Tullow Oil plc

2018 HALF YEAR RESULTS

25 July 2018

Tullow Oil plc – 2018 Half Year Results

West African production delivers $0.9bn revenue; $0.5bn gross profit; $0.4bn free cash flow
Good progress towards FIDs in East Africa; Namibia well to start multi-well exploration campaign
Aidan Heavey steps down as Chairman and retires 32 years after founding Tullow Oil

25 July 2018 – Tullow Oil plc (Tullow), the independent oil and gas exploration and production group, announces its half year results for the six months ended 30 June 2018. 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:

"Today's results are further evidence of the progress that Tullow has made in the first half of 2018. With this firm financial foundation, we can concentrate on growth across our three core businesses. Over the next two years, we will increase production from our current assets in West Africa, progress two large onshore developments in East Africa and step up our search for material new oil fields in Africa and South America through a multi-year exploration campaign which will initially focus on Namibia and Guyana. There is much to look forward to for Tullow's shareholders, host countries and staff."

PAUL McDADE ALSO PAID A PERSONAL TRIBUTE TO AIDAN HEAVEY:

"Aidan has dedicated his career to the African Oil & Gas industry. He founded Tullow 32 years ago as a small gas producer in Senegal and since then Tullow has had operations in 45 countries around the world including 20 countries in Africa. He has been a pioneer and an inspiration across Africa for decades, especially in Ghana, Uganda and Kenya. Aidan has also been a mentor to me for many years and I could not have wished for a better Chairman in my first years as CEO. Everyone at Tullow will miss Aidan and wishes him and his family all the very best for the future."

2018 HALF YEAR RESULTS SUMMARY

- Revenue of $905 million[1]; gross profit of $521 million; post tax profit of $55 million; free cash flow of $401 million
- Net debt and gearing reduced to $3.1 billion and 2.0x; debt maturities extended with issue of $800 million of senior notes; facility headroom and free cash now $1.2 billion
- Three-year cost reduction programme delivers $708 million of savings versus original target of $500 million
- West Africa first half 2018 working interest oil production averaged 88,200 bopd[2]; 2018 full year oil production guidance upgraded from 82-90,000 bopd to 86-92,000 bopd
- First incremental production from Ghana drilling programme expected in August; second rig due to start drilling October 2018
- Kenya Early Oil Pilot Scheme and oil trucking started June 2018; phased development project on track for sanction late 2019
- Uganda deal completion expected in coming months; Upstream and pipeline FEED and upstream ESIAs have been completed; contract awards under evaluation and overall project sanction expected around the end of 2018
- High-impact exploration campaign starts with Cormorant well in Namibia in September 2018; investing up to $150 million per year in exploration and drilling three to five high impact frontier wells annually
- 2018 capex forecast remains $460 million, includes second rig in Ghana
- Unsuccessful litigation in the English Commercial Court vs Seadrill and in arbitration with Kosmos re: West Leo rig
- Dorothy Thompson appointed Chair of Tullow with effect from 20 July 2018; Aidan Heavey has stepped down from the Board and retired from Tullow

FINANCIAL OVERVIEW

	1H 2018	1H 2017
Sales revenue ($m)*	905	788
Gross profit ($m)	521	303
Profit/(loss) after tax ($m)	55	(348)
Free cash flow ($m)	401	205
Gearing (times)	2.0	3.3
Net debt ($m)	3,082	3,834

[1] Revenue does not include proceeds for Tullow's corporate Business Interruption insurance of $129 million (1H 2017: $54 million)
[2]includes 11,900 bopd of production-equivalent insurance payments

Dividend

The Board considered carefully whether to pay an interim dividend but concluded that, for the moment, free cash flow is best used to continue to pay down debt and to invest in assets.

Board changes

Dorothy Thompson succeeded Aidan Heavey, Tullow's Founder, as Chair after the Board meeting on 20 July 2018. Aidan retired from Tullow and the Board at the same time. Dorothy was originally appointed an independent non-executive Director of Tullow on 25 April 2018.

Operations review

Group Production

Tullow's West Africa first half 2018 oil production averaged 88,200 bopd, in line with expectations. This includes 11,900 bopd of production-equivalent insurance payments relating to the Jubilee field that has been realised under Tullow's Corporate Business Interruption insurance policy. First half 2018 working interest gas production averaged 2,800 boepd. This results in a total Group oil and gas production average for the first half of 91,000 boepd.

The TEN field in Ghana and Tullow's non-operated assets in Gabon, Côte D'Ivoire and Equatorial Guinea all performed ahead of expectations. The Jubilee field in Ghana performed slightly below expectations, however, enhancements to the gas compression system completed during the recent FPSO shutdowns are expected to improve oil production capacity.

Tullow's 2018 full year working interest oil production forecast, including production-equivalent insurance payments, has been upgraded to 86-92,000 bopd. Working interest gas production is expected to average around 3,000 boepd, reflecting a later start-up of gas sales from TEN. Overall Group production guidance for the full year is increased to 89-95,000 boepd.

WEST AFRICA

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

> *"This has been a period of strong delivery in West Africa which continues to be Tullow's engine for growth. Jubilee has performed well and, following gas de-bottlenecking on the FPSO, now has higher oil production capacity. The Jubilee FPSO turret has been stabilised and the vessel is now ready for its final rotation. The TEN fields have continued to exceed expectations and we will be testing facility capacity by the end of the year. In our Central and West Africa non-operated business, focused investment has seen production levels increase and stabilise across the portfolio."*

Ghana

In the first half of the year, Tullow contracted a second rig, the Stena Forth, a sixth-generation drillship, to work on its drilling programme in Ghana. The rig has been contracted for an initial three-well campaign with flexible extension options and is due to start drilling in October 2018 alongside the Maersk Venturer which began work in March 2018. This additional rig capacity will enable Tullow to carry out simultaneous drilling and completion activity, allowing the tie-in of new wells to be brought forward. There is no effect on the Group's capital expenditure forecast for 2018 as the Maersk Venturer began drilling later than initially planned.

Overall Tullow is aiming to have five new wells across Jubilee and TEN on-line before the end of the year, increasing production through both facilities. In 2019, the Group intends to drill further wells to sustain and maximise plateau production. Tullow is also evaluating additional exploration acreage in Ghana which will be made available in the upcoming licence round.

Jubilee

In the first half of 2018, gross production from the Jubilee field averaged 66,000 bopd (net: 23,400 bopd). Tullow's net production is increased to 35,300 bopd after including 11,900 bopd of net production-equivalent insurance payments. Production in the first half of the year is slightly below expectations due to downtime related to maintenance work on the gas compression system. While this maintenance work briefly impacted production, enhancements to the gas compression capacity completed in the recent shut-downs have positively impacted oil production capacity. The Jubilee FPSO has been regularly producing above 100,000 bopd gross from existing wells since these works were carried out.

In the first half of the year, two new Jubilee production wells, J51-P and J53-P, were drilled by the Maersk Venturer as part of the current drilling campaign. These wells have successfully met all pre-drill expectations and will be completed and brought on stream during the third and fourth quarters of 2018. A previously drilled Jubilee water injection well will also be tied-in.

The Turret Remediation Project is now entering its final phases. The FPSO Kwame Nkrumah was shut down twice in the first half of 2018 for work to stabilise the turret bearing for periods of 19 days and 21 days respectively. This work has successfully been completed and the turret has been secured to a newly installed bearing plate. A final short shutdown is planned for the end of 2018 to rotate the FPSO to its permanent heading and install the final spread mooring anchoring system. This shutdown will have a minimal impact on production. The Joint Venture Partners have also agreed to install a Catenary Anchor Leg Mooring (CALM) buoy for offtake from the FPSO. The installation of the CALM buoy, which is likely to take place in 2020, is not expected to affect production and it is anticipated that the cost of both fabrication and installation will be covered by the Joint Venture's Hull & Machinery insurance.

Tullow forecasts full year gross production from the Jubilee field to average around 78,100 bopd (net: 27,700 bopd), up from 75,800 bopd gross (net: 26,900 bopd) previously guided. Tullow expects net production-equivalent insurance payments for the full year to be around 8,700 bopd (previously 10,200 bopd). Accordingly, full year net production guidance from Jubilee, including production-equivalent insurance payments, is now around 36,400 bopd.

TEN

The TEN fields performed well in the first half of 2018, with gross production averaging 65,100 bopd (net: 30,700 bopd). Due to this strong performance in the first half of the year, Tullow has increased its gross full year production forecast for TEN to around 65,500 bopd (net: 30,900 bopd).

The first additional Ntomme well (Nt-05P) was successfully drilled in the first half of the year and is expected to start production in August 2018. A second well is expected to be completed around the end of the year and start production in early 2019, at which time Tullow expects to be able to increase gross production to around 80,000 bopd. The TEN FPSO has previously been tested at rates in excess of the 80,000 bopd design capacity and the vessel's ability to produce above this design capacity for long-term operations will be tested in 2019 as further wells come on stream.

Gas from the TEN fields was supplied to the Ghana National Gas Company to replace Jubilee gas during the Jubilee shutdowns. Gas sales from TEN are expected to commence later in this quarter.

Seadrill and Kosmos litigation

Following a trial in the English Commercial Court in May 2018, the court ruled on 3 July that Tullow was not entitled to terminate its West Leo rig contract with Seadrill on 4 December 2016 by invoking the contract's force majeure provisions. Following advice from counsel, Tullow will not be appealing this ruling. Tullow has now paid Seadrill a contractual termination fee, other standby fees that accrued in the 60 days prior to termination of the contract and interest amounting to $248 million in aggregate and is due to pay a further $11 million of Ghana withholding tax in August.

Although Tullow regards these as joint venture costs, Kosmos disputed separately, through an International Chamber of Commerce arbitration against Tullow, its share of the liability (c. 20%) of any costs related to the use of the West Leo rig beyond 1 October 2016. On 17 July 2018, the arbitration tribunal delivered a final and binding award in favour of Kosmos which determined that Kosmos is not liable for its share of the Seadrill liabilities. The arbitration award also provided that Tullow is due to reimburse Kosmos $14 million for rig demobilisation costs and certain of its legal costs.

Central & West Africa non-operated portfolio

Production in the first half of the year was strong across the West Africa non-operated portfolio and averaged around 22,200 bopd net, substantially above expectations. The Equatorial Guinea fields have performed particularly well following a change of operator and Tullow has therefore increased its annual net production forecast from the Okume and Ceiba fields to 6,400 bopd net (up from 4,800 bopd net).

Full year guidance for the Central & West Africa non-operated portfolio has been increased to 21,800 bopd net (from 19,100 bopd net).

In Mauritania, the Chinguetti FPSO has been demobilised following the successful temporary suspension of 15 wells as part of decommissioning the asset.

UK

Gas production from the UK in the first half of the year averaged 2,800 boepd net. Tullow still expects annualised 2018 UK gas production to be around 2,000 boepd as the final producing fields will cease production in the third quarter of the year. Decommissioning activities continue in the North Sea with well plug and abandonment operations progressing to plan.

EAST AFRICA

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

> *"Our teams in East Africa have put in a substantial amount of effort as we drive two projects towards their respective Final Investment Decisions (FIDs). In Uganda, we expect to reach project sanction and complete our farm-down by the end of the year. In Kenya, EOPS is proving its worth as a pilot scheme across all aspects of the onshore oil project. We are taking those insights into our commercial and technical discussions with government, communities, partners and banks as we continue to move the full field development forward."*

Kenya

Full Field Development

The Kenya development plan is progressing well and, at this early stage, the project remains on track for FID in late 2019 and First Oil in 2022. In February 2018, Tullow announced that 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 oil in place of up to 4 billion barrels. The additional remaining conventional undrilled prospect inventory of the basin is approximately 230 mmbo risked mean recoverable, not including further potential in under-explored plays.

Tullow and its Joint Venture Partners 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 foundation stage includes a 60,000 to 80,000 bopd Central Processing Facility (CPF) and an export pipeline to Lamu. The installed infrastructure from this initial phase is expected to be utilised for the optimisation of the remaining South Lokichar oil fields and future oil discoveries, allowing the incremental development of these fields to be completed at a lower unit cost post-First Oil.

Total gross capex associated with the Foundation Stage is expected to be $2.9 billion, split between $1.8 billion for the upstream and $1.1 billion for the pipeline.

Front End Engineering and Design (FEED) and Environmental and Social Impact Assessment (ESIA) work for the upstream Foundation Stage are now under way, following the award of the upstream FEED and Integrated Project Management contracts to WorleyParsons in May 2018. FEED and the ESIA work for the pipeline are also progressing to plan, with the midstream FEED contract awarded to Wood Group. Commercial discussions continue with potential pipeline contractors.

Extended injection and production testing continues, with water injection testing ongoing at Ngamia-11 and continued oil production from the Ngamia-8 well. The Ngamia-3 well also successfully started production in June 2018. Results from the wells to date are in line with expectations and data will be used to inform the development plan for the Foundation Stage of the South Lokichar Development.

Early Oil Pilot Scheme

The transfer of stored crude oil from Turkana to Mombasa by road commenced on 3 June 2018. This milestone was marked by a ceremony attended by H.E. President Uhuru Kenyatta, H.E. Deputy President H.E. William Ruto, the Turkana County Governor, Turkana MPs as well as many other Government Ministers and officials. The first truck arrived at the Refinery in Mombasa on 7 June 2018, where the oil will be stored for future export. A first lifting of low sulphur Kenyan crude oil from Mombasa is expected in the first quarter of 2019.

Initially, the trucks will transport approximately 600 bopd produced through well testing and this is expected to steadily increase to 2,000 bopd once the EOPS is fully operational and production testing commences from the Amosing field.

In recent weeks, trucking operations have been suspended due to protests by the local community. Local government officials and the Ministry of Petroleum & Mining (Energy) have been working to resolve these issues so that trucking can resume as soon as possible and in a sustainable manner.

Uganda

Tullow and its Joint Venture Partners, Total and CNOOC Ltd, are awaiting approval of the farm-down transaction from the Government of Uganda. This approval is expected in the second half of the year. At completion of the farm-down, Tullow anticipates receiving a cash payment of $100 million and a payment of the working capital completion adjustment and deferred consideration for the pre-completion period ($59 million for 2017 and an estimated c.$70 million for 2018). A further $50 million cash consideration is due to be received when FID is taken.

The Joint Venture Partners continue to work towards reaching FID for the development project around the end of 2018 with operational activity continuing as planned. The upstream FEED is now complete and initial technical and commercial reviews of this work have begun, which will ultimately result in the award of the Engineering, Procurement and Construction (EPC) contracts. Important geophysical and geotechnical surveys across the upstream area, including at the proposed location for the Central Processing Facility, were completed in June. The upstream ESIA has been completed and has been submitted to the National Environmental Management Authority for review with approval expected in the third quarter.

Discussions on the key pipeline project agreements continue between the Joint Venture Partners and the Ugandan and Tanzanian Governments. The pipeline FEED and EPC tender process for the pipeline have been completed with the award to be made in the second half. Project financing for the pipeline is also progressing with the development of the financial model ongoing. In the second half, Tullow anticipates completing key commercial, technical and land agreements with the Governments of Uganda and Tanzania as well as the submission of an ESIA for the pipeline to both Governments.

NEW VENTURES

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

> *"Although we are only drilling one well in 2018, the addition of new licenses and inventory of prospects built during the downturn will allow us to drill an average of 3 to 5 low-cost frontier wells in future years. We have built a licence position in some of the most sought-after acreage in the world and have identified the best prospects with the right equities and risk following careful technical and financial screening. In 2019, we expect to drill frontier exploration wells in Guyana and Suriname and are considering other high potential options in Africa and South America."*

Africa

Côte d'Ivoire

In Côte d'Ivoire, Tullow began its work programme across its new onshore blocks in early April 2018 with a full tensor gravity gradiometry (FTG) survey covering 8,600 sq km. This survey was completed in May 2018 and the data is currently being interpreted and will be used to optimise the location of a 2D seismic survey planned for 2019. Tullow continues to reprocess 3D seismic data for the offshore Block CI-524 which sits alongside the maritime border with Ghana, next to Tullow's operated TEN fields.

Tullow also signed a farm-out agreement for a 30% interest in all seven onshore licences (CI-301, CI-302, CI-518, CI-519, CI-520 CI-521 and CI-522) to Cairn Energy Plc, subject to obtaining the necessary Government approvals. This farm-down will leave Tullow with a 60% operated interest in each licence with most of the pre-drilling exploration costs carried.

Namibia

Tullow expects to start drilling the high-impact Cormorant prospect in the PEL37 licence in Namibia in September 2018. The well will target light oil and there are several similarly-sized follow-up prospects nearby. This frontier well will take approximately 30 days to drill and will be drilled by the Ocean Rig Poseidon.

Tullow agreed a farm-down of a 15% interest in the neighbouring PEL30 licence to ONGC Videsh in November 2017. The farm-down is awaiting final Government and partner approvals.

Mauritania

In Mauritania, a major 9,000 sq km 3D seismic survey across Block C-18 was completed. Tullow's share of the cost was carried under previous farm-down agreements. Interpretation of this survey and the Block C-3 survey, recorded in 2017, is in progress to identify prospects for future drilling. Both Block C-3 and Block C-18 offer potential drilling candidates for late 2019.

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

Guyana

In Guyana, technical and commercial ranking of potential prospects across both the Kanuku and Orinduik licences is ongoing. The exploration team continues to see significant potential across multiple prospects in this area and is working to define which of these prospects will be matured for drilling in 2019 and 2020.

Earlier this year, Tullow agreed to increase its equity share in the Kanuku licence, offshore Guyana, from 30% to 37.5% in a farm-in deal with Repsol. This deal is subject to Government of Guyana approval.

Jamaica

In Jamaica, a 2,200 sq km 3D survey was completed successfully in May 2018 and the data is now being processed.

Peru

In Peru, as previously announced in January 2018, Tullow agreed the terms to acquire a 100% stake in offshore Blocks Z-64, Z-65, Z-66, Z-67 and Z-68. However, in May 2018, the Supreme Decrees, authorising PeruPetro, the state regulator, to execute licence contracts for these blocks, were revoked by the Peruvian Government. Tullow was disappointed by this outcome, as the Group has operated throughout under the strict guidance of PeruPetro and the Ministry of Energy and Mines, and had complied with the process and procedures required under Peruvian law to agree new exploration licences. Since the revocation, Tullow has formally expressed its continued interest in the licences and will continue to work closely with PeruPetro towards execution of these licences.

Separately, Tullow has agreed to acquire a 35% interest in Block Z-38 through a farm-down from Karoon Gas Australia. This agreement remains 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.

Suriname

A two-year extension was granted for Block 47 where the Goliathberg prospect is a drilling candidate for 2019.

Uruguay

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

Pakistan

In Pakistan, Tullow completed the sale of three blocks (Bannu West, Kalchas and Block 28) to Mari Oil and Gas for a cash consideration of $5.5 million.

Finance review

Les Wood, Chief Financial Officer, commented today:

"Tullow's balance sheet now provides a firm foundation for growth with gearing reduced to 2x Net debt/EBITDAX and debt maturities extended following the recent bond issue. By exceeding our original $500m target and delivering savings of $708m savings since 2015, we have successfully embedded financial discipline into Tullow and this approach to expenditure will continue even as the oil price recovers. We are now focussed on balancing the use of our free cash flow across further debt reduction, investing in our assets, returns to shareholders and seeking opportunities for growth."

Financial results summary	1H 2018	1H 2017
Working interest production volume (boepd) [1]	79,100	82,400
Sales volume (boepd)	74,700	76,700
Realised oil price ($/bbl)	67.5	57.3
Total revenue ($m) [2]	905	788
Gross profit ($m)	521	303
Underlying cash operating costs per boe ($/boe)[3]	10.9	11.9
Exploration costs written off ($m)	9	4
Impairment of property, plant and equipment, net ($m)	8	642
Operating profit/(loss) ($m)	300	(395)
Profit/(loss) before tax ($m)	150	(558)
Profit/(loss) after tax ($m)	55	(348)
Basic earnings/(loss) per share (cents)	3.9	(28.3)
Capital investment ($m) [3, 4]	145	61
Adjusted EBITDAX (last twelve months basis) ($m) [3]	1,579	1,156
Net debt ($m) [3]	3,082	3,834
Gearing (times) [3]	2.0	3.3
Free cash flow ($m) [3]	401	205

1. *Including the impact of production-equivalent insurance payment barrels from the Jubilee field, Group working interest production was 91,000 boepd (1H 2017: 87,400 boepd).*
2. *Total revenue does not include receipts for Tullow's corporate Business Interruption Insurance of $129 million (1H 2017: $54 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. *Capital investment excludes Ugandan expenditure of $23 million in the first half of 2018 that will be recovered, following completion of the farm-down.*

Production and commodity prices

Total Group working interest production for the period, including insurance receipts equivalent to 11,900 bopd, averaged 91,000 boepd (1H 2017: 87,400 boepd). Actual working interest production for the first half averaged 79,100 boepd, a decrease of 4% for the period (1H 2017: 82,400 boepd). This is primarily due to lower production from Jubilee as the FPSO was shut down for two periods in the first half of 2018 for the planned remediation work to stabilise the turret bearing.

The realised oil price after hedging for the period was $67.5/bbl (1H 2017: $57.3/bbl). The increase in oil prices led to a loss on the realisation of hedges entered in to by the Group, reducing total revenue. However, hedging remains a key element of the Group's risk management strategy.

Operating costs, depreciation and expenses

Underlying cash operating costs (defined in the non-IFRS measures section), amounted to $181 million; $10.9/boe (1H 2017: $166 million; $11.9/boe). The decrease in operating costs per barrel is a result of higher production, including production equivalent insurance barrels.

DD&A charges before impairment on production and development assets amounted to $290 million; $17.5/boe (1H 2017: $263 million; $16.6/boe), the increase being attributed to increased production volumes, but partially offset by the impact of impairments recorded in 2017.

Administrative expenses of $59 million (1H 2017: $51 million) were slightly higher than the prior period, predominantly as a result of the strengthening of Sterling against the US dollar. Administrative expenses also include $12 million (1H 2017: $6 million) associated with IFRS 2 Share-based Payments.

In June 2015 the Group set a target to remove $500 million of cash costs from the business over a three-year period. During 2017 this target was increased to $650 million. The three-year period concluded on 30 June 2018, with the Group delivering $708 million of savings. The ongoing cost of running the business has reduced significantly and will continue to be a key area of focus.

Impairment of property, plant and equipment, net	1H 2018	1H 2017
Pre-tax impairment of property, plant and equipment, net ($m)	8	642
Associated deferred tax credit ($m)	–	(224)
Post-tax impairment of property, plant and equipment, net ($m)	8	418

The Group incurred this non-cash impairment of property, plant, and equipment due to minor changes to estimates on the cost of decommissioning certain UK assets.

Exploration costs written off	1H 2018	1H 2017
Exploration costs written off ($m)	9	4

During the first half of 2018 the Group recorded exploration costs written off of $9 million which predominantly related to write-offs of New Venture activities.

Provisions

The Group has recorded an additional pre-tax income statement charge of $143.9 million in respect of the unsuccessful Seadrill and Kosmos litigation described on page 3.

Derivative financial instruments

Tullow continues to undertake hedging activities as part of the ongoing management of its business risk to protect against oil price volatility and to ensure the availability of cashflow for reinvestment in capital programmes that are driving business growth.

At 30 June 2018, the Group's derivative instruments had a net negative fair value of $142 million (1H 2017: positive $123 million), inclusive of deferred premium.

As a result of the implementation of IFRS 9: Financial instruments, the Group's opening hedge reserves on 1 January 2018 decreased by $74 million. Refer to note 2 for further details.

Hedge position	2H 2018	2019	2020
Oil hedges			
Volume – bopd	45,000	34,732	10,997
Average floor price protected ($/bbl)	52.23	51.98	56.59

Net financing costs

Net financing costs for the period were $145 million (1H 2017: $166 million). The decrease in financing costs is associated with the reduction in interest on borrowings due to a reduction in the average level of net debt in 2018 compared to 2017. This was partially offset by the finance lease costs associated with the recording of the TEN FPSO as a finance lease in the second half of 2017 and increased costs due to the accelerated unwind of costs associated with the repayment of the bonds that were originally due for repayment in 2020. Net financing costs include interest incurred on the Group's debt facilities, foreign exchange gains/losses, the unwinding of a 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. A reconciliation of net financing costs is included in Note 8.

Taxation

The overall net tax expense of $96 million (1H 2017: $210 million credit) primarily relates to expenses in respect of the Group's production activities in West Africa including non-operated European assets and non-recurring deferred tax credits associated with exploration write-offs, impairments and onerous lease provisions. After adjusting for the non-recurring amounts related to exploration write-offs, impairments, disposals and onerous lease provisions and their associated deferred tax benefit, the Group's underlying effective tax rate is 48% (1H 2017: 18%). The increase in the underlying effective tax rate is mainly due to increased profits from production activities taxed at higher rates of taxation, lower tax credits from Norwegian exploration activities and a reduction in the utilisation of losses.

Profit/(loss) after tax from continuing activities and basic earnings/(loss) per share

The profit from continuing activities for the period amounted to $55 million (1H 2017: $348 million loss). Basic profit per share was 3.9 cents (1H 2017: 28.3 cents loss).

Reconciliation of net debt

	$m
Year-end 2017 net debt	**3,471**
Sales revenue	(905)
Other operating income – lost production insurance proceeds	(129)
Operating costs	181
Operating expenses	141
Cash flow from operations	**(712)**
Movement in working capital	(105)
Tax paid	58
Purchases of intangible exploration and evaluation assets and property, plant, and equipment	187
Other investing activities	(1)
Other financing activities	189
Foreign exchange gain on cash and debt	(5)
1H 2018 net debt	**3,082**

Capital investment

Capital expenditure amounted to $145 million (1H 2017: $77 million) with $117 million invested in development activities and $28 million in exploration and appraisal activities. More than 75% of the total was invested in Ghana, Kenya and Uganda and 95% was invested in Africa.

The Group's 2018 capital investment associated with operating activities is expected to total approximately $460 million. This total excludes c.$70 million of forecast Uganda expenditure which will be repaid from either the working capital completion adjustment or deferred consideration following the completion of the Uganda farm-down, which is expected in the second 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 expenditure 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.$59 million. A further $50 million cash consideration is due to be received when FID is achieved.

Balance sheet

On 23 March 2018, Tullow completed its offering of $800 million of senior notes, due in 2025. The offering was significantly oversubscribed and increased from the initial offering of $650 million. Proceeds have been used to redeem, in full, senior notes due in 2020 and repay drawings on the Reserve Based Lending facility. The senior notes offering further extended Tullow's debt maturities, with no scheduled debt repayments until 2021. On 4 April 2018, commitments under Tullow's Revolving Corporate Facility amortised in line with the schedule to $500 million, and on 18 April 2018 Tullow voluntarily cancelled a further $150 million of commitments under the facility, reducing financing costs of undrawn committed facilities.

As a result of the implementation of IFRS 9: Financial instruments, the Group's opening non-current borrowings on 1 January 2018 increased by $144 million. Refer to note 2 for further details.

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. The Group had $1.2 billion of debt liquidity headroom and free cash at 30 June 2018. The Group's forecasts show that the Group will have sufficient financial headroom for the 12 months from the date of approval of the half year results. Therefore, 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 half year results.

2018 principal financial risks and uncertainties

The Board determines the key risks for the Group and monitors mitigation plans and performance on a monthly basis. Summary detail of the principal risks and uncertainties facing the Group at the half year end are detailed in note 18. There have been limited changes in respect of these risks since the Annual Report was published. Since 31 December 2017 oil prices have improved from $67/bbl to $79/bbl at 30 June 2018 helping moderate the risks from a low oil price environment. However, businesses operating in the extractives sector face increasing pressure to contribute more to the national economies in their countries of operation through the assertion of tax or regulatory changes or different contractual interpretations reflecting increased community/political/regulatory influence. The Group's risk mitigation activities remain unchanged.

Events since 30 June 2018

Following a trial in the English Commercial Court in May 2018, the court ruled on 3 July that Tullow was not entitled to terminate its West Leo rig contract with Seadrill on 4 December 2016 by invoking the contract's force majeure provisions. On 17 July 2018, an arbitration tribunal delivered a final and binding award in favour of Kosmos which determined that Kosmos is not liable for its share of the Seadrill liabilities. Refer to the 'Seadrill and Kosmos litigation' paragraph of the operations review, and note 15 for further details.

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 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 adjustments.

The Directors believe that 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 because it eliminates certain accounting adjustments such as capitalised finance costs and decommissioning asset additions.

	1H 2018	1H 2017
Additions to property, plant, and equipment	106.7	(26.6)
Additions to intangible exploration and evaluation assets	105.5	144.7
Less		
Decommissioning asset additions [1]	14.1	(9.4)
Capitalised share based payment charge [2]	0.6	2.3
Capitalised finance costs [3]	32.7	31.9
Additions to administrative assets [4]	2.0	1.0
Norwegian tax refund [5]	0.2	1.2
Uganda capital investment [6]	23.1	15.8
Other non-cash capital expenditure [7]	(5.5)	14.4
Capital investment	**145.0**	**60.9**
Movement in working capital	16.9	80.9
Additions to administrative assets	2.0	1.0
Norwegian tax refund	0.2	1.2
Uganda capital investment	23.1	15.8
Cash capital expenditure per the cash flow statement	**187.2**	**159.8**

Notes:

1. *Decommissioning assets are recorded as an equal and opposite amount to the Group's decommissioning provisions. Decommissioning assets are depreciated over the life of the relevant asset until the point of decommissioning. Any increases in a provision due to a change in scope of the obligation results in an increase in the decommissioning asset. The asset is recorded under the property, plant and equipment line item in the balance sheet. Any new decommissioning assets, or increases in decommissioning assets, from the previous year are shown as additions to that line item.*
2. *Capitalised share-based payment charge relates to the portion of the non-cash share-based payment charge that relates to employees who work on capital projects.*
3. *Capitalised finance costs relates to the portion of the Group's borrowing costs that is deemed to fund development activities.*
4. *Administrative assets represent fixtures, fittings and office equipment such as computers. Because they are not directly attributable to the exploration or development of oil and gas, the Group excludes their costs from its definition of capital investment.*
5. *Capital expenditure is adjusted for the Norwegian tax refunds. The Norwegian tax refund represents 78% of the Group's qualifying exploration expenditure in Norway during each of each period. The refund is paid in the year following the year in which the expense is incurred.*
6. *Capital investment excludes Ugandan expenditure that will be recovered, subject to completion of the farm-down.*
7. *Other adjustments include cash re-imbursements for capital expenditure under sale and purchase agreements between their effective date and completion date and exclusion of other non-cash adjustments to fixed asset additions made in accordance with IFRS.*

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 30 June 2018 was $213.6 million current and $1,254.2 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.

	30 June 2018	30 June 2017
Current borrowings	-	512.5
Non-current borrowings	3,475.3	3,553.0
Unamortised arrangement fees[1]	(33.7)	38.5
Adjustment to convertible bonds[2]	33.8	48.4
Less cash and cash equivalents[3]	(393.4)	(318.4)
Net debt	**3,082.0**	**3,834.0**

Notes:

1. *Unamortised arrangement fees are incurred on creation or amendment of borrowing facilities. They are capitalised as incurred, set against the associated liability, and amortised over the life of the borrowing facility to which they relate.*
2. *On initial recognition the Convertible Bonds were measured at fair value the difference between this and the principal ($48.4 million) was included as a component of equity and a decrease to borrowings. Over the life of the Convertible Bonds, the fair value reduces until the carrying value of the borrowings are equal to the principal outstanding for repayment on maturity. However, the equity component of the convertible bond remains unchanged, and is thus different to the figure included in the reconciliation above.*
3. *Cash and cash equivalents includes an amount of $224 million (1H 2017: $136 million) which the Group holds as operator in joint venture bank accounts. In addition to the cash held in joint venture bank accounts the Group had $51 million (1H 2017: $30 million) held in restricted bank accounts.*

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 profit/(loss) from continuing activities adjusted for income tax (expense)/credit, finance costs, finance revenue, 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 (last twelve months basis) therefore excludes interest on obligations under finance leases of $95.4 million, and interest income on amounts due from joint venture partners for finance leases of $45.2 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 2.0x.

Detailed reconciliation of adjusted EBITDAX to figures reported within the half year results has not been presented as the figures reported within the half year results are not presented on a last twelve months basis.

	As at 1H 2018	As at 1H 2017
Adjusted EBITDAX (last twelve months basis)	1,579.0	1,155.5
Net debt	3,082.0	3,834.0
Gearing (times)	**2.0**	**3.3**

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.

	1H 2018	1H 2017
Cost of sales	513.6	538.6
Less		
Operating lease expense [1]	-	53.4
Depletion and amortisation of oil and gas assets [2]	289.9	263.4
Underlift, overlift, and oil stock movements [3]	27.4	36.0
Share-based payment charge included in cost of sales [4]	0.8	1.3
Other cost of sales [5]	14.5	18.2
Underlying cash operating costs	**181.0**	**166.3**
Production (MMboe)	**16.54**	**13.97**
Underlying cash operating costs per boe ($/boe)	**10.9**	**11.9**

Notes:

1. *Operating lease expense are cost of sales amounts incurred under the Group's operating leases as determined in accordance with IFRS. For 1H 2017 this included TEN FPSO lease costs. However, on recognition as a finance lease, which occurred in August 2017, the expense associated with the TEN FPSO was recorded within depletion and amortisation of oil and gas assets.*
2. *Depletion and amortisation of oil and gas assets is the depreciation and amortisation of the Group's oil and gas assets over the life of an asset on a unit of production basis.*
3. *Under lifting or offtake arrangements for oil and gas produced in certain operations in which the Group has interests with other commercial partners, each participant may not receive and sell its precise share of the overall production in each period. The resulting imbalance between cumulative entitlement and cumulative production less stock constitutes "underlift" or "overlift". Underlift and overlift are valued at market value and included within other current assets and other current payables on the Group's balance sheet, respectively. Movements during an accounting period are charged to cost of sales rather than charged through revenue, and as a result gross profit is recognised on an entitlements basis.*
4. *Share-based payment charge included in cost of sales relates to the portion of the non-cash share-based payment charge that relates to employees who work on operational projects.*
5. *Other cost of sales includes purchases of gas from third parties to fulfil gas sales contracts and royalties paid in cash.*

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 provide returns to shareholders through dividends. Free cash flow is defined as net cash from operating activities, net cash used in investing activities, net cash used in financing activities and foreign exchange gains, adjusted for repayment of bank loans, drawdown of bank loans, debt arrangement fees and proceeds from the issue of share capital.

	1H 2018	1H 2017
Net cash from operating activities	759.5	502.2
Net cash used in investing activities	(185.9)	(150.6)
Net cash used in financing activities	(468.7)	(316.2)
Foreign exchange gain	4.5	1.1
Net proceeds from issue of share capital	-	(754.7)
Debt arrangement fees	11.5	8.0
Repayment of bank loans	1,210.1	1,069.9
Drawdown of bank loans	(930.0)	(155.0)
Free cash flow	**401.0**	**204.7**

Responsibility statement

The Directors confirm that to the best of their knowledge:

a. the condensed set of financial statements has been prepared in accordance with IAS 34 'Interim Financial Reporting';

b. the interim management report includes a fair review of the information required by DTR 4.2.7R (indication of important events during the first six months and description of principal risks and uncertainties for the remaining six months of the year); and

c. the interim management report includes a true and fair review of the information required by DTR 4.2.8R (disclosure of related parties' transactions and changes therein).

The Directors of Tullow Oil plc are as listed in the Group's 2017 Annual Report and Accounts. A list of the current Directors is maintained on the Tullow Oil plc website: www.tullowoil.com.

By order of the Board,

Paul McDade
Chief Executive Officer
24 July 2018

Les Wood
Chief Financial Officer
24 July 2018

Disclaimer

This statement contains certain forward-looking statements that are subject to the usual risk factors and uncertainties associated with the oil and gas exploration and production business. Whilst the Group believes the expectations reflected herein to be reasonable in light of the information available to them at this time, the actual outcome may be materially different owing to factors beyond the Group's control or within the Group's control where, for example, the Group decides on a change of plan or strategy. Accordingly, no reliance may be placed on the figures contained in such forward-looking statements.

Independent review report to Tullow Oil plc

We have been engaged by the company to review the condensed set of financial statements in the half-yearly financial report for the six months ended 30 June 2018 which comprises the income statement, the balance sheet, the statement of changes in equity, the cash flow statement and related notes 1 to 17. We have read the other information contained in the half-yearly financial report and considered whether it contains any apparent misstatements or material inconsistencies with the information in the condensed set of financial statements.

This report is made solely to the company in accordance with International Standard on Review Engagements (UK and Ireland) 2410 "Review of Interim Financial Information Performed by the Independent Auditor of the Entity" issued by the Financial Reporting Council. Our work has been undertaken so that we might state to the company those matters we are required to state to it in an independent review report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the company, for our review work, for this report, or for the conclusions we have formed.

Directors' responsibilities

The half-yearly financial report is the responsibility of, and has been approved by, the directors. The directors are responsible for preparing the half-yearly financial report in accordance with the Disclosure and Transparency Rules of the United Kingdom's Financial Conduct Authority.

As disclosed in note 2, the annual financial statements of the group are prepared in accordance with IFRSs as adopted by the European Union. The condensed set of financial statements included in this half-yearly financial report has been prepared in accordance with International Accounting Standard 34 "Interim Financial Reporting" as adopted by the European Union.

Our responsibility

Our responsibility is to express to the Company a conclusion on the condensed set of financial statements in the half-yearly financial report based on our review.

Scope of review

We conducted our review in accordance with International Standard on Review Engagements (UK and Ireland) 2410 "Review of Interim Financial Information Performed by the Independent Auditor of the Entity" issued by the Financial Reporting Council for use in the United Kingdom. A review of interim financial information consists of making inquiries, primarily of persons responsible for financial and accounting matters, and applying analytical and other review procedures. A review is substantially less in scope than an audit conducted in accordance with International Standards on Auditing (UK) and consequently does not enable us to obtain assurance that we would become aware of all significant matters that might be identified in an audit. Accordingly, we do not express an audit opinion.

Conclusion

Based on our review, nothing has come to our attention that causes us to believe that the condensed set of financial statements in the half-yearly financial report for the six months ended 30 June 2018 is not prepared, in all material respects, in accordance with International Accounting Standard 34 as adopted by the European Union and the Disclosure and Transparency Rules of the United Kingdom's Financial Conduct Authority.

Deloitte LLP

Statutory Auditor

London

24 July 2018

Condensed consolidated income statement

Six months ended 30 June 2018

	Notes	6 months ended 30.06.18 Unaudited $m	6 months ended 30.06.17 Unaudited Restated $m	Year ended 31.12.17 Audited Restated $m
Continuing activities				
Sales revenue		905.1	787.5	1,722.5
Other operating income – lost production insurance proceeds		129.3	54.3	162.1
Cost of sales	7	(513.6)	(538.6)	(1,069.3)
Gross profit		520.8	303.2	815.3
Administrative expenses	7	(59.5)	(51.4)	(95.3)
Restructuring costs	7	(1.5)	(1.4)	(14.5)
Gain/(loss) on disposal		4.9	(0.6)	(1.6)
Exploration costs written off	10	(8.6)	(3.9)	(143.4)
Impairment of property, plant and equipment, net	11	(7.9)	(641.7)	(539.1)
Provision for onerous service contracts, net		(149.3)	0.9	1.0
Operating profit/(loss)		298.9	(394.9)	22.4
(Loss)/gain on hedging instruments		(3.5)	3.2	1.4
Finance revenue	8	31.7	12.9	42.0
Finance costs	8	(176.6)	(179.1)	(351.7)
Profit/(loss) from continuing activities before tax		150.5	(557.9)	(285.9)
Income tax (expense)/credit	9	(96.0)	209.8	110.6
Profit/(loss) for the year from continuing activities		54.5	(348.1)	(175.3)
Attributable to:				
Owners of the Company		53.9	(347.7)	(176.3)
Non-controlling interest		0.6	(0.4)	1.0
		54.5	(348.1)	(175.3)
Earnings per ordinary share from continuing activities		¢	¢	¢
Basic	3	3.9	(28.3)	(13.7)
Diluted	3	3.7	(28.3)	(13.7)

Condensed consolidated statement of comprehensive income and expense

Six months ended 30 June 2018

	6 months ended 30.06.18 Unaudited $m	6 months ended 30.06.17 Unaudited Restated $m	Year ended 31.12.17 Audited Restated $m
Profit/(loss) for the period	54.5	(348.1)	(175.3)
Items that may be reclassified to the income statement in subsequent periods			
Cash flow hedges			
(Losses)/gains arising in the period	(67.1)	78.1	6.7
(Losses)/gains arising in the period – time value	(34.7)	13.6	(64.7)
Reclassification adjustments for items included in profit on realisation	13.4	(88.3)	(161.8)
Reclassification adjustments for items included in profit on realisation – time value	26.0	25.5	51.5
Exchange differences on translation of foreign operations	2.5	(3.3)	9.0
Other comprehensive expense	(59.9)	(13.5)	(146.1)
Tax relating to components of other comprehensive expense	–	(0.6)	24.3
Net other comprehensive expense for the period	(59.9)	(14.1)	(121.8)
Total comprehensive expense for the period	(5.4)	(323.1)	(310.3)
Attributable to:			
Owners of the Company	(6.0)	(322.7)	(311.3)
Non-controlling interest	0.6	(0.4)	1.0
	(5.4)	(323.1)	(310.3)

Condensed consolidated balance sheet

As at 30 June 2018

	Notes	30.06.18 Unaudited $m	30.06.17 Unaudited Restated $m	31.12.17 Audited Restated $m
ASSETS				
Non-current assets				
Intangible exploration and evaluation assets	10	2,010.6	2,100.6	1,933.4
Property, plant and equipment	11	5,052.8	4,365.9	5,254.7
Investments		1.0	1.0	1.0
Other non-current assets	12	751.6	200.3	789.8
Derivative financial instruments		–	21.8	0.8
Deferred tax assets		783.1	763.8	724.5
		8,599.1	7,453.4	8,704.2
Current assets				
Inventories		187.8	145.6	168.0
Trade receivables		87.2	112.8	171.4
Other current assets	12	829.2	525.4	768.3
Current tax assets		56.1	143.2	57.7
Derivative financial instruments		1.3	101.8	1.8
Cash and cash equivalents		393.4	318.4	284.0
Assets classified as held for sale	13	893.9	963.6	873.1
		2,448.9	2,310.8	2,324.3
Total assets		11,048.0	9,764.2	11,028.5
LIABILITIES				
Current liabilities				
Trade and other payables	14	(1,112.4)	(624.0)	(1,025.6)
Provisions	15	(391.0)	(88.1)	(230.8)
Borrowings		–	(512.5)	–
Current tax liabilities		(37.5)	(22.4)	(45.0)
Derivative financial instruments		(98.8)	(0.9)	(53.1)
Liabilities classified as held for sale	13	–	(111.0)	–
		(1,639.7)	(1,358.9)	(1,354.5)
Non-current liabilities				
Trade and other payables	14	(1,355.3)	(105.6)	(1,422.6)
Borrowings		(3,475.3)	(3,553.0)	(3,606.4)
Provisions	15	(741.1)	(962.7)	(801.6)
Deferred tax liabilities		(1,207.6)	(1,079.9)	(1,101.2)
Derivative financial instruments		(44.7)	(0.1)	(25.8)
		(6,824.0)	(5,701.3)	(6,957.6)
Total liabilities		(8,463.7)	(7,060.2)	(8,312.1)
Net assets		2,584.3	2,704.0	2,716.4
EQUITY				
Called up share capital	16	208.9	207.5	208.2
Share premium	16	1,340.3	1,311.8	1,326.8
Equity component of convertible bonds		48.4	48.4	48.4
Foreign currency translation reserve		(220.7)	(235.5)	(223.2)
Hedge reserve		(56.3)	117.4	(2.6)
Hedge reserve – Time value		(82.5)	(21.5)	(73.8)
Other reserves		740.9	740.9	740.9
Retained earnings		594.3	526.1	681.3
Equity attributable to equity holders of the Company		2,573.3	2,695.1	2,706.0
Non-controlling interest		11.0	8.9	10.4
Total equity		2,584.3	2,704.0	2,716.4

Condensed statement of changes in equity

As at 30 June 2018

	Share capital $m	Share premium $m	Equity component of convertible bonds $m	Foreign currency translation reserve[1] $m	Hedge Reserve[2] $m	Hedge reserve – Time value[4] $m	Other reserves[3] $m	Retained earnings[4] $m	Total $m	Non-controlling interest $m	Total Equity $m
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
Adjustment on adoption of IFRS 9, net of tax	–	–	–	–	–	(60.6)	–	60.6	–	–	–
Loss for the period	–	–	–	–	–	–	–	(347.7)	(347.7)	(0.4)	(348.1)
Hedges, net of tax	–	–	–	–	(10.8)	39.1	–	–	28.3	–	28.3
Currency translation adjustments	–	–	–	(3.3)	–	–	–	–	(3.3)	–	(3.3)
Issue of shares – Rights Issue	60.0	692.5	–	–	–	–	–	–	752.5	–	752.5
Share-based payment charges	–	–	–	–	–	–	–	35.2	35.2	–	35.2
Distribution to non-controlling interests	–	–	–	–	–	–	–	–	–	(3.1)	(3.1)
At 30 June 2017	207.5	1,311.8	48.4	(235.5)	117.4	(21.5)	740.9	526.1	2,695.1	8.9	2,704.0
Loss for the period	–	–	–	–	–	–	–	156.2	156.2	1.5	157.7
Hedges, net of tax	–	–	–	–	(120.0)	(52.3)	–	–	(172.3)	–	(172.3)
Currency translation adjustments	–	–	–	12.3	–	–	–	–	12.3	–	12.3
Issue of employee share options	0.7	15.0	–	–	–	–	–	–	15.7	–	15.7
Share-based payment charges	–	–	–	–	–	–	–	(1.0)	(1.0)	–	(1.0)
At 1 January 2018	208.2	1,326.8	48.4	(223.2)	(2.6)	(73.8)	740.9	681.3	2,706.0	10.4	2,716.4
Adjustment on adoption of IFRS 9, net of tax	–	–	–	–	–	–	–	(143.5)	(143.5)	–	(143.5)
Profit for the period	–	–	–	–	–	–	–	53.9	53.9	0.6	54.5
Hedges, net of tax	–	–	–	–	(53.7)	(8.7)	–	–	(62.4)	–	(62.4)
Currency translation adjustments	–	–	–	2.5	–	–	–	–	2.5	–	2.5
Issue of shares	0.7	13.5	–	–	–	–	–	(14.2)	–	–	–
Share-based payment charges	–	–	–	–	–	–	–	16.8	16.8	–	16.8
At 30 June 2018	208.9	1,340.3	48.4	(220.7)	(56.3)	(82.5)	740.9	594.3	2,573.3	11.0	2,584.3

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.*
4. *For further details of the adjustment on adoption of IFRS 9, refer to note 2. Note that the figures for 1 January 2017 to 1 January 2018 have been restated in relation to adoption of IFRS 9.*

Condensed consolidated cash flow statement

Six months ended 30 June 2018

	Notes	6 months ended 30.06.18 Unaudited $m	6 months ended 30.06.17 Unaudited Restated $m	Year ended 31.12.17 Audited Restated $m
Cash flows from operating activities				
Profit/(loss) before taxation		150.5	(557.9)	(285.9)
Adjustments for:				
Depreciation, depletion, and amortisation		298.9	272.1	592.2
(Gain)/loss on disposal		(4.9)	0.6	1.6
Exploration costs written off	10	8.6	3.9	143.4
Impairment of property, plant and equipment, net	11	7.9	643.8	541.1
Provision for onerous service contracts, net		149.3	0.9	(1.0)
Decommissioning expenditure		(59.0)	(10.5)	(25.7)
Share-based payment charge		12.7	20.4	33.9
Loss on hedging instruments		3.5	(3.2)	(1.4)
Finance revenue	8	(31.7)	(12.9)	(42.0)
Finance costs	8	176.6	179.1	351.7
Operating cash flow before working capital movements		712.4	536.3	1,307.9
Decrease/(increase) in trade and other receivables		43.0	123.3	122.0
Decrease/(increase) in inventories		(20.5)	9.6	(20.8)
(Decrease)/increase in trade payables		82.1	(129.8)	(251.4)
Cash flows from operating activities		817.0	539.4	1,157.4
Taxes (paid)/received		(57.5)	(37.2)	65.2
Net cash from operating activities		759.5	502.2	1,222.9
Cash flows from investing activities				
Proceeds from disposals		–	7.0	8.0
Purchase of intangible exploration and evaluation assets		(93.1)	(91.4)	(189.7)
Purchase of property, plant and equipment		(94.1)	(68.4)	(117.8)
Interest received		1.3	2.2	3.1
Net cash used in investing activities		(185.9)	(150.6)	(296.4)
Cash flows from financing activities				
Net proceeds from issue of share capital		–	754.7	768.1
Debt arrangement fees		(11.5)	(8.0)	(56.4)
Repayment of borrowings		(1,210.1)	(1,069.9)	(1,613.6)
Drawdown of borrowings		930.0	155.0	305.0
Repayment of obligations under finance leases		(57.4)	(1.7)	(62.6)
Finance costs paid		(119.7)	(143.3)	(265.4)
Distributions to non-controlling interests		–	(3.0)	(3.0)
Net cash used in financing activities		(468.7)	(316.2)	(927.9)
Net increase/(decrease) in cash and cash equivalents		104.9	35.4	(1.4)
Cash and cash equivalents at beginning of period		284.0	281.9	281.9
Foreign exchange gain		4.5	1.1	3.5
Cash and cash equivalents at end of period		393.4	318.4	284.0

Notes to the preliminary financial statements

Six months ended 30 June 2018

1. General information

The condensed financial statements for the six month period ended 30 June 2018 have been prepared in accordance with International Accounting Standard (IAS) 34 Interim Financial Reporting and the requirements of the Disclosure and Transparency Rules (DTR) of the Financial Conduct Authority (FCA) in the United Kingdom as applicable to interim financial reporting.

The Condensed financial statements represent a 'condensed set of financial statements' as referred to in the DTR issued by the FCA. Accordingly, they do not include all the information required for a full annual financial report and are to be read in conjunction with the Group's financial statements for the year ended 31 December 2017, which were prepared in accordance with International Financial Reporting Standards (IFRS) adopted for use by the European Union (EU). The Condensed financial statements are unaudited and do not constitute statutory accounts as defined in section 434 of the Companies Act 2006. The financial information for the year ended 31 December 2017 does not constitute statutory accounts as defined in section 434 of the Companies Act 2006. This information was derived from the statutory accounts for the year ended 31 December 2017, a copy of which has been delivered to the Registrar of Companies. The auditor's report on these accounts was unqualified, did not include a reference to any matters to which the auditor drew attention by way of an emphasis of matter and did not contain a statement under sections 498 (2) or (3) of the Companies Act 2006.

2. Accounting policies

The annual financial statements of Tullow Oil plc are prepared in accordance with IFRSs as issued by the International Accounting Standards Board and as adopted by the European Union. The condensed set of financial statements included in this half-yearly financial report has been prepared in accordance with International Accounting Standard 34 'Interim Financial Reporting', as adopted by the European Union and the Disclosure and Transparency Rules of the Financial Services Authority.

Basis of preparation

The condensed set of financial statements included in this half-yearly financial report has been prepared on a going concern basis as the Directors consider that the Group has adequate resources to continue in operational existence for the foreseeable future as explained in the Finance Review.

The accounting policies adopted in the 2018 half-yearly financial report are the same as those adopted in the 2017 Annual report and accounts other than the implementation of IFRS 9: Financial Instruments and IFRS 15: Revenue from Contracts with Customers from 1 January 2018. The adoption of these standards is discussed below.

New International Financial Reporting Standards adopted

IFRS 9: Financial Instruments

The implementation of IFRS 9 had two key impacts on the Group's financial statements. These related to the treatment of modification or exchange of financial liabilities and the treatment of the 'cost of hedging' of options.

1) The classification and measurement of financial liabilities is materially consistent with that required by IAS 39 with the exception of the treatment of modification or exchange of financial liabilities which do not result in de-recognition. The Group has identified that retrospective application of IFRS 9 has increased the carrying value of the Reserves Based Lending credit facility by $143.5 million and resulted in the need to record a modification loss due to the refinancing of the facility in November 2017. Given the refinancing occurred in November 2017, the condensed income statement for the six months ended 30 June 2017 has not been impacted. However, implementation reduced retained earnings on 1 January 2018. This will lower the finance costs recognised over the remaining life of the facility compared to the treatment under IAS 39. No other material impact as a result of IFRS 9's classification and measurement requirements has been identified.
2) The Group adopted the hedge accounting requirements of IFRS 9 effective 1 January 2018. The new hedge accounting rules will align the hedge accounting treatments more closely with the Group risk management strategy, and address previous inconsistencies and weakness in the hedge accounting model in IAS 39. The Group has identified a change in the treatment of the 'cost of hedging' of options on adoption of IFRS 9, specifically with respect to the fair value movement of time value. The fair value movement of time value, to the extent which it relates to the hedged item, has been presented as a separate component in the statement of comprehensive income and expenses. The 'gain/loss on hedging instruments' line in the Group's income statement now solely captures inefficiencies in the underlying hedges. This requirement has been applied retrospectively, as required, on adoption of IFRS 9.

A summary of the impact of the implementation of IFRS 9 is shown overleaf:

Income statement

	6 months ended 30.06.17 Unaudited – Previously reported $m	6 months ended 30.06.17 Unaudited – Adjusted $m	Transition adjustment on implementation of IFRS 9 (1) $m	Transition adjustment on implementation of IFRS 9 (2) $m
(Loss)/gain on hedging instruments	42.3	3.2	–	(39.1)
Loss from continuing activities before tax	(518.8)	(557.9)	–	(39.1)
Loss for the year from continuing activities	(309.0)	(348.1)	–	(39.1)

	Year ended 31.12.17 Audited – Previously reported $m	Year ended 31.12.17 Audited – Adjusted $m	Transition adjustment on implementation of IFRS 9 (1) $m	Transition adjustment on implementation of IFRS 9 (2) $m
(Loss)/gain on hedging instruments	(11.8)	1.4	–	13.2
Loss from continuing activities before tax	(299.1)	(285.9)	–	13.2
Loss for the year from continuing activities	(188.5)	(175.3)	–	13.2

Balance sheet

	31 December 2016 $m	1 January 2017 $m	Transition adjustment on implementation of IFRS 9 (1) $m	Transition adjustment on implementation of IFRS 9 (2) $m
Hedge reserve – Time value	–	(60.6)	–	(60.6)
Retained earnings	778.0	838.6	–	60.6
Total equity	2,242.5	2,242.5	–	–

	31 December 2017 $m	1 January 2018 $m	Transition adjustment on implementation of IFRS 9 (1) $m	Transition adjustment on implementation of IFRS 9 (2) $m
Non-current liabilities				
Borrowings	(3,606.4)	(3,749.9)	(143.5)	–
Net assets	2,716.4	2,572.9	(143.5)	–
Hedge reserve – Time value	–	(73.8)	–	(73.8)
Retained earnings	607.5	681.3	(143.5)	73.8
Total equity	2,716.4	2,572.9	(143.5)	–

The classification and measurement of financial assets have changed with the implementation of IFRS 9. However, this has not materially changed the measurement of financial assets of the Group.

The IFRS 9 impairment model requiring the recognition of 'expected credit losses', in contrast to the requirement to recognise 'incurred credit losses' under IAS 39, has not had a material impact on the Group's financial statements. Trade receivables are generally settled on a short time frame and the Group's other financial assets are due from counterparties without material credit risk concerns at the time of transition.

IFRS 15: Revenue from Contracts with Customers

The implementation of IFRS 15 has impacted the presentation of the Group's sales revenue and cost of sales. In the UK, the Group can purchase gas in order to meet sales commitments that cannot be fulfilled solely via the Group's production. Previously, this purchased gas had been recorded as revenue when sold. However, IFRS 15 requires this to be net against cost of sales. Historically, the value of these sales has not been considered material. This is not expected to have a material ongoing impact on the Group's financial statements as the Group expects to cease sales of gas in the UK during 2018.

The Group has elected to apply the 'modified retrospective' approach to transition permitted by IFRS 15 under which comparative financial information is not restated. This election has been made as the adjustment on implementation of IFRS 15 is not considered material to the Group's financial statements. It is not considered material as the transition has not impacted gross profit in the comparative periods or retained earnings on 1 January 2018.

Amounts presented for comparative periods in 2017 include revenues determined in accordance with the group's previous accounting policies relating to revenue. The amounts presented do not represent the revenue from contracts with customers that would have been reported for those periods had IFRS 15 been applied using a fully retrospective approach to transition.

Disclosure of disaggregated revenue information consistent with the requirement included in IFRS 15 has not had an impact on the information presented in note 6.

The Group's accounting policy under IFRS 15 is that revenue is recognised when the Group satisfies a performance obligation by transferring oil or gas to a customer. The title to oil and gas typically transfers to a customer at the same time as the customer takes physical possession of the oil or gas. Typically, at this point in time, the performance obligations of the Group are fully satisfied. The accounting for revenue under IFRS 15 does not, therefore, represent a substantive change from the Group's previous accounting policy for recognising revenue from sales to customers.

Upcoming International Financial Reporting Standards not yet adopted

IFRS 16: Leases

The adoption of IFRS 16 Leases, which the Group will adopt for the year commencing 1 January 2019, will impact both the measurement and disclosures of leases over a low value threshold and with terms longer than one year. The Group's assessment of lease agreements that exist across the Group is ongoing. The assessment also includes a review of who the customer is for existing lease contracts related to joint arrangements. The Group expects to complete its full assessment of the expected financial impact of transition to IFRS 16 in the second half of 2018.

3. Earnings/(loss) per share

The calculation of basic earnings per share is based on the profit for the period after taxation attributable to equity holders of the parent of $53.9 million (1H 2017: $347.7 million loss) and a weighted average number of shares in issue of 1,389.5 million (1H 2017: 1,227.2 million).

The calculation of diluted earnings per share is based on the profit/(loss) for the period after taxation as for basic earnings per share. The number of shares outstanding, however, is adjusted to show the potential dilution if employee share options are converted into ordinary shares. The weighted average number of ordinary shares is increased by 49.7 million (1H 2017: 49.0 million) resulting in a diluted weighted average number of shares of 1,439.2 million (1H 2017: 1,276.2 million).

4. Dividends

The Directors intend to recommend that no 2018 interim dividend be paid (2017 interim dividend: Nil).

5. Approval of accounts

These unaudited half year results were approved by the Board of Directors on 24 July 2018.

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. The Group has one class of business, being the exploration, development, production and sale of hydrocarbons and therefore the Group's reportable segments under IFRS 8 are West Africa; East Africa; and New Ventures. The following tables present revenue, profit and certain asset and liability information regarding the Group's business segments for the six months ended 30 June 2018, the six months ended 30 June 2017, and the year ended 31 December 2017.

	West Africa $m	East Africa $m	New Ventures $m	Unallocated $m	Total $m
Six months ended 30 June 2018					
Sales revenue by origin	905.1	–	–	–	905.1
Other operating income – lost production insurance proceeds	–	–	–	129.3	129.3
Segment result	385.0	(0.5)	(7.1)	(22.4)	355.0
Gain on disposal					4.9
Unallocated corporate expenses					(61.0)
Operating profit					298.9
Gain on hedging instruments					(3.5)
Finance revenue					31.7
Finance costs					(176.6)
Profit before tax					150.5
Income tax expense					(96.0)
Profit after tax					54.5
Total assets	7,690.9	2,650.9	308.7	397.5	11,048.0
Total liabilities	(4,397.4)	(147.1)	(71.7)	(3,847.5)	(8,463.7)
Other segment information					
Capital expenditure:					
Property, plant and equipment	104.6	0.8	0.3	1.0	106.7
Intangible exploration and evaluation assets	1.5	84.3	19.7	–	105.5
Depletion, depreciation and amortisation	(291.4)	(0.1)	–	(7.4)	(298.9)
Impairment of property, plant and equipment, net	(7.9)	–	–	–	(7.9)
Exploration costs written off	–	–	(8.6)	–	(8.6)

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

6. Segmental reporting contd.

	West Africa $m	East Africa $m	New Ventures $m	Unallocated $m	Total $m
Six months ended 30 June 2017 (Restated)					
Sales revenue by origin	787.5	–	–	–	787.5
Other operating income – lost production insurance proceeds	–	–	–	54.3	54.3
Segment result	(406.5)	0.1	2.6	62.3	(341.5)
Loss on disposal					(0.6)
Unallocated corporate expenses					(52.8)
Operating loss					(394.9)
Loss on hedging instruments					3.2
Finance revenue					12.9
Finance costs					(179.1)
Loss before tax					(557.9)
Income tax credit					209.8
Loss after tax					(348.1)
Total assets	6,665.2	2,441.7	487.4	169.9	9,764.2
Total liabilities	(2,751.0)	(140.8)	(145.5)	(4,022.9)	(7,060.2)
Other segment information					
Capital expenditure:					
Property, plant and equipment	(27.9)	0.3	0.3	0.7	(26.6)
Intangible exploration and evaluation assets	5.0	124.2	15.5	–	144.7
Depletion, depreciation and amortization	(264.5)	(0.3)	–	(7.3)	(272.1)
Impairment of property, plant and equipment, net	(641.7)	–	–	–	(641.7)
Exploration costs written off/(reversed)	(5.7)	–	1.8	–	(3.9)
Year ended 31 December 2017 (Restated)					
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	133.8
Loss on disposal					(1.6)
Unallocated corporate expenses					(109.8)
Operating profit					22.4
Loss on hedging instruments					1.4
Finance revenue					42.0
Finance costs					(351.7)
Loss before tax					(285.9)
Income tax credit					110.6
Loss after tax					(175.3)
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
Depletion, depreciation and amortization	(577.1)	(0.5)	–	(14.6)	(592.2)
Impairment of property, plant and equipment	(539.1)	–	–	–	(539.1)
Exploration costs written off	(6.9)	(2.3)	(134.2)	–	(143.4)

	Sales revenue 6 months ended 30.06.18 $m	Sales revenue 6 months ended 30.06.17 $m	Sales revenue Year ended 31.12.17 $m	*Non-current assets 30.06.18 $m	*Non-current assets 30.06.17 $m	*Non-current assets 31.12.17 $m
Congo	–	9.1	8.8	–	–	–
Côte d'Ivoire	41.6	39.9	42.3	68.0	86.1	74.5
Equatorial Guinea	72.4	39.9	92.2	109.9	131.1	134.7
Gabon	105.0	102.3	251.8	149.5	148.4	161.9
Ghana	655.2	537.2	1,196.1	5,498.3	4,395.9	5,675.1
Mauritania	2.2	5.5	13.8	–	–	–
Netherlands	–	17.4	29.4	–	–	–
UK	28.7	36.2	88.1	–	4.0	–
Other	–	–	–	–	–	–
Total West Africa	905.1	787.5	1,722.5	5,825.7	4,765.5	6,046.2
Kenya	–	–	–	1,093.6	995.0	1,064.8
Uganda	–	–	–	608.2	530.8	574.4
Total East Africa	–	–	–	1,701.8	1,525.8	1,639.2
Norway	–	–	–	13.0	12.8	13.5
Other	–	–	–	205.4	284.6	194.6
Total New ventures	–	–	–	218.4	297.4	208.1
Unallocated	–	–	–	70.1	79.1	85.4
Total	905.1	787.5	1,722.5	7,816.0	6,667.8	7,978.9

**Excludes derivative financial instruments and deferred tax assets.*

7. Operating profit/(loss)

	6 months ended 30.06.18 Unaudited $m	6 months ended 30.06.17 Unaudited $m	Year ended 31.12.17 Audited $m
Cost of sales			
Operating costs	181.0	166.3	386.2
Operating lease payments	–	53.4	62.5
Depletion and amortisation of oil and gas assets	289.9	263.4	574.3
Underlift, overlift and oil inventory movement	27.4	36.0	(2.3)
Share-based payment charge included in cost of sales	0.8	1.3	1.1
Other cost of sales	14.5	18.2	47.5
Total cost of sales	513.6	538.6	1,069.3
Administrative expenses			
Share-based payment charge included in administrative expenses	11.9	5.8	32.8
Depreciation of other fixed assets	9.0	8.7	17.9
Relocation costs associated with restructuring	(0.9)	0.2	1.6
Other administrative costs	39.5	36.7	43.0
Total administrative expenses	59.5	51.4	95.3
Restructuring costs			
Total restructuring costs	1.5	1.4	14.5

8. Net financing costs

	6 months ended 30.06.18 Unaudited $m	6 months ended 30.06.17 Unaudited $m	Year ended 31.12.17 Audited $m
Interest on bank overdrafts and borrowings	145.5	151.0	290.7
Interest on obligations under finances leases	49.3	0.8	46.1
Total borrowing costs	194.8	151.8	336.8
Less amounts included in the cost of qualifying assets	(32.7)	(31.9)	(66.5)
	162.1	119.9	270.3
Finance and arrangement fees	–	1.8	4.6
Foreign exchange losses	6.4	47.2	57.1
Unwinding of discount on decommissioning provisions	8.1	10.2	19.7
Total finance costs	176.6	179.1	351.7
Interest income on amounts due from joint venture partners for finance leases	(24.2)	–	(21.0)
Other finance revenue	(7.5)	(12.9)	(21.0)
Total finance revenue	(31.7)	(12.9)	(42.0)
Net financing costs	144.9	166.2	309.7

9. Taxation on profit on ordinary activities

The overall net tax expense of $96 million (1H 2017: $210 million credit) primarily relates to expenses in respect of the Group's production activities in West Africa including non-operated European assets and non-recurring deferred tax credits associated with exploration write-offs, impairments and onerous lease provisions. After adjusting for the non-recurring amounts related to exploration write-offs, impairments, disposals and onerous lease provisions and their associated deferred tax benefit, the Group's underlying effective tax rate is 48% (1H 2017: 18%). The increase in the underlying effective tax rate is mainly due to increased profits from production activities taxed at higher rates of taxation, lower tax credits from Norwegian exploration activities and a reduction in the utilisation of losses.

10. Intangible exploration and evaluation assets

	6 months ended 30.06.18 Unaudited $m	6 months ended 30.06.17 Unaudited $m	Year ended 31.12.17 Audited $m
At 1 January	1,933.4	2,025.8	2,025.8
Additions	105.5	144.7	319.0
Disposals	–	(0.4)	(40.0)
Amounts written off	(8.6)	(3.9)	(143.4)
Transfer to property, plant, and equipment	–	–	(188.7)
Net transfer to assets held for sale	(21.2)	(67.6)	(43.4)
Currency translation adjustments	1.5	2.0	4.1
At 30 June/31 December	2,010.6	2,100.6	1,933.4

Exploration costs written off/(reversed)	Rationale for write-off 6 months ended 30.06.18	Write off 30.06.18 Unaudited $m	Remaining recoverable amount 30.06.18 Unaudited $m
Suriname – Block 54	a	(2)	6
Other	a,b	2	–
New ventures	c	9	–
Exploration costs written off		9	

a. Current year expenditure/(credits) on assets previously written off

b. Licence relinquishments

c. New ventures expenditure is written off as incurred

11. Property, plant and equipment

	Oil and gas assets 6 months ended 30.06.18 Unaudited $m	Other fixed assets 6 months ended 30.06.18 Unaudited $m	Total 6 months ended 30.06.18 Unaudited $m	Oil and gas assets 6 months ended 30.06.17 Unaudited $m	Other fixed assets 6 months ended 30.06.17 Unaudited $m	Total 6 months ended 30.06.17 Unaudited $m	Oil and gas assets Year ended 31.12.17 Audited $m	Other fixed assets Year ended 31.12.17 Audited $m	Total Year ended 31.12.17 Audited $m
Cost									
At 1 January	11,592.6	279.7	11,872.3	10,772.5	251.9	11,024.4	10,772.5	251.9	11,024.4
Additions	104.7	2.0	106.7	(27.6)	1.0	(26.6)	880.7	7.0	887.7
Disposals	–	(0.4)	(0.4)	–	(0.7)	(0.7)	(362.6)	(1.6)	(364.2)
Transfer to assets held for sale	–	–	–	(345.9)	–	(345.9)	–	–	–
Transfer from intangible assets	–	–	–	–	–	–	188.7	–	188.7
Currency translation adjustments	(22.4)	(6.0)	(28.4)	61.1	12.8	73.9	113.3	22.4	135.7
At 30 June/31 December	11,674.9	275.3	11,950.2	10,460.1	265.0	10,725.1	11,592.6	279.7	11,872.3
Depreciation, depletion and amortisation									
At 1 January	(6,425.3)	(192.3)	(6,617.6)	(5,500.8)	(160.7)	(5,661.5)	(5,500.8)	(160.7)	(5,661.5)
Charge for the year	(289.9)	(9.0)	(298.9)	(263.4)	(8.7)	(272.1)	(574.3)	(17.9)	(592.2)
Impairment loss	(7.9)	–	(7.9)	(643.8)	–	(643.8)	(584.5)	–	(584.5)
Reversal of impairment loss	–	–	–	–	–	–	43.4	–	43.4
Transfer to assets held for sale	–	–	–	285.5	–	285.5	–	–	–
Disposal	–	0.4	0.4	–	0.8	0.8	300.0	1.7	301.7
Currency translation adjustments	22.0	4.6	26.6	(59.3)	(8.8)	(68.1)	(109.1)	(15.4)	(124.5)
At 30 June/31 December	(6,701.1)	(196.3)	(6,897.4)	(6,181.8)	(177.4)	(6,359.2)	(6,425.3)	(192.3)	(6,617.6)
Net book value at 30 June/31 December	4,973.8	79.0	5,052.8	4,278.3	87.6	4,365.9	5,167.3	87.4	5,254.7

12. Other assets

	30.06.18 Unaudited $m	30.06.17 Unaudited $m	31.12.17 Audited $m
Non-current			
Amounts due from joint venture partners	667.7	147.4	731.7
Uganda VAT recoverable	34.9	35.9	34.9
Other non-current assets	49.0	17.0	23.2
	751.6	200.3	789.8
Current			
Amounts due from joint venture partners	502.9	299.8	567.8
Underlifts	18.4	25.3	37.1
Prepayments	42.0	26.9	38.2
VAT & WHT recoverable	4.5	5.3	5.4
Other current assets	261.4	168.1	119.8
	829.2	525.4	768.3

13. Assets and liabilities classified as 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. 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. The disposal is expected to complete in the second half of 2018.

14. Trade and other payables

	30.06.18 Unaudited $m	30.06.17 Unaudited $m	31.12.17 Audited $m
Current			
Trade payables	112.2	24.4	83.3
Other payables	163.7	126.4	114.5
Overlifts	56.9	25.4	30.4
Accruals	547.1	427.7	552.0
VAT and other similar taxes	18.9	18.0	17.3
Current portion of finance lease	213.6	2.1	228.1
	1,112.4	624.0	1,025.6
Non-current			
Other non-current liabilities	101.1	82.0	105.1
Non-current portion of finance lease	1,254.2	23.6	1,317.5
	1,355.3	105.6	1,422.6

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 change in trade payables and in other payables predominantly represents timing differences and levels of work activity.

15. Provisions

	30.06.18 Unaudited $m	30.06.17 Unaudited $m	31.12.17 Audited $m
Current			
Decommissioning	119.5	88.1	103.2
Other	271.5	–	127.6
	391.0	88.1	230.8
Non-current			
Decommissioning	734.6	823.2	794.2
Other	6.5	139.5	7.4
	741.1	962.7	801.6

Following a trial in the English Commercial Court in May 2018, the court ruled on 3 July that Tullow was not entitled to terminate its West Leo rig contract with Seadrill on 4 December 2016 by invoking the contract's force majeure provisions. Following advice from counsel, Tullow will not be appealing this ruling. Tullow has now paid Seadrill a contractual termination fee, other standby fees that accrued in the 60 days prior to termination of the contract and interest amounting to $248 million in aggregate and is due to pay a further $11 million of Ghana withholding tax in August.

Although Tullow regards these as joint venture costs, Kosmos disputed separately, through an International Chamber of Commerce arbitration against Tullow, its share of the liability (c. 20%) of any costs related to the use of the West Leo rig beyond 1 October 2016. On 17 July 2018, the arbitration tribunal delivered a final and binding award in favour of Kosmos which determined that Kosmos is not liable for its share of the Seadrill liabilities. The arbitration award also provided that Tullow is due to reimburse Kosmos $14 million for rig demobilisation costs and certain of its legal costs. In relation to these two matters the Group has recorded an additional pre-tax income statement charge of $143.9 million during the period.

16. Called up share capital and share premium

In the six months ended 30 June 2018, the Group issued 5.2 million shares in respect of employee share options (1H 2017: 1.8 million new shares in respect of employee share options and 466.9 million new shares in relation to the Rights Issue).

As at 30 June 2018, the Group had in issue 1,391.8 million allotted and fully paid ordinary shares of GBP 10 pence each (30 June 2017: 1,383.2 million).

17. Contingencies

	30.06.18 Unaudited $m	30.06.17 Unaudited $m	31.12.17 Audited $m
Contingent liabilities			
Performance guarantees	99.9	89.6	115.6
Other contingent liabilities	130.3	185.3	185.3
	230.2	274.9	300.9

Performance guarantees are in respect of abandonment obligations, committed work programmes and certain financial obligations.

Other contingent liabilities include amounts for ongoing legal disputes with third parties where we consider the likelihood of a cash outflow to be higher than remote but not probable.

18. 2018 principal financial risks and uncertainties

The Board determines the key risks for the Group and monitors mitigation plans and performance on a monthly basis. The principal risks and uncertainties facing the Group at the half year end are summarised below. The Group's approach to managing risks and other further details, including risk mitigation and assurance, can be found in the 2017 Annual Report and Accounts.

Principal risk	Cause	Potential impact
Strategic		
Strategy not fully achievable in a sustained low oil price environment	• Low oil price environment due to global supply/demand balances and shift to alternative energy sources as a result of climate change	• Inability to deleverage the business • Inability to monetise chosen assets • Capital committed to suboptimal projects • Overheads not matched to asset base • Portfolio not optimised to sustain long-term strategy
Inability to progress major portfolio options	• Reduction in market appetite for E&P assets • Uncertainty around projects	• Inability to monetise chosen assets and deleverage balance sheet • Write-downs on acquired assets • Failure to exit mature assets with low returns • Exposure to decommissioning costs
Disruption to business due to community/political/regulatory influence	• Fiscal pressures on Government as a result of reduced revenues due to low oil price • Local currency exchange rate challenges • Uncertainty arising from changes in Government leadership • Pace of national content requirements • Government inability to deliver infrastructure on time for projects and provide security for critical infrastructure	• Significant variance to plans due to delayed regulatory approvals/lack of support • Regulatory, contractual interpretation and tax changes (including in breach of stabilisation provisions) affecting profitability and viability of projects/ operations and leading to disputes and/or material financial loss • Inability to achieve community support for new projects due to opposition/loss of licence to operate • Unplanned costs due to community unrest/opposition • Significant security risk to Tullow employees and contractors • Inability to execute commercial transactions • Exposure to onerous contracts resulting in financial loss

Financial		
Insufficient liquidity and funding capability	• Oil price downturn • Lack of capital discipline and unsuccessful portfolio management • Reduced asset quality limiting ability to raise debt • Reduced bank/DCM appetite for E&P sector • Significant unplanned cash outflows and elevated leverage	• Inability to finance strategic objectives • Ability to raise further debt constrained • Inability to fund capital investment/projects
Failure to manage oil price risk	• Low oil price environment due to global supply/demand balances and shift to alternative energy sources as a result of climate change	• Reduced cash flows, revenue, EBITDA, asset value and debt capacity • Insufficient funding to support investment programme
Operational		
Major process safety/equipment/EHS failure	• Inadequate maintenance of safety critical equipment on board Jubilee/ TEN FPSOs • Loss of wells, subsea equipment or FPSO systems • Error in well design, equipment selection or programme • Ineffective standards and procedures, improper work practices or lack of training • Loss of rig position	• Multiple fatalities • Serious environmental or asset damage • Serious financial/reputational damage • Significant loss of production, injection or export capacity and disruption to business operations
Inability to replenish exploration portfolio	• Lack of/under investment in portfolio high-grading activities • Lack of dedicated resources to identify new business activities • Failure to encourage entrepreneurial/ creative exploration innovation or demotivation of key staff	• Failure to generate a quality drill-ready prospect queue • Loss of reputation and exploration value from share price • Sustained exploration failure results in poor or no drill-ready prospects and diminished future development options and production ramp-up
Major cyber or information security incident	• External cyber-attack resulting in network compromise or disruptive/ destructive impact to Industrial Control Systems • Deliberate or accidental internal theft/loss of confidential information	• Disruption to or halt of critical business systems resulting in stopped production, explosion or loss of life • Loss or theft of confidential information • Loss of competitive advantage and intellectual property • Reputational damage
Failure to have a balanced, diverse workforce and attractive employee proposition	• Tullow culture and values not embedded • Staff do not support our current operating model • Lack of confidence in strategy and senior leadership • Diversity and localisation plans not effectively implemented • Ineffective staff development and reward programmes	• Loss of key personnel/lack of succession and increased staff turnover • Lack of in-house skills and requirement to buy in short-term contractors increase costs • Negative relations with the Government due to failure to implement localisation plans • Reputational damage
Compliance		
Major breach of business or ethical conduct standards	• External cyber-attack resulting in network compromise or disruptive/ destructive impact to Industrial Control Systems • Deliberate or accidental internal theft/loss of confidential information	• Unethical behaviour • Breach of anti-corruption laws • Tullow investigated resulting in reputational damage/fines • Senior officers prosecuted under anti-corruption laws

19. Commercial Reserves and Contingent Resources summary 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 2018	245.7	268.9	-	-	-	-	245.7	268.9	290.5
Revisions	0.9	2.8	-	-	-	-	0.9	2.8	1.4
Disposals	-	(7.7)	-	-	-	-	-	(7.7)	(1.3)
Transfers	2.1	-	-	-	-	-	2.1	-	2.1
Production	(13.6)	(4.6)	-	-	-	-	(13.6)	(4.6)	(14.3)
30 June 2018	235.1	259.4	-	-	-	-	235.1	259.4	278.4
CONTINGENT RESOURCES									
1 January 2018	121.4	465.1	637.8	42.7	-	4.2	759.1	512.0	844.4
Revisions	5.0	16.7	-	-	-		5.0	16.7	7.9
Disposals	(0.1)	(89.2)	-	-	-	(4.2)	(0.1)	(93.4)	(15.7)
Transfers	(2.1)	-	-	-	-	-	(2.1)	-	(2.1)
30 June 2018	124.2	392.6	637.8	42.7	-	-	762.0	435.3	834.5
TOTAL									
30 June 2018	359.3	652.0	637.8	42.7	-	-	997.1	694.7	1,112.9

1. *Proven and Probable Commercial Reserves are based on a Group reserves report produced 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.*
2. *Proven and Probable Contingent Resources are based on both Tullow's estimates and the Group reserves report produced by an independent engineer.*

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 1,086.9 mmboe at 30 June 2018 (31 December 2017: 1,284.1 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 development within the foreseeable future.

20. Group average working interest production

Oil production	1H 2018 average production (bopd)	FY 2018 forecast (bopd)
Ghana		
Jubilee	*23,400*	*27,700*
TEN Oil	*30,700*	*30,900*
Total Ghana Oil	54,100	*58,600*
Equatorial Guinea		
Ceiba	*2,600*	2,400
Okume	*4,100*	*4,000*
Total Equatorial Guinea	*6,700*	*6,400*
Gabon		
Tchatamba	*4,300*	4,400
Limande	*1,700*	*1,600*
Etame Complex	*1,000*	*1,000*
Other Gabon	*5,200*	*5,200*
Total Gabon	12,200	12,200
Côte d'Ivoire	3,300	3,200
OIL PRODUCTION SUB-TOTAL	**76,300**	**80,400**
Jubilee production-equivalent insurance payments	11,900	8,700
OIL PRODUCTION SUB-TOTAL (inc. Jubilee production-equivalent insurance payments**)**	**88,200**	**89,100**

Gas production	(boepd)	(boepd)
UK	2,800	**2,000**
TEN Gas	-	1,100
Gas SUB-TOTAL	**2,800**	**3,000**
GROUP TOTAL	**79,100**	**83,400**
GROUP TOTAL (inc. Jubilee production-equivalent insurance payments**)**	**91,000**	**92,100**

Notes to Editors

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 80 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 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	
All participants	+44 (0)330 336 9411
UK free phone	0800 279 7204
Access Code	9869978

Webcast

To join the live video webcast or play the on-demand version, please use this link:

https://edge.media-server.com/m6/p/aud6efap.

You will need to have either Real Player or Windows Media Player installed on your computer. The replay will be available from around noon on 25 July 2018.

FOR FURTHER INFORMATION CONTACT:

Tullow Oil plc	**Murray Consultants**
(London)	(Dublin)
(+44 20 3249 9000)	(+353 1 498 0300)
Chris Perry	Pat Walsh
George Cazenove	Joe Heron
Nicola Rogers	

Follow Tullow on:

Twitter: www.twitter.com/TullowOilplc

You Tube: www.youtube.com/TullowOilplc

Facebook: www.facebook.com/TullowOilplc

LinkedIn: www.linkedin.com/company/Tullow-Oil