Tullow Oil plc

2017 FULL YEAR RESULTS

7 February 2018

Tullow Oil plc – 2017 Full Year Results

$1.7 billion sales revenue; $543 million free cash flow; 2.6x gearing ratio
Kenya's potential confirmed; proposed First Oil in early 2020s
Exploration portfolio fully re-set: multiple high impact campaigns over next three years

7 February 2018 – Tullow Oil plc (Tullow), the independent oil and gas exploration and production group, announces its full year results for the year ended 31 December 2017. Details of a presentation in London, webcast and conference calls are available on the last page of this announcement or visit the Group's website www.tullowoil.com.

COMMENTING TODAY, PAUL McDADE, CHIEF EXECUTIVE OFFICER, SAID:

"I am pleased to report that Tullow made excellent progress in 2017 as demonstrated by our substantial free cash flow generation and significantly reduced gearing. Strong production and disciplined cost management has allowed us to continue to both reduce debt and invest in our high-return production assets in Ghana. The assessment of the results from our appraisal campaign in Kenya also fully supports progress towards a major development of the South Lokichar Basin. As we continue to retain a keen focus on the financial discipline that has served us so well, we are now also looking to grow the value of our business both through exploration, following a full re-set of the portfolio, and through other opportunities that the recovery in the sector will present."

2017 FULL YEAR RESULTS SUMMARY

- Revenue of $1.7 billion plus lost production insurance proceeds of $162 million; gross profit of $815 million; post tax loss of $189 million after write-offs and non-cash impairments; free cash flow of $543 million
- $2.5 billion RBL re-financed in November 2017; year-end 2017 net debt of $3.5 billion with facility headroom including free cash of $1.1 billion; net debt to adjusted EBITDAX gearing ratio of 2.6x
- 2017 capex of $225 million; 2018 capex forecast of $460 million (excluding Uganda expenditure of $110 million which will be repaid following completion of the Uganda farm-down)
- West Africa 2017 net working interest oil production, including production-equivalent insurance payments, averaged 89,100 bopd; 2018 production is expected to average between 82,000 and 90,000 bopd
- Incremental drilling programme due to start in February 2018; this additional well capacity combined with current strong production from both Jubilee and TEN fields will maximise and sustain production in the coming years
- Kenya resources assessment completed: 240 – 560 – 1,230 mmbo (1C–2C–3C) contingent recoverable resources from an overall discovered STOIIP of up to 4 billion barrels. Phased development is planned with FID in 2019 and First Oil in 2021/22
- Uganda deal completion expected in H1 2018; JV Partners working towards FID around mid-year
- Exploration portfolio now reset through disposals, farm-downs and the addition of significant new positions in Côte d'Ivoire and Peru. Multiple high impact exploration campaigns planned over next three years, starting with the high-impact Cormorant well in Namibia in H2 2018

FINANCIAL OVERVIEW

	FY 2017	FY 2016
Total revenue ($m)	1,723	1,270
Gross profit ($m)	815	547
Administrative expenses ($m)	(95)	(116)
Restructuring costs ($m)	(15)	(12)
Loss on disposal ($m)	(2)	(3)
Goodwill impairment ($m)	–	(164)
Exploration costs written off ($m)	(143)	(723)
Impairment of property, plant and equipment, net ($m)	(539)	(168)
Provision for onerous service contracts, net ($m)	1	(115)
Operating profit/(loss) ($m)	22	(755)
Loss after tax ($m)	(189)	(597)
Free cash flow ($m)	543	(792)

Board changes, AGM and dividend

On 11 January 2017, Tullow announced that Paul McDade, then Chief Operating Officer, was to be appointed as Chief Executive Officer (CEO) and Aidan Heavey, then CEO, was to be appointed as Chairman, effective after the Group's AGM on 26 April 2017. Simon Thompson, Chairman, and Ann Grant, Senior Independent Director (SID), retired at the AGM with Jeremy Wilson replacing Ms Grant as SID. Aidan Heavey was appointed Chairman of Tullow for a maximum of two years from taking office. Accordingly, the Nominations Committee have begun the process of finding a new Chairman and expect to make an appointment by the end of 2018. Ian Springett, Chief Financial Officer, retired from the Board in June 2017 due to ill-health and was replaced by Les Wood, previously Interim CFO and, before that, Vice-President, Commercial and Finance. On 6 February 2018, Anne Drinkwater informed the Board that she has decided not stand for re-election at the 2018 AGM and will therefore cease to be a Director with effect from the end of the AGM.

Tullow's AGM will take place on 25 April 2018 at 12pm at the Company's offices at Building 9, Chiswick Park, 566 Chiswick High Road, London, W4 5XT.

While significantly improved free cash flow is creating a broader range of options for Tullow in how it allocates capital, the Group is currently focused on investing in its portfolio of assets and debt reduction. Therefore, after careful consideration, the Board has recommended that no dividend is paid for 2017.

Operations review

Production

Tullow's West Africa 2017 oil production exceeded expectations for the year averaging 89,100 bopd. This includes 7,400 bopd of net production-equivalent payments received under Tullow's Corporate Business Interruption insurance for the Jubilee field. In Europe, working interest gas production performed in line with expectations with full year net production averaging 5,600 boepd. This brings Tullow's total average working interest production in 2017 to 94,700 boepd.

In 2018, working interest oil production, including production-equivalent insurance payments, is expected to average between 82,000 and 90,000 bopd. Working interest gas production, which includes TEN associated gas sales and the impact of the Netherlands assets sales in 2017, is expected to average between 3,500 and 4,500 boepd. This brings overall Group production guidance, for both oil and gas, to between 86,000 and 95,000 boepd.

WEST AFRICA

Gary Thompson, Executive Vice President for West Africa, commented today:

> *"Tullow's West African operations remain at the core of Tullow. In 2017, West Africa delivered over 89,000 bopd of high-margin, low-cost oil and in 2018 we will invest in Ghana to sustain this impressive performance over the coming years. Drilling is due to commence on the Ntomme field by the end of this month and we continue to evaluate the business case of procuring additional rig capacity. I have been particularly pleased by the performance of the TEN fields, with production exceeding 70,000 bopd for the last three months, especially given the delays on completing the development wells which resulted from the ITLOS drilling moratorium. I look forward to similarly strong performances from Jubilee, TEN and our other West African oil fields in 2018."*

Ghana

Jubilee

Full year 2017 gross production from the Jubilee field averaged 89,600 bopd (net: 31,800 bopd). Tullow's Corporate Business Interruption insurance has reimbursed 7,400 bopd of net production-equivalent insurance payments, bringing expected full year effective net production from Jubilee to 39,200 bopd. Gross production in the latter part of 2017 was consistently above 90,000 bopd and we expect to build on this as we commence drilling in 2018.

Turret Remediation Project

Following the discovery of the issue with the turret bearing of the Jubilee FPSO Kwame Nkrumah in 2016, Tullow has been able to continue efficient production operations while working on the permanent solution which involves converting the FPSO to a spread-moored vessel. The first phase of this work, involving the installation of a stern anchoring system, was completed in February 2017, after which the tugs maintaining the FPSO on heading control were removed.

Preparations continue in advance of the planned turret bearing stabilisation work in the first quarter of 2018. This work is expected to take place over two shut-down periods, totalling four-to-six weeks. A further planned shut-down of approximately three weeks is expected around year end 2018 to rotate the FPSO to its permanent heading and install the final spread mooring anchoring system.

Greater Jubilee Full Field Development Plan

The Government of Ghana approved the Greater Jubilee Full Field Development Plan in October 2017, allowing Tullow and its Joint Venture Partners to prepare for a multi-year incremental drilling programme to maximise and sustain oil production and gas export. The initial focus will be the drilling and completion of new wells in the Jubilee unit area that will make use of existing infrastructure, and the completion of a well previously drilled in the Mahogany discovery. 4D seismic acquired in the first half of 2017 is being used to optimise well locations and ongoing reservoir management.

Production in 2018

Tullow expects 2018 gross production from the Jubilee field to average 75,800 bopd (net: 26,900 bopd), which takes into account the planned shut-downs associated with the turret remediation work. Tullow's Corporate Business Interruption insurance cover, which compensates Tullow for lost production associated with the remediation works, is expected to reimburse Tullow 10,200 bopd of net production-equivalent insurance payments. Jubilee effective net production is therefore expected to average around 37,100 bopd for 2018.

TEN

The TEN fields performed well in 2017 with gross production exceeding initial guidance, averaging 56,000 bopd (net: 26,400 bopd). This strong performance was as a result of production and water injection optimisation which continues to be effective and the field has performed consistently above 70,000 bopd for the last three months. Production from the 11 wells drilled so far, indicate reserves estimates for both Ntomme and Enyenra to be in line with previous guidance.

In June 2017, a commissioning capacity test and facility blowdown was completed demonstrating that the FPSO can operate at its design capacity of 80,000 bopd and at higher rates as indicated by a 24-hour test conducted around 100,000 bopd. Final commissioning of the TEN FPSO was completed in the second half of 2017. The TEN gas manifold was also installed and commissioned in 2017 and a gas export trial to Ghana National Gas Company facilities was successfully completed. This connection will allow for the export and sale of TEN gas as well as the ability to supply gas in substitution for Jubilee gas during the planned Jubilee turret remediation shut-downs in 2018.

On 23 September 2017, the International Tribunal for the Law of the Sea (ITLOS) made its decision with regard to the maritime boundary dispute between Ghana and Côte d'Ivoire. The new maritime boundary, as determined by the tribunal, does not affect the TEN fields. Tullow subsequently received notification from the Government of Ghana to recommence drilling in the TEN fields and a multi-year incremental drilling programme will start this year, seeking to ramp up production from the TEN fields to utilise the full capacity of the FPSO and sustain this over a number of years.

In the last quarter of 2017, Tullow signed the TEN Associated Gas (TAG) Gas Sales Agreement with the Ghana National Petroleum Corporation and Tullow anticipates the start of gas sales from TEN in the first half of 2018. Gross gas sales equivalent to 4,200 boepd (net: 2,000 boepd) have been forecast for the year.

Production in 2018

Tullow expects 2018 gross oil production from the TEN fields to average 64,000 bopd (net: 30,200 bopd). During the year, the rig schedule and timing of drilling and completion operations will be optimised, providing upside potential to this initial estimate.

Ghana drilling in 2018

Tullow has secured the Maersk Venturer rig which is expected to start drilling later this month. The rig will be used across the TEN and Jubilee fields and has been contracted for up to four years with early termination provisions. The first well planned is an Ntomme production well in the TEN fields followed by a Jubilee production well located in the north-eastern area of the field. Work is ongoing to finalise the sequence of further wells to optimise output from both the Jubilee and TEN fields. Tullow and its Joint Ventures Partners continue to evaluate the business case for contracting a second rig that would allow the acceleration of drilling across both fields.

Non-operated Portfolio and Europe gas production

2017 West Africa net non-operated production exceeded expectations at 23,500 bopd. Net production in 2018 is expected to be around 19,100 bopd. The reduced year-on-year forecast is primarily due to natural decline as a result of sustained low investment levels during a period of low oil prices, combined with the exit from the M'Boundi field, Congo (Brazzaville), effective from July 2017, and the cessation of production at the Chinguetti field in Mauritania.

Full year gas production from Europe averaged 5,600 boepd in 2017, which includes production from Tullow's Netherlands assets prior to the completion of their sale in November 2017. In mid-2017 Tullow started the planning, engineering and procurement processes to decommission up to 10 operated wells in the UK Continental Shelf during 2018. Site surveys and other preparatory works will be undertaken during the first quarter of 2018, which will be followed by approximately six months of well plug and abandonment operations. Tullow expects annual production from its UK assets to average around 1,900 boepd in 2018, which takes into account cessation of production at the end of the third quarter of 2018, ahead of decommissioning activities.

EAST AFRICA

Mark MacFarlane, Executive Vice President for East Africa, commented today:

> *"The exploration and appraisal campaign in Kenya has confirmed the presence of substantial oil resources in the South Lokichar Basin. After over six years of hard work, we can now move forward to commercialising these low cost resources through a phased development of the basin involving a central processing facility and an export pipeline to the Kenyan coast. In 2018, we will focus on taking the project towards FID in 2019 with a prudent and flexible plan of execution that can take advantage of low oil services costs and deliver first oil and cash flow as soon as possible. With good progress being made in Uganda towards FID, East Africa is on the verge of becoming a major oil exporting region."*

Kenya

The South Lokichar basin appraisal programme has confirmed material oil resources to support substantial oil production and an export pipeline to the Kenyan coast pending a Final Investment Decision (FID) which is planned for 2019. The proposed development plan reflects the Partnership's desire to sanction the project in a manner that is commercially robust, ensures the earliest possible FID and First Oil and supports the required infrastructure given the location of the South Lokichar basin some 750 km from the Kenyan coast.

Appraisal campaign and resource estimates

A total of 21 appraisal wells have been drilled in the South Lokichar basin. Tullow has also conducted extended well tests, water injection tests, well interference tests and water-flood trials, all of which have proved invaluable for planning the development of the oil fields. The appraisal campaign has firmed up the Group's resource estimates and improved Tullow's understanding of the subsurface at the key producing fields.

Following a full assessment of all the exploration and appraisal data, Tullow estimates that the South Lokichar basin contains the following recoverable resources: 240 – 560 – 1,230 mmbo (1C–2C–3C) from an overall discovered STOIIP of up to 4 billion barrels. This estimate of recoverable resources is consistent with previous guidance provided during the exploration and appraisal phase (Pmean of 750 mmbo). The additional remaining conventional undrilled prospect inventory of the basin is approximately 230 mmbo risked mean recoverable, not including further potential in tight-oil plays in the future.

Development

Tullow and its Joint Venture Partners have proposed to the Government of Kenya that the Amosing and Ngamia fields should be developed as the Foundation Stage of the South Lokichar development. This stage would include a 60,000 to 80,000 bopd Central Processing Facility (CPF) and an export pipeline to Lamu. This approach brings significant benefits as it enables an early FID of the Amosing and Ngamia fields taking full advantage of the current low-cost environment for both the field and infrastructure development and provides the best opportunity to deliver First Oil in a timeline that meets the Government of Kenya (GoK) expectations. The installed infrastructure from this initial phase can then be utilised for the optimisation of the remaining South Lokichar oil fields, allowing the incremental development of these fields to be completed at a lower unit cost post-First Oil.

The Foundation Stage is currently planned to involve an initial 210 wells through 18 well pads at Ngamia and 70 wells through seven well pads at Amosing. This stage will target volumes of around 210 mmbo of the total estimated 2C resources of 560 mmbo and a plateau rate of 60,000 to 80,000 bopd. The incremental development of the remaining 2C resources and the significant upside potential is expected to increase plateau production to 100,000 bopd or greater. It is anticipated that the FEED and baseline Environmental and Social Impact Assessments (ESIA) for the foundation development will commence in the second quarter of 2018, with FID targeted for 2019 and First Oil for 2021/22. Total gross capex associated with the Foundation Stage is expected to be $2.9 billion, of which $1.8 billion is investment in the upstream and $1.1 billion is for the pipeline.

Tullow and its Joint Venture Partners, following the extended election period, have re-engaged with representatives of the Government of Kenya on the overall approach and timelines for progressing the development.

Early Oil Pilot Scheme (EOPS)

The EOPS Agreement between the Joint Venture Partners and the Government of Kenya was signed on 14 March 2017 allowing all EOPS upstream contracts to be awarded. Initial injectivity testing has started at Ngamia-11 and oil production and water injection facilities are being constructed in the field ready to commence production/injection in the first quarter of 2018. Oil produced is being initially stored until all necessary consents and approvals are granted and work is completed for the transfer of crude oil to Mombasa by road.

Uganda

Farm-down to Total and CNOOC

On 9 January 2017, Tullow announced that it had agreed to transfer 21.57% of its 33.33% Uganda interests to Total for a total consideration of $900 million. CNOOC subsequently exercised its pre-emption rights under the joint operating agreements to acquire 50% of the interests being transferred to Total on the same terms and conditions. Having signed pre-emption documents with its Joint Venture Partners and officially notified the Government of Uganda of the transaction, Tullow and its Joint Venture Partners are awaiting approval of the transaction from the Government of Uganda.

As previously disclosed, Tullow anticipates that the farm-down with Total and CNOOC will complete in the first half of 2018 with a cash payment of $100 million on completion and payment of the working capital completion adjustment and deferred consideration for the pre-completion period (including $60 million for the whole of 2017) being received at this time. A further $50 million cash consideration is due to be received when FID is achieved.

The Joint Venture Partners are also working towards reaching FID around mid-year 2018; at which point Tullow's second cash instalment from the farm-down will be due. In line with its post-transaction status, Tullow has been reducing its operational footprint in Uganda and is now fully prepared for a non-operated presence only.

Operational activity is continuing as planned, with FEED and ESIAs for both the upstream and pipeline progressing in line with the FID schedule. Discussions on the pipeline project continue amongst Joint Venture Partners and with both the Ugandan and Tanzanian Governments regarding the key commercial and transportation agreements.

East Africa Crude Oil Export Pipeline (EACOP)

The Governments of Uganda and Tanzania signed an Intergovernmental Agreement (IGA) for the pipeline, the critical infrastructure for this project, on 26 May 2017. This has secured the pipeline routing and allowed discussions to commence with the Governments of Uganda and Tanzania on the Host Government Agreements and other key commercial agreements.

NEW VENTURES

Ian Cloke, Executive Vice President for New Ventures, commented today:

"The New Ventures team has worked exceptionally hard over the past three years to re-set the exploration portfolio for the new industry environment. Through a series of farm-downs, country exits and large-scale licence acquisitions, we now have a prospect and lead inventory that sits in industry hot spots and in under-explored or emergent petroleum systems in geographies and geologies that we know well. Our high-impact, low-cost, basin-testing prospects across Africa and South America have been carefully screened, both technically and commercially, and we look forward to starting this new exploration cycle with the Cormorant well, offshore Namibia, later this year."

Africa

Côte d'Ivoire

Tullow has agreed terms to add a further two exploration licences in Côte d'Ivoire to its portfolio, CI-524 and CI-520. These licence awards have been approved by the Ivorian cabinet and formal signing is anticipated in the first quarter of 2018.

Block CI-524 sits alongside the maritime border with Ghana, next to Tullow's operated TEN fields. The initial work programme will include re-processing of the 3D seismic data before a decision is made whether to drill a well.

Block CI-520, once signed, completes the Group's coverage of a transform basin fault play built during 2017 when the Group was awarded a 90% interest in six onshore licences (CI-521, CI-522, CI-518, CI-519, CI-301 and CI-302). The Group plans to conduct a full tensor gradiometry gravity survey (FTG) across the 8,600 sq km onshore area in the first half of 2018, before acquiring 2D seismic in 2019.

Mauritania

In the second half of 2017, Tullow completed farm-downs in respect of its 90% interest in Block C-18 in Mauritania to Total, Kosmos and BP leaving Tullow with a 15% non-operated interest. This followed a 600 sq km 3D survey completed earlier in 2017. A two-year extension to the licence term was also granted. In December 2017, the new operator, Total, commenced a large 9,000 sq km 3D seismic survey which is expected to be completed in the first quarter of 2018. A further 3D survey in Block C-3 to cover new shallow water plays was completed in the fourth quarter of 2017. Both blocks offer potential drilling candidates for late 2019. Finally, Tullow relinquished its interest in Block C-10 at the end of November as insufficient commercial justification could be made to enter into a third phase of the licence.

Namibia

Tullow plans to drill the high-impact Cormorant prospect in the PEL37 licence in Namibia in the second half of 2018 and preparations for drilling are under way. The well will target light oil and there are a number of similarly-sized follow-up prospects in close proximity. Also in Namibia, Tullow agreed a farm-down of a 15% interest in the neighbouring PEL30 licence to ONGC Videsh in November 2017. The farm-down is subject to Government and partner approvals with completion expected in the first quarter of 2018. This followed the farm-down of a 30% interest in PEL37 in October 2017, also to ONGC Videsh.

Zambia

In Zambia, a 20,000 sq km FTG survey and passive seismic survey to cover frontier Tertiary age rift basins finished in October 2017 and the next steps are being evaluated.

South America

Peru

Tullow has agreed terms to add six new licences covering 28,000 sq km, offshore Peru, to its portfolio. The Group has concluded negotiations with Perupetro and agreed to acquire a 100% stake in Blocks Z-64, Z-65, Z-66, Z-67 & Z-68. The agreements are subject to final approval by the Peruvian Ministry of Energy and Mines and Ministry of Economy and Finance, with formal signing of the licences anticipated in the first quarter of 2018. Tullow has also agreed to acquire a 35% interest in Block Z-38 through a farm-down from Karoon Gas Australia, also subject to Government approval. The new oil prone acreage will complement the Group's South America position and contains a number of attractive prospects and leads. Block Z-38 is already covered by high quality 3D seismic and includes the Marina prospect which is a potential candidate for drilling in 2019.

Guyana

Tullow has agreed to increase its equity share in the Kanuku licence, offshore Guyana, from 30% to 37.5% in a farm-in deal with Repsol. The deal is subject to Government approval. Following acquisition of new 3D seismic on the licence in 2017, the JV Partnership is interpreting the data to firm up prospects for possible drilling in 2019 in this exciting area, up-dip from Exxon's Liza discovery.

Processing 3D seismic data acquired during 2017 on the Orinduik licence is also ongoing to mature and rank identified prospects.

Uruguay

In Uruguay, a 2,555 sq km 3D seismic survey was completed in 2017. The data from this survey is currently being processed.

Suriname

The Araku-1 well drilled in October 2017 in Block 54 in Suriname was unsuccessful, but did prove the presence of a new petroleum system in the Demerara plateau which is now being followed up. At a gross cost of $35 million (net: $11 million), Tullow demonstrated its ability to drill high-risk, wildcat frontier wells at appropriate equity and at low cost. A two-year extension was granted for the adjacent Block 47 where the Goliathberg prospect is a potential drilling candidate for 2019.

Jamaica

In November 2017, Tullow agreed, subject to Government approval, a farm-down of 20% of its 100% interest in the Walton Morant licence in Jamaica to United Oil & Gas plc. A nine-month extension to the licence term was also granted, enabling a 2,100 sq km 3D survey to commence in April 2018. This follows a successful 667 km 2D seismic survey in Jamaica in the first half of 2017.

Asia

Tullow is in the process of selling its Pakistan assets and expects to complete this process in 2018.

Europe

The Group completed its exit from Norway in 2017 allowing the New Ventures team to focus on Africa and South America

Finance review

Les Wood, Chief Financial Officer, commented today:

"Tullow's balance sheet is considerably stronger at the start of 2018 following the $0.75 billion Rights Issue, strong free cash flow generation of $543 million and delivery of key objectives, including the successful $2.5 billion refinancing. Our gearing is approaching our target level of below 2.5x Net Debt/EBITDAX providing the financial and operational flexibility we need to invest in our business. We have also driven down both our corporate and asset costs and have embedded financial discipline across the Group. Tullow is well placed to build on this strong financial platform in 2018."

Financial results summary	2017	2016	Change
Working interest production volume (boepd)[1]	87,300	67,100	30%
Sales volume (boepd)	82,200	59,900	37%
Realised oil price ($/bbl)	58.3	61.4	(5%)
Realised gas price (p/therm)	43	34	26%
Total revenue ($m)[2]	1,723	1,270	36%
Gross profit ($m)	815	547	49%
Underlying cash operating costs per boe ($/boe)[3,4]	11.1	14.3	22%
Exploration costs written off ($m)	143	723	80%
Impairment of property, plant and equipment, net ($m)	539	168	–
Operating profit/(loss) ($m)	22	(755)	–
Loss before tax ($m)	(299)	(908)	67%
Loss after tax ($m)	(189)	(597)	68%
Basic loss per share (cents)	(14.7)	(55.8)	74%
Capital investment ($m)[3,5]	225	857	74%
Adjusted EBITDAX ($m)[3]	1,346	941	43%
Net debt ($m)[3]	3,471	4,782	27%
Gearing (times)[3]	2.6	5.1	2.5
Free cash flow ($m)[3]	543	(792)	–

1. Including the impact of production-equivalent insurance payment barrels from the Jubilee field, Group working interest production was 94,700 boepd.
2. Total revenue does not include receipts for Tullow's corporate Business Interruption insurance of $162 million. This is included in Other Operating Income which is a component of Gross Profit
3. Underlying cash operating costs per boe, capital investment, adjusted EBITDAX, net debt, gearing and free cash flow are non-IFRS measures and are explained later in this section.
4. Excluding prior year accrual reversals, the underlying cash operating costs were $11.7/boe.
5. Capital investment excludes Ugandan expenditure of $58 million in 2017 that will, subject to completion of the farm-down, be offset by either the working capital completion adjustment or deferred consideration. It is also net of the reversal of $69 million of prior year accruals due to change in estimates.

Production and commodity prices

Working interest production averaged 87,300 boepd, an increase of 30% for the year (2016: 67,100 boepd). Including the impact of production-equivalent insurance payment barrels from the Jubilee field, working interest production averaged 94,700 boepd (2016: 71,700 boepd), an increase of 32%. The increase resulted from the first full year of production from the TEN fields and improved operational performance at Jubilee in response to implementation of the first phases of remediating the turret. This was offset by declines due to the disposal of the Netherlands assets during the year, as well as reductions across the non-operated West Africa portfolio.

The Group’s realised oil price after hedging was $58.3/bbl and $54.2/bbl before hedging (2016: $61.4/bbl and $41.7/bbl respectively). The increase in underlying oil prices reduced the net contribution of the realisation of hedges entered in to by the Group to total revenue. However, hedging remains a key element of the Group’s risk management strategy. The Group’s realised European gas price after hedging was 43 pence/therm (2016: 34 pence/therm), an increase of 27% driven by improvements in underlying European gas prices.

Underlying cash operating costs, depreciation, impairments, write-offs, and administrative expenses

Underlying cash operating costs amounted to $386 million; $11.1/boe (2016: $377 million; $14.3/boe). Underlying cash operating costs were net of $51 million of insurance proceeds (2016: $32 million). The decrease of 22% in underlying cash operating costs per boe was principally due to the impact of ongoing cost saving initiatives and increased working interest production volumes.

DD&A charges before impairment on production and development assets amounted to $574 million; $16.6/boe (2016: $449 million; $17.0/boe).

The Group recognised an impairment charge of $539 million in respect of 2017 (2016: $168 million) which reflects lower long-term oil and gas price forecasts than previous years. This is lower than the impairment charge of $642 million reported at the Half Year results, due to the lower Dated Brent forward curve at that time. The Group did not recognise any impairment of goodwill during the year as it was fully impaired in 2016 (2016: $164 million).

During 2017, exploration costs written off were $143 million and included $71 million in Mauritania due to a licence that was not renewed, $36 million due to the decision to exit Pakistan, $6 million on disposals of assets in the Netherlands, $10 million on unsuccessful drilling costs in Suriname, and $17 million of New Ventures activity. The total exploration costs written off, net of tax, were $139 million (2016: $424 million).

Administrative expenses of $95 million (2016: $116 million) include an amount of $33 million (2016: $41 million) associated with share-based payment charges. The Group is on track to generate savings, over three years to mid-2018, in excess of $650 million, ahead of the Company's original target of $500 million. Savings of $581 million have been achieved as at 31 December 2017.

During 2017, the Group recognised an income statement charge for restructuring costs of $15 million (2016: $12 million) relating to headcount reductions associated with organisation simplifications and certain country exits. This has been presented separately from administrative expenses in the income statement.

Provision for onerous service contracts

At the end of 2017, Tullow had provided $131 million (2016: $133 million) for onerous service contracts due to the reduction in planned future activity under those contracts. The changes in estimates for the provision resulted in an income statement credit in 2017 of $1 million (2016: charge of $115 million).

Derivative financial instruments

Tullow undertakes hedging activities as part of the ongoing management of its business risk to protect against volatility and to ensure the availability of cash flow for reinvestment in capital programmes that are driving business growth. From 2015 to 2017, this approach generated net revenue of c. $0.85 billion and the systematic approach will continue even as oil prices appear to be stabilising. The 2018 hedging programme protects 60% of group production at an average floor of $52/bbl, with 40% of group production capped through collars at an average of $75/bbl, 20% uncapped and fully exposed to the upside and the remaining 40% of production unhedged.

At 31 December 2017, the Group’s derivative instruments had a net negative fair value of $76 million (2016: positive $91 million), net of deferred premium. While all of the Group’s commodity derivative instruments currently qualify for hedge accounting, a pre-tax charge of $12 million (2016: credit of $18 million) in relation to the change in time value of the Group’s commodity derivative instruments has been recognised within finance costs in the income statement for 2017.

Hedge position at 31 December 2017	2018	2019	2020
Oil hedges			
Volume – bopd	45,000	22,232	997
Average floor price protected ($/bbl)	52.23	48.87	50.00

Net financing costs

Net financing costs for the year were $310 million (2016: $172 million). The increase in financing costs is associated with a decrease in the value of capitalised interest due to the completion of the TEN development in 2016, and the commencement of recording interest on obligations under the TEN FPSO finance lease. This was offset by a reduction in interest on borrowings due to a reduction in the average level of net debt in 2017 compared to 2016. Net financing costs include interest incurred on the Group’s debt facilities, foreign exchange gains/losses, the unwinding of discount on decommissioning provisions, and the net financing costs associated with finance lease assets, offset by interest earned on cash deposits and capitalised borrowing costs.

Taxation

The net credit of $111 million (2016: credit of $311 million) relates to a tax charge in respect of hedging profits, Gabon and Equatorial Guinea production activities offset by credits in respect of the Group's North Sea and Ghana production activities and non-recurring deferred tax credits associated with exploration write-offs and impairments.

The group's statutory effective tax rate for 2017 is 37.0 per cent (2016: 34.2 per cent). The increase in the tax rate for 2017 is mainly due to deferred tax credits associated with the impairment of property, plant, and equipment.

After adjusting for non-recurring amounts related to exploration write-offs, disposals, impairments and onerous lease provisions and their associated deferred tax benefit, the Group's adjusted tax rate is 23.8 per cent (2016: 23.3 per cent). The adjusted tax rate has remained relatively consistent due to the mix of profits, notably the impact of increased profits from overseas production taxed at higher rates offset by hedging profits and business interruption insurance proceeds taxed at the UK's effective corporate tax rate of 19.25%.

The Group's future statutory effective tax rate is sensitive to the geographic mix in which pre-tax profits and exploration costs written off arise. It is however expected that the adjusted tax rate should again broadly follow the UK's standard rate of corporation tax as more of the Group's profit is forecast to arise in the UK.

Loss after tax from continuing activities and loss per share

The loss for the year from continuing activities amounted to $189 million (2016: $597 million loss). Basic loss per share was 14.7 cents (2016: 55.8 cents loss).

Reconciliation of net debt

	$m
Year-end 2016 net debt	**4,782**
Sales revenue	(1,723)
Other operating income – lost production insurance proceeds	(162)
Operating costs	386
Operating expenses	199
Cash flow from operations	**(1,300)**
Movement in working capital	135
Tax received, net	(65)
Purchases of intangible exploration and evaluation assets and property, plant, and equipment	308
Other investing activities	(11)
Rights issue proceeds	(721)
Other financing activities	340
Foreign exchange gain on cash and debt	4
Year-end 2017 net debt	**3,471**

Capital investment

2017 capital investment (net of Uganda expenditure) amounted to $225 million, net of prior year accrual reversals of $69 million, (2016: $0.9 billion) with $127 million invested in development activities and $98 million invested in exploration and appraisal activities. More than 80% of the total was invested in Kenya and Ghana and over 90% was invested in Africa. Capital expenditure will continue to be carefully controlled during 2018. The Group's 2018 capital expenditure associated with operating activities is expected to total approximately $460 million. This total excludes $110 million of forecast Uganda expenditure which will be repaid from either the working capital completion adjustment or deferred consideration post the completion of the Uganda farm-down, which is expected in the first half of the year. The capex total comprises Ghana capex of c.$250 million, West Africa non-operated capex of c.$40 million, Kenya pre-development expenditure of c.$80 million and Exploration and Appraisal spend of c.$90 million.

At completion of the Uganda farm-down, Tullow is also due to receive $100 million cash consideration along with re-imbursement of 2017 capex of c.$60 million. A further $50 million cash consideration is due to be received when FID is achieved.

Portfolio management

Tullow's farm-down in Uganda continues to progress and the Joint Venture Partners await approval of the transaction from the Government of Uganda.

During 2017 Tullow also completed the sale of its remaining Dutch and Norwegian assets.

Credit Ratings

Tullow maintains corporate credit ratings with Standard & Poor's and Moody's Investors Service. In early January, Standard & Poor's announced that they had revised the outlook on Tullow's 'B' corporate credit rating to positive from stable. Moody's Investors Service upgraded Tullow's Corporate Family Rating to B1 from B2. Moody's Investors Service upgraded their ratings of Tullow's corporate bonds to B3 from Caa1.

Balance sheet

On 29 November 2017, Tullow announced that it had completed the refinancing of $2.5 billion of Reserves Based Lending ("RBL") credit facilities. The $2.5 billion of credit facilities are split between a commercial bank facility of $2.4 billion and an IFC facility of $100 million. The fully committed facilities are revolving with a three-year grace period and final maturity of November 2024. Tullow also decided to reduce the commitments of its Revolving Corporate Credit Facility to $600 million from $800 million, ahead of the scheduled amortisation that was due to occur in January 2018. As of year-end 2017, Tullow has total headroom including free cash of $1.1 billion with no material near-term debt maturities, and net debt of $3.5 billion.

During 2017, the Group's net debt to adjusted EBITDAX gearing ratio has reduced from 5.1x to 2.6x. This reduction has been driven by increased adjusted EBITDAX generated by the business of $1,346 million compared to $941 million in 2016 and lower net debt as a result of the significant free cash flow generated in 2017 and the $721m net proceeds from the Rights Issue. This takes Tullow close to its target gearing position of below 2.5x.

Liquidity risk management and going concern

The Group closely monitors and manages its liquidity headroom. Cash forecasts are regularly produced and sensitivities run for different scenarios including, but not limited to, changes in commodity prices and different production rates from the Group's producing assets. The Group had $1.1 billion of debt liquidity headroom and free cash at the end of 2017. The Group's forecasts show that the Group will be able to operate within its current debt facilities and have sufficient financial headroom for the 12 months from the date of approval of the 2017 Annual Report and Accounts.

Based on the analysis above, the Directors have a reasonable expectation that the Company has adequate resources to continue in operational existence for the foreseeable future. Thus they continue to adopt the going concern basis of accounting in preparing the annual Financial Statements.

2018 principal financial risks and uncertainties

The principal financial risks to performance identified for 2018 are:

- Inability to progress major portfolio options
- Disruption to business due to community/political/regulatory influence
- Failure to manage oil price risk
- Major process safety/equipment/EHS failures

Events since 31 December 2017

There has not been any event since 31 December 2017 that has resulted in a material impact on the year end results.

Non-IFRS measures

The Group uses certain measures of performance that are not specifically defined under IFRS or other generally accepted accounting principles. These non-IFRS measures include capital investment, net debt, gearing, adjusted EBITDAX, underlying cash operating costs and free cash flow.

Capital investment

Capital investment is a useful indicator of the Group's organic expenditure on exploration and appraisal assets and oil and gas assets incurred during a period. Capital investment is defined as additions to property, plant and equipment and intangible exploration and evaluation assets less decommissioning asset additions, capitalised share-based payment charge, capitalised finance costs, additions to administrative assets, Norwegian tax refund, and certain other non-cash capital expenditure.

	2017 $m	2016 $m
Additions to property, plant and equipment	887.7	818.5
Additions to intangible exploration and evaluation assets	319.0	291.4
Less		
Decommissioning asset additions	(33.6)	57.1
Finance lease asset additions	837.6	–
Capitalised share-based payment charge	0.3	2.7
Capitalised finance costs	66.5	138.8
Additions to administrative assets	7.0	1.6
Norwegian tax refund	2.1	50.5
Uganda capital investment	57.5	–
Other non-cash capital expenditure	44.7	2.2
Capital investment	**224.6**	**857.0**
Movement in working capital	16.3	122.1
Additions to administrative assets	7.0	1.6
Norwegian tax refund	2.1	50.5
Uganda capital investment	57.5	–
Cash capital expenditure per the cash flow statement	**307.5**	**1,031.2**

Net debt

Net debt is a useful indicator of the Group's indebtedness, financial flexibility and capital structure because it indicates the level of cash borrowings after taking account of cash and cash equivalents within the Group's business that could be utilised to pay down the outstanding cash borrowings. Net debt is defined as current and non-current borrowings plus unamortised arrangement fees and the equity component of any compound debt instrument less cash and cash equivalents. The Group's definition of net debt does not include the Group's finance leases as the Group's focus is the management of cash borrowings and a finance lease is viewed as deferred capital investment. The value of the Group's Finance Lease liabilities as at 31 December 2017 was $228.1 million current and $1,317.5 million non-current, it should be noted that these balances are recorded gross for operated assets and are therefore not representative of the Group's net exposure under these contracts.

	2017 $m	2016 $m
Current borrowings	–	591.5
Non-current borrowings	3,606.4	4,388.4
Unamortised arrangement fees	100.2	35.5
Equity component of convertible bonds	48.4	48.4
Less cash and cash equivalents	(284.0)	(281.9)
Net debt	**3,471.0**	**4,781.9**

Gearing and Adjusted EBITDAX

Gearing is a useful indicator of the Group's indebtedness, financial flexibility and capital structure and can assist securities analysts, investors and other parties to evaluate the Group. Gearing is defined as net debt divided by Adjusted EBITDAX. Adjusted EBITDAX is defined as loss from continuing activities less income tax credit, finance costs, finance revenue, (loss)/gain on hedging instruments, depreciation, depletion, amortisation, share-based payment charge, restructuring costs, gain/(loss) on disposal, goodwill impairment, exploration costs written off, impairment of property, plant and equipment net, provisions for inventory and provision for onerous service contracts. Adjusted EBITDAX therefore excludes interest on obligations under finance leases of $46.1 million, and interest income on amounts due from joint venture partners for finance leases of $21.0 million, as in assessing business performance, management considers lease payments in substance to represent deferred capital expenditure. Had these been included in the calculation of Adjusted EBITDAX, calculated Gearing would have been unchanged at 2.6x.

	2017 $m	2016 $m
Loss from continuing activities	(188.5)	(597.3)
Less		
Income tax credit	(110.6)	(311.0)
Finance costs	351.7	198.2
Finance revenue	(42.0)	(26.4)
Loss/(gain) on hedging instruments	11.8	(18.2)
Depreciation, depletion and amortisation	592.2	466.9
Share-based payment charge	33.9	43.9
Restructuring costs	14.5	12.3
Loss on disposal	1.6	3.4
Goodwill impairment	–	164.0
Exploration costs written off	143.4	723.0
Impairment of property, plant and equipment, net	539.1	167.6
Provision for onerous service contracts, net	(1.0)	114.9
Adjusted EBITDAX	**1,346.1**	**941.3**
Net debt	**3,471.0**	**4,781.9**
Gearing (times)	**2.6**	**5.1**

Underlying cash operating costs

Underlying cash operating costs is a useful indicator of the Group's underlying cash costs incurred to produce oil and gas. Underlying cash operating costs eliminates certain non-cash accounting adjustments to the Group's cost of sales to produce oil and gas. Underlying cash operating costs is defined as cost of sales less operating lease expense, depletion and amortisation of oil and gas assets, underlift, overlift and oil stock movements, share-based payment charge included in cost of sales, and certain other cost of sales. Underlying cash operating costs are divided by production to determine underlying cash operating costs per boe.

	2017 $m	2016 $m
Cost of sales	1,069.3	813.1
Less		
Operating lease expense	62.5	21.0
Depletion and amortisation of oil and gas assets	574.3	448.5
Underlift, overlift and oil stock movements	(2.3)	(76.5)
Share-based payment charge included in cost of sales	1.1	2.7
Other cost of sales	47.5	40.2
Underlying cash operating costs	**386.2**	**377.2**
Production (MMboe)	34.7	26.4
Underlying cash operating costs per boe ($/boe)	**11.1**	**14.3**

Excluding prior year accrual reversals, the underlying cash operating costs were $11.7/boe.

Free cash flow

Free cash flow is a useful indicator of the Group's ability to generate organic cash flow to fund the business and strategic acquisitions, reduce borrowings and available to return to shareholders through dividends. Free cash flow is defined as net cash from operating activities, net cash used in investing activities, net cash generated by financing activities and foreign exchange loss less repayment of bank loans, drawdown of bank loans and issue of convertible bonds.

	2017 $m	2016 $m
Net cash from operating activities	1,222.9	512.5
Net cash used in investing activities	(296.4)	(967.2)
Net cash (used in)/generated by financing activities	(927.9)	399.3
Foreign exchange gain/(loss)	3.5	(18.4)
Net proceeds from issue share capital	(768.1)	–
Repayment of bank loans	1,613.6	769.1
Drawdown of bank loans	(305.0)	(1,187.5)
Issue of convertible bonds	–	(300.0)
Free cash flow	**542.6**	**(792.2)**

Group income statement

Year ended 31 December 2017

	Notes	2017 $m	2016 $m
Continuing activities			
Sales revenue		1,722.5	1,269.9
Other operating income – lost production insurance proceeds	7	162.1	90.1
Cost of sales	5	(1,069.3)	(813.1)
Gross profit		815.3	546.9
Administrative expenses	5	(95.3)	(116.4)
Restructuring costs	5	(14.5)	(12.3)
Loss on disposal		(1.6)	(3.4)
Goodwill impairment		–	(164.0)
Exploration costs written off	9	(143.4)	(723.0)
Impairment of property, plant and equipment, net	10	(539.1)	(167.6)
Provision for onerous service contracts, net		1.0	(114.9)
Operating profit/(loss)		22.4	(754.7)
(Loss)/gain on hedging instruments		(11.8)	18.2
Finance revenue	6	42.0	26.4
Finance costs	6	(351.7)	(198.2)
Loss from continuing activities before tax		(299.1)	(908.3)
Income tax credit	8	110.6	311.0
Loss for the year from continuing activities		(188.5)	(597.3)
Attributable to:			
Owners of the Company		(189.5)	(599.9)
Non-controlling interest		1.0	2.6
		(188.5)	(597.3)
Loss per ordinary share from continuing activities		¢	¢
Basic	2	(14.7)	(55.8)
Diluted	2	(14.7)	(55.8)

Comparative basic and diluted loss per ordinary share from continuing activities have been re-presented as a result of the Rights Issue

Group statement of comprehensive income and expense

Year ended 31 December 2017

	2017 $m	2016 $m
Loss for the year	(188.5)	(597.3)
Items that may be reclassified to the income statement in subsequent periods		
Cash flow hedges		
Gain/(loss) arising in the year	6.7	(135.3)
Reclassification adjustments for items included in loss on realisation	(161.8)	(415.2)
Exchange differences on translation of foreign operations	9.0	17.1
Other comprehensive loss	(146.1)	(533.4)
Tax relating to components of other comprehensive loss	24.3	108.8
Net other comprehensive loss for the year	(121.8)	(424.6)
Total comprehensive expense for the year	(310.3)	(1,021.9)
Attributable to:		
Owners of the Company	(311.3)	(1,024.5)
Non-controlling interest	1.0	2.6
	(310.3)	(1,021.9)

Group balance sheet

As at 31 December 2017

	Notes	2017 $m	2016 $m
ASSETS			
Non-current assets			
Intangible exploration and evaluation assets	9	1,933.4	2,025.8
Property, plant and equipment	10	5,254.7	5,362.9
Investments		1.0	1.0
Other non-current assets	11	789.8	175.7
Derivative financial instruments		0.8	15.8
Deferred tax assets		724.5	758.9
		8,704.2	8,340.1
Current assets			
Inventories		168.0	155.3
Trade receivables		171.4	118.4
Other current assets	11	768.3	838.9
Current tax assets		57.7	138.3
Derivative financial instruments		1.8	91.7
Cash and cash equivalents		284.0	281.9
Assets classified as held for sale	12	873.1	837.1
		2,324.3	2,461.6
Total assets		11,028.5	10,801.7
LIABILITIES			
Current liabilities			
Trade and other payables	13	(1,025.6)	(916.1)
Provisions	14	(230.8)	(51.9)
Borrowings		–	(591.5)
Current tax liabilities		(45.0)	(83.1)
Derivative financial instruments		(53.1)	(5.9)
		(1,354.5)	(1,648.5)
Non-current liabilities			
Trade and other payables	13	(1,422.6)	(112.3)
Borrowings		(3,606.4)	(4,388.4)
Provisions	14	(801.6)	(1,106.7)
Deferred tax liabilities		(1,101.2)	(1,292.4)
Derivative financial instruments		(25.8)	(10.9)
		(6,957.6)	(6,910.7)
Total liabilities		(8,312.1)	(8,559.2)
Net assets		2,716.4	2,242.5
EQUITY			
Called up share capital		208.2	147.5
Share premium		1,326.8	619.3
Equity component of convertible bonds		48.4	48.4
Foreign currency translation reserve		(223.2)	(232.2)
Hedge reserve		(2.6)	128.2
Other reserves		740.9	740.9
Retained earnings		607.5	778.0
Equity attributable to equity holders of the Company		2,706.0	2,230.1
Non-controlling interest		10.4	12.4
Total equity		2,716.4	2,242.5

Group statement of changes in equity

Year ended 31 December 2017

	Called up share capital $m	Share premium $m	Equity component of convertible bonds $m	Foreign currency translation reserve[1] $m	Hedge reserve[2] $m	Other reserves[3] $m	Retained earnings $m	Total $m	Non-controlling interest $m	Total Equity $m
At 1 January 2016	147.2	609.8	–	(249.3)	569.9	740.9	1,336.4	3,154.9	19.8	3,174.7
Loss for the year	–	–	–	–	–	–	(599.9)	(599.9)	2.6	(597.3)
Hedges, net of tax	–	–	–	–	(441.7)	–	–	(441.7)	–	(441.7)
Currency translation adjustments	–	–	–	17.1	–	–	–	17.1	–	17.1
Issue of convertible bonds	–	–	48.4	–	–	–	–	48.4	–	48.4
Issue of employee share options	0.3	9.5	–	–	–	–	–	9.8	–	9.8
Vesting of PSP shares	–	–	–	–	–	–	(9.4)	(9.4)	–	(9.4)
Share-based payment charges	–	–	–	–	–	–	50.9	50.9	–	50.9
Distribution to non-controlling interests	–	–	–	–	–	–	–	–	(10.0)	(10.0)
At 1 January 2017	147.5	619.3	48.4	(232.2)	128.2	740.9	778.0	2,230.1	12.4	2,242.5
Loss for the year	–	–	–	–	–	–	(189.5)	(189.5)	1.0	(188.5)
Hedges, net of tax	–	–	–	–	(130.8)	–	–	(130.8)	–	(130.8)
Currency translation adjustments	–	–	–	9.0	–	–	–	9.0	–	9.0
Rights Issue	60.0	693.8	–	–	–	–	–	753.8	–	753.8
Issue of employee share options	0.7	13.7	–	–	–	–	–	14.4	–	14.4
Vesting of PSP shares	–	–	–	–	–	–	(15.2)	(15.2)	–	(15.2)
Share-based payment charges	–	–	–	–	–	–	34.2	34.2	–	34.2
Distribution to non-controlling interests	–	–	–	–	–	–	–	–	(3.0)	(3.0)
At 31 December 2017	208.2	1,326.8	48.4	(223.2)	(2.6)	740.9	607.5	2,706.0	10.4	2,716.4

1. *The foreign currency translation reserve represents exchange gains and losses arising on translation of foreign currency subsidiaries, monetary items receivable from or payable to a foreign operation for which settlement is neither planned nor likely to occur, which form part of the net investment in a foreign operation, and exchange gains or losses arising on long-term foreign currency borrowings which are a hedge against the Group's overseas investments.*
2. *The hedge reserve represents gains and losses on derivatives classified as effective cash flow hedges.*
3. *Other reserves include the merger reserve and the treasury shares reserve which represents the cost of shares in Tullow Oil plc purchased in the market and held by the Tullow Oil Employee Trust to satisfy awards held under the Group's share incentive plans.*

Group cash flow statement

Year ended 31 December 2017

	Notes	2017 $m	2016 $m
Cash flows from operating activities			
Loss before taxation		(299.1)	(908.3)
Adjustments for:			
Depreciation, depletion and amortisation		592.2	466.9
Loss on disposal		1.6	3.4
Goodwill impairment		–	164.0
Exploration costs written off	9	143.4	723.0
Impairment of property, plant and equipment, net	10	541.1	167.6
Provision for onerous service contracts, net	14	(1.0)	114.9
Payments under onerous service contracts	14	–	(132.0)
Decommissioning expenditure	14	(25.7)	(23.0)
Share-based payment charge		33.9	43.9
Loss/(gain) on hedging instruments		11.8	(18.2)
Finance revenue	6	(42.0)	(26.4)
Finance costs	6	351.7	198.2
Operating cash flow before working capital movements		1,307.9	774.0
Decrease/(increase) in trade and other receivables		122.0	(99.4)
Increase in inventories		(20.8)	(47.8)
Decrease in trade payables		(251.4)	(29.8)
Cash flows from operating activities		1,157.7	597.0
Income taxes received/(paid)		65.2	(84.5)
Net cash from operating activities		1,222.9	512.5
Cash flows from investing activities			
Proceeds from disposals		8.0	62.8
Purchase of intangible exploration and evaluation assets		(189.7)	(275.2)
Purchase of property, plant and equipment		(117.8)	(756.0)
Interest received		3.1	1.2
Net cash used in investing activities		(296.4)	(967.2)
Cash flows from financing activities			
Net proceeds from issue of share capital		768.1	9.9
Debt arrangement fees		(56.4)	(31.7)
Repayment of bank loans		(1,613.6)	(769.1)
Drawdown of bank loans		305.0	1,187.5
Issue of convertible bonds		–	300.0
Repayment of obligations under finance leases		(62.6)	(3.3)
Finance costs paid		(265.4)	(284.0)
Distribution to non-controlling interests		(3.0)	(10.0)
Net cash (used in)/provided by financing activities		(927.9)	399.3
Net decrease in cash and cash equivalents		(1.4)	(55.4)
Cash and cash equivalents at beginning of year		281.9	355.7
Foreign exchange gain/(loss)		3.5	(18.4)
Cash and cash equivalents at end of year		284.0	281.9

Notes to the preliminary financial statements

Year ended 31 December 2017

1. Basis of Accounting and Presentation of Financial Information

Whilst the financial information in this preliminary announcement has been prepared in accordance with International Financial Reporting Standards (IFRS) and International Financial Reporting Interpretation Committee (IFRIC) interpretations adopted for use by the European Union, with those parts of the Companies Act 2006 applicable to companies reporting under IFRS and with the requirements of the United Kingdom Listing Authority (UKLA) Listing Rules, this announcement does not contain sufficient information to comply with IFRS. The Group will publish full financial statements that comply with IFRS in March 2018.

The financial information for the year ended 31 December 2017 does not constitute statutory accounts as defined in sections 435 (1) and (2) of the Companies Act 2006. Statutory accounts for the year ended 31 December 2016 have been delivered to the Registrar of Companies and those for 2017 will be delivered following the Company's annual general meeting. The auditor has reported on these accounts; their reports were unqualified, did not include a reference to any matters to which the auditor drew attention by way of emphasis of matter and did not contain a statement under section 498 (2) or (3) of the Companies Act 2006.

The accounting policies applied are consistent with those adopted and disclosed in the Group's financial statements for the year ended 31 December 2016. There have been a number of amendments to accounting standards and new interpretations issued by the International Accounting Standards Board which were applicable from 1 January 2017, however these have not had a material impact on the accounting policies, methods of computation or presentation applied by the Group.

2. Loss per Share

Basic loss per ordinary share amounts are calculated by dividing net loss for the year attributable to ordinary equity holders of the parent by the weighted average number of ordinary shares outstanding during the year.

Diluted loss per ordinary share amounts are calculated by dividing net loss for the year attributable to ordinary equity holders of the parent by the weighted average number of ordinary shares outstanding during the year plus the weighted average number of ordinary shares that would be issued if employee and other share options or the convertible bonds were converted into ordinary shares. Due to losses incurred in 2017 and 2016 all potential ordinary shares are antidilutive.

Comparative basic and diluted earnings per share and weighted average number of shares have been re-presented as a result of the Rights Issue. The shares in issue have been amended by an adjustment factor to reflect the bonus element inherent in a discounted Rights Issue, and to allow meaningful comparison between periods.

3. 2017 Annual Report and Accounts

The Annual Report and Accounts will be mailed in March 2018 only to those shareholders who have elected to receive it. Otherwise, shareholders will be notified that the Annual Report and Accounts is available on the Group's website (www.tullowoil.com). Copies of the Annual Report and Accounts will also be available from the Company's registered office at Building 9, Chiswick Park, 566 Chiswick High Road, London W4 5XT.

4. Segmental reporting

The information reported to the Group's Chief Executive Officer for the purposes of resource allocation and assessment of segment performance is focused on three Business Delivery Teams, West Africa (including non-operated producing European assets), East Africa and New Ventures. Therefore the Group's reportable segments under IFRS 8 are West Africa; East Africa; and New Ventures. The following tables present revenue, loss and certain asset and liability information regarding the Group's reportable business segments for the years ended 31 December 2017 and 31 December 2016.

	West Africa $m	East Africa $m	New Ventures $m	Unallocated $m	Total $m
2017					
Sales revenue by origin	1,722.5	–	–	–	1,722.5
Other operating income – lost production insurance proceeds	–	–	–	162.1	162.1
Segment result	86.9	(2.2)	(133.9)	183.0	133.8
Loss on disposal of other assets					(1.6)
Unallocated corporate expenses					(109.8)
Operating profit					22.4
Loss on hedging instruments					(11.8)
Finance revenue					42.0
Finance costs					(351.7)
Loss before tax					(299.1)
Income tax credit					110.6
Loss after tax					(188.5)
Total assets	7,857.2	2,585.2	306.0	280.1	11,028.5
Total liabilities	(4,295.6)	(169.2)	(97.1)	(3,750.2)	(8,312.1)
Other segment information					
Capital expenditure:					
Property, plant and equipment	43.1	1.1	0.3	5.6	50.1
Intangible exploration and evaluation assets	5.5	257.5	56.0	–	319.0
Depreciation, depletion and amortisation	(577.1)	(0.5)	–	(14.6)	(592.2)
Impairment of property, plant and equipment, net	(539.1)	–	–	–	(539.1)
Exploration costs written off	(6.9)	(2.3)	(134.2)	–	(143.4)

Capital expenditure on property, plant, and equipment excludes the addition of the TEN FPSO right of use asset of $837.6 million.

4. Segmental reporting contd.

	West Africa $m	East Africa $m	New Ventures $m	Unallocated $m	Total $m
2016					
Sales revenue by origin	1,269.9	–	–	–	1,269.9
Other operating income – lost production insurance proceeds	–	–	–	90.1	90.1
Segment result	269.9	(341.0)	(512.3)	(39.2)	(622.6)
Loss on disposal of other assets					(3.4)
Unallocated corporate expenses					(128.7)
Operating loss					(754.7)
Gain on hedging instruments					18.2
Finance revenue					26.4
Finance costs					(198.2)
Loss before tax					(908.3)
Income tax credit					311.0
Loss after tax					(597.3)
Total assets	7,701.7	2,383.5	467.2	249.3	10,801.7
Total liabilities	(3,200.9)	(157.6)	(142.0)	(5,058.7)	(8,559.2)
Other segment information					
Capital expenditure:					
Property, plant and equipment	817.0	0.3	0.4	0.8	818.5
Intangible exploration and evaluation assets	9.9	137.4	144.1	–	291.4
Depreciation, depletion and amortisation	(450.4)	(0.9)	(1.0)	(14.6)	(466.9)
Impairment of property, plant and equipment, net	(167.2)	–	(0.4)	–	(167.6)
Exploration costs written off	(7.7)	(341.0)	(374.3)	–	(723.0)
Goodwill impairment	–	–	(164.0)	–	(164.0)

Unallocated expenditure and net liabilities include amounts of a corporate nature and not specifically attributable to a reportable segment. The liabilities comprise the Group's external debt and other non-attributable corporate liabilities.

5. Other costs

	Notes	2017 $m	2016 $m
Cost of sales			
Operating costs		386.2	377.2
Operating lease payments		62.5	21.0
Depletion and amortisation of oil and gas assets	10	574.3	448.5
Underlift, overlift and oil stock movements		(2.3)	(76.5)
Share-based payment charge included in cost of sales		1.1	2.7
Other cost of sales		47.5	40.2
Total cost of sales		1,069.3	813.1
Administrative expenses			
Share-based payment charge included in administrative expenses		32.8	41.2
Depreciation of other fixed assets	10	17.9	18.4
Relocation costs associated with major simplification project		1.6	(0.5)
Other administrative costs		43.0	57.3
Total administrative expenses		95.3	116.4
Restructuring costs		14.5	12.3

6. Net financing costs

	2017 $m	2016 $m
Interest on bank overdrafts and borrowings	290.7	304.7
Interest on obligations under finance leases	46.1	1.8
Total borrowing costs	336.8	306.5
Less amounts included in the cost of qualifying assets	(66.5)	(138.8)
	270.3	167.7
Finance and arrangement fees	2.8	5.4
Other interest expense	1.8	–
Foreign exchange losses	57.1	–
Unwinding of discount on decommissioning provisions	19.7	25.1
Total finance costs	351.7	198.2
Interest income on amounts due from joint venture partners for finance leases	(21.0)	–
Other finance revenue	(21.0)	(26.4)
Total finance revenue	(42.0)	(26.4)
Net financing costs	309.7	171.8

7. Insurance proceeds

During 2017 the Group continued to issue insurance claims in respect of the Jubilee turret remediation project. Insurance proceeds of $220.9 million were recorded in the year ended 31 December 2017 (2016: $145.0 million). Proceeds related to lost production under the Business Interruption insurance policy of $162.1 million (2016 $90.1 million) were recorded as other operating income – lost production insurance proceeds in the income statement. Proceeds related to compensation for incremental operating costs under the Business Interruption and Hull and Machinery insurance policies of $50.9 million (2016: $31.8 million) were recorded within the operating costs line of cost of sales (see note 5). Proceeds related to compensation for capital costs under the Hull and Machinery insurance policy of $7.9 million (2016: $23.1 million) were recorded within additions to property, plant and equipment (see note 10).

8. Taxation on loss on ordinary activities

a. Analysis of tax credit for the year

	2017 $m	2016 $m
Current tax		
UK corporation tax	30.1	67.3
Foreign tax	6.2	(18.5)
Total corporate tax	36.3	48.8
UK petroleum revenue tax	(2.1)	(1.1)
Total current tax	34.2	47.7
Deferred tax		
UK corporation tax	(8.7)	9.4
Foreign tax	(114.6)	(369.8)
Total deferred corporate tax	(123.3)	(360.4)
Deferred UK petroleum revenue tax	(21.5)	1.7
Total deferred tax	(144.8)	(358.7)
Total tax credit	(110.6)	(311.0)

b. Factors affecting tax credit for period

The tax rate applied to profit on ordinary activities in preparing the reconciliation below is the UK corporation tax rate applicable to the Group's non-upstream UK profits. The difference between the total tax credit shown above and the amount calculated by applying the standard rate of UK corporation tax applicable to UK profits of 19% (2016: 20%) to the loss before tax is as follows:

	2017 $m	2016 $m
Group loss on ordinary activities before tax	(299.1)	(908.3)
Tax on Group loss on ordinary activities at the standard UK corporation tax rate of 19% (2016: 20%)	(56.8)	(181.7)
Effects of:		
Non-deductible exploration expenditure	21.6	25.8
Other non-deductible expenses	12.6	22.7
Derecognition of deferred tax previously recognised	–	30.2
Recognition of deferred tax previously unrecognised	(21.5)	–
Impairment of goodwill	–	127.9
Utilisation of tax losses not previously recognised	(0.3)	(9.5)
Net losses not recognised	18.4	61.7
Petroleum revenue tax (PRT)	–	(6.7)
Adjustment relating to prior years	1.9	(2.1)
Adjustments to deferred tax relating to change in tax rates	12.6	(0.8)
Higher rate of taxation on Norway losses	13.1	(286.4)
Other tax rates applicable outside the UK and Norway	(88.0)	(86.8)
PSC income not subject to corporation tax	(15.4)	(1.6)
Tax incentives for investment	(2.8)	(3.7)
Other income not subject to corporation tax	(6.0)	–
Group total tax credit for the year	(110.6)	(311.0)

The Finance Act 2016 further reduced the main rate of UK corporation tax applicable to all companies subject to corporation tax, except for those within the oil and gas ring fence, to 19% from 1 April 2017 and 17% from 1 April 2020. These changes were substantively enacted on 6 September 2016 and hence the effect of the change on the deferred tax balances has been included, depending upon when deferred tax is expected to reverse.

The Group's profit before taxation will continue to arise in jurisdictions where the effective rate of taxation differs from that in the UK, such as Ghana (35%), Gabon (55%), and Equatorial Guinea (35%). Furthermore, unsuccessful exploration expenditure is often incurred in jurisdictions where the Group has no taxable profits, such that no related tax benefit arises. Accordingly, the Group's tax charge will continue to vary according to the jurisdictions in which pre-tax profits and exploration costs written off arise.

The Group has tax losses of $3,642.0 million (2016: $2,844.0 million) that are available for offset against future taxable profits in the companies in which the losses arose. Deferred tax assets have not been recognised in respect of these losses as they may not be used to offset taxable profits elsewhere in the Group due to uncertainty of recovery.

The Group has recognised deferred tax assets of $530.0 million (2016: $535.0 million) in relation to tax losses only to the extent of anticipated future taxable income or gains in relevant jurisdictions.

No deferred tax liability is recognised on temporary differences of $7.9 million (2016: $8.2 million) relating to unremitted earnings of overseas subsidiaries as the Group is able to control the timing of the reversal of these temporary differences and it is probable that they will not reverse in the foreseeable future.

Tax relating to components of other comprehensive income

During 2017 $24.3 million (2016: $108.8 million) of tax has been recognised through other comprehensive income of which $24.9 million (2016: $107.8 million) is current and $0.6 million (2016: $1.0 million) is deferred tax relating to all debit (2016: credits) on cash flow hedges arising in the year.

Current tax assets

As at 31 December 2017, current tax assets were $57.7 million (2016: $138.3 million) of which $44.6m relates to the UK (2016: $29.0 million) and $3.1 million relates to Norway (2016: $90.0 million), where 78% of exploration expenditure is refunded as a tax refund in the year following the incurrence of such expenditure.

9. Intangible exploration and evaluation assets

	2017 $m	2016 $m
At 1 January	2,025.8	3,400.0
Additions	319.0	291.4
Disposals	(40.0)	–
Amounts written off	(143.4)	(723.0)
Write-off associated with Norway contingent consideration	–	(36.5)
Transfer to assets held for sale	(43.4)	(912.3)
Transfer to property, plant and equipment	(188.7)	–
Currency translation adjustments	4.1	6.2
At 31 December	1,933.4	2,025.8

Included within 2017 additions is $66.5 million of capitalised interest (2016: $50.2 million). The Group only capitalises interest in respect of intangible exploration and evaluation assets where it is considered that development is ongoing.

Transfers to property, plant, and equipment related to the Greater Jubilee Full Field Development plan of development approval and the cost associated with the Mahogany and Teak discoveries.

The below table provides a summary of the exploration costs written-off on a pre-and post-tax basis by country.

Country	CGU	Rationale for 2017 write-off	2017 Pre-tax write-off /(reversal) $m	2017 Post-tax write-off /(reversal) $m	2017 Remaining recoverable amount $m
Kenya	Country	a	2.3	2.3	1,058.2
Madagascar	Various	d	(4.0)	(4.0)	–
Mauritania	Blocks C6, C10 & C18	b,c	71.1	71.1	22.4
Netherlands	Licence E18 & F16	e	6.2	3.2	–
Pakistan	Various	e	36.1	36.1	5.5
Suriname	Block 31 & Coronie	a	10.3	10.3	30.7
Other	Various	b	4.3	2.8	–
New Ventures	Various	f	17.1	17.1	–
Total write-off			143.4	138.9	

a. Current year unsuccessful drilling results.

b. Current year expenditure and actualisation of accruals associated with CGUs previously written off.

c. Licence relinquishments.

d. Country exit.

e. Revision of value based on disposal/farm-down activities

f. New Ventures expenditure is written off as incurred.

10. Property, plant and equipment

	2017 Oil and gas assets $m	2017 Other fixed assets $m	2017 Total $m	2016 Oil and gas assets $m	2016 Other fixed assets $m	2016 Total $m
Cost						
At 1 January	10,772.5	251.9	11,024.4	10,439.9	289.5	10,729.4
Additions	880.7	7.0	887.7	816.9	1.6	818.5
Disposals	(362.6)	(1.6)	(364.2)	(276.1)	(2.7)	(278.8)
Transfer from intangible assets	188.7	–	188.7	–	–	–
Currency translation adjustments	113.3	22.4	135.7	(208.2)	(36.5)	(244.7)
At 31 December	11,592.6	279.7	11,872.3	10,772.5	251.9	11,024.4
Depreciation, depletion and amortisation						
At 1 January	(5,500.8)	(160.7)	(5,661.5)	(5,360.0)	(165.0)	(5,525.0)
Charge for the year	(574.3)	(17.9)	(592.2)	(448.5)	(18.4)	(466.9)
Impairment loss	(584.5)	–	(584.5)	(184.3)	(0.4)	(184.7)
Reversal of impairment loss	43.4	–	43.4	10.9	–	10.9
Disposal	300.0	1.7	301.7	276.1	2.6	278.7
Currency translation adjustments	(109.1)	(15.4)	(124.5)	205.0	20.5	225.5
At 31 December	(6,425.3)	(192.3)	(6,617.6)	(5,500.8)	(160.7)	(5,661.5)
Net book value at 31 December	5,167.3	87.4	5,254.7	5,271.7	91.2	5,362.9

The 2017 additions include capitalised interest of $nil (note 6) in respect of the TEN development project (2016: $88.6 million). The carrying amount of the Group's oil and gas assets includes an amount of $816.7 million (2016: $17.8 million) in respect of assets held under finance leases. The currency translation adjustments arose due to the movement against the Group's presentation currency, USD, of the Group's UK and Dutch assets which have functional currencies of GBP and EUR respectively. The 2017 income statement impairment charge includes $2.0 million of insurance proceeds (2016: $6.2 million).

	Trigger for 2017 impairment/(reversal)	2017 Impairment/(reversal) $m	Pre-tax discount rate assumption
Limande and Turnix CGU (Gabon)	a	23.5	13%
Echira, Niungo, and Igongo CGU (Gabon)	b	(12.8)	15%
M'boundi (Congo)	c	(16.1)	n/a
Espoir (Côte d'Ivoire)	a	18.3	10%
Ceiba and Okume (Equatorial Guinea)	b	(7.0)	10%
TEN (Ghana)	a,c	535.4	10%
Jubilee (Ghana)	d	(2.0)	n/a
Netherlands CGU	e	7.2	n/a
UK "CGU"[f]	b	(7.4)	n/a
Impairment		539.1	

a. Decrease to long-term price assumptions (refer to accounting policy on significant estimates).
b. Increase to short-term price assumptions (Dated Brent forward curve)
c. Change to decommissioning estimate.
d. Impairment of a component of the asset which is covered by insurance proceeds. This cash item does not impact the carrying value of property, plant, and equipment.
e. Revision of value based on disposal/farm-down activities.
f. The fields in the UK are grouped into one CGU as all fields within those countries share critical gas infrastructure.

During 2017 and 2016 the Group applied the following nominal oil price assumptions for impairment tests:

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6 onwards
2017	Forward curve	Forward curve	$59/bbl	$66/bbl	$68/bbl	$75/bbl inflated at 2%
2016	Forward curve	Forward curve	$70/bbl	$70/bbl	$70/bbl	$90/bbl

The prices assumed in 2017 decreased due to downward revisions by expert forecasters. Oil prices stated above are benchmark prices to which an individual field price differential is applied. All impairment assessments are prepared on a value-in-use basis using discounted future cash flows based on 2P reserves profiles.

11. Other assets

	2017 $m	2016 $m
Non-current		
Amounts due from joint venture partners	731.7	127.3
Uganda VAT recoverable	34.9	35.9
Other non-current assets	23.2	12.5
	789.8	175.7
Current		
Amounts due from joint venture partners	567.8	560.4
Underlifts	37.1	34.9
Prepayments	38.2	26.3
VAT recoverable	5.4	5.7
Other current assets	119.8	211.6
	768.3	838.9

The increase in amounts due from joint venture partners relates to the recognition of the TEN FPSO finance lease. Other current assets have decreased due to the increased timeliness of the receipt of funds from insurers.

12. Assets held for sale

In 2017, Tullow announced that it had agreed a substantial farm-down of its assets in Uganda. Under the Sale and Purchase Agreement, Tullow has agreed to transfer 21.57% of its 33.33% Uganda interests for a total consideration of $900 million. CNOOC subsequently exercised its pre-emption rights under the joint operating agreements to acquire 50% of the interests being transferred on the same terms and conditions. This led to Tullow signing pre-emption documents with its Joint Venture Partners. Upon completion, the farm-down will leave Tullow with an 11.76% interest in the upstream and pipeline projects. This is expected to reduce to a 10% interest in the upstream project when the Government of Uganda formally exercises its back-in right. Although it has not yet been determined what interests the Governments of Uganda and Tanzania will take in the pipeline project, Tullow expects its interests in the upstream and pipeline projects to be aligned.

The consideration is split into $200 million in cash, consisting of $100 million payable on completion of the transaction, $50 million payable at FID and $50 million payable at first oil. The remaining $700 million is in deferred consideration and represents reimbursement in cash of a proportion of Tullow's past exploration and development costs. The deferred consideration is payable to Tullow as the upstream and pipeline projects progress and these payments will be used by Tullow to fund its share of the development costs. Tullow expects the deferred consideration to cover its share of upstream and pipeline development capex to first oil and beyond. Completion of the transaction is subject to certain conditions, including the approval of the Government of Uganda, after which Tullow will cease to be an operator in Uganda. Following signature of the pre-emption documents by the Joint Venture Partners, the Government of Uganda was officially notified of the transaction and its approval was sought. The disposal is expected to complete in mid-2018.

The estimated fair value of the consideration was $829.7 million on recognition which, when compared to the carrying value of the Group's interest in Uganda, resulted in an exploration write-off of $330.4 million in 2016. The fair value of the deferred consideration was calculated using expected timing of receipts based on management's best estimate of the expected capital profile of the project discounted at the relevant counterparty's cost of borrowing. Additions to this value have been recognised in relation to capitalised interest. The present value of the consideration will be determined on completion and assessed against the carrying value of the net assets of the disposal group. This represents a level 3 financial asset.

The divestment of the Norway business was completed during 2017 with $7.3 million of assets held for sale at 31 December 2016 being disposed in full during 2017. Consequently, there were no Norwegian assets held for sale at 31 December 2017.

The divestment of the Netherlands business was completed during 2017 with $113.1 million of assets held for sale at 30 June 2017 being disposed in full. Consequently, there were no Netherlands assets held for sale at 31 December 2017.

12. Assets held for sale contd.

The major classes of assets and liabilities comprising the assets classified as held for sale as at 31 December 2017 were as follows:

	Uganda 2017 $m	Total 2017 $m	Uganda 2016 $m	Norway 2016 $m	Total 2016 $m
Intangible exploration and evaluation assets	873.1	873.1	829.7	7.4	837.1
Total assets classified as held for sale	873.1	873.1	829.7	7.4	837.1
Net assets of disposal groups	873.1	873.1	829.7	7.4	837.1

13. Trade and other payables

Current liabilities

	2017 $m	2016 $m
Trade payables	83.3	46.9
Other payables	114.5	124.6
Overlifts	30.4	6.9
Accruals	552.0	721.2
VAT and other similar taxes	17.3	14.6
Current portion of finance lease	228.1	1.9
	1,025.6	916.1

Payables related to operated joint ventures (primarily related to Ghana and Kenya) are recorded gross with the debit representing the partners' share recognised in amounts due from joint venture partners (note 11). The change in trade payables and in other payables predominantly represents timing differences and levels of work activity.

Non-current liabilities

	2017 $m	2016 $m
Other non-current liabilities	105.1	87.7
Non-current portion of finance lease	1,317.5	24.6
	1,422.6	112.3

The Group's finance leases are the TEN FPSO and the Espoir FPSO (2016: Espoir FPSO). The finance lease for the TEN FPSO met the criteria for recognition on 1 August 2017. A finance lease liability has been recorded at a gross value of $1,521.0 million as Tullow entered the lease on behalf of the TEN Joint Venture. The present value of the lease liability unwinds over the expected life of the lease and is reported within finance costs as interest on obligations under finance leases. A receivable from Joint Venture partners of $719.0 million has been recognised in other assets to reflect the value of future payments that will be met by cash calls from partners. The present value of the receivable from Joint Venture Partners unwinds over the expected life of the lease and is reported within finance revenue. The net cash outflows of $62.6 million related to the lease agreement since its recognition as a finance lease have been reported in the repayment of obligations under finance leases line in the cash flow statements. A right of use property, plant, and equipment asset of $775.8 million was also recorded at 31 December 2017. Prior to recognition as a finance lease, it was accounted for as an operating lease, and included as operating lease payments within cost of sales (note 5).

14. Provisions

	Decommissioning 2017 $m	Other provisions 2017 $m	Total 2017 $m	Decommissioning 2016 $m	Other provisions 2016 $m	Total 2016 $m
At 1 January	1,014.4	144.2	1,158.6	1,008.8	243.3	1,252.1
New provisions and changes in estimates	(33.6)	(9.2)	(42.8)	57.1	71.4	128.5
Disposals	(100.7)	–	(100.7)	–	–	–
Payments	(33.7)	–	(33.7)	(23.0)	(132.0)	(155.0)
Transfer to accruals	–	–	–	–	(35.0)	(35.0)
Unwinding of discount	19.7	–	19.7	25.1	–	25.1
Currency translation adjustment	31.3	–	31.3	(53.6)	(3.5)	(57.1)
At 31 December	897.4	135.0	1,032.4	1,014.4	144.2	1,158.6
Current provisions	103.2	127.6	230.8	49.0	2.9	51.9
Non-current provisions	794.2	7.4	801.6	965.4	141.3	1,106.7

Included within other provisions is provision for onerous service contracts and provision for restructuring costs. Due to the historical reduction in original planned future work programmes the Group identified a number of onerous service contracts in prior years. The expected unutilised capacity has been provided for in 2016 and 2017 resulting in an income statement credit of $1.0 million (2016: charge of $114.9 million).

The decommissioning provision represents the present value of decommissioning costs relating to the European and African oil and gas interests.

	Inflation assumption	Discount rate assumption	Cessation of production assumption	2017 $m	2016 $m
Congo	n/a	n/a	n/a	–	18.3
Côte d'Ivoire	2%	3%	2026	49.7	48.1
Equatorial Guinea	2%	3%	2028-2029	133.9	130.0
Gabon	2%	3%	2021-2034	55.8	54.2
Ghana	2%	3%	2034-2036	278.0	267.6
Mauritania	2%	3%	2018	120.7	130.9
Netherlands	n/a	n/a	n/a	–	100.7
UK	2%	3%	2018-2020	259.3	264.6
				897.4	1,014.4

15. Commercial Reserves and Contingent Resources summary (unaudited) working interest basis

	West Africa		East Africa		New Ventures		TOTAL		
	Oil mmbbl	Gas bcf	Oil mmbbl	Gas bcf	Oil mmbbl	Gas bcf	Oil mmbbl	Gas bcf	Petroleum mmboe
COMMERCIAL RESERVES									
1 January 2017	272.1	189.7	–	–	–	–	272.1	189.7	303.7
Revisions	3.2	14.3	–	–	–	–	3.2	14.3	5.5
Transfer from contingent resources	–	79.0	–	–	–	–	–	79.0	13.2
Disposals	–	–	–	–	–	–	–	–	–
Production	(29.6)	(14.1)	–	–	–	–	(29.6)	(14.1)	(31.9)
31 December 2017	245.7	268.9	–	–	–	–	245.7	268.9	290.5
CONTINGENT RESOURCES									
1 January 2017	128.1	730.5	632.5	42.7	–	4.2	760.6	773.2	890.1
Revisions	(0.2)	(186.4)	–	–	–	–	(0.2)	(186.4)	(31.3)
Additions	1.7	–	5.3	–	–	–	7.0	–	7.0
Disposals	(8.2)	–	–	–	–	–	(8.2)	–	(8.2)
Transfers to commercial reserves	–	(79.0)	–	–	–	–	–	(79.0)	(13.2)
31 December 2017	121.4	465.1	637.8	42.7	–	4.2	759.1	507.8	844.4
TOTAL									
31 December 2017	367.1	734.0	637.8	42.7	–	4.2	1,004.8	776.7	1,134.9

1. Proven and Probable Commercial Reserves are as audited and reported by an independent engineer. Reserves estimates for each field are reviewed by the independent engineer based on significant new data or a material change with a review of each field undertaken at least every two years, with the exception of minor assets contributing less than 5% of the Group's reserves.
2. Proven and Probable Contingent Resources are as audited and reported by an independent engineer. Resources estimates are reviewed by the independent engineer based on significant new data received following exploration or appraisal drilling.
3. The West Africa revisions to reserves (+5 mmboe) relate mainly to audits of Jubilee, TEN, Okume and Echira.
4. The Kenya addition to oil contingent resources relates to the booking of the Erut discovery announced 17 January 2017. The West Africa addition to oil contingent resources relates to Simba.
5. The West Africa revision to gas contingent resources relates to a reduction in the estimate of the size of the Gas cap in Ntomme and reduction of injected gas blow-down volume for Jubilee.
6. The West Africa transfer of gas from contingent resources to reserves relates to Jubilee sales gas.

The Group provides for depletion and amortisation of tangible fixed assets on a net entitlements basis, which reflects the terms of the Production Sharing Contracts related to each field. Total net entitlement reserves were 284.1 mmboe at 31 December 2017 (31 December 2016: 283.2 mmboe).

Contingent Resources relate to resources in respect of which development plans are in the course of preparation or further evaluation is under way with a view to future development.

About Tullow Oil plc

Tullow is a leading independent oil & gas, exploration and production group, quoted on the London, Irish and Ghanaian stock exchanges (symbol: TLW). The Group has interests in 90 exploration and production licences across 16 countries which are managed as three business delivery teams: West Africa, East Africa and New Ventures.

EVENTS ON THE DAY

In conjunction with these results, Tullow is conducting a London Presentation and a number of events for the financial community.

09.00 GMT - UK/European conference call

To access the call please dial the appropriate number below shortly before the call and ask for the Tullow Oil plc conference call. The telephone numbers and access codes are:

Live event	
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Webcast

To join the live video webcast or play the on-demand version, please use this link: https://edge.media-server.com/m6/p/xzdogikb. The replay will be available from noon on 7 February 2018.

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