TULLOW OIL PLC

2016
FULL YEAR RESULTS

8 February 2017

Tullow Oil plc – 2016 Full Year Results

2016 revenue of $1.3 billion and operating cash flow of $0.8 billion
Debt reduction under way with positive free cash flow in Q4 2016 after TEN first oil
Substantial farm-down in Uganda; development capex covered beyond first oil

8 February 2017 – Tullow Oil plc (Tullow), the independent oil and gas exploration and production group, announces its full year results for the year ended 31 December 2016. Details of a presentation in London, webcast and conference calls are available on page 28 of this announcement or visit the Group's website www.tullowoil.com.

COMMENTING TODAY, AIDAN HEAVEY, CHIEF EXECUTIVE, SAID:

"The clear highlight of 2016 was delivering Ghana's second major oil and gas development, the TEN fields, on time and on budget. Production from TEN, alongside our other West African oil production, has provided Tullow with positive free cash flow and enabled us to begin the important process of deleveraging our balance sheet. As we focus our free cash flow primarily on reducing our debt, capital discipline remains critical. We have made excellent progress with our East African developments and are building a high quality exploration portfolio to grow our business. As I move to become Chairman of the Group and hand over to Paul McDade, Tullow has the right assets and expertise to take full advantage of the opportunities ahead."

2016 FULL YEAR RESULTS SUMMARY

- Revenue of $1.3 billion; post tax loss of $0.6 billion after write-offs and impairments. Operating cash flow of $0.8 billion.
- Year-end 2016 net debt of $4.8 billion with significant facility headroom and free cash of $1.0 billion. During the year, $300 million of convertible bonds issued; Corporate Facility extended to April 2018; $345 million RBL accordion secured.
- On 7 February 2017 the Corporate Facility was extended by a further year to April 2019.
- 2016 capex of $0.9 billion; 2017 capex forecast of $0.5 billion including $125 million to be offset by Uganda farm-down deal.
- West Africa net working interest oil production, including production-equivalent insurance payments, averaged 65,500 bopd in 2016 and in 2017 is expected to average between 78,000 and 85,000 bopd.
- TEN development delivered on time and on budget in August 2016; 2017 gross forecast of 50,000 bopd. Drilling is expected to resume in 2018 after the ITLOS ruling which is expected in late 2017.
- Jubilee field 2017 net production forecast of 36,300 bopd, including insured barrels; Turret Remediation Project making good progress with costs being offset by insurance payments.
- Uganda deal provides upfront cash and deferred payments to cover upstream and pipeline capex to first oil and beyond.
- Kenya exploration and appraisal programmes continue to support resource growth; Erut-1 oil discovery de-risks additional prospects in the north of the South Lokichar Basin.
- New Ventures activity delivers acreage in Zambia and Guyana; 2017 activity includes high impact Araku-1 well in Suriname and seismic campaigns in Mauritania, Kenya, Ghana, Jamaica, Uruguay and Guyana to identify future drilling candidates.

FINANCIAL OVERVIEW

	FY 2016	FY 2015	Change
Sales revenue ($m)	1,269.9	1,606.6	-21%
Gross profit ($m)	546.9	591.3	-8%
Administrative expenses ($m)	(116.4)	(193.6)	40%
Restructuring costs ($m)	(12.3)	(40.8)	70%
Loss on disposal ($m)	(3.4)	(56.5)	94%
Goodwill impairment ($m)	(164.0)	(53.7)	-205%
Exploration costs written off ($m)	(723.0)	(748.9)	3%
Impairment of property, plant and equipment, net ($m)	(167.6)	(406.0)	59%
Provision for onerous service contracts, net ($m)	(114.9)	(185.5)	38%
Operating loss ($m)	(754.7)	(1,093.7)	31%
Loss after tax ($m)	(597.3)	(1,036.9)	42%
Operating cash flow before working capital ($m)	774.0	967.1	-20%

Board changes, AGM and dividend

On 11 January 2017, Tullow announced that Paul McDade, currently COO, will be appointed as CEO and Aidan Heavey, currently CEO, will be appointed as Chairman, effective after the Group's AGM in 2017. Simon Thompson, Chairman, and Ann Grant, senior independent director (SID), will retire at the AGM with Jeremy Wilson replacing Ms Grant as SID. Graham Martin retired as executive director at the 2016 AGM.

Tullow's AGM will take place on 26 April 2017 at 12pm at the Company's offices at Building 9, Chiswick Park, 566 Chiswick High Road, London, W4 5XT.

In view of current financial constraints, the Board is again recommending that no dividend is paid. At a time when Tullow is focusing on capital allocation, financial flexibility and cost reductions, the Board believes that Tullow and its shareholders are better served by retaining funds in the business.

Operations review

Production

Tullow's West Africa 2016 oil production was in line with recent guidance averaging 65,500 bopd. This includes 4,600 bopd of production-equivalent payments relating to the Jubilee field received under Tullow's corporate Business Interruption insurance policy. In Europe, assets performed in line with expectations and full year working interest gas production averaged 6,200 boepd.

In 2017, West Africa working interest oil production, including production-equivalent insurance payments, is expected to average between 78,000 and 85,000 bopd. Europe working interest gas production is expected to average between 6,000 and 7,000 boepd.

WEST AFRICA*

2016 net production	Total net reserves and resources	2016 net sales revenue	2016 net investment
67,100 boepd**	553.5 mmboe	$1,270 million	$694 million

*Tullow's West Africa Business Delivery Team also manages the Group's European operations which are reflected in the above table; production excludes production-equivalent insurance payments

** Including the impact of insured barrels from the Jubilee field, West Africa working interest production was 71,700 boepd.

Ghana

Jubilee

In February 2016, an issue with the turret bearing of the Jubilee FPSO Kwame Nkrumah was identified resulting in the need to implement new operating and offtake procedures, utilising tugs, a dynamically positioned shuttle tanker and a storage tanker. After a period of planning, Tullow and its JV Partners established that the preferred long-term solution to the turret issue is to convert the FPSO to a permanently spread-moored vessel, with offtake through a new deep-water offloading buoy. The first phase of this work, involving the installation of a stern anchoring system, is expected to be completed in February 2017, after which the tugs maintaining the FPSO on heading control will no longer be required.

The next phase of the project will involve modifications to the turret systems for long-term spread-moored operations. In addition, the assessment of the optimum long-term heading continues, in order to determine if a rotation of the FPSO is required. Detailed planning for these works continues with the JV Partners and the Ghanaian Government, with final decisions and approvals being sought in the first half of 2017. Work is expected to be carried out in the second half of 2017, with an anticipated facility shutdown of up to 12 weeks, although work continues to optimise and reduce the shutdown period.

The final phase of the project will involve the installation of a deep water offloading buoy which is planned to be installed in the first half of 2018. This will remove the need for the dynamically positioned shuttle tanker and storage tanker and the associated operating costs. This phase of work also requires approval of both the Government of Ghana and the Jubilee JV Partners.

The capital costs associated with the remediation works, the lost revenue resulting from the shutdown period, and the increased operating costs are expected to be covered by the Joint Venture Hull and Machinery insurance policy and Tullow's corporate Business Interruption insurance policy.

Full year 2016 production from the Jubilee field averaged 73,700 bopd (net: 26,200 bopd). In addition, under Tullow's corporate Business Interruption insurance the Group received insurance payments which equates to 4,600 bopd of net equivalent production. Tullow expects 2017 production from the Jubilee field to average 68,500 bopd (net: 24,300 bopd), assuming 12 weeks of shutdown associated with the next phase of remediation works. Tullow's corporate Business Interruption insurance policy is expected to reimburse Tullow for the equivalent of 12,000 bopd of annualised net production for this shutdown period, increasing Tullow's effective net production to around 36,300 bopd in 2017.

In December 2015, Tullow submitted the Greater Jubilee Full Field Development Plan to the Government of Ghana. This project, to extend field production and increase commercial reserves, was redesigned given the current oil price environment to reduce the overall capital requirement and allow flexibility on the timing of capital investment. Tullow has sought to address comments made by the Government of Ghana on the plan submitted in December 2015 and in light of the current Turret Remediation Project, approval of the plan by the Government of Ghana is now expected in mid-2017.

TEN

In May 2013, the Government of Ghana approved the TEN Plan of Development, Tullow's second major operated deep water development project. The project remained on schedule and on budget throughout the development phase with first oil delivered in August 2016. Net capital expenditure by Tullow in 2016 was approximately $600 million, in line with the Group's forecast.

Following first oil, the oil production, gas compression/injection and water injection systems were commissioned and are operational. In early January 2017, the capacity of the FPSO was successfully tested at an average rate in excess of the design capacity of 80,000 bopd during a 24 hour flow test. Gross annualised working interest production in 2016 averaged 14,600 bopd (net: 6,900 bopd).

Production testing and initial results from the 11 wells indicate reserves estimates for both Ntomme and Enyenra to be in line with previously guided expectations. However, due to some issues with managing pressures in the Enyenra reservoir and because no new wells can be drilled until after the ITLOS ruling, which is expected in late 2017, Tullow is managing the existing wells in a prudent and sustainable manner. As a result, Tullow expects production from TEN to be around 50,000 bopd (net: 23,600 bopd) in 2017, although work continues to evaluate ways to increase production.

Gas production from the TEN fields is currently being re-injected. The gas export line between the TEN and Jubilee developments is expected to be connected this month with gas export expected to commence later in 2017.

Proceedings at ITLOS with regard to the maritime border dispute between Ghana and Côte d'Ivoire continue, with oral hearings scheduled for this month, and a final ruling anticipated in the fourth quarter of 2017. Drilling is expected to resume in 2018 after the final ruling.

West Africa non-operated portfolio

West Africa non-operated production was in-line with expectations in 2016 at 27,800 bopd net. Due to low oil prices, capital expenditure was reduced substantially across a number of these fields in 2016. While this reduced investment helps maximise near-term cashflow it does impact the rate of production decline, and as a result 2017 forecast production across the West African non-operated portfolio is expected to be around 22,000 bopd net. There is flexibility to increase capital investment in the medium term to offset production decline in these mature assets, as market conditions improve.

Europe production

Full year gas production from Europe averaged 6,200 boepd net in 2016. Decommissioning operations in the UK Southern North Sea on the CMS assets are continuing on schedule and are expected to be completed in the first quarter of 2017. 2017 average net production is expected to be around 6,500 boepd.

EAST AFRICA

2016 net production	Total net reserves and resources	2016 net sales revenue	2016 net investment
nil	639.6 mmboe	nil	$86 million

Kenya

Exploration and Appraisal

Exploration and appraisal of the South Lokichar basin continued in 2016 and the initial phase was completed in the first half of the year. The success of this programme and analysis of the discoveries led management to upgrade the South Lokichar mean resource estimate to 750 mmbo. Also in the first half of the year, Tullow expanded its exploration drilling programme in Kenya to the Kerio Valley Basin in Block 12A where the Cheptuket-1 well encountered oil shows, seen in cuttings and rotary sidewall cores. Post-well analysis is still in progress. Further exploration activities in Block 12A and Tullow's other remaining unexplored Kenyan acreage continue to be evaluated.

After identifying a number of new prospects and appraisal opportunities, drilling re-commenced in the South Lokichar Basin in mid-December 2016 with a four-well exploration and appraisal programme. The first was Erut-1, an exploration well located at the northern limit of the basin, approximately 11 km north of the Etom field. The well discovered a gross oil interval of 55 metres with 25 metres of net oil pay at a depth of 700 metres. The overall oil column for the field is estimated to be 100 to 125 metres. Pending lab results, the oil recovered from Erut-1 appears to be a typical South Lokichar waxy light crude. This well proves that oil has migrated to the northern limit of the South Lokichar basin and has de-risked multiple prospects in this area. The rig is now drilling the Amosing-6 well to appraise undrilled volumes. It will then move to drill the Ngamia-10 well, an appraisal well to the south of the Ngamia discovery well. The fourth well planned in this programme will drill the Etete prospect, a structure approximately 2 km south of the Etom field. This programme could be extended by up to four additional wells depending upon the results from these initial four wells. Tullow believes that significant upside remains across the South Lokichar Basin with the potential to increase the resource estimate to over 1 billion barrels of recoverable oil.

Field development

Good progress was made during 2016 on a standalone development in Kenya with an export pipeline to Lamu; life-of-field development costs (comprising operating expenditure, capital expenditure and potential pipeline tariffs) are expected to be in the region of $25 to $30 per barrel. Preparations for the upstream development Front End Engineering Design (FEED) are under way, with FEED expected to commence in the second half of 2017. Other activity during the year included water injection trials which were successfully completed on the Amosing oil discovery in the South Lokichar Basin. Data from the trials shows the viability of water injection for development planning and a similar programme of water injection tests on the Ngamia oil discovery is scheduled to commence later this month. The Environmental and Social Impact Assessments (ESIA) scoping report and terms of reference were approved and ESIA baseline surveys are nearing completion.

Tullow and its JV Partners, Africa Oil and Maersk Oil, signed an MoU in July 2016 with the Government of Kenya which confirms the intent of the parties to jointly progress the development of a Kenya crude oil pipeline. Subsequent to this, the JV Partners and the Government of Kenya are also in the final stages of negotiation of a Joint Development Agreement (JDA) which sets out a structure for the Government of Kenya and the JV Partners to progress the development of the export pipeline. This agreement will ultimately enable important studies to commence such as pipeline FEED, ESIA, as well as studies on pipeline financing and ownership.

An Early Oil Pilot Scheme (EOPS), which involves the transportation of early South Lokichar oil production to Mombasa by road, was sanctioned by the JV Partners in the third quarter of 2016. The various agreements are in the final stages of negotiations with the Government of Kenya. The EOPS will use existing upstream wells and oil storage tanks to initially produce approximately 2,000 bopd gross in 2017. The EOPS will provide important information which will assist in full field development planning.

Uganda

Field development

In April 2016, the Government of Uganda confirmed its decision to route an oil export pipeline through Tanzania to the port of Tanga, providing clarity on the development of Uganda's oil resources. In August 2016, the Government awarded eight Production Licences in the Tullow and Total operated areas. The Government of Uganda has also made significant progress on the constitution of both the Petroleum Authority to regulate the oil industry and the Uganda National Oil Company which will be the Government representative in the Uganda Joint Venture.

The first phase of the upstream ESIA has also been completed; the second phase is in progress. FEED for both the upstream and pipeline are expected to commence this month. Overall, the Government and JV Partners continue to aspire to achieve FID by the end of 2017, with first oil expected to occur 3 years after FID.

Farm-down to Total

On 9 January 2017, Tullow announced that it had agreed a substantial farm-down of its assets in Uganda to Total. Under the Sale and Purchase Agreement, Tullow has agreed to transfer 21.57% of its 33.33% Uganda interests to Total for a total consideration of $900 million. 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 right to back-in. 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 by Total 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. The disposal is expected to complete in 2017.

Tullow believes this agreement will allow the Lake Albert Development to move ahead and increases the likelihood of FID around the end of 2017.

NEW VENTURES

2016 net production nil	Total net reserves and resources nil	2016 net sales revenue nil	2016 net investment $77 million

Tullow has continued to actively manage its New Ventures portfolio throughout 2016 through both licence acquisitions and farm downs of existing acreage to optimise the allocation of exploration expenditure. Notwithstanding a lower exploration budget, Tullow continues to successfully replenish and high-grade its exploration portfolio, and believes that the portfolio should give the Group significant low-cost opportunities for the future.

New Ventures activity in 2016 also involved the continued refinement of the Group's frontier exploration portfolio and Tullow has taken the decision not to pursue its interests in Madagascar, Ethiopia, French Guiana, Guinea, Norway and Greenland and the Group has, with the exception of Norway, now exited these countries.

Africa

In June 2016, Tullow extended its East African rift play acreage through the award of Petroleum Exploration Licence 28, onshore Zambia. The 53,000 sq km block builds on Tullow's existing low-cost, core East African Tertiary rift basins, giving the Group access to three further unexplored basins. Tullow initially plans to complete geological studies, acquire a gravity survey and collect passive seismic data. If the results are positive the Group will then acquire a 2D seismic survey in the block.

During the year, there was a focus on interpreting previously acquired seismic surveys to prepare prospects in advance of making the decision on whether to drill. Encouraging oil plays have been identified in Blocks C3 and C10 in Mauritania and in the PEL30 and PEL37 licences in Namibia. Tullow plans to acquire a 3D seismic survey over its Mauritanian acreage in June 2017.

South America

Tullow has continued to advance its operations in South America and plans are ongoing to drill the high impact Araku prospect (Tullow: 30%), offshore Suriname, in the second half of 2017. This prospect is a large structural trap which has a resource potential estimated at over 500 mmbo. It has been significantly de-risked by a 3D seismic survey carried out in 2015 which identified geophysical characteristics that are consistent with potential oil or gas effects in the target reservoirs. A rig is currently being sourced for the well which is expected to cost $14 million net to drill.

In Guyana, the Group is planning to acquire 3D seismic data over the offshore Orinduik licence, awarded in 2016, and Kanuku licence which are located up-dip of ExxonMobil's Liza oil discovery. These programmes are expected to cover up to 6,000 sq km and will enable evaluation of attractive leads mapped on existing 2D seismic data.

Offshore Uruguay, a 2,500 sq km 3D seismic programme commenced in January 2017 to capture data over high-quality leads identified in Block 15 in the Pelotas Basin.

In Jamaica, following the completion of a drop core and seep study in the Walton Morant blocks that identified a live oil seep, Tullow will acquire a further 680 km of 2D seismic data before considering the acquisition of a 3D seismic survey.

Europe

The divestment of the Norway business is progressing well with two deals completed before year-end and one in January 2017. Four licences, including the Wisting oil discovery, have been sold to Statoil, eight licences, including the Oda asset, have been sold to Aker BP ASA and two further licences have been sold to ConocoPhillips. A further two sales were executed in December 2016 with two separate parties. These sales, covering a further 13 licences, and which include the 2016 Cara oil and gas discovery, are expected to complete by April 2017. In aggregate, the Norway asset sales are expected to yield proceeds of up to $0.2 billion. Once completed, the Group will no longer hold any licences on the Norwegian Continental Shelf.

Asia

In May 2016, Tullow agreed to sell a 20% interest and transfer operatorship of the Bannu West licence in Pakistan to Mari Petroleum. The Government's approval of the Bannu West transfer is nearing completion. In July, 2016 Tullow received Government approval of the transfer of operatorship of Block 28 in Pakistan to OGDCL. The Group's position in Pakistan is now entirely non-operated.

Finance review

Financial results summary	2016	2015	Change
Working interest production volume (boepd)[1]	67,100	73,400	-9%
Sales volume (boepd)	59,900	67,600	-11%
Realised oil price ($/bbl)	61.4	67.0	-8%
Realised gas price (p/therm)	33.9	41.8	-19%
Sales revenue ($m)[2]	1,270	1,607	-21%
Underlying cash operating costs per boe ($/boe)[3]	14.3	15.1	5%
Exploration costs written off ($m)	723	749	3%
Impairment of property, plant and equipment, net ($m)	168	406	59%
Operating loss ($m)	(755)	(1,094)	31%
Loss before tax ($m)	(908)	(1,297)	30%
Loss after tax ($m)	(597)	(1,037)	42%
Basic earnings per share (cents)	(65.8)	(113.6)	42%
Operating cash flow before working capital ($m)	774	967	-20%
Operating cash flow before working capital per boe ($/bbl)	29.4	35.9	-18%
Capital investment ($m)[3]	857	1,720	-50%
Net debt ($m)[3]	4,782	4,019	19%
Gearing (times)[3]	5.1	3.8	1.3
Free cash flow ($m)[3]	(792)	(940)	16%

1. Including the impact of insured barrels from the Jubilee field, Group working interest production was 71,700 boepd.

2. Sales revenue excludes $90 million of other operating income which represents accrued proceeds under Tullow's corporate Business Interruption insurance policy.

3. Underlying cash operating costs per boe, capital investment, net debt, gearing and free cash flow are non-IFRS measures and are explained later in this section.

Production and commodity prices

Working interest production averaged 67,100 boepd, a decrease of 9% for the year (2015: 73,400 boepd). Including the impact of insured barrels from the Jubilee field, working interest production averaged 71,700 boepd, a decrease of 2%. The impact of first oil from the TEN fields was offset by reduced production from the Jubilee field as a result of the Turret Remediation Project, declines in UK and Netherlands gas production as well as reductions across the non-operated West Africa portfolio. Sales volumes for West African oil and European gas averaged 51,100 bopd and 8,800 boepd respectively.

On average, oil prices in 2016 were lower than in 2015. The Group's realised oil price after hedging in 2016 was $61.4/bbl and $41.7/bbl before hedging (2015: $67.0/bbl and $50.4/bbl respectively), a decrease of 8% versus a 16% decrease in Brent oil prices over the period. European gas prices in 2016 were lower than in 2015. The Group's realised European gas price after hedging in 2016 was 33.9 pence/therm (2015: 41.8 pence/therm), a decrease of 19%.

Underlying cash operating costs, depreciation, impairments and administrative expenses

Underlying cash operating costs amounted to $377 million; $14.3/boe (2015: $406 million; $15.1/boe). Underlying cash operating costs in 2016 includes $32 million of insurance proceeds. The decrease of 5% in underlying cash operating costs per boe was principally due to the impact of ongoing cost saving initiatives and due to the start-up of the TEN fields which have a low operating cost per boe.

DD&A charges before impairment on production and development assets amounted to $449 million; $17.0/boe (2015: $551 million; $20.5/boe). The Group recognised an impairment charge of $168 million (2015: $406 million) in respect of lower forecasts of oil and gas prices and an increase in estimated future decommissioning costs. The Group recognised an impairment of goodwill of $164 million (2015: $54 million) associated with the disposal of the Group's Norwegian assets.

Administrative expenses of $116 million (2015: $194 million) include an amount of $41 million (2015: $48 million) associated with a share-based payment charge. The Major Simplification Project, which was undertaken during 2015, is on track to generate savings of approximately $600 million by mid-2018, ahead of the Company's initial target of $500 million, with savings of approximately $300 million having been achieved as at 31 December 2016.

During 2016, the Group recognised an income statement charge for restructuring costs of $12 million (2015: $41 million) relating to headcount reductions associated with the Major Simplification Project and Norway country exit. This has been presented separately from administrative expenses in the income statement.

Exploration costs written off	**2016 $m**	2015 $m
Exploration costs written off	(723)	(749)
Associated deferred tax credit	299	277
Net exploration costs written off	(424)	(472)

During 2016, the Group spent $82 million, including Norway exploration costs on a post-tax basis, on exploration and appraisal activities and has written off $58 million in relation to this expenditure. This included write-offs in Norway ($18 million) and New Ventures costs ($18 million). In addition, the Group has written off $366 million in relation to prior years' expenditure primarily as a result of the farm-down in Uganda ($248 million), the disposals in Norway ($61 million) and country exit in Madagascar ($22 million). The total exploration costs written off net of tax is $424 million (2015: $472 million).

Provision for onerous service contracts

At the end of 2016, Tullow had provided $133 million (2015: $186 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 charge in 2016 of $115 million (2015: $186 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.

At 31 December 2016, the Group's derivative instruments had a net positive fair value of $91 million (2015: positive $623 million), net of deferred premium. While all of the Group's commodity derivative instruments currently qualify for hedge accounting, a pre-tax credit of $18 million (2015: charge of $59 million) in relation to the change in time value of the Group's commodity derivative instruments has been recognised in the income statement for 2016.

Hedge position at 31 December 2016	2017	2018	2019
Oil hedges			
Volume – bopd	42,500	22,000	7,979
Average floor price protected ($/bbl)	60.23	51.88	45.53

Net financing costs

Net financing costs for the year were $172 million (2015: $145 million). The increase in financing costs is associated with an increase in borrowing levels and a decrease in capitalised interest on the TEN development due to first oil. 2016 net financing costs include interest incurred on the Group's debt facilities, foreign exchange gains and the decommissioning finance charge, offset by interest earned on cash deposits and borrowing costs capitalised principally against the Ugandan assets and the TEN development.

Taxation

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

The Group's statutory effective tax rate for 2016 is 34.2% (2015: 20.1%). The increase in the tax rate for 2016 is mainly due to higher deferred tax credits on exploration costs written off and other impairments in addition to lower prior year tax charges relating to Uganda.

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 for 2016 is 23.3% (2015: 29%). The decrease in the adjusted tax rate is primarily a result of lower profits from overseas production activities and an increase in hedging profits taxed at the UK corporate tax rate of 20%.

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 broadly follow the UK's standard rate of corporation tax over the short term 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 $597 million (2015: $1,037 million loss). Basic loss per share was 65.8 cents (2015: 113.6 cents loss).

Dividend per share

In view of the fall in the oil price, the Board suspended the payment of dividends in early 2015. At a time when Tullow is focusing on capital allocation, financial flexibility and cost reductions, the Board believes that Tullow and its shareholders are better served by retaining funds in the business.

Operating cash flow

Operating cash flow before working capital movements decreased by 20% to $0.8 billion (2015: $1.0 billion) as a result of reduced sales volumes and lower realised commodity prices, partially offset by lower cash operating costs and revenue from the TEN development. In 2016, this cash flow together with increased debt facilities helped fund the Group's $1.0 billion of capital expenditure in exploration and development activities and $284 million servicing the Group's debt facilities.

Reconciliation of net debt	$m
Year-end 2015 net debt	**4,019**
Sales revenue	1,270
Other operating income – lost production insurance proceeds	90
Operating costs	(377)
Operating expenses	(209)
Cash flow from operations	**774**
Movement in working capital	(177)
Tax paid	(85)
Capital expenditure	(1,031)
Disposals	63
Other investing activities	1
Financing activities	(319)
Foreign exchange gain on cash and debt	11
Year-end 2016 net debt	**4,782**

Capital investment

2016 capital investment amounted to $0.9 billion (2015: $1.7 billion) with $0.8 billion invested in development activities and $0.1 billion invested in exploration and appraisal activities. More than 80% of the total was invested in Kenya, Ghana and Uganda and over 90%, more than $0.8 billion, was invested in Africa. Capital expenditure will continue to be carefully controlled during 2017. The Group's capital expenditure associated with operating activities is expected to reduce from $0.9 billion in 2016 to $0.5 billion in 2017. The 2017 total comprises Ghana capex of c.$90 million, West Africa non-operated capex of c.$30 million, Kenya pre-development expenditure of c.$100 million and exploration and appraisal spend limited to c.$125 million. Uganda expenditure of c.$125 million will be offset by completion of the Uganda farm-down.

Portfolio management

On 9 January 2017, Tullow announced that it had agreed a substantial farm-down of its assets in Uganda to Total. Under the Sale and Purchase Agreement, Tullow has agreed to transfer 21.57% of its 33.33% Uganda interests to Total for a total consideration of $900 million. 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 right to back-in. 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 by Total 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. The disposal is expected to complete in 2017.

The divestment of the Norway business is progressing well with two deals completed before year-end and one in January 2017. Four licences, including the Wisting oil discovery, have been sold to Statoil, eight licences, including the Oda asset, have been sold to Aker BP ASA and two further licences have been sold to ConocoPhillips. A further two sales were executed in December 2016 with two separate parties. These sales, covering a further 13 licences, and which include the 2016 Cara oil and gas discovery, are on track to complete in the first quarter of 2017. In aggregate, the Norway asset sales are expected to yield proceeds of up to $0.2 billion. Once completed, the Group will no longer hold any licences on the Norwegian Continental Shelf.

Balance sheet

Following the scheduled amortisation of RBL facility commitments in October 2016, the Group ended the year with available credit under the RBL facility of $3.3 billion, $1.0 billion under the Corporate Facility, $1.3 billion of corporate bonds, $300 million of Convertible bonds and $116 million under the Norwegian Exploration Finance Facility. At the end of 2016, Tullow had total facility headroom and free cash of $1.0 billion, in aggregate, and net debt of $4.8 billion.

In April 2016 the Corporate Facility was extended to April 2018 with commitments reducing to $800 million in April 2017 and to $600 million in January 2018. On 7 February 2017, the Corporate Facility was extended by a further year to April 2019 with commitments of $500 million from April 2018 reducing to $400 million in October 2018. In October 2016 Tullow also secured $345 million of new commitments from its existing lenders by exercising an accordion facility embedded in the RBL which will take effect from 1 April 2017. The new commitments will largely offset the impact of the scheduled RBL amortisation in April 2017 and will ensure Tullow has appropriate headroom throughout 2017 as it refinances its bank facilities.

Liquidity risk management and going concern

The Group closely monitors and manages its liquidity risk. 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. In the currently low commodity price environment, the Group has taken appropriate action to reduce its cost base and had $1.0 billion of debt liquidity headroom and free cash at the end of 2016. 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 2016 Annual Report and Accounts.

Notwithstanding our forecasts of liquidity headroom throughout the 12 month period, risk remains in relation to the volatility of the oil price environment, operational performance of the Group's assets, their impact on operating cash flows and the Group's currently contracted debt maturity profiles, such that the Group's liquidity position may deteriorate within the assessment period.

To mitigate these risks and to fulfil the Group's objective to reduce net debt, the Group continues to closely monitor cash flow projections and will take mitigating actions in advance to maintain our liquidity. Actions available to the Group include additional funding options, further rationalisation of our cost base including cuts to discretionary capital expenditure and portfolio management.

Based on the analysis above and the level of mitigating actions available, 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.

2017 principal financial risks and uncertainties

The principal financial risks to performance identified for 2017 are:

- Oil price and overall market volatility
- Operational performance and project delivery
- Maintaining capital and operating cost discipline
- Execution of financial strategy to maintain appropriate liquidity

Events since year-end

On 5 January 2017, Tullow announced that Ian Springett, CFO, has taken an extended leave of absence to undergo treatment for a medical condition, with Les Wood, Vice President Finance and Commercial, appointed Interim CFO.

On 9 January 2017, Tullow announced that it had agreed a substantial farm-down of its assets in Uganda to Total. For further details please see above.

On 11 January 2017, the Group announced that Paul McDade, currently Chief Operating Officer, will be appointed Chief Executive Officer following Tullow's Annual General Meeting on 26 April 2017. This follows an internal and external process led by Tullow's Nominations Committee. At the same time, after six years on Tullow's Board and five as Chairman, Simon Thompson will step down from the Board. Aidan Heavey, Chief Executive Officer and founder of Tullow Oil, will succeed Mr. Thompson as Chairman of the Group for a transitional period of up to but not exceeding two years. Ann Grant, Senior Independent Director, will retire at the AGM after nine years' service on the Board. Jeremy Wilson, a non-executive Director of Tullow and Chairman of the Remuneration Committee, will succeed Ms Grant as Senior Independent Director.

On 17 January 2017, the Group announced that the Erut-1 well in Block 13T, Northern Kenya, had discovered a gross oil interval of 55 metres with 25 metres of net oil pay at a depth of 700 metres. The overall oil column for the field is estimated to be 100 to 125 metres.

On 7 February 2017, Tullow agreed a one year maturity extension of its Corporate Facility to April 2019, with commitments of $500 million from April 2018 reducing to $400 million in October 2018. The extension has been significantly oversubscribed, demonstrating the continued support from Tullow's relationship banks.

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.

	2016 $m	2015 $m
Additions to property, plant and equipment	818.5	1,258.2
Additions to intangible exploration and evaluation assets	291.4	626.3
Less		
Decommissioning asset additions	(57.1)	147.4
Capitalised share-based payment charge	(2.7)	(18.6)
Capitalised finance costs	(138.8)	(160.1)
Additions to administrative assets	(1.6)	(23.1)
Norwegian tax refund	(50.5)	(50.4)
Other non-cash capital expenditure	(2.2)	(59.7)
Capital investment	857.0	1,720.0
Movement in working capital	122.1	(53.9)
Additions to administrative assets	1.6	23.1
Norwegian tax refund	50.5	50.4
Cash capital expenditure per the cash flow statement	**1,031.2**	**1,739.6**

Net debt

Net debt is a useful indicator of the Group's indebtedness, financial flexibility and capital structure because it indicates the level of borrowings after taking account of cash and cash equivalents within the Group's business that could be utilised to pay down the outstanding 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.

	2016 $m	2015 $m
Current borrowings	591.5	73.8
Non-current borrowings	4,388.4	4,262.4
Unamortised arrangement fees	35.5	38.8
Equity component of convertible bonds	48.4	–
Less cash and cash equivalents	(281.9)	(355.7)
Net debt	**4,781.9**	**4,019.3**

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.

	2016 $m	2015 $m
Loss from continuing activities	(597.3)	(1,036.9)
Less		
Income tax credit	(311.0)	(260.4)
Finance costs	198.2	149.0
Finance revenue	(26.4)	(4.2)
(Gain)/loss on hedging instruments	(18.2)	58.8
Depreciation, depletion and amortisation	466.9	580.1
Share-based payment charge	43.9	48.7
Restructuring costs	12.3	40.8
Loss on disposal	3.4	56.5
Goodwill impairment	164.0	53.7
Exploration costs written off	723.0	748.9
Impairment of property, plant and equipment, net	167.6	406.0
Provisions for inventory	–	22.2
Provision for onerous service contracts, net	114.9	185.5
Adjusted EBITDAX	**941.3**	**1,048.7**
Net debt	**4,781.9**	**4,019.3**
Gearing (times)	**5.1**	**3.8**

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.

	2016 $m	2015 $m
Cost of sales	813.1	1,015.3
Less		
Operating lease expense	21.0	–
Depletion and amortisation of oil and gas assets	448.5	551.2
Underlift, overlift and oil stock movements	(76.5)	(1.5)
Share-based payment charge included in cost of sales	2.7	0.8
Other cost of sales	40.2	58.5
Underlying cash operating costs	**377.2**	**406.3**

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.

	2016 $m	2015 $m
Net cash from operating activities	512.5	978.2
Net cash used in investing activities	(967.2)	(1,679.6)
Net cash generated by financing activities	399.3	745.5
Foreign exchange loss	(18.4)	(7.4)
Repayment of bank loans	769.1	191.8
Drawdown of bank loans	(1,187.5)	(1,168.8)
Issue of convertible bonds	(300.0)	–
Free cash flow	**(792.2)**	**(940.3)**

Condensed consolidated income statement

Year ended 31 December 2016

	Notes	2016 $m	2015 $m
Continuing activities			
Sales revenue		1,269.9	1,606.6
Other operating income – lost production insurance proceeds	8	90.1	–
Cost of sales	7	(813.1)	(1,015.3)
Gross profit		546.9	591.3
Administrative expenses	7	(116.4)	(193.6)
Restructuring costs	7	(12.3)	(40.8)
Loss on disposal		(3.4)	(56.5)
Goodwill impairment		(164.0)	(53.7)
Exploration costs written off	10	(723.0)	(748.9)
Impairment of property, plant and equipment, net	11	(167.6)	(406.0)
Provision for onerous service contracts, net		(114.9)	(185.5)
Operating loss		(754.7)	(1,093.7)
Gain/(loss) on hedging instruments		18.2	(58.8)
Finance revenue		26.4	4.2
Finance costs		(198.2)	(149.0)
Loss from continuing activities before tax		(908.3)	(1,297.3)
Income tax credit	9	311.0	260.4
Loss for the year from continuing activities		(597.3)	(1,036.9)
Attributable to:			
Owners of the Company		(599.9)	(1,034.8)
Non-controlling interest		2.6	(2.1)
		(597.3)	(1,036.9)
Loss per ordinary share from continuing activities		¢	¢
Basic	2	(65.8)	(113.6)
Diluted	2	(65.8)	(113.6)

Condensed consolidated statement of comprehensive income and expense

Year ended 31 December 2016

	2016 $m	2015 $m
Loss for the year	(597.3)	(1,036.9)
Items that may be reclassified to the income statement in subsequent periods		
Cash flow hedges		
(Loss)/gains arising in the year	(135.3)	513.0
Reclassification adjustments for items included in (loss)/profit on realisation	(415.2)	(302.4)
Exchange differences on translation of foreign operations	17.1	(43.6)
Other comprehensive (loss)/income	(533.4)	167.0
Tax relating to components of other comprehensive (loss)/income	108.8	(42.3)
Net other comprehensive (loss)/income for the year	(424.6)	124.7
Total comprehensive expense for the year	(1,021.9)	(912.2)
Attributable to:		
Owners of the Company	(1,024.5)	(910.1)
Non-controlling interest	2.6	(2.1)
	(1,021.9)	(912.2)

Condensed consolidated balance sheet

As at 31 December 2016

	Notes	2016 $m	2015 $m
ASSETS			
Non-current assets			
Goodwill		–	164.0
Intangible exploration and evaluation assets	10	2,025.8	3,400.0
Property, plant and equipment	11	5,362.9	5,204.4
Investments		1.0	1.0
Other non-current assets	12	175.7	223.4
Derivative financial instruments		15.8	218.7
Deferred tax assets		758.9	295.3
		8,340.1	9,506.8
Current assets			
Inventories		155.3	107.2
Trade receivables		118.4	80.8
Other current assets	12	838.9	763.2
Current tax assets		138.3	127.6
Derivative financial instruments		91.7	406.5
Cash and cash equivalents		281.9	355.7
Assets classified as held for sale	13	837.1	–
		2,461.6	1,841.0
Total assets		10,801.7	11,347.8
LIABILITIES			
Current liabilities			
Trade and other payables	14	(916.1)	(1,110.6)
Provisions	15	(51.9)	(187.0)
Borrowings		(591.5)	(73.8)
Current tax liabilities		(83.1)	(208.3)
Derivative financial instruments		(5.9)	(2.1)
		(1,648.5)	(1,581.8)
Non-current liabilities			
Trade and other payables	14	(112.3)	(99.3)
Borrowings		(4,388.4)	(4,262.4)
Provisions	15	(1,106.7)	(1,065.1)
Deferred tax liabilities		(1,292.4)	(1,164.5)
Derivative financial instruments		(10.9)	–
		(6,910.7)	(6,591.3)
Total liabilities		(8,559.2)	(8,173.1)
Net assets		2,242.5	3,174.7
EQUITY			
Called up share capital		147.5	147.2
Share premium		619.3	609.8
Equity component of convertible bonds		48.4	–
Foreign currency translation reserve		(232.2)	(249.3)
Hedge reserve		128.2	569.9
Other reserves		740.9	740.9
Retained earnings		778.0	1,336.4
Equity attributable to equity holders of the Company		2,230.1	3,154.9
Non-controlling interest		12.4	19.8
Total equity		2,242.5	3,174.7

Condensed consolidated statement of changes in equity

Year ended 31 December 2016

	Called up share capital $m	Share premium $m	Equity component of convertible bonds $m	Foreign currency translation reserve $m	Hedge reserve $m	Other reserves $m	Retained earnings $m	Total $m	Non-controlling interest $m	Total Equity $m
At 1 January 2015	147.0	606.4	–	(205.7)	401.6	740.9	2,305.8	3,996.0	24.3	4,020.3
Loss for the year	–	–	–	–	–	–	(1,034.8)	(1,034.8)	(2.1)	(1,036.9)
Hedges, net of tax	–	–	–	–	168.3	–	–	168.3	–	168.3
Currency translation adjustments	–	–	–	(43.6)	–	–	–	(43.6)	–	(43.6)
Issue of employee share options	0.2	3.4	–	–	–	–	–	3.6	–	3.6
Vesting of PSP shares	–	–	–	–	–	–	(1.9)	(1.9)	–	(1.9)
Share-based payment charges	–	–	–	–	–	–	67.3	67.3	–	67.3
Distribution to non-controlling interests	–	–	–	–	–	–	–	–	(2.4)	(2.4)
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 31 December 2016	147.5	619.3	48.4	(232.2)	128.2	740.9	778.0	2,230.1	12.4	2,242.5

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.*

Condensed consolidated cash flow statement

Year ended 31 December 2016

	Notes	2016 $m	2015[1] $m
Cash flows from operating activities			
Loss before taxation		(908.3)	(1,297.3)
Adjustments for:			
Depreciation, depletion and amortisation		466.9	580.1
Loss on disposal		3.4	56.5
Goodwill impairment		164.0	53.7
Exploration costs written off	10	723.0	748.9
Impairment of property, plant and equipment, net	11	167.6	406.0
Provision for onerous service contracts, net	15	114.9	185.5
Payments under onerous service contracts	15	(132.0)	–
Provisions for inventory		–	22.2
Decommissioning expenditure	15	(23.0)	(40.8)
Share-based payment charge		43.9	48.7
(Gain)/loss on hedging instruments		(18.2)	58.8
Finance revenue		(26.4)	(4.2)
Finance costs		198.2	149.0
Operating cash flow before working capital movements		774.0	967.1
Increase in trade and other receivables		(99.4)	(26.5)
(Increase)/decrease in inventories		(47.8)	9.0
(Decrease)/increase in trade payables		(29.8)	(6.3)
Cash flows from operating activities		597.0	943.3
Income taxes (paid)/received		(84.5)	34.9
Net cash from operating activities		512.5	978.2
Cash flows from investing activities			
Proceeds from disposals		62.8	55.8
Purchase of intangible exploration and evaluation assets		(275.2)	(647.6)
Purchase of property, plant and equipment		(756.0)	(1,092.0)
Interest received		1.2	4.2
Net cash used in investing activities		(967.2)	(1,679.6)
Cash flows from financing activities			
Net proceeds from issue of share capital		9.9	3.5
Debt arrangement fees		(31.7)	(25.7)
Repayment of bank loans		(769.1)	(191.8)
Drawdown of bank loans		1,187.5	1,168.8
Issue of convertible bonds		300.0	–
Repayment of obligations under finance leases		(3.3)	(3.3)
Finance costs paid		(284.0)	(203.6)
Distribution to non-controlling interests		(10.0)	(2.4)
Net cash generated by financing activities		399.3	745.5
Net (decrease) /increase in cash and cash equivalents		(55.4)	44.1
Cash and cash equivalents at beginning of year		355.7	319.0
Foreign exchange loss		(18.4)	(7.4)
Cash and cash equivalents at end of year		281.9	355.7

1. An amount of $372.8 million has been re-presented between movements in trade payables and purchase of property, plant and equipment related to movements in capital accruals. This reduced the cash outflow for the purchase of property, plant and equipment in 2015 from $1,464.8m to $1,092.0m, with a corresponding adjustment to the cash flow from changes in trade payables, resulting in the net cash inflow from increases in trade payables of $366.5m becoming a net cash outflow from decreases in trade payables of $6.3m.

Notes to the preliminary financial statements

Year ended 31 December 2016

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 2017.

The financial information for the year ended 31 December 2016 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 2015 have been delivered to the Registrar of Companies and those for 2016 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 2015. 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 2016, 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 of $599.9 million (2015: $1,034.8 million, loss), by the weighted average number of ordinary shares outstanding during the year of 911.9 million (2015: 911.3 million).

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. The diluted weighted average number of ordinary shares increased by 96.6 million (2015: 25.1 million) in respect of employee share options, resulting in a diluted weighted average number of shares of 1,033.0 million (2015: 936.3 million). Due to losses made in 2016 and 2015 all potential ordinary shares are antidilutive.

3. Dividends

In view of current capital allocation priorities, the Board is again recommending that no dividend is paid. At a time when Tullow is focusing on capital allocation, financial flexibility and cost reductions, the Board believes that Tullow and its shareholders are better served by retaining funds in the business.

4. 2016 Annual Report and Accounts

The Annual Report and Accounts will be mailed in March 2017 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.

5. Annual General Meeting

Tullow's AGM will take place on 26 April 2017 at 12pm at Tullow Oil plc, Building 9, Chiswick Park, 566 Chiswick High Road, London, W4 5XT.

6. 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 2016 and 31 December 2015.

	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)

6. Segmental reporting contd.

	West Africa $m	East Africa $m	New Ventures $m	Unallocated $m	Total $m
2015					
Sales revenue by origin	1,606.6	–	–	–	1,606.6
Segment result	(189.7)	(28.3)	(461.2)	(123.6)	(802.8)
Loss on disposal of other assets					(56.5)
Unallocated corporate expenses					(234.4)
Operating loss					(1,093.7)
Loss on hedging instruments					(58.8)
Finance revenue					4.2
Finance costs					(149.0)
Loss before tax					(1,297.3)
Income tax credit					260.4
Loss after tax					(1,036.9)
Total assets	7,510.5	2,601.6	1,011.2	224.5	11,347.8
Total liabilities	(3,085.8)	(341.4)	(331.8)	(4,414.1)	(8,173.1)
Other segment information					
Capital expenditure:					
Property, plant and equipment	1,245.0	0.5	1.5	11.2	1,258.2
Intangible exploration and evaluation assets	23.1	399.6	203.6	–	626.3
Depreciation, depletion and amortisation	(553.2)	(1.1)	(1.2)	(24.6)	(580.1)
Impairment of property, plant and equipment, net	(406.0)	–	–	–	(406.0)
Exploration costs written off	(380.0)	(28.3)	(340.6)	–	(748.9)
Goodwill impairment	–	–	(53.7)	–	(53.7)

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

7. Operating loss

	Notes	2016 $m	2015 $m
Cost of sales			
Operating costs		377.2	406.3
Operating lease payments		21.0	–
Depletion and amortisation of oil and gas assets	11	448.5	551.2
Underlift, overlift and oil stock movements		(76.5)	(1.5)
Share-based payment charge included in cost of sales		2.7	0.8
Other cost of sales		40.2	58.5
Total cost of sales		813.1	1,015.3
Administrative expenses			
Share-based payment charge included in administrative expenses		41.2	47.9
Depreciation of other fixed assets	11	18.4	28.9
Relocation costs associated with major simplification project		(0.5)	5.9
Other administrative costs		57.3	110.9
Total administrative expenses		116.4	193.6
Restructuring costs	15	12.3	40.8

8. Insurance proceeds

During 2016 the Group issued insurance claims in respect of the Jubilee turret remediation project. Insurance proceeds of $145.0 million were recorded in the year ended 31 December 2016 (2015: $nil). Proceeds related to lost production under the Business Interruption insurance policy of $90.1 million (2015: $nil) 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 $31.8 million (2015: $nil) were recorded within the operating costs line of cost of sales. Proceeds related to compensation for capital costs under the Hull and Machinery insurance policy of $23.1 million (2015: $nil) were recorded within additions to property, plant and equipment.

9. Taxation on loss on ordinary activities

a. Analysis of tax credit for the year

	2016 $m	2015 $m
Current tax		
UK corporation tax	67.3	(3.5)
Foreign tax	(18.5)	94.9
Total corporate tax	48.8	91.4
UK petroleum revenue tax	(1.1)	(0.3)
Total current tax	47.7	91.1
Deferred tax		
UK corporation tax	9.4	6.9
Foreign tax	(369.8)	(354.0)
Total deferred corporate tax	(360.4)	(347.1)
Deferred UK petroleum revenue tax	1.7	(4.4)
Total deferred tax	(358.7)	(351.5)
Total tax credit	(311.0)	(260.4)

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 current tax credit shown above and the amount calculated by applying the standard rate of UK corporation tax applicable to UK profits of 20% (2015: 20%) to the loss before tax is as follows:

	2016 $m	2015 $m
Group loss on ordinary activities before tax	(908.3)	(1,297.3)
Tax on Group loss on ordinary activities at the standard UK corporation tax rate of 20% (2015: 20%)	(181.7)	(259.5)
Effects of:		
Non-deductible exploration expenditure	25.8	114.7
Other non-deductible expenses	22.7	97.7
Derecognition of deferred tax previously recognised	30.2	–
Impairment of goodwill	127.9	10.7
Utilisation - tax losses not previously recognised	(9.5)	–
Net losses not recognised	61.7	15.8
Petroleum revenue tax (PRT)	(6.7)	(4.4)
UK corporation tax deductions for current PRT	–	2.2
Adjustment relating to prior years	(2.1)	(14.9)
Adjustments to deferred tax relating to change in tax rates	(0.8)	(1.0)
Higher rate of taxation on Norway income	(286.4)	(132.7)
Other tax rates applicable outside the UK and Norway	(86.8)	(164.6)
PSC income not subject to corporation tax	(1.6)	(28.5)
Uganda capital gains tax	–	108.2
Tax incentives for investment	(3.7)	(4.1)
Group total tax credit for the year	(311.0)	(260.4)

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. 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 $2,844.0 million (2015: $1,802.0 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.

No deferred tax liability is recognised on temporary differences of $8.2 million (2015: $8.5 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 2016, $108.8 million (2015: $42.3 million) of tax has been recognised through other comprehensive income of which $107.8 million (2015: $43.2 million) is current and $0.9 million (2015: $0.9 million) is deferred tax relating to all credits (2015: charges) on cash flow hedges arising in the year.

Current tax assets

As at 31 December 2016, current tax assets were $138.3 million (2015: $127.6 million) of which $90.0 million (2015: $55.0 million) relates to Norway, where 78% of exploration expenditure is refunded as a tax refund in the year following the incurrence of such expenditure.

10. Intangible exploration and evaluation assets

	2016 $m	2015 $m
At 1 January	3,400.0	3,660.8
Additions	291.4	626.3
Disposals	–	(5.2)
Amounts written off	(723.0)	(748.9)
Write-off associated with Norway contingent consideration	(36.5)	–
Transfer to assets held for sale	(912.3)	–
Transfer to property, plant and equipment	–	(63.6)
Currency translation adjustments	6.2	(69.4)
At 31 December	2,025.8	3,400.0

Included within 2016 additions is $50.2 million of capitalised interest (2015: $49.7 million). The Group only capitalises interest in respect of intangible exploration and evaluation assets where it is considered that development is ongoing.

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 2016 write-off	2016 Current year expenditure written-off $m	2016 Prior year expenditure written-off $m	2016 Post-tax write off $m	2016 Pre-tax write off $m	2016 Remaining recoverable amount $m
Ethiopia	Country	b	1.9	–	1.9	1.9	–
Gabon	Arouwe licence	b	1.0	–	1.0	1.6	–
Ghana	New Ventures	f	2.3	–	2.3	3.5	–
Guinea	Country	b	5.6	–	5.6	5.6	–
Greenland	Country	b	1.0	–	1.0	1.0	–
Kenya	Blocks 10A & L8	b	(2.6)	–	(2.6)	(2.6)	–
Madagascar	Country	b, d	4.1	21.5	25.6	25.6	–
Mauritania	Blocks C6, C7 & C18	b, c	0.2	9.3	9.5	9.5	–
Mozambique	Country	b	(1.0)	–	(1.0)	(1.0)	–
Netherlands	Licence E18 & F16	b	0.8	–	0.8	1.5	49.0
Norway	Country	a, b, c, d, e	17.8	61.0	78.8	286.9	7.1
Pakistan	Kup well	a	1.9	8.8	10.7	10.7	–
Suriname	Block 31 & Coronie	b, c	1.3	18.0	19.3	19.3	–
Uganda	Country	e	–	247.8	247.8	330.4	453.1
Other	Various	b	4.9	–	4.9	4.9	–
New Ventures	Various	f	18.4	–	18.4	24.2	–
Total write-off			57.6	366.4	424.0	723.0	

a. Current year unsuccessful drilling results
b. Current year expenditure or 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
.

11. Property, plant and equipment

	2016 Oil and gas assets $m	2016 Other fixed assets $m	2016 Total $m	2015 Oil and gas assets $m	2015 Other fixed assets $m	2015 Total $m
Cost						
At 1 January	10,439.9	289.5	10,729.4	9,240.3	283.7	9,524.0
Additions	816.9	1.6	818.5	1,235.1	23.1	1,258.2
Disposals	(276.1)	(2.7)	(278.8)	(6.2)	(3.6)	(9.8)
Transfer from intangible assets	–	–	–	63.6	–	63.6
Currency translation adjustments	(208.2)	(36.5)	(244.7)	(92.9)	(13.7)	(106.6)
At 31 December	10,772.5	251.9	11,024.4	10,439.9	289.5	10,729.4
Depreciation, depletion and amortisation						
At 1 January	(5,360.0)	(165.0)	(5,525.0)	(4,489.1)	(147.9)	(4,637.0)
Charge for the year	(448.5)	(18.4)	(466.9)	(551.2)	(28.9)	(580.1)
Impairment loss	(184.3)	(0.4)	(184.7)	(467.2)	–	(467.2)
Reversal of impairment loss	10.9	–	10.9	61.2	–	61.2
Disposal	276.1	2.6	278.7	6.4	3.6	10.0
Currency translation adjustments	205.0	20.5	225.5	79.9	8.2	88.1
At 31 December	(5,500.8)	(160.7)	(5,661.5)	(5,360.0)	(165.0)	(5,525.0)
Net book value at 31 December	5,271.7	91.2	5,362.9	5,079.9	124.5	5,204.4

The 2016 additions include capitalised interest of $88.6 million in respect of the TEN development project (2015: $110.4 million). The carrying amount of the Group's oil and gas assets includes an amount of $17.8 million (2015: $27.4 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 2016 income statement impairment charge includes $6.2 million of insurance proceeds.

	Trigger for 2016 impairment	2016 Impairment $m	Pre-tax discount rate assumption	Short-term price assumption	Mid-term price assumption	Long-term price assumption
UK GCU[d]	a	48.0	n/a	n/a	n/a	n/a
Limande CGU[e] (Gabon)	a	3.1	13%	2yr forward curve	$70/bbl	$90/bbl
Echira CGU[e] (Gabon)	a	2.2	13%	2yr forward curve	$70/bbl	$90/bbl
Etame CGU[e] (Gabon)	a	1.5	13%	2yr forward curve	$70/bbl	$90/bbl
Oba (CGU)[e]		(10.9)	15%	2yr forward curve	$70/bbl	$90/bbl
M'boundi (Congo)	a	6.4	12%	2yr forward curve	$70/bbl	$90/bbl
Espoir (Côte d'Ivoire)	a	12.3	10%	2yr forward curve	$70/bbl	$90/bbl
TEN (Ghana)	a	97.0	10%	2yr forward curve	$70/bbl	$90/bbl
Jubilee (Ghana)	c	3.7	n/a	n/a	n/a	n/a
Chinguetti (Mauritania)	b	10.1	10%	2yr forward curve	$70/bbl	$90/bbl
Impairment		173.4				

a. Delay in estimated step up to oil and gas mid-term and long-term price assumptions.
b. Increase in decommissioning estimate.
c. Impairment of a component of the asset which is covered by insurance proceeds.
d. The fields in the UK are grouped into one CGU as all fields within those countries share critical gas infrastructure.
e. The Limande, Echria, Etame and Oba CGUs in Gabon comprise a number of fields which share export infrastructure.

All impairment assessments are prepared on a Value In Use basis using discounted future cash flows based on 2P reserves profiles. The principal assumptions are oil price and the pre-tax discount rate which is nominal. Oil prices stated above are benchmark prices to which an individual field price differential is applied.

Based on the approximate volatility of the 2016 oil price, a reduction in the forward curve of $20/bbl is considered to be a reasonably possible change for the purposes of sensitivity analysis. This would increase the impairment charge by $487.8 million. A $15/bbl reduction in both the mid-term and the long-term price assumption assumed, which is based on the range seen in external oil price market forecasts, would increase the impairment charge by $744.4 million.

A 1% increase in the pre-tax discount rate would increase the impairment by $129.3 million. The Group believe a 1% increase in the pre-tax discount rate to be a reasonable possibility based on historical analysis of the Group's and a peer group of companies impairment discount rates.

12. Other assets

	2016 $m	2015 $m
Non-current		
Amounts due from joint venture partners	127.3	161.8
Uganda VAT recoverable	35.9	50.3
Other non-current assets	12.5	11.3
	175.7	223.4
Current		
Amounts due from joint venture partners	560.4	584.4
Underlifts	34.9	2.4
Prepayments	26.3	77.9
VAT recoverable	5.7	9.2
Other current assets	211.6	89.3
	838.9	763.2

The decrease in amounts due from joint venture partners relates to the decrease in operated current liabilities, which are recorded gross with the corresponding debit recognised as an amount due from joint venture partners, in Kenya and Ghana. Other current assets have increased due to accrued insurance proceeds.

13. Assets held for sale

On 9 January 2017, Tullow announced that it had agreed a substantial farm-down of its assets in Uganda to Total. Under the Sale and Purchase Agreement, Tullow has agreed to transfer 21.57% of its 33.33% Uganda interests to Total for a total consideration of $900 million. 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 right to back-in. 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 by Total 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. The disposal is expected to complete in 2017.

The estimated fair value of the consideration is $829.7 million which when compared to the carrying value of the Group's interest in Uganda resulted in an exploration write-off of $330.4 million. 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 Total's cost of borrowing. This represents a level 3 financial asset.

The divestment of the Norway business is progressing well with two deals completed before year-end and one in January 2017. Four licences, including the Wisting oil discovery, have been sold to Statoil, eight licences, including the Oda asset, have been sold to Aker BP ASA and two further licences have been sold to ConocoPhillips. A further two sales were executed in December 2016 with two separate parties. These sales, covering a further 13 licences, and which include the 2016 Cara oil and gas discovery, are on track to complete in the first quarter of 2017. In aggregate, the Norway asset sales are expected to yield proceeds of up to $0.2 billion. Once completed, the Group will no longer hold any licences on the Norwegian Continental Shelf. Combined with the transactions that completed in 2016, transfer to assets held for sale of the Norwegian assets was $82.6 million of which $7.4 million remained as held for sale at 31 December 2016.

The major classes of assets and liabilities comprising the assets classified as held for sale are as follows:

	Uganda 2016 $m	Norway 2016 $m	Total 2016 $m
Intangible exploration and evaluation assets	829.7	7.4	837.1
Total assets classified as held for sale	829.7	7.4	837.1
Total liabilities associated with assets classified as held for sale	–	–	–
Net assets of disposal groups	829.7	7.4	837.1

14. Trade and other payables

Current liabilities

	2016 $m	2015 $m
Trade payables	46.9	24.0
Other payables	124.6	61.2
Overlifts	6.9	3.7
Accruals	721.2	993.3
VAT and other similar taxes	14.6	26.9
Current portion of finance lease	1.9	1.5
	916.1	1,110.6

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 12). The increase in trade payables and in other payables predominantly represent timing differences.

Non-current liabilities

	2016 $m	2015 $m
Other non-current liabilities	87.7	72.8
Non-current portion of finance lease	24.6	26.5
	112.3	99.3

Trade and other payables are non-interest bearing except for finance leases.

15. Provisions

	Decommissioning 2016 $m	Other provisions 2016 $m	Total 2016 $m	Decommissioning 2015 $m	Other provisions 2015 $m	Total 2015 $m
At 1 January	1,008.8	243.3	1,252.1	1,192.9	67.5	1,260.4
New provisions and changes in estimates	57.1	71.4	128.5	(147.4)	177.1	29.7
Disposals	–	–	–	0.8	0.3	1.1
Payments	(23.0)	(132.0)	(155.0)	(40.8)	–	(40.8)
Transfer to accruals	–	(35.0)	(35.0)	–	–	–
Unwinding of discount	25.1	–	25.1	28.3	0.1	28.4
Currency translation adjustment	(53.6)	(3.5)	(57.1)	(25.0)	(1.7)	(26.7)
At 31 December	1,014.4	144.2	1,158.6	1,008.8	243.3	1,252.1
Current provisions	49.0	2.9	51.9	–	187.0	187.0
Non-current provisions	965.4	141.3	1,106.7	1,008.8	56.3	1,065.1

Included within other provisions is provision for onerous service contracts and provision for restructuring costs. Due to the reduction in planned future work programmes the Group has identified a number of onerous service contracts. The expected unutilised capacity has been provided for in 2015 and 2016 resulting in an income statement charge of $114.9 million (2015: $185.5 million). During 2016, the Group incurred $12.3 million (2015: $44.9 million) in respect of restructuring costs. A provision in respect of contingent consideration due on the acquisition of Spring Energy has been released in 2016 ($43.5 million) as the Group concluded that payment of such consideration is not probable.

15. Provisions contd.

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	2016 $m	2015 $m
Congo	2%	3%	2027	18.3	15.2
Cote d'Ivoire	2%	3%	2026	48.1	53.3
Equatorial Guinea	2%	3%	2028-2029	130.0	126.2
Gabon	2%	3%	2021-2034	54.2	61.0
Ghana	2%	3%	2034-2036	267.6	257.7
Mauritania	2%	3%	2017	130.9	121.4
Netherlands	2%	3%	2020-2036	100.7	90.5
UK	2%	3%	2015-2018	264.6	283.5
				1,014.4	1,008.8

16. 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 2016	287.6	205.8	-	-	-	-	287.6	205.8	321.8
Revisions	13.8	(0.2)	-	-	-	-	13.8	(0.2)	13.8
Transfer from contingent resources	(7.4)	-	-	-	-	-	(7.4)	-	(7.4)
Disposals	-	-	-	-	-	-	-	-	-
Production	(21.9)	(15.9)	-	-	-	-	(21.9)	(15.9)	(24.5)
31 December 2016	272.1	189.7	-	-	-	-	272.1	189.7	303.7
CONTINGENT RESOURCES									
1 January 2016	115.8	724.9	628.8	42.6	101.5	4.2	846.1	771.7	974.7
Revisions	4.8	5.6	3.7	-	-	-	8.5	5.6	9.5
Additions	-	-	-	-	-	-	-	-	-
Disposals	-	-	-	-	(101.5)	-	(101.5)	-	(101.5)
Transfers to commercial reserves	7.4	-	-	-	-	-	7.4	-	7.4
31 December 2016	128.0	730.5	632.5	42.6	0.0	4.2	760.6	777.3	890.1
TOTAL									
31 December 2016	400.1	920.2	632.5	42.6	0.0	4.2	1,032.7	967.0	1,193.8

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 relate to Jubilee, Tchatamba, Ezanga, Espoir, M'Oba, and an equity revision for certain Gabonese fields.
4. The West Africa transfers relate to the Etame and MBoundi fields which were transferred to Contingent Resources.
5. The West Africa revision to gas contingent resources relates to the relinquishment of the Pelican field in Mauritania.
6. New Ventures disposals to contingent resources relate to the Norway country exit and Zaedyus license relinquishment.

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 283.2 mmboe at 31 December 2016 (31 December 2015: 299.1 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 over 100 exploration and production licences across 18 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. A replay facility will be available from approximately noon on 8 February 2017 until 15 February 2017. The telephone numbers and access codes are:

Live event		**Replay facility available from Noon**	
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