable case frequency (TRCF) is the number of staff or contractor injuries requiring medical treatment or time off for every million hours worked. It is a standard measure of occupational safety. See "Environment and society" on pages 53-54.

ADDITIONAL PERFORMANCE INDICATORS

Earnings on a current cost of supplies basis attributable to Royal Dutch Shell plc shareholders ($ million)
2015 3,842 2014 19,041

Earnings per share on a current cost of supplies basis ($)
2015 0.61 2014 3.02

Earnings on a current cost of supplies basis (CCS earnings) attributable to Royal Dutch Shell plc shareholders is the income for the period, adjusted for the after-tax effect of oil-price changes on inventory and non-controlling interest. See "Summary of results" on page 18.

CCS earnings per share, which is on a diluted basis above, is calculated by dividing CCS earnings attributable to shareholders by the average number of shares outstanding over the year, increased by the average number of dilutive shares related to share-based compensation plans.

Capital investment ($ million)
2015 28,861 2014 37,339

Capital investment is a measure used to make decisions about allocating resources and assessing performance. It is defined as capital expenditure and investments in joint ventures and associates as reported in the "Consolidated Statement of Cash Flows" plus exploration expense, excluding exploration wells written off, new finance leases and other adjustments. See "Liquidity and capital resources" on page 52 and "Non-GAAP measures reconciliations and other definitions" on page 198.

Capital investment has replaced net capital investment as a performance indicator and is aligned with the basis for capital allocation in our annual Business Plan.

Return on average capital employed
2015 1.9% 2014 7.1%

Return on average capital employed (ROACE) is defined as annual income, adjusted for after-tax interest expense, as a percentage of average capital employed during the year. Capital employed is the sum of total equity and total debt. ROACE measures the efficiency of our utilisation of the capital that we employ and is a common measure of business performance. See "Summary of results" on page 19 and "Non-GAAP measures reconciliations and other definitions" on page 199.

Gearing
2015 14.0% 2014 12.2%

Gearing is defined as net debt (total debt less cash and cash equivalents) as a percentage of total capital (net debt plus total equity), at December 31. It is a measure of the degree to which our operations are financed by debt. See "Liquidity and capital resources" on page 50.

Employees (thousand)
2015 93 2014 94

The employees indicator consists of the annual average full-time employee equivalent of the total number of people on full-time or part-time employment contracts with Shell subsidiaries, including our share of employees of certain additional joint operations. See "Our people" on page 60.

Proved oil and gas reserves (million boe)
2015 11,747 2014 13,081

Proved oil and gas reserves are the total estimated quantities of oil and gas from Shell subsidiaries and Shell's share from joint ventures and associates that geoscience and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs, at December 31, under existing economic conditions, operating methods and government regulations. Gas volumes are converted into barrels of oil equivalent (boe) using a factor of 5,800 standard cubic feet per barrel. Reserves are crucial to an oil and gas company, since they constitute the source of future production. Reserves estimates are subject to change due to a wide variety of factors, some of which are unpredictable. See "Summary of results" on page 19.

Operational spills of more than 100 kilograms
2015 108 2014 153

The operational spills indicator is the number of incidents in respect of activities where we are the operator in which 100 kilograms or more of oil or oil products were spilled as a result of those activities. See "Environment and society" on page 56.

Refining Energy Intensity Index (EII™) (indexed to 2002)
2015 95.4 2014 94.9

The Energy Intensity Index (EII™), as described in *Solomon Associates Refinery Comparative Performance Analysis Methodology 2014,* is a benchmark to compare energy efficiency of fuel refineries and paraffinic base oil plants. The Solomon EII™ is defined as the energy consumed by a refinery divided by the energy standard for the specific individual refinery configuration. See "Environment and society" on page 56.

Direct greenhouse gas emissions (million tonnes of CO_2 equivalent)
2015 72 2014 76

Direct greenhouse gas emissions from facilities operated by Shell, expressed in CO_2 equivalent. See "Environment and society" on pages 55-56.

Number of operational Tier 1 process safety events
2015 51 2014 57

A Tier 1 process safety event is an unplanned or uncontrolled release of any material, including non-toxic and non-flammable materials, from a process with the greatest actual consequence resulting in harm to members of our workforce or a neighbouring community, damage to equipment, or exceeding a threshold quantity as defined by the API Recommended Practice 754 and IOGP Standard 456. See "Environment and society" on pages 53-54.

SELECTED FINANCIAL DATA

The selected financial data set out below are derived, in part, from the "Consolidated Financial Statements". This data should be read in conjunction with the "Consolidated Financial Statements" and related Notes, as well as with this Strategic Report.

CONSOLIDATED STATEMENT OF INCOME AND OF COMPREHENSIVE INCOME DATA					$ MILLION
	2015	2014	2013	2012	2011
Revenue	264,960	421,105	451,235	467,153	470,171
Income for the period	2,200	14,730	16,526	26,960	31,093
Income/(loss) attributable to non-controlling interest	261	(144)	155	248	267
Income attributable to Royal Dutch Shell plc shareholders	1,939	14,874	16,371	26,712	30,826
Comprehensive (loss)/income attributable to Royal Dutch Shell plc shareholders	(811)	2,692	18,243	24,470	26,250

CONSOLIDATED BALANCE SHEET DATA					$ MILLION
	2015	2014	2013	2012	2011
Total assets	340,157	353,116	357,512	350,294	337,474
Total debt	58,379	45,540	44,562	37,754	37,175
Share capital	546	540	542	542	536
Equity attributable to Royal Dutch Shell plc shareholders	162,876	171,966	180,047	174,749	158,480
Non-controlling interest	1,245	820	1,101	1,433	1,486

EARNINGS PER SHARE					$
	2015	2014	2013	2012	2011
Basic earnings per €0.07 ordinary share	0.31	2.36	2.60	4.27	4.97
Diluted earnings per €0.07 ordinary share	0.30	2.36	2.60	4.26	4.96

SHARES					MILLION
	2015	2014	2013	2012	2011
Basic weighted average number of A and B shares	6,320.3	6,311.5	6,291.1	6,261.2	6,212.5
Diluted weighted average number of A and B shares	6,393.8	6,311.6	6,293.4	6,267.8	6,221.7

OTHER FINANCIAL DATA		$ MILLION, EXCEPT WHERE OTHERWISE INDICATED			
	2015	2014	2013	2012	2011
Net cash from operating activities	29,810	45,044	40,440	46,140	36,771
Dividends paid to Royal Dutch Shell plc shareholders	9,370	9,444	7,198	7,390	6,877
Increase/(decrease) in cash and cash equivalents	10,145	11,911	(8,854)	7,258	(2,152)
Earnings by segment [A]					
Upstream	(5,663)	15,841	12,638	22,244	24,466
Downstream	10,243	3,411	3,869	5,382	4,170
Corporate	(425)	(156)	372	(203)	102
Total segment earnings	4,155	19,096	16,879	27,423	28,738
Attributable to non-controlling interest	(313)	(55)	(134)	(259)	(205)
Earnings on a current cost of supplies basis attributable to Royal Dutch Shell plc shareholders [A][B]	3,842	19,041	16,745	27,164	28,533
Capital investment [A][B]	28,861	37,339	46,041	36,761	31,051
Divestments [A][B]	5,540	15,019	1,738	6,958	7,548
Operating expenses [A][B]	41,144	45,225	44,379	41,987	42,035
Return on average capital employed [A][B]	1.9%	7.1%	7.9%	13.6%	16.6%
Gearing at December 31 [A]	14.0%	12.2%	16.1%	9.8%	13.9%

[A] See "Summary of results" on pages 18-19.
[B] See "Non-GAAP measures reconciliations and other definitions" on pages 198-199. Divestments include proceeds from sale of interests in Shell Midstream Partners, L.P.

UPSTREAM

KEY STATISTICS	$ MILLION, EXCEPT WHERE OTHERWISE INDICATED		
	2015	2014	2013
Segment earnings [A]	(5,663)	15,841	12,638
Including:			
Revenue (including inter-segment sales) [A]	53,927	92,299	92,869
Share of profit of joint ventures and associates [A]	1,962	5,502	6,120
Interest and other income [A]	2,356	4,029	659
Operating expenses [B]	19,828	22,003	20,612
Exploration	5,719	4,224	5,278
Depreciation, depletion and amortisation [A]	23,001	17,868	16,949
Taxation charge [A]	10	15,277	17,803
Capital investment [B]	23,527	31,293	40,303
Divestments [B]	2,747	10,589	1,086
Oil and gas production available for sale (thousand boe/d)	2,954	3,080	3,199
Equity sales of LNG (million tonnes)	22.6	24.0	19.6
Proved oil and gas reserves at December 31 (million boe)	11,747	13,081	13,944

[A] See Note 4 to the "Consolidated Financial Statements" on page 127.
[B] See "Non-GAAP measures reconciliations and other definitions" on pages 198-199.

OVERVIEW
Our Upstream businesses explore for and extract crude oil and natural gas, often in joint arrangements with international and state-owned oil and gas companies. We also extract bitumen from mined oil sands which we convert into synthetic crude oil. We liquefy natural gas by cooling it and transport the liquefied natural gas (LNG) to customers around the world. We also convert natural gas to liquids (GTL) to provide high-quality fuels and other products, and we market and trade crude oil and natural gas (including LNG) in support of our Upstream businesses.

BUSINESS CONDITIONS
Global oil demand rose by 1.8% (1.7 million barrels per day (b/d)) in 2015, according to the International Energy Agency's January 2016 *Oil Market Report*. The Brent crude oil price averaged $52/b, the lowest level since 2005. It traded in a range of $35-67/b in 2015, ending the year at about $36/b. See "Market overview" on pages 16-17.

We estimate that global gas demand grew by less than 1% in 2015, which is much lower than the average annual growth rate of about 2.3% in the past decade. In the USA, the natural gas price at the Henry Hub averaged $2.6 per million British thermal units (MMBtu) in 2015, 40% lower than in 2014, and traded in a range of $1.5-3.3/MMBtu. In Europe, natural gas prices fell during 2015. The average natural gas price at the UK National Balancing Point was 14% lower than in 2014. At the main continental European gas trading hubs – in the Netherlands, Belgium and Germany – prices were similarly weak. See "Market overview" on pages 16-17.

EARNINGS 2015-2014
Segment earnings in 2015 were a loss of $5,663 million, which included a net charge of $7,443 million. This net charge included $4,616 million in the third quarter related to impairments, redundancy and restructuring, and other items such as contract provisions and well write-offs, associated with management's decision in the quarter to cease Alaska drilling activities for the foreseeable future and the Carmon Creek project in Canada. Charges for Alaska were $2,584 million, which included $755 million associated with well write-offs, and charges for Carmon Creek were $2,032 million. The net charge also reflected other impairment charges of some $4,575 million, principally triggered by the downward revision of our long-term oil and gas price outlook. These charges were partly offset by net gains on divestments of around $1,640 million and a credit of $604 million reflecting a statutory tax rate reduction in the UK. Other net charges of $496 million related to the negative impact of a statutory tax rate change in Canada, redundancy and restructuring costs and the impact of fair value accounting of certain commodity derivatives and gas contracts.

Segment earnings in 2014 of $15,841 million included a net charge of $664 million, reflecting impairment charges of $2,406 million and further charges of $718 million related to an update of an Australian deferred tax asset and a deferred tax liability related to an associate company. These charges were partly offset by divestment gains of $2,073 million, the net effect of fair value accounting of commodity derivatives and certain gas contracts and the impact of amendments to our Dutch pension plan.

Excluding the net charges as described above, segment earnings in 2015 decreased by 89% compared with 2014. Earnings were principally impacted by the significant decline in oil and gas prices (around $15,875 million) and the effect of the weakening of the Australian dollar and Brazilian real on deferred tax positions (around $440 million in total). Earnings benefited from lower operating expenses, including favourable exchange rate effects and divestments (around $1,655 million in total), and decreased depreciation, depletion and amortisation (around $515 million). Integrated Gas contributed significantly (around $5.2 billion) to 2015 earnings. Upstream Americas incurred a loss in 2015, primarily driven by low oil and gas prices and the weakening of the Brazilian real, and partly offset by lower operating expenses and a more liquids-based production mix.

Global realised liquids prices were 48% lower than in 2014. Global realised gas prices were 27% lower than in 2014, with a 47% decrease in the Americas and a 24% decrease outside the Americas.

EARNINGS 2014-2013
Segment earnings in 2014 of $15,841 million included a net charge of $664 million, as described above. Segment earnings in 2013 of $12,638 million included a net charge of $2,479 million, primarily related to the impairment of liquids-rich shale properties in North America, partly offset by net tax credits and gains on divestments.

Excluding the net charges described above, segment earnings in 2014 increased by 9% compared with 2013, driven by increased contributions from liquids production volumes from both the start-up of new high-margin deep-water projects and improved operational performance. Earnings also

UPSTREAM CONTINUED

reflected lower exploration expenses, primarily driven by fewer well write-offs, and increased contributions from Trading and Supply. Earnings were impacted by declining oil prices, losses in Upstream Americas tight-gas and liquids-rich shale, and higher depreciation.

CAPITAL INVESTMENT AND DIVESTMENTS

Capital investment in 2015 was $23.5 billion compared with $31.3 billion in 2014, reflecting our decision to curtail spending by reducing the number of new investment decisions and pursuing lower-cost development solutions.

Divestments in 2015 were $2.7 billion in 2015, compared with $10.6 billion in 2014. Divestments in 2015 were mainly from the sale of OMLs 18, 29, 71 and 72, and the Nembe Creek Trunk Line (NCTL) in Nigeria, and of our interest in Elba Liquefaction Company, LLC (Elba Liquefaction). In 2014, divestments related to a portion of our shareholding in Woodside and our interest in Wheatstone in Australia, to part of our interest in Parque das Conchas (BC-10) in Brazil and to Haynesville and Pinedale in the USA.

PORTFOLIO AND BUSINESS DEVELOPMENT

We took the following key portfolio decisions in 2015:

- In April 2015, the Boards of the Company and BG Group plc (BG) announced that they had reached agreement on the terms of a recommended cash and share offer to be made by the Company for BG. In January 2016, shareholders of both the Company and BG voted in favour of the transaction, which was completed on February 15, 2016. See "Strategy and outlook" on page 15.
- Offshore Alaska, we drilled the Burger J well to target depth as planned. The well was considered a dry hole, with minor oil and gas shows, and the result renders the Burger prospect uneconomic. This, combined with the current economic and regulatory environment, led us to cease further exploration activity offshore Alaska for the foreseeable future.
- In Canada, we announced that we will not continue construction of the 80 thousand barrels of oil equivalent per day (boe/d) Carmon Creek thermal in-situ project (Shell interest 100%). After a careful review of the project, it was determined that it does not rank in our portfolio.
- In Malaysia, the LNG Dua JVA expired and we transferred our 15% shareholding to PETRONAS, in accordance with the original JVA terms. With the expiry of the Malaysia LNG Dua production-sharing contract (PSC), we handed over the operatorship and our 50% interest to PETRONAS.
- We took one major final investment decision (FID) and postponed a number of FIDs. We decided to advance the Appomattox deep-water development (Shell interest 79%) in the Gulf of Mexico, USA. Appomattox will initially produce from the Appomattox and Vicksburg fields, with peak production estimated to be 175 thousand boe/d.

In January 2016, in the United Arab Emirates, we decided to exit the joint development of the Bab sour gas reservoirs (Shell interest 40%) with Abu Dhabi National Oil Company (ADNOC) in the emirate of Abu Dhabi, and to stop further work on the project. The development of the project no longer fits with our strategy, particularly in view of the economic climate prevailing in the energy industry.

In February 2016, we announced that we postponed the FID on the Bonga South West deep-water project in Nigeria and that, together with our partners, we elected to postpone the FID of the proposed LNG project in Canada to late 2016.

We achieved the following operational milestones in 2015:

- In Nigeria, Shell Nigeria Exploration and Production Company Ltd (SNEPCO) announced the first production from the Bonga Phase 3 project (Shell interest 55%). Bonga Phase 3 is an expansion of the Bonga Main development, with peak production expected to be about 50 thousand boe/d. The oil will be transported through existing pipelines to the Bonga floating production, storage and offloading facility (FPSO), which has the capacity to produce more than 200 thousand barrels of oil and 150 million standard cubic feet (scf) of gas per day.
- Also in Nigeria, Erha North Phase 2 began production. Erha North Phase 2 (Shell interest 43.75%) is a deep-water subsea development situated 100 kilometres offshore, in 1,000 metres of water, 6 kilometres north of the Erha field.
- In Ireland, we achieved first production from the Corrib gas field (Shell interest 45%). At peak production, the Corrib gas field is expected to produce around 45 thousand boe/d.
- In Australia, the partners in the Browse joint arrangement agreed to enter the front-end engineering and design (FEED) phase for the proposed non-operated Browse floating liquefied natural gas (FLNG) development (Shell interest 27%), using Shell FLNG technology. The proposed development is expected to produce around 12 million tonnes per annum (mtpa) of LNG.

In Australia, production of LNG and condensate started at the Gorgon LNG project on Barrow Island, off the northwest coast, in March 2016.

We continued to divest selected assets during 2015, including the following:

- In Nigeria, we completed the sale of our 30% interest in OMLs 18 and 29 and related facilities in the Eastern Niger Delta, and the NCTL.
- Also in Nigeria, we completed the sale of our 30% interests in OMLs 71 and 72 to West African Exploration and Production Company Limited, as part of our ongoing portfolio review and optimisation. Both of these blocks were non-producing.
- In the USA, we sold our 49% interest in Elba Liquefaction to Kinder Morgan, Inc., and exited the Elba Liquefaction project as a result. We retain the rights to 100% of the liquefaction capacity through a tolling arrangement.

In New Zealand, we agreed to sell our 83.75% interest in the Maui natural gas pipeline to First State Investments for a consideration of around $0.2 billion. The transaction is expected to be completed in 2016, subject to regulatory approval.

PRODUCTION AVAILABLE FOR SALE

In 2015, production was 2,954 thousand boe/d compared with 3,080 thousand boe/d in 2014. Liquids production increased by 2% and natural gas production decreased by 9% compared with 2014.

Production in 2015 was impacted by the divestment of a number of assets (mainly shale assets in the USA and OMLs in Nigeria), field declines, curtailment of production at Groningen in the Netherlands, licence expiries in Malaysia in 2015 and Abu Dhabi in 2014, and higher maintenance activities.

These reductions were partly offset by new field start-ups and the continued ramp-up of existing fields, in particular Cardamom and Mars B in the Gulf of Mexico and Bonga in Nigeria, which together contributed approximately 120 thousand boe/d to production in 2015. Positive PSC price effects provided further offset.

EQUITY SALES OF LNG

Equity sales of LNG of 22.6 million tonnes were 6% lower than in 2014, mainly reflecting the expiry of the Malaysia LNG Dua Joint Venture Agreement (JVA), the divestment of a portion of our shareholding in Woodside Petroleum Limited (Woodside) in Australia and increased maintenance activities.

PROVED RESERVES

Shell subsidiaries' and the Shell share of joint ventures and associates' estimated net proved oil and gas reserves are summarised later in this section on page 33 and set out in more detail in "Supplementary information – oil and gas (unaudited)" on pages 153-161.

In 2015, proved reserves before taking production into account decreased by 220 million boe, of which 157 million boe came from Shell subsidiaries and 63 million boe from the Shell share of joint ventures and associates.

In 2015, after taking production into account, our proved reserves decreased by 1,334 million boe to 11,747 million boe at December 31, 2015.

In order to illustrate the potential impact of falling commodity prices on our 2014 proved reserves base, we replaced the 2014 yearly average price with the 2015 yearly average price in the analysis below, holding all other variables, such as 2014 costs estimates, constant. Applying this methodology, 1,707 million boe of proved reserves would have been excluded from our SEC proved reserves at December 31, 2014, if the 2015 year average price had been used. This negative price effect of 1,707 million boe was the combined result of a decrease of 2,080 million boe due to earlier economic cut-off, a decrease of 279 million boe due to proved undeveloped reserves (PUD) no longer being economic, and an increase of 652 million boe due to a higher entitlement share as a result of the lower yearly average price. The 1,707 million boe negative price effect includes reductions of 446 million boe of proved reserves for Carmon Creek, and 950 million boe for Muskeg River Mine, both in Canada. Because of actions we took during 2015, our actual outcome does not reflect this significant price effect. For example, the 2014 proved reserves associated with the Muskeg River Mine remain part of our 2015 proved reserves base because we were able to obtain significant structural cost improvements in 2015 which offset the significant decline in prices.

Shell subsidiaries

Before taking production into account, Shell subsidiaries' proved reserves decreased by 157 million boe in 2015. This comprised a reduction of 211 million barrels of oil and natural gas liquids and an addition of 54 million boe (315 thousand million scf) of natural gas. The reduction of 157 million boe was the net effect of a reduction of 150 million boe from revisions and reclassifications; an addition of 4 million boe from improved recovery; an addition of 89 million boe from extensions and discoveries; and a net decrease of 100 million boe related to purchases and sales.

After taking into account production of 907 million boe (of which 27 million boe were consumed in operations), Shell subsidiaries' proved reserves decreased by 1,064 million boe to 9,117 million boe at December 31, 2015.

Shell subsidiaries' proved developed reserves decreased by 210 million boe to 6,567 million boe, and PUD decreased by 854 million boe to 2,550 million boe.

The total reduction of 157 million boe proved reserves in Shell subsidiaries before taking production into account included an increase of 595 million boe due to an increased entitlement share in production sharing and tax/variable royalty contracts due to the lower yearly average price.

SYNTHETIC CRUDE OIL

The 220 million boe reduction in total proved reserves included an addition of 230 million barrels of synthetic crude oil, largely due to a reduction in variable royalty due to the lower yearly average price. In 2015, synthetic crude oil production was 52 million barrels, of which 2 million barrels were consumed in operations. At December 31, 2015, synthetic crude oil proved reserves were 1,941 million barrels, of which 1,405 million barrels were proved developed reserves and 536 million barrels were PUD.

BITUMEN

The 220 million boe reduction in total proved reserves included a reduction of 420 million barrels of bitumen, largely caused by the cessation of the Carmon Creek project. In 2015, bitumen crude oil production was 5 million barrels with minimal volumes consumed in operations. At December 31, 2015, bitumen crude oil proved reserves were 3 million barrels.

Shell share of joint ventures and associates

Before taking production into account, the Shell share of joint ventures and associates' proved reserves decreased by 63 million boe in 2015. This comprised a reduction of 63 million barrels of oil and natural gas liquids and a negligible reduction of natural gas (2 thousand million scf). The reduction of 63 million boe was the net effect of a reduction of 82 million boe from revisions and reclassifications, an addition of 2 million boe from extensions and discoveries, an increase of 1 million boe from improved recovery and an increase of 16 million boe from purchases.

After taking into account production of 207 million boe (of which 9 million boe were consumed in operations), the Shell share of joint ventures and associates' proved reserves decreased by 270 million boe to 2,630 million boe at December 31, 2015.

The Shell share of joint ventures and associates' proved developed reserves decreased by 151 million boe to 2,055 million boe, and PUD decreased by 119 million boe to 575 million boe.

The total reduction of 63 million boe proved reserves in joint ventures and associates before taking production into account included an increase of 5 million boe due to increased entitlement share in production sharing and tax/variable royalty contracts due to the lower yearly average price.

PROVED UNDEVELOPED RESERVES

In 2015, Shell subsidiaries' and the Shell share of joint ventures and associates' PUD decreased by 973 million boe to 3,125 million boe. A large number of Shell fields saw reductions in PUD as a result of the lower yearly average price, with the largest reductions due to the cessation of Carmon Creek (Canada), economic limit test (ELT) failure of Stones (USA); and volumes matured to proved developed reserves in Soku (Africa) and Troll and Corrib (Europe). The most significant additions to PUD occurred in Muskeg River Mine (Canada) and Caesar Tonga (USA). The 973 million boe decrease in PUD was the net effect of a reduction of 1,070 million boe from revisions and reclassifications, an addition of 96 million boe from extensions, discoveries and improved recovery; and a net increase of 1 million boe related to purchases and sales.

During 2015, a total of 463 million boe of PUD were matured to proved developed reserves from projects coming on stream. An amount of 112 million boe was matured to proved developed reserves from contingent resource as a result of project execution during the year.

PUD held for five years or more (PUD5+) at December 31, 2015, amounted to 1,432 million boe, a decrease of 168 million boe compared with the end of 2014. These PUD5+ remain undeveloped because development either: requires the installation of gas compression and the drilling of additional wells, which will be executed when required to support existing gas delivery commitments (in the Netherlands and Russia); requires gas cap blow down which is awaiting end-of-oil production (in Nigeria); or will take longer than five years because of the complexity and scale of the project (Australia and Kazakhstan).

UPSTREAM CONTINUED

The decrease in PUD5+ of 168 million boe was due to the maturation of 98 million boe PUD5+ to proved developed reserves and a net reduction of 70 million boe of PUD5+ as a result of certain projects no longer passing the ELT due to the lower yearly average price and technical downward revisions to certain PUD5+, partially offset by the ageing of a small amount of PUD that are now more than five years old. Three fields – Soku (Africa), Troll (Europe) and Malampaya (Asia) – were the main contributors to the reduction from PUD5+ to proved developed reserves from compression projects being brought on stream and PUD volumes being matured to proved developed reserves. The fields with the largest PUD5+ at December 31, 2015, were Muskeg River Mine (Canada), followed by Gorgon and Jansz-Io (Oceania), Groningen (Europe), and Kashaghan (Asia).

During 2015, we spent $13.9 billion on development activities related to PUD maturation.

DELIVERY COMMITMENTS

We sell crude oil and natural gas from our producing operations under a variety of contractual obligations. Most contracts generally commit us to sell quantities based on production from specified properties, although some natural gas sales contracts specify delivery of fixed and determinable quantities, as discussed below.

In the past three years, with the exception of Brunei, we met all contractual delivery commitments. In the period 2016 to 2018, we are contractually committed to deliver to third parties and joint ventures and associates a total of approximately 3,700 thousand million scf of natural gas from our subsidiaries, joint ventures and associates. The sales contracts contain a mixture of fixed and variable pricing formulae that are generally referenced to the prevailing market price for crude oil, natural gas or other petroleum products at the time of delivery.

The shortfall between our delivery commitments and our proved developed reserves is estimated at 29% of our total gas delivery commitments. This shortfall is expected to be met through the development of proved undeveloped reserves as well as new projects and purchases on the spot market.

EXPLORATION

In 2015, we made six notable discoveries and appraisals, including in Australia, Brazil, the UK and the USA. Discoveries will be evaluated further in order to establish the extent of commercially producible volumes they contain.

In 2015, we participated in 148 productive exploratory wells with proved reserves allocated (Shell share: 114 wells). For further information, see "Supplementary information – oil and gas (unaudited)" on page 169.

In 2015, we participated in a further 185 wells (Shell share: 117 wells) that remained pending determination at December 31, 2015.

In total, the net undeveloped acreage in our exploration portfolio decreased by around 4.8 million acres in 2015, with the largest contributions comprising acreage relinquishment in Benin, China, Gabon, Russia, Saudi Arabia, Tunisia, Ukraine and the USA; and an acreage reduction in Canada. These effects were partially offset by acreage acquisitions in Algeria, Australia, Indonesia and Myanmar.

BUSINESS AND PROPERTY

Our subsidiaries, joint ventures and associates are involved in all aspects of upstream activities, including matters such as land tenure, entitlement to produced hydrocarbons, production rates, royalties, pricing, environmental protection, social impact, exports, taxes and foreign exchange.

The conditions of the leases, licences and contracts under which oil and gas interests are held vary from country to country. In almost all cases outside North America, the legal agreements are generally granted by, or entered into with, a government, state-owned company or government-run oil and gas company, and the exploration risk usually rests with the independent oil and gas company. In North America, these agreements may also be with private parties that own mineral rights. Of these agreements, the following are most relevant to our interests:

- Licences (or concessions), which entitle the holder to explore for hydrocarbons and exploit any commercial discoveries. Under a licence, the holder bears the risk of exploration, development and production activities, and is responsible for financing these activities. In principle, the licence holder is entitled to the totality of production less any royalties in kind. The government, state-owned company or government-run oil and gas company may sometimes enter into a joint arrangement as a participant sharing the rights and obligations of the licence but usually without sharing the exploration risk. In a few cases, the state-owned company, government-run oil and gas company or agency has an option to purchase a certain share of production.
- Lease agreements, which are typically used in North America and are usually governed by similar terms as licences. Participants may include governments or private entities, and royalties are either paid in cash or in kind.
- Production-sharing contracts (PSCs) entered into with a government, state-owned company or government-run oil and gas company. PSCs generally oblige the independent oil and gas company, as contractor, to provide all the financing and bear the risk of exploration, development and production activities in exchange for a share of the production. Usually, this share consists of a fixed or variable part that is reserved for the recovery of the contractor's cost (cost oil). The remaining production is split with the government, state-owned company or government-run oil and gas company on a fixed or volume/revenue-dependent basis. In some cases, the government, state-owned company or government-run oil and gas company will participate in the rights and obligations of the contractor and will share in the costs of development and production. Such participation can be across the venture or on a field-by-field basis. Additionally, as the price of oil or gas increases above certain predetermined levels, the independent oil and gas company's entitlement share of production normally decreases, and vice versa. Accordingly, its interest in a project may not be the same as its entitlement.

Europe

DENMARK

We have a non-operating interest in a producing concession in Denmark (Shell interest 36.8%), which was granted in 1962 and will expire in 2042. The Danish government is one of our partners with a 20% interest.

IRELAND

We are the operator of the Corrib gas project (Shell interest 45%). Corrib has the potential to supply a significant proportion of the country's gas requirements. Gas started to flow from the field, which is 83 kilometres off Ireland's northwest coast, on December 30, 2015.

ITALY

We have two non-operating interests in Italy: the Val d'Agri producing concession (Shell interest 39.23%) and the Tempa Rossa concession (Shell interest 25%). The Val d'Agri Phase 2 project is currently in FEED phase and work is being carried out to manage key non-technical risks. The Tempa Rossa field is under development and first oil is expected in 2018.

NETHERLANDS

Shell and ExxonMobil are 50:50 shareholders in Nederlandse Aardolie Maatschappij B.V. (NAM), the largest hydrocarbon producer in the

Netherlands. An important part of NAM's gas production comes from the onshore Groningen gas field, in which the Dutch government has a 40% interest and NAM a 60% interest.

In the second quarter of 2015, the Minister of Economic Affairs of the Netherlands (the Minister) announced a further reduction in the Groningen production for 2015 to 30 billion cubic metres (bcm), in an effort to diminish the potential for seismic activity, while allowing a further 3 bcm to be taken from the Norg underground storage to ensure security of supply. The State Council ("Raad van State") ruled in November 2015 that the Groningen production limit be set at 27 bcm for the gas year 2016, until the Minister takes a new resolution on NAM's production plan. The Minister is expected to approve a new development plan for Groningen no later than October 1, 2016. NAM produced 28.1 bcm from the Groningen field in 2015. While the Dutch government currently supports the full development of the Groningen gas field, any decision to change the development plan to reduce the ultimate recovery of resources would adversely affect our proved reserves. See "Risk factors" on page 10.

NAM also has a 60% interest in the Schoonebeek oil field, which has been redeveloped using enhanced oil recovery (EOR) technology. In June 2015, due to pipeline integrity issues identified, NAM decided to shut-in the Schoonebeek field. Production is expected to resume by the end of 2016. NAM also operates a significant number of other onshore gas fields and offshore gas fields in the North Sea.

NORWAY

We are a partner in 30 production licences on the Norwegian continental shelf. We are the operator in 13 of these, of which two are producing: the Ormen Lange gas field (Shell interest 17.8%) and the Draugen oil field (Shell interest 44.6%). The other producing fields are Troll, Gjøa, Kvitebjørn and Valemon. The Draugen field has an operational waterflood.

UK

We operate a significant number of our interests on the UK Continental Shelf on behalf of a 50:50 joint arrangement with ExxonMobil. Most of our UK oil and gas production comes from the North Sea. We have various interests where we are not the operator in the Atlantic Margin area, principally in the West of Shetland area (Clair, Shell interest 28%, and Schiehallion, Shell interest approximately 55%). We also have interests ranging from 20% to 49% in the Beryl area fields.

Waterfloods are operational in the Beryl, Clair and Pierce fields. The Schiehallion and Loyal fields production and water injection is closed-in as the fields are being redeveloped; the fields are currently planned to resume production by mid-2017.

REST OF EUROPE

We also have interests in Albania, Germany and Greenland.

Asia (including the Middle East and Russia)

BRUNEI

Shell and the Brunei government are 50:50 shareholders in Brunei Shell Petroleum Company Sendirian Berhad (BSP). BSP has long-term oil and gas concession rights onshore and offshore Brunei, and sells most of its gas production to Brunei LNG Sendirian Berhad (BLNG, Shell interest 25%). BLNG was the first LNG plant in Asia-Pacific and sells most of its LNG on long-term contracts to customers in Asia. Production from the Champion field is supported by water injection, and gas injection is installed in the South West Ampa field.

In addition to our interest in BSP, we are the operator for the Block A concession (Shell interest 53.9%), which is under exploration and development, and also the operator for exploration Block Q (Shell interest 50%). We have a 35% non-operating interest in the Block B concession, where gas and condensate are produced from the Maharaja Lela field.

We also have non-operating interests in deep-water exploration Block CA-2 (Shell interest 12.5%) and in exploration Block N (Shell interest 50%), both under PSCs.

CHINA

We jointly develop and produce from the onshore Changbei tight-gas field under a PSC with China National Petroleum Corporation (CNPC). The PSC includes the development of tight gas in different geological layers of the block. In Sichuan, we have agreed with CNPC to appraise, develop and produce from tight-gas and liquids-rich shale formations in the Jinqiu block under a PSC (Shell interest 49%) and have a PSC for shale-gas exploration, development and production in the Fushun Yongchuan block (Shell interest 49%).

We also have an interest in an offshore oil and gas block in the Yinggehai basin, under a PSC (Shell interest 49%).

INDONESIA

We have a 35% participating interest in the offshore Masela block where INPEX Masela is the operator. The Masela block contains the Abadi gas field. The operator has selected an FLNG concept for the field's development phase. The development plan approval process is ongoing with the government of Indonesia.

In May 2015, we signed a PSC with the Indonesian government for the exploration and potential development of acreage called Pulau Moa, offshore in eastern Indonesia.

IRAN

Shell transactions with Iran are disclosed separately. See "Section 13(r) of the US Securities Exchange Act of 1934 Disclosure" on page 197.

IRAQ

We have a 45% interest in the Majnoon oil field that we operate under a technical service contract that expires in 2030. The other shareholders in Majnoon are PETRONAS (30%) and the Iraqi government (25%), which is represented by the Missan Oil Company. Majnoon is located in southern Iraq and is one of the world's largest oil fields. Production at Majnoon averaged 211 thousand boe/d in 2014 and 206 thousand boe/d in 2015.

We also have a 20% interest in the West Qurna 1 field, which is operated by ExxonMobil.

According to the provisions of both contracts, our equity entitlement volumes will be lower than our interest implies.

We also have a 44% interest in the Basrah Gas Company, which gathers, treats and processes associated gas, produced from the Rumaila, West Qurna 1 and Zubair fields, that was previously being flared. The processed gas and associated products, such as condensate and liquefied petroleum gas (LPG), are sold primarily to the domestic market with the potential to export any surplus.

KAZAKHSTAN

We have a 16.8% interest in the North Caspian Production Sharing Agreement which covers the offshore Kashagan field, where the North Caspian Operating Company is the operator. This shallow-water field covers an area of approximately 3,400 square kilometres. Phase 1 development of the field is expected to lead to plateau production of about 300 thousand boe/d, on a 100% basis, with the possibility of increasing

UPSTREAM CONTINUED

further with additional phases of development. Following the completion of pipeline replacement and other preparation activities, the operator expects production to start around the end of 2016.

Kashagan production will be supported by gas injection.

We also have an interest of 55% in the Pearls PSC, covering an area of approximately 900 square kilometres in the Kazakh sector of the Caspian Sea. It includes two oil discoveries, Auezov and Khazar.

We also have a 5.43% interest in Caspian Pipeline Consortium, which owns an oil pipeline running from the Caspian Sea to the Black Sea across parts of Kazakhstan and Russia.

MALAYSIA

We explore for and produce oil and gas offshore Sabah and Sarawak under 18 PSCs, in which our interests range from 20% to 85%.

Offshore Sabah, we operate five producing oil fields (Shell interests ranging from 29% to 50%). These include the Gumusut-Kakap deep-water field (Shell interest 29%) where production via a dedicated floating production system commenced in 2014. We have additional interests ranging from 30% to 50% in PSCs for the exploration and development of four blocks. These include the Malikai deep-water field (Shell interest 35%) which we are developing, as the operator. We also have a 21% interest in the Siakap North-Petai deep-water field and a 30% interest in the Kebabangan field, neither of which we operate.

Offshore Sarawak, we are the operator of 12 producing gas fields (Shell interests ranging from 37.5% to 70%). Nearly all of the gas produced is supplied to Malaysia LNG in Bintulu, where we have a 15% interest in the Tiga LNG joint venture, and to our Shell MDS GTL plant in Bintulu. In May 2015, the Malaysia LNG Dua JVA expired, resulting in the transfer of our 15% shareholding to PETRONAS, in accordance with the original JVA terms. The Malaysia LNG Dua PSC expired in August 2015, at which time we handed over the operatorship and our 50% interest to PETRONAS.

Waterflood is operational in the St. Joseph field and is under installation at the Malikai field. In the Gumusut Kakap field, both gas and water injections were commissioned in 2015 and are operational.

We also have a 40% interest in the 2011 Baram Delta EOR PSC and a 50% interest in Block SK-307. Additionally, we have interests in five exploration PSCs: deep-water block 2B, SK318, SK319, SK320 and SK408.

We operate a GTL plant (Shell interest 72%) adjacent to the Malaysia LNG facilities in Bintulu. Using Shell technology, the plant converts gas into high-quality middle distillates, drilling fluids, waxes and speciality products.

OMAN

We have a 34% interest in Petroleum Development Oman (PDO); the Omani government has a 60% interest. PDO is the operator of more than 160 oil fields, mainly located in central and southern Oman over an area of 114,000 square kilometres. The concession expires in 2044. In various assets in PDO, production is supported by water injection, gas injection, steam injection or polymer flood projects.

We are also participating in the Mukhaizna oil field (Shell interest 17%) where steam flooding, an EOR method, is being applied.

We have a 30% interest in Oman LNG, which mainly supplies Asian markets under long-term contracts. We also have an 11% indirect interest in Qalhat LNG, which is part of the Oman LNG complex.

QATAR

Pearl in Qatar is the world's largest GTL plant. We operate it under a development and production-sharing contract with the government. The fully-integrated facility has capacity for production, processing and transportation of 1.6 billion scf/d of gas from Qatar's North Field. It has an installed capacity of about 140 thousand boe/d of high-quality liquid hydrocarbon products and 120 thousand boe/d of natural gas liquids (NGL) and ethane. In 2015, Pearl produced 4.1 million tonnes of GTL products.

Of Pearl's two trains, the second train will undergo planned maintenance, starting in March 2016 and continuing into the second quarter of 2016, for an estimated two-month period. The first train underwent similar planned maintenance in 2015, which was completed in April 2015.

We have a 30% interest in Qatargas 4, which comprises integrated facilities to produce about 1.4 billion scf/d of gas from Qatar's North Field, an onshore gas-processing facility and an LNG train with a collective production capacity of 7.8 mtpa of LNG and 70 thousand boe/d of condensate and NGL. The LNG is shipped mainly to China, Europe and the United Arab Emirates.

RUSSIA

We have a 27.5% interest in Sakhalin-2, an integrated oil and gas project located in a subarctic environment. In 2015, the project produced approximately 320 thousand boe/d and the output of LNG exceeded 10 million tonnes.

Our 100% interest in an exploration and production licence for the Lenzitsky block in the Yamalo Nenets Autonomous District was relinquished in 2015. We have a 100% interest in the North Vorkutinsky 1 and North Vorkutinsky 2 exploration and production licences in Komi Republic (Timan Pechora). We also have a 50% interest through Khanty-Mansiysk Petroleum Alliance (a 50:50 joint venture with Gazprom Neft) in three exploration licence blocks in western Siberia: South Lungorsky 1, Yuilsky 4 and Yuilsky 5.

We have a 50% interest in the Salym fields in western Siberia, Khanty Mansiysk Autonomous District, where production was approximately 120 thousand boe/d in 2015. In the Salym fields, production is supported by water injection.

As a result of European Union and US sanctions prohibiting certain defined oil and gas activities in Russia, we suspended our shale oil exploration activities undertaken through Salym and Khanty-Mansiysk Petroleum Alliance in 2014.

UNITED ARAB EMIRATES

In Abu Dhabi, we have a 15% interest in the licence of Abu Dhabi Gas Industries Limited (GASCO), which expires in 2028. GASCO exports propane, butane and heavier-liquid hydrocarbons, which it extracts from the wet gas associated with the oil produced by the Abu Dhabi Company for Onshore Oil Operations (ADCO).

We were working with ADNOC on the development of the Bab sour gas reservoirs in Abu Dhabi (Shell interest 40%). However, following a careful and thorough evaluation of technical challenges and costs, we have decided to exit the joint development of the Bab sour gas reservoirs with ADNOC and to stop further work on the project.

REST OF ASIA

We also have interests in Jordan, Kuwait, Myanmar, the Philippines and Turkey.

Oceania

AUSTRALIA

We have interests in offshore production and exploration licences in the North West Shelf (NWS) and Greater Gorgon areas of the Carnarvon Basin, as well as in the Browse Basin and Timor Sea. Some of these interests are held directly and others indirectly through a shareholding of about 14% in Woodside. All interests in Australian assets quoted below are direct interests.

Woodside is the operator of the Pluto LNG project. Woodside is also the operator on behalf of the joint-arrangement participants in the NWS gas, condensate and oil fields, which produced more than 500 thousand boe/d in 2015. We provide technical support for the NWS development.

We have a 50% interest in Arrow Energy Holdings Pty Limited (Arrow), a Queensland-based joint venture with PetroChina. Arrow owns coal-bed methane assets and a domestic power business.

We have a 25% interest in the Gorgon LNG project, which involves the development of some of the largest gas discoveries to date in Australia, beginning with the offshore Gorgon (Shell interest 25%) and Jansz-Io (Shell interest 19.6%) fields. The Gorgon LNG project on Barrow Island started LNG and condensate production in March 2016.

We are the operator of a permit in the Browse Basin in which two separate gas fields were found: Prelude in 2007 and Concerto in 2009. Our development concept for these fields is based on our FLNG technology. The Prelude FLNG project (Shell interest 67.5%) is expected to produce about 110 thousand boe/d of gas and NGL, delivering 3.6 mtpa of LNG, 1.3 mtpa of condensate and 0.4 mtpa of LPG. Major milestones during 2015 were the lifting of all topsides onto the FLNG facility and the conclusion of the well drilling campaign.

We are also a partner in the Browse joint arrangement (Shell interest 27%) covering the Brecknock, Calliance and Torosa gas fields. In 2015, the Browse partners supported a FEED decision for an FLNG development.

Our other interests include a joint arrangement, with Shell as the operator, of the undeveloped Crux gas and condensate field (Shell interest 82%), and the Woodside-operated, undeveloped Sunrise gas field in the Timor Sea (Shell interest 26.6%).

We are a partner in both Shell-operated and other exploration joint arrangements where we are not the operator in multiple basins including Bonaparte, Browse, Exmouth Plateau, Greater Gorgon, Outer Canning and Outer Exmouth.

REST OF OCEANIA

We also have interests in New Zealand.

Africa

NIGERIA

Our share of production, onshore and offshore, in Nigeria was approximately 278 thousand boe/d in 2015, compared with approximately 300 thousand boe/d in 2014. Security issues and crude oil theft in the Niger Delta continued to be significant challenges in 2015.

Onshore

The Shell Petroleum Development Company of Nigeria Limited (SPDC) is the operator of a joint arrangement (Shell interest 30%) that has 17 Niger Delta onshore OMLs, which expire in 2019. Of the Nigeria onshore proved reserves, 196 million boe are expected to be produced before the expiry of the current licences and 402 million boe beyond. To provide funding, modified carry agreements are in place for certain key projects and are being reimbursed.

SPDC supplies gas to Nigeria LNG Ltd (NLNG) mainly through its Gbaran-Ubie and Soku projects. As part of the strategic review of its interests in the eastern Niger Delta, SPDC has divested its 30% interest in OMLs 18, 29, and the NCTL. OML 25 is held for sale, subject to the resolution of pending litigation. Additional divestments may occur as a result of the strategic review.

The level of crude oil theft activities and sabotage in 2015 was significantly lower than in 2014, following the divestment of OMLs 18 and 29, and the NCTL in 2015.

In our Nigerian operations, we face various risks and adverse conditions which could have a material adverse effect on our operational performance, earnings, cash flows and financial condition (see "Risk factors" on page 09). These risks and conditions include: security issues surrounding the safety of our people, host communities and operations; sabotage and theft; our ability to enforce existing contractual rights; litigation; limited infrastructure; potential legislation that could increase our taxes or costs of operations; the effect of lower oil and gas prices on the government budget; and regional instability created by militant activities. In addition, the Nigerian government is contemplating new legislation to govern the petroleum industry which, if passed into law, could have a material adverse effect on our existing and future activities in that country. There are limitations to the extent to which we can mitigate these risks. We carry out regular portfolio assessments to remain a competitive player in Nigeria for the long term. We support the Nigerian government's efforts to improve the efficiency, functionality and domestic benefits of Nigeria's oil and gas industry, and monitor legislative developments for possible contribution. We monitor the security situation and liaise with host communities, governmental and non-governmental organisations to help promote peace and safe operations. We continue to provide transparency of spills management and reporting, along with our deployment of oil spill response capability and technology. We execute a maintenance strategy to support sustainable equipment reliability, and have implemented a multi-year programme to support sustainable reduction in the routine flaring of associated gas. See "Environment and society" on pages 55-56.

Offshore

Our main offshore deep-water activities are carried out by SNEPCO (Shell interest 100%) which has interests in four deep-water blocks, under PSC terms. SNEPCO operates OMLs 118 (including the Bonga field, Shell interest 55%) and 135 (Bolia and Doro, Shell interest 55%) and has a 43.75% interest in OML 133 (Erha), where we are not the operator, and a 50% interest in oil production lease 245 (Zabazaba, Etan). SNEPCO also has an approximate 43% interest in the Bonga South West/Aparo development via its 55% interest in OML 118. After close consultation with our partners, it is clear that the Bonga South West deep-water project requires further project cost reductions to make it economically viable in the current business environment. An FID is not expected before 2017.

First oil was produced in the third quarter of 2015 from the Bonga Phase 3 development. It is expected to contribute some 50 thousand boe/d at peak production through the existing Bonga FPSO export facility.

First oil was also achieved in the third quarter of 2015 from the Erha North Phase 2 development. The project, in which SNEPCO has a 43.75% interest, is a tie-back to the Erha FPSO. The Phase 2 development is expected to result in around 120 million recoverable barrels of oil from the field.

Production from the Bonga and Erha North fields is supported by water

UPSTREAM CONTINUED

injection. The Erha Main field production is supported by a combination of water and gas injection.

Five shallow-water licences (OMLs 71, 72, 74, 77 and 79) were renewed in December 2014 and will expire in 2034. In 2015, we sold OMLs 71 and 72, both of which were non-producing.

Liquefied natural gas
We have a 25.6% interest in NLNG, which operates six LNG trains with a total capacity of 22.0 mtpa.

REST OF AFRICA
We also have interests in Algeria, Egypt, Gabon, Namibia, South Africa and Tanzania.

North America

CANADA
We have more than 1,800 mineral leases in Canada, mainly in Alberta and British Columbia. We produce and market natural gas, NGL, synthetic crude oil and bitumen. In addition, we have significant exploration acreage offshore. Bitumen is a very heavy crude oil produced through conventional methods as well as through EOR methods. Synthetic crude oil is produced by mining bitumen-saturated sands, extracting the bitumen from the sands and transporting it to a processing facility where hydrogen is added to produce a wide range of feedstocks for refineries.

Gas and liquids-rich shale
We continued to develop fields in Alberta and British Columbia during 2015 through drilling programmes and investment in infrastructure to facilitate new production. We own and operate natural gas processing and sulphur-extraction plants in Alberta and natural gas processing plants in British Columbia. In 2014, we entered into a joint venture (Shell interest 50%) to evaluate an investment in an LNG export facility in Kitimat on the west coast of Canada. Together with our partners, we have elected to postpone the FID of the proposed LNG project to late 2016.

Synthetic crude oil
We operate the Athabasca Oil Sands Project (AOSP) in north-east Alberta as part of a joint arrangement (Shell interest 60%). The bitumen is transported by pipeline for processing at the Scotford Upgrader, which we also operate and is located in the Edmonton area.

We also have a number of other minable oil sands leases in the Athabasca region with expiry dates ranging from 2018 to 2025. By completing the Alberta Department of Energy's prescriptive development requirements prior to their expiry, leases may be extended.

Carbon capture and storage
The Quest carbon capture and storage project (Shell interest 60%), which is expected to capture and permanently store more than 1 mtpa of carbon dioxide from the Scotford Upgrader, began operations in late 2015.

Bitumen
We produce and market bitumen in the Peace River area of Alberta. We also have heavy oil resources in approximately 1,200 square kilometres in the Grosmont oil sands area, also in northern Alberta. We announced that we will not continue construction of the 80 thousand boe/d Carmon Creek thermal in-situ project (Shell interest 100%). We have retained the Carmon Creek leases and preserved some equipment while continuing to evaluate options for these assets.

Offshore
We have a 31.3% interest in the Sable Offshore Energy project, a natural-gas complex off the east coast of Canada, and other acreages in deep-water offshore Nova Scotia and Newfoundland. We have a 50% interest and operatorship in the Shelburne exploration project offshore Nova Scotia. We also have a number of exploration licences off the west coast of British Columbia and in the Mackenzie Delta in the Northwest Territories.

USA
We produce oil and gas in the Gulf of Mexico, heavy oil in California and primarily tight gas and oil from liquids-rich shales in Pennsylvania and Texas. The majority of our oil and gas production interests are acquired under leases granted by the owner of the minerals underlying the relevant acreage, including many leases for federal onshore and offshore tracts. Such leases usually run on an initial fixed term that is automatically extended by the establishment of production for as long as production continues, subject to compliance with the terms of the lease (including, in the case of federal leases, extensive regulations imposed by federal law).

Gulf of Mexico
The Gulf of Mexico is our major production area in the USA, and accounts for over 62% of our oil and gas production in the country. We have an interest in approximately 400 federal offshore production leases and our share of production averaged 253 thousand boe/d in 2015. Key producing assets are Auger, Brutus, Enchilada, Mars, Mars B, Perdido, Ram Powell and Ursa, which we operate, and Caesar Tonga and Na Kika, which we do not operate. Production from the Ursa and Perdido-Great White fields is supported by water injection. Efforts are ongoing to reinstate water injection at the Mars field.

We continued exploration, development and abandonment activities in the Gulf of Mexico in 2015, with an average contracted offshore rig fleet of seven mobile rigs and seven platform rigs. We also secured 17 blocks in the central Gulf of Mexico lease sales in 2015.

Onshore
We have significant tight-gas and liquids-rich shale acreage, centred on Pennsylvania in north-east USA and in the Delaware Permian Basin in west Texas.

California
We have a 51.8% interest in Aera Energy LLC (Aera), which operates in the San Joaquin Valley in California. Aera operates approximately 15,000 wells, producing around 130 thousand boe/d of heavy oil and gas.

Aera fields Belridge, Lost Hills, Cymric, McKittrick, Coalinga, Midway Sunset, Ventura and San Ardo are all operated under a combination of water and steam injection.

Alaska
We operated for almost 50 years off the coast of Alaska, including in the Cook Inlet, and the Beaufort and Chukchi seas, until 1998. Between 2005 and 2012, we acquired our current Alaska portfolio, which includes 339 federal leases for exploration in the Beaufort and Chukchi Seas, and 18 state leases in North Slope Beaufort coastal waters. The federal Chukchi leases expire in 2020. The vast majority of federal Beaufort leases end in 2017 and the remaining two in 2019. The state Beaufort leases end in 2022.

In September 2015, we safely drilled the Burger J well in the Chukchi Sea to a depth of 2,073 metres. The well was deemed a dry hole, and the result renders the Burger prospect uneconomic. The well was sealed and abandoned in accordance with regulations. We will not conduct further exploration offshore Alaska for the foreseeable future. This decision reflects not only the outcome of the Burger J well, but also the high costs associated with the project, and the challenging and unpredictable federal regulatory environment for the Alaska outer continental shelf.

Subsequently, we safely demobilised all personnel and vessels from the Chukchi Sea. All operations were conducted without significant injury or environmental issues. We conveyed the results of the exploration season to stakeholders and worked closely with them in the subsequent winding down of operations.

Our leasehold in Alaska remains material and prospective, and strategies to generate value from this acreage – including lease extensions – will be developed and progressed accordingly. In October 2015, the Bureau of Safety and Environmental Enforcement denied our request to extend expiration dates for the federal leases. We have appealed the decision.

South America

BRAZIL

Offshore

We operate several deep-water producing fields in the Campos Basin. They include the BC-10 field (Shell interest 50%), which is supported with water injection, and the Bijupirá and Salema fields (Shell interest 80%). We expect to start production from the BC-10 Phase 3 project in 2016.

In January 2015, we signed a purchase and sale agreement to divest our interest in the Bijupirá and Salema fields, pending regulatory approvals. The agreement was cancelled in February 2016 and these assets therefore remain in our portfolio.

In the Santos Basin, we have a 20% interest in a 35-year PSC to develop the Libra pre-salt oil field and operate exploration block BM-S-54 (Shell interest 80%).

In August 2015, we ceased exploration on block BM-ES-27 (Shell interest 17.5%) in the Espirito Santos basins.

Onshore

In February 2015, we returned our block in the São Francisco basin area (Shell interest 60%) to the regulator.

We have an 18% interest in Brazil Companhia de Gas de São Paulo (Comgás), a natural gas distribution company in the state of São Paulo.

REST OF SOUTH AMERICA

We also have interests in Argentina, Colombia and French Guiana. Furthermore, we have an interest in the LNG plants in Peru and Trinidad and Tobago.

Trading and Supply

We market a portion of our share of equity production of LNG and trade LNG volumes around the world through our hubs in Dubai and Singapore. We also market and trade natural gas, power, carbon-emission rights and crude oil from certain of our Upstream operations in the Americas and Europe.

UPSTREAM CONTINUED

CAPITAL INVESTMENT IN OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES BY GEOGRAPHICAL AREA

$ MILLION	2015	2014
Oil and gas exploration and production activities		
Europe [A]	2,999	4,273
Asia	3,208	3,875
Oceania	3,526	5,068
Africa	2,312	2,825
North America – USA	7,409	8,210
North America – Canada	2,148	3,162
South America	666	1,109
Total	22,268	28,522
Other Upstream activities [B]	1,259	2,771
Total Upstream [C]	23,527	31,293

[A] Includes Greenland.
[B] Comprise LNG, GTL, trading and supply activities, and wind activities.
[C] See "Non-GAAP measures reconciliations and other definitions" on page 198.

LOCATION OF OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES [A] (AT DECEMBER 31, 2015)

	Exploration	Development and/or production	Shell operator[B]
Europe			
Albania	■		
Denmark	■	■	
Germany	■	■	
Greenland	■		■
Ireland	■	■	■
Italy	■	■	
Netherlands	■	■	■
Norway	■	■	■
UK	■	■	■
Asia [C]			
Brunei	■	■	■
China	■	■	■
Indonesia	■	■	■
Iraq		■	■
Jordan	■		■
Kazakhstan	■	■	
Malaysia	■	■	■
Myanmar	■		■
Oman	■	■	
Philippines	■	■	■
Qatar		■	■
Russia	■	■	■
Turkey	■		■
Oceania			
Australia	■	■	■
New Zealand	■	■	■
Africa			
Algeria	■		
Egypt	■	■	■
Gabon	■	■	■
Namibia	■		■
Nigeria	■	■	■
South Africa	■		■
Tanzania	■		
North America			
USA	■	■	■
Canada	■	■	■
South America			
Argentina	■	■	■
Brazil	■	■	■
Colombia	■		■
French Guiana	■		■

[A] Includes joint ventures and associates. Where a joint venture or associate has properties outside its base country, those properties are not shown in this table.
[B] In several countries where "Shell operator" is indicated, Shell is the operator of some but not all exploration and/or production ventures.
[C] Shell suspended all exploration and production activities in Syria in December 2011.

PROVED OIL AND GAS RESERVES

SUMMARY OF PROVED OIL AND GAS RESERVES OF SHELL SUBSIDIARIES AND SHELL SHARE OF JOINT VENTURES AND ASSOCIATES [A] (AT DECEMBER 31, 2015) BASED ON AVERAGE PRICES FOR 2015

	Crude oil and natural gas liquids (million barrels)	Natural gas (thousand million scf)	Synthetic crude oil (million barrels)	Bitumen (million barrels)	Total all products (million boe)[B]
Proved developed					
Europe	225	9,404	–	–	1,846
Asia	1,176	14,221	–	–	3,628
Oceania	45	1,654	–	–	330
Africa	437	1,386	–	–	676
North America					
USA	455	572	–	–	554
Canada	20	636	1,405	3	1,538
South America	44	37	–	–	50
Total proved developed	2,402	27,910	1,405	3	8,622
Proved undeveloped					
Europe	203	1,982	–	–	545
Asia	400	1,834	–	–	716
Oceania	93	4,292	–	–	833
Africa	142	850	–	–	289
North America					
USA	105	182	–	–	136
Canada	2	319	536	–	593
South America	12	6	–	–	13
Total proved undeveloped	957	9,465	536	–	3,125
Total proved developed and undeveloped					
Europe	428	11,386	–	–	2,391
Asia	1,576	16,055	–	–	4,344
Oceania	138	5,946	–	–	1,163
Africa	579	2,236	–	–	965
North America					
USA	560	754	–	–	690
Canada	22	955	1,941	3	2,131
South America	56	43	–	–	63
Total	3,359	37,375	1,941	3	11,747

[A] See "Supplementary information – oil and gas (unaudited)" on pages 153-161.
[B] Natural gas volumes are converted into oil equivalent using a factor of 5,800 scf per barrel.

UPSTREAM CONTINUED

OIL AND GAS PRODUCTION (AVAILABLE FOR SALE)

CRUDE OIL AND NATURAL GAS LIQUIDS [A] — THOUSAND BARRELS

	2015		2014		2013	
	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates
Europe						
Denmark	17,396	–	18,834	–	20,927	–
Italy	11,179	–	11,792	–	11,997	–
Norway	14,337	–	14,893	–	14,589	–
UK	20,762	–	14,746	–	14,445	–
Other [B]	874	1,311	849	1,986	934	1,952
Total Europe	64,548	1,311	61,114	1,986	62,892	1,952
Asia						
Brunei	823	18,663	648	18,576	564	20,011
Iraq	20,009	–	19,218	–	8,416	–
Malaysia	22,980	–	16,754	–	15,441	–
Oman	78,404	–	74,781	–	74,527	–
Russia	22,016	10,273	23,579	10,403	25,152	10,527
United Arab Emirates	–	–	–	2,397	–	58,104
Other [B]	24,480	7,923	27,165	8,115	25,202	8,155
Total Asia	168,712	36,859	162,145	39,491	149,302	96,797
Total Oceania [B]	7,858	3,050	9,191	3,688	9,371	4,771
Africa						
Gabon	12,472	–	12,144	–	10,781	–
Nigeria	67,832	–	69,851	–	63,800	–
Other [B]	6,159	–	5,008	–	4,254	–
Total Africa	86,463	–	87,003	–	78,835	–
North America						
USA	104,263	–	98,895	–	86,670	–
Canada	8,599	–	8,389	–	7,626	–
Total North America	112,862	–	107,284	–	94,296	–
South America						
Brazil	13,307	–	16,575	–	7,706	–
Other [B]	576	–	361	–	273	3,327
Total South America	13,883	–	16,936	–	7,979	3,327
Total	454,326	41,220	443,673	45,165	402,675	106,847

[A] Reflects 100% of production of subsidiaries except in respect of PSCs, where the figures shown represent the entitlement of the subsidiaries concerned under those contracts.
[B] Comprises countries where 2015 production was lower than 7,300 thousand barrels or where specific disclosures are prohibited.

SYNTHETIC CRUDE OIL — THOUSAND BARRELS

	2015	2014	2013
	Shell subsidiaries	Shell subsidiaries	Shell subsidiaries
North America – Canada	49,891	46,934	46,017

BITUMEN — THOUSAND BARRELS

	2015	2014	2013
	Shell subsidiaries	Shell subsidiaries	Shell subsidiaries
North America – Canada	5,258	5,779	6,903

NATURAL GAS [A]

MILLION STANDARD CUBIC FEET

	2015		2014		2013	
	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates
Europe						
Denmark	48,211	–	49,708	–	53,283	–
Germany	58,230	–	66,718	–	73,123	–
Netherlands	–	429,626	–	581,028	–	721,344
Norway	253,108	–	252,284	–	256,396	–
UK	101,276	–	104,346	–	109,470	–
Other [B]	15,892	–	15,840	–	15,409	–
Total Europe	476,717	429,626	488,896	581,028	507,681	721,344
Asia						
Brunei	21,337	162,862	22,228	155,244	18,442	164,446
China	46,481	–	53,065	–	60,034	–
Malaysia	254,523	–	241,908	–	238,940	–
Russia	3,887	131,697	4,170	128,175	4,261	126,764
Other [B]	386,450	118,421	420,169	118,198	378,412	115,469
Total Asia	712,678	412,980	741,540	401,617	700,089	406,679
Oceania						
Australia	132,209	67,382	132,801	87,830	125,654	100,707
New Zealand	55,906	–	69,052	–	61,407	–
Total Oceania	188,115	67,382	201,853	87,830	187,061	100,707
Africa						
Egypt	65,002	–	54,079	–	46,072	–
Nigeria	195,064	–	234,599	–	201,311	–
Total Africa	260,066	–	288,678	–	247,383	–
North America						
USA	264,351	–	360,846	–	394,538	–
Canada	234,055	–	214,756	–	231,897	–
Total North America	498,406	–	575,602	–	626,435	–
Total South America [B]	12,853	–	12,449	–	11,896	444
Total	2,148,835	909,988	2,309,018	1,070,475	2,280,545	1,229,174

[A] Reflects 100% of production of subsidiaries except in respect of PSCs, where the figures shown represent the entitlement of the companies concerned under those contracts.
[B] Comprises countries where 2015 production was lower than 41,795 million scf or where specific disclosures are prohibited.

UPSTREAM CONTINUED

AVERAGE REALISED PRICE BY GEOGRAPHICAL AREA

CRUDE OIL AND NATURAL GAS LIQUIDS $/BARREL

	2015		2014		2013	
	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates
Europe	49.77	45.97	94.57	89.68	105.23	99.27
Asia	47.73	52.21	89.47	96.85	96.46	70.34
Oceania	43.39	50.01[A]	82.26	88.07[A]	90.50	91.91[A]
Africa	51.80	–	100.55	–	110.14	–
North America – USA	44.99	–	87.90	–	98.10	–
North America – Canada	25.45	–	59.19	–	63.14	–
South America	42.38	–	88.68	–	97.17	94.01
Total	47.52	51.82	91.09	95.87	99.83	72.69

[A] Includes Shell's 14% share of Woodside from June 2014 (previously: 23% from April 2012), a publicly listed company on the Australian Securities Exchange. We have limited access to data; accordingly, the numbers are estimated.

SYNTHETIC CRUDE OIL $/BARREL

	2015	2014	2013
	Shell subsidiaries	Shell subsidiaries	Shell subsidiaries
North America – Canada	40.87	81.83	87.24

BITUMEN $/BARREL

	2015	2014	2013
	Shell subsidiaries	Shell subsidiaries	Shell subsidiaries
North America – Canada	30.25	70.19	67.40

NATURAL GAS $/THOUSAND SCF

	2015		2014		2013	
	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates
Europe	7.10	6.46	8.58	8.26	10.29	9.17
Asia	3.02	7.06	4.57	11.50	4.51	10.73
Oceania	6.80	6.73[A]	10.49	11.01[A]	11.55	9.45[A]
Africa	2.10	–	2.71	–	2.84	–
North America – USA	2.39	–	4.52	–	3.92	–
North America – Canada	2.29	–	4.39	–	3.26	–
South America	2.46	–	2.85	–	2.91	0.42
Total	4.07	6.77	5.68	9.72	5.85	9.72

[A] Includes Shell's 14% share of Woodside from June 2014 (previously: 23% from April 2012), a publicly listed company on the Australian Securities Exchange. We have limited access to data; accordingly, the numbers are estimated.

AVERAGE PRODUCTION COST BY GEOGRAPHICAL AREA

CRUDE OIL, NATURAL GAS LIQUIDS AND NATURAL GAS [A] $/BOE

	2015		2014		2013	
	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates	Shell subsidiaries	Shell share of joint ventures and associates
Europe	16.97	5.07	19.47	4.25	17.66	3.57
Asia	7.42	6.89	7.87	7.62	6.52	5.74
Oceania	13.43	14.66[B]	13.62	14.44[B]	11.55	13.17[B]
Africa	11.96	–	14.86	–	14.43	–
North America – USA	20.28	–	21.35	–	21.57	–
North America – Canada	18.85	–	22.96	–	22.20	–
South America	21.31	–	25.26	–	37.72	16.96
Total	13.42	6.77	15.10	6.68	14.35	5.52

[A] Natural gas volumes are converted into oil equivalent using a factor of 5,800 scf per barrel.
[B] Includes Shell's 14% share of Woodside from June 2014 (previously: 23% from April 2012), a publicly listed company on the Australian Securities Exchange. We have limited access to data; accordingly, the numbers are estimated.

SYNTHETIC CRUDE OIL $/BARREL

	2015	2014	2013
	Shell subsidiaries	Shell subsidiaries	Shell subsidiaries
North America – Canada	31.50	42.46	41.81

BITUMEN $/BARREL

	2015	2014	2013
	Shell subsidiaries	Shell subsidiaries	Shell subsidiaries
North America – Canada	18.58	23.24	23.03

UPSTREAM CONTINUED

LNG AND GTL PLANTS AT DECEMBER 31, 2015

LNG LIQUEFACTION PLANTS IN OPERATION

	Asset	Location	Shell interest (%)[A]	100% capacity (mtpa)[B]
Asia				
Brunei	Brunei LNG	Lumut	25	7.8
Malaysia	Malaysia LNG Tiga	Bintulu	15	7.7
Oman	Oman LNG	Sur	30	7.1
	Qalhat (Oman) LNG	Sur	11[C]	3.7
Qatar	Qatargas 4	Ras Laffan	30	7.8
Russia	Sakhalin LNG	Prigorodnoye	28	9.6
Oceania				
Australia	Australia North West Shelf	Karratha	19[C]	16.3
	Australia Pluto 1	Karratha	12[C]	4.3
Africa				
Nigeria	Nigeria LNG	Bonny	26	22.0
South America				
Peru	Peru LNG	Pampa Melchorita	20	4.5
Trinidad and Tobago	Atlantic LNG	Point Fortin	20-25	14.8

[A] Shell interest is rounded to the nearest whole percentage point.
[B] As reported by the operator.
[C] Interest, or part of the interest, is held via indirect shareholding.

LNG LIQUEFACTION PLANTS UNDER CONSTRUCTION

	Asset	Location	Shell interest (%)[A]	100% capacity (mtpa)
Oceania				
Australia	Gorgon[B]	Barrow Island	25	15.6
	Prelude	Browse Basin	68	3.6

[A] Shell interest is rounded to the nearest whole percentage point.
[B] Production of LNG and condensate started in March 2016.

GTL PLANTS IN OPERATION

	Asset	Location	Shell interest (%)	100% capacity (b/d)
Asia				
Malaysia	Shell MDS	Bintulu	72	14,700
Qatar	Pearl	Ras Laffan	100	140,000

EQUITY SALES OF LNG

EQUITY SALES OF LNG

MILLION TONNES	2015	2014	2013
Australia	3.4	3.7	3.7
Brunei	1.6	1.5	1.7
Malaysia	1.8	2.7	2.6
Nigeria	5.0	5.0	4.4
Oman	1.9	1.8	2.0
Peru	0.7	0.8	–
Qatar	2.4	2.4	2.3
Russia	2.9	2.9	2.9
Trinidad and Tobago	2.9	3.2	–
Total	22.6	24.0	19.6

EARNINGS AND CASH FLOW INFORMATION

2015								$ MILLION
					North America			
	Europe[A]	Asia	Oceania	Africa	USA	Other	South America	Total
Revenue	12,721	22,299	1,858	5,620	6,384	4,405	640	53,927
Share of profit/(loss) of joint ventures and associates	506	1,664	(802)	491	(94)	70	127	1,962
Interest and other income	(41)	556	(13)	1,754	148	(1)	(47)	2,356
Total revenue and other income	13,186	24,519	1,043	7,865	6,438	4,474	720	58,245
Purchases excluding taxes	4,336	6,925	148	525	30	1,327	12	13,303
Production and manufacturing expenses	2,890	4,725	772	1,806	3,870	3,472	481	18,016
Taxes other than income tax	128	434	113	347	81	–	63	1,166
Selling, distribution and administrative expenses	685	62	7	2	212	26	16	1,010
Research and development	612	27	–	–	121	42	–	802
Exploration	261	1,255	195	161	3,336	164	347	5,719
Depreciation, depletion and amortisation	2,807	4,311	480	1,749	6,342	6,625	687	23,001
Interest expense	328	100	54	130	194	48	27	881
Income before taxation	1,139	6,680	(726)	3,145	(7,748)	(7,230)	(913)	(5,653)
Taxation charge/(credit)	339	2,714	428	886	(2,853)	(1,788)	284	10
Income after taxation	800	3,966	(1,154)	2,259	(4,895)	(5,442)	(1,197)	(5,663)
Net cash from operating activities	1,303	8,882	(76)	2,946	124	87	(85)	13,181
Less: working capital movements	(382)	430	(1,161)	785	121	46	125	(36)
Net cash from operating activities excluding working capital movements	1,685	8,452	1,085	2,161	3	41	(210)	13,217

[A] Includes Greenland.

2014								$ MILLION
					North America			
	Europe[A]	Asia	Oceania	Africa	USA	Other	South America	Total
Revenue	17,891	35,629	3,299	11,129	13,553	9,250	1,548	92,299
Share of profit/(loss) of joint ventures and associates	1,128	3,173	266	937	(4)	77	(75)	5,502
Interest and other income	68	845	2,292	503	327	(71)	65	4,029
Total revenue and other income	19,087	39,647	5,857	12,569	13,876	9,256	1,538	101,830
Purchases excluding taxes	5,848	10,113	344	1,505	1,909	3,383	(63)	23,039
Production and manufacturing expenses	3,255	4,905	809	2,483	4,572	3,391	678	20,093
Taxes other than income tax	264	948	211	836	201	–	165	2,625
Selling, distribution and administrative expenses	777	103	9	1	136	7	22	1,055
Research and development	642	28	–	–	134	51	–	855
Exploration	458	1,331	232	307	1,548	88	260	4,224
Depreciation, depletion and amortisation	1,815	4,621	430	2,054	6,665	1,808	475	17,868
Interest expense	364	90	55	144	211	60	29	953
Income before taxation	5,664	17,508	3,767	5,239	(1,500)	468	(28)	31,118
Taxation charge/(credit)	3,599	7,542	2,103	2,416	(626)	78	165	15,277
Income after taxation	2,065	9,966	1,664	2,823	(874)	390	(193)	15,841
Net cash from operating activities	3,975	14,619	1,684	4,629	3,935	2,685	312	31,839
Less: working capital movements	1,148	(1,470)	(845)	616	(994)	360	(285)	(1,470)
Net cash from operating activities excluding working capital movements	2,827	16,089	2,529	4,013	4,929	2,325	597	33,309

[A] Includes Greenland.

UPSTREAM CONTINUED

2013								$ MILLION
					North America			
	Europe[A]	Asia	Oceania	Africa	USA	Other	South America	Total
Revenue	23,144	35,916	3,414	11,007	9,762	8,878	748	92,869
Share of profit of joint ventures and associates	1,469	3,235	111	1,162	1	55	87	6,120
Interest and other income	(123)	572	172	(14)	20	52	(20)	659
Total revenue and other income	24,490	39,723	3,697	12,155	9,783	8,985	815	99,648
Purchases excluding taxes	9,088	9,761	290	1,378	(1,175)	2,989	48	22,379
Production and manufacturing expenses	2,998	4,162	762	1,978	4,588	3,594	389	18,471
Taxes other than income tax	328	1,254	226	963	223	–	85	3,079
Selling, distribution and administrative expenses	993	85	7	1	47	26	35	1,194
Research and development	648	15	–	–	178	106	–	947
Exploration	627	1,082	396	354	1,790	312	717	5,278
Depreciation, depletion and amortisation	1,444	3,114	434	1,293	7,954	2,550	160	16,949
Interest expense	359	76	47	133	210	61	24	910
Income before taxation	8,005	20,174	1,535	6,055	(4,032)	(653)	(643)	30,441
Taxation charge/(credit)	4,883	10,977	475	3,100	(1,500)	(203)	71	17,803
Income after taxation	3,122	9,197	1,060	2,955	(2,532)	(450)	(714)	12,638
Net cash from operating activities	5,215	12,834	1,717	5,027	3,775	1,414	132	30,114
Less: working capital movements	1,251	(88)	(929)	1,391	(86)	(346)	119	1,312
Net cash from operating activities excluding working capital movements	3,964	12,922	2,646	3,636	3,861	1,760	13	28,802

[A] Includes Greenland.

DOWNSTREAM

KEY STATISTICS	$ MILLION, EXCEPT WHERE OTHERWISE INDICATED		
	2015	2014	2013
Segment earnings [A]	10,243	3,411	3,869
Including:			
Revenue (including inter-segment sales) [A]	237,746	378,046	404,427
Share of profit of joint ventures and associates [A]	2,215	1,693	1,525
Interest and other income [A]	1,156	41	273
Operating expenses [B]	20,816	22,701	23,292
Depreciation, depletion and amortisation [A]	3,667	6,619	4,421
Taxation charge [A]	1,639	1,085	1,129
Capital investment [B]	5,119	5,910	5,528
Divestments [B]	2,282	4,410	643
Refinery availability (%) [C][D]	90	93	94
Chemical plant availability (%) [C]	85	85	92
Refinery processing intake (thousand b/d)	2,805	2,903	2,915
Oil products sales volumes (thousand b/d)	6,432	6,365	6,164
Chemicals sales volumes (thousand tonnes)	17,148	17,008	17,386

[A] See Note 4 to the "Consolidated Financial Statements" on page 127. Segment earnings are presented on a current cost of supplies basis.
[B] See "Non-GAAP measures reconciliations and other definitions" on pages 198-199.
[C] The basis of calculation differs from that used for the "Refinery and chemical plant availability" measure in "Performance indicators" on page 20, which excludes downtime due to uncontrollable factors.
[D] With effect from 2015, refinery availability includes Shell-operated process units only. Comparative data has been restated.

OVERVIEW
Shell's Downstream organisation is made up of a number of different Oil Products and Chemicals business activities, part of an integrated value chain, that collectively turn crude oil into a range of refined products which are moved and marketed around the world for domestic, industrial and transport use. The products we sell include gasoline, diesel, heating oil, aviation fuel, marine fuel, liquefied natural gas (LNG) for transport, lubricants, bitumen and sulphur. In addition, we produce and sell petrochemicals for industrial use worldwide.

Our Oil Products activities comprise Refining, Trading and Supply, Pipelines and Marketing, referred to as classes of business. Marketing includes Retail, Lubricants, Business to Business (B2B) and Alternative Energies. In Trading and Supply, we trade crude oil, oil products and petrochemicals, to optimise feedstocks for Refining and Chemicals, to supply our Marketing businesses and third parties, and for our own profit. Chemicals has major manufacturing plants, located close to refineries, and its own marketing network.

BUSINESS CONDITIONS
Industry gross refining margins were higher on average in 2015 than in 2014 in each of the key refining hubs in Europe, Singapore and the USA. Oil products demand growth was stronger globally, driven in part by the sustained lower oil price environment compared with 2014. The refining industry has seen a period of generally tightening capacity, reducing the overcapacity that has been observed for several years. However, the improved gross margins have probably delayed some further capacity rationalisation, especially in Europe. In 2016, demand for gasoline is expected to be a key driver of gross refining margins, especially in the middle of the year, supported by demand for middle distillates. The overall outlook remains unclear because of continuing economic uncertainty, geopolitical tensions in some regions that could lead to supply disruptions, and continued overcapacity in the global refining market. See "Market overview" on page 18.

In Chemicals, Asian naphtha cracker margins increased in 2015 compared with 2014 due to periods of reduced cracker availability. European naphtha cracker margins remained high in 2015, supported by periods of low cracker availability. US ethane cracker margins were significantly lower due to a narrower differential between crude oil prices and US natural gas prices. The outlook for petrochemicals in 2016 will depend on economic growth, especially in Asia, and developments in relative raw material prices which will be influenced by crude oil prices. See "Market overview" on page 18.

EARNINGS 2015-2014
Segment earnings are presented on a current cost of supplies basis (see "Summary of results" on page 18), which in 2015 were $1,955 million higher than on a first-in, first-out basis (2014: $4,366 million higher), as shown in "Non-GAAP measures reconciliations and other definitions" on page 198.

Segment earnings of $10,243 million in 2015 were 200% higher than in 2014. Earnings in 2015 included a net gain of $495 million compared with a net charge of $2,854 million in 2014, described at the end of this section.

Excluding the impact of these items, earnings in 2015 were $9,748 million compared with $6,265 million in 2014. Oil Products earnings accounted for 83% of these 2015 earnings and Chemicals for 17%.

The earnings improvement of $3,483 million (56%) compared with 2014 was principally driven by lower operating expenses, as a result of favourable exchange rates and divestments (45% of the improvement), higher realised refining margins, reflecting the industry environment (39% of the improvement), and other items (16% of the improvement) mainly reflecting a lower effective tax rate.

Improvements in earnings analysed by class of business were as follows:

- Refining represented 69% of the improvement. Realised refining margins were significantly higher overall and higher in all countries except Canada. The increase was driven by stronger industry margins and improved availability early in 2015 which allowed our refineries to capitalise on the stronger margin environment. Overall in 2015, refinery availability decreased to 90% from 93% in 2014. In Europe, realised margins benefited from the stronger margin environment despite lower availability. In Asia, realised margins were higher due to the stronger margin environment despite worse operational performance, particularly

DOWNSTREAM CONTINUED

at the Bukom refinery in Singapore. In Canada, realised margins were impacted by a significantly weaker margin environment. In the USA, realised margins benefited from the stronger margin environment as well as improved operational performance from lower planned and unplanned downtime. Earnings at Motiva Enterprises LLC (Motiva)'s (Shell interest 50%) Port Arthur refinery were stronger through both a stronger margin environment and improved operational performance.

- Trading and Supply represented 10% of the improvement, driven by market volatility and optimisation opportunities, and one-off tax credits.
- Pipelines represented 3% of the improvement, which was mainly due to higher margins and joint venture earnings.
- Marketing earnings were in line with 2014, despite unfavourable exchange rate effects and divestments. Higher earnings, mainly in Lubricants, were offset by lower results from Business to Business Fuels and our Raízen joint venture (Shell interest 50%) in Brazil. Raízen earnings were impacted by unfavourable exchange rate effects as the Brazilian real weakened against the dollar.
- Chemicals represented 9% of the improvement, mainly due to tight industry supply conditions and lower taxation. These industry conditions, driven by competitor outages in Asia, benefited intermediate products globally and base chemicals in Asia. Partly offsetting these benefits were weaker margins in the USA, and unit shutdowns at the Moerdijk site in the Netherlands which had a larger earnings impact in 2015 than in 2014.

Oil product sales volumes were 1% higher than in 2014, mainly due to improved Trading and Supply volumes. Marketing volumes were lower than in 2014 due to divestments. Excluding divestments, Marketing volumes were 2% higher than in 2014, benefiting from higher Retail volumes in the USA as a result of a stronger driving season.

Chemicals sales volumes were 1% higher than in 2014. The increase was mostly driven by higher demand in Asia and improved market conditions for intermediate products globally.

Depreciation, depletion and amortisation were significantly lower in 2015 compared with 2014, mainly due to impairments in 2014 described below.

Segment earnings in 2015 included a net gain of $495 million, reflecting net gains on divestments of $1,095 million (primarily in China, France and Norway), reported in interest and other income, partly offset by impairment charges of $505 million (mainly related to the Westward Ho pipeline in the USA and to expenditure at the Bukom refinery in Singapore) and other net charges of $95 million.

Segment earnings in 2014 included a net charge of $2,854 million, primarily from impairments (mainly in respect of refineries in Asia and Europe) and also from restructuring charges, fair value accounting of commodity derivatives and a provision connected to a prior year sale obligation. Partly offsetting these charges was a gain related to Dutch pension plan amendments.

EARNINGS 2014-2013

Segment earnings in 2014 were $3,411 million, 12% lower than 2013. Earnings in 2014 included a net charge of $2,854 million described above, and earnings in 2013 included a net charge of $597 million resulting primarily from impairments and deferred tax adjustments, which were partly due to a beneficial tax rate change in the UK and gains on divestments.

Excluding the impact of these items, earnings in 2014 were $6,265 million compared with $4,466 million in 2013. Oil Products earnings accounted for 78% of 2014 earnings and Chemicals for 22%.

The earnings improvement of $1,799 million (40%) was the result of higher realised refining margins from improved operating performance and a stronger industry environment (accounting for 35% of the earnings improvement); higher margins from Trading and Supply (accounting for 32% of the earnings improvement) which were due to increased price volatility and profitable short positions; lower operating expenses (accounting for 18% of the earnings improvement) mainly as a result of divestments; lower depreciation (accounting for 9% of the earnings improvement) as a result of divestments and reduced depreciation from impaired assets; and higher Marketing and Pipeline margins (accounting for 9% of earnings improvement). Lower margins from Chemicals, primarily driven by market conditions for intermediate products and shutdowns of some units at Moerdijk, offset 11% of these improvements.

REFINERY AND CHEMICAL PLANT AVAILABILITY

Refinery availability was 90% in 2015 compared with 93% in 2014 and 94% in 2013. The lower availability in 2015 reflected the impact of a fire at the Bukom refinery.

Chemical plant availability was 85% in 2015, compared with 85% in 2014 and 92% in 2013. Lower availability in 2015 and 2014 reflected unit shutdowns at the Moerdijk site in each year.

CAPITAL INVESTMENT AND DIVESTMENTS

Capital investment was $5.1 billion in 2015 compared with $5.9 billion in 2014. In Refining and Chemicals, it decreased by $0.1 billion to $3.6 billion. In Marketing, it decreased by $0.7 billion to $1.5 billion. In 2015, 60% of our capital investment was used to maintain the integrity and performance of our asset base, compared with 54% in 2014.

Divestments were $2.3 billion in 2015, compared with $4.4 billion 2014, principally from divestments in China, France, Norway and the UK, and proceeds from sale of interests in Shell Midstream Partners, L.P.

PORTFOLIO AND BUSINESS DEVELOPMENTS

We took the following key portfolio decisions in 2015:

- In Canada, we took the final investment decision (FID) for a de-bottlenecking project at the Scotford refinery, which is expected to increase hydrocracking capacity by about 20%. Completion is expected in 2016.
- In the Netherlands, we took the FID to build a major new unit at the Pernis refinery. The new solvent deasphalter unit will remove heavier fractions from crude oil, allowing the refinery to upgrade a larger proportion of its oil intake into lighter, high-grade products. Construction work is planned to start later in 2016, subject to permit approvals, with completion expected by the end of 2018.
- In the USA, we took the FID to construct a fourth alpha olefins unit, which is expected to add 425 thousand tonnes per annum (ktpa) of alpha olefins production capacity at our chemical manufacturing site in Geismar, Louisiana. This project is expected to be completed by the end of 2018 and make the site the largest alpha olefins producer in the world.

We achieved the following operational milestones in 2015:

- In China, we opened a new lubricant blending plant in Tianjin. The plant has the capacity to produce 330 million litres of finished products per annum and brings our number of blending plants in China to eight.
- Also in China, we signed a heads of agreement with China National Offshore Oil Corporation (CNOOC) to expand our joint venture at Nanhai (Shell interest 50%) in the Guangdong province. The expansion, which is pre-FID, would double the joint venture's ethylene production to over two million tonnes per annum. CNOOC has started construction work on the expansion, with completion expected by the end of 2017.

- In Germany, we handed over the Harburg refinery to Nynas in December 2015. The transaction was agreed in 2011, and a first phase to hand over the base oil plant was completed in 2014.
- In Singapore, we started up a new 140 ktpa high-purity ethylene oxide purification unit and a new 140 ktpa ethoxylates unit at Jurong Island. These production units more than double the production of both chemical products at Jurong.
- In the USA, Shell Midstream Partners, L.P. sold additional interests to public investors via the issuance of additional limited partnership units, reducing our interest in the partnership to approximately 60%, and generating proceeds of $595 million.
- Also in the USA, we continued detailed engineering design and site preparation for the construction of a proposed petrochemicals plant (Shell interest 100%) in the Appalachian region.

We continued to review our portfolio to divest positions that fail to deliver competitive performance or no longer meet our longer-term strategic objectives. Major divestments in 2015 included:

- our 75% interest in Tongyi Lubricants in China.
- Butagaz, our liquefied petroleum gas (LPG) business in France. Butagaz constituted the majority of our LPG business. Following the sale, we only have LPG businesses in Argentina, Canada and Hong Kong.
- most of our retail, commercial fuels, and supply and distribution logistics business in Norway to ST1 Nordic Oy (ST1). The Shell brand will continue to be highly visible in Norway through a retail brand licence agreement. In addition, Shell has entered into a joint venture (Shell interest 50%) with ST1 to sell aviation fuel in Norway.
- 185 service stations across the UK to independent dealers. All service stations will retain the Shell brand and sell Shell's fuels.

In addition, we reached agreements to sell the following, with expected completion in 2016:

- our marketing business in Denmark to Couche-Tard. This includes a retail brand licence agreement under which the Shell brand will remain highly visible in Denmark.
- a 33.24% holding in Showa Shell in Japan to Idemitsu. We are retaining a 1.80% interest.
- our 51% shareholding in the Shell Refining Company in Malaysia to Malaysia Hengyuan International Ltd.

BUSINESS AND PROPERTY

Refining

We have interests in 23 refineries worldwide with the capacity to process a total of around 3.1 million barrels of crude oil per day (Shell share). Our refining capacity is 34% in Europe and Africa, 39% in the Americas and 27% in Asia and Oceania.

The Port Arthur refinery in Texas, USA, owned and operated by Motiva (a 50:50 joint venture with Saudi Refining, Inc), is the largest refinery in North America and includes one of the world's largest single-site base oil manufacturing plants.

Trading and Supply

Trading and Supply trades in physical and financial contracts, lease storage and transportation capacities, and manages shipping and wholesale commercial fuel activities globally.

With more than 100 distribution terminals and 770 supply points in around 25 countries, our supply and distribution infrastructure is well positioned to make deliveries around the world. This includes supplying feedstocks for our refineries and chemical plants and finished products such as gasoline, diesel and aviation fuel to our Marketing businesses and customers.

Shell Wholesale Commercial Fuels provides transport, industrial and heating fuels. Our range of products, from reliable main-grade fuels to premium products, can offer tangible benefits. These include fuel economy, enhanced equipment performance, reduction in maintenance frequency and costs as well as reduced emissions.

Pipelines

Shell Pipeline Company LP (Shell interest 100%) owns and operates seven tank farms across the USA and transports more than 1.5 billion barrels of crude oil and refined products a year through about 6,000 kilometres of pipelines in the Gulf of Mexico and five US states. Our various non-operated ownership interests provide about a further 13,000 pipeline kilometres.

We carry more than 40 types of crude oil and more than 20 grades of gasoline, as well as diesel, aviation fuel, chemicals and ethylene.

Shell Midstream Partners, L.P., a Midstream Limited Partnership (MLP), was formed by Shell in 2014 to own, operate, develop and acquire pipelines and other midstream assets. Its assets consist of interests in entities that own crude oil and refined products pipeline systems and related assets that serve as key infrastructure to store onshore and offshore crude oil production and transport to refining markets and to deliver refined products to major demand centres. Shell controls the general partner and holds a majority share in the MLP.

Marketing

RETAIL

There were close to 43,000 Shell-branded retail stations operating in over 70 countries at the end of 2015. We have more than 100 years' experience in fuel development. In recent years, we have concentrated on developing fuels with special formulations designed to clean engines and improve performance. We sell such fuels under the Shell V-Power brand in more than 50 countries.

LUBRICANTS

Across approximately 100 countries, we produce, market or sell technically-advanced lubricants not only for passenger cars, motorcycles, trucks and coaches but also for industrial machinery in the manufacturing, mining, power generation, agriculture and construction sectors.

We have a global lubricants supply chain with a network of eight base oil manufacturing plants, 45 lubricant blending plants, 15 grease plants and four gas-to-liquids base oil storage hubs.

Through our marine activities, we primarily provide lubricants, but also fuels and related technical services, to the shipping and maritime sectors. Following rationalisation of our product portfolio, we now supply around 80 grades of lubricants and nine types of fuel to vessels worldwide, ranging from large ocean-going tankers to small fishing boats.

BUSINESS TO BUSINESS

Our Business-to-Business (B2B) activities encompass the sale of fuels and speciality products and services to a broad range of commercial customers.

DOWNSTREAM CONTINUED

Shell Aviation fuels more than two million aircraft a year, with a presence at more than 800 airports in around 40 countries.

We continue to pursue opportunities in the LNG for transport sector, developing projects that provide us and our customers with the best commercial value. Since October 2015, we have had access to import and storage capacity at the Gas Access to Europe (GATE) terminal in the Netherlands, enabling us to supply our own LNG to marine and road customers in northwest Europe. We will also supply LNG for our truck refuelling network in the Netherlands from the terminal.

Shell Bitumen supplies over 1,600 customers across 28 countries and provides enough bitumen to resurface 450 kilometres of road lanes every day. It also invests in technology research and development to create innovative products.

Shell Sulphur Solutions is a business which manages the complete value chain of sulphur, from refining to marketing. The business provides sulphur for industries such as mining and textiles and also develops new products which incorporate sulphur, such as fertilisers.

ALTERNATIVE ENERGIES

Raízen, our joint venture in Brazil, produces ethanol from sugar cane and manages a retail network. With an annual production capacity of more than 2 billion litres, it is one of the largest biofuel producers in the world. Raízen opened its first cellulosic ethanol plant at its Costa Pinto mill in Brazil in 2015. It is expected to produce 40 million litres a year of advanced biofuels from sugar-cane residues. We also continue to research and explore the potential of hydrogen as a fuel.

Chemicals

MANUFACTURING

Our plants produce a range of base chemicals, including ethylene, propylene and aromatics, as well as intermediate chemicals such as styrene monomer, propylene oxide, solvents, detergent alcohols, ethylene oxide and ethylene glycol. We have the capacity to produce over 6 million tonnes of ethylene a year.

MARKETING

Each year, we supply more than 17 million tonnes of petrochemicals to around 1,000 major industrial customers worldwide. Our products are used to make numerous everyday items, from clothing and cars to detergents and bicycle helmets.

DOWNSTREAM BUSINESS ACTIVITIES WITH IRAN, SUDAN AND SYRIA

Iran

Shell transactions with Iran are disclosed separately. See "Section 13(r) of the US Securities Exchange Act of 1934 Disclosure" on page 197.

Sudan

We ceased all operational activities in Sudan in 2008. However, we completed soil remediation work in 2015 related to earlier operations in the country.

Syria

We are in compliance with all European Union and US sanctions. We supply limited quantities of polyols via a Netherlands-based distributor to private sector customers in Syria. Polyols are commonly used for the production of foam in mattresses and soft furnishings.

DOWNSTREAM DATA TABLES

The tables below reflect Shell subsidiaries, the 50% Shell interest in Motiva in the USA and instances where Shell owns the crude oil or feedstocks processed by a refinery. Other joint ventures and associates are only included where explicitly stated.

OIL PRODUCTS – COST OF CRUDE OIL PROCESSED OR CONSUMED [A]			$ PER BARREL
	2015	2014	2013
Total	40.91	82.76	90.36

[A] Includes Upstream margin on crude oil supplied by Shell subsidiaries, joint ventures and associates. Excludes cost of crude oil processed or consumed by Motiva.

CRUDE DISTILLATION CAPACITY [A]	THOUSAND B/CALENDAR DAY [B]		
	2015	2014	2013
Europe	1,037	1,033	1,033
Asia	816	810	810
Oceania	–	80	118
Africa	82	82	82
Americas	1,219	1,212	1,212
Total	3,154	3,217	3,255

[A] Average operating capacity for the year, excluding mothballed capacity.
[B] Calendar day capacity is the maximum sustainable capacity adjusted for normal unit downtime.

ETHYLENE CAPACITY [A]	THOUSAND TONNES/YEAR		
	2015	2014	2013
Europe	1,702	1,659	1,659
Asia	2,222	1,922	1,922
Oceania	–	–	–
Africa	–	–	–
Americas	2,235	2,212	2,212
Total	6,159	5,793	5,793

[A] Includes the Shell share of capacity entitlement (offtake rights) of joint ventures and associates, which may be different from nominal equity interest. Nominal capacity is quoted at December 31.

OIL PRODUCTS – CRUDE OIL PROCESSED [A]			THOUSAND B/D
	2015	2014	2013
Europe	870	941	1,010
Asia	685	688	706
Oceania	–	59	116
Africa	56	69	61
Americas	1,150	1,149	1,100
Total	2,761	2,906	2,993

[A] Includes natural gas liquids, share of joint ventures and associates and processing for others.

REFINERY PROCESSING INTAKE [A]			THOUSAND B/D
	2015	2014	2013
Crude oil	2,596	2,716	2,732
Feedstocks	209	187	183
Total	2,805	2,903	2,915
Europe	903	941	933
Asia	627	639	634
Oceania	–	64	105
Africa	56	69	54
Americas	1,219	1,190	1,189
Total	2,805	2,903	2,915

[A] Includes crude oil, natural gas liquids and feedstocks processed in crude distillation units and in secondary conversion units.

REFINERY PROCESSING OUTTURN [A]			THOUSAND B/D
	2015	2014	2013
Gasolines	1,012	1,049	1,049
Kerosines	316	331	368
Gas/Diesel oils	972	1,047	1,014
Fuel oil	290	316	274
Other	449	395	389
Total	3,039	3,138	3,094

[A] Excludes own use and products acquired for blending purposes.

CHEMICALS SALES VOLUMES [A]			THOUSAND TONNES
	2015	2014	2013
Europe			
Base chemicals	3,000	3,287	3,423
Intermediates and others	1,936	2,019	2,281
Total	4,936	5,306	5,704
Asia			
Base chemicals	2,319	2,220	2,266
Intermediates and others	3,576	2,901	2,989
Total	5,895	5,121	5,255
Oceania			
Base chemicals	–	–	–
Intermediates and others	–	35	62
Total	–	35	62
Africa			
Base chemicals	–	–	–
Intermediates and others	37	43	47
Total	37	43	47
Americas			
Base chemicals	3,036	3,251	3,218
Intermediates and others	3,244	3,252	3,100
Total	6,280	6,503	6,318
Total product sales			
Base chemicals	8,355	8,758	8,907
Intermediates and others	8,793	8,250	8,479
Total	17,148	17,008	17,386

[A] Excludes feedstock trading and by-products.

OIL PRODUCT SALES VOLUMES [A][B]			THOUSAND B/D
	2015	2014	2013
Europe			
Gasolines	403	405	415
Kerosines	251	264	226
Gas/Diesel oils	779	841	962
Fuel oil	186	176	194
Other products	240	205	168
Total	1,859	1,891	1,965
Asia			
Gasolines	379	343	325
Kerosines	214	191	191
Gas/Diesel oils	533	515	483
Fuel oil	340	325	322
Other products	489	441	256
Total	1,955	1,815	1,577
Oceania			
Gasolines	–	52	87
Kerosines	51	48	51
Gas/Diesel oils	–	64	115
Fuel oil	–	–	–
Other products	–	10	19
Total	51	174	272
Africa			
Gasolines	37	36	45
Kerosines	9	9	9
Gas/Diesel oils	57	52	43
Fuel oil	1	–	3
Other products	15	7	14
Total	119	104	114
Americas			
Gasolines	1,325	1,268	1,149
Kerosines	204	206	234
Gas/Diesel oils	584	583	519
Fuel oil	86	68	96
Other products	249	256	238
Total	2,448	2,381	2,236
Total product sales [C]			
Gasolines	2,144	2,104	2,021
Kerosines	729	718	711
Gas/Diesel oils	1,953	2,055	2,122
Fuel oil	613	569	615
Other products	993	919	695
Total	6,432	6,365	6,164

[A] Excludes deliveries to other companies under reciprocal sale and purchase arrangements, which are in the nature of exchanges. Sales of condensate and natural gas liquids are included.
[B] Includes the Shell share of sales volumes from Raízen.
[C] Certain contracts are held for trading purposes and reported net rather than gross. The effect in 2015 was a reduction in oil product sales of approximately 1,158,000 b/d (2014: 1,067,000 b/d; 2013: 921,000 b/d).

DOWNSTREAM CONTINUED

MANUFACTURING PLANTS AT DECEMBER 31, 2015

REFINERIES IN OPERATION

				Thousand barrels/calendar day, 100% capacity[B]			
	Location	Asset class	Shell interest (%)[A]	Crude distillation capacity	Thermal cracking/ visbreaking/ coking	Catalytic cracking	Hydro-cracking
Europe							
Denmark	Fredericia	●	100	67	40	–	–
Germany	Miro [C]		32	310	65	89	–
	Rheinland	■ ●	100	325	44	–	80
	Schwedt [C]		38	220	47	50	–
Netherlands	Pernis	■ ●	100	404	45	48	83
Asia							
Japan	Mizue (Toa) [C]	● ◆	18	64	24	38	–
	Yamaguchi [C]	◆	13	110	–	25	–
	Yokkaichi [C]	● ◆	26	234	–	55	–
Malaysia	Port Dickson [D]	◆	51	107	–	39	–
Pakistan	Karachi [C]		30	43	–	–	–
Philippines	Tabangao		67	96	31	–	–
Saudi Arabia	Al Jubail [C]	● ◆	50	292	85	–	45
Singapore	Pulau Bukom	■ ●	100	468	70	34	55
Africa							
South Africa	Durban [C]	◆	38	165	23	34	–
Americas							
Argentina	Buenos Aires	● ◆	100	100	18	20	–
Canada							
Alberta	Scotford	◆	100	92	–	–	62
Ontario	Sarnia	◆	100	73	4	19	9
USA							
California	Martinez	●	100	144	42	65	37
Louisiana	Convent [C]	◆	50	227	–	82	45
	Norco [C]	■	50	229	25	107	39
Texas	Deer Park	■ ●	50	312	78	63	53
	Port Arthur [C]	●	50	578	144	81	73
Washington	Puget Sound	● ◆	100	137	23	52	–

[A] Shell interest is rounded to nearest whole percentage point; Shell share of production capacity may differ.
[B] Calendar day capacity is the maximum sustainable capacity adjusted for normal unit downtime.
[C] Not operated by Shell.
[D] In 2015, we agreed to sell our interest in Port Dickson refinery to Malaysia Hengyuan International Ltd. The transaction is expected to be completed in 2016.

■ Integrated refinery and chemical complex.
● Refinery complex with cogeneration capacity.
◆ Refinery complex with chemical unit(s).

MAJOR CHEMICAL PLANTS IN OPERATION [A]

	Location	Thousand tonnes/year, Shell share capacity[B] Ethylene	Styrene monomer	Ethylene glycol	Higher olefins[C]	Additional products
Europe						
Germany	Rheinland	315	–	–	–	A
Netherlands	Moerdijk [D]	972	725	155	–	A, I
UK	Mossmorran [E]	415	–	–	–	–
	Stanlow [E]	–	–	–	330	I
Asia						
China	Nanhai [E]	475	320	175	–	A, I, P
Japan	Yamaguchi [E]	–	–	–	11	A, I
Saudi Arabia	Al Jubail [E]	366	400	–	–	A, O
Singapore	Jurong Island	281	1,020	1,005	–	A, I, P, O
	Pulau Bukom	1,100	–	–	–	A, I
Americas						
Canada	Scotford	–	485	520	–	A, I
USA	Deer Park	836	–	–	–	A, I
	Geismar	–	–	400	920	I
	Norco	1,399	–	–	–	A
Total		6,159	2,950	2,255	1,261	

[A] Major chemical plants are large integrated chemical facilities, typically producing a range of chemical products from an array of feedstocks, and are a core part of our global Chemicals business.
[B] Shell share of capacity of subsidiaries, joint arrangements and associates (Shell and non-Shell operated), excluding capacity of the Infineum additives joint ventures.
[C] Higher olefins are linear alpha and internal olefins (products range from C6-C2024).
[D] Due to operational incidents in 2014 and 2015, not all units were fully in operation at December 31, 2015.
[E] Not operated by Shell.

A Aromatics, lower olefins.
I Intermediates.
P Polyethylene, polypropylene.
O Other.

OTHER CHEMICAL LOCATIONS [A]

	Location	Products
Europe		
Germany	Karlsruhe	A
	Schwedt	A
Netherlands	Pernis	A, I, O
Asia		
Japan	Kawasaki	A, I
	Yokkaichi	A
Malaysia	Bintulu	I
	Port Dickson	A
Africa		
South Africa	Durban	I
Americas		
Argentina	Buenos Aires	I
Canada	Sarnia	A, I
USA	Martinez	O
	Mobile	A
	Puget Sound	I

[A] Other chemical locations reflect locations with smaller chemical units, typically serving more local markets.

A Aromatics, lower olefins.
I Intermediates.
O Other.

CORPORATE

EARNINGS			$ MILLION
	2015	2014	2013
Segment earnings	(425)	(156)	372
Including:			
Net interest and investment expense	995	913	832
Foreign exchange losses	731	263	189
Taxation and other	(1,301)	(1,020)	(1,393)

OVERVIEW

The Corporate segment covers the non-operating activities supporting Shell. It comprises Shell's holdings and treasury organisation, including its self-insurance activities as well as its headquarters and central functions. All finance expense and income as well as related taxes are included in the Corporate segment earnings rather than in the earnings of the business segments.

The holdings and treasury organisation manages many of the Corporate entities and is the point of contact between Shell and external capital markets. It conducts a broad range of transactions – from raising debt instruments to transacting foreign exchange. Treasury centres in London, Singapore and Rio de Janeiro support these activities.

Headquarters and central functions provide business support in the areas of communications, finance, health, human resources, information technology, legal services, real estate and security. They also provide support for the shareholder-related activities of the Company. The central functions are supported by business service centres located around the world, which process transactions, manage data and produce statutory returns, among other services. The majority of the headquarters and central-function costs are recovered from the business segments. Those costs that are not recovered are retained in Corporate.

SELF-INSURANCE

Shell mainly relies on self-insurance for many of its risk exposures and capital is set aside to meet self-insurance obligations (see "Risk factors" on pages 10-11). The capital held to support the self-insurance obligations is at a level at least equivalent to what would be held in the third-party insurance market. Periodically, surveys of key assets are undertaken that provide risk-engineering knowledge and best practices to Shell subsidiaries with the aim to reduce their exposure to hazard risks. Actions identified during these surveys are monitored to completion.

INFORMATION TECHNOLOGY

Given our reliance on information technology systems for our operations, we continuously monitor external developments and share information on threats and security incidents. Shell employees and contractors are subject to mandatory courses and regular awareness campaigns, aimed at protecting us against cyber threats. We periodically review and adapt our disaster recovery plans and security response processes, and seek to enhance our security monitoring capability. See "Risk factors" on page 11.

EARNINGS 2015-2013

Segment earnings in 2015 were a loss of $425 million, compared with a loss of $156 million in 2014 and a gain of $372 million in 2013.

Net interest and investment expense increased by $82 million between 2014 and 2015. Interest expense was higher, mostly driven by new bond issuances 2015 (see "Liquidity and capital resources" on page 50), partly offset by an improvement in the liquidity premium associated with currency swaps, and an increase in the amount of interest capitalised. In 2014, net interest and investment expense decreased by $81 million compared with 2013. Interest expense was higher, mostly driven by new bond issuances and additional finance leases, including those assumed as a result of the acquisition of Repsol LNG businesses. These effects were partly offset by an improvement in the liquidity premium associated with currency swaps.

Foreign exchange losses of $731 million in 2015 (2014: $263 million; 2013: $189 million) were mainly due to the impact of exchange rates on non-functional currency loans and cash balances in operating units. The dollar strengthened against all major currencies to which Shell has exposure.

Taxation and other earnings increased by $281 million in 2015 compared with 2014, mainly due to a gain on the sale of an office building in the UK, partly offset by lower tax credits. In 2014, taxation and other earnings were $373 million lower than 2013, mainly due to lower tax credits.

LIQUIDITY AND CAPITAL RESOURCES

We manage our businesses to deliver strong cash flows to fund investment for profitable growth. Our aim is that, across the business cycle, "cash in" (including cash from operations and divestments) at least equals "cash out" (including capital expenditure, interest and dividends), while maintaining a strong balance sheet. Our priorities for applying our cash are the servicing and reduction of debt commitments, payment of dividends, share buybacks and capital investment.

OVERVIEW

The most significant factors affecting our operating cash flow are earnings and movements in working capital, which are mainly impacted by: realised prices for crude oil and natural gas; production levels of crude oil and natural gas; and refining and marketing margins.

Changes in realised crude oil and natural gas prices and production levels can have a significant impact on our operating cash flow. The extent of the impact from a decrease or increase in prices depends on: the extent to which contractual arrangements are tied to market prices; the dynamics of production-sharing contracts; the existence of agreements with governments or state-owned oil and gas companies that have limited sensitivity to crude oil and natural gas prices; tax impacts; and the extent to which changes in commodity prices flow through into operating costs. Changes in benchmark prices of crude oil and natural gas in any particular period therefore provide only a broad indicator of changes in our Upstream earnings in that period. In the longer term, replacement of proved oil and gas reserves will affect our ability to maintain or increase production levels, which in turn will affect our cash flows and earnings.

Changes in any one of a range of factors derived from either within the industry or the broader economic environment can influence refining and marketing margins. The precise impact of any such changes depends on how the oil markets respond to them. The market response is affected by factors such as: whether the change affects all crude oil types or only a specific grade; regional and global crude-oil and refined-products inventories; and the collective speed of response of refiners and product marketers in adjusting their operations. As a result, margins fluctuate from region to region and from period to period.

STATEMENT OF CASH FLOWS

Net cash from operating activities in 2015 was $29.8 billion, a decrease from $45.0 billion in 2014. The decrease mainly reflected lower income, which was principally a result of the significant decline in oil and gas prices. The increase in net cash from operating activities in 2014, compared with $40.4 billion in 2013, mainly reflected a higher cash inflow from working capital movements.

Net cash used in investing activities was $22.4 billion in 2015, an increase from $19.7 billion in 2014. The increase was mainly the result of lower proceeds from sale of assets, which more than offset a reduction in capital expenditure. Net cash used in investing activities decreased from $40.1 billion in 2013 to $19.7 billion in 2014, mainly as a result of lower capital expenditure and higher proceeds from sale of assets.

Net cash from financing activities in 2015 was an inflow of $3.8 billion compared with cash outflows of $12.8 billion in 2014 and $9.0 billion in 2013. This included net debt issued of $14.9 billion (2014: $0.4 billion; 2013: $5.4 billion), partly offset by payment of dividends to Royal Dutch Shell plc shareholders of $9.4 billion (2014: $9.4 billion; 2013: $7.2 billion) and interest paid of $1.7 billion (2014: $1.5 billion; 2013: $1.3 billion).

Cash and cash equivalents were $31.8 billion at December 31, 2015 (2014: $21.6 billion; 2013: $9.7 billion). This includes amounts held for the acquisition of BG Group plc (BG).

CASH FLOW INFORMATION [A] — $ BILLION

	2015	2014	2013
Net cash from operating activities excluding working capital movements			
Upstream	13.2	33.3	28.8
Downstream	10.6	4.5	7.5
Corporate	0.5	0.8	1.2
Total	24.3	38.6	37.5
Decrease in inventories	2.8	8.0	0.6
Decrease/(increase) in current receivables	9.9	(1.6)	5.6
Decrease in current payables	(7.2)	–	(3.3)
Decrease in working capital	5.5	6.4	2.9
Net cash from operating activities	29.8	45.0	40.4
Net cash used in investing activities	(22.4)	(19.7)	(40.1)
Net cash from/(used in) financing activities	3.8	(12.8)	(9.0)
Currency translation differences relating to cash and cash equivalents	(1.0)	(0.6)	(0.2)
Increase/(decrease) in cash and cash equivalents	10.2	11.9	(8.9)
Cash and cash equivalents at the beginning of the year	21.6	9.7	18.6
Cash and cash equivalents at the end of the year	31.8	21.6	9.7

[A] See the "Consolidated Statement of Cash Flows" on page 119.

LIQUIDITY AND CAPITAL RESOURCES CONTINUED

FINANCIAL CONDITION AND LIQUIDITY

Our financial position is strong. Despite the weakness in commodity prices, with an average Brent crude oil price of $52 per barrel in 2015 ($99 per barrel in 2014), our gearing increased by less than 2% over the year, from 12.2% at end 2014 to 14.0% at end 2015. Gearing, defined as net debt (total debt less cash and cash equivalents) as a percentage of total capital (net debt plus total equity), is a key measure of our capital structure. Across the business cycle, we aim to manage gearing within a range of 0-30%. Note 14 to the "Consolidated Financial Statements" on pages 134-135 provides information on our debt arrangements, including gearing.

We are affected by the global macroeconomic environment as well as financial and commodity market conditions. This exposes us to treasury and trading risks, including liquidity risk, market risk (interest rate risk, foreign exchange risk and commodity price risk) and credit risk. See "Risk factors" on page 10 and Note 19 to the "Consolidated Financial Statements" on pages 142-144. The size and scope of our businesses require a robust financial control framework and effective management of our various risk exposures.

Market risk and credit risk

In the normal course of business, financial instruments of various kinds are used for the purposes of managing exposure to interest rate, foreign exchange and commodity price movements. Our treasury and trading operations are highly centralised, and seek to manage credit exposures associated with our substantial cash, foreign exchange and commodity positions. Our portfolio of cash investments is diversified to avoid concentrating risk in any one instrument, country, or counterparty. We monitor our investments and adjust them in light of new market information. Exposure to failed financial and trading counterparties was not material in 2015. Treasury standards are applicable to all our subsidiaries, and each subsidiary is required to adopt a treasury policy consistent with these standards. Other than in exceptional cases, the use of external derivative instruments is confined to specialist trading and central treasury organisations that have appropriate skills, experience, supervision, control and reporting systems.

Pension commitments

We have substantial pension commitments, whose funding is subject to capital market risks (see "Risk factors" on page 10). We address key pension risks in a number of ways. Principal among these is the Pensions Forum, chaired by the Chief Financial Officer, which provides guidance on Shell's input to pension strategy, policy and operation. The forum is supported by a risk committee in reviewing the results of assurance processes with respect to pension risks. In general, local trustees manage the funded defined benefit pension plans and set the required contributions based on independent actuarial valuations in accordance with local regulations. Our total employer contributions to defined benefit pension plans were $1.3 billion in 2015 and are estimated to be $1.4 billion in 2016.

Liquidity

We satisfy our funding and working capital requirements from the cash generated by our operations and through the issuance of debt. Despite challenging market conditions for our industry, we have continued to have good access to the international debt capital markets. Our debt is principally financed from these markets through central debt programmes consisting of:

- a $10 billion global commercial paper (CP) programme, exempt from registration under section 3 (a)(3) of the US Securities Act of 1933, with maturities not exceeding 270 days;
- a $10 billion CP programme, exempt from registration under section 4(2) of the US Securities Act of 1933, with maturities not exceeding 397 days;
- an unlimited Euro medium-term note (EMTN) programme (also referred to as the Multi-currency Debt Securities Programme); and
- an unlimited US universal shelf (US shelf) registration.

All CP, EMTN and US shelf issuances are undertaken by Shell International Finance B.V., the issuance company for Shell, with its debt being guaranteed by Royal Dutch Shell plc (the Company).

We also maintain a $7.48 billion committed credit facility that was undrawn at December 31, 2015. Following the second one-year extension agreed in November 2015, the facility expires in 2020. This facility and internally available liquidity provide back-up coverage for CP. Other than certain borrowings in local subsidiaries, we do not have any other committed credit facilities.

Our total debt increased by $12.8 billion in 2015 to $58.4 billion at December 31, 2015, and the amount, excluding leases, will mature as follows: 10% in 2016; 11% in 2017; 15% in 2018; 8% in 2019; and 56% in 2020 and beyond. The portion of debt maturing in 2016 is expected to be repaid from a combination of cash balances, cash generated from operations, divestments and issuance of new debt.

In 2015, we issued $15.0 billion of bonds under our US shelf registration, and $5.3 billion of bonds under our EMTN programme, the proceeds of which were primarily used to finance the BG acquisition (see below). Periodically, for working capital purposes, we issued CP. We believe our current working capital is sufficient for present requirements.

In accordance with the UK City Code on Takeovers and Mergers, we maintained sufficient certain funds for the estimated £13.2 billion cash consideration portion of the BG acquisition from the date of announcement in April 2015 until the date of completion in February 2016. We entered into a £10.07 billion bridge credit facility on May 1, 2015, which was cancelled unused on February 10, 2016, once funds had been accumulated and the completion date was certain. We raised these funds through long-term debt issuance in 2015.

While our subsidiaries are subject to restrictions, such as foreign withholding taxes on the transfer of funds in the form of cash dividends, loans or advances, such restrictions are not expected to have a material impact on our ability to meet our cash obligations.

CAPITALISATION TABLE		$ MILLION
	Dec 31, 2015	Dec 31, 2014
Equity attributable to Royal Dutch Shell plc shareholders	162,876	171,966
Current debt	5,530	7,208
Non-current debt	52,849	38,332
Total debt [A]	58,379	45,540
Total capitalisation	221,255	217,506

[A] Of total debt, $53.2 billion (2014: $39.5 billion) was unsecured and $5.2 billion (2014: $6.0 billion) was secured. See Note 14 to the "Consolidated Financial Statements" on pages 134-135 for further disclosure on debt, including the amount guaranteed by the Company.

The consolidated ratio of earnings to fixed charges of Shell for each of five years ended December 31, 2011-2015, is as follows:

RATIO OF EARNINGS TO FIXED CHARGES [A]

	2015	2014	2013	2012	2011
Ratio of earnings to fixed charges	1.93	14.41	20.11	31.12	35.71

[A] See "Exhibit 7.1" on page E1 for the calculation of the ratio of earnings to fixed charges.

DIVIDENDS

Our policy is to grow the dollar dividend through time, in line with our view of our underlying earnings and cash flow. When setting the dividend, the Board of Directors looks at a range of factors, including the macro environment, the current balance sheet and future investment plans.

We returned $12.0 billion to our shareholders through dividends in 2015. Some of those dividends were paid out as 96.3 million shares issued to shareholders who had elected to receive new shares instead of cash, under our Scrip Dividend Programme which was reintroduced in March 2015 from the first quarter 2015 interim dividend onwards.

We have announced an interim dividend in respect of the fourth quarter of 2015 of $0.47 per share, in line with the dividend for the same quarter of 2014. See Note 23 to the "Consolidated Financial Statements" on page 150. The fourth quarter interim dividend will be payable to shareholders, including former BG shareholders, on the register at February 19, 2016. The Board expects that the first quarter 2016 interim dividend will be $0.47 per share.

PURCHASES OF SECURITIES

At the 2015 Annual General Meeting (AGM), shareholders granted an authority, which will expire at the end of the 2016 AGM, for the Company to repurchase up to 633 million of its shares. Under a similar authority granted at the 2014 AGM, we continued a share buyback programme, repurchasing 12.7 million shares in January 2015, to offset the dilution created by the issuance of shares under our Scrip Dividend Programme. The share buyback programme was suspended in February 2015. All of the shares purchased under the buyback programme are cancelled. A resolution will be proposed at the 2016 AGM to renew authority for the Company to purchase its own share capital up to specified limits for another year. Shares are also purchased by the employee share ownership trusts and trust-like entities (see the "Directors' Report" on page 68) to meet delivery commitments under employee share plans. All share purchases are made in open-market transactions.

The table below provides information on purchases of shares in 2015 by the issuer and affiliated purchasers. Purchases in euros and sterling are converted into dollars using the exchange rate on each transaction date.

PURCHASES OF EQUITY SECURITIES BY ISSUER AND AFFILIATED PURCHASERS IN 2015 [A]

	A shares			B shares		A ADSs	
Purchase period	Number purchased for employee share plans	Number purchased for cancellation[C]	Weighted average price ($)[B]	Number purchased for employee share plans	Weighted average price ($)[B]	Number purchased for employee share plans	Weighted average price ($)[B]
January	–	12,717,512	32.06	–	–	1,133,754	65.00
February	–	–	–	–	–	–	–
March	343,670	–	31.16	184,916	33.02	98,567	62.57
April	–	–	–	–	–	–	–
May	–	–	–	–	–	–	–
June	52,359	–	29.97	150,233	30.32	–	–
July	–	–	–	–	–	–	–
August	–	–	–	–	–	21,097	50.22
September	–	–	–	163,535	24.19	–	–
October	–	–	–	–	–	–	–
November	–	–	–	–	–	–	–
December	–	–	–	181,366	22.15	–	–
Total 2015	396,029	12,717,512	32.03	680,050	27.40	1,253,418	64.56

[A] Excludes shares issued to affiliated purchasers pursuant to the Scrip Dividend Programme.
[B] Average price paid per share includes stamp duty and brokers' commission.
[C] Under the share buyback programme.

LIQUIDITY AND CAPITAL RESOURCES CONTINUED

CAPITAL INVESTMENT AND DIVESTMENTS

The reduction in capital investment in 2015 compared with 2014 reflects our decision to curtail spending by reducing the number of new investment decisions and designing lower-cost development solutions.

CAPITAL INVESTMENT [A]		$ MILLION
	2015	2014
Upstream	23,527	31,293
Downstream	5,119	5,910
Corporate	215	136
Total	28,861	37,339

[A] See "Non-GAAP measures reconciliations and other definitions" on page 198.

In 2015, we continued to divest assets that fail to deliver competitive performance or no longer meet our longer-term strategic objectives, including assets in China, France, Nigeria, Norway, the UK and the USA. Divestments also included the sale of interests in Shell Midstream Partners, L.P.

DIVESTMENTS		$ MILLION
	2015	2014
Upstream	2,747	10,589
Downstream	2,282	4,410
Corporate	511	20
Divestments [A]	5,540	15,019

[A] See "Non-GAAP measures reconciliations and other definitions" on page 198.

CONTRACTUAL OBLIGATIONS

The table below summarises our principal contractual obligations at December 31, 2015, by expected settlement period. The amounts presented have not been offset by any committed third-party revenue in relation to these obligations.

CONTRACTUAL OBLIGATIONS					$ BILLION
	Less than 1 year	Between 1 and 3 years	Between 3 and 5 years	5 years and later	Total
Debt [A]	5.0	13.2	9.4	24.3	51.9
Finance leases [A]	1.1	1.8	1.7	5.5	10.1
Operating leases [A]	5.3	7.2	6.1	7.6	26.2
Purchase obligations [B]	89.0	51.3	32.5	112.5	285.3
Other long-term contractual liabilities [C]	–	0.4	–	0.7	1.1
Total	100.4	73.9	49.7	150.6	374.6

[A] See Note 14 to the "Consolidated Financial Statements" on page 135. Debt contractual obligations exclude interest, which is estimated to be $1.5 billion payable in less than one year, $2.7 billion between one and three years, $1.9 billion between three and five years, and $11.2 billion in five years and later. For this purpose, we assume that interest rates with respect to variable interest rate debt remain constant at the rates in effect at December 31, 2015, and that there is no change in the aggregate principal amount of debt other than repayment at scheduled maturity as reflected in the table. Finance lease contractual obligations include interest.
[B] A purchase obligation is an agreement to purchase goods or services that is enforceable and legally binding and specifies terms such as: fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transaction.
[C] Includes all obligations included in "Trade and other payables" in "Non-current liabilities" on the "Consolidated Balance Sheet" that are contractually fixed as to timing and amount. In addition to these amounts, Shell has certain obligations that are not contractually fixed as to timing and amount, including contributions to defined benefit pension plans (see Note 17 to the "Consolidated Financial Statements" on pages 139-141) and obligations associated with decommissioning and restoration (see Note 18 to the "Consolidated Financial Statements" on pages 141-142).

GUARANTEES AND OTHER OFF-BALANCE SHEET ARRANGEMENTS

Guarantees at December 31, 2015, were $0.6 billion (2014: $3.3 billion). This includes $0.3 billion (2014: $1.6 billion) of guarantees of debt of joint ventures and associates.

FINANCIAL INFORMATION RELATING TO THE ROYAL DUTCH SHELL DIVIDEND ACCESS TRUST

The results of operations and financial position of the Royal Dutch Shell Dividend Access Trust (the Trust) are included in the consolidated results of operations and financial position of Shell. Certain condensed financial information in respect of the Trust is given below. See "Royal Dutch Shell Dividend Access Trust Financial Statements" on pages 185-189.

For the years 2015, 2014 and 2013 the Trust recorded income before tax of £2,726 million, £2,470 million and £2,361 million respectively. In each period this reflected the amount of dividends received on the dividend access share.

At December 31, 2015, the Trust had total equity of £nil (2014: £nil; 2013: £nil), reflecting cash of £2 million (2014: £1 million; 2013: £1 million) and unclaimed dividends of £2 million (2014: £1 million; 2013: £1 million). The Trust only records a liability for an unclaimed dividend, and a corresponding amount of cash, to the extent that cheques expire, which is one year after their issuance, or to the extent that they are returned unpresented.

ENVIRONMENT AND SOCIETY

Our success in business depends on our ability to meet a range of environmental and social challenges. We must show we can operate safely and manage the effect our activities can have on neighbouring communities and society as a whole. If we fail to do this, we may incur liabilities or sanctions, lose business opportunities, harm our reputation, or our licence to operate may be impacted (see "Risk factors" on page 10).

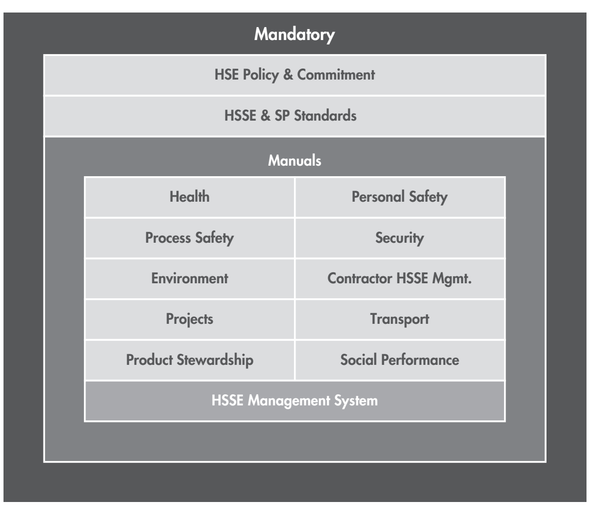
Data in this section are reported on a 100% basis in respect of activities where we are the operator. Reporting on this operational control basis differs from that applied for financial reporting purposes in the "Consolidated Financial Statements" on pages 115-152. Detailed data and information on our 2015 environmental and social performance will be published in the Shell Sustainability Report in April 2016.

CONTROL FRAMEWORK

The Shell General Business Principles (Principles) set out our responsibilities to shareholders, customers, employees, business partners and society. They set the standards for the way we conduct business, with integrity and respect for people, the environment and communities. All ventures that we operate must conduct their activities in line with our business principles.

We work to minimise the environmental impact of new projects and existing operations and we engage with local communities and non-governmental organisations to understand and respond to their concerns. We have standards and a clear governance structure in place to help manage potential impacts. Our standards are defined in our Health, Safety, Security, Environment and Social Performance (HSSE&SP) Control Framework, in line with our Commitment and Policy and the Shell Code of Conduct, and are supported by a number of guidance documents. They apply to every Shell entity, including all employees and contractors, and to Shell-operated ventures. The Control Framework defines standards and accountabilities at each level of the organisation, and sets out the procedures and processes people are required to follow. We manage HSSE&SP risks to "As Low As Reasonably Practicable" (ALARP), which is a business responsibility, supported by the HSSE&SP function. The process safety and HSSE&SP assurance team provides assurance on the effectiveness of HSSE&SP controls.

HSSE & SP CONTROL FRAMEWORK



Our three Golden Rules require our employees and contractors to comply with laws and regulations as well as our standards and procedures, to intervene in unsafe or non-compliant situations, and to respect our neighbours.

In ventures not operated by us, Shell-appointed representatives encourage our partners to apply standards and principles similar to our own. We support these ventures in their implementation of our Control Framework, or of a similar framework, and offer to review the effectiveness of their implementation. Even if such a review is not carried out, we periodically evaluate health, safety, security, environment and community risks faced by our ventures which we do not operate. If one of these ventures falls below expectations, plans are put in place, in agreement with our partners, to improve performance.

SAFETY

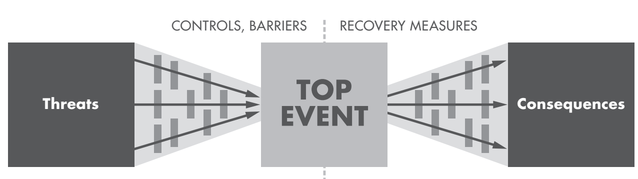
Safety is central to the responsible delivery of energy. We develop and operate our facilities with the aim of preventing any incidents that may harm our employees, contractors or nearby communities, or cause damage to our assets or adversely impact the environment. We manage safety risks across our businesses through clear standards, controls and compliance systems combined with a safety-focused culture.

Our global standards and operating procedures define the controls and physical barriers we require to prevent incidents. For example, our offshore wells are designed with at least two independent barriers to mitigate the risk of an uncontrolled release of hydrocarbons. We regularly inspect, test and maintain these barriers to ensure they meet our standards. We also routinely prepare and practise our emergency response to potential incidents such as an oil spill or a fire. This involves working closely with local services and regulatory agencies to jointly test our plans and procedures. These tests continually improve our readiness to respond. If an incident does occur, we have procedures in place to reduce the impact on people and the environment.

We continue to strengthen the safety culture among our employees and contractors. Our safety goal is to achieve no harm and no leaks across all of our operations. We refer to this as our Goal Zero ambition. We expect everyone working for us to intervene and stop work that may appear to be unsafe. In addition to our ongoing safety awareness programmes, we hold an annual global safety day to give employees and contractors time to reflect on how to prevent incidents. We expect everyone working for us to comply with our 12 mandatory Life-Saving Rules. If employees break these rules, they face disciplinary action up to and including termination of employment. If contractors break the Life-Saving Rules, they can be removed from the worksite.

Process safety involves making sure the right precautions are in place to prevent unplanned releases of hydrocarbons or chemicals. In the event of a loss of containment such as a spill or a leak, we employ independent recovery measures to prevent the release from becoming catastrophic. This system of barriers and recovery measures is known as a "bow-tie", a model that visually represents a system where process safety hazards are managed through prevention and response barriers.

RISK MANAGEMENT APPROACH



ENVIRONMENT AND SOCIETY CONTINUED

While we continually work to minimise the likelihood of incidents, some do occur. We investigate all incidents to understand the underlying causes and translate these into improvements in standards or ways of working that can be applied broadly across similar facilities in Shell. As set out in "Performance indicators" on pages 20-21, our total recordable case frequency (injuries per million working hours) was 0.94 in 2015, compared with 0.99 in 2014, and there were 51 operational Tier 1 process safety events in 2015, compared with 57 in 2014. Detailed information on our 2015 safety performance will be published in the Shell Sustainability Report in April 2016.

CLIMATE CHANGE

Our approach to climate change

We have long recognised that the use of fossil fuels contributes to climate change. In November 2015, 195 nations approved the *Paris Agreement* which must be ratified by 55 countries that account for at least 55% of global greenhouse gas (GHG) emissions. We welcome the efforts made by governments to reach a global climate agreement. The *Paris Agreement* provides a framework which is intended to enable governments to implement effective measures to reduce GHG emissions. The goal of limiting the increase in global temperatures to well below 2°C will be extremely challenging.

In the future, growth in energy demand means that all sources of energy will be needed over the longer term. Therefore, all forms of GHG reduction measures must be accelerated and increased in scale, including significant growth in carbon capture and storage (CCS) and renewables, significant improvements in energy efficiency, and sustained reductions in demand. The management of GHG emissions will become increasingly important as concerns over climate change lead to tighter environmental regulations. Policies and regulations designed to limit the increase in global temperatures to well below 2°C could have a material adverse effect on us. While we support the efforts to reduce GHG emissions, governments, when adopting rules and regulations, should balance the need to limit increases in temperature with society's need for energy.

Some governments have introduced carbon pricing mechanisms, which can be an effective measure to reduce GHG emissions across the economy at lowest overall cost to society. We expect more governments to follow and governments may also require companies to apply technical measures to reduce their GHG emissions. This could result in increased investments and higher project costs for us and higher energy and product costs for consumers (see "Risk factors" on pages 09-10). Our portfolio exposure is reviewed annually against changing GHG regulatory regimes and physical conditions to identify emerging risks. We test the resilience of our portfolio against externally published, future pathways, including a low emissions pathway.

To test the resilience of new projects, we assess potential costs associated with GHG emissions when evaluating all new investments. Our approach applies a uniform project screening value (PSV) of $40 (real terms) per tonne of carbon dioxide (CO_2) equivalent to the total GHG emissions of each investment. This PSV is generally applied when evaluating our new projects around the world to test their resilience across a range of future scenarios. The project development process features a number of checks that may require development of detailed GHG and energy management plans. High-emitting projects undergo additional sensitivity testing, including the potential for future CCS projects. Projects in the most GHG-exposed asset classes have GHG intensity targets that reflect standards sufficient to allow them to compete and prosper in a more CO_2 regulated future. These processes can lead to projects being stopped, designs being changed, and potential GHG mitigation investments being identified, in preparation for when regulation would make these investments commercially compelling.

The International Energy Agency (IEA) has developed a *450 Scenario* that sets out an energy pathway consistent with the goal of limiting the average global temperature increase to 2°C. This is accomplished by seeking to limit the concentration of greenhouse gases in the atmosphere to around 450 parts per million of CO_2 equivalent. By the year 2030, the IEA's *450 Scenario* describes an energy sector with significant renewables penetration, marked improvement in vehicle as well as process efficiency, and widespread replacement of coal by natural gas in power generation. Under this scenario, CCS is expected by 2030 to be storing around 40 times the volume of CO_2 it does at present. The IEA has assumed oil and gas prices in 2030 of around $97 per barrel and $9 per MMbtu respectively, and global CO_2 equivalent costs of $100 per tonne (all in real terms). The related impact on expected production is that global demand for oil would fall by 17% between 2015 and 2030, while demand for natural gas would grow by 8% during that period. The *450 Scenario* assumptions intensify through to 2050 and beyond to simulate the level of global GHG emission reductions needed to achieve the scenario goals.

We have evaluated our portfolio under the *450 Scenario*. The IEA's projected GHG regulation is expected to result in lower demand for some of our products and potential impairments to some of our less energy-efficient assets. However, we could also see certain benefits as a robust global CO_2 price would make some forms of energy, such as natural gas and renewables, more competitive compared with coal. A robust CO_2 price would also help encourage the development of CCS. Our preliminary view, looking at 2030, is that the aggregate impact under the IEA's *450 Scenario* would be positive overall for us compared with our own outlook. This is primarily due to the higher oil and gas prices assumed by the IEA. While the IEA assumes significant global CO_2 costs of $100/tonne (in real terms) in 2030, our portfolio sensitivity to oil and gas prices significantly exceeds our sensitivity to CO_2 costs associated with our GHG emissions.

While the IEA assumes significant GHG regulatory costs by 2030, the net impact on us will be influenced by developments in the allocation of free allowances under CO_2 pricing regimes as well as the ability to recover the increased costs from customers. The outlook for these critical elements differs by region and asset type. We actively monitor and model such influences, using our own estimates of developments in global GHG regulation rather than the external reference point of the IEA's *450 Scenario*, to better represent country-level policy granularity.

Accordingly, we have also evaluated the resilience of our portfolio using our own business-case model that assumes an average global temperature increase of 2-3°C by 2100. This model uses our best estimates for future oil and gas prices and expected trends in GHG policies, including existing and proposed regulations. Using our model, we expect our existing portfolio to remain relatively resilient in 2030, primarily as a result of our significant gas reserves and the relative energy efficiency of certain of our portfolio assets. While our model assumes lower overall regulatory costs associated with our CO_2 emissions in 2030 than the IEA estimate of $100/tonne, we also expect lower oil and gas prices, which projects a less positive outcome than under the IEA's *450 Scenario*.

Based on the above analysis, we believe current oil, gas and CO_2 prices are too low to stimulate the fossil fuel substitution necessary to meet the *Paris Agreement* goal of limiting the average global temperature increase to well below 2°C.

As energy demand increases and easily accessible oil and gas resources decline, we are developing resources that require more energy and advanced technologies to produce. As our production becomes more energy intensive, this could result in an associated increase in direct GHG emissions from our Upstream facilities. See "Risk factors" on pages 09-10.

We are seeking cost-effective ways to manage GHG emissions and see potential business opportunities in developing such solutions. Our main contributions to reducing global GHG emissions are in four areas: supplying more natural gas to replace coal for power generation; supplying biofuels; progressing CCS technologies; and implementing energy-efficiency measures in our operations where reasonably practical. To support this, we continue to advocate the introduction of effective government-led carbon pricing mechanisms.

According to the IEA, over 40% of global emissions in 2013 came from electricity and heat generation. For many countries, using more gas in power generation instead of coal can make the largest contribution, at the lowest cost, to meeting their GHG emission reduction objectives. We expect that, in combination with renewables and use of CCS, natural gas will be essential for significantly lower CO_2 emissions. With our leading position in liquefied natural gas (LNG), our portfolio of conventional gas assets and our technologies for recovering gas from tight rock formations, we can supply natural gas to replace coal for power generation. Natural gas can also act as a partner for intermittent renewable energy, such as solar and wind, to maintain a steady supply of electricity, because gas-fired plants can start and stop relatively quickly.

We believe that low-carbon biofuels are one of the most viable ways to reduce CO_2 from transport fuels in the coming years. Our Raízen joint venture (Shell interest 50%) in Brazil produces low-carbon biofuel from sugar cane. We are also investing in research to help develop and commercialise advanced biofuels.

CCS is a technology used for capturing CO_2 from flue gas before it is emitted into the atmosphere, transporting it through pipelines and injecting it into a deep geological formation for long-term storage. According to the IEA, CCS could contribute around 13% of the CO_2 mitigation effort required by 2050, assuming that use of CCS technology grows in accordance with the IEA scenario. In November 2015, we launched our Quest CCS project in Canada, which is designed to capture and safely store more than 1 million tonnes of CO_2 each year. We are also involved in the CCS test centre in Mongstad, Norway, the Gorgon CO_2 injection project in Australia and the Qatar Carbonates and Carbon Storage Research Centre. At the Peterhead power station in Scotland, which is operated by the British energy company SSE, we were developing the world's first full-scale CCS project for a natural gas-fired power plant. Unfortunately, in late 2015, the UK government decided not to fund the project, which meant that it could not proceed. However, our technical data and reports will be made public. We also have technology that can remove both CO_2 and sulphur dioxide from industrial flue gases. It is being used at the Boundary Dam coal-fired power plant in Canada.

We continue to work on improving energy efficiency at our oil and gas production facilities, refineries and chemical plants. Measures include our GHG and energy management programme that focuses on the efficient operation of existing equipment by using monitoring systems which give us instant information that we can use to make energy-saving changes.

In addition, we work to help our customers conserve energy and reduce their GHG emissions, including through the development and sale of advanced fuels and lubricants.

Our performance

Our direct GHG emissions decreased from 76 million tonnes of CO_2 equivalent in 2014 to 72 million in 2015. The level of flaring in our Upstream businesses fell by 8% in 2015 compared with 2014, despite an increase in flaring levels in Malaysia in line with increased oil production in 2015. Our emissions also decreased as a result of divestments (for example, in Nigeria and the Geelong refinery in Australia), a higher level of maintenance shutdowns and the start-up of Quest. These decreases were partially offset by updated Global Warming Potentials (GWPs). GWP is an index used to compare the impact of emissions from various greenhouse gases to the impact of emissions from the equivalent mass of CO_2. Our 2014 reporting was based on the GWPs from the *Second Assessment Report* published by the International Panel on Climate Change (IPCC). Consistent with updated UK regulations, our 2015 reporting is based on the GWPs from the *Fourth Assessment Report*. For example, as a result, GWP for methane increased from 21 to 25.

In 2015, we signed up to the World Bank's "Zero Routine Flaring by 2030" initiative. This is an important initiative to ensure all stakeholders, including governments and companies, work together to address routine flaring. Flaring, or burning off, of gas in our Upstream businesses contributed around 17% to our overall GHG emissions in 2015. The majority of this flaring takes place at facilities where there is no infrastructure to capture the gas produced with oil, known as associated gas. Gas flaring from these operations may rise in coming years if oil production increases before the related gas-gathering equipment is in place. In October 2015, we brought a project on stream to capture gas for reinjection in Malaysia. At the end of 2015, we also brought a project on stream that captures gas from the Majnoon field in Iraq to help supply the domestic market. We expect to further reduce our flaring levels in 2016, as gas gathering facilities that started at the end of 2015 in Malaysia and Iraq reach full capacity.

In parallel, our involvement in Basrah Gas Company (BGC), a joint venture between Shell, South Gas Company and Mitsubishi Corporation in the south of Iraq, continues to reduce flaring in the country. It is the largest gas project in Iraq's history and the world's largest flaring reduction project. BGC captures associated gas that would otherwise be flared from three non-Shell operated oil fields in southern Iraq (Rumaila, West Qurna 1 and Zubair) for use in the domestic market. It reached a peak raw gas throughput of 515 million standard cubic feet per day in 2015.

Around 25% of our flaring in 2015 took place in Nigeria, where a challenging operating environment and shortfalls in funding from the government-owned Nigerian National Petroleum Company – which has the majority interest in a venture operated by The Shell Petroleum Development Company of Nigeria Limited (SPDC) – has slowed progress on projects that are intended to gather additional associated gas that is currently flared.

Despite the noted funding challenges, flaring intensity levels in SPDC decreased by about 15% in 2015 compared with 2014. Work to improve asset reliability reduced the rate of flaring and the divestment of assets in Oil Mining Leases 18, 24 and 29 further contributed to the decrease in flaring emissions.

We recognise the importance of reducing methane emissions and take our responsibilities seriously. Methane from the flaring and venting of associated gas in our Upstream oil operations was the largest contributor to our reported methane emissions in 2015. We are working to reduce methane emissions from these sources by reducing the overall level of flaring and venting. In addition, we continue to implement "Leak Detection and Repair" programmes across our sites to identify high-emission equipment, such as high-bleed pneumatic devices, and unintended losses, so they can be replaced or repaired. We continue to work to confirm that we have identified all potential methane sources and have reported our emissions from these sources in line with regulations and industry standards.

ENVIRONMENT AND SOCIETY CONTINUED

GHG emissions data are provided below in accordance with UK regulations introduced in 2013. GHG emissions comprise CO_2, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulphur hexafluoride. The data are calculated using locally regulated methods where they exist. Where there is no locally regulated method, the data are calculated using the 2009 API Compendium, which is the recognised industry standard under the GHG Protocol Corporate Accounting and Reporting Standard. There are inherent limitations to the accuracy of such data. Oil and gas industry guidelines (IPIECA/API/IOGP) indicate that a number of sources of uncertainty can contribute to the overall uncertainty of a corporate emissions inventory.

GREENHOUSE GAS EMISSIONS

	2015	2014
Emissions (million tonnes of CO_2 equivalent)		
Direct [A]	72	76
Energy indirect [B]	9	10
Intensity ratios (tonne/tonne)		
All facilities [C]	0.23	0.23
Downstream refineries [D]	0.29	0.29
Upstream facilities [E]	0.14	0.14

[A] Emissions from the combustion of fuel and the operation of facilities. 2015 emissions are calculated using GWPs from the IPCC's *Fourth Assessment Report*.
[B] Emissions from the purchase of electricity, heat, steam and cooling for our own use using a market-based method.
[C] In tonnes of total direct and energy indirect GHG emissions per tonne of crude oil and feedstocks processed and petrochemicals produced in Downstream manufacturing, and oil and gas produced and gas processed by gas-to-liquid (GTL) facilities in Upstream. The regulations require the reporting of a ratio which expresses the annual emissions in relation to a quantifiable factor associated with our activities. However, oil and gas industry guidelines (IPIECA/API/IOGP) state that only presenting normalised environmental performance data separately for different business activities would generally provide meaningful information. As a result, we are also reporting the most appropriate ratio for our Downstream and Upstream businesses.
[D] In tonnes of direct and energy indirect GHG emissions per tonne of crude oil and feedstocks processed. The ratio includes chemical plants where they are integrated with refineries.
[E] In tonnes of direct and energy indirect GHG emissions per tonne of oil and gas produced. The ratio excludes GTL facilities.

As set out in "Performance indicators" on page 21, our Refining Energy Intensity Index (EII[TM]) was 95.4 in 2015, compared with 94.9 in 2014. Detailed information on our 2015 environmental performance will be published in the Shell Sustainability Report in April 2016.

SPILLS

Large spills of crude oil, oil products and chemicals associated with our operations can result in major clean-up costs as well as fines and other damages. They can also affect our licence to operate and harm our reputation. We have clear requirements and procedures designed to prevent spills, and our asset integrity programmes include the design, maintenance and operation of spill containment facilities.

Our business units are responsible for organising and executing oil-spill responses in line with Shell guidelines as well as with relevant legal and regulatory requirements. All our offshore installations have plans in place to respond to spills. These plans detail response strategies and techniques, available equipment, and trained personnel and contracts. We are able to call upon significant resources such as containment booms, collection vessels and aircraft. We are also able to draw upon the contracted services of oil-spill response organisations, if required. We conduct regular exercises that seek to ensure these plans remain effective. We have further developed our capability to respond to spills to water, and maintain a Global Response Support Network to support our worldwide response capability. This is also supported by our global Oil Spill Excellence Center, which tests local capability, and maintains our capability globally to respond to a significant incident.

We are a founding member of the Marine Well Containment Company, a non-profit industry consortium providing a well-containment response system for the Gulf of Mexico. In addition, we were a founding member of the Subsea Well Response Project, an industry cooperative effort to enhance global well-containment capabilities. The additional well-containment capability developed by this project is now managed by an industry consortium via Oil Spill Response Limited.

We also maintain site-specific emergency response plans in the event of an onshore spill. Like the offshore response plans, these are designed to meet Shell guidelines as well as relevant legal and regulatory requirements. They also provide for the initial assessment of incidents and the mobilisation of resources needed to manage them.

In 2015, the number of operational spills of more than 100 kilograms decreased to 108 from 153 in 2014 (see "Performance indicators" on page 21). At the end of February 2016, there were two spills under investigation in Nigeria that may result in adjustments.

Although most oil spills in Nigeria result from sabotage and theft of crude oil, there are instances where spills occur in our operations due to operational failures, accidents or corrosion. SPDC responds to all oil spills originating in the area immediately surrounding its pipelines and other facilities, regardless of the cause. It has been working to reduce operational spills that are under its control. It maintains a public website to track the response, investigation and clean-up of every spill from its facilities due to operational failure, sabotage or theft.

Accelerating implementation of the United Nations Environment Programme (UNEP)'s Environmental Assessment of Ogoniland was identified as a priority in 2015 by the newly elected Buhari administration. In August 2015, an 18-month roadmap was agreed between the government, UNEP and SPDC, which included approval of a governance model and funding framework for the Ogoni Restoration Fund recommended by UNEP.

In 2015, SPDC and the Bodo community signed a memorandum of understanding to restart the clean-up of the Bodo creeks affected by two operational spills in 2008. The clean-up will be overseen by an independent project director appointed by the Bodo mediation team. Contractors for the first phase of the clean-up were deployed to the field in 2015; however, the preliminary assessment works were stopped by the community shortly afterwards. Efforts are ongoing to engage all stakeholders so that the clean-up exercise can begin.

As both UNEP and the co-chairs of the Bodo mediation team have noted, it is essential that clean-up and remediation are accompanied by concerted efforts by government, communities and the oil and gas industry to prevent re-pollution. SPDC is pursuing a range of initiatives to prevent and minimise the impact of sabotage and crude oil theft within Ogoniland, including community-based pipeline surveillance, education and alternative livelihoods programmes.

HYDRAULIC FRACTURING

Over the last decade, we have established our onshore oil and gas portfolio using advances in technology to access previously uneconomic tight-oil and tight-gas resources, including those locked in shale formations. This energy resource continues to play an important role in meeting global energy demand.

One of the key technologies applied in tight-oil and tight-gas fields is known as hydraulic fracturing, a technique that has been used since the 1950s. It involves pumping a fluid that is typically 99% water and sand and around 1% chemical additives into tight sand or shale rock at high pressure. This creates threadlike fissures, typically the diameter of a human hair, through which oil and gas can flow.

In 2011, we developed and publicly shared a set of five global principles that govern the onshore tight/shale oil and gas activities where hydraulic fracturing is used. The principles cover safety, air quality, water production and use, land use, and engagement with local communities. We support regulations consistent with these principles, which are designed to reduce risks to the environment and seek to ensure the safety of those living near our operations. As new technologies, challenges and regulatory requirements emerge, we review and update these principles. Each of our projects takes into account the local context, including the geology of the area and impacts such as noise and traffic, and we then design our activities with the aim to suit the local conditions.

Some jurisdictions are considering more stringent permitting, well-construction and other regulations relating to fracturing, as well as local bans and other land use restrictions. Such regulations could subject our operations to delays, increased costs or prohibitions. Our current standards meet or exceed the existing regulatory requirements of the jurisdictions where we operate. We believe we can safely and responsibly explore, develop and produce tight-oil and tight-gas where hydraulic fracturing technology is used – and we support regulation, as long as it is workable and effective.

Examples of topics which our principles cover include groundwater protection, chemicals used for hydraulic fracturing, water use and seismicity.

To protect and isolate potable groundwater from hydraulic-fracturing fluids in the wellbore, we line all our wells with steel casing and cement. All of our wells are expected to have two or more subsurface barriers to protect groundwater. We monitor a wellbore's integrity before, during and after hydraulic fracturing. When we acquire assets, we evaluate the assets' wells for conformity with our safety and operating principles, and put in place a plan with a timeline for rectifying any inconsistencies as far as reasonably practical.

To the extent allowed by our suppliers, we support full disclosure of the chemicals used in hydraulic-fracturing fluids for Shell-operated wells. Material Safety Data Sheet information is available on site where wells are being hydraulically fractured. We support regulation to require suppliers to release such information. The chemicals used in hydraulic fracturing will vary from well to well and from contractor to contractor, but some can be toxic. For that reason, we have stringent procedures for handling hydraulic-fracturing chemicals in accordance with the design and assurance processes described above. The formations into which these additives may be injected are typically more than a thousand metres below freshwater aquifers. Our procedures require that potable groundwater must be isolated from well completion and production activities. Moreover, we only use air, water or a water-based liquid while drilling through the potable groundwater aquifer to a depth below the aquifer. The casing and cement are then put in place before drilling is resumed and hydraulic fracturing is initiated.

We recycle or reuse as much water as we believe is reasonably practical. We store, treat or dispose of water in accordance with regulatory requirements and Shell standards, which meet or exceed those regulatory requirements.

There have been reports linking hydraulic fracturing to earth tremors. Most seismic events occur naturally due to motion along faults under stress in the earth's crust. Some areas are more seismically active than others. We analyse publicly available seismic, geologic and geophysical data to determine historical seismicity in areas where we plan to operate, and if seismic activity beyond historic levels is detected, we will investigate and review our operations. We are supportive of local regulations that are fit-for-purpose, based on local geology and surface conditions, in managing the risk of induced seismicity in our operating areas. In addition to adhering to local regulations, we have our own guidelines, which outline monitoring, mitigation and response procedures to avoid or minimise seismicity associated with hydraulic fracturing.

OIL SANDS

We are developing mineable oil sands resources in Alberta, Canada. We use an aqueous extraction method (warm water) to extract bitumen, which is a heavy oil. Tailings are the residual by-products that remain after the bitumen is separated from the mined oil sands ore. They are composed of sand, clay, water, silts, some residual bitumen and other hydrocarbons, salts and trace metals, some of which are toxic. Tailings are initially stored in an above-ground tailings facility adjacent to the mined pit until the mined-out pit area is ready for tailings materials and fluids placement. This in-pit backfilling process begins approximately eight to ten years after mining has started. This period allows for mining to progress enough to allow dykes to be built within the mined pit to provide areas for tailings containment as mining continues to advance. We take active measures to prevent wildlife from interacting with the tailings facilities, and have barriers to prevent tailings water from seeping into groundwater. We regularly monitor the local groundwater and surface water bodies to confirm that these barriers are effective at preventing contamination.

In addition, tailings facilities allow water to be recycled, minimising the amount of water intake from the river. Over 75% of the water used in our oil sands mining operations is recycled from the tailings facilities at our mines.

The tailings management areas at the Athabasca Oil Sands Project's Muskeg River and Jackpine mines covered an area of approximately 43 square kilometres at the end of 2015. We estimate that the active tailings' footprint will start to decrease between 2020 and 2025 as the Muskeg River Mine external tailings facility is reclaimed and tailings materials are deposited in a pit as part of the in-pit backfilling process.

Previously, tailings were managed under the Alberta Energy Regulator's Directive 074, which had more prescriptive targets for tailings remediation. In March 2015, the Government of Alberta replaced it with a new policy – the Tailings Management Framework (TMF) – to manage existing and new tailings pond accumulation and remediation. The TMF and associated regulation will manage tailings throughout a project life cycle and will include limits on tailings accumulation. The framework also ensures that tailings are treated and progressively reclaimed and that all fluid tailings meet the TMF's definition of "ready to reclaim" within 10 years of the end of mine life. We continue to work towards improving tailings treatment technologies to treat fluid fine tailings that have a high percentage of fine particles.

EXPLORATION IN ALASKA

We operated for almost 50 years off the coast of Alaska, including the Cook Inlet and the Beaufort and Chukchi seas, until 1998. Between 2005 and 2012, we acquired our current portfolio, which includes 339 federal leases for exploration in the Beaufort and Chukchi seas, and 18 state leases in North Slope coastal waters.

In September 2015, we safely drilled the Burger J well to a depth of 2,073 metres. The well was deemed a dry hole and was sealed and abandoned in accordance with US regulations. We will not conduct further exploration offshore Alaska for the foreseeable future. This decision reflects not only the the Burger J well results, but also the high costs associated with the project, and the challenging and unpredictable federal regulatory environment for offshore Alaska.

Subsequently, we safely demobilised all personnel and vessels from the Chukchi Sea. All operations were conducted without significant injury or environmental issues. We conveyed the results of the exploration season to stakeholders and worked closely with them in the subsequent winding down of operations.

ENVIRONMENT AND SOCIETY CONTINUED

WATER

Although the availability of fresh water is a global issue of increasing importance, water constraints are mainly local, requiring local solutions. A combination of increasing demand for water resources, growing stakeholder expectations and concerns, and water-related legislation may drive actions that affect our ability to secure access to fresh water and to discharge water from our operations. We require our assets and projects to assess risks to water availability and, in areas of water scarcity, we develop water-management action plans that identify ways to use less fresh water, recycle water and closely monitor its use. We design and operate our facilities to help reduce their freshwater use.

On Pulau Bukom, a small island in southern Singapore, a country with limited water supplies, we use recycled water and convert sea water for steam generation at our refinery. We also make a conscious effort to reuse our process water. As a result, we are relying less on water from mainland Singapore, which frees up resources for use by local residents.

At our oil sands operations in Canada, we use far less than our water allocation from the Athabasca River and we seek to minimise the amount withdrawn during the winter months when the flow rate is low. We also reduce the amount of fresh water needed in operations by recycling water from the tailings ponds. Most of the water we use is recycled and we are investigating new ways to further reduce fresh water intake.

Our biofuel joint venture Raízen has been introducing a system that partially recovers water from sugar cane to be reused in mills, boilers, cooling towers and other equipment in the production line.

Our Pearl GTL plant in Qatar does not take fresh water from its arid surroundings. The water produced in the GTL manufacturing process is recycled in the operation, fulfilling all the water needs of the plant.

BIOFUELS

The international market for biofuels is growing, driven largely by the introduction of new energy policies in Europe and the USA that call for more renewable, lower-carbon fuels for transport. According to the IEA, sustainable biofuels are expected to play an increasingly important role in helping to meet customers' fuel needs and reduce CO_2 emissions.

From cultivation to use, some biofuels emit significantly less CO_2 compared with conventional gasoline. But this depends on several factors, such as how the raw materials are produced. Other challenges include concerns over land competing with food crops, labour rights, and the water used in the production process.

In 2015, we used around 9.5 billion litres of biofuel in our gasoline and diesel blends worldwide, which makes us one of the world's largest biofuel suppliers. We include our own long-established sustainability clauses in our supply contracts. These clauses are designed to prevent the sourcing of biofuels from suppliers that may not abide by human rights guidelines, or that may have cleared land rich in biodiversity. In addition, where possible, we source biofuels that have been certified against internationally recognised sustainability standards.

We are also developing our own capabilities to produce sustainable biofuel components. Raízen produces approximately 2 billion litres annually of ethanol from sugar cane. This ethanol can reduce CO_2 emissions by around 70% compared with gasoline, from cultivation of the sugar cane to using the ethanol as fuel.

The Raízen joint-venture agreement includes developing joint sustainability principles, standards and operating procedures that also apply to third-party suppliers. We also continue to work with industry, governments and voluntary organisations towards the development of global sustainability standards for biofuels.

We continue to invest in new ways of producing biofuels from sustainable feedstocks, such as biofuels made from waste products or cellulosic biomass. These advanced biofuels could potentially emit less CO_2 in the production process than the biofuels available today.

Raízen's cellulosic ethanol plant at its Costa Pinto mill in Brazil was opened in 2015. The technology was first developed from our funding of the Iogen Energy venture, which was subsequently transferred to Raízen. It is expected to produce 40 million litres a year of advanced biofuels from sugar-cane residues.

We are working on three routes for manufacturing cellulosic biofuels and now have three pilot plants at various stages of completion. The pilot plants are designed to convert cellulosic biomass, which are non-food plants and wastes, into a range of products, including gasoline, diesel, aviation fuel and ethanol. The plant built in Houston, Texas, in 2012, continues to provide valuable data in support of improving the digestion of biomass. A second plant to test a pre-treatment process for cellulosic ethanol is now being commissioned in Houston. A third plant has been approved and is expected to be built in Bangalore, India.

ENVIRONMENTAL COSTS

We are subject to a variety of environmental laws, regulations and reporting requirements in the countries where we operate. Infringing any of these laws, regulations and requirements could result in significant costs, including clean-up costs, fines, sanctions and third-party claims, as well as harm our reputation and our ability to do business.

Our ongoing operating expenses include the costs of avoiding unauthorised discharges into the air and water, and the safe disposal and handling of waste.

We place a premium on developing effective technologies that are also safe for the environment. However, when operating at the forefront of technology, there is always the possibility that a new technology brings with it environmental impacts that have not been assessed, foreseen or determined to be harmful, when originally implemented. While we believe we take all reasonable precautions to limit these risks, we are subject to additional remedial environmental and litigation costs as a result of our operations' unknown and unforeseen impacts on the environment. Although these costs have so far not been material to us, no assurance can be given that this will always be the case.

In this regard, as oil and gas fields mature, it is possible in certain circumstances for seismic activity to increase based on the unique geology of individual fields. While earth tremors as a result of gas production have been acknowledged in the Groningen gas field in the Netherlands since 1993, an earthquake with the magnitude of 3.6 on the Richter scale in August 2012 resulted in new insights and led to increased concerns in the local community (see "Risk factors" on page 10). The field is operated by Nederlandse Aardolie Maatschappij B.V. (NAM) (Shell interest 50%) and is one of the largest onshore gas fields in Europe. An extensive study is in progress to better understand seismic risk in the area. Several universities and researchers are involved and a report is expected in 2016. Interim results from November 2015 included a fully-integrated seismic risk assessment. This risk assessment demonstrated that all the analysed production levels meet the acceptable risk boundaries set by the Ministry of Economic Affairs of the Netherlands.

The Dutch government has imposed significant gas production reduction measures since 2014. A range of actions have been taken to improve safety, liveability and economic prospects in the region, including the cap on extraction. A long-term programme has been developed by the National Coordinator for Groningen to work with regional authorities and residents on issues such as improving the handling of claims and the resolution of disputes. NAM is working together with all relevant parties.

SECURITY

Our operations expose us to social instability, civil unrest, terrorism, piracy, acts of war and risks of pandemic diseases that could have a material adverse effect on our business (see "Risk factors" on page 09). We seek to obtain the best possible information to enable us to assess threats and risks. We conduct detailed assessments for all sites and activities, and implement appropriate risk mitigation measures to detect, deter and respond to security threats. This includes building strong and open relationships with government security agencies, the physical hardening of sites, journey management, and information risk management. We conduct training and awareness campaigns, including travel advice and medical assistance before travel. The identities of our employees and contractors and their access to our sites and activities, both physical and logical, are consistently verified and controlled. We manage and exercise crisis response and management plans.

NEIGHBOURING COMMUNITIES

Earning the trust of local communities is essential to the success of our projects and operations. We have global requirements for social performance – how we perform in our relationship with communities.

The requirements set clear rules and expectations for how we engage with and respect communities that may be impacted by our operations. Shell-operated major projects and facilities are required to have a social performance plan and an effective community feedback mechanism. This helps the business to understand the social context in which we plan to operate, identifies potential negative effects on the community and manages impacts. In addition, we have specific requirements intended to minimise our impact on indigenous peoples' traditional lifestyles and on handling involuntary resettlement.

HUMAN RIGHTS

Our Principles and Code of Conduct require our employees and contractors to respect the human rights of fellow workers and communities where we operate. Our approach is informed by the Universal Declaration of Human Rights, the core conventions of the International Labour Organization and the United Nations' Guiding Principles on Business and Human Rights.

We have specific policies in place in areas across our activities where respect for human rights is particularly important to the way we operate, such as communities, labour, procurement and security. We also work with other companies and non-governmental organisations to improve the way we apply these principles. Our approach to human rights helps us operate in a responsible way, aimed at delivering projects without delays and minimising the social impacts of our operations. It also enables us to better share certain benefits of our activities, such as creating new jobs and contracts that help develop local economies.

OUR PEOPLE

Our aim is to be the world's most competitive and innovative energy company. We recruit, train and recompense people according to a strategy that aims to maintain a productive organisation, deploying talent across the business effectively; accelerating development of our people; growing and strengthening our leadership capabilities; and enhancing employee performance through strong engagement.

EMPLOYEE OVERVIEW

At December 31, 2015, we employed 90,000 people, compared with 94,000 at the end of 2014. The net decrease included the impact by the end of 2015, partially offset by recruitment, of our decision to reduce the number of roles across our organisation by 7,500 in 2015-2016.

We continued to recruit externally to execute our strategy and growth plans for the future, hiring about 1,000 graduates and 1,500 experienced professionals. About 40% of our graduate recruits came from universities outside Europe and the Americas, compared with 30% in 2014, in response to increasing demand for skilled people in other regions, principally in Asia. The majority of our graduate recruits came from technical disciplines.

During 2015, we employed an average of 93,000 people, shown by geographical area in the table below.

EMPLOYEES BY GEOGRAPHICAL AREA (AVERAGE NUMBERS) THOUSAND

	2015	2014	2013
Europe	25	25	25
Asia	29	28	27
Oceania	1	2	3
Africa	3	3	3
North America	31	32	31
South America	4	4	3
Total	93	94	92

EMPLOYEE COMMUNICATION AND INVOLVEMENT

We strive to maintain a healthy industrial relations environment in which dialogue between management and employees – both directly and, where appropriate, through employee representative bodies – is embedded in our work practices. On a quarterly basis, management briefs employees on our operational and financial results through various channels, including team meetings, face-to-face gatherings, an email from the Chief Executive Officer, webcasts and online publications.

The Shell People Survey is one of the principal tools used to measure employee engagement: the degree of affiliation and commitment to Shell. It provides insights into employees' views and has had a consistently high response rate. The average employee engagement score in 2015 was 80% favourable, as it was in 2014.

We promote safe reporting of views about our processes and practices. In addition to local channels, the Shell Global Helpline enables employees to report potential breaches of the Shell General Business Principles and Shell Code of Conduct, confidentially and anonymously, in a choice of several languages. See "Corporate governance" on page 70.

DIVERSITY AND INCLUSION

We have a culture that embraces diversity and fosters inclusion. By embedding these principles in our operations, we have a better understanding of the needs of our varied customers, partners and stakeholders throughout the world and can benefit from a wider talent pool. We provide equal opportunity in recruitment, career development, promotion, training and rewards for all employees, including those with disabilities. Where possible, we make reasonable adjustments in job design and provide appropriate training for employees who have become disabled.

We actively monitor representation of women and local nationals in senior leadership positions, and have talent-development processes to support us in delivering more diverse representation.

At the end of 2015, the proportion of women in senior leadership positions was 19% compared with 18% at the end of 2014. Senior leadership positions is a Shell measure based on senior salary group levels and is distinct from the term "senior manager" in the statutory disclosures set out below.

GENDER DIVERSITY DATA (AT DECEMBER 31, 2015) NUMBER

	Men		Women	
Directors of the Company	8	73%	3	27%
Senior managers [A]	754	78%	218	22%
Employees (thousand)	63	70%	27	30%

[A] Senior manager is defined in section 414C(9) of the Companies Act 2006 and accordingly the number disclosed comprises the Executive Committee members who were not Directors of the Company, as well as other directors of Shell subsidiaries.

The local national coverage is the number of senior local nationals (both those working in their respective base country and those expatriated) as a percentage of the number of senior leadership positions in their base country.

LOCAL NATIONAL COVERAGE (AT DECEMBER 31, 2015)

	Number of selected key business countries		
	2015	2014	2013
Greater than 80%	12	12	12
Less than 80%	8	8	8
Total	20	20	20

EMPLOYEE SHARE PLANS

We have a number of share plans designed to align employees' interests with our performance through share ownership. For information on the share-based compensation plans for Executive Directors, see the "Directors' Remuneration Report" on pages 98-102.

Performance Share Plan and Long-term Incentive Plan

Conditional awards of the Company's shares are made under the terms of the Performance Share Plan (PSP) to some 17,000 employees each year. From 2015, senior executives received conditional awards of the Company's shares under the terms of the Long-term Incentive Plan (LTIP) rather than under the terms of the PSP. The extent to which the awards vest under both plans is determined over a three-year performance period but the performance conditions applicable to each plan are different. Under the PSP, half of the award is linked to the key performance indicators described in "Performance indicators" on page 20, averaged over the period. The other half of the award is linked to a comparative performance condition which involves a comparison with four of our main competitors over the period, based on four relative performance measures. Under the LTIP, the award is solely linked to the comparative performance condition described above. Under both plans, all shares that vest are increased by an amount equal to the notional dividends accrued on those shares during the period from the award date to the vesting date. In certain circumstances awards may be adjusted before delivery or reclaimed after delivery. None of the awards results in beneficial ownership until the shares vest. See Note 21 to the "Consolidated Financial Statements" on pages 147-148.

Restricted Share Plan
Under the Restricted Share Plan, awards are made on a highly selective basis to senior staff. Shares are awarded subject to a three-year retention period. All shares that vest are increased by an amount equal to the notional dividends accrued on those shares during the period from the award date to the vesting date. In certain circumstances awards may be adjusted before delivery or reclaimed after delivery.

Global Employee Share Purchase Plan
Eligible employees in participating countries may participate in the Global Employee Share Purchase Plan. This plan enables them to make contributions from net pay towards the purchase of the Company's shares at a 15% discount to the market price, either at the start or at the end of an annual cycle, whichever date offers the lower market price.

UK Sharesave Scheme
Eligible employees of participating companies in the UK may participate in the UK Sharesave Scheme. Options are granted over the Company's shares at market value on the invitation date. These options are normally exercisable after completion of a three-year or five-year contractual savings period.

UK Shell All Employee Share Ownership Plan
Eligible employees of participating companies in the UK may participate in the Shell All Employee Share Ownership Plan, under which monthly contributions from gross pay are made towards the purchase of the Company's shares.

ACQUISITION OF BG GROUP PLC
We acquired BG Group plc (BG) in February 2016. See "Strategy and outlook" on page 15. BG has about 5,000 employees. As a result of the identified synergies, we expect an overall potential reduction of approximately 2,800 roles globally across the combined organisation, which is in addition to the reduction of 7,500 mentioned earlier under "Employee overview".

As a result of the acquisition, certain conditional employee share awards made in 2015 under BG's Long-Term Incentive Plan were exchanged for equivalent conditional awards over shares in the Company. Certain participants in the BG Sharesave Scheme rolled over their outstanding BG share options into options over the Company's shares.

Strategic Report signed on behalf of the Board

/s/ Michiel Brandjes

Michiel Brandjes
Company Secretary
March 9, 2016