STRATEGIC REPORT
CHAIRMAN'S MESSAGE

The energy landscape has fundamentally transformed in the nearly nine years that I have served as Chairman.

Technological advances have enabled a surge in gas and oil production from deep beneath the ocean and unlocked important new shale resources over the last few years, for example.

Shell plans to continue to invest in innovative technology, talented people and the development of new energy sources that will be vital to meet rising long-term demand, while limiting carbon emissions.

But the short-term outlook for energy markets is uncertain.

The International Monetary Fund (IMF) estimates that the world economy grew by 3.3% in 2014, unchanged from 2013. In January 2015, the IMF revised its forecast for 2015 down from 3.8% to 3.5%, pointing to concerns over the Russian and eurozone economies, combined with slowing growth in China.

Concerns over economic growth, coupled with buoyant global oil production, drove a decline in crude oil prices during the second half of 2014, ending a three-year spell of relatively high prices. Although the Brent crude oil price averaged $99 per barrel in 2014, down from $109 in 2013, it ended the year at $55.

Shell will continue to look carefully at how and where to allocate capital in an economic environment that remains fragile.

A sustained period of low oil prices could, of course, challenge the economics of some of our planned projects and make them less attractive. But we must continue to take a long-term view in a world where energy demand continues to rise.

ROBUST STRATEGY

In 2014, our steps to improve capital discipline helped deliver solid returns to shareholders. We delivered strong cash flow for the year and also completed our programme of divesting some parts of our portfolio ahead of schedule and before oil prices fell in the second half of the year.

Our strong balance sheet allows us to continue to invest, despite short-term price volatility, while our emphasis on employing innovative technologies will help make our new projects competitive sources of supply.

Many new energy resources will be needed in the longer term. Global primary energy demand could grow by 37% from 2012 to 2040, according to the International Energy Agency (IEA).

The IEA expects renewable energy to meet an increasing share of global energy needs. But its central scenario, which takes into account existing government commitments and plans, points to a 14% rise in oil consumption and a 55% rise in gas consumption by 2040.

Gas will be increasingly in demand partly because of the important role it can play in reducing carbon emissions when replacing coal, particularly in power plants.

Becoming the most competitive and innovative gas supplier has been a clear strategic goal for Shell throughout my time as Chairman, especially in liquefied natural gas (LNG), which is now central to the global trade in gas. Shell has evolved from being predominantly an oil producer to a company that produces more gas than oil.

We are building a large floating LNG production facility, called Prelude, which will help access gas resources in remote waters. Prelude is one example of the technological advances we are making to help meet future demand.

Our deep-water technology is another. It enabled us to start production in 2014 at major projects in the Gulf of Mexico and off the coasts of Malaysia and Nigeria.

Through our joint venture Raízen in Brazil, we are also now one of the world's largest producers of low-carbon biofuel.

CLIMATE CHANGE

It is clear that new technologies will be needed to tackle climate change effectively. For example, carbon capture and storage (CCS) technology to store carbon dioxide (CO_2) safely underground could substantially reduce the amount of CO_2 emitted in energy production at lower cost than many other technologies.

But widespread government and industry support is needed to ensure that enough CCS plants are built around the world to make a substantial contribution to the wider drive to reduce CO_2.

All sectors of society must work together to combat climate change effectively. One vital and pressing step is to set up effective systems for putting a price on carbon emissions. It is an efficient way to encourage companies to change their activities in ways that have a deep and lasting impact on emissions.

I was encouraged to hear at the United Nations (UN) Climate Summit in New York in September 2014 that the need for effective carbon pricing systems had broad support. I hope that significant progress can be made on this at the crucial UN Climate Change Conference in Paris in December 2015.

INNOVATION AND INNOVATORS

I have had the privilege of working with many talented, creative and forward-thinking people at Shell. Their focus on developing innovative ways to produce and refine new energy resources should benefit our shareholders and customers in the years ahead by keeping our products competitive in any economic environment.

Perhaps the best example is the Pearl gas-to-liquids (GTL) complex in Qatar. The final decision to go ahead with the project was taken at the first Board meeting I chaired in 2006. Back then, there was some scepticism, outside Shell at least, about the project's ambitious scope and viability as a major investment.

We proved the sceptics wrong. Today we know that a GTL project on this scale, it is the largest such plant in the world, does work. Watching Pearl develop and seeing its products now benefiting customers around the world has been one of the most rewarding experiences during my time at Shell.

Pearl's success underscores the importance of continuing our strategy of making disciplined investments in key projects and new technologies. This is how we can compete more effectively on the global stage as we continue to create value for our customers, partners and investors.

Jorma Ollila
Chairman

CHIEF EXECUTIVE OFFICER'S REVIEW

After my first year as Chief Executive Officer, I am pleased to see that we are delivering on our three key priorities of improved financial performance, enhanced capital efficiency and continued strong project delivery.

We have come a long way. Shell's earnings on a current cost of supplies basis attributable to shareholders improved in 2014 compared with 2013, largely thanks to our prudent investment strategy and delivery of major new projects around the world.

We achieved these better results despite the fall in oil prices during the second half of 2014, a decline mainly caused by plentiful supply and weak global demand.

Our improved operational performance, prudent spending and sales of assets that are not central to our strategy helped us enter this period of low oil prices from a position of strength.

But there is still work to be done. I want to see more competitive performance across Shell in 2015 and beyond.

We continued our focus on safety, but sadly five people working for Shell in 2014 lost their lives. There was also an explosion at our Moerdijk chemical plant in the Netherlands, but thankfully it caused no serious injuries.

Tragically, we lost four colleagues and eight of their family members in the Malaysia Airlines disaster over Ukraine in July. That was a deeply saddening experience for all.

2014 MILESTONES

For 2014, our earnings on a current cost of supplies basis attributable to shareholders were $19 billion, which included impairments of $5 billion and gains on divestments of $2 billion, compared with $17 billion in 2013, which included impairments of $4 billion. Net cash flow from operating activities rose to $45 billion from $40 billion in 2013.

We reduced our capital investment from $46 billion in 2013 to $37 billion.

Underlining our ongoing commitment to shareholder returns, we distributed $12 billion to shareholders in dividends, including those taken as shares under our Scrip Dividend Programme, and spent $3 billion on share repurchases in 2014. This compares with $11 billion of dividends and $5 billion of share repurchases in 2013.

Our Upstream earnings rose from 2013 to 2014, reflecting improved operational performance and the start of production from new deep-water projects. These included Gumusut-Kakap in Malaysia, which is expected to produce up to 135 thousand barrels per day of oil equivalent (boe/d) and the 40 thousand boe/d Bonga North West development off the coast of Nigeria. We also began production from the Cardamom and Olympus platforms in the Gulf of Mexico. However, production from new projects was more than offset by the expiry of a licence in Abu Dhabi and the impact of asset sales. Our oil and gas production averaged 3.1 million boe/d in 2014, 4% less than in 2013.

The integration of the Repsol liquefied natural gas (LNG) businesses acquired in January helped boost our LNG sales to 24 million tonnes, up 22% on 2013.

It was a good year for our exploration drive, with 10 notable discoveries. The resources we uncovered – including in the USA, Gabon and Malaysia – could be important sources of gas and oil for decades to come.

We continued to streamline our Downstream operations, selling most of our businesses in Australia and Italy, for example. While there is some growth potential in businesses such as chemicals, lubricants and in China, we continue to look for opportunities to reduce our costs and optimise our Downstream portfolio.

PRUDENT PATH OF GROWTH

The fall in oil prices in 2014 was part of the volatility our industry has always faced. But it underlined the importance of being selective in our investments and keeping a tight grip on costs.

Divestments, together with the initial public offering in Shell Midstream Partners, L.P., generated $15 billion in proceeds in 2014. They included shale oil and gas interests in North America and downstream businesses in several countries, meeting our target for 2014-15 well ahead of schedule. We plan to continue to divest assets in 2015.

To improve returns and control costs during this period of low prices, we have also reduced our potential spending on organic growth by $15 billion for 2015-2017. For example, together with our partners Qatar Petroleum, we have decided not to proceed with the proposed Al Karaana petrochemicals project in Qatar because it is too costly in the current environment.

We expect organic capital investment to be lower in 2015 than 2014 levels of around $35 billion. But we want to preserve our growth to ensure we continue to generate cash flow and dividends for our shareholders. That is why we are still planning to invest in economically-sound projects this year in key growth areas, such as deep water and LNG.

Clearly, we do not want to miss future growth opportunities simply because they may seem unaffordable in the low oil price world we see today.

However, in this period of economic uncertainty, we also need to remain cautious and are prepared to curb spending further if warranted by the evolving market outlook.

STRONG LONG-TERM DEMAND

In the long term, we expect demand for energy to continue to rise as populations and prosperity increase. Billions of people across the developing world need better access to energy to improve their lives.

We expect the global energy supply mix to evolve significantly in the decades ahead with gas, the cleanest-burning fossil fuel, becoming more widely used for power generation. While we expect renewables such as wind, solar and biofuels to play an increasing role, oil and gas will be vital to meet the considerable expected increase in energy demand.

At the same time, the need to tackle climate change requires effective policies that help meet the world's energy needs while significantly reducing carbon dioxide (CO_2) emissions.

Facilities to capture and store CO_2 should be a key part of the global solution. Our Quest project to capture and safely store CO_2 from a Canadian oil sands facility is expected to be completed in 2015. We are also planning a carbon capture and storage (CCS) facility at the Peterhead gas-fired power plant in the UK.

CHIEF EXECUTIVE OFFICER'S REVIEW CONTINUED

Effective carbon-pricing systems are needed. They can drive a shift from coal- to gas-fired power generation, encourage greater energy efficiency and create the frameworks for the widespread use of CCS.

In the shorter term, the world economy is going through a period of relatively slow growth. There is no change in the long-term outlook for energy demand, however, as the global population rises and living standards improve.

We will continue our strategy of strengthening our position as a leader in the oil and gas industry while supplying energy in a responsible way.

By stepping up our drive to improve our financial performance and continuing to invest in good projects and opportunities, we are working hard to add more value for our shareholders.

This may mean making tough choices during a testing time for the energy industry. But it will help Shell deliver where it matters – the bottom line. I am determined that we can and will combine the disciplined pursuit of efficiency today with a vision of long-term sustainability which will secure our leadership role in the decades to come.

Ben van Beurden
Chief Executive Officer

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.

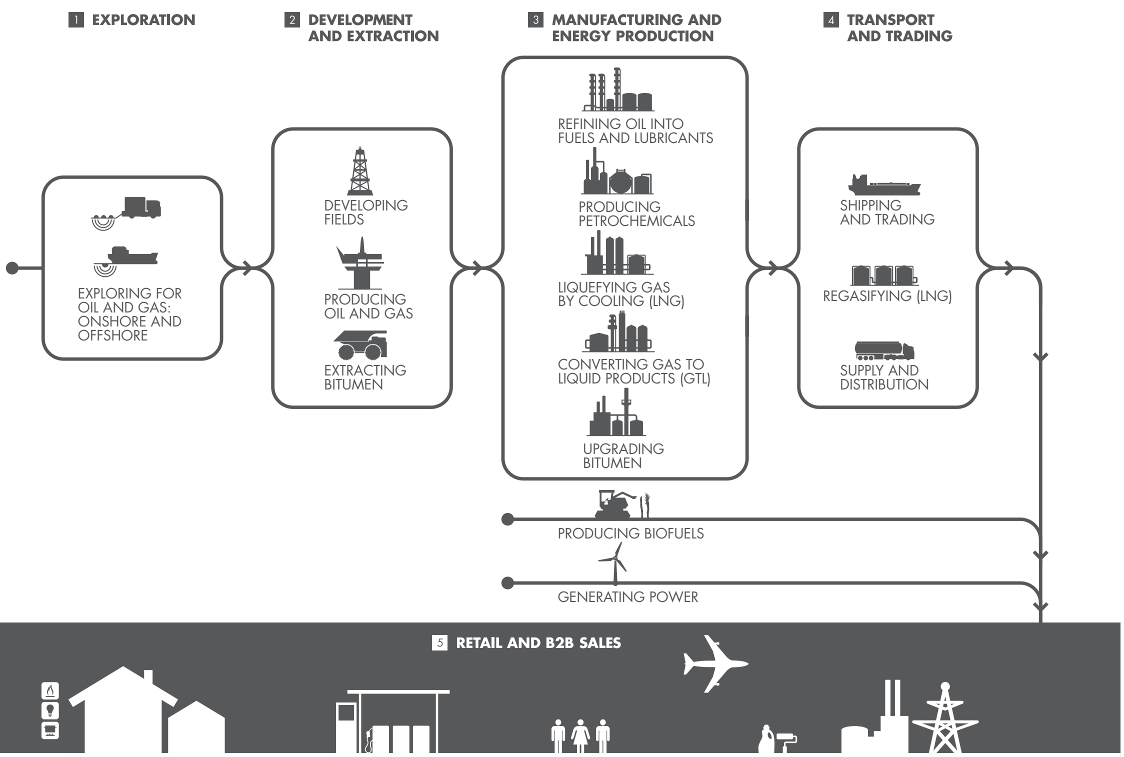
ACTIVITIES

Shell is one of the world's largest independent oil and gas companies in terms of market capitalisation, operating cash flow and production. We aim for strong operational performance and productive investments around the world.

We explore for oil and gas worldwide, both from conventional fields and from sources such as tight rock, shale and coal formations.

We work to develop new oil and gas supplies from major fields. For example, in 2014 we began production from the Gumusut-Kakap deep-water project in Malaysia, the Mars B and Cardamom developments in the deep-water Gulf of Mexico, USA, and the Bonga North West project off the coast of Nigeria. We also invest in expanding our integrated gas business. For example, in January 2014, we acquired a part of Repsol S.A.'s liquefied natural gas (LNG) portfolio, including supply positions in Peru and Trinidad and Tobago.

Our portfolio of refineries and chemical plants enables us to capture value from the oil and gas that we produce. Furthermore, we are a leading biofuel producer and fuel retailer in Brazil, through our Raízen joint venture. We have a strong retail position not only in the major industrialised countries, but also in developing countries. 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, Shell has more than 15,000 granted patents and pending patent applications.



BUSINESS OVERVIEW CONTINUED

BUSINESSES AND ORGANISATION

Upstream International

Our Upstream International business manages Shell's Upstream activities outside the Americas. It explores for and recovers 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.

Upstream Americas

Our Upstream Americas business manages Shell's Upstream activities in North and South America. It explores for and recovers 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, including assets in Peru and Trinidad and Tobago acquired in 2014. It also 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.

Downstream

Our Downstream business manages Shell's refining and marketing activities for oil products and chemicals. These activities are organised into globally managed classes of business. Refining includes manufacturing, supply and shipping of crude oil. Marketing sells a range of products including fuels, lubricants, bitumen and liquefied petroleum gas (LPG) for home, transport and industrial use. Chemicals produces and markets petrochemicals for industrial customers, including the raw materials for plastics, coatings and detergents. Downstream also trades Shell's hydrocarbons and other energy-related products, supplies the Downstream businesses and provides shipping services. Additionally, Downstream oversees Shell's interests in alternative energy (including biofuels but excluding wind).

Projects & Technology

Our Projects & Technology organisation manages the delivery of Shell's major projects and drives research and innovation to create 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, and for all wells activities and CO_2 management.

SEGMENTAL REPORTING

Our reporting segments are 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 activities. Corporate comprises Shell's holdings and treasury organisation, including its self-insurance activities as well as its headquarters and central functions. See Note 2 to the "Consolidated Financial Statements".

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

	2014	2013	2012
Upstream			
Third parties	45,240	47,357	43,431
Inter-segment	47,059	45,512	51,119
Total	92,299	92,869	94,550
Downstream			
Third parties	375,752	403,725	423,638
Inter-segment	2,294	702	772
Total	378,046	404,427	424,410
Corporate			
Third parties	113	153	84
Total	113	153	84

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

	2014	%	2013	%	2012	%
Europe	154,709	36.7	175,584	38.9	184,223	39.4
Asia, Oceania, Africa	149,869	35.6	157,673	34.9	156,310	33.5
USA	70,813	16.8	72,552	16.1	91,571	19.6
Other Americas	45,714	10.9	45,426	10.1	35,049	7.5
Total	421,105	100.0	451,235	100.0	467,153	100.0

RESEARCH AND DEVELOPMENT

Innovative technology provides ways for Shell to stand apart from its competitors. It helps our current businesses perform, and it makes future businesses possible.

Since 2007, we have spent more to research and develop innovative technology than any other international oil and gas company. In 2014, research and development (R&D) expenses were $1,222 million, slightly down from $1,318 million in 2013 and $1,307 million in 2012.

Such levels of investment in R&D enable us to advance technologies that help us access new resources and better meet the needs of our customers and partners. This includes: seismic processing and visualisation software that reveal previously unnoticed geological details; drilling-rig equipment that delivers wells more quickly and more safely; oil-recovery methods that increase production from fields; processes that refine crude oil and liquefy natural gas more efficiently; as well as fuel and lubricant formulations that perform better.

As in 2014, in 2015 we continue to focus strongly on technologies that support our various businesses and reduce the environmental footprint of our operations and products.

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.

We are exposed to fluctuating prices of crude oil, natural gas, oil products and chemicals.
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 from each other. Factors that influence supply and demand include operational issues, natural disasters, weather, political instability, conflicts, economic conditions and actions by major oil-producing countries. Price fluctuations could have a material effect on our business, including on our cash flows and earnings. For example, in a low oil and gas price environment, Shell would generate less revenue from its Upstream production, and as a result some long-term projects might become less profitable, or even incur losses. Additionally, low oil and gas prices could result in the debooking of proved oil or gas reserves, if they become uneconomic in this type of environment. Prolonged periods of low oil and gas prices, or rising costs, could result in projects being delayed or cancelled and/or in the impairment of some assets. They may also impact our ability to maintain our long-term investment programme. 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 might result in lower profitability, particularly in our Downstream business.

Our ability to deliver competitive returns and pursue commercial opportunities depends in part on the robustness and, ultimately, the accuracy of our price assumptions.
Shell reviews the oil and gas price assumptions it uses to evaluate project decisions and commercial opportunities on a periodic basis. We generally test projects and other opportunities against a long-term price range of $70-110 per barrel for Brent crude oil and $3.5-5.0 per million British thermal units for gas at the Henry Hub. While we believe our current long-term price assumptions are prudent, if such assumptions proved to be incorrect it could have a material adverse effect on Shell. For near-term planning purposes, we stress test the financial framework against a wider range of prices.

Our ability to achieve strategic objectives depends on how we react to competitive forces.
We face competition in each of our businesses. While we seek to differentiate our products, many of them are competing in commodity-type markets. If we do not manage our expenses adequately, our cost efficiency could deteriorate and our unit costs may increase. This in turn could erode our competitive position. Increasingly, we compete with government-run oil and gas companies, particularly in seeking access to oil and gas resources. Today, these government-run companies control vastly greater quantities of oil and gas resources than the major, publicly held oil and gas companies. Government-run entities have access to significant resources and may be motivated by political or other factors in their business decisions, which may harm our competitive position or hinder our access to desirable projects.

As our business model involves treasury and trading risks, we are affected by the global macroeconomic environment as well as financial and commodity market conditions.
Shell subsidiaries, joint ventures and associates are subject to differing economic and financial market conditions throughout the world. Political or economic instability affects such markets. Shell uses 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 an adverse effect on our operations. Commodity trading is an important component of our Upstream and Downstream businesses and is integrated with our supply business. Treasury and trading risks include, among others, exposure to movements in interest rates, foreign exchange rates and commodity prices, counterparty default and various operational risks. As a global company doing business in more than 70 countries, we are exposed to changes in currency values and exchange controls. While we undertake some currency hedging, we do not do so for all of our activities. See Notes 6 and 19 to the "Consolidated Financial Statements". Shell has significant financial exposure to the euro and could be materially affected by a significant change in its value or any structural changes to the European Union (EU) or the European Economic and Monetary Union affecting the euro. While 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 to us. Therefore, a sovereign debt downgrade or default could have a material adverse effect on Shell.

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 large ones. Challenges include uncertain geology, frontier conditions, the existence and availability of necessary technology and engineering resources, availability of skilled labour, project delays, 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, and in frontier areas, such as the Arctic. Such potential obstacles may impair our delivery of these projects, as well as our ability to fulfil related contractual commitments. 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 developing and applying new technologies and recovery processes to existing fields and mines. Failure to replace proved reserves could result in lower future production, cash flow and earnings.

In 2014, we have reduced our tight-gas and liquids-rich shale portfolio. If future well results do not meet our expectations, there could be additional asset sales and/or impairments.

OIL AND GAS PRODUCTION AVAILABLE FOR SALE MILLION BOE [A]	2014	2013	2012
Shell subsidiaries	895	850	825
Shell share of joint ventures and associates	229	318	369
Total	1,124	1,168	1,194

[A] Natural gas volumes are converted to 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]	2014	2013	2012
Shell subsidiaries	10,181	10,835	9,873
Shell share of joint ventures and associates	2,900	3,109	3,701
Total	13,081	13,944	13,574
Attributable to non-controlling interest [D]	11	12	18
Attributable to Royal Dutch Shell plc shareholders	13,070	13,932	13,556

[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 to oil equivalent using a factor of 5,800 scf per barrel.
[D] Proved reserves attributable to non-controlling interest in Shell subsidiaries.

RISK FACTORS CONTINUED

An erosion of our business reputation would have a negative impact on our brand, our ability to secure new resources and our licence to operate.
Shell is one of the world's leading energy brands, and its brand and reputation are important assets. 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. Failure – real or perceived – to follow these Principles, or other real or perceived failures of governance or regulatory compliance, could harm our reputation. This could impact our licence to operate, damage our brand, harm our ability to secure new resources and limit our ability to access the capital markets. Many other factors may impact our reputation, including those discussed in several of the other risk factors.

Our future performance depends on the successful development and deployment of new technologies.
Technology and innovation are essential to Shell 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, the delivery of our strategy and our licence to operate may be adversely affected. We operate in environments where the most advanced technologies are needed. While these technologies are regarded as safe for the environment with today's knowledge, there is always the possibility of unknown or unforeseeable environmental impacts that could harm our reputation, licence to operate or expose us to litigation or sanctions.

Rising climate change concerns could lead to additional regulatory measures that may result in project delays and higher costs.
In the future, in order to help meet the world's energy demand, we expect our production to rise and more of our production to come from higher energy-intensive sources than at present. Therefore, it is expected that both the CO_2 intensity of our production, as well as our absolute Upstream CO_2 emissions, will increase as our business grows. Examples of such developments are our in-situ Peace River project and our oil sands activities in Canada. Additionally, as production from Iraq increases, we expect that CO_2 emissions from flaring will rise as long as no gas gathering systems are in place. We continue to work with our partners to find ways to capture the gas that is flared. Over time, we expect that a growing share of our CO_2 emissions will be subject to regulation and result in increasing our costs. Furthermore, continued and increased attention to climate change, including activities by non-governmental and political organisations, as well as more interest by the broader public, is likely to lead to additional regulations designed to reduce greenhouse gas emissions. If we are unable to find economically viable, as well as publicly acceptable, solutions that reduce our CO_2 emissions for new and existing projects or products, we may experience additional costs, delayed projects, reduced production and reduced demand for hydrocarbons.

The nature of our operations exposes the communities in which we work and us to a wide range of health, safety, security and environment risks.
The health, safety, security and environment (HSSE) risks to which we are potentially exposed cover a wide spectrum, given the geographic range, operational diversity and technical complexity of Shell's daily operations. We have operations, including oil and gas production, transport and shipping of hydrocarbons, and refining, in difficult geographies or climate zones, as well as environmentally sensitive regions, such as the Arctic or maritime environments, especially in deep water. These and other operations expose the communities in which we work and us to the risk, among others, of major process safety incidents, effects of natural disasters, 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 to business activities and, depending on their cause and severity, material damage to our reputation, exclusion from bidding on mineral rights and eventually loss of licence to operate. In certain circumstances, liability could be imposed without regard to Shell's fault in the matter. Requirements governing HSSE matters often change and are likely to become more stringent over time. The operator could be asked to adjust its future production plan, as we have seen in the Netherlands, impacting production and costs. We could incur significant additional costs in the future complying with such requirements or as a result of violations of, or liabilities under, HSSE laws and regulations, such as fines, penalties, clean-up costs and third-party claims.

Shell mainly self-insures its risk exposures.
Shell insurance subsidiaries provide hazard insurance coverage to Shell entities. While from time to time the insurance subsidiaries may seek reinsurance for some 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 Shell's obligations.

A further erosion of the business and operating environment in Nigeria would adversely impact Shell.
In our Nigerian operations we face various risks and adverse conditions, some of which deteriorated during 2014. 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 impact of lower oil and gas prices on the government budget; and regional instability created by militant activities. The Nigerian government is contemplating new legislation to govern the petroleum industry which, if passed into law, would likely have a significant adverse impact on Shell's existing and future activities in that country.

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 laws and regulations. In addition, Shell and its joint ventures 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; local content requirements; foreign exchange controls; and changing environmental regulations and disclosure requirements. In our Upstream activities these developments can and do affect land tenure, re-writing of leases, entitlement to produced hydrocarbons, production rates, royalties and pricing. Parts of our Downstream activities are subject to price controls in some countries. From time to time, cultural and political factors play a role in unprecedented and unanticipated judicial outcomes that could adversely affect Shell. If we do not comply with policies and regulations, this may 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; by failing to honour existing contractual commitments; and by 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, thus potentially subjecting us to both criminal and civil sanctions.

Our operations expose us to social instability, civil unrest, terrorism, piracy, acts of war and risks of pandemic diseases that could have an adverse impact 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 does – affect Shell. Such potential developments that could impact our business include acts of political or economic terrorism, acts of piracy on the high seas, conflicts including war, 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. The risks of pandemic diseases, such as Ebola, can impact our operations directly and indirectly. If such risks materialise, they could result in injuries and disruption to business activities.

We rely heavily on information technology systems for our operations.

The operation of many of our business processes depends on the availability of 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 through the internet to our IT systems, including more sophisticated and coordinated attempts often referred to as advanced persistent threats. Shell seeks to detect and investigate all such security incidents, aiming to prevent their recurrence. Disruption of critical IT services, or breaches of information security, could have adverse consequences for Shell.

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 of such plans; both depend on various assumptions. Volatility in capital markets, and the resulting consequences for investment performance and interest rates, may result in significant changes to the funding level of future liabilities. In case of a shortfall, Shell might be required to make substantial cash contributions, depending on the applicable local regulations. See Note 17 to the "Consolidated Financial Statements".

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 may 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 taxation or regulatory policies of host governments or other events. Estimates may 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 may also be subject to correction due to errors in the application of published rules and changes in guidance. Any downward adjustment would indicate lower future production volumes and may lead to impairment of some assets.

Many of our major projects and operations are conducted in joint arrangements or associates. This may 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 may apply) and government sanction risks. 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.

Violations of antitrust and competition law 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. Shell and its joint ventures and associates have been fined for violations of antitrust and competition law. 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. 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.

Violations of anti-bribery and corruption law and anti-money laundering law carry fines and expose us and/or our employees to criminal sanctions and civil suits.

In 2010, Shell 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 its use of the freight-forwarding firm Panalpina. In November 2013, following Shell's fulfilment of the terms of the DPA, the criminal charges filed in connection with the DPA were dismissed. Shell's ethics and compliance programme was enhanced during the DPA and remains in full force and effect. Any violations of the FCPA or other relevant anti-bribery and corruption legislation or anti-money laundering legislation could have a material adverse effect on the Company.

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 Shell to regulatory investigations, which may result in fines and penalties. Shell 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.

RISK FACTORS CONTINUED

Violations of trade controls, including sanctions, 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 faced by Shell continues to expand. For example, the EU and the USA continue to impose restrictions and prohibitions on certain transactions involving Iran and 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 may lead to significant penalties or prosecution of Shell or its employees.

We execute acquisitions and divestments in the pursuit of our strategy. A number of risks impact the success of such acquisitions and divestments.
Acquisitions may not succeed due to reasons such as difficulties in integrating activities and realising synergies, outcomes varying from key assumptions, host governments reacting or responding in a different manner from that envisaged, or liabilities and costs being underestimated. Any of these would reduce our ability to realise the expected benefits. We may not be able to successfully divest non-core assets at acceptable prices, resulting in increased pressure on our cash position. In the case of divestments, 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.

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

The Company’s Articles of Association determine the jurisdiction for shareholder disputes. This might 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 for any reason determined to be invalid or unenforceable, the dispute may 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, may be determined in accordance with these provisions. See “Corporate governance”.

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.

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. We expect over 80% of our capital investment in 2015 to be in our Upstream businesses.

In Upstream, we focus on exploration for new liquids 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 upstream and downstream "engines" are strongly cash-generative, mature businesses, which will underpin our financial performance to at least the end of this decade. We only make investments in selective growth positions and apply Shell's distinctive technology and operating performance to extend the productive lives of our assets and to enhance their profitability.
- Our growth priorities follow two strategic themes: integrated gas and deep water. These will provide our medium-term growth and we expect them to become core engines in the future. We utilise Shell's technological know-how and global scale to unlock highly competitive resources positions.
- Our longer-term strategic themes are "resource plays" such as shale oil and gas as well as "future opportunities", including the Arctic, Iraq, Kazakhstan, Nigeria and heavy oil, where we believe large reserves positions could potentially become available, with the pace of development driven by market and local operating conditions, as well as the regulatory environment.

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 in liquids and natural gas production.

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.

OUTLOOK

We continuously seek to improve our operating performance, with an emphasis on health, safety and environment, asset performance and operating costs. For 2015, we will continue to focus on the three key priorities set out in 2014: improving our financial performance, enhancing our capital efficiency and continuing our focus on project delivery.

In 2015, we expect organic capital investment to be lower than 2014 levels of around $35 billion. We are considering further reductions to capital investment should the evolving market outlook warrant that step, but are aiming to retain growth potential for the medium term. Asset sales are a key element of our strategy, improving our capital efficiency by focusing our investment on the most attractive growth opportunities. Proceeds from sales of non-strategic assets in 2014, and from the initial public offering in Shell Midstream Partners, L.P., totalled $15 billion, successfully completing our divestment programme for 2014-2015. The completed divestment programme will result in various production and tax effects in 2015. We also expect higher levels of downtime in 2015, especially in Upstream and Chemicals, driven by increased maintenance activities. We will continue the initiatives started in 2014, which are expected to improve our North America resource plays and Oil Products businesses. We have new initiatives underway in 2015 that are expected to improve our upstream engine and resource plays outside the Americas. The focus of these initiatives will be on the profitability of our portfolio and growth potential.

Shell has built up a substantial portfolio of project options for future growth. This portfolio has been designed to capture energy price upside and manage Shell's exposure to industry challenges from cost inflation and political risk. Today's lower oil prices are creating opportunities to reduce our own costs and to take costs out of the supply chain.

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, divestment proceeds 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" and "Risk factors".

MARKET OVERVIEW

GLOBAL ECONOMIC GROWTH

According to the International Monetary Fund's (IMF) January 2015 *World Economic Outlook*, global economic growth was 3.3% in 2014, unchanged from 2013. The IMF estimated that the eurozone's gross domestic product (GDP) grew by 0.8% in 2014 compared with a contraction of 0.5% in 2013, US growth was 2.4%, up from 2.2% in 2013, while Chinese growth slowed from 7.8% in 2013 to 7.4%. The average GDP growth rate for emerging markets and developing economies fell to 4.4%, compared with 4.7% in 2013.

Growth in 2014 fell short of the IMF's forecast of 3.7% made at the beginning of 2014. Harsh winter weather in the first quarter weighed on US growth for the year, Japan's growth was hampered by a substantial increase in value added tax in the second quarter, while the eurozone's return to growth has been slow. Meanwhile, growth has slowed in important markets such as China, Russia and Brazil.

The IMF expects global economic growth to rise to 3.5% in 2015, but that would still be less than the annual average of 3.9% for the previous 10 years.

GLOBAL OIL AND GAS DEMAND AND SUPPLY

Reflecting the economic conditions described above, global oil demand rose by 0.7% (0.6 million barrels per day (b/d)) in 2014, according to the International Energy Agency's (IEA) January 2015 *Oil Market Report*. The IEA repeatedly revised down its oil demand growth estimate for the year from 1.4 million b/d in early 2014. Demand grew in emerging economies, while remaining almost flat in advanced economies.

On the non-OPEC supply side, the US Energy Information Administration reported another year of continued supply growth in the Lower 48 US states: in 2014 supply grew by some 1 million b/d year-on-year. As a consequence of somewhat reduced demand growth and strong non-OPEC supply growth, oil prices fell from about $110 per barrel (/b) in mid-2014 to $75/b just ahead of the November OPEC meeting at which the members decided to maintain their production at 30 million b/d, rather than to reduce their production to balance non-OPEC supply growth. The market interpreted this decision as an increased risk of oversupply and oil prices further declined to lows of around $54/b in December.

We estimate that global gas demand grew by about 1% in 2014, similar to growth in 2013, which is much lower than the average annual growth rate of about 2.5% in the past decade. A combination of unusually mild weather, except in the USA, a decline in natural gas production and weak 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 China and the USA, driven by their power generation and industrial sectors. European gas demand has weakened over the last few years and this trend is likely to have continued in 2014, according to gas industry association Eurogas.

CRUDE OIL AND NATURAL GAS PRICES

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

OIL AND GAS AVERAGE INDUSTRY PRICES [A]

	2014	2013	2012
Brent ($/b)	99	109	112
West Texas Intermediate ($/b)	93	98	94
Henry Hub ($/MMBtu)	4.3	3.7	2.8
UK National Balancing Point (pence/therm)	50	68	60
Japan Customs-cleared Crude ($/b)	108	110	115

[A] Yearly average prices are based on daily spot prices. The 2014 average price for Japan Customs-cleared Crude excludes December data.

The Brent crude oil price, an international crude-oil benchmark, traded in a range of $54-115/b in 2014, ending the year at $55/b. Both the Brent and the West Texas Intermediate (WTI) average crude oil prices for 2014 were lower than in 2013, as a result of demand growth being outpaced by continued non-OPEC supply growth, in particular in North America.

WTI continued to trade at a discount to Brent, and followed the Brent price trajectory. The discount narrowed compared with 2013 after an expansion in pipeline capacity helped improve access for refineries on the US Gulf Coast to WTI that is delivered to the landlocked Cushing, Oklahoma, trading hub.

Looking ahead, substantial price volatility can be expected in the short to medium term. Oil prices may strengthen if the global economy accelerates, or if supply tightens as a result of a deceleration in non-OPEC production growth due to current price weakness, in particular US light tight oil, or if supply disruptions occur in major producing countries. Alternatively, oil prices may weaken further if economic growth slows or production continues to rise.

Unlike crude oil pricing, which is global in nature, gas prices vary significantly from region to region. In the USA, the natural gas price at the Henry Hub averaged $4.3 per million British thermal units (MMBtu) in 2014, 16% higher than in 2013, and traded in a range of $2.7-7.9/MMBtu. The year began with one of the coldest winters on record and Henry Hub average monthly gas prices peaked in February at $5.8/MMBtu. But robust growth in gas production and normal weather in the summer led to a steep decline in prices from a high of $4.7/MMBtu in mid-June to $3.8/MMBtu by the end of July. An early cold snap caused a price spike to $4.4/MMBtu in mid-November, but it had fallen to $3.0/MMbtu by the end of the year.

In Europe, gas prices fell. In the UK, the average price at the UK National Balancing Point was 21% lower than in 2013. In continental Europe, price decreases at the main gas trading hubs in Belgium, Germany and the Netherlands were similar to those at the UK National Balancing Point. Lower prices reflected milder than expected weather and improved supplies of LNG on the global market. The dominance of oil-indexed gas pricing is decreasing in continental Europe, with many natural gas contracts now including spot market pricing as a major component.

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 are predominantly indexed to the price of Japan Customs-cleared Crude (JCC). In Japan, LNG import contracts have historically been indexed to the JCC benchmark.

We see growing demand for LNG in China, India, the Middle East, South America and South-east Asia. In these markets, LNG supply is offered on term and spot bases. North American export projects have been offering future gas supply linked to US Henry Hub prices.

CRUDE OIL AND NATURAL GAS PRICES FOR INVESTMENT EVALUATION

The range of possible future crude oil and natural gas prices used in project and portfolio evaluations by Shell is determined after an assessment of short-, medium- and long-term price drivers under different sets of assumptions. Historical analysis, trends and statistical volatility are considered in this assessment, as are analyses of possible future economic conditions, geopolitics, actions by OPEC, 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.

We expect oil and gas prices to remain volatile. For the purposes of making investment decisions, generally we test the economic performance of long-term projects against price ranges of $70-110/b for Brent crude oil and $3.5-5.0/MMBtu for gas at the Henry Hub. As part of our normal business practice, the range of prices used for this purpose is subject to review and change, and was last confirmed in the fourth quarter of 2014. See "Risk factors".

REFINING AND PETROCHEMICAL MARKET TRENDS

Industry refining margins were higher on average in 2014 than in 2013 in the key refining hubs of the USA and Singapore, and were little changed in Europe. In particular, margins improved in the USA where increased domestic crude oil and natural gas production lowered oil acquisition costs (relative to international prices). Some demand growth, especially around the summer driving season in the USA, also contributed to higher US Gulf Coast margins. In 2015, increased demand for middle distillates is expected to be a key driver of refining margins, supported by demand for gasoline in the middle of the year. However, the overall outlook remains unclear because of continuing economic uncertainty, geopolitical tensions in some regions that could lead to supply disruptions and overcapacity in the global refining market.

In Chemicals, industry naphtha cracker margins increased from 2013, particularly in Asia where there was less cracker capacity available. US ethane cracker margins were high relative to naphtha cracker margins in other regions due to ample ethane supply. The outlook for petrochemicals for 2015 is dependent on the growth of the global economy, especially in Asia, and developments in raw material prices.

SUMMARY OF RESULTS

INCOME FOR THE PERIOD			$ MILLION
	2014	2013	2012
Earnings by segment [A]			
Upstream	15,841	12,638	22,244
Downstream	3,411	3,869	5,382
Corporate	(156)	372	(203)
Total segment earnings [A]	19,096	16,879	27,423
Attributable to non-controlling interest	(55)	(134)	(259)
Earnings on a current cost of supplies basis attributable to Royal Dutch Shell plc shareholders	19,041	16,745	27,164
Current cost of supplies adjustment [A]	(4,366)	(353)	(463)
Non-controlling interest	199	(21)	11
Income attributable to Royal Dutch Shell plc shareholders	14,874	16,371	26,712
Non-controlling interest	(144)	155	248
Income for the period	14,730	16,526	26,960

[A] See Note 2 to the "Consolidated Financial Statements". Segment earnings are presented on a current cost of supplies basis.

EARNINGS 2014-2012

Global realised liquids prices were 8% lower in 2014 than in 2013. Global realised natural gas prices were 6% lower than in 2013, with a 20% increase in the Americas and an 11% decrease outside the Americas.

Oil and gas production available for sale in 2014 was 3,080 thousand barrels of oil equivalent per day (boe/d), compared with 3,199 thousand boe/d in 2013. Liquids production was down 4% and natural gas production decreased by 4% compared with 2013. Excluding the impact of divestments, the Abu Dhabi licence expiry, production-sharing contract price effects and security impacts in Nigeria, production volumes in 2014 increased by 2% compared with 2013.

Realised refining margins in 2014 were significantly higher overall and higher in all regions apart from the US West Coast compared with 2013. The increase was driven by operational improvements and a stronger margin environment in most regions.

Earnings on a current cost of supplies basis (CCS earnings) attributable to shareholders in 2014 were 14% higher than in 2013, which in turn were 38% lower than in 2012. Segment earnings are presented on this 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 2014 CCS earnings were $4,366 million higher than earnings calculated on a FIFO basis (2013: $353 million higher; 2012: $463 million higher).

Upstream earnings in 2014 were $15,841 million, compared with $12,638 million in 2013 and $22,244 million in 2012. The 25% increase from 2013 to 2014 was mainly driven by increased contributions from liquids production volumes from both the start-up of new high-margin deep-water projects and improved operational performance, higher divestment gains, lower exploration expenses, primarily driven by fewer well write-offs, increased contributions from Trading and lower impairment charges. These effects were partially offset by the impact of declining oil prices and higher depreciation (excluding impairments). The 43% decrease from 2012 to 2013 reflected higher depreciation charges (partly driven by impairments), lower divestment gains, higher exploration expenses (mainly driven by well write-offs), higher operating expenses and lower liquids and LNG realisations. Earnings in 2013 were also impacted by a deterioration in the operating environment in Nigeria and the impact of the weakening Australian dollar on a deferred tax liability. These effects were partly offset by the contribution of our Pearl GTL plant in Qatar and higher gas price realisations in the Americas, together with net tax gains in 2013 compared with net tax charges and higher decommissioning provisions in 2012.

Downstream earnings in 2014 were $3,411 million compared with $3,869 million in 2013 and $5,382 million in 2012. The 12% decrease from 2013 to 2014 reflected significantly higher charges for impairment which were partially offset by higher realised refining margins, higher earnings from Trading and Supply and lower costs (mainly as a result of divestments). The 28% decrease from 2012 to 2013 reflected significantly lower realised refining margins and higher charges for impairment, partly offset by higher contributions from Chemicals and Trading.

Corporate earnings in 2014 were a loss of $156 million, compared with a gain of $372 million in 2013 and a loss of $203 million in 2012. Compared with 2013, Corporate earnings in 2014 reflected lower tax credits, higher net interest expense and adverse currency exchange rate effects. Compared with 2012, earnings in 2013 were higher mainly due to a tax credit, the recharge to the business segments of certain costs and lower net interest expense, partly offset by adverse currency exchange rate effects.

NET CAPITAL INVESTMENT AND GEARING

Net capital investment was $23.9 billion, 46% lower than in 2013. This was driven by higher proceeds from divestments and lower capital investment (see "Non-GAAP measures reconciliations").

Gearing was 12.2% at the end of 2014, compared with 16.1% at the end of 2013, as a result of a significant increase in cash and cash equivalents (driven by the lower net capital investment), combined with a 2% increase in total debt and a 5% decrease in equity.

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" and set out in more detail in "Supplementary information – oil and gas (unaudited)".

In 2014, Shell added 301 million boe of proved reserves before taking production into account, of which 271 million boe were from Shell subsidiaries and 30 million boe were from the Shell share of joint ventures and associates. These additions were positively impacted by lower commodity prices (44 million boe) and negatively impacted by sales that exceeded purchases (274 million boe).

In 2014, total oil and gas production available for sale was 1,124 million boe. An additional 40 million boe was produced and consumed in operations. Production available for sale from subsidiaries was 895 million boe with an additional 30 million boe consumed in operations. The Shell share of the production available for sale of joint ventures and associates was 229 million boe with an additional 10 million boe consumed in operations.

Accordingly, after taking production into account, there was a decrease of 863 million boe in proved reserves, comprising a decrease of 654 million boe from subsidiaries and a decrease of 209 million boe from the Shell share of joint ventures and associates.

KEY ACCOUNTING ESTIMATES AND JUDGEMENTS

Refer to Note 3 to the "Consolidated Financial Statements" for a discussion of key accounting estimates and judgements.

LEGAL PROCEEDINGS

Refer to Note 25 to the "Consolidated Financial Statements" for a discussion of legal proceedings.

PERFORMANCE INDICATORS

KEY PERFORMANCE INDICATORS

Total shareholder return
2014 **-3.0%** 2013 8.6%

Total shareholder return (TSR) is the difference between the share price at the start of the year and the share price at the end of the year, plus gross dividends delivered during the calendar year (reinvested quarterly), expressed as a percentage of the year-start share price. The TSRs of major publicly traded oil and gas companies can be directly compared, providing a way to determine how Shell is performing against its industry peers.

Net cash from operating activities ($ billion)
2014 **45** 2013 40

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 Shell's ability to generate cash for both investment and distribution to shareholders.

Project delivery
2014 **83%** 2013 88%

Project delivery reflects Shell's capability to complete major projects on time and within budget on the basis of targets set in the 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).

Production available for sale (thousand boe/d)
2014 **3,080** 2013 3,199

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 to equivalent barrels of oil to make the summation possible. Changes in production have a significant impact on Shell's cash flow.

Equity sales of liquefied natural gas (million tonnes)
2014 **24.0** 2013 19.6

Equity sales of liquefied natural gas (LNG) is a measure of the operational performance of Shell's Upstream business and LNG market demand.

Refinery and chemical plant availability
2014 **92.1%** 2013 92.5%

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 Shell's Downstream manufacturing facilities.

Total recordable case frequency (injuries per million working hours)
2014 **0.99** 2013 1.15

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.

ADDITIONAL PERFORMANCE INDICATORS

Earnings on a current cost of supplies basis attributable to Royal Dutch Shell plc shareholders ($ million)
2014 **19,041** 2013 16,745

Earnings per share on a current cost of supplies basis ($)
2014 **3.02** 2013 2.66

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. CCS earnings per share is calculated by dividing CCS earnings attributable to shareholders by the average number of shares outstanding. See "Summary of results" and Note 2 to the "Consolidated Financial Statements".

Net capital investment ($ million)
2014 **23,899** 2013 44,303

Net capital investment is a measure used to make decisions about allocating resources and assessing performance. It is defined as net cash used in investing activities as reported in the "Consolidated Statement of Cash Flows" plus exploration expense, excluding exploration wells written off, new finance leases and other adjustments. See "Non-GAAP measures reconciliations".

Return on average capital employed
2014 **7.1%** 2013 7.9%

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 Shell's utilisation of the capital that it employs and is a common measure of business performance. See "Liquidity and capital resources – Return on average capital employed".

Gearing
2014 **12.2%** 2013 16.1%

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 Shell's operations are financed by debt. See Note 14 to the "Consolidated Financial Statements".

Proved oil and gas reserves attributable to Royal Dutch Shell plc shareholders (million boe)
2014 **13,070** 2013 13,932

Proved oil and gas reserves attributable to Royal Dutch Shell plc shareholders are the total estimated quantities of oil and gas from Shell subsidiaries (excluding reserves attributable to non-controlling interest) 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, as at December 31, under existing economic conditions, operating methods and government regulations. Gas volumes are converted to 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 based on a wide variety of factors, some of which are unpredictable. See "Risk factors".

Operational spills of more than 100 kilograms
2014 **153** 2013 174

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.

Employees (thousand)
2014 **94** 2013 92

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.

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
	2014	2013	2012	2011	2010
Revenue	421,105	451,235	467,153	470,171	368,056
Income for the period	14,730	16,526	26,960	31,093	20,474
(Loss)/income attributable to non-controlling interest	(144)	155	248	267	347
Income attributable to Royal Dutch Shell plc shareholders	14,874	16,371	26,712	30,826	20,127
Comprehensive income attributable to Royal Dutch Shell plc shareholders	2,692	18,243	24,470	26,250	19,893

CONSOLIDATED BALANCE SHEET DATA					$ MILLION
	2014	2013	2012	2011	2010
Total assets	353,116	357,512	350,294	337,474	317,271
Total debt	45,540	44,562	37,754	37,175	44,332
Share capital	540	542	542	536	529
Equity attributable to Royal Dutch Shell plc shareholders	171,966	180,047	174,749	158,480	140,453
Non-controlling interest	820	1,101	1,433	1,486	1,767

EARNINGS PER SHARE					$
	2014	2013	2012	2011	2010
Basic earnings per €0.07 ordinary share	2.36	2.60	4.27	4.97	3.28
Diluted earnings per €0.07 ordinary share	2.36	2.60	4.26	4.96	3.28

SHARES					NUMBER
	2014	2013	2012	2011	2010
Basic weighted average number of A and B shares	6,311,490,678	6,291,126,326	6,261,184,755	6,212,532,421	6,132,640,190
Diluted weighted average number of A and B shares	6,311,605,118	6,293,381,407	6,267,839,545	6,221,655,088	6,139,300,098

OTHER FINANCIAL DATA					$ MILLION
	2014	2013	2012	2011	2010
Net cash from operating activities	45,044	40,440	46,140	36,771	27,350
Net cash used in investing activities	19,657	40,146	28,453	20,443	21,972
Dividends paid	9,560	7,450	7,682	7,315	9,979
Net cash used in financing activities	12,790	8,978	10,630	18,131	1,467
Increase/(decrease) in cash and cash equivalents	11,911	(8,854)	7,258	(2,152)	3,725
Earnings/(losses) by segment [A]					
Upstream	15,841	12,638	22,244	24,466	15,935
Downstream	3,411	3,869	5,382	4,170	2,950
Corporate	(156)	372	(203)	102	91
Total segment earnings	19,096	16,879	27,423	28,738	18,976
Attributable to non-controlling interest	(55)	(134)	(259)	(205)	(333)
Earnings on a current cost of supplies basis attributable to Royal Dutch Shell plc shareholders [B]	19,041	16,745	27,164	28,533	18,643
Net capital investment [C]					
Upstream	20,704	39,217	25,320	19,083	21,222
Downstream	3,079	4,885	4,275	4,342	2,358
Corporate	116	201	208	78	100
Total	23,899	44,303	29,803	23,503	23,680

[A] See Notes 2 and 4 to the "Consolidated Financial Statements".
[B] See table in "Summary of results".
[C] See "Non-GAAP measures reconciliations".

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KEY STATISTICS			$ MILLION
	2014	2013	2012
Segment earnings	15,841	12,638	22,244
Including:			
Revenue (including inter-segment sales)	92,299	92,869	94,550
Share of profit of joint ventures and associates	5,502	6,120	8,001
Production and manufacturing expenses	20,093	18,471	16,354
Selling, distribution and administrative expenses	1,055	1,194	1,211
Exploration	4,224	5,278	3,104
Depreciation, depletion and amortisation	17,868	16,949	11,387
Net capital investment [A]	20,704	39,217	25,320
Oil and gas production available for sale (thousand boe/d)	3,080	3,199	3,262
Equity LNG sales volume (million tonnes)	24.0	19.6	20.2
Proved oil and gas reserves at December 31 (million boe) [B]	13,070	13,932	13,556

[A] See "Non-GAAP measures reconciliations".
[B] Excludes reserves attributable to non-controlling interest in Shell subsidiaries.

OVERVIEW

Our Upstream businesses explore for and extract crude oil and natural gas, often in joint arrangements with international and national oil and gas companies. This includes the extraction of 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 0.7% (0.6 million barrels per day (b/d)) in 2014, according to the International Energy Agency's January 2015 *Oil Market Report.* Demand grew in emerging economies while remaining almost flat in advanced economies. The Brent crude oil price, an international crude-oil benchmark, traded in a range of $54-115 per barrel (/b) in 2014, ending the year at $55/b.

We estimate that global gas demand grew by about 1% in 2014, similar to growth in 2013, which is much lower than the average annual growth rate of about 2.5% in the past decade. A combination of unusually mild weather, except in the USA, a decline in natural gas production and weak 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 China and the USA, driven by their power generation and industrial sectors. European gas demand has weakened over the last few years and this trend is likely to have continued in 2014, according to gas industry association Eurogas.

EARNINGS 2014-2013

Segment earnings of $15,841 million included a net charge of $664 million, reflecting impairment charges of $2,406 million, predominantly related to tight-gas shale properties in the USA, 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 mainly related to Wheatstone and to a portion of our shareholding in Woodside Petroleum Limited (Woodside) in Australia, Oil Mining Lease (OML) 24 in Nigeria and Haynesville in the USA. Other favourable impacts mainly related to the net effect of fair value accounting of commodity derivatives and certain gas contracts, and to amendments to our Dutch pension plan.

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

Global realised liquids prices were 8% lower than in 2013. Global realised gas prices were 6% lower than in 2013, with a 20% increase in the Americas and an 11% decrease outside the Americas.

Equity LNG sales volumes of 24.0 million tonnes were 22% higher than in 2013, mainly reflecting the contribution from the Atlantic LNG and Peru LNG assets following the acquisition from Repsol S.A. in January 2014, and higher volumes from Nigeria LNG which in 2013 was impacted by reduced feed gas supply and the impact of a blockade of shipments.

EARNINGS 2013-2012

Segment earnings in 2013 of $12,638 million included a net charge of $2,479 million, as described above. Segment earnings in 2012 of $22,244 million included a net gain of $2,137 million, mainly related to gains on divestments, partly offset by impairments for onshore gas assets in the USA, net tax charges and decommissioning provisions.

Excluding the net charge and net gain described above, segment earnings in 2013 decreased by 25% compared with 2012 because of higher exploration expenses (mainly driven by well write-offs), operating expenses and depreciation, and lower liquids and LNG realisations. Earnings were also impacted by a deterioration in the operating environment in Nigeria and the impact of the weakening Australian dollar on a deferred tax liability. This was partly offset by an increased contribution from our Pearl GTL plant (Pearl) in Qatar and higher gas prices in the Americas.

UPSTREAM CONTINUED

NET CAPITAL INVESTMENT

Net capital investment was $21 billion in 2014, compared with $39 billion in 2013. Capital investment in 2014 was $31 billion (of which $8 billion was exploration expenditure, including acquisitions of unproved properties). Capital investment in 2013 was $40 billion. Divestment proceeds were $11 billion in 2014 compared with $1 billion in 2013.

Net capital investment was lower than in 2013 mainly due to higher divestment proceeds and lower expenditure on acquisitions. Major divestment proceeds in 2014 relate to a portion of our shareholding in Woodside and to Wheatstone in Australia, Parque das Conchas (BC-10) in Brazil and Haynesville and Pinedale in the USA. In 2014, acquisition expenditure was lower than in 2013 which included the acquisition of interests in Libra and BC-10 in Brazil and expenditure for the acquisition of LNG businesses from Repsol S.A.

PORTFOLIO ACTIONS AND BUSINESS DEVELOPMENT

We achieved the following operational milestones in 2014:

In Malaysia, first oil was produced from the Shell-operated Gumusut-Kakap deep-water development (Shell interest 29%). Peak production of around 135 thousand barrels of oil equivalent per day (boe/d) is expected. Work on the gas injection facilities is continuing.

Also in Malaysia, the Siakap North-Petai development (Shell interest 21%) commenced production and is expected to deliver peak production of around 30 thousand boe/d.

In Nigeria, first oil was produced from the Shell-operated Bonga North West deep-water development (Shell interest 55%) which is expected to deliver peak production of around 40 thousand boe/d. Oil from the subsea facilities is transported by a new undersea pipeline to the existing Bonga floating production, storage and offloading (FPSO) export facility, which has been upgraded to handle the additional oil flow.

In the USA, there were two major start-ups in the deep-water Gulf of Mexico with first oil produced from the Mars B (Shell interest 71.5%) and Cardamom (Shell interest 100%) developments. Production from these developments is planned to ramp up to 80 thousand boe/d and 50 thousand boe/d respectively.

The acquisition of part of Repsol S.A.'s LNG portfolio was completed in January 2014, including LNG supply positions in Peru and Trinidad and Tobago, for a net cash purchase price of $3.8 billion, adding 7.2 million tonnes per annum (mtpa) of directly managed LNG volumes through long-term off-take agreements, including 4.2 mtpa of equity LNG plant capacity.

We also took several final investment decisions during 2014, including the following:

In Brunei, the final investment decision was taken on the Maharaja Lela South development (Shell interest 35%). The development is expected to deliver peak production of 35 thousand boe/d.

In Nigeria, we took the final investment decision on the Bonga Main Phase 3 project (Shell interest 55%). The development is expected to deliver some 40 thousand boe/d at peak production through the existing Bonga FPSO.

In the USA, we took the final investment decision on the Coulomb Phase 2 project (Shell interest 100%) in the Gulf of Mexico. The development is a subsea tie-back into the Na Kika semi-submersible storage platform and is expected to deliver some 20 thousand boe/d at peak production.

We continued to divest selected Upstream assets during 2014, including the following:

In Australia, we sold 78.27 million shares in Woodside for $3.0 billion, reducing Shell's interest from 23% to 14%.

Also in Australia, we sold our 8% interest in the Wheatstone-Iago joint venture and our 6.4% interest in the Wheatstone LNG project, which is under development, for $1.5 billion.

In Brazil, we sold a 23% interest in the Shell-operated deep-water project BC-10 to Qatar Petroleum International for $1.2 billion, including closing adjustment.

Also in Brazil, we sold our non-operated 20% interest in the BM-ES-23 concession in the Espirito Santos basin offshore for $0.2 billion.

In Canada, we sold our 100% interest in the Orion steam assisted gravity drainage project for $0.3 billion.

In Nigeria, we sold our 30% interest in OML 24 and related onshore facilities for $0.6 billion.

In Upstream Americas tight-gas and liquids-rich shale, we completed a review of our portfolio and strategy. Major divestments of non-core positions are now complete and in 2014 included our interests in:

- the Haynesville tight-gas shale asset in Louisiana, USA, for $1.1 billion including closing adjustments;
- the Pinedale tight-gas shale asset in Wyoming, USA, for $0.9 billion including closing adjustments and 155 thousand net acres in the Marcellus and Utica shale areas in Pennsylvania, USA. We now hold a 100% interest in the Tioga Area of Mutual Interest;
- approximately 106,000 net acres of the Eagle Ford liquids-rich shale asset in Texas, USA, for $0.5 billion including closing adjustments;
- the Mississippi Lime acreage in Kansas, USA, for $0.1 billion; and
- additional assets for a total of $0.5 billion.

AVAILABLE-FOR-SALE PRODUCTION

In 2014, production was 3,080 thousand boe/d compared with 3,199 thousand boe/d in 2013. Liquids and natural gas production both decreased by 4% compared with 2013.

Production was reduced by 10% as a result of the ADCO licence expiry in Abu Dhabi in January 2014, field declines and the divestment of a number of assets (mainly shale assets in the Americas and the reduction in our shareholding in Woodside).

This reduction was partly offset by new field start-ups and the continuing ramp-up of existing projects, in particular Majnoon in Iraq and Mars B and BC-10 Phase 2 in the Americas, which contributed some 130 thousand boe/d to production in 2014. Improved operational performance in 2014 provided further offset.

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 Upstream section and set out in more detail in "Supplementary information – oil and gas (unaudited)".

In 2014, Shell added 301 million boe of proved reserves before taking production into account, of which 271 million boe came from Shell subsidiaries and 30 million boe from the Shell share of joint ventures and associates.

The change in the yearly average commodity prices between 2013 and 2014 resulted in a net positive impact on the proved reserves of 44 million boe.

In 2014, after taking into account production, our total proved reserves declined by 863 million boe.

Shell subsidiaries

Before taking production into account, Shell subsidiaries added 271 million boe of proved reserves in 2014. This comprised 42 million barrels of oil and natural gas liquids and 229 million boe (1,329 thousand million scf) of natural gas. Of the 271 million boe: 276 million boe were from the net effects of revisions and reclassifications; 9 million boe were from improved recovery; 191 million boe came from extensions and discoveries; and a net decrease of 205 million boe related to purchases and sales.

After taking into account production of 925 million boe (of which 30 million boe were consumed in operations), Shell subsidiaries' proved reserves decreased by 654 million boe in 2014.

Shell subsidiaries' proved developed reserves decreased by 12 million boe to 6,777 million boe, while proved undeveloped reserves decreased by 642 million boe to 3,404 million boe.

The total addition of 271 million boe before taking production into account included a net positive impact from commodity price changes of 43 million boe of proved reserves.

SYNTHETIC CRUDE OIL

Of the 301 million boe added to proved reserves, 81 million barrels were synthetic crude oil. In 2014, we had synthetic crude oil production of 49 million barrels of which 2 million barrels were consumed in operations. At December 31, 2014, we had synthetic crude oil proved reserves of 1,763 million barrels, of which 1,273 million barrels were proved developed reserves and 490 million barrels were proved undeveloped reserves.

BITUMEN

Of the 301 million boe added to proved reserves, 12 million barrels were bitumen. The addition of 12 million barrels comprised an increase of 17 million barrels from net effects of revisions and reclassifications, and an addition of 1 million barrels from extensions and discoveries and a decrease from sales of 6 million barrels. After taking into account production of 6 million barrels, bitumen proved reserves were 428 million barrels at December 31, 2014.

Shell share of joint ventures and associates

Before taking production into account, there was an increase of 30 million boe in the Shell share of joint ventures and associates' proved reserves in 2014. This comprised 11 million barrels of oil and natural gas liquids and 19 million boe (112 thousand million scf) of natural gas. Of the 30 million boe, 91 million boe came from the net effects of revisions and reclassifications, 8 million boe came from extensions and discoveries and a decrease of 69 million boe from sales.

After taking into account production of 239 million boe (of which 10 million boe were consumed in operations), the Shell share of joint ventures and associates' proved reserves decreased by 209 million boe in 2014.

The Shell share of joint ventures and associates' proved developed reserves decreased by 336 million boe to 2,206 million boe, and proved undeveloped reserves increased by 127 million boe to 694 million boe.

The total addition of 30 million boe before taking production into account was impacted by net positive impact from commodity price changes of 1 million boe of proved reserves.

Proved undeveloped reserves

In 2014, Shell subsidiaries' and the Shell share of joint ventures and associates' proved undeveloped reserves (PUD) decreased by 515 million boe to 4,098 million boe. A number of Shell fields saw some changes to proved undeveloped reserves, with the largest reductions occurring in the USA in Mars and in Europe in Schiehallion. The most significant additions to the PUD occurred in Champion and Champion West in Asia and in Canada in Muskeg River Mine. The 515 million boe decrease in proved undeveloped reserves comprised: a reduction of 259 million boe from revisions; a net reclassification of 125 million boe from proved undeveloped to proved developed reserves; a net reclassification of 266 million boe from proved undeveloped reserves to contingent resource; an addition of 208 million boe from extensions, discoveries and improved recovery; and a net decrease of 73 million boe related to purchases and sales.

An amount of 174 million boe was matured to proved developed reserves from contingent resource as a result of project execution during the year.

Shell proved undeveloped reserves held for five years or more (PUD5+) at December 31, 2014, amount to 1,600 million boe, a net increase of 774 million boe compared with the end of 2013. 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 Netherlands, Norway, the Philippines 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 (in countries like Kazakhstan). The increase in PUD5+ reflects the ageing of 808 million boe PUD booked in 2009 and the transfer of 34 million boe PUD to proved developed reserves. The largest contributors to the increase of PUD5+ are Muskeg River Mine, Gorgon and Jansz-Io. Two fields, Bonga and Val d'Agri, contribute to a reduction in PUD5+ due to projects being brought on stream. The Shell fields with the largest PUD5+ are now Muskeg River Mine, followed by Gorgon, Groningen (second and third stage compression), Jansz-Io and Kashaghan.

During 2014, Shell spent $17.3 billion on development activities related to PUD maturation.

DELIVERY COMMITMENTS

Shell sells crude oil and natural gas from its producing operations under a variety of contractual obligations. Most contracts generally commit Shell 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, Shell met all contractual delivery commitments.

In the period 2015 to 2017, Shell is contractually committed to deliver to third parties and joint ventures and associates a total of

UPSTREAM CONTINUED

approximately 4,000 thousand million scf of natural gas from Shell 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 Shell's delivery commitments and its proved developed reserves is estimated at 21% of Shell's 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 2014, Shell made 10 notable discoveries, including in the USA, Gabon and Malaysia. Discoveries will be evaluated further in order to establish the extent of commercially producible volumes they contain.

In 2014, Shell participated in 151 productive exploratory wells with proved reserves allocated (Shell share: 99 wells). For further information, see "Supplementary information – oil and gas (unaudited) – Acreage and wells".

In 2014, Shell participated in a further 126 wells (Shell share: 77 wells) that remained pending determination at December 31, 2014.

In total, the net acreage in Shell's exploration portfolio decreased by 34,000 square kilometres, comprising acreage decreases of 13,000 square kilometres in South America (withdrawal), 11,500 square kilometres in Australia (divestment), 8,000 square kilometres in Turkey (relinquishment), 5,000 square kilometres in Canada (divestment), and increases in acreage of 11,500 square kilometres in Namibia (licence award) and 9,000 square kilometres in Greenland (equity increase).

BUSINESS AND PROPERTY

Shell 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, government entity 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 Shell's 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, government entity or government-run oil and gas company may sometimes enter as a participant in a joint arrangement sharing the rights and obligations of the licence but usually without sharing the exploration risk. In a few cases, the government entity, 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, government entity 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, government entity or government-run oil and gas company on a fixed or volume/revenue-dependent basis. In some cases, the government, government entity 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%), which is at an advanced stage of construction. Corrib has the potential to supply a significant proportion of the country's gas requirement. The pipeline connection between the offshore wells and the onshore processing terminal is complete. Initial operation and testing of equipment has commenced at the terminal, using gas from the national grid in advance of first gas production from the field, which is expected in 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%). During the second quarter of 2014 we entered the front-end engineering and design (FEED) phase on the non-operated project Val d'Agri Phase 2, which is expected to deliver peak production of some 65 thousand boe/d. 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. NAM also has a 60% interest in the Schoonebeek oil field, which has been redeveloped using enhanced oil recovery technology. NAM also operates a significant number of other onshore gas fields and offshore gas fields in the North Sea. In January 2015, the Minister of Economic Affairs of the Netherlands approved NAM's production plan for the Groningen field for 2014 to 2016. This caps production levels at 42.5 billion cubic metres for 2014 and 39.4 billion cubic metres in each of 2015 and 2016, in an effort to diminish the potential for seismic activity. Since issuing his decision on the Groningen production plan, the Minister of Economic Affairs has stated that he intends to cap production at 16.5 billion cubic metres for the first half of 2015.

NORWAY
We are a partner in more than 30 production licences on the Norwegian continental shelf. We are the operator in 14 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.

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 non-operated interests in the Atlantic Margin area, principally in the West of Shetlands 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.

REST OF EUROPE
Shell also has interests in Albania, Austria, Germany, Greece, Greenland, Hungary, Slovakia, Spain and Ukraine.

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.

We are the operator for the Block A concession (Shell interest 53.9%), which is under exploration and development, and also 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. In February 2014, the final investment decision was taken on the Maharaja Lela South development (Shell interest 35%). It is expected to deliver a total peak production of 35 thousand boe per day.

In addition, we 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 operate 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, Shell and CNPC have agreed 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 three offshore oil and gas blocks in the Yinggehai basin, each 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 a floating LNG (FLNG) concept for the field's development phase.

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

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 Majnoon shareholders 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. In 2013, we successfully restarted production and Majnoon reached the milestone of first commercial production of 175 thousand boe/d. In 2014, production at Majnoon averaged 194 thousand boe/d.

We also have a 20% interest in the West Qurna 1 field. Our participating interest in the West Qurna concession has increased from 15% to 20% when the contract was renegotiated in 2014 and the government share reduced from 25% to 5% and prorated to the funding shareholders.

According to the provisions of both contracts, Shell's equity entitlement volumes will be lower than the Shell 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 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, increasing further with additional phases of development. After the start of production from the Kashagan field in September 2013, operations had to be stopped in October 2013 due to gas leaks from the sour gas pipeline. Following investigations, it has been decided that both the oil and the gas pipeline will be replaced. Replacement activities are ongoing, with production expected to restart in 2017.

We 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.

MALAYSIA
We explore for and produce oil and gas located offshore Sabah and Sarawak under 19 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 October 2014. We have additional interests ranging from 30% to 50% in PSCs for the exploration and development of four deep-water blocks. These include the Malikai field (Shell interest 35%) which is being developed with Shell as the operator. We also have a 21% interest in the Siakap North-Petai field, which commenced production in 2014, and a 30% interest in the Kebabangan field.

Offshore Sarawak, we are the operator of 17 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 Dua (where our licence is due to expire in 2015) and Tiga LNG plants. 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: Deepwater Block 2B, SK318, SK319, SK408 and SK320.

UPSTREAM CONTINUED

We operate a gas-to-liquids (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. During 2014, the Amal steam enhanced oil recovery project has been ramping up towards its expected peak production following a successful start-up in 2013.

We are also participating in the Mukhaizna oil field (Shell interest 17%) where steam flooding, an enhanced oil recovery method, is being applied on a large scale.

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, another LNG facility in the country.

QATAR

Pearl in Qatar is the world's largest GTL plant. Shell operates it under a development and production-sharing contract with the government. The fully integrated facility includes production, transport and processing 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 NGL and ethane. In 2014, Pearl produced 4.5 million tonnes of GTL products.

Of Pearl's two trains, the first train is undergoing maintenance in the first quarter of 2015, for an estimated two month period.

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 2014, the project produced 320 thousand boe/d and the output of LNG exceeded 10 million tonnes.

We have a 100% interest in an exploration and production licence for the Lenzitsky block in the Yamalo Nenets Autonomous District. In 2014, we returned the Arkatoisky (also in the Yamalo Nenets Autonomous District) and the Barun-Yustinsky (in Kalmykia) licence blocks to the government.

We also have a 50% interest through Khanty-Mansiysk Petroleum Alliance V.O.F. (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, where production was 130 thousand boe/d in 2014.

As a result of EU and US sanctions prohibiting defined oil and gas activities in Russia, in 2014 we paused our liquids-rich shales exploration activities, which were being undertaken through Salym and Khanty-Mansiysk Petroleum Alliance V.O.F.

UNITED ARAB EMIRATES

In Abu Dhabi, we held a concessionary interest of 9.5% in the oil and gas operations run by Abu Dhabi Company for Onshore Oil Operations (ADCO) from 1939 to January 2014, when the licence expired. We also 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 ADCO.

We also participate in a 30-year joint venture to potentially develop the Bab sour gas reservoirs in Abu Dhabi (Shell interest 40%). Shell and the Abu Dhabi National Oil Company are in a period of commercial and technical work that may lead to development, subject to the signing of the respective joint-venture agreements.

REST OF ASIA

Shell also has interests in India, Japan, Jordan, the Philippines, Saudi Arabia, Singapore, South Korea 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 14% in Woodside, reduced from 23% by a sale of shares in 2014. 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 six joint-venture participants in the NWS gas, condensate and oil fields, which produced more than 500 thousand boe/d in 2014. Shell provides 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 is under construction on Barrow Island and is expected to start before the end of 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. We are developing these fields on the basis of 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. During 2014, construction of the Prelude FLNG project continued, with a major milestone being the lifting of the first topside modules onto the deck of the hull.

We are also a partner in the Browse joint ventures (Shell interests ranging from 25% to 35%) covering the Brecknock, Calliance and Torosa gas fields. In 2013, the Browse joint venture selected Shell's FLNG technology to progress to the basis of design phase of the project.

Our other interests include: a joint venture with Shell as the operator of the Crux gas and condensate field (Shell interest 82%); the Shell-operated AC/P41 block (Shell interest 75%); and the Sunrise gas field in the Timor Sea (Shell interest 26.6%). We sold our interest in the Wheatstone-Iago joint venture and our 6.4% interest in the Wheatstone LNG project during the second quarter of 2014.

We are a partner in both Shell-operated and other, non-operated, exploration joint ventures in multiple basins including the Bonaparte, Exmouth Plateau, Greater Gorgon, Outer Canning and South Exmouth.

REST OF OCEANIA
Shell also has interests in New Zealand.

Africa

NIGERIA
Shell's share of production, onshore and offshore, in Nigeria was approximately 300 thousand boe/d in 2014, compared with approximately 265 thousand boe/d in 2013. Security issues and crude oil theft in the Niger Delta continued to be significant challenges in 2014.

Onshore
The Shell Petroleum Development Company of Nigeria Ltd (SPDC) is the operator of a joint arrangement (Shell interest 30%) that has more than 25 Niger Delta onshore oil mining leases (OMLs), which expire in 2019. 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. SPDC is undertaking a strategic review of its interests in the eastern Niger Delta and has divested its 30% interest in OML 24. Agreements have been signed for the divestment of the SPDC interests in three other onshore OMLs; completion is subject to the consent of the Federal Government of Nigeria. Additional divestments may occur as a result of the strategic review.

While the level of crude oil theft activities and sabotage in 2014 was similar to 2013, the impact on production was smaller due to various mitigation measures. During 2014, force majeure related to security issues, sabotage and crude oil theft was only declared once, compared with four times in 2013.

Offshore
Our main offshore deep-water activities are carried out by Shell Nigeria Exploration and Production Company (SNEPCO, Shell interest 100%) which has interests in four deep-water blocks. SNEPCO operates OMLs 118 (including the Bonga field, Shell interest 55%) and 135 (Bolia and Doro, Shell interest 55%) and holds a 43.75% interest in OML 133 (Erha) and a 50% interest in oil production lease 245 (Zabazaba, Etan). SNEPCO also has an approximate 43% interest in the Bonga Southwest/Aparo development via its 55% interest in OML 118. Deep-water offshore activities are typically governed through PSCs.

First oil was produced from the Bonga North West deep-water development in the third quarter of 2014, while in October the final investment decision on the Bonga Main phase 3 project was taken, which is expected to contribute some 40 thousand boe/d at peak production through the existing Bonga FPSO export facility.

SPDC also has an interest in six shallow-water offshore leases, of which five are under final negotiation for extension for a period of 20 years.

Liquefied natural gas
Shell has a 25.6% interest in NLNG, which operates six LNG trains with a total capacity of 22.0 mtpa. In 2014, LNG production was higher than in 2013, as 2013 was impacted by gas supply constraints and the impact of a blockade of NLNG export facilities by the Nigerian Maritime Administration and Safety Agency.

REST OF AFRICA
Shell also has interests in Algeria, Benin, Egypt, Gabon, Namibia, Somalia, South Africa, Tanzania and Tunisia.

North America

CANADA
We have more than 1,900 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 enhanced oil recovery 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 2014 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 Colombia. During 2014, we began decommissioning our Burnt Timber gas facility in Alberta. Also 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. This project completed FEED in 2014, with the final investment decision expected not earlier than 2016 and cash flows expected early next decade.

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 is also operated by Shell and located in the Edmonton area. The Quest carbon capture and storage project (Shell interest 60%), which is expected to capture and permanently store more than 1 mtpa of CO_2 from the Scotford Upgrader, is under construction and is expected to start operation towards the end of 2015.

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 a certain minimum level of development prior to their expiry, leases may be extended.

Bitumen
We produce and market bitumen in the Peace River area of Alberta. Additional heavy oil resources and advanced recovery technologies are under evaluation on approximately 1,200 square kilometres in the Grosmont oil sands area, also in northern Alberta. Construction of our Carmon Creek project (Shell interest 100%), which began in 2013, continues. Carmon Creek is an in-situ project that is expected to produce up to 80 thousand boe/d.

UPSTREAM CONTINUED

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. During 2014, we sold a 50% interest in the Shelburne project offshore Nova Scotia and retain a 50% interest as operator. 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 50% of Shell's oil and gas production in the country. We have an interest in approximately 450 federal offshore leases and our share of production averaged almost 225 thousand boe/d in 2014. Key producing assets are Auger, Brutus, Enchilada, Mars, Na Kika, Olympus, Perdido, Ram-Powell and Ursa.

We continued significant exploration and development activities in the Gulf of Mexico in 2014, with an average contracted offshore rig fleet of nine mobile rigs and five platform rigs. We also secured five blocks in the central and western lease sales in 2014.

Onshore

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

During 2014, we divested our interests in the Eagle Ford shale formation in Texas, the Mississippi Lime in Kansas, the Utica shale position in Ohio and our acreage in the Sandwash Niobrara basins in Colorado. In addition, we sold our Haynesville gas assets in Louisiana for cash and sold our Pinedale gas assets in Wyoming in exchange for cash and additional acreage in the Marcellus and Utica shale areas in Pennsylvania.

In recent years, we have invested significant amounts in our tight-gas and liquids-rich shale portfolio. There is still a large amount of drilling that must be conducted in our properties in order to establish our future plans. Following the asset sales in 2014, the current focus is on de-risking and future development of our core assets, while continuing to look for options to enhance the value of our portfolio in the current market.

California

We have a 51.8% interest in Aera Energy LLC (Aera), which has assets in the San Joaquin Valley and Los Angeles Basin areas of southern California. Aera operates more than 15,000 wells, producing approximately 130 thousand boe/d of heavy oil and gas.

Alaska

We have more than 410 federal leases for exploration in the Beaufort and Chukchi seas in Alaska. In January 2014, we decided to suspend our 2014 drilling campaign due to obstacles raised by the Ninth Circuit Court of Appeal's decision with regard to the Department of the Interior's (DOI) 2008 oil and gas lease sale in the Chukchi Sea. In August 2014, we submitted an Exploration Plan for a two-rig programme in the Chukchi Sea. In November 2014, the DOI issued a draft Supplemental Environmental Impact Statement (SEIS) and the comment period closed in December 2014. We anticipate that the DOI will continue to work in accordance with their proposed timeline to complete the SEIS in sufficient time to allow us to pursue our plans to drill in 2015.

REST OF NORTH AMERICA

Shell also has interests in Mexico.

South America

BRAZIL

We are the operator of several producing fields in the Campos Basin, offshore Brazil. They include the Bijupirá and Salema fields (Shell interest 80%) and the BC-10 field (Shell interest 50%). We started production from the BC-10 Phase 2 project in October 2013, which reached peak production of 41 thousand boe/d in 2014. In 2013, we exercised our pre-emptive rights to acquire an additional 23% in the BC-10 project and in 2014 we sold a 23% interest to Qatar Petroleum International, which returned our interest to 50%.

We operate one block in the São Francisco onshore basin area (Shell interest 60%) and operate one offshore exploration block in the Santos Basin, BM-S-54 (Shell interest 80%). We also have an interest in one offshore exploration block in the Espirito Santo basins, BM-ES-27 (Shell interest 17.5%). In November 2014, we divested our 20% interest in BM-ES-23.

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

We have a 20% interest in a 35-year PSC to develop the Libra pre-salt oil field located in the Santos Basin.

In January 2015, we reached an agreement to divest our operating interest in our deep-water production asset Bijupira Salema, pending regulatory approvals.

REST OF SOUTH AMERICA

The acquisition of part of Repsol S.A.'s LNG portfolio was completed in January 2014, including LNG supply positions in Peru and Trinidad and Tobago, adding 7.2 mtpa of directly managed LNG volumes through long-term off-take agreements, including 4.2 mtpa of equity LNG plant capacity.

Shell also has interests in Argentina, Colombia, French Guiana and Venezuela.

Trading

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

SUMMARY OF PROVED OIL AND GAS RESERVES OF SHELL SUBSIDIARIES AND SHELL SHARE OF JOINT VENTURES AND ASSOCIATES [A][B] (AT DECEMBER 31, 2014) BASED ON AVERAGE PRICES FOR 2014

	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)[C]
Proved developed					
Europe	372	10,160	–	–	2,124
Asia	1,169	13,615	–	–	3,516
Oceania	51	1,831	–	–	367
Africa	534	1,162	–	–	734
North America					
USA	494	1,275	–	–	714
Canada	26	939	1,273	9	1,470
South America	51	42	–	–	58
Total proved developed	2,697	29,024	1,273	9	8,983
Proved undeveloped					
Europe	236	2,136	–	–	604
Asia	513	2,486	–	–	942
Oceania	89	4,247	–	–	821
Africa	157	1,459	–	–	409
North America					
USA	217	286	–	–	266
Canada	18	672	490	419	1,043
South America	12	6	–	–	13
Total proved undeveloped	1,242	11,292	490	419	4,098
Total proved developed and undeveloped					
Europe	608	12,296	–	–	2,728
Asia	1,682	16,101	–	–	4,458
Oceania	140	6,078	–	–	1,188
Africa	691	2,621	–	–	1,143
North America					
USA	711	1,561	–	–	980
Canada	44	1,611	1,763	428	2,513
South America	63	48	–	–	71
Total	3,939	40,316	1,763	428	13,081

[A] Includes 11 million boe of reserves attributable to non-controlling interest in Shell subsidiaries.
[B] Oceania includes Shell's 14% share of Woodside, a publicly listed company on the Australian Securities Exchange. Shell has no access to data at December 31, 2014; accordingly, the numbers are estimated.
[C] Natural gas volumes are converted to oil equivalent using a factor of 5,800 scf per barrel.

UPSTREAM CONTINUED

LOCATION OF OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES [A] (AT DECEMBER 31, 2014)

	Exploration	Development and/or production	Shell operator[B]
Europe			
Albania	■		
Denmark	■	■	
Germany	■	■	
Greenland	■		■
Ireland		■	■
Italy		■	
Netherlands	■	■	■
Norway	■	■	■
UK	■	■	■
Ukraine	■		■
Asia [C]			
Brunei	■	■	■
China	■	■	■
Indonesia	■	■	
Iraq		■	■
Jordan	■		■
Kazakhstan	■	■	
Malaysia	■	■	■
Oman	■	■	
Philippines	■	■	■
Qatar	■	■	■
Russia	■	■	■
Saudi Arabia	■		
Turkey	■		■
Oceania			
Australia	■	■	■
New Zealand	■	■	■
Africa			
Benin	■		
Egypt	■	■	
Gabon	■	■	■
Namibia	■		■
Nigeria	■	■	■
South Africa	■		■
Tanzania	■		
Tunisia	■		■
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.

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

$ MILLION	2014	2013
Oil and gas exploration and production activities		
Europe [A]	4,273	4,770
Asia	3,875	5,421
Oceania	5,068	6,237
Africa	2,825	2,639
North America – USA	8,210	9,155
North America – Canada	3,162	3,154
South America	1,109	4,158
Total	28,522	35,534
Other Upstream activities [B]	2,771	4,769
Total Upstream [C]	31,293	40,303

[A] Includes Greenland.
[B] Comprise LNG, GTL, trading and wind activities.
[C] See "Non-GAAP measures reconciliations" for a reconciliation to capital expenditure.

AVERAGE REALISED PRICE BY GEOGRAPHICAL AREA

OIL AND NATURAL GAS LIQUIDS $/BARREL

	2014		2013		2012	
	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	94.57	89.68	105.23	99.27	108.13	104.60
Asia	89.47	96.85	96.46	70.34	107.76	67.33
Oceania	82.26	88.07[A]	90.50	91.91[A]	91.62	90.14[A]
Africa	100.55	–	110.14	–	112.45	–
North America – USA	87.90	–	98.10[B]	–	103.59	110.00
North America – Canada	59.19	–	63.14	–	68.31	–
South America	88.68	–	97.17	94.01	100.01	97.33
Total	91.09	95.87	99.83[B]	72.69	107.15	76.01

[A] Includes Shell's 14% share of Woodside as from June 2014 (previously: 23% as from April 2012; 24% before that date), a publicly listed company on the Australian Securities Exchange. We have limited access to data; accordingly, the numbers are estimated.
[B] Average realised prices have been corrected from $101.00/b (USA) and $100.42/b (Total).

NATURAL GAS $/THOUSAND SCF

	2014		2013		2012	
	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	8.58	8.26	10.29	9.17	9.48	9.64
Asia	4.57	11.50	4.51	10.73	4.81	10.13
Oceania	10.49	11.01[A]	11.55	9.45[A]	11.14	9.48[A]
Africa	2.71	–	2.84	–	2.74	–
North America – USA	4.52	–	3.92	–	3.17	7.88
North America – Canada	4.39	–	3.26	–	2.36	–
South America	2.85	–	2.91	0.42	2.63	1.04
Total	5.68	9.72	5.85	9.72	5.53	9.81

[A] Includes Shell's 14% share of Woodside as from June 2014 (previously: 23% as from April 2012; 24% before that date), a publicly listed company on the Australian Securities Exchange. We have limited access to data; accordingly, the numbers are estimated.

SYNTHETIC CRUDE OIL $/BARREL

	2014	2013	2012
	Shell subsidiaries	Shell subsidiaries	Shell subsidiaries
North America – Canada	81.83	87.24	81.46

BITUMEN $/BARREL

	2014	2013	2012
	Shell subsidiaries	Shell subsidiaries	Shell subsidiaries
North America – Canada	70.19	67.40	68.97

UPSTREAM CONTINUED

AVERAGE PRODUCTION COST BY GEOGRAPHICAL AREA

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

	2014		2013		2012	
	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	19.47	4.25	17.66	3.57	14.50	3.56
Asia	7.87	7.62	6.52	5.74	7.53	4.71
Oceania	13.62	14.44[B]	11.55	13.17[B]	9.06	16.97[B]
Africa	14.86	–	14.43	–	9.52	–
North America – USA	21.35	–	21.57	–	20.09	18.24
North America – Canada	22.96	–	22.20	–	19.47	–
South America	25.26	–	37.72	16.96	16.36	11.01
Total	15.10	6.68	14.35	5.52	12.47	6.05

[A] Natural gas volumes are converted to oil equivalent using a factor of 5,800 scf per barrel.
[B] Includes Shell's 14% share of Woodside as from June 2014 (previously: 23% as from April 2012; 24% before that date), a publicly listed company on the Australian Securities Exchange. We have limited access to data; accordingly, the numbers are estimated.

SYNTHETIC CRUDE OIL — $/BARREL

	2014	2013	2012
	Shell subsidiaries	Shell subsidiaries	Shell subsidiaries
North America – Canada	42.46	41.81[A]	43.40[A]

[A] Average production costs have been corrected from $38.22/b (2013) and $40.40/b (2012).

BITUMEN — $/BARREL

	2014	2013	2012
	Shell subsidiaries	Shell subsidiaries	Shell subsidiaries
North America – Canada	23.24	23.03	24.11

OIL AND GAS PRODUCTION (AVAILABLE FOR SALE)

CRUDE OIL AND NATURAL GAS LIQUIDS [A] THOUSAND BARRELS

	2014		2013		2012	
	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	18,834	–	20,927	–	26,748	–
Italy	11,792	–	11,997	–	14,127	–
Norway	14,893	–	14,589	–	14,568	–
UK	14,746	–	14,445	–	22,075	–
Other [B]	849	1,986	934	1,952	1,031	1,592
Total Europe	61,114	1,986	62,892	1,952	78,549	1,592
Asia						
Brunei	648	18,576	564	20,011	663	26,521
Iraq	19,218	–	8,416	–	2,032	–
Malaysia	16,754	–	15,441	–	14,916	–
Oman	74,781	–	74,527	–	75,075	–
Russia	23,579	10,403	25,152	10,527	–	38,180
United Arab Emirates	–	2,397	–	58,104	–	53,103
Other [B]	27,165	8,115	25,202	8,155	19,668	8,341
Total Asia	162,145	39,491	149,302	96,797	112,354	126,145
Total Oceania	9,191	3,688	9,371	4,771	10,181	6,494
Africa						
Gabon	12,144	–	10,781	–	13,957	–
Nigeria	69,851	–	63,800	–	87,592	–
Other [B]	5,008	–	4,254	–	4,477	–
Total Africa	87,003	–	78,835	–	106,026	–
North America						
USA	98,895	–	86,670	–	56,630	24,540
Canada	8,389	–	7,626	–	5,456	–
Total North America	107,284	–	94,296	–	62,086	24,540
South America						
Brazil	16,575	–	7,706	–	12,628	–
Other [B]	361	–	273	3,327	330	3,495
Total South America	16,936	–	7,979	3,327	12,958	3,495
Total	443,673	45,165	402,675	106,847	382,154	162,266

[A] Includes natural gas liquids. Royalty sales are excluded. Reflects 100% of production attributable to subsidiaries except in respect of PSCs, where the figures shown represent the entitlement of the subsidiaries concerned under those contracts.
[B] Comprises countries where 2014 production was lower than 7,300 thousand barrels or where specific disclosures are prohibited.

UPSTREAM CONTINUED

NATURAL GAS [A]

MILLION STANDARD CUBIC FEET

	2014		2013		2012	
	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	49,708	–	53,283	–	73,809	–
Germany	66,718	–	73,123	–	79,558	–
Netherlands	–	581,028	–	721,344	–	661,548
Norway	252,284	–	256,396	–	260,742	–
UK	104,346	–	109,470	–	120,212	–
Other [B]	15,840	–	15,409	–	15,849	–
Total Europe	488,896	581,028	507,681	721,344	550,170	661,548
Asia						
Brunei	22,228	155,244	18,442	164,446	18,616	187,231
China	53,065	–	60,034	–	48,083	–
Malaysia	241,908	–	238,940	–	209,505	–
Russia	4,170	128,175	4,261	126,764	–	136,702
Other [B]	420,169	118,198	378,412	115,469	291,132	115,870
Total Asia	741,540	401,617	700,089	406,679	567,336	439,803
Oceania						
Australia	132,801	87,830	125,654	100,707	128,869	88,834
New Zealand	69,052	–	61,407	–	66,627	–
Total Oceania	201,853	87,830	187,061	100,707	195,496	88,834
Africa						
Egypt	54,079	–	46,072	–	51,589	–
Nigeria	234,599	–	201,311	–	271,051	–
Total Africa	288,678	–	247,383	–	322,640	–
North America						
USA	360,846	–	394,538	–	388,647	1,816
Canada	214,756	–	231,897	–	225,265	–
Total North America	575,602	–	626,435	–	613,912	1,816
Total South America	12,449	–	11,896	444	16,213	377
Total	2,309,018	1,070,475	2,280,545	1,229,174	2,265,767	1,192,378

[A] Reflects 100% of production attributable to subsidiaries except in respect of PSCs, where the figures shown represent the entitlement of the companies concerned under those contracts.
[B] Comprises countries where 2014 production was lower than 41,795 million scf or where specific disclosures are prohibited.

SYNTHETIC CRUDE OIL

THOUSAND BARRELS

	2014	2013	2012
	Shell subsidiaries	Shell subsidiaries	Shell subsidiaries
North America – Canada	46,934	46,017	45,903

BITUMEN

THOUSAND BARRELS

	2014	2013	2012
	Shell subsidiaries	Shell subsidiaries	Shell subsidiaries
North America – Canada	5,779	6,903	7,401

LNG AND GTL PLANTS AT DECEMBER 31, 2014

LNG LIQUEFACTION PLANTS IN OPERATION

	Location	Shell interest (%)[A]	100% capacity (mtpa)[B]
Atlantic LNG	Point Fortin	20-25	14.8
Australia North West Shelf	Karratha	19	16.3
Australia Pluto 1	Karratha	12	4.3
Brunei LNG	Lumut	25	7.8
Malaysia LNG (Dua) [C]	Bintulu	15	9.6
Malaysia LNG (Tiga)	Bintulu	15	7.7
Nigeria LNG	Bonny	26	22.0
Oman LNG	Sur	30	7.1
Peru LNG	Pampa Melchorita	20	4.5
Qalhat (Oman) LNG	Sur	11	3.7
Qatargas 4	Ras Laffan	30	7.8
Sakhalin LNG	Prigorodnoye	27.5	9.6

[A] Interest may be held via indirect shareholding.
[B] As reported by the operator.
[C] Our interest in the Dua plant is due to expire in 2015.

LNG LIQUEFACTION PLANTS UNDER CONSTRUCTION

	Location	Shell interest (%)	100% capacity (mtpa)
Gorgon	Barrow Island	25	15.3
MMLS LNG	Moveable units [A]	49	2.5
Prelude	Offshore Australia	67.5	3.6

[A] Location pending final investment decision.

GTL PLANTS IN OPERATION

	Country	Shell interest (%)	100% capacity (b/d)
Bintulu	Malaysia	72	14,700
Pearl	Qatar	100	140,000

EQUITY LNG SALES VOLUMES

SHELL SHARE OF EQUITY LNG SALES VOLUMES — MILLION TONNES

	2014	2013	2012
Australia	3.7	3.7	3.6
Brunei	1.5	1.7	1.7
Malaysia	2.7	2.6	2.5
Nigeria	5.0	4.4	5.1
Oman	1.8	2.0	1.9
Peru	0.8	–	–
Qatar	2.4	2.3	2.4
Sakhalin	2.9	2.9	3.0
Trinidad and Tobago	3.2	–	–
Total	24.0	19.6	20.2

UPSTREAM CONTINUED

EARNINGS AND CASH FLOW INFORMATION

2014 $ MILLION

					North America		South	
	Europe[A]	Asia	Oceania	Africa	USA	Other	America	Total
Revenue	17,891	35,629	3,299	11,129	13,553	9,250	1,548	92,299
Share of profit 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	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.

2013 $ MILLION

					North America		South	
	Europe[A]	Asia	Oceania	Africa	USA	Other	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	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.

2012								$ MILLION
					North America			
	Europe[A]	Asia	Oceania	Africa	USA	Other	South America	Total
Revenue	26,569	31,438	3,463	14,966	8,657	8,003	1,454	94,550
Share of profit of joint ventures and associates	1,667	3,866	395	950	1,150	25	(52)	8,001
Interest and other income	70	793	2,107	984	569	149	164	4,836
Total revenue and other income	28,306	36,097	5,965	16,900	10,376	8,177	1,566	107,387
Purchases excluding taxes	10,689	8,699	277	1,878	659	2,958	85	25,245
Production and manufacturing expenses	2,651	3,761	834	1,915	3,477	3,434	282	16,354
Taxes other than income tax	350	410	318	1,248	39	–	144	2,509
Selling, distribution and administrative expenses	843	196	4	3	126	19	20	1,211
Research and development	595	16	–	–	135	121	2	869
Exploration	398	460	175	699	802	372	198	3,104
Depreciation, depletion and amortisation	1,583	1,903	306	1,277	3,930	2,072	316	11,387
Interest expense	311	68	34	116	170	53	22	774
Income before taxation	10,886	20,584	4,017	9,764	1,038	(852)	497	45,934
Taxation	6,421	11,205	1,095	5,361	(121)	(408)	137	23,690
Income after taxation	4,465	9,379	2,922	4,403	1,159	(444)	360	22,244
Net cash from operating activities	6,677	11,457	2,107	6,615	4,483	1,047	675	33,061
Less: working capital movements	18	(587)	469	(410)	526	(73)	167	110
Net cash from operating activities excluding working capital movements	6,659	12,044	1,638	7,025	3,957	1,120	508	32,951

[A] Includes Greenland.

DOWNSTREAM

KEY STATISTICS			$ MILLION
	2014	2013	2012
Segment earnings [A]	3,411	3,869	5,382
Including:			
Revenue (including inter-segment sales)	378,046	404,427	424,410
Share of earnings of joint ventures and associates [A]	1,698	1,525	1,354
Production and manufacturing expenses	9,845	9,807	9,539
Selling, distribution and administrative expenses	12,489	13,114	12,860
Depreciation, depletion and amortisation	6,619	4,421	3,083
Net capital investment [B]	3,079	4,885	4,275
Refinery availability (%) [C]	94	92	93
Chemical plant availability (%) [C]	85	92	91
Refinery processing intake (thousand b/d)	2,903	2,915	2,819
Oil products sales volumes (thousand b/d)	6,365	6,164	6,235
Chemicals sales volumes (thousand tonnes)	17,008	17,386	18,669

[A] See Notes 2 and 4 to the "Consolidated Financial Statements". Segment earnings are presented on a current cost of supplies basis.
[B] See "Non-GAAP measures reconciliation".
[C] The basis of calculation differs from that used for the "Refinery and chemical plant availability" measure in "Performance indicators", which excludes downtime due to uncontrollable factors.

OVERVIEW

Shell's Downstream organisation is made up of a number of different 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, sulphur and liquefied petroleum gas (LPG). In addition, we produce and sell petrochemicals for industrial use worldwide.

Our Downstream activities comprise Refining, Pipelines, Marketing, Chemicals and Trading and Supply. Marketing includes Retail, Lubricants, Business to Business (B2B) and Alternative Energies. Chemicals has major manufacturing plants, located close to refineries, and its own marketing network. 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.

BUSINESS CONDITIONS

Industry refining margins were higher on average in 2014 than in 2013 in the key refining hubs of the USA and Singapore, and were little changed in Europe. In particular, margins improved in the USA where increased domestic crude oil and natural gas production lowered oil acquisition costs (relative to international prices). Some demand growth, especially around the summer driving season in the USA, also contributed to higher US Gulf Coast margins.

In 2015, increased demand for middle distillates is expected to be a key driver of refining margins, supported by demand for gasoline in the middle of the year. However, the overall outlook remains unclear because of continuing economic uncertainty, geopolitical tensions in some regions that could lead to supply disruptions and overcapacity in the global refining market.

In Chemicals, industry naphtha cracker margins increased from 2013, particularly in Asia where there was less cracker capacity available. US ethane cracker margins were high relative to naphtha cracker margins in other regions due to ample ethane supply. The outlook for petrochemicals for 2015 is dependent on the growth of the global economy, especially in Asia, and developments in raw material prices.

EARNINGS 2014-2013

Segment earnings are presented on a current cost of supplies basis (see "Summary of results"), which in 2014 were $4,366 million higher than earnings if presented on first-in, first-out basis (2013: $353 million higher). Segment earnings in 2014 were $3,411 million, 12% lower than 2013. Earnings in 2014 included net charges of $2,854 million, mainly impairments, and in 2013 included net charges of $597 million, described at the end of this section. Excluding the impact of these net charges, earnings in 2014 were 40% higher. The improvement was driven by higher realised refining margins from improved operating performance and a stronger industry environment, higher earnings from Trading and Supply, and lower costs mainly as a result of divestments. Partly offsetting these benefits were lower earnings from Chemicals, impacted by market conditions for intermediate products and shutdowns of some units at Moerdijk in the Netherlands.

Refining made a profit in 2014, compared with a loss in 2013. Realised refining margins were significantly higher overall and higher in all regions except the US West Coast. The increase was driven by operational improvements and stronger industry margin environments in most regions. In Europe, despite a slightly weaker margin environment, realised margins benefited from strong operational performances at the Pernis and Rheinland sites. Realised margins in Canada were higher in 2014 because the Scotford Upgrader was shut for part of 2013. US Gulf Coast realised margins benefited from improved operational performance. The margin environment in Asia improved. There was a loss of margins from the Geelong refinery in Australia which was sold in 2014. US West Coast realised margins were lower mainly due to a maintenance shutdown at Puget Sound in 2014. Motiva's performance was stronger in 2014 through both improved operational performance and a stronger margin environment. Overall refinery availability increased to 94% from 92% in 2013.

Trading and Supply earnings were significantly higher than 2013, benefiting from increased price volatility and profitable short positions in an oil market where prices declined during the second half of 2014.

Chemicals earnings were lower than in 2013, impacted by two incidents at Moerdijk that disrupted operations. The first, an explosion and fire at the MSPO2 unit, caused a partial shutdown of the site but had only limited financial impact. The second incident, a contamination of the steam boiler water feed, caused a temporary shutdown of all units for the fourth quarter of 2014 with more significant financial impact.

We expect a significant impact to earnings in 2015 from some units continuing to be non-operational. Additionally, earnings decreased for intermediate products due to weaker general market conditions compared with 2013. Sales prices were higher in 2013 due to industry supply constraints caused by competitor production outages.

Marketing earnings were higher than in 2013 across most businesses despite the divestment of businesses in Australia and Italy. Driving the improvement were stronger unit margins, helped by premium product pricing in Retail, active price management in Lubricants and LPG, and lower costs in Retail. Earnings from Raizen, our biofuels joint venture in Brazil, were higher than in 2013 despite the negative effects of the weakening Brazilian real, mainly as a result of stronger unit margins in the Marketing business.

Oil products sales volumes were 3% higher than in 2013. Higher Trading volumes more than offset lower Marketing volumes, which were impacted by the sale of businesses in Australia and Italy. Excluding these portfolio effects, Marketing volumes were similar to 2013.

Chemicals sales volumes were 2% lower than in 2013, mainly as a result of plant outages at Moerdijk. Chemicals plant availability decreased to 85% from 92% in 2013, mainly due to these outages.

Overall, operating expenses were 3% lower than in 2013. Production and manufacturing expenses were similar to 2013 as the effects of inflation and higher maintenance costs were offset by more favourable exchange rates and divestments. Selling, distribution and administrative expenses decreased due to divestments, reduced spending related to lower volumes in some businesses and more favourable exchange rates.

Depreciation, depletion and amortisation significantly increased in 2014 compared with 2013, mainly due to impairments described below. Excluding the impairments, depreciation decreased compared with 2013 due to divestments and reduced depreciation from impaired assets.

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.

Segment earnings in 2013 included a net charge of $597 million, resulting primarily from impairments and deferred tax adjustments which were partly offset by a beneficial tax rate change in the UK and gains on divestments.

EARNINGS 2013-2012

Segment earnings in 2013 were $3,869 million, 28% lower than in 2012. Segment earnings were 16% lower excluding the impact of the net charge of $597 million in 2013 described above and the net gain of $39 million in 2012 resulting from net gains on divestments and a tax credit, partly offset by legal and environmental provisions. The 16% decrease was mostly due to Refining making a loss, due to weaker margins, which was partly offset by higher contributions from Chemicals and Trading. Contributions from Marketing were broadly similar to 2012.

Realised refining margins were significantly lower than in 2012 due to a deterioration in industry conditions. Industry refining margins were lower in all regions, except for US Gulf Coast margins which were slightly higher. Lower US West Coast margins in 2013 reflected an excess supply of gasoline in the region. Margins in 2013 were also impacted by a narrower spread between the Brent and West Texas Intermediate (WTI) crude oil price benchmarks, as an expansion in pipeline capacity increased the ability to move oil from the landlocked area of Cushing, Oklahoma, where WTI is delivered. In Europe, margins remained weak due to: low regional demand; increased imports from Asia, Russia and the USA; and limited export opportunities to the USA due to high gasoline inventories there. Margins in Asia-Pacific were impacted by excess capacity and weak demand due to an economic slowdown.

NET CAPITAL INVESTMENT

Net capital investment was $3.1 billion in 2014 compared with $4.9 billion in 2013. The decrease was primarily due to higher divestment proceeds, which were $2.8 billion in 2014 compared with $0.6 billion in 2013.

Capital investment was $5.9 billion in 2014 compared with $5.5 billion in 2013. In Refining and Chemicals, it increased by $0.5 billion to $3.7 billion and in Marketing it decreased by $0.1 billion to $2.2 billion. In 2014, 54% of our capital investment was used to maintain the integrity and performance of our asset base, compared with 61% in 2013.

PORTFOLIO ACTIONS

In Pipelines, we formed Shell Midstream Partners, L.P. (see "Business and property – Pipelines" in this section).

In Lubricants, with our joint-venture partner Hyundai Oilbank, we opened a base oil manufacturing plant in Daesan, South Korea (Shell interest 40%). The plant has the capacity to produce some 13 thousand barrels of AP1 Group II base oils per day. The first batch of base oil was successfully blended in the Zhapu lubricant oil blending plant in China in August 2014. Shell will take a majority of the output from this plant in the first few years which will significantly increase the volume of Group II base oils for our supply chain in the region.

In Chemicals, Shell has taken full control of Ellba Eastern (Pte) Ltd, through the acquisition of the outstanding 50% interest. The company, which was already operated by Shell, produces styrene monomer and propylene oxide. The buyout enables integration with and optimisation of Shell's existing asset base on Jurong Island, in Singapore, allowing for future growth. With our partner Qatar Petroleum, we have decided not to proceed with the Al Karaana petrochemicals project in Qatar.

Our Raízen joint venture in Brazil has commissioned a second-generation biofuels plant, which will use technology from Iogen Energy to produce about 40 million litres of cellulosic ethanol a year from leaves, bark and other sugar cane waste. Additionally, Raizen acquired the fuel distributor Distribuidora Latina and its 200-plus retail stations.

We continued to review our portfolio to divest positions that fail to deliver competitive performance or no longer meet our longer-term strategic objectives.

We sold the majority of our Downstream businesses in Australia and Italy. In Australia we retained the aviation business; in Italy we retained the lubricants business.

We sold our shareholdings in the Kralupy and Litvinov refineries in the Czech Republic. We announced the intention to explore viable options for the Port Dickson refinery in Malaysia (Shell interest 51%), including the potential sale or conversion of operations to a storage terminal.

We signed an agreement to sell our retail, commercial fuels and bitumen businesses and supply terminals in Norway to ST1. They will continue to operate under the Shell brand. We intend to continue to

DOWNSTREAM CONTINUED

operate the aviation business as a joint venture with ST1. The Gasnor, marine and lubricants businesses are not included in the agreement.

We have announced our intention to sell the Fredericia refinery, retail, aviation and commercial fuels businesses in Denmark. We intend to continue to sell lubricants via a distributor.

BUSINESS AND PROPERTY

Refining

We have interests in 24 refineries worldwide with the capacity to process a total of over 3.1 million barrels of crude oil per day (Shell share). Approximately 35% of our refining capacity is in Europe and Africa, with 39% in the Americas and 26% in Asia and Oceania.

The Port Arthur refinery in Texas, USA, owned by Motiva Enterprises LLC (Shell interest 50%), is the largest refinery in North America and includes one of the world's largest single-site base oil manufacturing plants.

Pipelines

Shell Pipeline Company 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 3,800 miles of pipelines in the Gulf of Mexico and five US states. Our various non-operated ownership interests provide a further 8,000 pipeline miles and offer opportunities for sharing best practices with other pipeline operators.

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

Shell Midstream Partners L.P., was formed to own, operate, develop and acquire pipelines and other midstream assets, and was listed on the New York Stock Exchange under the ticker symbol "SHLX" on October 29, 2014. The partnership's initial assets, which include a portion of Shell's interest in four pipelines that transport crude oil and refined products offshore from the Gulf of Mexico and along the US Gulf Coast and East Coast, consist of interests in entities that own crude oil and refined products pipelines which serve as key infrastructure for transporting growing volumes of oil, produced onshore and offshore, to Gulf Coast refining markets. It also delivers refined products from those refineries to major demand centres. Shell controls the general partner and holds a majority share in the limited partnership.

Marketing

RETAIL

There were close to 43,000 Shell-branded retail stations in over 70 countries at the end of 2014. 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 60 countries.

LUBRICANTS

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

We lead the global market in branded lubricants. Our passenger car and heavy-duty engine oil brands are the most popular in the USA and China – the world's largest markets for lubricants.

We have a global lubricants supply chain with a network of eight base oil manufacturing plants, 50 lubricant blending plants, 18 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. We supply almost 100 grades of lubricants and 10 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.

Shell Aviation fuels more than 7,000 aircraft every day at approximately 800 airports in around 40 countries. On average, we refuel an aircraft every 12 seconds.

Shell Gas (LPG) provides liquefied petroleum gas and related services to retail, commercial and industrial customers for cooking, heating, lighting and transport.

Shell 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 environmental benefits, such as reduced emissions. We continue to pursue opportunities in the LNG for transport sector, developing projects that provide us and our customers with the best commercial value. Shell is the first customer of a new, dedicated LNG for transport infrastructure at the Gas Access to Europe (Gate) terminal in the port of Rotterdam in the Netherlands. Shell has committed to buy capacity from the Gate terminal, which has enabled investment in the terminal expansion.

Shell Bitumen supplies on average 11,000 tonnes of products every day to 1,600 customers worldwide and 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. We investigate alternative energy technologies with a long-term view to develop them into profitable business opportunities. We were one of the first companies to invest in advanced biofuels and 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 nearly 6 million tonnes of ethylene a year.

MARKETING

We sell petrochemicals to about 1,000 major industrial customers worldwide. Our Chemicals business is one of the top 10 chemicals enterprises in the world by revenue. Its products are used to make numerous everyday items, from clothing and cars to detergents and bicycle helmets.

Trading and Supply

We trade in physical and financial contracts, lease storage and transportation capacities, and manage shipping activities globally.

With more than 1,500 storage tanks and approximately 150 distribution facilities 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.

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".

Sudan

We ceased all operational activities in Sudan in 2008. We have, however, continued soil remediation in 2014 related to earlier operations in the country.

Syria

We are in compliance with all EU 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
	2014	2013	2012
Total	82.76	90.36	106.82

[A] Includes Upstream margin on crude oil supplied by Shell subsidiaries, joint ventures and associates.

CRUDE DISTILLATION CAPACITY [A]	THOUSAND B/CALENDAR DAY [B]		
	2014	2013	2012
Europe	1,033	1,033	1,084
Asia	810	810	664
Oceania	80	118	158
Africa	82	82	83
Americas	1,212	1,212	1,212
Total	3,217	3,255	3,201

[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		
	2014	2013	2012
Europe	1,659	1,659	1,659
Asia	1,922	1,922	1,922
Oceania	–	–	–
Africa	–	–	–
Americas	2,212	2,212	2,212
Total	5,793	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 as at December 31.

OIL PRODUCTS – CRUDE OIL PROCESSED [A]			THOUSAND B/D
	2014	2013	2012
Europe	941	1,010	1,069
Asia	688	706	761
Oceania	59	116	93
Africa	69	61	70
Americas	1,149	1,100	1,024
Total	2,906	2,993	3,017

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

REFINERY PROCESSING INTAKE [A]			THOUSAND B/D
	2014	2013	2012
Crude oil	2,716	2,732	2,620
Feedstocks	187	183	199
Total	2,903	2,915	2,819
Europe	941	933	970
Asia	639	634	520
Oceania	64	105	150
Africa	69	54	62
Americas	1,190	1,189	1,117
Total	2,903	2,915	2,819

[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
	2014	2013	2012
Gasolines	1,049	1,049	995
Kerosines	331	368	321
Gas/Diesel oils	1,047	1,014	996
Fuel oil	316	274	256
Other	395	389	452
Total	3,138	3,094	3,020

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

DOWNSTREAM CONTINUED

OIL PRODUCT SALES VOLUMES [A]	THOUSAND B/D		
	2014	2013	2012
Europe			
Gasolines	405	415	450
Kerosines	264	226	234
Gas/Diesel oils	841	962	909
Fuel oil	176	194	180
Other products	205	168	184
Total	1,891	1,965	1,957
Asia			
Gasolines	343	325	352
Kerosines	191	191	172
Gas/Diesel oils	515	483	515
Fuel oil	325	322	355
Other products	441	255	220
Total	1,815	1,576	1,614
Oceania			
Gasolines	52	87	93
Kerosines	48	51	48
Gas/Diesel oils	64	115	107
Fuel oil	–	–	4
Other products	10	19	26
Total	174	272	278
Africa			
Gasolines	36	45	58
Kerosines	9	9	16
Gas/Diesel oils	52	43	53
Fuel oil	–	3	9
Other products	7	15	13
Total	104	115	149
Americas			
Gasolines	1,268	1,149	1,123
Kerosines	206	234	264
Gas/Diesel oils	583	519	528
Fuel oil	68	96	89
Other products	256	238	233
Total	2,381	2,236	2,237
Total product sales [B]			
Gasolines	2,104	2,021	2,076
Kerosines	718	711	734
Gas/Diesel oils	2,055	2,122	2,112
Fuel oil	569	615	637
Other products	919	695	676
Total	6,365	6,164	6,235

[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] Certain contracts are held for trading purposes and reported net rather than gross. The effect in 2014 was a reduction in oil product sales of 1,067,000 b/d (2013: 921,000 b/d; 2012: 856,000 b/d).

CHEMICALS SALES VOLUMES [A]	THOUSAND TONNES		
	2014	2013	2012
Europe			
Base chemicals	3,287	3,423	3,771
First-line derivatives and others	2,019	2,281	2,626
Total	5,306	5,704	6,397
Asia			
Base chemicals	2,220	2,266	2,588
First-line derivatives and others	2,901	2,989	3,074
Total	5,121	5,255	5,662
Oceania			
Base chemicals	–	–	–
First-line derivatives and others	35	62	75
Total	35	62	75
Africa			
Base chemicals	–	–	–
First-line derivatives and others	43	47	54
Total	43	47	54
Americas			
Base chemicals	3,251	3,218	3,336
First-line derivatives and others	3,252	3,100	3,145
Total	6,503	6,318	6,481
Total product sales			
Base chemicals	8,758	8,907	9,695
First-line derivatives and others	8,250	8,479	8,974
Total	17,008	17,386	18,669

[A] Excludes feedstock trading and by-products.

MANUFACTURING PLANTS AT DECEMBER 31, 2014

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	63	40	–	–
Germany	Harburg	●	100	58	14	–	–
	Miro [C]		32	310	65	89	–
	Rheinland	■ ●	100	325	44	–	80
	Schwedt [C]		38	220	47	50	–
Netherlands	Pernis	■ ●	100	404	45	48	81
Asia							
Japan	Mizue (Toa) [C]	● ◆	18	64	24	38	–
	Yamaguchi [C]	◆	13	110	–	25	–
	Yokkaichi [C]	● ◆	26	234	–	55	–
Malaysia	Port Dickson	◆	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	462	77	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	71	5	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	79	63	53
	Port Arthur [C]	●	50	569	138	81	67
Washington	Puget Sound	● ◆	100	137	23	52	–

[A] Shell interest 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.

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

DOWNSTREAM CONTINUED

MAJOR CHEMICAL PLANTS IN OPERATION [A]

		Thousand tonnes/year, Shell share capacity				
	Location	Ethylene	Styrene monomer	Ethylene glycol	Higher olefins[B]	Additional products
Europe						
Germany	Rheinland	272	–	–	–	A
Netherlands	Moerdijk [C]	972	725	155	–	A, I
UK	Mossmorran [D]	415	–	–	–	–
	Stanlow [D]	–	–	–	330	I
Asia						
China	Nanhai [D]	475	320	175	–	A, I, P
Japan	Yamaguchi [D]	–	–	–	11	A, I
Saudi Arabia	Al Jubail [D]	366	400	–	–	A, O
Singapore	Jurong Island	281	1,069	1,005	–	A, I, P, O
	Pulau Bukom	800	–	–	–	A, I
Americas						
Canada	Scotford	–	485	520	–	A, I
USA	Deer Park	836	–	–	–	A, I
	Geismar	–	–	400	920	I
	Norco	1,376	–	–	–	A
Total		5,793	2,999	2,255	1,261	

[A] Shell share of capacity of subsidiaries, joint arrangements and associates (Shell and non-Shell operated), excluding capacity of the Infineum additives joint ventures.
[B] Higher olefins are linear alpha and internal olefins (products range from C6-C2024).
[C] Due to a fire and separate breakdown of the steam boilers in 2014, Moerdijk was not fully in operation at December 31, 2014.
[D] Not operated by Shell.

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

OTHER CHEMICAL LOCATIONS

	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 Aromatics, lower olefins.
I Intermediates.
O Other.

CORPORATE

EARNINGS			$ MILLION
	2014	2013	2012
Net interest and investment expense	(913)	(832)	(1,001)
Foreign exchange (losses)/gains	(263)	(189)	169
Other – including taxation	1,020	1,393	629
Segment earnings	(156)	372	(203)

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 the 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.

EARNINGS 2014-2012

Segment earnings for 2014 were a loss of $156 million, compared with a gain of $372 million in 2013 and a loss of $203 million in 2012.

Net interest and investment expense increased by $81 million between 2013 and 2014. 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. In 2013, net interest and investment expense decreased by $169 million compared with 2012. Interest expense was lower, mostly driven by an increase in the amount of interest capitalised due to the continued ramp-up of projects in Australia and the Gulf of Mexico, and an improvement in the liquidity premium associated with currency swaps. These effects were partly offset by lower interest income.

Foreign exchange losses of $263 million in 2014 (2013: losses of $189 million; 2012: gains of $169 million) were mainly due to the impact of exchange rates on non-functional currency loans and cash balances in operating units.

Other earnings decreased by $373 million in 2014 compared with 2013, mainly due to lower tax credits. In 2013, other earnings were $764 million higher than in 2012, mainly due to a Danish tax credit and the recharge to the business segments of certain costs which were previously reported in Corporate.

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.

Gearing, calculated 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%. During 2014, gearing ranged from 11.7% to 16.1% (2013: 9.1% to 16.1%). See Note 14 to the "Consolidated Financial Statements".

With respect to the objective of maintaining a strong balance sheet, our priorities for applying our cash are servicing debt commitments, paying dividends, investing for organic and inorganic growth, and returning surplus cash to our shareholders.

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.

Since the contribution of Upstream to earnings is larger than that of Downstream, changes affecting Upstream – particularly changes in realised crude oil and natural gas prices and production levels – have the largest impact on Shell's operating cash flow. While Upstream benefits from higher realised crude oil and natural gas prices, the extent of such benefit (and the extent of an impact from a decline in these 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 national oil and gas companies that have limited sensitivity to crude oil 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 Upstream earnings experienced in that period. In the longer term, replacement of proved oil and gas reserves will affect our ability to maintain or increase production levels in Upstream, which in turn will affect our cash flow and earnings.

In Downstream, changes in any one of a range of factors derived from either within the industry or the broader economic environment can influence 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 the industry refiners and product marketers in adjusting their operations. As a result, refinery and marketing margins fluctuate from region to region and from period to period. Downstream earnings are reported on a current cost of supplies basis, which excludes the effect of changes in the oil price on inventory carrying amounts. However, cash flow from operations is not affected by the reporting basis.

STATEMENT OF CASH FLOWS

Net cash from operating activities in 2014 was $45.0 billion, an increase from $40.4 billion in 2013. There was a cash inflow from working capital movements of $6.4 billion in 2014, compared with $2.9 billion in 2013. The decrease in net cash from operating activities in 2013 compared with 2012 ($46.1 billion) mainly reflected the reduction in earnings and lower dividends from joint ventures and associates

Net cash used in investing activities was $19.7 billion in 2014, a decrease from $40.1 billion in 2013. The decrease was mainly the result of lower capital expenditure ($8.3 billion) and higher proceeds from the sale of assets ($8.7 billion). The increase in net cash used in investing activities in 2013 compared with 2012 ($28.4 billion) was mainly the result of higher capital expenditure and lower proceeds from the sale of assets.

Net cash used in financing activities in 2014 was $12.8 billion (2013: $9.0 billion; 2012: $10.6 billion). This included payment of dividends to Royal Dutch Shell plc shareholders of $9.4 billion (2013: $7.2 billion; 2012: $7.4 billion), repurchases of shares of $3.3 billion (2013: $5.0 billion; 2012: $1.5 billion) and interest paid of $1.5 billion (2013: $1.3 billion; 2012: $1.4 billion), partly offset in 2014 by $1.0 billion received from the Shell Midstream Partners, L.P. initial public offering and by net debt issued of $0.4 billion (2013: net debt issued of $5.4 billion; 2012: issued debt offset by debt repaid).

Cash and cash equivalents were $21.6 billion at December 31, 2014 (2013: $9.7 billion; 2012: $18.6 billion).

CASH FLOW INFORMATION [A]			$ BILLION
	2014	2013	2012
Net cash from operating activities excluding working capital movements			
Upstream	33.3	28.8	32.9
Downstream	4.5	7.5	8.0
Corporate	0.8	1.2	1.8
Total	38.6	37.5	42.7
Decrease/(increase) in inventories	8.0	0.6	(1.7)
(Increase)/decrease in current receivables	(1.6)	5.6	14.1
Decrease in current payables	–	(3.3)	(9.0)
Decrease in working capital	6.4	2.9	3.4
Net cash from operating activities	45.0	40.4	46.1
Net cash used in investing activities	(19.7)	(40.1)	(28.4)
Net cash used in financing activities	(12.8)	(9.0)	(10.6)
Currency translation differences relating to cash and cash equivalents	(0.6)	(0.2)	0.2
Increase/(decrease) in cash and cash equivalents	11.9	(8.9)	7.3
Cash and cash equivalents at the beginning of the year	9.7	18.6	11.3
Cash and cash equivalents at the end of the year	21.6	9.7	18.6

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

FINANCIAL CONDITION AND LIQUIDITY

Our financial position is strong. In 2014, we generated a return on average capital employed (ROACE) of 7.1% (see "Return on average capital employed" in this section) and year-end gearing was 12.2% (2013: 16.1%). We returned $11.8 billion to our shareholders through dividends in 2014. Some of those dividends were paid out as 64.6 million shares issued to shareholders who had elected to receive new shares instead of cash. To offset the dilution created by the issuance of those shares, 87.7 million shares were repurchased and cancelled as part of our share buyback programme. In May 2014, we announced the cancellation of our Scrip Dividend Programme. As a result, the second and third quarter 2014 interim dividends have been, and the fourth quarter 2014 interim dividend will be, settled entirely in cash, rather than offering a share-based alternative. In March 2015, we announced that the Scrip Dividend Programme is being reintroduced with effect from the first quarter 2015 interim dividend onwards.

The size and scope of our businesses require a robust financial control framework and effective management of our various risk exposures. Financial turbulence in the eurozone and the USA, and other international events continue to put significant stress on the business environment in which we operate.

Our treasury and trading operations are highly centralised, and seek to manage credit exposures associated with our substantial cash, foreign exchange and commodity positions.

We diversify our cash investments across a range of financial instruments and counterparties in an effort to avoid concentrating risk in any one type of investment or country. We carefully monitor our investments and adjust them in light of new market information.

Exposure to failed financial and trading counterparties was not material in 2014 (see Note 19 to the "Consolidated Financial Statements").

Total employer contributions to our defined benefit pension plans in 2014 were $1.8 billion (2013: $2.6 billion) and are estimated to be $2.0 billion in 2015, reflecting current funding levels. See Notes 3 and 17 to the "Consolidated Financial Statements".

Cash and cash equivalents amounted to $21.6 billion at the end of 2014 (2013: $9.7 billion). Cash and cash equivalents are held in various currencies but primarily in dollars, euros and sterling. Total debt increased by $1.0 billion in 2014 to $45.5 billion at December 31, 2014. The total debt outstanding (excluding leases) at December 31, 2014, will mature as follows: 18% in 2015; 10% in 2016; 10% in 2017; 15% in 2018; and 47% in 2019 and beyond. The debt maturing in 2015 is expected to be repaid from a combination of cash balances and cash generated from operations.

We also maintain a $7.48 billion committed credit facility that was undrawn as at December 31, 2014. Following a one-year extension agreed in November 2014, the facility currently expires in 2019, but may in November 2015, by mutual agreement, be extended for one further year.

We believe our current working capital is sufficient for present requirements. We satisfy our funding and working capital requirements from the cash generated by our businesses and through the issuance of external debt. Our external debt is principally financed from the international debt capital 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;
- $25 billion euro medium-term note (EMTN) programme; and
- an unlimited US universal shelf (US shelf) registration.

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

Further information is included in Note 14 to the "Consolidated Financial Statements".

In 2014, we took advantage of relatively favourable market conditions in the European market (compared with the US market) and issued $6.4 billion of bonds under our EMTN programme, partly to pre-finance bond maturities in 2015. Periodically, for working capital purposes, we issued commercial paper (2013: we issued commercial paper and $7.75 billion of long-term bonds).

Our $7.48 billion committed credit facility and internally available liquidity provide back-up coverage for commercial paper. Other than certain borrowings in local subsidiaries, we do not have any other committed credit facilities. We consider additional facilities to be neither necessary nor cost-effective for financing purposes, given our size, credit rating and cash-generative nature.

The maturity profile of our outstanding commercial paper is actively managed in an effort to ensure that the amount of commercial paper maturing within 30 days remains consistent with the level of supporting liquidity.

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.

The consolidated ratio of earnings to fixed charges of Shell for each of five years ended December 31, 2010-2014, is as follows:

RATIO OF EARNINGS TO FIXED CHARGES

	2014	2013	2012	2011	2010
Ratio of earnings to fixed charges	14.41	20.11	31.12	35.71	21.75

For the purposes of the table above, earnings consist of pre-tax income from continuing operations (before adjustment for non-controlling interest) plus fixed charges (excluding capitalised interest) less undistributed income of joint ventures and associates. Fixed charges consist of expensed and capitalised interest (excluding accretion expense) plus interest within rental expenses (for operating leases). Refer to "Exhibit 7.1" regarding the calculation of the ratio of earnings to fixed charges.

LIQUIDITY AND CAPITAL RESOURCES
CONTINUED

CAPITALISATION TABLE	$ MILLION	
	Dec 31, 2014	Dec 31, 2013
Equity attributable to Royal Dutch Shell plc shareholders	171,966	180,047
Current debt	7,208	8,344
Non-current debt	38,332	36,218
Total debt [A]	45,540	44,562
Total capitalisation	217,506	224,609

[A] Of total debt, $39.5 billion (2013: $40.0 billion) was unsecured and $6.0 billion (2013: $4.6 billion) was secured. Further disclosure on debt, including the amount guaranteed by Royal Dutch Shell plc, is in Note 14 to the "Consolidated Financial Statements".

DIVIDENDS
Our policy is to grow the US dollar dividend through time in line with our view of Shell's 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 have announced an interim dividend in respect of the fourth quarter of 2014 of $0.47 per share, a 4.4% increase compared with the US dollar dividend for the same quarter of 2013. The Board expects that the first quarter 2015 interim dividend will be $0.47 per share, in line with the same quarter of 2014.

NET CAPITAL INVESTMENT
The reduction in net capital investment in 2014 compared with 2013 was driven by higher proceeds from divestments and lower capital investment. See "Non-GAAP measures reconciliations".

NET CAPITAL INVESTMENT	$ MILLION	
	2014	2013
Upstream	20,704	39,217
Downstream	3,079	4,885
Corporate	116	201
Total	23,899	44,303

PURCHASES OF SECURITIES
At the 2014 Annual General Meeting (AGM), shareholders granted an authority, which will expire at the end of the 2015 AGM, for the Company to repurchase up to 633 million of its shares. Under this authority, and a similar authority granted at the 2013 AGM, in 2014 we continued a share buyback programme to offset the dilution created by the issuance of shares under our Scrip Dividend Programme. All of the shares purchased under the buyback programme are cancelled. A resolution will be proposed at the 2015 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") 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 2014 and up to February 17, 2015, by the issuer and affiliated purchasers. Purchases in euros and sterling are converted into dollars using the exchange rate at each transaction date.

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

	A shares			B shares			A ADSs	
Purchase period	Number purchased for employee share plans	Number purchased for cancellation[C]	Weighted average price ($)[B]	Number purchased for employee share plans	Number purchased for cancellation[C]	Weighted average price ($)[B]	Number purchased for employee share plans	Weighted average price ($)[B]
2014								
January	–	–	–	–	10,838,990	37.58	938,671	70.81
February	–	–	–	–	14,335,172	38.02	–	–
March	–	–	–	–	7,254,411	38.97	–	–
April	–	–	–	–	–	–	–	–
May	–	3,900,000	39.68	–	–	–	–	–
June	–	5,566,873	40.35	–	–	–	–	–
July	–	4,758,786	40.97	–	–	–	–	–
August	–	5,611,290	40.01	–	–	–	–	–
September	300,000	11,000,929	38.80	784,300	–	39.64	79,073	76.29
October	123,925	21,734,700	35.61	2,058,620	–	31.16	–	–
November	–	–	–	–	–	–	–	–
December	283,600	2,705,000	32.21	149,740	–	35.18	89,253	68.30
Total 2014	707,525	55,277,578	37.72	2,992,660	32,428,573	37.70	1,106,997	71.00
2015								
January	–	12,717,512	32.15	–	–	–	1,133,754	65.00
February	–	–	–	–	–	–	–	–
Total 2015 [D]	–	12,717,512	32.15	–	–	–	1,133,754	65.00

[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.
[D] As at February 17, 2015.

CONTRACTUAL OBLIGATIONS

The table below summarises Shell's principal contractual obligations at December 31, 2014, 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]	6.7	7.7	8.7	15.0	38.1
Finance leases [B]	1.1	1.9	1.7	6.3	11.0
Operating leases [C]	5.7	9.1	6.1	9.9	30.8
Purchase obligations [D]	119.5	66.4	46.2	170.0	402.1
Other long-term contractual liabilities [E]	–	0.9	0.4	0.3	1.6
Total	133.0	86.0	63.1	201.5	483.6

[A] Contractual repayments excluding $6.7 billion of finance lease obligations. See Note 14 to the "Consolidated Financial Statements".
[B] Includes interest. See Note 14 to the "Consolidated Financial Statements".
[C] See Note 14 to the "Consolidated Financial Statements".
[D] Includes all significant items, including: fixed or minimum quantities to be purchased; fixed, minimum or any agreement to purchase goods and services that is enforceable, legally binding and specifies variable price provisions; and the approximate timing of the purchase.
[E] 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") and obligations associated with decommissioning and restoration (see Note 18 to the "Consolidated Financial Statements").

The table above excludes interest expense related to debt, which is estimated to be $1.1 billion payable in less than one year, $2.0 billion payable between one and three years, $1.5 billion payable between three and five years, and $7.1 billion payable 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, 2014, and that there is no change in the aggregate principal amount of debt other than repayment at scheduled maturity as reflected in the table.

GUARANTEES AND OTHER OFF-BALANCE SHEET ARRANGEMENTS

Guarantees at December 31, 2014, were $3.3 billion (2013: $3.1 billion). This includes $1.6 billion (2013: $2.2 billion) of guarantees of debt of joint ventures and associates, for which the largest amount outstanding during 2014 was $2.2 billion (2013: $2.2 billion).

RETURN ON AVERAGE CAPITAL EMPLOYED

ROACE measures the efficiency of Shell's utilisation of the capital that it employs. In this calculation, ROACE is defined as income for the period adjusted for after-tax interest expense as a percentage of the average capital employed for the period. The tax rate used is Shell's effective tax rate for the period. Capital employed consists of total equity, current debt and non-current debt.

CALCULATION OF RETURN ON AVERAGE CAPITAL EMPLOYED $ MILLION

	2014	2013	2012
Income for the period	14,730	16,526	26,960
Interest expense after tax	938	808	938
Income before interest expense	15,668	17,334	27,898
Capital employed – opening	225,710	213,936	197,141
Capital employed – closing	218,326	225,710	213,936
Capital employed – average	222,018	219,823	205,539
ROACE	7.1%	7.9%	13.6%

In 2014, about 32% of our average capital employed was not generating any revenue, which reduced our ROACE by approximately 4%. These assets included projects being developed and exploration acreage.

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" for separate financial statements for the Trust.

For the years 2014, 2013 and 2012 the Trust recorded income before tax of £2,470 million, £2,361 million and £2,383 million respectively. In each period this reflected the amount of dividends received on the dividend access share.

At December 31, 2014, the Trust had total equity of £nil (2013: £nil; 2012: £nil), reflecting cash of £1,497,815 (2013: £1,333,658; 2012: £1,202,271) and unclaimed dividends of £1,497,815 (2013: £1,333,658; 2012: £1,202,271). 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.

The Shell General Business Principles (Principles) include a commitment to sustainable development that involves balancing short- and long-term interests, and integrating economic, environmental and social aspects into our business decisions. We have rigorous standards and a firm governance structure in place to help manage potential impacts. We also work with communities, business partners, non-governmental organisations and other bodies to address potential impacts and share the benefits of our operations and projects.

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". Detailed data and information on our 2014 environmental and social performance will be published in April 2015 in the Shell Sustainability Report.

SAFETY

Sustaining our licence to operate depends on maintaining the safety and reliability of our operations. We manage safety risk across our businesses through 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 agencies to jointly test our plans and procedures. The 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. 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 workers 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.

While we continually work to minimise the likelihood of incidents, some do occur, for example, there was an explosion at our Moerdijk chemical site in the Netherlands in 2014. 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.

CLIMATE CHANGE

Growth in energy demand means that all sources of energy will be needed over the longer term. With hydrocarbons forecast to provide the bulk of the energy needed over coming decades, policymakers are focusing on regulations that balance energy demand with environmental concerns. The management of emissions of carbon dioxide (CO_2) will become increasingly important as concerns over climate change lead to tighter environmental regulation.

We already assess potential costs associated with CO_2 emissions when evaluating projects. However, in future, governments may increasingly impose a price on CO_2 emissions that relevant companies will have to incorporate in their investment plans and governments may also require companies to apply technical measures to reduce their CO_2 emissions. This could result in higher energy, product and project costs. Currently enacted, proposed and future legislation is also expected to increase the cost of doing business. Furthermore, in our own operations, we are working to understand the potential physical impact of climate change in the future on our facilities and new projects.

As energy demand increases and easily accessible oil and gas resources decline, we are developing resources that require more energy and require advanced technology to produce. As our production becomes more energy intensive, we expect there will be an associated increase in the direct CO_2 emissions from the Upstream facilities we operate.

We are seeking cost-effective ways to manage CO_2 emissions and see potential business opportunities in developing such solutions. Our main contributions to reducing CO_2 emissions are in four areas: supplying more natural gas; supplying more biofuels; progressing carbon capture and storage (CCS) technologies; and implementing energy efficiency measures in our operations. To support this, we continue to advocate the introduction of effective carbon pricing.

According to the International Energy Agency (IEA), almost 40% of global primary energy is currently used to generate electricity. For many countries, using more gas in power generation instead of coal can make the largest contribution, at the lowest cost, to meeting their CO_2 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 beyond 2020. With Shell's leading position in liquified natural gas (LNG) and new technologies for recovering gas from tight rock formations, we can supply natural gas to replace coal in power generation.

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 in Brazil produces low-carbon biofuel from sugar cane. We are also investing in research to help develop and commercialise advanced biofuels.

The IEA has stated that CCS could contribute around 15% of the CO_2 mitigation effort required by 2050. To advance CCS technologies, Shell is involved in CCS projects including the Quest project in Canada, the Mongstad test centre in Norway and the Gorgon CO_2 injection project in Australia. In 2012, we submitted a proposal for a project in Peterhead, in the UK, to store CO_2 in a depleted gas reservoir in the North Sea. In 2014, Shell signed an agreement with the UK government to progress detailed design of the Peterhead CCS project. It could potentially capture and store around 10 million tonnes of CO_2 over 10 years from a gas-fired power station. These projects are part of an important demonstration phase for CCS, during which government support is essential. Initiatives such as the European Union's acceptance of CCS as an offsetting activity under the Clean Development Mechanism are a positive step in progressing such technologies.

We continue to work on improving energy efficiency at our oil and gas production projects, oil refineries and chemical plants. Measures include our CO_2 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 CO_2 emissions, including through the development and sale of advanced fuels and lubricants.

Our direct greenhouse gas (GHG) emissions increased from 73 million tonnes of CO_2 equivalent in 2013 to 76 million in 2014. The increase in flaring, or burning off, of gas in our Upstream business was the main contributor to this increase. 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 further in coming years if oil production increases.

Most of the increase in flaring in 2014 relates to Majnoon in Iraq in line with increased oil production. Majnoon represented around 35% of our flaring in 2014. We have agreed two projects to capture most of the associated gas from future production. The first project is scheduled to be completed in 2015. We expect lower flaring levels starting in 2016 when gas gathering equipment is operational.

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-operated oil fields in southern Iraq (Rumaila, West Qurna 1 and Zubair) for use in the domestic market.

Around 30% of our flaring takes 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 joint arrangement operated by Shell Petroleum Development Company of Nigeria Ltd (SPDC) – has slowed progress on projects that are expected to gather additional associated gas currently flared.

Greenhouse gas emissions data are provided below in accordance with UK regulations introduced in 2013. Greenhouse gas emissions comprise carbon dioxide, 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/OGP) indicate that a number of sources of uncertainty can contribute to the overall uncertainty of a corporate emissions' inventory.

GREENHOUSE GAS EMISSIONS

	2014	2013
Emissions (million tonnes of CO_2 equivalent)		
Direct [A]	76	73
Energy indirect [B]	10	10
Intensity ratios (tonne/tonne)		
All facilities [C]	0.23	0.22
Downstream refineries [D]	0.29	0.30
Upstream facilities [E]	0.14	0.12

[A] Emissions from the combustion of fuel and the operation of facilities.
[B] Emissions from the purchase of electricity, heat, steam and cooling for our own use.
[C] In tonnes of total direct and energy indirect 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 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/OGP) 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 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 emissions per tonne of oil and gas produced. The ratio excludes gas-to-liquids facilities.

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.

Shell 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 a spill. 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 worldwide response capability. This is also supported by our global Oil Spill Excellence Center, which tests local capability, and maintains Shell's capability globally to respond to a significant incident.

Shell is 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, Shell was 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.

Shell also maintains 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 2014, the number of operational spills of more than 100 kilograms decreased to 153 from 174 in 2013. At the end of February 2015, there were three 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, regardless of the cause, originating in the area immediately surrounding its pipelines and other facilities. 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.

In January 2015, SPDC announced a £55 million settlement agreement with the Bodo community in respect of two operational spills in 2008. The settlement provides for an individual payment to each claimant who accepts the agreement in compensation for losses arising from the spills, up to £35 million in total. The remaining £20 million payment will be made for the benefit of the Bodo community generally. In 2009, clean-up work took place, but we were prevented from accessing some of the spill sites by the community, and this area has subsequently seen additional spills as a result of oil theft and sabotage. Divisions within the community and the litigation process itself created further regrettable delays to the clean-up process. With the support of the former Dutch Ambassador to Nigeria and the involvement of the National Coalition on Gas Flaring and Oil Spills in the Niger Delta (a federation of 25 Niger Delta environmental non-governmental organisations), the community agreed to separate out the clean-up activity from the litigation. Despite some further delays caused

ENVIRONMENT AND SOCIETY CONTINUED

by intra-community divisions, we are pleased that a clean-up plan supported by the community is in place.

HYDRAULIC FRACTURING

Over the last decade, we have expanded our onshore oil and gas portfolio using advances in technology to access previously uneconomic tight-oil and gas resources, including those locked in shale formations.

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 mixture of water, sand and chemical additives at high pressure into a rock formation, creating tiny fissures through which oil and gas can flow. 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.

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.

To the extent allowed by our suppliers, Shell supports 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. Shell supports 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.

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. Shell analyses 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.

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. We have adopted a set of operating principles for all of our onshore tight-oil and gas operations. Our current standards meet or exceed the existing regulatory requirements of the jurisdictions where we operate.

OIL SANDS

We are developing mineable oil sands resources in Alberta, Canada. We use an aqueous extraction method (i.e. 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 some residual bitumen, water, sand, silt, clay particles and naturally occurring trace heavy metals. Tailings are stored in an above-ground tailings' facilities until the mined-out pit area can be backfilled with tailings materials and fluids. This in-pit backfilling process begins approximately eight to10 years after mining has started. This time allows for mining to progress enough to allow for containment to be built after the area is mined, and for tailings material to be placed as mining continues to advance. Tailings contain naturally occurring chemicals that are toxic. We monitor tailings continuously, assess their potential environmental impact, and take measures to protect wildlife and to mitigate the potential for contamination of surface water and groundwater.

In addition, tailings facilities serve an important purpose in the operation, as they allow water to be recycled, reducing the amount of water required 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 cover an area of 37 square kilometres. The increase in area from 24 square kilometres in 2014 aligns with the development plans for both project sites. Of the 37 square kilometres, six square kilometres are part of the in-pit backfilling process and two square kilometres have been allocated to processing or drying of fluid tailings as part of our atmospheric fines drying process. We estimate that the tailings' footprint will start to decrease between 2020 to 2025 as the external tailings facilities start to be reclaimed and tailings materials are deposited in pit as part of the in-pit backfilling process.

Alberta regulations require that the land which is disturbed must be reclaimed – for example, through revegetation or reforestation – to a capability equivalent to that which existed prior to development. Dried tailings can be blended and treated to produce material suitable for use in land reclamation. We continue to experience challenges with tailings that have a high percentage of fine particles and liquid content. We are working with the Alberta Government and the Alberta Energy Regulator to ensure that we are in compliance with all oil sands regulatory requirements, including those regarding tailings.

In late 2010, we found water at the bottom of a section of a pit at the Muskeg River Mine. The water was confirmed to be saline and to originate from a deep aquifer below the mine pit. Upon discovery, containment was built to ensure the water remained in the containment area. There has been no inflow from or outflow to the aquifer since January 2012 and the water is contained in the pit where it is continuously monitored and poses minimal risk to the environment or mine production processes. To enable use of the area where the inflow occurred, plans to manage the saline water are in development, including transferring this water to holding ponds where it would be stored and actively monitored while permanent solutions are being considered and is out of the way of the active mining/tailings backfilling area.

EXPLORATION IN ALASKA

We hold more than 410 federal leases for exploration in the Beaufort and Chukchi seas in Alaska. We previously operated for almost 50 years in Alaska, including in both these seas, until 1998. We are familiar with these shallow waters and the hydrocarbon reservoirs beneath them, which are of relatively low pressure.

In 2014, the US Coast Guard published its investigation on the 2012 grounding of the Kulluk mobile offshore drilling unit (MODU), which took place around 1,900 kilometres from the drilling site. The vessel was successfully recovered and ultimately recycled. There were no significant injuries or environmental damage associated with the grounding. Identified issues have been addressed. Enhancements to the programme based on lessons learned from 2012 operations include:

- The Kulluk has been replaced by the Transocean Polar Pioneer, which is a harsh weather semi-submersible drilling unit.
- Modifications and subsequent sea trials have been conducted on the Aiviq (towing vessel).
- Additional ships have been contracted to provide increased backup in operational support.
- An additional helicopter will be contracted to support aviation activities and provide further backup for air operations.
- Global guidelines for wet towing of MODUs have been developed. They include processes and procedures for towing MODUs including in harsh weather environments. Shell has shared these guidelines with the US Coast Guard towing task force referenced in the report.

We have strengthened our contractor management and Arctic organisation and, together with the contractors, improved our planning and processes.

To prepare for drilling off the coast of Alaska, we have developed a well intervention and oil spill response capability that includes capping and oil spill response vessels. The Arctic Containment System has been modified since 2012 and is expected to be available for the 2015 drilling season. Improvements have also been made to emergency response assets and additional equipment has been purchased to enhance response capabilities based on the lessons learned during the 2012 season. Maintenance and inventory of critical spare parts for the oil spill response equipment have been enhanced by utilising a dedicated maintenance and storage facility in Anchorage. We have a range of equipment and vessels necessary to respond to a spill 24 hours a day in case a spill happens during our exploration season in Alaska in 2015.

WATER

Fresh water availability and water management are increasingly important strategic business issues for Shell and the energy industry in general, bringing both challenges and opportunities. Global demand for fresh water is growing while access to fresh water is becoming more constrained in some parts of the world.

Shell's water use may expand in the future with the further development of shale oil and gas, oil sands and our biofuel business. 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. Although the availability of fresh water is a global issue, water constraints are mainly local, requiring local solutions. In areas of water scarcity, we develop water management action plans and design our operations to minimise their water use.

For example, at Groundbirch, a tight-gas asset in Canada, we are recycling approximately 75% of the water produced. We also jointly commissioned a recycling water treatment plant with the Canadian City of Dawson Creek. The plant treats sewage wastewater for use by Shell and the community.

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. About 75% of the water we use is recycled and we are investigating new ways to further reduce fresh water intake.

Water is needed to produce ethanol and our biofuel joint venture Raízen has been introducing a system that recycles 90% of the water used in the industrial process.

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. Shell predicts that biofuels will increase from 3% of the global transport fuel mix today to around 10% by 2050. According to the IEA, sustainable biofuels are expected to play an increasingly important role in helping to meet our 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 2014, we used around 9 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 and, where possible, we source biofuels that have been certified against internationally recognised sustainability standards. 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.

We are also developing our own capabilities to produce sustainable biofuel components. The Raízen joint venture produces approximately 2 billion litres annually of ethanol from sugar cane in Brazil – the most sustainable and cost competitive of today's biofuels. 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 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 developing more advanced biofuels for the future. For example, in 2014 Raízen completed the construction of a commercial-scale pilot plant to produce second-generation bioethanol. This cellulosic ethanol will be generated from sugar cane by-product and therefore will have less impact on food and feed prices. Government support will be required to accelerate the speed of advanced biofuels development.

ENVIRONMENT AND SOCIETY CONTINUED

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 ability to do business and our reputation.

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 Shell, no assurance can be made 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. For example, after more than 60 years of developing the Groningen gas field in the Netherlands, seismic activity has increased leading to measurable earth tremors. Our Dutch joint venture Nederlandse Aardolie Maatschappij B.V. (NAM) has followed the production plan approved in 2014 by the Minister of Economic Affairs of the Netherlands. It is working with the government to identify effective responses and will follow any future requirements.

NEIGHBOURING COMMUNITIES AND HUMAN RIGHTS

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.

Shell has long been involved with developments in business and human rights in line with the United Nations' Guiding Principles on Business and 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.

We have specific policies in place in areas across Shell's 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, delivering projects without delays and minimising the social impacts of our operations. It also enables us to better share the benefits of our activities, such as creating new jobs and contracts that help develop local economies.

OUR PEOPLE

Our people are central to our aim of being the world's most competitive and innovative energy company. We recruit, train and recompense according to a people strategy based on three priorities: resourcing and developing talent now and in the future; strengthening leadership and professionalism; and enhancing individual and organisational performance.

EMPLOYEE OVERVIEW

In 2014, Shell employed an average of 94,000 people in more than 70 countries. We continued to recruit externally to execute our strategy and growth plans for the future, hiring about 1,200 graduates and 2,000 experienced professionals. The majority of each came from technical disciplines. More than 30% of our graduate recruits came from universities outside Europe and the Americas in response to increasing demand for skilled people in other regions.

The table below shows our average employee numbers by geographical area. The increase in 2014 compared with 2013 reflects our continuing growth strategy in Asia and the Americas.

EMPLOYEES BY GEOGRAPHICAL AREA (AVERAGE NUMBERS) THOUSAND

	2014	2013	2012
Europe	25	25	24
Asia	28	27	25
Oceania	2	3	3
Africa	3	3	3
North America	32	31	29
South America	4	3	3
Total	94	92	87

EMPLOYEE COMMUNICATION AND INVOLVEMENT

We strive to maintain a constructive working environment with employees and, where appropriate, employee representative bodies. However, collective bargaining negotiations can result in disputes, strikes or work stoppages, such as the United Steelworkers union strike initiated on February 1, 2015 , at the Deer Park refinery and laboratory in Texas, USA. While talks are ongoing, we look forward to reaching a mutually acceptable settlement.

Two-way dialogue between management and staff is embedded in our work practices. On a quarterly basis, management briefs employees on Shell's operational and financial results through various channels, including team meetings, face-to-face gatherings, a personal 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 2014 was 80% favourable, as it was in 2013.

We promote safe reporting of views about our processes and practices. In addition to local channels, our global telephone helpline and website enable employees to report potential breaches of the Shell General Business Principles and Code of Conduct, confidentially and anonymously, in a choice of several languages.

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 2014, the proportion of women in senior leadership positions was 18.1% compared with 17.2% in 2013. 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, 2014) NUMBER

	Men		Women	
Directors of the Company	9	75%	3	25%
Senior managers [A]	829	79%	217	21%
Employees (thousands)	66	71%	28	29%

[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.

With effect from 2014, we revised our local nationals representation metric to ensure it adequately takes account of the senior local nationals working overseas. In 20 selected key business countries, we began measuring local national coverage, which is defined as the number of senior local nationals (both those working in the respective country and those expatriated) as a percentage of the number of senior leadership positions in their base country.

LOCAL NATIONAL COVERAGE (AT DECEMBER 31, 2014)

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

EMPLOYEE SHARE PLANS

Shell has a number of share plans designed to align employees' interests with Shell's performance through share ownership. For information on the share-based compensation plans for Executive Directors, see the "Directors' Remuneration Report".

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 will receive 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", 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".

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.

Strategic Report signed on behalf of the Board

/s/ Michiel Brandjes

Michiel Brandjes
Company Secretary
March 11, 2015