2021
Full Year
Results

Tullow Oil plc
9 March 2022

TULLOW OIL PLC - 2021 FULL YEAR RESULTS

9 March 2022 – Tullow Oil plc ("Tullow"), the independent oil and gas exploration and production group ("Group"), announces its Full Year Results for the year ended 31 December 2021. Details of a management presentation, webcast and conference call are available on the last page of this announcement or visit the Group's website www.tullowoil.com.

Rahul Dhir, Chief Executive Officer, Tullow Oil plc, commented today:

"Following a transformational 2021, in which Tullow successfully refinanced its balance sheet, drilled highly productive wells in Ghana and demonstrated operational excellence and financial discipline across the Group, we are now concentrating on the successful delivery of our long-term business plan. This year will see a great deal of activity at our flagship Jubilee field with investment in new infrastructure and new wells to grow production in the near term and we are taking on the operation and maintenance of the FPSO. At TEN, we will drill two important, strategic wells that will help define our future plans for the fields and we will continue to build production in Gabon. I also expect us to make tangible progress towards our ambitious target of achieving Net Zero by 2030. With additional opportunities to deliver value across our portfolio, including gas commercialisation in Ghana, our revised Kenya development project and an exciting well in a proven play in Guyana, we are well-placed to deliver value from our assets and to grow our business."

2021 FULL YEAR RESULTS SUMMARY

- Revenue of $1,273 million; gross profit of $634 million; loss after tax of $81 million primarily driven by exploration costs written off, impairments, restructuring costs and other provisions.
- Underlying operating cash flow[1] of $711 million and free cash flow[1] of $245 million.
- Capital and decommissioning expenditure of $263 million[1] and $69 million respectively.
- Net debt at year-end of $2.1 billion; gearing of 2.2x[1] net debt/EBITDAX; liquidity headroom of $0.9 billion.
- Group working interest production averaged 59.2 kboepd, in line with guidance with notable production growth from Jubilee in Ghana and Simba in Gabon, but lower production than expected from TEN and Espoir.
- In Ghana, strong performance delivered across key operational areas of FPSO uptime, water injection and gas processing. Drilling recommenced in April, with four wells and a workover successfully completed, ahead of plan.
- Commitment made to becoming Net Zero on Scope 1 and 2 emissions by 2030 and to eliminate routine flaring in Ghana by 2025.
- Received $133 million from divestment of non-core interests in Equatorial Guinea and the Dussafu Marin Permit in Gabon.
- Comprehensive debt refinancing completed in May, with new $1.8 billion five-year Senior Secured Notes; a new undrawn $500 million revolving credit facility provides strong liquidity headroom.
- Continued focus on costs helped achieve c.25% year-on-year reduction in administrative expenses to $64 million; operating costs reduced to $269 million (2020: $332 million), driven by lower facilities operations and maintenance costs in Ghana, as well as asset disposals.
- Phuthuma Nhleko appointed Chair of Tullow, succeeding Dorothy Thompson who stepped down on 31 December 2021.

2021 key financial results

	2021	2020
Total revenue ($m)	1,273	1,396
Gross profit ($m)	634	403
Loss after tax ($m)	(81)	(1,222)
Free cash flow ($m) [1]	245	432
Net debt ($m) [1]	2,131	2,376
Gearing (times)[1]	2.2	3.0

[1] Alternative performance measures are reconciled on pages 31 to 34.

2022 OUTLOOK

- Group working interest oil production guidance remains 55 to 61 kboepd based on Tullow's existing equity interests in TEN and Jubilee. This forecast will be adjusted following completion of the pre-emption of the sale of Occidental Petroleum's interest in Ghana to Kosmos Energy. The estimated full year impact of the completed pre-emption would be an addition of c.5 kboepd (net) to the Group's 2022 production forecast, adjusted for completion timing.
- Full year underlying operating cash flow[1] guidance remains c.$750 million, assuming $75/bbl for the remainder of the year.
- Full year free cash flow guidance remains c.$100 million assuming $75/bbl for the remainder of the year; year-to-date cash flow positively impacted by oil prices at the start of the year, largely offsetting the one-off impact of a $76 million payment to HiTec Vision in relation to the purchase of Spring Energy in 2013, following an arbitral decision in HiTec Vision's favour. Material cash flow

contribution secured in February with receipt of $75 million contingent consideration following Final Investment Decision (FID) in Uganda.

- Capex of c.$350 million, split c.$270 million in Ghana, c.$30 million for non-operated portfolio, c.$5 million in Kenya, and exploration spend of c.$45 million. Decommissioning spend is expected to be c.$100 million.
- Three new wells at Jubilee and three new wells at the TEN fields planned, including two strategic wells at TEN to further define future development plans, as well as investment in infrastructure for the undeveloped Jubilee South East and North East areas.
- Tullow will self-operate the Jubilee FPSO from mid-2022 onwards, following the scheduled end of the contract with MODEC, enabling the Group to realise further efficiency improvements and cost savings.
- Tullow expects to secure a gas commercialisation agreement in Ghana which will come into effect once all foundation gas volumes have been delivered; this is forecast to occur before year-end.
- In Kenya, a revised Field Development Plan was submitted in late 2021 and discussions are progressing with potential strategic partners.
- In mid-2022 Tullow will participate in the Repsol operated Beebei-Potaro well, which is a follow-up to the Carapa light oil discovery made in 2020 in the Kanuku licence, offshore Guyana.
- Work plan in place to progress towards Net Zero target, focusing on gas compression facilities on the Jubilee FPSO; MOU signed with the Ghana Forestry Commission to identify and develop nature-based carbon offset projects in Ghana to offset hard to abate and residual emissions.

ENVIRONMENT, SOCIAL AND GOVERNANCE (ESG)

Environmental

In March 2021, Tullow committed to achieving Net Zero on its Scope 1 and 2 emissions by 2030 on a net equity basis. As part of this commitment, we have identified the core gas handling and process modifications required to reduce our operated emissions at our FPSOs. Work to increase gas processing capacity at the Jubilee FPSO is planned during a scheduled shutdown in the second quarter of 2022, which, together with compressor upgrades and other de-bottlenecking initiatives through 2022 and early 2023, will increase gas handling capacity and contribute towards the target of eliminating routine flaring in Ghana by 2025. The Group increased average daily gas offtake in Ghana in 2021, and natural gas from Jubilee and TEN provides power for c.30% of Ghana's national grid which in turn increases the availability of reliable power in Ghana and reduces the country's reliance on diesel and biomass for domestic power and heat generation. The Group is currently negotiating Gas Sales Agreements for associated natural gas as well as discussing development concepts for non-associated gas with the Government of Ghana, which will allow for greater quantities of natural gas to be supplied to Ghana's national grid and potentially beyond.

Elsewhere, as part of Tullow's re-design of its development in northern Kenya, carbon emissions from this project will be limited through a combination of heat conservation, use of associated gas for power and reinjection of excess gas into the reservoir to eliminate flaring. There are also opportunities to use the Kenyan national grid which is substantially powered by renewables and options to offset remaining emissions through local projects. In addition, the 825-kilometre-long pipeline that will transport crude oil from Turkana to the port of Lamu will be buried to further reduce the environmental impact of the project.

Tullow is committed to off-setting its residual, hard-to-abate emissions and has appointed a Group Carbon Offset Manager to lead the carbon offset strategy and identify high-quality offset projects. To this end, Tullow recently signed a Memorandum of Understanding with the Ghana Forestry Commission to identify and develop a portfolio of Reduced Emissions from Deforestation and Forest Degradation (REDD+) and afforestation/reforestation (ARR) projects that will support Ghana's REDD+ strategy and Tullow's offset targets. The portfolio will target a minimum of 600,000 tonnes per annum of verified carbon emissions reductions that will be certified under leading carbon standards such as the Verified Carbon Standard (VCS) and the Climate Community and Biodiversity Standard (CCB).

Social

In Tullow's Half-Year Results statement, published in September 2021, the Group underscored its purpose to build a better future through the responsible development of oil and gas resources and to build Shared Prosperity in the countries where it works. It remains Tullow's view that as long as global hydrocarbon demand exists, it is imperative that African economies have the opportunity to benefit from the responsible development of their resources. At COP26 in Glasgow, President Akufo-Addo of Ghana articulated the case for continued development of Ghana's resources as part of a fair energy transition for developing countries.

With a long and proud history in Africa, Tullow is uniquely positioned to be a financially and operationally responsible contractor to its host Governments and to ensure that their oil and gas resources are developed efficiently and safely while minimising the environmental impact.

Tullow's social impact is presented in the Sustainability Report which details the Group's efforts in Local Content and Social Investment as well as its total payments to Governments which amounted to $234 million in 2021.

Governance

As previously announced, Les Wood, Chief Financial Officer (CFO) will step down from the Board and leave Tullow at the end of March. Tullow's recruitment of a new CFO to replace Les is ongoing and the process is expected to conclude shortly. The Nominations Committee have approved the appointment of Richard Miller, Group Financial Controller, as interim CFO with effect from 1 April. Richard is a chartered accountant and has worked in a number of senior roles within Finance since he joined Tullow in 2011.

With the appointment of Phuthuma Nhleko as Non-executive Chairman of Tullow from 1 January 2022, Tullow now has three African nationals on the Board out of nine directors. Female representation on the Board has dropped from 33% to 22% (two out of nine) following Dorothy Thompson's departure from Tullow. Jeremy Wilson, Tullow's Senior Independent Non-executive Director, will retire from the Board later this year following nine years' service.

Finally, Tullow's 2021 Sustainability Report, which will be published alongside the Annual Report and Accounts later this month, details the Group's commitment to the environment and its approach to managing climate risk. Tullow will also publish a separate Climate Risk Report as part of its TCFD disclosures.

OPERATIONAL REVIEW

Production, Reserves and Resources

In 2021, Group working interest production averaged 59.2 kboepd, in line with guidance, with notable production growth from the Jubilee field in Ghana and Simba field in Gabon, but lower production than expected from the TEN fields in Ghana and the Espoir field in Côte d'Ivoire.

In 2022, Group working interest production guidance is 55 to 61 kboepd. This forecast is based on Tullow's existing equity interests in Jubilee (35.48%) and TEN (47.175%) and will be adjusted following completion of the pre-emption of the sale of Occidental Petroleum's interest in Ghana to Kosmos Energy. The estimated full year impact of the completed pre-emption would be an addition of c.5 kboepd (net) to the Group's 2022 production forecast, subject to adjustment for completion timing.

Group average working interest production	FY 2021 (kboepd)	FY 2022 range (kboepd)
Ghana[1]	42.1	39-42
Jubilee	26.6	28-30
TEN	15.5	11-12
Non-operated portfolio[2]	17.2	16-19
Group	59.2	55-61

[1] Ghana production represented before impact of pre-emption on Deep Water Tano (DWT) Block

[2] 2021 figure includes partial production from assets in Equatorial Guinea and the Dussafu Marin Permit in Gabon, ahead of divestment during the year. 2022 production guidance does not include any production from these assets.

The Group's audited 2P reserves decreased from 260 mmboe at the end of 2020 to 231 mmboe at the end of 2021. About half of this reduction was the result of the sale of assets in Equatorial Guinea and the Dussafu Marin Permit in Gabon (15 mmboe). Reserve additions and positive revisions included a 13 mmboe increase at Jubilee following improved field performance and acceleration of new projects and a 11 mmboe increase in the non-operated portfolio due to better field performance and maturation of new projects. These gains were offset by a 16 mmboe decrease at TEN reflecting poorer than expected Ntomme field performance and re-categorisation of certain reserves at Enyenra. Overall, with the Group producing 22 mmboe during 2021, the organic reserves replacement ratio was approximately 36%.

The Group's audited 2C resources decreased from 640 mmboe to 623 mmboe. The reduction was driven primarily by the sale of assets in Equatorial Guinea and Gabon, the maturation of selected TEN projects from 2C to 2P and poorer than expected field performance at TEN. However, these reductions were largely offset by a positive revision from Tullow's auditors of the Kenyan assets, to align with the updated Field Development Plan.

Ghana

Jubilee

The Jubilee field averaged 74.9 kbopd gross (net 26.6 kbopd) in 2021, ahead of guidance at the start of the year. Average daily production grew from c.70 kbopd at the beginning of the year to exceed 90 kbopd by year-end, as new wells were brought onstream and operational performance remained high with FPSO uptime averaging c.98%, gas offtake rates averaging c.85 mmscfd and water injection rates averaging over 200 kbwpd. The annual gas offtake rate was impacted by overrunning maintenance and subsequent reduced capacity at the the Ghana National Gas Company (GNGC) onshore gas processing plant during the fourth quarter of the year. Tullow continues to work closely with GNGC to help improve offtake reliability. Gas offtake has now returned to regular rates of over 100 mmscfd and Tullow and its JV Partners are still targeting average offtake of c.135 mmscfd in 2022.

The drilling programme, which commenced in April, delivered two producers (J56-P online in July, J57-P online in December), one water injector (J55-WI online in September) and a work over (J12-WI online early in January 2022). Strong drilling performance was achieved during the year with wells costing approximately 20% less than wells drilled from 2018 to 2020, ahead of the assumptions included in the Business Plan.

The field continues to perform well, and average 2022 production is expected to increase to between c.80 to 84 kbopd gross (net: 28 to 30 kbopd). This forecast includes a planned shutdown in the second quarter of 2022 for approximately two weeks. Three new wells are planned to be drilled at Jubilee in 2022, focused on delivering reliable in-year production: a water injector, which will provide pressure support to existing producers, is due onstream in the first quarter; this will be followed by a producer and a second water injector.

The core developed area of the Jubilee field has c.1.5 billion barrels gross oil initially in place (STOIIP), with an estimated ultimate recovery (EUR) approaching 40%. To date, around half of the expected reserves have been produced. Outside of the core area, the development of the Jubilee North East (JNE) and Jubilee South East (JSE) areas marks a step change that targets relatively untapped areas of the field, containing over 500mmbbls gross oil in place. These areas combined gross EUR is over 170 mmbbls gross oil, of which less than 10% has been produced. The 2022 work programme is focused on investment in infrastructure for the JSE and JNE projects that will access the undeveloped resources and lead to meaningful production growth in subsequent years.

TEN

The TEN fields averaged 32.8 kbopd gross (net: 15.5 kbopd) in 2021, below guidance given at the start of the year. This was primarily due to higher production decline rates than expected on particular wells. A gas injector at the Ntomme field (Nt06-GI), was brought onstream in the fourth quarter to provide pressure support to existing production wells. Nt06-GI also encountered oil at the base of the well, de-risking the development potential of areas further to the north of Ntomme. In 2021, uptime on the TEN FPSO was c.97%, water injection was c.65 kbwpd and gas injection was c.135 mmscfd. In 2022, TEN is expected to produce between 22 to 26 kbopd gross (net: 11-12kbopd).

Within the core developed areas of Ntomme and Enyenra, which contain c.750 mmbbls gross oil initially in place (STOIIP), around half of the expected reserves have been produced to date. However, production decline within this core area has been faster than expected and while material reserves remain, the overall view of ultimate recovery from these fields has reduced. As a consequence, Tullow and its Joint Venture (JV) Partners have improved their understanding of the broader TEN area and the significant remaining potential. The addition of undeveloped reservoirs in the Tweneboa area, accessible from the Ntomme riser base area, and the extension of the Enyenra field development to the north and south of the core developed area, introduce a similar volume of undeveloped STOIIP as the core areas. Tullow and its JV Partners will start to target these new areas in 2022, with two development wells planned in the Ntomme riser base area. Investment in infrastructure will allow these to be brought on stream from 2023. Furthermore, an additional production well is planned in the undeveloped Enyenra North area in the fourth quarter of the year.

Operational Transformation Plan

The operational transformation that Tullow embarked on in 2020 has delivered strong performance across safety, reliability and costs. A singular focus on personal and process safety across the organisation and visible leadership have provided a foundation for a strong safety culture. The production potential is being maximised by optimising performance of every element of production from the reservoir to the surface facilities. High levels of facility uptime have been achieved at both FPSOs by addressing long-standing equipment defects and sustaining this by implementing systemised monitoring and mitigating of equipment risk. In addition, Tullow is building an equipment systems maintenance management infrastructure to help sustain the reliability improvements. All this has been achieved by taking more direct control of day-to-day operations on the Jubilee and TEN FPSOs.

In order to build on these improvements and to achieve the ambition to be a top quartile operator in terms of safety, reliability and costs, Tullow, supported by its JV Partners and the Government of Ghana, has taken the decision to self-operate the Jubilee FPSO. Accordingly, Tullow will take over all operations and maintenance (O&M) from MODEC on the Jubilee field when the current O&M contract comes to a scheduled end in 2022. This will allow greater control and integration over the core areas of safety, efficiency, emissions, reliability and local content, in turn presenting an opportunity to further reduce costs.

Progress towards elimination of routine flaring in Ghana

As part of Tullow's commitment to becoming a Net Zero Company by 2030 on its Scope 1 and 2 emissions, work to increase gas processing capacity at the Jubilee FSPO is planned during a scheduled shutdown in the second quarter of 2022, which together with compressor upgrades and other facility de-bottlenecking activities through 2022 and early 2023 will increase gas handling capacity and contribute towards the target of eliminating routine flaring in Ghana by 2025. Other activities planned during the shutdown will focus on maintenance, integrity, and reliability of the FPSO for the long-term.

Ghana gas commercialisation

Associated gas from Jubilee and non-associated gas from the TEN fields has the potential to be a significant value driver for Tullow and for Ghana. In 2009, Tullow and its JV Partners pledged to provide 200 bcf of rich/wet associated gas ("Foundation gas") from the Jubilee field free of charge to the Government of Ghana. The Group currently expects to complete the provision of this Foundation gas, which Tullow estimates has delivered over c. $2.4 billion of value to Ghana including the onshore extraction of liquids yields, by the end of 2022. Based on Tullow's calculations, gas from the Jubilee field currently fuels c.30% of thermal power generation in Ghana and continued offtake of associated gas from the Jubilee field is vital to maintaining oil production, increasing power generation in Ghana and the production of Liquid Petroleum Gas for Ghana's domestic market. Tullow is currently in commercial negotiations with the Government of Ghana to finalise the Post Foundation Volume Gas Sales Agreement which would deliver 500 BCF of natural gas and would add c.6 kboepd to Group production. The Group's investment in upstream gas handling infrastructure on the Jubilee FPSO and the ability to supply comingled Jubilee & TEN gas gives Tullow confidence that it can meet growing domestic demand and be the most competitive supplier of gas into the Ghanaian market.

Tullow is also in positive discussions with JV partners and the Government of Ghana on the development of incremental gas volumes present at the TEN fields where c.1 tcf of gas is estimated to be in place. Because of the upstream infrastructure in place, including a gas pipeline to shore, TEN gas is well-placed to be a stable and reliable source of gas at potential rates of 6 kboepd for Ghana and, as the power sector in West Africa develops further, the wider region. With such substantial volumes in place, this resource has the potential to drive significant industrial transformation in Ghana across the mining and petrochemical sectors among others and be a reliable and low-cost provider of wet gas at a time when the benefit of having significant domestic gas supplies is so clear.

Pre-emption of Deep Water Tano component of Kosmos Energy/Occidental Petroleum Ghana transaction

In November 2021, Tullow exercised its right of pre-emption related to the sale of Occidental Petroleum's interests in the Jubilee and TEN fields in Ghana to Kosmos Energy. As a result, Tullow's equity interests are expected to increase to 38.9% in the Jubilee field and 54.8% in the TEN fields upon completion of the transaction. The transaction documents are now in agreed form between Tullow and Kosmos. On this basis, Tullow and Kosmos have jointly requested consent from the Government of Ghana and discussions with the Government are progressing positively.

NON-OPERATED PORTFOLIO

Production from Tullow's non-operated portfolio averaged 17.2 kboepd in 2021, including contributions from Tullow's continuing interests in Gabon, Côte d'Ivoire and partial contribution from divested assets. 2022 net production is expected to average between 16 to 19 kboepd.

In February 2021, Tullow announced an agreement to sell its entire interests in Equatorial Guinea and the Dussafu Marin Permit in Gabon to Panoro Energy ASA. The deals were completed in March 2021 and June 2021, respectively, for $180 million including contingent cash payments of up to $40 million which are linked to asset performance and oil price.

In Gabon, the Simba expansion project made good progress in 2021, and an infill well was brought onstream in September 2021. A new 10-inch pipeline, allowing increased oil offtake from the field, became operational in December 2021. After initial operational issues post start-up, the well is now performing as expected and consequently, net production for the Simba field in 2022 is expected to average c.6kbopd, 40% higher than in 2021. Also in Gabon, two infrastructure-led exploration wells were drilled in the year near the Tchatamba field. One well was unsuccessful and the other resulted in the Wamba (TCTS-B14) discovery in the second half of 2021. Wamba is adjacent to the Tchatamba South oil field and extended production tests are planned in 2022.

In Côte d'Ivoire, the Espoir field was shut down for approximately four weeks in the first half of the year following a major incident onboard the FPSO in January 2021. A further shutdown of approximately eight weeks was conducted in the second half of the year to carry out remediation work identified by BW Offshore, the FPSO operator. The field is now back onstream and Tullow continues to engage with the operator (CNR International) on further remediation plans for the FPSO and on identifying development drilling opportunities.

DECOMMISSIONING

In the UK, post-decommissioning surveys have been completed and submitted as part of the operated decommissioning programme approval process, with formal approval expected in 2022. The Group's non-operated decommissioning activities are ongoing and are expected to continue through to 2026.

In Mauritania, the Group's operated decommissioning programme of the Banda and Tiof fields is expected to commence in the fourth quarter of 2022. Planning is well advanced, with major service providers secured. Non-operated decommissioning of the Chinguetti field is ongoing and seabed infrastructure clearance is expected to complete this year.

The expected remaining UK and Mauritania decommissioning exposure over 2022-26 is c.$180 million, with over half of this forecast spend in 2022. The final exposure may vary depending on the final required scope and work programmes agreed across the various projects. Provisioning for decommissioning of producing assets in Ghana and parts of the non-operated portfolio has commenced this year at c.$30 million per annum.

KENYA

In 2021 Tullow and its JV Partners (Africa Oil and Total Energies) completed the redesign of the Kenya development project (Blocks 10BB and 13T licences) to ensure it is a technically, commercially and environmentally robust project. The key changes to the development concept have been driven by incorporating the production data from the Early Oil Pilot Scheme (EOPS), optimising the number of wells to be drilled and changing the producer to injector ratio, adding the Ekales field into the first phase of production and increasing the Central Processing Facility capacity to 130,00 bopd and the pipeline size from 18" to 20" to handle the increased flow rates.

These changes have increased total gross capital expenditure (capex), which covers both the upstream and the pipeline to First Oil, to c.$3.4 billion and delivers a 30% increase in resources whilst lowering the unit cost to $22/bbl (previously c.$31/bbl). A higher production plateau of 120 kbopd is now planned, with expected gross oil recovery of 585 mmbo over the full life of the field. This resource position is supported by a Competent Persons Report completed by external international auditors Gaffney Cline Associates (GCA).

Simultaneous to the development, an exploration and appraisal (E&A) plan will be implemented to ensure the remaining five discoveries are developed efficiently. This will extend and sustain initial plateau rates while keeping costs low by using the rigs used for development drilling. The E&A plan also focuses on additional exploration potential within the Blocks 10BB and 13T licences and exploring the wider Blocks 10BA and 12B licence acreage.

Tullow and its JV Partners have taken the opportunity of this review to improve the environmental and social aspects of the project. Carbon emissions will be limited through a combination of heat conservation, use of associated gas for power and reinjection of excess gas into the reservoir. Further, there are opportunities to use the Kenyan national grid that is substantially powered by renewables and options to offset remaining emissions. As per the previous development plan, the 825 kilometres long pipeline that will transport the crude oil from Turkana to the port of Lamu will be heated and buried to avoid long-term disruption. The project will also require water for reservoir pressure which will be abstracted through a pipeline from the Turkwell Dam and will also be used to provide water to local communities.

This project would also be Kenya’s first oil and gas development and would represent a stable, long-term source of income for the Government of Kenya.

In line with licence extension requirements, Tullow and its JV Partners submitted a final FDP to the Government of Kenya in December 2021, incorporating their feedback on the draft FDP submitted earlier in the year.

Submission of the FDP for the 10BB/13T licences will allow Tullow and its JV Partners to secure the Production Licences for blocks and the continuation of the exploration licences on the 10BA and 12B blocks through the commitments made in the E&A plan. The JV is now working closely with the Ministry of Petroleum and Mines to secure FDP approval which needs to be ratified by the Kenyan parliament. The FDP is conditional on a number of critical work streams for both the Government of Kenya and the JV Partners, including, but not limited to, the successful introduction of a new strategic partner. Constructive discussions with interested parties are progressing as Tullow and the JV Partners look to secure a strategic partner for the project.

EXPLORATION

In Tullow’s core area of West Africa, the exploration team is focused on maturing near-field and infrastructure-led (ILX) exploration opportunities around existing producing fields, to unlock additional value from the Group’s asset base.

In Gabon, focus in on strengthening the prospective resource base within the Simba licence and several low-risk and compelling investment options adjacent to infrastructure have been identified which will be considered for future drilling programmes.

In Côte d’Ivoire, Tullow has a 90% interest in offshore Block CI-524 which is a continuation of the proven Cretaceous turbidite plays that are producing at the adjacent TEN and Jubilee fields. This block presents a unique opportunity due to Tullow’s deep understanding of the area and its proximity to the Group's producing fields that could realise cost and operational synergies in the event of discoveries. Focus has been on maturing opportunities through 3D seismic reprocessing which has identified additional prospective resources in several stacked reservoirs that are being matured as future drilling candidates. Tullow, together with its JV Partner PetroCi, has proceeded into the second exploration phase in CI-524, which includes a commitment well to be drilled before August 2024.

In Ghana, focus is on opportunities around the Jubilee and TEN fields to unlock additional value from the Group’s asset base, with potential reserves additions from ILX opportunities.

Tullow also continues to focus on unlocking value from the substantial prospective resource base in the emerging basins of Guyana and Argentina, while seeking to mitigate capital exposure from historical work commitments. In 2022, commitments include the Beebei-Potaro exploration well in the Kanuku Block in Guyana, which will target the Cretaceous light oil play of the Guyana-Suriname Basin, as well as seismic acquisition over Block MLO 122 in Argentina.

In 2021, Tullow drilled the unsuccessful Goliathberg-Voltzberg North exploration well, on Block 47, offshore Suriname. The well encountered good quality reservoir but only minor oil shows. In Argentina, a multi-client 3D seismic acquisition was completed on Tullow-operated licences MLO114 and MLO119. In Côte d’Ivoire, Tullow has now exited all onshore blocks but retains its 90% interest in the offshore Block CI-524, adjacent to the TEN fields.

The Group continued to rationalise its portfolio during the year and exited 11 exploration blocks in 2021, including all of its licences in Suriname and Peru, reorienting its exploration effort towards near-field and infrastructure-led exploration activities to enhance value in core areas. In January 2022, Tullow also exited the PEL 90 licence in Namibia.

FINANCE REVIEW

Financial summary	2021	2020
Working interest production volume (boepd)	59,200	74,900
Sales volume (boepd)	55,450	74,600
Realised oil price ($/bbl)	62.7	50.9
Total revenue ($m)	1,273	1,396
Gross profit ($m)	634	403
Underlying cash operating costs per boe ($/boe)[1]	12.4	12.1
Exploration costs written off ($m)	60	987
Impairment of property, plant and equipment, net ($m)	54	251
Operating profit/(loss)($m)	515	(1,018)
Profit/(Loss) before tax ($m)	203	(1,273)
Loss after tax ($m)	(81)	(1,222)
Basic loss per share (cents)	(5.7)	(86.6)
Capital investment ($m)[1]	263	288
Adjusted EBITDAX ($m)[1]	961	804
Net debt ($m)[1]	2,131	2,376
Gearing (times)[1]	2.2	3.0
Free cash flow ($m)[1]	245	432
Underlying operating cash flow ($m) [1]	711	598
Pre-financing cash flow ($m) [1]	529	625

[1] Alternative performance measures are explained and reconciled on pages 31 to 34.

Production and commodity prices

Group working interest production averaged 59,200 boepd, a decrease of 21 per cent for the year (2020: 74,900 boepd). The decrease in production primarily resulted from the sale of Tullow's interests in Equatorial Guinea and the Dussafu Marine Permit in Gabon in 1H21, and lower than expected production from the TEN fields.

The Group's realised oil price after hedging for the period was $62.7/bbl and before hedging $70.3/bbl. (2020: $50.9/bbl and $42.9/bbl respectively). There has been a strong recovery in oil markets which has led to higher realised prices partially offset by hedge losses, decreasing total revenue by $153 million (2020: increased revenue by $219 million).

	2021	2020
Profit and Loss		
Revenue ($m)	1,273	1,396
Underlift/Overlift income/(expense) ($m)	20	(161)
Balance Sheet		
Underlift ($m)	27	20
Overlift ($m)	(1)	(4)

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

Underlying cash operating costs amounted to $269 million; $12.4/boe (2020: $332 million; $12.1/boe). The reduction in operating costs is mainly driven by the disposal of Equatorial Guinea in 2021 ($23 million) and decrease in Facilities O&M costs in Ghana ($47 million), offset by an increase in Gabon mainly due to the costs relating to the Simba well which came onstream in 2021 ($12 million). Cash operating costs excluding COVID-19 operating procedures and shuttle tanker operations in Ghana were $12.1/boe (2020: $11.8 /boe).

Depreciation, depletion and amortisation (DD&A) charges on production and development assets amounted to $361 million; $16.7/boe (2020: $446 million; $16.3/boe). This increase in DD&A per barrel is mainly attributable to a downward revision of TEN 2P reserves.

Administrative expenses of $64 million (2020: $87 million) have decreased against the comparative period. In February 2020, Tullow concluded its Business Review, which included a review of the Group's organisation structure and resources and resulted in a significant headcount reduction. Furthermore, the Group has focused on reducing non-payroll G&A costs including outsourced information systems expenses, professional fees and office rent. However, this is partially offset by the adverse GBP:USD FX variance in 2021. During 2021, Tullow met its $125 million cost savings target by delivering $127 million in cash savings and is expected to deliver in excess of this in 2022 and beyond.

The Group recognised a net impairment charge on producing assets of $54 million in respect of 2021 (2020: $251 million). Impairments primarily related to the TEN fields following reduced 2P reserves and higher capital expenditure offset by higher price assumptions and lower expected future decommissioning costs. The TEN fields' impairment was offset by impairment reversals on the non-operated fields associated with increased 2P reserves and higher price assumptions.

Impairment of property, plant and equipment (PP&E)	2021	2020
Pre-tax impairment of PP&E, net ($m)	54	251
Associated deferred tax credit ($m)	(21)	(68)
Post-tax impairment of PP&E, net ($m)	33	183

The total exploration cost written off for the year ended 31 December 2021 was $60 million (2020: $987 million), predominantly driven by the write-off of the GVN-1 well costs and licence costs of Blocks 47 and 54 in Suriname. The remaining write-offs comprise of licence level costs associated with Peru, Comoros, Côte d'Ivoire and Namibia due to no planned activity and licence exits. This is partially offset by a release of an indirect tax provision following settlement in Uganda relating to its disposal in 2020.

Exploration costs written off	2021	2020
Exploration costs written off ($m)	60	987

Asset Disposals

In March 2021, the Group completed the sale of its assets in Equatorial Guinea with a cash consideration received of $88.9 million. This transaction included contingent future payments of up to $16.0 million which are linked to asset performance and oil price. As per the SPA, a further $5.0 million of additional consideration was also received on completion of the sale of the Dussafu Marin Permit in Gabon.

In June 2021, the Group completed the asset sale of the Dussafu Marin Permit in Gabon with a cash consideration received of $39.0 million. This transaction included contingent future payments of up to $24.0 million which are linked to asset performance and oil price.

Tullow received $75 million (net of $7 million indemnity provision relating to tax audits) from Total following a Final Investment Decision (FID) for the Lake Albert Development in Uganda on 16 February 2022.

Derivative financial instruments

Tullow continues to undertake hedging activities as part of the ongoing management of its business risk to protect against commodity price volatility and to ensure the availability of cash flow for re-investment in capital programmes that are driving business delivery.

At 31 December 2021, Tullow's hedge portfolio provides downside protection for 75% of forecast production entitlements through to May 2023 and 50% for a further 12 months to May 2024. Since completion of the comprehensive debt refinancing in May where increased hedges for May 2021 to May 2024 (75%, 75%, 50%) were a requirement, new hedges have been placed with $55/bbl floors and weighted average sold calls of c.$76/bbl for the period January 2022 to May 2024. The strong recovery in oil prices allowed the Group to secure sold calls above $95/bbl by the end of the hedging programme implementation.

All of the Group's derivatives are Level 2 (2020: Level 2). There were no transfers between fair value levels during the year.

At 31 December 2021, the Group's derivative instruments had a net negative fair value of $180 million (2020: net positive $2 million).

2021 hedge position	Bopd	Bought put (floor)	Sold call	Bought call
Collars	39,000	$48.12	$66.47	–
Three-way collars (call spread)	1,000	$50.00	$72.80	$82.80
Total/weighted average	40,000	$48.17	$66.63	$82.80

Hedge position as at 31 December 2021 (forward looking)	2022	2023	2024
Hedged volume (kbopd)	42,500	33,100	11,300
Weighted average bought put (floor) ($/bbl)	$51/bbl	$55/bbl	$55/bbl
Weighted average sold call ($/bbl)	$78/bbl	$75/bbl	$75/bbl

Net financing costs

Net financing costs for the year were $312 million (2020: $255 million). The increase in financing costs during the period is mainly driven by finance fees, such as legal and advisor fees related to the assessment of alternative refinancing options of the extinguished RBL Facility directly expensed to the income statement ($18 million), as well as increased average cost of debt following completion of the refinancing transactions in May 2021, partly offset by the net gain on early settlement and derecognition of the RBL Facility and the 2022 Notes ($8 million credit).

Net financing costs include interest incurred on the Group's debt facilities, foreign exchange gains/losses, the unwinding of discount on decommissioning provisions, and the net financing costs associated with lease assets. These costs are offset by interest earned on cash deposits. A reconciliation of net financing costs is included in Note 6.

Taxation

The net tax expense of $283 million (2020: credit of $52 million) primarily relates to tax charges in respect of the Group's production activities in West Africa, as well as UK decommissioning assets, reduced by deferred tax credits associated with exploration write-offs, impairments and other provisions.

Based on a profit before tax for the period of $203 million (2020: loss of $1,273 million), the effective tax rate is 139.8 per cent (2020: 4.1 per cent). After adjusting for non-recurring amounts related to restructuring costs, exploration write-offs, disposals, impairments, other provisions and their associated deferred tax benefit, the Group's adjusted effective tax rate is 117.1 per cent (2020: 35.6 per cent). The adjusted effective tax rate has increased primarily due to there being no UK tax benefit from net interest and hedging losses of $417 million, compared to net profits of $16 million arising on hedging gain and net interest in 2020. Non-deductible expenditure in Ghana, the change in mix of taxable and non-taxable profits in Gabon, prior year adjustments and taxes on uncertain tax treatments are additional contributing factors.

The Group's future statutory effective tax rate is sensitive to the geographic mix in which pre-tax profits and exploration costs written off arise. Unsuccessful exploration is often incurred in jurisdictions where the Group has no taxable profits such that no related tax benefit results. Consequently, the Group's tax charge will continue to vary according to the jurisdictions in which pre-tax profits and exploration costs write-offs occur.

Analysis of adjusted effective tax rate ($'m)		Adjusted Profit/(loss) before tax	Tax (expense)/credit	Adjusted Effective tax rate
Ghana	FY 2021	450.9	(163.3)	36.2%
	FY 2020	0.4	0.6	(139.2)%
Gabon	FY 2021	178.3	(88.5)	49.6%
	FY 2020	46.1	(34.6)	75.2%
Equatorial Guinea	FY 2021	15.5	(5.4)	35.0%
	FY 2020	18.6	0.8	(4.1)%
Corporate	FY 2021	(386.0)	(41.8)	(10.8)%
	FY 2020	(25.8)	8.1	31.3%
Other non-operated & exploration	FY 2021	(0.4)	(3.6)	(1,033.9)%
	FY 2020	(20.1)	4.0	(20.0)%
Total	**FY 2021**	258.4	(302.7)	117.1%
	FY 2020	59.4	(21.1)	35.6%

Loss after tax from continuing activities and loss per share

The loss for the year from continuing activities amounted to $81 million (2020: $1,222 million loss). Basic loss per share was 5.7 cents (2020: 86.6 cents loss per share).

Reconciliation of net debt	$m
Year-end 2020 net debt	2,375.6
Sales revenue	(1,273.2)
Operating costs	268.7
Other operating and administrative expenses	109.2
Cash flow from operations	(895.3)
Movement in working capital	52.3
Tax paid	56.1
Purchases of intangible exploration and evaluation assets and property, plant and equipment	236.5
Other investing activities	(134.8)
Other financing activities	447.4
Foreign exchange loss on cash	(6.9)
Year-end 2021 net debt	2,130.9

Capital investment

Capital expenditure amounted to $263 million (2020: $288 million) with $205 million invested in production and development activities and $58 million invested in exploration and appraisal activities.

Tullow will continue to maintain capital discipline with 2022 capital investment primarily directing investment to maximising value from the Group's producing assets. The Group's 2022 capital expenditure is expected to total c.$350 million and comprises Ghana c.$270 million, West Africa non-operated c.$30 million, Kenya c.$5 million, and exploration c. $45 million.

Borrowings

On 17 May 2021, the Group completed a comprehensive refinancing of its debt with the issuance of five-year $1.8 billion Senior Secured Notes ("2026 Notes") and a new undrawn $500 million Super Senior Revolving Credit Facility ("SSRCF") which will be primarily used for working capital purposes.

The 2026 Notes have been used to (i) repay all amounts outstanding under, and cancel all commitments made available pursuant to, the Group's RBL Facility, (ii) redeem in full the Group's senior notes due 2022, (iii) repay in full and cancel the Group's convertible bonds and (iv) pay fees and expenses incurred in connection with the transactions.

The 2026 Notes, maturing in May 2026, require an annual prepayment of $100 million, in May, of the outstanding principal amount plus accrued and unpaid interest, with the balance due on maturity.

The Senior Notes due 2025 is payable in a single payment in March 2025.

The SSRCF, maturing in December 2024, comprises (i) a $500 million revolving credit facility and (ii) a $100 million letter of credit facility. The revolving credit facility remains undrawn as at 31 December 2021.

The 2026 Notes and the SSRCF are senior secured obligations of Tullow Oil Plc and are guaranteed by certain of the Group's subsidiaries.

Credit ratings

Tullow maintains corporate credit ratings with Standard & Poor's (S&P's) and Moody's Investors Service (Moody's).

On 5 February 2021, S&P's placed Tullow's CCC+ corporate credit rating and CCC+ ratings for bonds maturing in 2022 and 2025 on negative credit watch to reflect the uncertainty associated with ongoing debt refinancing discussions at the time. On 18 May 2021, S&P's upgraded Tullow's corporate credit rating to B-, removed the rating from negative credit watch and revised the outlook to stable. At the same time S&P's assigned a B- rating to the $1.8 billion 2026 Notes and confirmed the CCC+ rating of the $800 million Senior Notes maturing in 2025.

On 29 April 2021, Moody's assigned and placed under review for upgrade a B3 rating to the $1.8 billion 2026 Notes, and at the same time placed Tullow's Caa1 corporate credit rating under review for upgrade. Moody's confirmed their Caa2 ratings of the Senior Notes maturing in 2022 and 2025. On 20 October 2021, Moody's upgraded Tullow's corporate credit rating to B3 with stable outlook from Caa1 under review for upgrade, and at the same time upgraded its rating of the $1.8 billion Senior Secured Notes to B2 with stable outlook from B3 under review for upgrade. Moody's also affirmed their Caa2 rating of the Senior Notes maturing in 2025.

Liquidity risk management and going concern

Assessment period and assumptions

The Directors consider the going concern assessment period to be up to 31 March 2023. The Group closely monitors and manages its liquidity headroom. Cash forecasts are regularly produced and sensitivities run for different scenarios including, but not limited to, changes in commodity prices, different production rates from the Group's producing assets and different outcomes on ongoing disputes or litigation. Management has applied the following oil price assumptions for the going concern assessment:

Base Case: $76/bbl for 2022, $71/bbl for 2023; and

Low Case: $60/bbl for 2022, $60/bbl for 2023.

The Low Case includes, in addition to lower oil price assumptions, a 5 per cent production decrease and 12% increased operating costs compared to the Base Case, as well as increased outflows associated with ongoing disputes.

On 17 May 2021, the Group announced the completion of its offering of $1.8 billion 2026 Notes. The net proceeds, together with cash on balance sheet, have been used to (i) repay all amounts outstanding under, and cancel all commitments made available pursuant to, the Company's RBL Facility, (ii) redeem in full the Company's senior notes due 2022, (iii) at maturity, repay in full and cancel the Company's convertible bonds due 2021 and (iv) pay fees and expenses incurred in connection with the transactions. The Group also entered into a $600 million SSRCF which is undrawn and will be primarily used for working capital purposes. The 2026 Senior Notes and the SSRCF do not have any maintenance covenants (disclosure of key covenants and the determination of availability under the SSRCF are provided in note 18). Following completion of these transactions the Directors have concluded that the material uncertainties noted in the 2020 Annual Report and Accounts, associated with implementing a Refinancing Proposal and obtaining amendments or waivers in respect of covenant breaches or, in the event a Refinancing Proposal is implemented, the revised covenants are subsequently breached, no longer exist.

The Group had $0.9 billion liquidity headroom of unutilised debt capacity and non restrictive cash as at 31 December 2021. The Group's forecasts show that the Group will be able to operate within its current debt facilities and have sufficient financial headroom for the going concern assessment period under its Base Case and Low Case. These forecasts show full availability of the $600 million SSRCF, which under the Base Case remains undrawn. Furthermore management has performed a reverse stress test and the average oil price throughout the going concern period required to reduce headroom to zero during the assessment period is $39/bbl. Based on the analysis above, the Directors have a reasonable expectation that the Company has adequate resources to continue in operational existence for the foreseeable future. Thus, they have adopted the going concern basis of accounting in preparing the year end results.

Events since 31 December 2021

Adjusting events

On 15 February 2022 a panel of arbitrators, working under the jurisdiction of Norwegian law, delivered an award in favour of HiTec Vision (HiTec) in relation to its dispute with Tullow (Award). The panel had been asked to adjudicate as to whether discoveries made in the PL-537 Licence (Offshore Norway) between 2013 and 2016 had triggered a further payment under the SPA between Tullow and HiTec regarding the purchase of Spring Energy in 2013. With the Award, the panel has decided by way of split decision that conditions for a further payment outlined in the SPA were met. The Tribunal ruled that Tullow should pay $76 million. This amount also includes interest and costs. This has been recognised in the balance sheet as a liability as at 31 December 2021.

Non-adjusting events

FID for the Tilenga Project in Uganda and the East African Crude Oil Pipeline (EACOP) as reported by Total Energies Ltd on 1 February 2022 triggered a contingent consideration payment of $75 million (net of $ 7 million indemnity provision relating to tax audits) in relation to

Tullow's sale of its assets in Uganda to Total in 2020 which was received on 16 February 2022. This was recognised as a current receivable as at 31 December 2021.

There have not been any other events since 31 December 2021 that have resulted in a material impact on the year end results.

Group income statement

Year ended 31 December 2021

$m	Notes	2021	2020
Continuing activities			
Revenue		1,273.2	1,396.1
Cost of sales	5	(638.9)	(993.6)
Gross profit		634.3	402.5
Administrative expenses	5	(64.1)	(86.7)
Gain/ (loss) on disposal		120.3	(3.4)
Exploration costs written off	9	(59.9)	(986.7)
Impairment of property, plant and equipment, net	10	(54.3)	(250.6)
Restructuring costs and other provisions	5	(61.8)	(92.8)
Operating profit/ (loss)		514.5	(1,017.7)
Loss on hedging instruments		–	(0.8)
Finance income	6	44.3	59.4
Finance costs	6	(356.1)	(314.3)
Profit/ (loss) from continuing activities before tax		202.7	(1,273.4)
Income tax (expense)/ credit	7	(283.4)	51.9
Loss for the year from continuing activities		(80.7)	(1,221.5)
Attributable to			
Owners of the Company		(80.7)	(1,221.5)
Loss per ordinary share from continuing activities		¢	¢
Basic		(5.7)	(86.6)
Diluted		(5.7)	(86.6)

Group statement of comprehensive income and expense

Year ended 31 December 2021

$m	2021	2020
Loss for the year from continuing activities	(80.7)	(1,221.5)
Items that may be reclassified to the income statement in subsequent periods		
Cash flow hedges		
(Loss)/ gain arising in the year	(159.3)	271.0
Losses arising in the period – time value	(182.1)	(37.3)
Reclassification adjustments for items included in profit on realisation	112.3	(268.1)
Reclassification adjustments for items included in loss on realisation – time value	40.7	49.4
Exchange differences on translation of foreign operations	(1.4)	(5.3)
Other comprehensive (expense)/ income	(189.8)	9.8
Tax relating to components of other comprehensive (expense)/ income	2.7	(2.7)
Other comprehensive (expense)/ income for the year	(187.1)	7.1
Total comprehensive expense for the period	(267.8)	(1,214.4)
Attributable to		
Owners of the Company	(267.8)	(1,214.4)

Group balance sheet

As at 31 December 2021

$m	Notes	2021	2020
Assets			
Non-current asset			
Intangible exploration and evaluation assets	9	354.6	368.2
Property, plant and equipment	10	2,914.6	3,237.9
Other non-current assets	11	489.1	547.4
Derivative financial instruments		–	2.6
Deferred tax assets		354.4	494.3
		4,112.7	4,650.4
Current assets			
Inventories		134.8	96.1
Trade receivables		99.8	79.0
Other current assets	11	704.5	717.1
Current tax assets		19.7	36.4
Derivative financial instruments		–	17.2
Cash and cash equivalents		469.1	805.4
Assets classified as held for sale	12	–	155.6
		1,427.9	1,906.8
Total assets		5,540.6	6,557.2
Liabilities			
Current liabilities			
Trade and other payables	13	(751.1)	(750.7)
Borrowings		(100.0)	(3,170.5)
Provisions	14	(296.5)	(229.8)
Current tax liabilities		(115.1)	(52.2)
Derivative financial instruments		(80.9)	(17.8)
Liabilities directly associated with assets classified as held for sale	12	–	(187.3)
		(1,343.6)	(4,408.3)
Non-current liabilities			
Trade and other payables	13	(987.1)	(1,064.7)
Borrowings		(2,468.7)	–
Provisions	14	(431.0)	(620.9)
Deferred tax liabilities		(677.3)	(673.3)
Derivative financial instruments		(99.0)	–
		(4,663.1)	(2,358.9)
Total liabilities		(6,006.7)	(6,767.2)
Net liabilities		(466.1)	(210.0)
Equity			
Called up share capital		214.2	211.7
Share premium		1,294.7	1,294.7
Equity component of convertible bonds		–	48.4
Foreign currency translation reserve		(248.8)	(247.4)
Hedge reserve		(39.3)	4.8
Hedge reserve – time value		(146.9)	(5.4)
Merger reserve		755.2	755.2
Retained earnings		(2,295.2)	(2,272.0)
Equity attributable to equity holders of the Company		(466.1)	(210.0)
Total equity		(466.1)	(210.0)

Group statement of changes in equity

Year ended 31 December 2021

$m	Called up share capital	Share premium	Equity component of convertible bonds	Foreign currency translation reserve[1]	Hedge reserve[2]	Hedge reserve – time value[2]	Merger reserves	Retained earnings	Total
At 1 January 2020	210.9	1,294.7	48.4	(242.1)	4.6	(17.5)	755.2	(1,070.6)	983.6
Loss for the year	–	–	–	–	–	–	–	(1,221.5)	(1,221.5)
Hedges, net of tax	–	–	–	–	0.2	12.1	–	–	12.3
Currency translation adjustments	–	–	–	(5.3)	–	–	–	–	(5.3)
Exercise of employee share options	0.8	–	–	–	–	–	–	(0.8)	–
Share-based payment charges	–	–	–	–	–	–	–	20.9	20.9
At 1 January 2021	211.7	1,294.7	48.4	(247.4)	4.8	(5.4)	755.2	(2,272.0)	(210.0)
Profit for the year	–	–	–	–	–	–	–	(80.7)	(80.7)
Hedges, net of tax	–	–	–	–	(44.1)	(141.5)	–	–	(185.6)
Derecognition of the convertible bond[3]	–	–	(48.4)	–	–	–	–	48.4	–
Currency translation adjustments	–	–	–	(1.4)	–	–	–	–	(1.4)
Exercise of employee share options	2.5	–	–	–	–	–	–	(2.5)	–
Share-based payment charges	–	–	–	–	–	–	–	11.6	11.6
At 31 December 2021	214.2	1,294.7	–	(248.8)	(39.3)	(146.9)	755.2	(2,295.2)	(466.1)

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.
2. The hedge reserve represents gains and losses on derivatives classified as effective cash flow hedges.
3. On 12 July 2021 Tullow repaid the $300 million Convertible Bond due 2021. As the conversion option was not exercised, the equity component of $48.4 million has been transferred from the separate reserve to retained earnings.

Group cash flow statement

Year ended 31 December 2021

$m	Notes	2021	2020
Profit/ (loss) for the year from continuing activities		202.7	(1,273.4)
Adjustments for:			
Depreciation, depletion and amortisation	10	378.9	467.1
(Gain)/ loss on disposal		(120.3)	3.4
Exploration costs written off	9	59.9	986.7
Impairment of property, plant and equipment, net	10	54.3	250.6
Restructuring costs and other provisions		61.8	92.8
Payment under restructuring costs and other provisions	14	(12.6)	(58.4)
Decommissioning expenditure	14	(52.8)	(57.7)
Share-based payment charge		11.6	20.9
Loss on hedging instruments		–	0.8
Finance revenue	6	(44.3)	(59.4)
Finance costs	6	356.1	314.3
Operating cash flow before working capital movements		895.3	687.7
(Increase)/ decrease in trade and other receivables		(17.9)	195.2
(Increase)/ decrease in inventories		(41.9)	85.1
Increase/ (decrease) in trade payables		7.5	(161.9)
Cash generated from operating activities		843.0	806.1
Income taxes paid		(56.1)	(107.5)
Net cash from operating activities		786.9	698.6
Cash flows from investing activities			
Proceeds from disposals	8	132.8	513.4
Purchase of intangible exploration and evaluation assets		(86.1)	(213.6)
Purchase of property, plant and equipment		(150.4)	(217.3)
Interest received		2.0	1.8
Net cash (used in)/ from investing activities		(101.7)	84.3
Cash flows from financing activities			
Debt arrangement fees		(56.6)	–
Repayment of borrowings		(2,379.9)	(185.0)
Drawdown of borrowings		1,800.0	270.0
Payment of obligations under leases		(155.9)	(158.2)
Finance costs paid		(234.9)	(198.5)
Net cash used in financing activities		(1,027.3)	(271.7)
Net (decrease)/ increase in cash and cash equivalents		(342.1)	511.3
Cash and cash equivalents at beginning of year		805.4	288.8
Foreign exchange gain		5.8	5.4
Cash and cash equivalents at end of year		469.1	805.4

1. Basis of preparation and presentation of financial information

The Financial Statements have also been prepared in accordance with UK-adopted international accounting standards ("IFRSs") and International Financial Reporting Standards adopted pursuant to Regulation (EC) No. 1606/2002 as it applies in the European Union. The financial reporting framework that has been applied in the preparation of the parent company financial statements is applicable law and United Kingdom Accounting Standards, including FRS 101 "Reduced Disclosure Framework" (United Kingdom Generally Accepted Accounting Practice).

The financial information for the year ended 31 December 2021 does not constitute statutory accounts as defined in sections 435 (1) and (2) of the Companies Act 2006. Statutory accounts for the year ended 31 December 2020 have been delivered to the Registrar of Companies and those for 2021 will be delivered following the Company's annual general meeting. The auditor has reported on these accounts; their reports were unqualified. Their report did not include a reference to any other matters to which the auditor drew attention by way of emphasis of matter and did not contain a statement under section 498 (2) or (3) of the Companies Act 2006.

There were adjustments made in relation to a recognition of additional JV receivables ($23.4 million) and reclassification between accruals ($37.9 million) and provisions ($46 million) that should have been accounted in the prior period and was not done so in error. Consequently profit before tax for the current year is higher by $15.3 million with no impact on group cash flow statement. In the directors' judgement, these amounts were not considered material based on their nature as working capital reclassifications and in assessment against the relative impact of the financial statement line items, so the prior period amounts have not been corrected.

The Financial Statements have been prepared on the historical cost basis, except for derivative financial instruments and contingent consideration which have been measured at fair value which are carried at fair value less cost to sell. The Financial Statements are presented in US dollars and all values are rounded to the nearest $0.1 million, except where otherwise stated.

The accounting policies applied are consistent with those adopted and disclosed in the Group's financial statements for the year ended 31 December 2021. There have been a number of amendments to accounting standards and new interpretations issued by the International Accounting Standards Board which were applicable from 1 January 2021, however these have not any impact on the accounting policies, methods of computation or presentation applied by the Group. Further details on new International Financial Reporting Standards adopted will be disclosed in the 2021 Annual Report and Accounts.

Certain new accounting standards and interpretations have been published that are not mandatory for 31 December 2021 reporting periods and have not been early adopted by the Group. These standards are not expected to have a material impact on the entity in the current or future reporting periods and on foreseeable future transactions.

2. Loss per ordinary share

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

Diluted loss per ordinary share amounts are calculated by dividing net loss for the year attributable to ordinary equity holders of the Parent by the weighted average number of ordinary shares outstanding during the year plus the weighted average number of dilutive ordinary shares that would be issued if employee and other share options or the convertible bonds were converted into ordinary shares.

The adjustment in respect of convertible bonds and share options had an anti-dilutive impact on earnings and was thus not considered in determining diluted underlying EPS for the year ended 31 December 2021 and 2020.

3. 2021 Annual Report and Accounts

The 2021 Annual Report and Accounts will be mailed in March 2022 only to those shareholders who have elected to receive it. Otherwise, shareholders will be notified that the Annual Report and Accounts are available on the Group's website (www.tullowoil.com). Copies of the Annual Report and Accounts will also be available from the Company's registered office at Building 9, Chiswick Park, 566 Chiswick High Road, London, W4 5XT.

4. Segmental reporting

The information reported to the Group's Chief Executive Officer for the purposes of resource allocation and assessment of segment performance is focused on four Business Units – Ghana, Non-operated producing assets including Uganda and decommissioning assets, Kenya and Exploration. Therefore, the Group's reportable segments under IFRS 8 are Ghana, Non-operated, Kenya and Exploration.

The following tables present revenue, loss and certain asset and liability information regarding the Group's reportable business segments for the years ended 31 December 2021 and 31 December 2020.

$m	Ghana	Non-Operated	Kenya	Exploration	Corporate	Total
2021						
Sales revenue by origin	910.6	362.6	–	–	–	1,273.2
Segment result[1]	360.0	243.4	–	(70.5)	(12.8)	520.1
Other Provisions[2]	6.6	–	(13.2)	–	(52.1)	(58.7)
Gain on disposal						120.3
Unallocated corporate expenses[3]						(67.2)
Operating profit						514.5
Finance income						44.3
Finance costs						(356.1)
Profit before tax						202.7
Income tax expense						(283.4)
Loss after tax						(80.7)
Total assets	4,318.9	495.8	270.6	144.3	311.0	5,540.6
Total liabilities[4]	(2,497.3)	(467.7)	(24.0)	(36.8)	(2,980.9)	(6,006.7)
Other segment information						
Capital expenditure:						
Property, plant and equipment	99.6	43.9	–	–	4.6	148.1
Intangible exploration and evaluation assets	1.2	(11.8)	8.1	48.8	–	46.3
Depletion, depreciation and amortisation	(334.5)	(28.8)	(1.4)	(0.1)	(14.1)	(378.9)
Impairment of property, plant and equipment, net	(119.1)	64.8	–	–	–	(54.3)
Exploration costs written off	(1.2)	11.8	–	(70.5)	–	(59.9)

1. Segment result is a non IFRS measure which includes gross profit, exploration costs written off, impairment of property, plant and equipment. See reconciliation below.
2. This is included within Restructuring costs and other provisions in the Group Income Statement.
3. 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.
4. Total liabilities – Corporate comprise of the Group's external debt and other non-attributable liabilities.

Reconciliation of segment result	2021	2020
Segment result	520.1	(834.8)
Add back:		
Exploration costs written off	59.9	986.7
Impairment of Property, plant and equipment	54.3	250.6
Gross profit	634.3	402.5

4. Segmental reporting continued

$m	Ghana	Non-Operated	Kenya	Exploration	Corporate	Total
2020						
Sales revenue by origin	963.5	432.6	–	–	–	1,396.1
Segment result	124.9	(410.2)	(430.0)	(104.3)	(15.2)	(834.8)
Loss on disposal						(3.4)
Unallocated corporate expenses[2]						(179.5)
Operating loss						(1,017.7)
Loss on hedging instruments						(0.8)
Finance income						59.4
Finance costs						(314.3)
Loss before tax						(1,273.4)
Income tax credit						51.9
Loss after tax						(1,221.5)
Total assets	4,859.3	656.3	300.5	181.8	559.3	6,557.2
Total liabilities	(2,696.7)	(688.4)	(34.1)	(44.2)	(3,303.8)	(6,767.2)
Other segment information						
Capital expenditure:						
Property, plant and equipment	94.6	127.1	0.6	0.2	7.2	229.7
Intangible exploration and evaluation assets	0.9	68.5	9.5	91.8	–	170.7
Depletion, depreciation and amortisation	(390.1)	(60.7)	(1.5)	–	(14.8)	(467.1)
Impairment of property, plant and equipment, net	(149.1)	(100.5)	–	(0.4)	(0.6)	(250.6)
Exploration costs written off	(0.8)	(452.0)	(430.0)	(103.9)	–	(986.7)

5. Other costs

$m	2021	2020
Cost of sales		
Operating costs	268.7	331.7
Depletion and amortisation of oil and gas assets[1]	360.9	446.4
Underlift, overlift and oil inventory movement	(20.0)	160.5
Share-based payment charge included in cost of sales	0.5	0.9
Other cost of sales	28.8	54.1
Total cost of sales	638.9	993.6
Administrative expenses		
Share-based payment charge included in administrative expenses	11.1	20.0
Depreciation of other fixed assets	18.0	20.7
Other administrative costs	35.0	46.0
Total administrative expenses	64.1	86.7
Total restructuring costs and other provisions[2]	61.8	92.8

1. Depreciation expense on leased assets of $60.6 million as per note 11 includes a charge of $4.6 million on leased administrative assets, which is presented within administrative expenses in the income statement. The remaining balance of $56.0 million relates to other leased assets and is included within cost of sales.
2. This includes restructuring and redundancy costs of $3.1 million (2020: $67.8 million) as well as movement in other provisions of $58.7 million (2020: $25.0 million).

6. Net financing costs

$m	2021	2020
Interest on bank overdrafts and borrowings	243.0	205.8
Interest on obligations for leases	83.4	91.0
Total borrowing costs	326.4	296.8
Finance and arrangement fees	19.1	0.8
Other Interest expense	3.0	3.6
Unwinding of discount on decommissioning provisions	7.6	13.1
Total finance costs	356.1	314.3
Interest income on amounts due from Joint Venture partners for leases	(38.8)	(40.6)
Other finance revenue	(5.5)	(18.8)
Total finance income	(44.3)	(59.4)
Net financing costs	311.8	254.9

7. Taxation on loss on continuing activities

Factors affecting tax expense/ (credit) for the year

$m	2021	2020
Current tax on profits for the year		
UK corporation tax	(19.2)	(24.7)
Foreign tax	162.2	81.2
Adjustments in respect of prior periods	(3.3)	(25.6)
Total corporate tax	139.7	30.8
UK petroleum revenue tax	(1.2)	(3.4)
Total current tax	138.5	27.4
Deferred tax		
Origination and reversal of temporary differences		
UK corporation tax	18.1	19.8
Foreign tax	80.3	(85.3)
Adjustments in respect of prior periods	43.8	(11.7)
Total deferred corporate tax	142.2	(77.2)
Deferred UK petroleum revenue tax	2.7	(2.1)
Total deferred tax	144.9	(79.3)
Total income tax expense/ (credit)	283.4	(51.9)

7. Taxation on loss on continuing activities continued

Factors affecting tax expense/ (credit) for the year

$m	2021	2020
Profit/ (loss) from continuing activities before tax	202.7	(1,273.4)
Tax on profit/ (loss) from continuing activities at the standard UK corporation tax rate of 19% (2020: 19%)	38.5	(241.9)
Effects of:		
Non-deductible exploration expenditure	8.5	184.4
Other non-deductible expenses	13.3	46.5
Tax impact of change in discount rate on decommissioning provision	–	(2.1)
Deferred tax asset not recognised	94.4	31.0
Derecognition of deferred tax previously recognised	–	0.7
Utilisation of tax losses not previously recognised	(0.1)	(8.4)
Adjustment relating to prior years	40.4	(37.4)
Other tax rates applicable outside the UK	124.2	(43.4)
PSC (income)/ expense not subject to corporation tax	(15.8)	18.9
Other income not subject to corporation tax	(20.0)	(0.2)
Group total tax expense/ (credit)for the year	283.4	(51.9)

Current tax assets

As at 31 December 2021, current tax assets were $19.7 million (2020: $36.4 million) which relates to the UK.

Uncertain tax treatments

The Group is subject to various material claims which arise in the ordinary course of its business in various jurisdictions, including cost recovery claims, claims from other regulatory bodies and both corporate income tax and indirect tax claims. The Group is in formal dispute proceedings regarding a number of these tax claims with significant updates described in more detail below. The resolution of tax positions, through negotiation with the relevant tax authorities or litigation, can take several years to complete. In assessing whether these claims should be provided for in the Financial Statements, Management has considered them in the context of the applicable laws and relevant contracts for the countries concerned. Management has applied judgement in assessing the likely outcome of the claims and has estimated the financial impact based on external tax and legal advice and prior experience of such claims.

Due to the uncertainty of such tax items, it is possible that on conclusion of an open tax matter at a future date the outcome may differ significantly from Management's estimate. If the Group was unsuccessful in defending itself from all of these claims, the result would be additional liabilities of $1,025.5 million (2020: $1,070.2 million) which includes $33.6 million of interest and penalties (2020: $61.2 million).

Provisions of $127.9 million (2020: $129.3 million) are included in income tax payable ($34.1 million (2020: $30.4 million)), deferred tax liability ($41.0 million (2020: nil)), provisions ($52.8 million (2020: $52.4 million)) and accruals (nil (2020: $46.4 million)). Where these matters relate to expenditure which is capitalised within E&A and PP&E, any difference between the amounts accrued and the amounts settled is capitalised within the relevant asset balance, subject to applicable impairment indicators. Where these matters relate to producing activities or historical issues, any differences between the accrued and settled amounts are taken to the Group income statement.

The provisions and contingent liabilities relating to these disputes have increased following new claims being initiated and extrapolation of exposures to all open years, but have decreased following the conclusion of tax authority challenges and matters lapsing under statutes of limitation, giving rise to an overall decrease in provision of $1.4 million and decrease in contingent liability of $44.7 million.

Ghana tax assessments

In August 2018, Tullow Ghana Limited ("TGL") received a direct tax assessment from the Ghana Revenue Authority ("GRA") for financial years 2014 to 2016. After discussions, a final assessment was issued in December 2019 for $406 million requesting that $398 million be paid by 13 January 2020. The GRA is seeking to apply branch profits remittance tax under a law which the Group considers is not applicable to TGL, since it falls outside the tax regime set out in TGL's Petroleum Agreement and relevant double tax treaties. The GRA has additionally assessed TGL for unpaid withholding taxes and corporate income tax arising from the disallowance of loan interest. The Group considers that these assessments also breach TGL's rights under its Petroleum Agreement, applicable Ghanaian law and double taxation treaties, and, in some cases, have arisen as the result of errors in the GRA's calculations. In January 2020, TGL issued a Notice of Dispute with the Ministry of Energy ("MoE"), disputing the issues and suspending TGL's obligation to pay any taxes until the disputed issues have been resolved. In April 2020, the GRA issued a Demand Notice for $365 million ($337 million branch profits remittance tax and withholding tax, and $28 million corporate income tax) which was put on hold by the MoE. In September 2021 TGL received a revised final tax audit report for $471 million ($320 million branch profits remittance tax, $5 million withholding tax and $146 million corporate income tax). In October 2021 TGL filed a Request for Arbitration with the International Chamber of Commerce disputing the $320 million branch profits remittance tax assessment and an additional Notice of Dispute objecting against the disallowance of certain expenditure in the revised tax audit report.

In December 2021, TGL paid $3 million on account in respect of a revised withholding tax assessment of $3 million. TGL received a revised corporate

7. Taxation on loss on continuing activities continued

Uncertain tax treatments continued

income tax computation in February 2022 assessing a tax liability of $121 million but has yet to receive a Revised Assessment or Demand Notice based on this. If the latest position put forward by GRA is finalised in a Revised Assessment, this would result in assessments totalling $441 million including branch profits remittance tax. The Group disputes the assessments issued to date and the tax liability arising from the February 2022 tax calculation and is engaging with the GRA to seek settlement of the issues raised (excluding branch profits remittance tax) on a mutually acceptable basis outside of the ongoing dispute process.

Bangladesh litigation

The National Board of Revenue ("NBR") is seeking to disallow $118 million of tax relief in respect of development costs incurred by Tullow Bangladesh Limited ("TBL"). In 2013, the High Court found in favour of Tullow such that the tax relief should be reinstated. However, in March 2017, the NBR won its appeal to the Supreme Court, which was not clear as to the position or liability of TBL. A review application against this judgment was filed in April 2018. The hearing took place in November 2019 and TBL was unsuccessful. The NBR subsequently issued a payment demand to TBL in February 2020 for Taka 3,094 million (c$37 million) requesting payment by 15 March 2020. However, under the Production Sharing Contract ("PSC"), the Government is required to indemnify TBL against all taxes levied by any public authority, and the share of production paid to Petrobangla ("PB"), Bangladesh's national oil company, is deemed to include all taxes due which PB is then obliged to pay to the NBR. TBL sent the payment demand to PB and the Government requesting the payment or discharge of the payment demand under their respective PSC indemnities. TBL secured an extension of the payment deadline to 15 June 2021 from the NBR to allow discussions with PB and the Government to take place. Such discussions have been delayed several times due to the COVID pandemic. On 14 June 2021 TBL issued a formal notice of dispute under the PSC to the Government and PB. A further request for payment was received from NBR on 28 October 2021 demanding settlement by 15 November 2021. Arbitration proceedings were initiated under the PSC on 29 December 2021 and to date, no further enforcement action has been undertaken or threatened by NBR.

Kenya tax assessments

In March 2019, Tullow Kenya BV ("TKBV") received a VAT assessment for $11.7 million from the Kenya Revenue Authority ("KRA") in relation to consideration charged for the Block 12A farm-down. The Group considered that VAT was not applicable since TKBV was not VAT registered at the time of the disposal and the transaction was in relation to the sale of a capital asset or part of a business. The KRA sought to apply VAT on the basis that the transaction was a disposal of trading stock and therefore the exemption to register for VAT did not apply. The matter was heard by the Tax Appeals Tribunal ("TAT") and TKBV received a favourable judgment on 30 April 2021 which set aside the VAT assessment in its entirety. The KRA subsequently appealed the decision of the TAT to the High Court, but they withdrew that appeal on 19 July 2021. This matter can now be treated as closed.

Uganda Joint Venture Partner tax assessments

TOTAL E&P Uganda B.V. and CNOOC Uganda Limited have reached a settlement with the Uganda Revenue Authority on all existing and potential tax litigation and/or assessments for the period up to June 2015 for PAYE, VAT and WHT.

Other items

Other items totalling $547.5 million (2020: 745 million) comprise exposures in respect of claims for corporation tax in respect of disallowed expenditure or withholding taxes that are either currently under discussion with the tax authorities or which arise in respect of known issues for periods not yet under audit.

Timing of cash-flows

While it is not possible to estimate the timing of tax cash flows in relation to possible outcomes with certainty, management anticipate that there will not be material cash taxes paid in excess of the amounts provided for uncertain tax treatments in the next 12 months.

8. Asset Disposals

On 31 March 2021, the Group completed the sale of its assets in Equatorial Guinea with a cash consideration received of $88.9 million. This transaction included contingent future payments of up to $16.0 million which are linked to asset performance and oil price. As per the SPA, a further $5.0 million of additional consideration was also received on completion of Dussafu Marin Permit in Gabon.

On 9 June 2021, the Group completed the asset sale of Dussafu Marin Permit in Gabon with a cash consideration received of $39.0 million. This transaction included contingent future payments of up to $24.0 million which are linked to asset performance and oil price.

Given Tullow no longer holds interest in the above assets, based on publicly available information the Company has assessed that the asset performance condition is not met. Accordingly, no contingent consideration has been recognised as of 31 December 2021.

Book value of assets disposed	**Equatorial Guinea**	**Dussafu**	**Total**
	$m	**$m**	**$m**
Property, plant and equipment	72.9	52.0	124.9
Inventories	6.9	3.2	10.1
Other current assets	68.5	1.7	70.2
Total assets disposed	148.3	56.9	205.2
Trade and other payables	(36.1)	(18.5)	(54.6)
Provisions	(118.2)	(4.7)	(122.9)
Current tax liabilities	(13.6)	–	(13.6)
Deferred tax liabilities	(17.8)	–	(17.8)
Total liabilities disposed	(185.7)	(23.2)	(208.9)
Net (liabilities)/ assets disposed	(37.4)	33.7	(3.7)
Cash consideration	93.8	39.0	132.8
Transaction costs	(11.0)	(0.3)	(11.3)
Gain on disposal[1]	120.2	5.0	125.2

[1]. In addition to $125.2 million gain on disposals recognised following the Equatorial Guinea and Dussafu disposals, the Group recognised a loss of $5.1 million relating to its sale of Dutch assets to Hague and London Oil plc (HALO) in 2017, and a gain of $0.2 million relating to other transactions during the period which resulted in an overall gain of $120.3 million.

9. Intangible exploration and evaluation assets

$m	2021	2020
At 1 January	368.2	1,764.4
Additions	46.3	170.7
Exploration costs written off	(59.9)	(986.7)
Net transfer (to)/from assets held for sale	–	(580.4)
Currency translation adjustments	–	0.2
At 31 December	354.6	368.2

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

Country	Rationale for 2021 write-off	2021 pre-tax write off $m	2021 Remaining recoverable amount $m
Suriname	b,d	58.9	–
Uganda	c	(15.3)	–
Gabon	d	2.2	–
Peru	b	1.8	–
Cote d'Ivoire	b	6.6	–
Other	a	5.7	–
Total write-off		59.9	

a. Current year expenditure on assets previously written off
b. Licence relinquishments, expiry, planned exit or reduced activity
c. Release of indirect tax provision following settlement
d. Unsuccessful well costs written off

In Kenya, the Group had received a 15 month licence extension from September 2020 to December 2021 which was contingent on certain conditions, including submission of a technically and commercially compliant Field Development Plan (FDP). On 10 December 2021 Tullow and its JV Partners submitted an FDP to the Government of Kenya and fulfilled its licence obligations. The Group expects a production licence to be granted once due Government process has been completed. In line with its accounting policy, the Group has performed a VIU assessment of Kenya asset following identification of triggers for impairment reversal. This resulted in an NPV significantly in excess of the book value of $255.2 million. However, the Group has identified the following uncertainties in respect of the Group's ability to realise the estimated VIU; receiving and subsequently finalising an acceptable offer from a strategic partner and securing governmental approvals relating thereto, obtaining financing for the project and government deliverables. These items require satisfactory resolution before the Group can take FID. Due to the binary nature of these uncertainties the Group was unable to either adjust the cashflows or discount rate appropriately. It has therefore used its judgement and assessed a probability of achieving FID and therefore the recognition of commercial reserves. This probability was applied to the VIU to determine a risk adjusted VIU and compared against the net book value of the asset. Based on this there is no impairment or impairment reversal as at 31 December 2021. Should the uncertainties around the project are resolved there will be a reversal of previously recognised impairment. However, if the uncertainties are not resolved there will be an impairment of $255 million.

10. Property, plant and equipment

$m	2021 Oil and gas assets	2021 Other fixed assets	2021 Right of use assets	2021 Total	2020 Oil and gas assets	2020 Other fixed assets	2020 Right of use assets	2020 Total
Cost								
At 1 January	10,460.2	69.6	1,018.6	11,548.4	11,279.6	190.6	1,038.5	12,508.7
Additions	73.0	1.6	73.5	148.1	203.6	9.6	16.5	229.7
Disposals	–	(1.4)	–	(1.4)	(11.0)	(125.6)	(17.6)	(154.2)
Transfer to assets held for sale	–	–	–	–	(1,050.9)	–	(19.5)	(1,070.4)
Currency translation adjustments	(11.5)	(0.3)	(0.4)	(12.2)	38.9	(5.0)	0.7	34.6
At 31 December	10,521.7	69.5	1,091.7	11,682.9	10,460.2	69.6	1,018.6	11,548.4
Depreciation, depletion, amortisation and impairment								
At 1 January	(7,915.9)	(42.3)	(352.3)	(8,310.5)	(8,194.6)	(157.7)	(264.7)	(8,617.0)
Charge for the year	(304.9)	(13.4)	(60.6)	(378.9)	(382.3)	(12.4)	(72.4)	(467.1)
Impairment loss	(54.3)	–	–	(54.3)	(250.0)	(0.6)	–	(250.6)
Capitalised depreciation	–	–	(38.0)	(38.0)	–	–	(23.8)	(23.8)
Disposal	–	1.4	–	1.4	10.9	122.8	7.1	140.8
Transfer to assets held for sale	–	–	–	–	938.2	–	1.6	939.8
Currency translation adjustments	11.4	0.5	0.1	12.0	(38.1)	5.6	(0.1)	(32.6)
At 31 December	(8,263.7)	(53.8)	(450.8)	(8,768.3)	(7,915.9)	(42.3)	(352.3)	(8,310.5)
Net book value at 31 December	2,258.0	15.7	640.9	2,914.6	2,544.3	27.3	666.3	3,237.9

The currency translation adjustments arose due to the movement against the Group's presentation currency, USD, of the Group's UK assets which have functional currencies of GBP.

During 2021 and 2020, the Group applied the following nominal oil price assumption for impairment assessments:

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6 onwards
2021	$76/bbl	$71/bbl	$68/bbl	$65/bbl	$65/bbl	$65/bbl inflated at 2%
2020	$45/bbl	$50/bbl	$55/bbl	$60/bbl	$60/bbl	$60/bbl inflated at 2%

	Trigger for 2021 impairment/(reversal)	2021 Impairment/(reversal) $m	Pre-tax discount rate assumption	2021 Remaining recoverable amount[e] $m
Limande and Turnix CGU (Gabon)	a, c	(40.8)	13%	50.8
Ezanga (Gabon)	a, c	(17.0)	15%	22.4
Oba and Middle Oba CGU (Gabon)	a, c	(3.2)	15%	10.5
Espoir (Cote d'Ivoire)	a, c	(8.7)	10%	81.4
TEN (Ghana)	a,b,c	119.1	10%	1,171.4
Mauritania	b	2.1	n/a	–
UK CGU	b, d	2.8	n/a	–
		54.3		

a. Increase to short, medium and long-term oil price assumptions.
b. Change to decommissioning estimate.
c. Revision of value based on revisions to reserves.
d. The fields in the UK are grouped into one CGU as all fields within those countries share critical gas infrastructure.
e. The remaining recoverable amount of the asset is its value in use.

10. Property, plant and equipment continued

Impairments identified in the TEN fields of $119.1 million were primarily due to lower TEN 2P reserves and higher capital expenditure partially offset by price and lower decommissioning costs. This is offset by impairment reversals mainly in Gabon of $61.1 million and Espoir of $8.7 million as a result of higher oil prices and higher 2P reserves.

Oil prices stated above are benchmark prices to which an individual field price differential is applied. All impairment assessments are prepared on a VIU basis using discounted future cash flows based on 2P reserves profiles. A reduction or increase in the two-year forward curve of $5/bbl, based on the approximate range of annualized average oil price over recent history, and a reduction or increase in the medium and long-term price assumptions of $5/bbl, based on the range of annualised average historical prices, are considered to be reasonably possible changes for the purposes of sensitivity analysis. Decreases to oil prices specified above would increase the impairment charge by $157.7 million for Ghana and reduce the impairment reversal by $12.4 million for Non-Operated, whilst increases to oil prices specified above would result in a credit to the impairment charge of $157.7 million for Ghana and increase the impairment reversal by $1.3 million for Non-Operated. A 1 per cent increase in the pre-tax discount rate would increase the impairment by $40.7 million for Ghana and reduce the impairment reversal by $3.3 million for Non-Operated. The Group believes a 1 per cent change in the pre-tax discount rate to be a reasonable possibility based on historical analysis of the Group's and a peer group of companies' impairment.

11. Other assets

$m	2021	2020
Non-current		
Amounts due from joint venture partners	486.0	547.4
VAT recoverable	3.1	–
	489.1	547.4
Current		
Amounts due from joint venture partners	554.7	521.9
Underlifts	26.7	19.5
Prepayments	49.6	60.7
Other current assets	73.5	115.0
	704.5	717.1
	1,193.6	1,264.5

The decrease in non-current receivables from JV Partners compared to December 2020 mainly relate to reduction in time remaining on the TEN FPSO lease, net decrease in GNPC ("Ghana National Petroleum Corporation") receivable partially offset by increases associated with new lease liabilities. The movement in current receivables from JV Partners relates mainly to timing of partner balances partially offset by a recognition of the JV receivable associated with the recognition of the Maersk Venturer offshore drilling rig as a lease liability.

Other current assets mainly include the deferred consideration relating to the Uganda disposal, offset by an indemnity provision relating to tax audits ($67.9 million) and VAT recoverable ($5.6 million).

12. Assets and Liabilities held for sale

On 9 February 2021, the Group announced that it signed two separate Sale and Purchase Agreements with Panoro Energy ASA of its entire interest in Equatorial Guinea and its entire interest in the Dussafu Marin Permit in Gabon, in each case with an effective date of 1 July 2020. Both transactions completed in 1H21. Refer to note 9.

13. Trade and other payables

$m	2021	2020
Current liabilities		
Trade payables	60.2	38.3
Other payables	57.4	49.5
Overlifts	0.7	3.8
Accruals[1]	381.3	409.4
VAT and other similar taxes	–	8.9
Current portion of lease liabilities	251.5	240.8
	751.1	750.7
Non-current liabilities		
Other non-current liabilities[2]	75.2	89.0
Non-current portion of lease liabilities	911.9	975.7
	987.1	1,064.7

1. Accruals mainly relate to capital expenditure, interest expense on bonds and loans and staff related expenses.
2. Other non-current liabilities include balances related to JV Partners.

Payables related to operated Joint Ventures (primarily in Ghana and Kenya) are recorded gross with the amount 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.

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

14. Provisions

$m	Decommissioning 2021	Other provisions 2021	Total 2021	Decommissioning 2020	Other provisions 2020	Total 2020
At 1 January	696.1	154.6	850.7	850.1	76.2	926.3
New provisions, changes in estimates and reclassifications	(134.8)	90.0	(44.8)	14.9	136.6	151.5
Transfer to asset and liabilities held for sale	–	–	–	(129.2)	–	(129.2)
Payments	(69.3)	(15.7)	(85.0)	(57.7)	(58.4)	(116.1)
Unwinding of discount	7.6	–	7.6	13.1	–	13.1
Currency translation adjustment	(0.9)	(0.1)	(1.0)	4.9	0.2	5.1
At 31 December	498.7	228.8	727.5	696.1	154.6	850.7
Current provisions	101.2	195.3	296.5	104.4	125.4	229.8
Non-current provisions	397.5	33.5	431.0	591.7	29.2	620.9

Other provisions include non-income tax provisions of $52.8 million (2020:$52.4 million) and $176.0 million (2020: $102.2 million) of disputed cases and claims. Management estimates non-current other provisions would fall due between two and five years.

In January 2013, the Group acquired Spring Energy Norway AS (Spring) from HiTecVision V (HiTec), a Norwegian private equity company, and Spring employee minority shareholders. In addition to the initial consideration payable, under the sale and purchase agreement (Spring SPA) the Group agreed to make certain contingent bonus payments to HiTec and the Spring employee minority shareholders if certain discovery(ies) were deemed commercially viable on or before 31 December 2016. This included the Wisting prospect in licence PL537.

HiTec previously claimed that the conditions for a bonus payment under the Spring SPA had been met in respect of the Wisting prospect in PL537 as at 31 December 2016. Tullow disputed this position. In 2016, the Group sold its interest in PL537 to Equinor but remained responsible for this dispute. An arbitration took place in Norway in Q4 2021 to resolve this issue.

On 15 February 2022, the arbitration panel delivered an award in favour of HiTec. The Tribunal decided by way of split decision that conditions under the Spring SPA in respect of the bonus payment had been met. The Tribunal ruled that Tullow should pay $76 million to HiTec (an amount which includes interest and costs) and a further amount of $0.7 million in respect of Tribunal costs.

Above includes provision relating to a potential claim arising out of historical contractual agreement. Further information is not provided as it will be seriously prejudicial to the Company's interest.

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

14. Provisions continued

The Group has assumed cessation of production as the estimated timing for outflow of expenditure. However expenditure could be incurred prior to cessation of production or after and actual timing will depend on a number of factors including, underlying cost environment, availability of equipment and services and allocation of capital.

In 2021, the Group has increased the decommissioning discount rate by 0.5% from 31 December 2020 due to a movement in the risk-free rate. This resulted in a decrease of the provision by $23.7 million in Ghana, $3.7 million in Côte d'Ivoire and $4.3 million in Gabon.

Decommissioning provisions	Inflation assumption	Discount rate assumption 2021	Cessation of production assumption 2021	Total 2021 $m	Discount rate assumption 2020	Cessation of production assumption 2020	Total 2020 $m
Côte d'Ivoire	2%	1.5%	2033	61.7	1%	2031	63.9
Gabon	2%	1.5-2%	2026-2036	61.9	1-1.5%	2027-2037	61.8
Ghana	2%	1.5-2%	2035-2036	193.3	1-1.5%	2034-2036	323.5
Mauritania	n/a	n/a	2018	61.6	n/a	2018	89.0
UK	n/a	n/a	2018	120.2	n/a	2018	157.9
				498.7			696.1

The decrease in the Ghana decommissioning provision was associated with lower well cost estimates.

The Group's decommissioning activities are ongoing in the UK and Mauritania and majority of the future costs is expected to be incurred in 2022 ($101.1 million) and 2023 ($59.5 million). The remaining activities are planned to continue through to 2027, with an associated expenditure of $21.2 million.

15. Commercial Reserves and Contingent Resources summary working interest basis

	Ghana		Non-Operated		Kenya		Exploration		Total		
	Oil mmbbl	Gas bcf	Oil mmbbl	Gas bcf	Oil mmbbl	Gas bcf	Oil mmbbl	Gas bcf	Oil mmbbl	Gas bcf	Petroleum mmboe
COMMERCIAL RESERVES[1]											
1 January 2021	180.1	179.2	48.4	11.1	-	-	-	-	228.5	190.2	260.2
Revisions[3,4,6]	3.5	(40.3)	11.1	(2.7)	-	-	-	-	14.6	(43.0)	7.4
Disposals[6]	-	-	(14.6)	-	-	-	-	-	(14.6)	-	(14.6)
Production	(15.3)	-	(6.1)	(1.3)	-	-	-	-	(21.4)	(1.3)	(21.6)
31 December 2021	168.3	138.9	38.8	7.1	-	-	-	-	207.1	145.9	231.4
CONTINGENT RESOURCES[2]											
1 January 2021	217.0	749.1	59.5	78.4	170.8	-	54.5	-	501.7	827.5	639.7
Revisions[3,4,6]	(4.9)	(163.9)	0.3	-	60.6	-	-	-	56.0	(163.9)	28.7
Disposals[6]	-	-	(30.1)	(77.5)	-	-	-	-	(30.1)	(77.5)	(43.0)
31 December 2021	212.1	585.2	29.7	0.9	231.4	-	54.5	-	527.6	586.1	625.4
TOTAL											
31 December 2021	380.4	724.1	68.5	8.0	231.4	-	54.5	-	734.7	732.0	856.8

1. Proven and Probable Reserves above are as audited and reported by independent third-party reserve auditors. The auditor was provided with all the significant data up until 31 December 2021.
2. Proven and Probable Contingent Resources above are also as audited and reported by independent third-party auditors based on best available information as of 31 December 2021.
3. Reserves and resources revision in Ghana relates to successful infill drilling in Jubilee, improved field uptime on the two FPSOs, and the maturation of a number of projects including three new Jubilee wells, the TEN Enhancement project and the Tweneboa North Associated Gas project. This is partly offset by a downward revision on Ntomme and Enyenra existing producing wells, reflecting field performance.
4. Reserves revision in Gabon mainly relates to successful execution of a number of workover projects on Echira, Ezanga, and Tchatamba, and an infill well on Simba.
5. Resources revision in Kenya relates to independent evaluation of resources by Gaffney Cline & Associates, incorporating production data from the Early Oil Pilot Scheme (EOPS) and updated field development strategy.
6. Disposals consist of the sales of Equatorial Guinea (completed in March 2021) and Dussafu Asset (completed in June 2021).
7. A gas conversion factor of 6 mscf/boe is used to calculate the total Petroleum mmboe.

The Group provides for depletion and amortisation of tangible fixed assets on a net entitlement basis, which reflects the terms of the Production Sharing Contracts related to each field. Total net entitlement reserves were 222.0 mmboe at 31 December 2021 (31 December 2020: 248.9 mmboe).

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

Alternative performance 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 free cash flow, underlying operating cash flow and pre-financing 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, right-of-use 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.

$m	2021	2020
Additions to property, plant and equipment	148.1	229.7
Additions to intangible exploration and evaluation assets	46.3	170.7
Less		
Changes to decommissioning asset estimate	(134.8)	14.9
Right-of-use asset additions	73.5	16.5
Lease payments related to capital activities	(26.8)	(4.0)
Additions to administrative assets	1.6	9.6
Other non-cash capital expenditure	17.7	75.3
Capital investment	263.2	288.1
Movement in working capital	(28.3)	133.2
Additions to administrative assets	1.6	9.6
Cash capital expenditure per the cash flow statement	236.5	430.9

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 non-cash adjustments, less cash and cash equivalents. Non-cash adjustments include unamortised arrangement fees, adjustment to convertible bonds, and other adjustments.

$m	2021	2020
Borrowings	2,568.7	3,170.5
Non-cash adjustments	31.3	10.5
Less cash and cash equivalents	(469.1)	(805.4)
Net debt	2,130.9	2,375.6

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, gain/(loss) on hedging instruments, depreciation, depletion and amortisation, share-based payment charge, restructuring costs, gain/(loss) on disposal, exploration costs written off, impairment of property, plant and equipment net, and other provisions.

$m	2021	2020
Loss from continuing activities	(80.7)	(1,221.5)
Adjusted for		
Income tax expense/ (credit)	283.4	(51.9)
Finance costs	356.1	314.3
Finance revenue	(44.3)	(59.4)
Loss on hedging instruments	–	0.8
Depreciation, depletion and amortisation	378.9	467.1
Share-based payment charge	11.6	20.9
Restructuring costs and other provisions	61.8	92.8
Gain/ (loss) on disposal	(120.3)	3.4
Exploration costs written off	59.9	986.7
Impairment of property, plant and equipment, net	54.3	250.6
Adjusted EBITDAX	960.7	803.8
Net debt	2,130.9	2,375.6
Gearing (times)	2.2	3.0

Underlying cash operating costs

Underlying cash operating costs is a useful indicator of the Group's 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.

In 2020 and 2021, Tullow incurred abnormal non- recurring costs which are presented separately below. The adjusted normalised cash operating costs are a helpful indicator to the forward underlying costs of the business.

$m	2021	2020
Cost of sales	638.9	993.6
Less:		
Depletion and amortisation of oil and gas and leased assets	360.9	446.4
Underlift, overlift and oil stock movements	(20.0)	160.5
Share-based payment charge included in cost of sales	0.5	0.9
Other cost of sales	28.8	54.1
Underlying cash operating costs	268.7	331.7
Covid-19 & OOSYS costs	(7.9)	(11.2)
Total normalised operating costs	260.8	3205
Production (MMboe)	21.6	27.4
Underlying cash operating costs per boe ($/boe)	12.4	12.1
Normalised cash operating costs per boe ($/boe)	12.1	11.8

Free cash flow

Free cash flow is a useful indicator of the Group's ability to generate 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, and net cash from/(used) in investing activities, repayment of obligations under leases, finance costs paid and foreign exchange gain/(loss).

$m	2021	2020
Net cash from operating activities	786.9	698.6
Net cash from/(used in) investing activities	(101.7)	84.3
Repayment of obligations under leases	(155.9)	(158.2)
Finance costs paid	(234.9)	(198.5)
Debt arrangement fees	(56.6)	–
Foreign exchange gain	6.9	5.4
Free cash flow	244.7	431.6

Underlying operating Cash Flow and Pre-financing cashflow

Underlying operating cash flow is a useful indicator of the Group's assets ability to generate cash flow to fund further investment in the business, reduce borrowing and provide returns to shareholders. Underlying operating cash flow is defined as net cash from operating activities less repayments of obligations under leases plus decommissioning expenditure.

Pre-financing cash flow is a useful indicator of the Group's ability to generate cash flow to reduce borrowings and provide returns to shareholders through dividends. Pre-Financing cash flow is defined as underlying operating cash flow plus net cash from/(used) in investing activities, decommissioning expenditure and payments to/from decommissioning escrow fund.

$m	2021	2020
Net cash from operating activities	786.9	698.6
Less		
Decommissioning expenditure	52.8	57.7
Lease payments related to capital activities	26.8	–
Plus		
Repayment of obligations under leases	(155.9)	(158.2)
Underlying operating cash flow	710.6	598.1
Net cash from/(used in) investing activities	(101.7)	84.3
Decommissioning expenditure	(52.8)	(57.7)
Lease payments related to capital activities	(26.8)	–
Pre-financing cash flow	529.3	624.7

EVENTS ON THE DAY

In conjunction with these results, Tullow is conducting a virtual presentation webcast that can be watched live or on replay.

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) 2071 928338
UK freephone	0800 279 6619
Event plus passcode	3982437

WEBCAST

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

https://edge.media-server.com/mmc/p/nxe2e3tj

The replay will be available from noon on 9 March 2022.

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Notes to editors

Tullow is an independent oil & gas, exploration and production group, quoted on the London, Irish and Ghanaian stock exchanges (symbol: TLW). The Group has interests in over 30 exploration and production licences across eight countries. In March 2021, Tullow committed to becoming Net Zero on its Scope 1 and 2 emissions by 2030.

For further information, please refer to our website at www.tullowoil.com.

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