25 May 2021

Hurricane Energy plc

("Hurricane", the "Company", or the "Group")

Full-year Results 2020

Hurricane Energy plc, the UK based oil and gas company focused on hydrocarbons in naturally fractured basement reservoirs, announces its full-year results for the period ended 31 December 2020.

Key points

- Lancaster produced an average of 13,900 bopd in 2020, supported by 98% production uptime from the Aoka Mizu FPSO. However, production was significantly less than expected due to the field materially underperforming relative to pre-production expectations
- The Company recorded a loss for the year of $625.3 million, including impairment charges totalling $567.1 million in respect of the Lancaster field and the Company's exploration assets and an associated deferred tax write-off of $54.2 million
- An internal technical review of the Lancaster field reservoir model resulted in significant downgrades to Lancaster Reserves and Contingent Resources. This revised interpretation was broadly consistent with a Competent Person's Report by ERC Equipoise published in April 2021, and also negatively impacted the resource potential of the Company's other discoveries
- Net free cash† of $111.4 million at 31 December 2020 (31 December 2019: $133.6 million) was significantly less than anticipated due to lower oil prices caused by the COVID-19 pandemic as well as lower Lancaster production than anticipated. Net debt† at year-end was $118.6 million (31 December 2019: $96.4 million)
- In combination, lower than expected cash generation during 2020 and significantly reduced potential future cash flows from Lancaster means the Company will not be in a position to repay its $230 million of convertible bond debt at maturity in July 2022. After exploring all possible alternatives, the Company announced a proposed restructuring of the Company's Convertible Bond debt on 30 April 2021. Material uncertainties regarding the Company's ability to continue as a going concern have been identified, pending the results of the proposed financial restructuring process
- If duly approved and implemented, the proposed financial restructuring is expected to take effect in June 2021. This would deliver a viable balance sheet from which to execute the Company's revised strategy of maximising cash flow from the existing Lancaster wells and infrastructure to pay down debt. In parallel, the Company will continue to develop the technical and commercial case for further development opportunities at Lancaster and, if supported by its Bondholders, execute any further investment as efficiently as possible

† Non-IFRS measures. See Appendix B for definition and reconciliation to nearest equivalent statutory IFRS measures

Antony Maris, CEO of Hurricane, commented:

"This has been a profoundly difficult period for Hurricane and its stakeholders. The understanding of the West of Shetland fractured basement play has changed significantly. As a result, the potential of the Lancaster field is much smaller than originally thought and cannot support the level of debt in the Company which was sized for a much larger Reserves and Contingent Resources base.

Against this extremely challenging backdrop, the Company has explored all potential options to resolve the Company's financial situation, with the proposed financial restructuring ultimately being deemed the best possible outcome. We understand the impact this will have on our shareholders and the strong feelings that have been expressed as a result, but this was a necessary move in order to secure the Company's future.

If the proposed restructuring is approved and implemented, we will focus our efforts on maximising Lancaster cash flows to pay down debt, as well as making the case for further development of our West of Shetland asset base"

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About Hurricane

Hurricane was established to discover, appraise and develop hydrocarbon resources associated with naturally fractured basement reservoirs. The Company's acreage is concentrated on the Rona Ridge, in the West of Shetland region of the UK Continental Shelf.

The Lancaster field (100% owned by Hurricane) is the UK's first producing basement field, which was developed via an Early Production System consisting of two wells tied-back to the Aoka Mizu FPSO. Hydrocarbons were introduced to the FPSO system on 11 May 2019 and the first oil milestone was achieved on 4 June 2019.

In September 2018, Spirit Energy farmed-in to 50% of the Lincoln and Warwick assets, committing to a phased work programme.

Visit Hurricane's website at www.hurricaneenergy.com

Inside Information

This announcement contains inside information as stipulated under the market abuse regulation (EU no. 596/2014). Upon the publication of this announcement via regulatory information service this inside information is now considered to be in the public domain.

Competent Person

The technical information in this release has been reviewed by Antony Maris, Chief Executive Officer, who is a qualified person for the purposes of the AIM Guidance Note for Mining, Oil and Gas Companies. Mr Maris is a petroleum engineer with 35 years' experience in the oil and gas industry. He has a B.Sc.(Eng.) Petroleum Engineering (Hons) from the Imperial College of Science and Technology (University of London) Royal School of Mines A.R.S.M. and an MBA from Kingston Business School.

Standard

Reserves and Contingent Resource estimates for the Lancaster field contained in this announcement have been prepared in accordance with the Petroleum Resource Management System guidelines endorsed by the Society of Petroleum Engineers, World Petroleum Congress, American Association of Petroleum Geologists and Society of Petroleum Evaluation Engineers.

Chairman's Statement

A profoundly challenging year

Dear shareholders,

It was always expected that 2020 would be a crucial year for Hurricane, but we did not anticipate facing multiple shocks from under-performance at our key Lancaster field asset, the COVID-19 pandemic, a collapse in oil prices, and significant organisational change. As a result, we have had to make difficult decisions in order to reduce our financial leverage and deliver a viable financial platform from which to take the business forward, resulting in the proposed financial restructuring announced in April 2021.

Covid 19 pandemic

The rapid global spread of COVID-19 during 2020 led to distressing levels of mortality, as well as profound disruption to businesses and personal lives. Protecting Hurricane's people from the virus while supporting our suppliers and partners was a critical concern during the year. The comprehensive protective measures we have taken ensured uninterrupted offshore operations, and our onshore staff successfully adapted to changes in the working environment. We will aim to strike a suitable balance between office and home working in future.

Oil prices

The pandemic had a significant impact on oil markets, with Brent prices falling to a remarkable low of $13/bbl in April 2020 as global lockdowns choked off oil demand. While demand and prices recovered somewhat during 2020, the global oil supply-demand balance remains fragile, there are ongoing effects from COVID-19, and there are growing impacts from energy transition measures. As a result, in a market which has always been prone to price volatility, there is elevated uncertainty over the path of future oil prices.

Lancaster field under-performance

The Lancaster field Early Production System (EPS) was conceived as a long-term production test with the objective of obtaining critical performance data on the fractured basement reservoir type, which had never before been developed in the UK (and only rarely globally). Previous estimates of Reserves and Contingent Resources were based on standard well evaluation techniques and short-term tests only, which are more difficult to interpret in fractured basement.

It had always been recognised that a minimum of twelve months observation of reservoir performance would be required before firm conclusions could start to be drawn on the scale of Reserves and Contingent Resources in Lancaster.

We had been encouraged by the operational success of bringing the field on stream in May 2019, albeit with water production commencing earlier than expected and increasing over time.

During the first half of 2020, Lancaster experienced a significant deterioration in reservoir performance while attempting to ramp production up to towards the target of 20,000 bopd. This led to a decision to shut in the 205/21a-7z well in May 2020 and suspend production guidance for the year. This disappointing performance signalled a material departure from pre-production expectations, and a need to re-visit the basic geological model and data interpretations.

On 8 June 2020, it was announced that Dr Robert Trice had resigned as Chief Executive Officer (CEO) by mutual consent with the Board, and the ably qualified Beverley Smith agreed a temporary shift from her non-executive role to become Interim Chief Executive. A Technical Committee of the Board was established to provide further oversight as the subsurface team, under new leadership, re-examined the range of geological and reservoir models for Lancaster and the other Rona Ridge assets.

Technical review

A preliminary technical review of the Lancaster field was completed in September 2020, which concluded that the oil water contact was significantly shallower than previously estimated, and that effective reservoir properties within the fractured basement were worse than previously thought, consistent with the higher water production and more rapid pressure decline than originally anticipated. The revised reservoir and geological model, calibrated with observed performance, resulted in the Company significantly downgrading the Reserves and Contingent Resources for the Lancaster field in September 2020.

Greater Warwick Area

While the Company's main focus during 2020 was on Lancaster, the revised interpretation of the Lancaster oil water contact also triggered a review of the data and assumptions for all Rona Ridge assets. Further progress has been made on understanding the Greater Warwick Area (GWA) subsurface following extensive analysis of the results of the 2019 drilling programme and reinterpretation of existing seismic data. This work also incorporated the learnings and implications from the results at Lancaster, including observed pressure depletion at Lincoln as a result of Lancaster production. This led to the conclusion that hydrocarbon columns are likely limited to local structural closures, and resulted in a significant downgrade of the GWA licence resource potential in both the Lincoln and Warwick Crest discoveries. While the Company and its joint venture (JV) partner continue to evaluate options for the GWA asset, further appraisal of both discoveries would be required as a first step before any assessment of commerciality and Reserves can be made.

CPR

An independent Competent Persons Report (CPR) was commissioned from ERC Equipoise Limited (ERCE) and published in April 2021, the results of which were broadly consistent with the Lancaster and GWA Reserves and Contingent Resources estimates published by the Company in September 2020. Additionally, ERCE did not attribute any Contingent Resources to the Halifax well drilled in 2017.

Financial results

In 2020, we delivered sales revenues of $180.1 million at an average realised oil price of $35.2/bbl, resulting in operating cash flow of $80.2 million. Net free cash† of $111.4 million led to a year end net debt position of $118.6 million. The substantial downgrade of Reserves and Contingent Resources led to write-downs in the carrying value of the Lancaster field and exploration intangibles totalling $567.1 million and a write-down of deferred tax of $54.2 million, resulting in an after tax loss of $625.3 million for the year.

Strategy and outlook

Based on the revised understanding of Lancaster, further development options for the field were announced in December 2020 and updated in April 2021. The options include re-entry and side-track of the existing 205/21a-7z producing well in 2022; a seismic programme in 2022; and a water injection well and related works in 2023, to provide reservoir pressure support.

However, the estimated capital investment of $180 million required to implement these further Lancaster development options is significant compared to available cash, while abandonment and decommissioning costs must also be provided for. Future cash flows will be constrained by lower than expected and declining oil production rates from a single Lancaster well. Recognising the July 2022 maturity date for the Company's $230 million Convertible Bond, in December 2020 the Company announced that it would enter into a period of substantive discussions with certain key stakeholders, including its Bondholders, to seek funding support and address the Convertible Bond maturity date.

The outcome of these discussions was the proposed financial restructuring announced on 30 April 2021. While the proposed financial restructuring entails significant dilution for existing equity investors, it would deleverage the Company's balance sheet, enhance its liquidity position, extend its debt maturity profile, and provide a stable platform upon which the Company can continue to operate its business.

Having carefully and thoroughly considered the alternatives, including that the likely consequence of the proposed financial restructuring not being implemented is likely to be a controlled wind-down of operations followed by an insolvent liquidation, the Company believes that the outcome of implementing the proposed financial restructuring is likely to be better for the Company, its business and its operations and employees than in the event of this likely alternative, and is in the best interests of the Company's stakeholders taken as a whole.

If duly approved and implemented, the proposed financial restructuring is expected to take effect in June 2021. However, as approval and implementation of the proposed financial restructuring is outside of the Company's control, there is a material uncertainty that may cast significant doubt over the Company's ability to continue as a going concern. For further details and analysis, see the Going Concern section of this report.

As at the date of this report, more than 75% of Bondholders (by value) had acceded to a lock-up agreement which incorporates general undertakings to support the proposed financial restructuring. The proposed financial restructuring is an ongoing process and is subject, inter alia, to the approval of 75% (in value) of Bondholders present and voting at a meeting convened by the High Court of Justice and the subsequent sanction of that Court. There will also be a Court-convened meeting of shareholders to vote on the proposed financial restructuring. The Company will continue to publish announcements regarding the progress of the proposed financial restructuring at appropriate points in the process.

Corporate Governance

The executive team changed substantially during 2020. Alistair Stobie resigned as Chief Financial Officer and a director on 26 February 2020 by mutual agreement with the Board, and was replaced by Richard Chaffe, who had been Head of Finance since 2016.

After the announcement of Dr Trice's departure on 8 June 2020, Beverley Smith played a critical part in the Technical Review and company reorganisation as Interim Chief Executive, but in line with her desire to return to a non-executive role, a search was undertaken for a permanent Chief Executive. This resulted in Antony Maris being appointed Chief Executive designate on 21 August 2020 and he assumed the full role on 11 September 2020. Antony brought 35 years of wide-ranging oil and gas sector technical and managerial experience to Hurricane, including in fractured basement reservoir plays offshore Vietnam and onshore Yemen. Beverley now Chairs the Technical Committee of the Board.

On 6 July 2020 we announced the very sad news that Neil Platt had passed away. Neil was a highly respected colleague, and his enthusiasm and technical excellence were integral to the successful delivery and operation of the Lancaster EPS. He will be sorely missed. Steve Holmes was appointed Chief Operating Officer, bringing 41 years of diverse oil and gas development, operations and commercial experience including eight years with Hurricane.

On 8 June 2020, Roy Kelly resigned as Kerogen Capital's nominated director and was replaced by Dr Alan Parsley, while Jason Cheng resigned from his alternate director role. On 23 September 2020, Dr Parsley resigned as Kerogen Capital's nominated director, and Leonard Tao also stepped down from his alternate director role. Kerogen Capital therefore currently has no board representation, though it retains the right to appoint a director under the relationship deed signed in 2016 and remains a significant shareholder at the date of this report.

Given the poor production performance during 2020, the Remuneration Committee exercised its discretionary powers, and no awards were made to executive directors under the incentive compensation schemes in place.

Sustainability

Despite the challenges faced during the year, we did not lose sight of the need to advance our sustainability strategy, building on the disclosures and commitments made in our inaugural 2019 Environmental Social and Governance (ESG) Report. We established an ESG Committee of the Board, with Sandy Shaw as Chair, during 2020 to provide structured oversight of our programmes. We are committed to complying with evolving reporting requirements and will align with industry and regulatory efforts to decarbonise United Kingdom Continental Shelf (UKCS) operations.

Acknowledgements

The West of Shetland fractured basement play has not lived up to original expectations, with significantly reduced forecasts of Reserves and Contingent Resources. Much poorer production rates than expected, combined with very low oil prices during 2020, has necessitated a proposed financial restructuring. Looking forward, and on the basis that the proposed financial restructuring completes, I am confident that we have an executive and management team with the capability, drive and focus to maximise returns from these West of Shetland assets, for the benefit of all stakeholders.

I would like to sincerely thank the whole Hurricane team for their hard work during this difficult period, in particular compressing a significant amount of technical re-evaluation and commercial work into the period since the technical re-set began in June 2020.

Finally, I want to thank our key industry stakeholders for their constructive help during this profoundly challenging year, particularly the Oil and Gas Authority (OGA) and Bluewater.

Steven McTiernan

Chairman

Chief Executive Officer's Review

Introduction

My first report to you as CEO of Hurricane comes at a difficult time for the business. Underperformance at our key Lancaster asset has significantly reduced potential future cash flows, and current financial projections show the Company will not be in a position to repay its $230 million of Convertible Bond debt at maturity in July 2022. This has necessitated a proposed financial restructuring of the Company's debt. If completed, this restructuring will deliver a viable balance sheet which can support our revised strategy of maximising cash flow from the Lancaster field to repay debt, and in parallel continue to build the justification for future activity on our West of Shetland assets.

Risks in fractured basement reservoirs

While the discovery and appraisal of the Lancaster field yielded a significant amount of subsurface data, the development of the UKCS's first fractured basement field carried an above average degree of risk. Amongst the reasons why fractured basement plays had hitherto been largely ignored in the UKCS was the difficulty in drilling safely, and also heightened reservoir evaluation uncertainty, in particular because conventional logging tools and well testing techniques are not ideally suited to evaluating fractured basement reservoirs.

Hence, both before and after first production from Lancaster, there was a consistent emphasis in our communications on the need to acquire dynamic data from production operations, which was essential to help refine the wide range of Reserves and Contingent Resources estimates for Lancaster, and our other West of Shetland assets. While we have learned a great deal over the past 12 months, our fractured basement assets continue to require further investigation and analysis to narrow down the range of uncertainty on reservoir characteristics and parameters.

Revised Lancaster geological interpretation

First production from the two Lancaster field EPS wells was achieved on time and budget in May 2019. Production operations were initially characterised by a series of individual and combined tests on both the 205/21a-6 and 205/21a-7z wells. While the initial productivity of both wells exceeded expectations, early water production and a more rapid decline in reservoir pressure than anticipated were the first signs that asset performance was diverging from pre-production projections.

Initially, water production was interpreted as coming from an isolated, intra-reservoir, water bearing interval, although the consistent increase and quantum of water production began to challenge this theory in the first half of 2020. When the 205/21a-7z well was shut in at the end of May 2020, it was decided to instigate a formal review of the Lancaster field geological and reservoir models to rigorously assess and interpret the dynamic data acquired since first production.

The initial results of this technical review were announced in September 2020. Lancaster is now believed to be more complex than previously thought. Instead of being primarily a basement reservoir, we now believe the field has Mesozoic-aged sandstones onlapping the basement flanks which are contributing to current production. Furthermore, and most importantly, analysis of reservoir pressure, production and other data resulted in a material revision of the field's oil water contact (OWC), from a range of 1,597 – 1,678 metres TVDSS in the May 2017 RPS Energy Lancaster CPR to 1,330 metres TVDSS. This shallower OWC is consistent with the observed early and higher water production, and more rapid reservoir pressure decline, than originally expected.

Declining reservoir pressure will have a further impact on production operations as pressure approaches the bubble point (the point at which gas is liberated from oil within the reservoir). Producing below bubble point may extend the life of the Lancaster field. Following extensive technical interaction with the OGA, we have submitted a Field Development Plan Addendum (FDPA) that will, if approved, allow us this additional reservoir management flexibility, subject to quarterly review of operating procedures to ensure gas liberated in the reservoir is not produced to surface.

The Company's revised geological and reservoir performance interpretation was broadly consistent with the conclusions of ERCE's independent April 2021 CPR. ERCE estimates remaining Lancaster 2P Reserves of 7.1 MMbbls at 31 December 2020, based on future production from the 205/21a-6 well alone. We have, and will continue to, periodically test the 205/21a-7z well for reservoir management purposes, although the high and increasing water cut from this well makes sustained oil production unlikely due to the resulting excessive reservoir voidage.

In light of the revised interpretation of the OWC, the area of the P1368 Central licence outside the determined Lancaster field area was voluntarily relinquished in October 2020 and Hurricane was released of its obligation to drill a commitment well on the licence.

Further development options for the Lancaster field

Since the outset of the technical review, a significant amount of work has been compressed into a short period of time to further refine the revised technical interpretation and consider further development options for the field. In December 2020, we outlined potential next steps for Lancaster development, namely: re-entry, side-track to an updip location and re-completion of the existing 205/21a-7z well, to target the central area of the field to enhance near term performance; further seismic to better image the Mesozoic sandstones and refine the possible location of a water injection well; and, drilling a water injection well to provide reservoir pressure support and improved sweep to enhance both Reserves and production. These development scenarios were refined further during the engagement with our Bondholders.

The total combined cost of these development options is currently estimated at approximately $180 million. These options would commercialise some 8.7 MMbbls of ERCE's estimated 2C Contingent Resources of 37.9 MMbbls, the majority of which is currently classified as Development Unclarified pending further technical and commercial work, and the financing being in place to support any future activity.

Greater Warwick Area

During 2020, we continued to collaborate with our partner, Spirit Energy, to refine our understanding of the potential of the GWA licence following the 2019 drilling programme. Given the unclear results of that drilling programme, and with more time being required for technical and commercial analysis, the GWA JV signed a revised cost allocation agreement in March 2020, adjusting certain terms relating to Spirit Energy's original 2018 farm-in. This allowed Hurricane the flexibility to progress planning and acquisition of long-lead items for both a potential GWA tie-back well and gas export from the Aoka Mizu ahead of a firm decision by the JV to proceed.

During the year, the focus was on evaluating the Lincoln discovery. In July 2020, we announced that the OGA had given notice of a proposed field determination area over local structural closure at the Lincoln discovery. This was subsequently accepted by the GWA JV.

Downhole gauges were installed in the Lincoln 205/26b-14 well at the time of drilling in 2019, which allow for periodic collection of data to refine our understanding of reservoir conditions at Lincoln and any implications for regional geology. In July 2020, Lincoln pressure data was retrieved and indicated 20 psi pressure depletion. We attribute this to the impact of Lancaster production some 8 km distant, which suggests that Lancaster and Lincoln share the same aquifer pressure and gradient, and that the OWC at Lincoln is also likely to be close to the structural closure.

ERCE has estimated the OWC for the Lincoln discovery at 1,844 metres TVDSS (± 16 metres), and gross 2C Contingent Resources (Development Unclarified) of 36.9 MMbbls for the basement reservoir only. As at Lancaster, there is some evidence for Mesozoic sandstones of Jurassic and Cretaceous age above the Lincoln basement discovery, although these have not been demonstrated by drilling and the Company is currently assessing their potential.

The Company has a regulatory commitment to plug and abandon the Lincoln 205/26b-14 well. The OGA recently approved an extension of the deadline for this activity to 31 October 2021 (from 30 June 2021) to allow for completion of operations in the summer 2021 weather window. The GWA JV has contracted a rig for this activity, with a gross budgeted campaign cost of c.$13 million. The OGA has also agreed to extend the deadline for the GWA licence commitment well from 31 December 2020 to 30 June 2022 as a result of the disruption caused by the COVID-19 pandemic.

ERCE also estimated gross 2C Contingent Resources (Development Unclarified) for the Warwick Crest discovery of 50.9 MMbbls. No Contingent Resources were attributed by ERCE to the Halifax well drilled in 2017.

The Lincoln and Warwick Crest discoveries are at an early stage of appraisal. Further appraisal of both discoveries would be required as a first step before any assessment of commerciality and Reserves could be made. Any appraisal activity would involve a significant financial commitment for Hurricane, which the Company may not be able to fund. As a result of this funding uncertainty and the early stage of appraisal, there is currently no reasonable expectation that the Lincoln and Warwick Crest discoveries could generate any meaningful near-term cash realisation. The GWA JV partners will continue to evaluate and consider all options for the licence going forward.

Proposed Financial Restructuring

Although the Company retained net free cash† of approximately $111 million at the end of 2020, this was significantly less than expected because of low oil prices in 2020 and oil production rates at substantially lower and declining levels than original forecasts. Furthermore, the material reduction in Lancaster field Reserves has significantly reduced production expectations, in turn impacting future cash flow forecasts.

Given the negative impacts described above, and the likely capital cost of further investment in the Lancaster field, the Company decided to enter into a discussion with its Bondholders with regard to the funding of, and required support for, possible development options, while also addressing the July 2022 maturity of its Convertible Bond debt.

These discussions considered the likelihood that the Lancaster field will continue to produce from the 205/21a-6 well alone, the Company's necessary future spending requirements, contractual and decommissioning spending obligations, and the requirement for a viable balance sheet going forward. The engagement resulted in the Company announcing a proposed financial restructuring on 30 April 2021, which would entail a part-equitisation of the Convertible Bond, and significant dilution for existing shareholders. This difficult decision is however necessary to support the financial future of the Company.

As at the date of this document, more than 75% of Bondholders (by value) had acceded to a lock-up agreement which incorporates general undertakings to support the proposed financial restructuring. The proposed financial restructuring is an ongoing process and is subject, inter alia, to the approval of 75% (in value) of Bondholders present and voting at a meeting convened by the High Court of Justice and the subsequent sanction of that Court. There will also be a Court-convened meeting of shareholders to vote on the proposed financial restructuring. The Company will continue to publish announcements regarding the progress of the proposed financial restructuring at appropriate points in the process.

People and operations

While somewhat overshadowed by the subsurface work, Hurricane's operational delivery since start-up of the Lancaster field has been first class, and I commend our staff and key contractors on their performance against the backdrop of a challenging year.

Like many businesses, we have had to adapt our working practices and environments to reflect government and industry restrictions enacted to keep staff safe and reduce the impact of COVID-19, particularly on offshore operations. This has included a significant reduction in the manning of the Aoka Mizu FPSO to essential personnel only for most of the year. In March 2020, a crew member on the Aoka Mizu was evacuated to the mainland and subsequently tested positive for COVID-19. The individual made a full recovery.

Hurricane has worked closely with its contractors, suppliers, and local authorities to manage the impact of these restrictions on its employees and the Company, and to date has not experienced any adverse operational impact from COVID-19.

Our onshore staff have been working from home since March 2020 and, where possible, we actively encouraged flexible working recognising that employees may have responsibility for childcare, home schooling, family members as well as other obligations during the pandemic. Feedback suggests that when a return to the office is possible, our employees wish to preserve some measure of home working, and we will aim to achieve this where possible. We have also introduced initiatives to address staff isolation and encourage contact between colleagues while we are working remotely. I would also like to express my thanks to all our colleagues whose hard work and dedication during a challenging 2020 helped to compress many months of work on the technical review and development options screening into a fraction of that time, without compromising on rigour or quality.

Sustainability and environment

We have also maintained our focus on expanding our sustainability strategy, with an internal ESG Working Group established to enhance our ESG programme, with oversight from the new ESG Committee of the Board. We are fully aligned and supportive of the UK oil industry and regulatory initiatives to decarbonise the UKCS oil and gas operations and target net zero greenhouse gas emissions from the UKCS by 2050.

I am pleased to report that greenhouse gas emissions intensity from our own operations declined in 2020 vs. 2019. We were able to reduce diesel-related CO_2 emissions year-on-year as more of the associated gas production from the Lancaster field was used in the Aoka Mizu's gas turbine generators.

Previously, we had outlined plans to implement a gas export scheme for associated gas production from our West of Shetland assets. Unfortunately, these plans have been postponed due to the financial and subsurface challenges we faced in 2020 and a constrained funding environment. We will, however, continue to investigate all possible means to reduce our GHG emissions and implement these where it is technically, financially and logistically feasible to do so.

Outlook

Our business has seen significant change in the last 12 months. While this has caused upheaval and frustration for both employees and stakeholders, we hope to emerge from the proposed financial restructuring with a viable balance sheet that can support the company in our core strategy of maximising cash flow from the existing wells and infrastructure in the Lancaster field. While implementing the NFA case, we will also continue to develop the technical and commercial case for further development opportunities at Lancaster and, if supported by our Bondholders, execute any further investment case effectively.

I will also aim to reinvigorate the entrepreneurial spirit and commitment to success which allowed Hurricane to deliver the first UKCS fractured basement development on time and budget.

Antony Maris

Chief Executive Officer

Operations and Subsurface Review

Review of 2020 operational performance

Very sadly, Hurricane's previous Chief Operations Officer, Neil Platt, passed away in July 2020. Neil joined Hurricane in 2011 and was the driving force in delivering the Lancaster EPS project on time and budget. He was a much loved and respected colleague and is greatly missed by everyone at the Company.

From an operations perspective, the focus in 2020 was on maintaining safe, environmentally responsible and reliable operations from the Aoka Mizu FPSO, particularly in light of the impact from COVID-19 on UK offshore oil and gas operations. Furthermore, we also had to factor in the underperformance of the Lancaster production wells into operations and production planning, as well as deliver the production testing data required to assist in reassessing the subsurface potential of the field.

Aoka Mizu production uptime averaged 98% in 2020, significantly exceeding our 90% target. This is testament to the notable and varied contributions of both Hurricane's staff and Bluewater, particularly given offshore manning levels were reduced in light of the COVID-19 pandemic. Following completion of remaining equipment tests, final acceptance of the Aoka Mizu was achieved in November 2020.

The planned annual Aoka Mizu shutdown was undertaken in early September 2020 and was safely completed in five rather than the scheduled seven days. Our employees, contractors and partners should be congratulated on this excellent performance. Our 2021 annual shutdown is currently planned to take place in July 2021.

During the year there were 12 liftings totalling 5.1 MMbbls. We have been investigating ways to increase resilience, optionality and flexibility in our offloading schedule, through trial loadings of a number of alternative vessels which can deliver Lancaster crude. Two of these trials have been carried out successfully in 2021 to date, including a shuttle tanker with LNG fuelled propulsion, which has a lower greenhouse gas footprint than our existing tanker pool.

We have had to work in close cooperation with our stakeholders and government authorities to manage the impact of COVID-19 on offshore operations during 2020. We saw this first-hand in March 2020, when a crew member onboard the Aoka Mizu was evacuated to the mainland for medical reasons and subsequently tested positive for COVID-19. Subsequently a number of precautionary flights were arranged to return suspected COVID-19 cases to shore. We are happy to confirm that the individual who tested positive for COVID-19 made a full recovery. We have worked closely with Bluewater, as installation operator of the Aoka Mizu, with its response to the March COVID-19 case and also on the planning to mitigate the impact of COVID-19 on the crew of the Aoka Mizu. Throughout this period, safeguarding measures put in place ensured that production operations were unaffected.

During the year, we have developed and refined pre-mobilisation offshore COVID-19 travel arrangements before outbound staff are mobilised to the Aoka Mizu. Currently, passengers are required to complete an offshore travel pre-flight self-declaration form and undertake a pre-mobilisation temperature check and a COVID-19 test before being deemed 'fit to fly' and permitted to travel to the heliport for outbound travel to the Aoka Mizu. If the test result is positive, outbound travel is restricted until a further COVID-19 test confirms a negative result. Passengers who do not meet these criteria are requested to self-isolate for 10 days if they are able to do so or seek appropriate medical help if they cannot. Face coverings are provided to all passengers on transit to the FPSO, the use of which is mandatory when travelling by helicopter. Upon arrival at the FPSO, passengers are provided with their own single berth cabins, while daily COVID-19 health screening is undertaken, and mandatory COVID-19 testing has been introduced on the fourth day after arrival. The wearing of face masks to prevent airborne transmission is also required, where practicable. While UK border control travel restrictions are impacting our ability to mobilise and demobilise non-UK based offshore crew members as would be routinely planned, to date we have not experienced any significant negative impact from the pandemic on our operations.

Lancaster EPS oil production during 2020 totalled 5.1 MMbbls, or an average of 13,900 bopd. Production was higher in the first half of the year with both the 205/21a-6 and 205/21a-7z wells onstream in various configurations as part of the ongoing data gathering exercise. In May 2020, performance issues led to production from well 205/21a-7z being suspended. In June 2020, following a partial lifting of COVID-19 restrictions on UKCS activity, we successfully commissioned the electric submersible pumps (ESPs) installed in the Lancaster production wells. With the benefit of artificial lift from the ESPs, the 205/21a-7z well was brought back onstream at different rates to test performance and liquid output. However, with produced water now interpreted as originating from an underlying aquifer rather than an isolated water zone, part of the 205/21a-7z well is now considered to be in the water leg, with oil production being "coned" from the reservoir above the well.

As a result, a decision was taken in November 2020 to produce the field from the 205/21a-6 well alone. This production strategy has been implemented for the majority of the time since November 2020, with the well currently producing 11,250 bopd using artificial lift with a water cut of 30%. Under the NFA scenario, which is the likely outcome of the Company's proposed financial restructuring unless new development activity is approved (including by the Company's Bondholders), production from the 205/21a-6 well is expected to continue exhibiting a slow decline until the economic limit of the field is reached.

Based on current trends, it is possible that the wellhead flowing pressure in the Lancaster reservoir may approach the "bubble point" (the point at which gas is liberated from oil within the reservoir) in late 2021 or early 2022. We are currently in a discussion with the OGA on an addendum to the Lancaster Field Development Plan to allow reservoir pressure to go below bubble point, as an emerging gas cap may provide a "piston" like effect where oil in the Lancaster field is driven into the producing wells. Our production guidance for 2021 is 8,500 - 10,500 bopd, which is based on an FPSO production uptime assumption of 90% and production from the P6 well alone.

Planning is underway to meet our regulatory commitment to plug and abandon the Lincoln 205/26b-14 well, with the Stena Don rig contracted on behalf of the GWA licence partners to perform this activity during the summer of 2021.

Health and Safety

In 2020, Hurricane recorded one Lost Time Incident, when an offshore technician fell during scheduled maintenance activities and incurred injuries to his shoulder and ribs. The individual made a full recovery. The incident was fully investigated by Bluewater and Hurricane; with control of work, supervision and spatial awareness identified as the main underlying contributing factors to the Lost Time Incident. Safety and control procedures were strengthened as a result. The Lost Time Incident Frequency rate for 2020 was 1.29, compared to 0 for 2019.

The health and safety of our onshore colleagues has also been a priority given the home working arrangements put in place to manage the spread of COVID-19. We have conducted home working assessments to ensure that our staff have the necessary equipment and appropriate working conditions for safe and effective remote work.

Operational emissions

During 2020, our Scope 1 greenhouse gas emissions were 209,421 tonnes, or 41.2kg/bbl on an intensity basis. This compared to 145,388 tonnes and 48.0kg/bbl in 2019, when the Lancaster field was only producing for 7 months. Our 2019 greenhouse gas emissions have been restated to include emissions from logistical support to the FPSO, in line with the OGUK definition, and expanded to include other greenhouse gases specified by the Kyoto Protocol.

In particular, 10% of our CO_2 emissions in 2020 were from diesel consumption, down from 20% in 2019 following successful commissioning of the FPSO's fuel gas compressor and gas turbine generators. We will continue to look at ways of further reducing this figure in 2021 and beyond.

Previously, the tie-back of a well from the GWA licence was considered to be the trigger for the requirement to put in place a gas export scheme from our West of Shetland acreage. Long-lead items were acquired in 2019 for this purpose. However, the need for further work on the commercial potential of the GWA licence, allied to the financial constraints on our business, means we are not currently in a position to finance or implement a gas export scheme to significantly reduce our flaring emissions. However, we continue to look at ways of reducing our environmental footprint, whether physically or offsetting our emissions elsewhere. We remain fully cognisant of the increased scrutiny and oversight in this area.

Reserves and Contingent Resources

While the Lancaster field EPS was developed on time and on budget with first production achieved in May 2019, the field has significantly underperformed pre-production expectations. As a result, a full technical review of the Lancaster field and the Company's wider West of Shetland portfolio was commissioned in June 2020. In September 2020, the initial findings of this review were announced, resulting in a material downgrade to the Reserves and Contingent Resources for the Lancaster field (compared to the May 2017 RPS Energy Lancaster CPR) as a consequence of a significantly shallower OWC than previously thought, consistent with higher water production and more rapid pressure decline than originally anticipated.

The Contingent Resources associated with the Lincoln discovery were also downgraded (compared to the December 2017 RPS Energy West of Shetland CPR). This followed an extensive review of the 2019 drilling data and re-interpretation of seismic in light of the updated assessment of Lancaster, in particular that hydrocarbon columns are likely limited to local structural closures.

To provide an independent assessment of the Company's assets, ERC Equipoise was appointed as the Company's Independent Competent Person and Reserves auditor in November 2020. ERCE's CPR was published in April 2021, with the analysis and conclusions broadly consistent with the initial findings of the technical review in September 2020.

The revised interpretation of the Lancaster OWC also triggered a review of the Halifax historical data set and assumptions. No Contingent Resources were attributed by ERCE to the Halifax well drilled in 2017.

ERCE’s estimates of Lancaster field Reserves, and the Contingent Resources estimated for Lancaster and the Lincoln and Warwick Crest discoveries are detailed in the tables below. ERCE’s work was prepared in accordance with the June 2018 Petroleum Resources Management System (PRMS) as the standard for classification and reporting with an effective date of 31 December 2020.

The Company’s ability to monetise its Contingent Resources will require further technical appraisal, a commercially viable development plan to be agreed, sufficient additional funding for further appraisal and development, and regulatory, partner and Bondholder consents. The funding of any appraisal and/or development activity, and the Company’s financial planning more broadly, needs to consider the Company’s existing financial and contractual obligations, such as decommissioning and costs associated with the charter of the Aoka Mizu.

The Lincoln and Warwick Crest discoveries on the GWA licence are at an early stage of appraisal. While the Lincoln 205/26b-14 well flowed at approximately 9,800 bopd on test using an ESP in 2019 with a productivity index (PI) of 18 stb/d/psi, there remains significant uncertainty over future reservoir performance, and an appraisal programme to refine reservoir parameters would be required to better assess the potential for Lincoln’s Reserves and commerciality. Ahead of any such appraisal plan, the Company has a regulatory commitment to plug and abandon the Lincoln 205/26b-14 well by 31 October 2021 as described above.

The Warwick Crest discovery well flowed at approximately 2,000 bopd in 2019 on test using an ESP with a PI of 3 stb/d/psi. The Company considers that such a rate and PI is significantly below the level which would support a commercial development. An appraisal programme would be required to further refine the reservoir parameters of the Warwick Crest discovery, demonstrate increased flow rates and a higher PI and establish the potential for commerciality.

The potential GWA licence appraisal activity described above would involve a significant financial commitment for Hurricane before any assessment of commerciality can be made, which the Company may not be able to fund. As a result of this funding uncertainty and the early stage of appraisal, there is currently no reasonable expectation that the Lincoln and Warwick Crest discoveries could generate any meaningful near-term cash realisation. The GWA JV partners will continue to evaluate and consider all options for the licence going forward.

ERCE's estimates of Reserves for the Lancaster field

(MMbbl)	Gross			Net attributable to Hurricane		
	1P	2P	3P	1P	2P	3P
Developed Reserves (MMbbl)[1]	3.3	7.1	10.8	3.3	7.1	10.8

Notes:

1. In determining the economic Reserves for the Lancaster field, ERCE has assumed a Brent oil price of US$50/bbl in 2021, US$53/bbl in 2022, US$55/bbl in 2023 and US$56/bbl in 2024 and thereafter in real terms. Prices are escalated at 2.0% per annum inflation

ERCE's estimates of Contingent Resources for the Lancaster field

(MMbbl)	Gross			Net attributable to Hurricane		
	1C	2C	3C	1C	2C	3C
Contingent Resources, Development Pending (P8 well)[1,2]	4.0	3.2	1.9	4.0	3.2	1.9
Contingent Resources, Development Unclarified[3]	11.8	34.7	87.1	11.8	34.7	87.1
Total	**15.8**	**37.9**	**89.0**	**15.8**	**37.9**	**89.0**

Notes:

1. The P8 well is the proposed side-track of the existing 205/21a-7z well, which the Company is considering drilling in 2022
2. Incremental resources are computed by the subtraction of the Reserves estimates for Lancaster from estimates of future recoverable volumes from the combined activity of the P6 and P8 wells. As the forecasts for the combined activity of the P6 and P8 wells both accelerate production and add additional resources, the incremental resources associated with the P8 well decrease as the Reserves attributed to the Lancaster field increase
3. Contingent Resources, Development Unclarified, assume water injection is implemented as part of any further development

ERCE's estimates of Contingent Resources for the Lincoln discovery.

(MMbbl)	Gross			Net attributable to Hurricane		
	1C	2C	3C	1C	2C	3C
Contingent Resources, Development Unclarified[1,2]	17.4	36.9	79.8	8.7	18.5	39.9
Total	**17.4**	**36.9**	**79.8**	**8.7**	**18.5**	**39.9**

Notes:

1. Contingent Resources, Development Unclarified, assume water injection is implemented as part of any development
2. Net attributable figures are rounded to one decimal point

ERCE's estimates of Contingent Resources for the Warwick Crest discovery

(MMbbl)	Gross			Net attributable		
	1C	2C	3C	1C	2C	3C
Contingent Resources, Development Unclarified[1,2]	19.6	50.9	128.9	9.8	25.5	64.5
Total	**19.6**	**50.9**	**128.9**	**9.8**	**25.5**	**64.5**

Notes:

1. Contingent Resources, Development Unclarified, assume water injection is implemented as part of any development
2. Net attributable figures are rounded to one decimal point

Steve Holmes

Chief Operations Officer

Chief Financial Officer's Review

Key figures

	2020	2019
Production	5,078 Mbbl	3,030 Mbbl
Production rate*	13,900 bopd	12,900 bopd
Sales volumes	5,112 Mbbl	2,874 Mbbl
Revenue	$180.1m	$170.3m
Average sales price realised	$35.2/bbl	$59.3/bbl
Cash production cost per barrel†	$17.9/bbl	$21.8/bbl
Operating cash flow	$80.2m	$112.2m
Closing net free cash†	$111.4m	$133.6m
Net debt†	$118.6m	$96.4m
Underlying (loss)/profit before tax†	$(36.0)m	$30.0m
Statutory (loss)/profit after tax	$(625.3)m	$58.7m

* Rounded to nearest 100 bopd; 2019 rates calculated from First Oil in 2019.

† Non-IFRS measures. See Appendix B to the Financial Statements for definition and reconciliation to nearest equivalent statutory IFRS measures.

Overview

2020 was a year when Hurricane had to focus on financial discipline, on both the operating and capital side, amidst the challenges of COVID-19, macro-economic environment and the underperformance of the Lancaster field.

Despite the historic low oil prices seen across the period, and the reduced performance of the Lancaster wells, over 5.1 million barrels of Lancaster crude were sold across 12 cargoes, generating $180 million in revenue. The Group was still able to generate positive cash flow from operations of $80 million, thanks to the low operating costs and production efficiency of the Lancaster EPS. It is also testament to Hurricane's employees and key Tier 1 contractors that despite the ongoing impacts of COVID-19 there was minimal disruption to operations and business both offshore and onshore. Alongside operations at Lancaster, work continued on our joint venture with Spirit, including the build out of previously committed long-lead items for, and planning of, a potential future GWA tie-back and other studies to better understand the regional hydrocarbon potential.

The statutory loss for the year was driven by significant non-cash asset impairments relating to Lancaster ($519.2 million), where reduced performance of the Lancaster wells, combined with the more volatile oil price environment and uncertainty over future work programmes has materially reduced future expected cashflows from the asset; and Halifax ($35.4 million), as a result of the 2021 CPR attributing no Reserves or Contingent Resources to the area.

The Group incurred $62.0 million of cash capital expenditure (primarily on items and projects already committed to prior to the impact of COVID-19), ending the year with $111.4 million of net free cash†.

Although Hurricane closed the year with a strong net free cash† position, the reduced Reserves estimates and production outlook as a result of the revised understanding of the Lancaster field has significantly reduced potential future cash flows from the field, and consequently current financial projections show the Company will not be in a position to repay its $230 million of Convertible Bond debt at maturity in July 2022. As such, Hurricane entered into a period of stakeholder engagement with regards to funding of future projects, support for development options, and repayment of the Convertible Bond debt. In April 2021, Hurricane entered into a lock-up agreement with an ad hoc group of its Bondholders in order to secure their support for a proposed financial restructuring that will deleverage the balance sheet, enhance Hurricane's liquidity position, reduce the amount of debt repayable upon maturity of the Convertible Bonds and extend its debt maturity profile. If duly approved and implemented, the proposed financial restructuring is expected to take effect in June 2021 and will result in significant dilution for existing shareholders, a difficult, but necessary decision to support the financial future of the company.

As at the date of this report, the proposed financial restructuring is an ongoing process and is subject, inter alia, to the approval of the requisite majority (in value) of Bondholders and the sanction of the High Court of Justice. There will also be a Court-convened meeting of shareholders to vote on the proposed financial restructuring. The Company will continue to publish announcements regarding progress of the proposed financial restructuring at appropriate points in the process.

Revenue

Revenue recognised for the year was $180.1 million, with an average realised price of $35.2/bbl across 12 cargoes (comprising 5.1 million barrels). Whilst the average Dated Brent price for the year was $41.7/bbl, under the sales and marketing agreement Hurricane has in place with BP, the sale of Lancaster crude is priced at the average of either the first or last five days of the month of lifting (at the buyer's option). In volatile pricing environments, such as was seen during the unprecedented months in H1 2020, this meant that the contracted Dated Brent price was typically lower than the spot price at date of sale.

After taking into account this timing and volatility impact, the remaining discount to the contractual Brent price was $2.9/bbl (2019: $3.1/bbl), representing the discount or premium offered by the refinery purchasing the crude, BP's marketing fee, and freight and other necessary costs incurred by BP in transporting Lancaster crude to its ultimate destination. The refinery discounts experienced saw significant variability during the first half of 2020 amid a highly volatile crude market. With all cargoes sold to date having been on time, within specification and contractual terms, Hurricane has a growing reputation as a reliable producer.

Cost of sales

Total cost of sales was $179.8 million, including $96.6 million of non-cash depreciation charges. Cash production costs† (which exclude depreciation and accounting movements in inventory but include the fixed lease charges for the Aoka Mizu) were $90.6 million (2019: $66.0 million), equivalent to $17.9 per barrel (2019: $21.8/bbl).

The decrease in cash production costs per barrel† was partly due to the revenue-linked incentive tariff for the Aoka Mizu (whereby a reduction in realized sales prices results in a direct reduction in production costs, partially reducing oil price risk exposure to the Group). Excluding the incentive tariff, cash production costs reduced from $16.7/bbl in 2019 to $14.6/bbl in 2020, driven by higher average production rates in 2020 and cost reductions across operations.

Impairment of oil and gas assets

As a result of the downwards revision of estimated Reserves announced in September 2020 (which were refined and revised by ERCE in the April 2021 CPR), revised production forecasts following the shut in of 205/21a-7z well, and the more uncertain outlook for oil prices, a non-cash impairment charge of $519.2 million was recognised against the Lancaster oil and gas assets. This charge was estimated using the best estimate of future cashflows that could be generated from Lancaster, using a probability weighted expected value approach which took into account the fact that a no further activity case was most likely, and that any investment cases to significantly enhance production through new wells would require Bondholder approval, should the proposed financial restructuring complete. These estimates also included management's own forecasts of production rates using reservoir simulation models. For further details on the impairment charge, key assumptions and methodology used see note 2.3.1 below. These estimates and assumptions are subject to risk and uncertainty, and therefore changes to external factors and internal developments and plans (including the sanction or otherwise of any work programme, the timing thereof, oil prices, and any other intervening developments) have the ability to significantly impact these projections, which could lead to additional impairments or reversals in future periods.

Impairment of intangible assets

Following the conclusion of the group's technical review and publication of the 2021 CPR, a non-cash charge of $35.4 million was recognised to fully impair the carrying value of the Halifax well. The CPR did not attribute any Reserves or Contingent Resources to Halifax, nor does the Group have any current plans or budgets for substantive expenditure on further exploration or evaluation on this licence. Impairments and write-offs of intangible exploration and intangible assets included $12.1 million relating to Hurricane's share of idle hire costs for the Paul B Loyd Jr rig, which was contracted in anticipation of GWA drilling and/or well abandonment activity in 2020. Following the extension of consents to plug and abandon the 205/26b-14 Lincoln well from 2020 into 2021, and an extension of the consent to commence drilling the GWA commitment well to 30 June 2022, the JV partners took the decision to terminate the hire of the rig in May 2020 and settle the remaining minimum hire costs with the rig operator.

Other profit and loss

General and administrative costs (G&A) increased from $0.4 million in 2019 to $4.2 million in 2020. Excluding the impact of non-cash charges, net G&A before non-cash items decreased from $3.0 million to $2.9 million primarily due to more staff and administrative costs now included within cost of sales with 2020 representing the first full year of operations, partially offset by an increase in professional fees included within non-staff costs as we entered into a period of discussion with key stakeholders towards the end of the year.

Net finance costs increased from $21.5 million in 2019 to $35.5 million in 2020, driven by the cessation of interest capitalisation and the commencement of lease interest recognised effective at the date of First Oil in May 2019, and the cost of hedging options purchased in 2020 (see 'Hedging' below).

Convertible Bond accounting

The accounting for the Convertible Bond required the recognition of an embedded derivative liability related to the equity conversion option, with the liability effectively representing the value to Bondholders of the conversion option at the balance sheet date. The fair value of the embedded derivative is valued using an option pricing model, with the key inputs being the Company's share price and its share price volatility. Any decrease in the liability creates a corresponding non-cash credit in the income statement. See note 5.1 below for further details.

The fair value gain recognised during the year in relation to the embedded derivative was $35.4 million (2019: $34.7 million gain), primarily driven by decreases in the Company's share price.

The gains recognised in the year do not have any impact on the Group's cash position, amounts payable in respect of the Convertible Bond, or on its tax position. Upon conversion or repayment of the Convertible Bonds (or should the proposed financial restructuring be implemented), the derivative liability will be released to the Income Statement. Should the conversion rights not be exercised (for example, as a result of the proposed financial restructuring), a taxable gain of $39.0 million would arise (being the amount of the embedded derivative initially recognised on issuing the Convertible Bonds in 2017).

Hedging

In June 2020, Hurricane hedged a portion of its forecast production for the second half of 2020. A total of 1.8 million barrels (equivalent to c.10,000 bopd), was hedged through the purchase of put options with an average strike price of $35/bbl (Dated Brent). The average strike price of $35/bbl represented a floor for the hedged volumes with Hurricane retaining any upside in oil prices above this level. The cost of acquiring the put options was $3.4 million, and the options expired out of the money in December 2020. Under the terms of the proposed financial restructuring, so long as the Amended Bonds remain outstanding, the Group will not be permitted to enter into any further oil price hedging contracts.

Cashflow

The Group ended the year with $111.4 million of net free cash†, a decrease of $22.2 million from the position at 31 December 2019.

Even with oil prices falling to historic lows during the year and production being lower than expectations due to reservoir performance issues and shut-in of the 205/21a-7z well for over half of the year, the Lancaster EPS was still able to be cash generative, contributing cash per barrel (before working capital movements) of $17.4/bbl (2019: $37.5/bbl).

Other operating cash outflows included $3.4 million for the purchase of term put options and $2.1 million on plugging and abandoning the previously suspended Halifax and Whirlwind wells. After adjusting for movements in working capital, the Group's operating cash inflow for the year amounted to $80.2 million.

Cash capital expenditure in the period was $62.0 million reflecting, in the most part, items previously committed to or capital expenditure required to meet work obligations under the Group's licences. Expenditure on GLA activities related to preparations for gas export work, long-lead items in preparation for future drilling activity, and the cost of scoping production enhancement opportunities for the Lancaster field (including a possible water injector and a side-track of the existing 205/21a-7z well). Net cash outflows relating to GWA represented the Group's share of its costs of the joint operation, including long-lead items and FPSO enhancements relating to a potential future GWA tie-back, long-lead items for the GWA commitment well and idle rig costs of the Paul B Loyd Jr (see above).

Financing outflows of $26.8 million mainly included $17.3 million for coupon payments of the Convertible Bond and the fixed lease repayments primarily for the Aoka Mizu.

Restricted funds

As of 31 December 2020, the Group held $51.6 million of cash and liquid investments within restricted funds, relating to FPSO early termination fees and decommissioning security arrangements.

Following start-up of production from the EPS, the Group is required to set aside a contractually determined amount of cash generated from oil sales to cover a proportion of the termination costs of the FPSO lease should the Group wish to exit the charter outside of contractual option periods. The balance classified as restricted cash under this arrangement was $26.5 million (31 December 2019: $11.1 million).

As part of the original Lancaster Field Development Plan approval, Hurricane was required to provide security for its decommissioning liability on the Lancaster field on a post-tax basis. This had been satisfied by way of a decommissioning bond since February 2019. However, following the fall in oil prices in H1 2020 and the downward revision to the Lancaster field's Reserves, the bond provider requested Hurricane provide cash collateral for the entire bond value. As this would provide no benefit to Hurricane, the decommissioning bond was terminated by mutual agreement in October 2020, and has now reverted to the arrangement in place prior to the decommissioning bond structure, whereby £16.8 million ($22.8 million) of cash security is held in trust in order to continue meeting the obligation to provide post-tax security for the estimated cost of decommissioning the production wells, subsea infrastructure and related FPSO costs for the Lancaster Early Production System. In April 2021, the Regulator formally notified the Group of its intention to request an increase to the amount of decommissioning security for the Lancaster field, so that it is lodged on a pre-tax basis. Once completed, this will result in an additional £11.2 million being placed into escrow and classified as restricted cash, expected to occur in June 2021.

Decommissioning

The Group holds provisions totalling $61.2 million for the anticipated cost of decommissioning its suspended and producing wells and associated infrastructure. Current provisions comprise the cost of plugging and abandoning the Lincoln 205/26b-14 and the suspended Lancaster 205/21a-4z well. The estimated cost of decommissioning the Lincoln 205/26b-14 well is $13 million, of which Hurricane will bear 50%, and is required to be plugged and abandoned by 31 October 2021. Non-current provisions represent the estimated cost of plugging and abandoning the producing Lancaster 205/21a-6 and 205/21a-7z wells, removing the associated subsea infrastructure and related FPSO costs. As at 31 December 2020, £16.8 million ($22.8 million) of cash was held in trust under decommissioning security agreements in respect of the Lancaster EPS with an additional £11.2 million ($15.7 million) expected to be added into trust in June 2021 (see 'Restricted funds' above). During the year, the Halifax and Whirlwind wells were successfully plugged and abandoned at a cost of $2.1 million.

Tax

The Group recognised a total tax charge for 2020 of $54.2 million, all of which related to deferred tax and was non-cash. At 31 December 2019, following commencement of production from the Lancaster EPS and estimates of future taxable profits, a deferred tax asset and corresponding deferred tax credit of $54.3 million was recognised in respect of trading losses accumulated to date.

As a result of the 2021 CPR and technical review (and associated impairment of assets) estimates of future taxable profits have been revised downwards meaning that it is now not forecast that there will be sufficient future taxable profits against which to offset all of these tax losses. The deferred tax asset has therefore been written down to the estimated amount of recoverable tax losses, resulting in a net non-cash tax charge of $54.2 million in the year.

Tax losses

Due to the nature of the Group's business, it has accumulated significant tax losses since incorporation. The Group has $468.7 million of ring-fenced trading losses and other allowances and supplementary charge losses of $707.8 million, which have no expiry date and would be available for offset against future trading profits, and $383.5 million of capital allowances available against future ring-fenced trading profits. The Group also has pre-trading expenditure of $119.3 million, for which tax relief may be available should the Group's remaining licences reach the development stage.

Brexit

Management continues to monitor the impact of the UK's withdrawal from the European Union, which took effect from 31 January 2020, although in some instances there is still effectively a transition period until June 2021 (with respect to customs protocols and visa requirements). Some changes have been made to manifest and shipping processes to reflect known requirements. Firm decisions or guidance regarding final requirements remain subject to change; however, to date, the Group has not experienced any significant delays to goods or increased tariffs. As the overall proportion of EU-sourced suppliers is not significant, the Group's licences and activities are entirely based within the UK, and all crude oil sales are made to a UK customer; the Group therefore does not consider the ongoing implications of Brexit to be a significant risk. Management continues to monitor and engage with industry to ensure the Group is best placed to meet any new requirements as and when these are known.

Richard Chaffe

Chief Financial Officer

Going concern statement

The Group ended the year with $166.5 million of cash and cash equivalents and liquid investments, of which $114.9 million was unrestricted. After adjusting for working capital items, net free cash† at 31 December 2020 was $111.4 million. The Group's most significant long-term liabilities are the Convertible Bond in issue of $230 million with a coupon of 7.5% payable quarterly in arrears, which matures in July 2022 (and which, as outlined below and elsewhere in this document, the Group is currently seeking to restructure), and committed lease liabilities in respect of the Aoka Mizu FPSO.

Further details of the financial position of the Group, its cash flows and liquidity position are described in the Chief Financial Officer's Review above

The Group monitors its capital position and its liquidity risk regularly throughout the year, with cashflow models and forecasts regularly produced and refreshed based on production profiles, latest estimates of oil prices, operating and G&A budgets, working capital assumptions, movements to and from restricted funds, and the Group's debt repayments. Sensitivities are run to reflect different scenarios including changes in reservoir performance, movements in oil price and changes to the timing and/or quantum of capital expenditure projects.

Proposed financial restructuring

The proposed financial restructuring, expected to complete in June 2021 subject to Bondholder approval and court sanction, will primarily comprise:

- a reduction of the Convertible Bond principal outstanding from $230 million to $180 million; in exchange for the allotment and issue of new shares to existing Bondholders representing approximately 95% of the Group's enlarged issued share capital after completion of the transaction;
- the Amended Bonds carrying an annual coupon rate of 9.4% (cash pay) plus 5.0% (payment in kind), interest accruing quarterly; with a mandatory excess cash sweep mechanism to redeem payment in kind interest and principal at each interest payment date;
- the provision of certain security and subsidiary guarantees;
- the maturity date of the Amended Bonds extended to 31 December 2024; and
- the Amended Bonds now containing a key financial covenant that requires the Group's liquidity (being consolidated cash and cash equivalents of the Group that are not subject to any security interests or held under escrow arrangements) to be not less than $45 million until cessation of production from the Lancaster field.

The proposed financial restructuring is also dependent on certain conditions precedent being satisfied or waived by 75% of the participating Bondholders by value; the key condition being consent from the Regulator to an amendment to the Lancaster Field Development Plan to permit production with flowing bottom hole pressure up to 300 psi below the bubble point of the fluid (1,605 psia at 1,240 metres TVDSS).

There is no guarantee that the conditions will be satisfied (or waived, if applicable), in which case the proposed financial restructuring would not be implemented on its current terms or possibly at all.

Assessment of going concern - base case (which assumes implementation of the proposed financial restructuring)

The directors have performed a robust assessment of the going concern assumption, considering the Group's ability to continue as a going concern from the date of approval of these Financial

Statements through to 31 July 2022, (thus incorporating the redemption date of the Convertible Bond, absent the proposed financial restructuring) with the following key assumptions as its base case:

- completion of the proposed financial restructuring effective 30 June 2021;
- Dated Brent oil price of $65/bbl for the remainder of 2021, $64/bbl in 2022 and $62/bbl thereafter;
- production from the P6 well alone as modelled using reservoir simulation modelling;
- renegotiated terms of the Aoka Mizu FPSO charter; and
- no sanction of further investment cases.

These production profiles modelled incorporated different oil price and technical assumptions to those included in the ERCE CPR, but were within the ranges of reserves and contingent resources estimated by ERCE. The analysis included a review of the budget for the year ending December 2021 and onwards, committed capital expenditure, regret costs and longer-term forecasts and plans, including consideration of the principal risks faced by the Group, and taking into account the ongoing impact of the global COVID-19 pandemic on the macroeconomic situation and any potential impact to operations.

This analysis has considered whether cash inflows from operation of the Lancaster asset together with cash balances held, plus amounts due from Spirit of $12.0 million in respect of the joint venture funding, are forecast to be sufficient to allow the Group to meet its outstanding trade and other payables of $16.4 million and current decommissioning provisions of $15.5 million that existed at 31 December 2020, lease payments (primarily for the Aoka Mizu FPSO) and other operating costs, cash coupon payments and mandatory prepayment provisions on the proposed restructured Amended Bonds debt, and capital expenditure contracted for but not recognised as a liability; and whether the Group would be able to meet the minimum liquidity covenant of the Amended Bonds.

Under the base case, the Group is forecast to have sufficient headroom on the liquidity covenant throughout the going concern period.

Sensitivities to the base case were run where oil prices were reduced by a flat $10/bbl, and forecast production reduced by 10% throughout the going concern period. In these downside scenarios, individually and in aggregate, the Group was forecast to have headroom on the liquidity covenant throughout the going concern period.

As a reverse stress test, it was estimated that either an immediate reduction to the oil price to $40/bbl flat, a reduction to the forecast production rates by approximately 40%, or a complete cessation of production for approximately 4 months during the going concern window could cause a breach of the liquidity covenant. It is likely that these circumstances would also constitute an event of default by virtue of being a material adverse event or events under the terms of the Amended Bonds.

Assessment of going concern - proposed financial restructuring does not complete

Should the proposed financial restructuring not go ahead, both under the production simulations and oil price assumptions used in the base case above, or any reasonably possible movement in oil prices, production rates and other assumptions (individually or in aggregate), the directors do not forecast a scenario where there would be sufficient free cash available to fully repay the $230 million principal due on the Convertible Bond in July 2022. As such the ability of the Group to continue trading as a going concern would depend upon the occurrence of one or more of the following:

- a significant successful equity raise;
- Bondholders and creditors providing further financial waivers and/or amendments;
- the Group agreeing alternative plans for a proposed financial restructuring with stakeholders.

However, in the opinion of the directors, the possibilities of these scenarios being successful is remote; and should the proposed financial restructuring not complete, it is likely that there would be a controlled wind-down of operations followed by an insolvent liquidation of the Group.

Conclusion

Based on all required court and regulatory approval processes being complete and the required percentage of the Group's Bondholders by value having voted in favour of the proposed financial restructuring, the proposed financial restructuring is expected to complete in June 2021. The Bondholder approval requires the support of 75% (by value) of the Bondholders present (virtually) or by proxy and voting at a meeting convened by the court. As of 24 May 2021, in excess of 75% by value of Bondholders had acceded to a lock-up agreement agreeing to support the proposed financial restructuring. As a result of the going concern assessment presented above, and on the assumption that the proposed financial restructuring completes in the timeframe outlined, the directors have a reasonable expectation that, after also taking into consideration the current macroeconomic situation and uncertainty arising from the COVID-19 pandemic, the Group has adequate resources to continue in operational existence throughout the going concern period.

Therefore, the directors continue to adopt the going concern basis of accounting in preparing these consolidated financial statements and the financial statements do not include the adjustments that would result if the Group were unable to continue as a going concern.

However, successful completion of the proposed financial restructuring is subject to, inter alia, Bondholder approval and the Court sanctioning the proposal, and as such is outside of the Group's control. The directors therefore acknowledge that the events and conditions described above, relating to the uncertainties regarding management's ability to complete the restructuring and (should it not complete) management's ability to complete an alternative restructuring and prevent a controlled wind-down and/or insolvent liquidation of the Company, together in aggregate give rise to a material uncertainty that may cast significant doubt on the Group's and Company's ability to continue as a going concern.

As at the date of this document, the proposed financial restructuring is an ongoing process and is subject, inter alia, to the approval of the requisite majority (in value) of Bondholders and the sanction of the High Court of Justice. There will also be a Court-convened meeting of shareholders to vote on the proposed financial restructuring. The Company will continue to publish announcements regarding progress of the proposed restructuring at appropriate points in the process.

Group Statement of Comprehensive Income

	Notes	**Year ended 31 Dec 2020 $'000**	Year ended 31 Dec 2019 $'000
Revenue	2.1	**180,083**	170,283
Cost of sales	2.2	**(179,816)**	(118,453)
Gross profit		**267**	51,830
General and administrative expenses		**(4,229)**	(400)
Impairment of oil and gas assets	2.3	**(519,152)**	–
Impairment of intangible exploration and evaluation assets and exploration expense written off	2.4	**(47,945)**	(66,468)
Operating loss		**(571,059)**	(15,038)
Finance income		**2,696**	1,741
Finance costs		**(38,160)**	(23,206)
Fair value gain on Convertible Bond embedded derivative	5.1	**35,431**	34,691
Loss before tax		**(571,092)**	(1,812)
Tax	6.1	**(54,233)**	60,487
Total comprehensive (loss)/profit for the year		**(625,325)**	58,675

		Cents	Cents
(Loss)/earnings per share – basic	3.1	**(31.43)**	2.97
(Loss)/earnings per share – diluted	3.1	**(31.43)**	1.70

All results arise from continuing operations.

Group Balance Sheet

	Notes	**31 Dec 2020 $'000**	31 Dec 2019 $'000
Non-current assets			
Intangible exploration and evaluation assets	2.4	**55,390**	75,874
Oil and gas assets	2.3	**208,027**	796,155
Other non-current assets		**2,605**	3,080
Deferred tax assets		**78**	54,311
Liquid investments	4.1	**22,811**	–
Cash and cash equivalents	4.1	**–**	3,065
		288,911	932,485
Current assets			
Inventory	2.2	**11,285**	9,945
Trade and other receivables		**14,524**	50,435
Cash and cash equivalents	4.1	**143,703**	168,369
		169,512	228,749
Total assets		**458,423**	1,161,234
Current liabilities			
Trade and other payables		**(16,356)**	(72,369)
Lease liabilities	5.2	**(18,479)**	(9,501)
Decommissioning provisions		**(15,466)**	(12,484)
		(50,301)	(94,354)
Non-current liabilities			
Lease liabilities	5.2	**(78,842)**	(89,685)
Convertible Bond liability	5.1	**(216,034)**	(206,604)
Convertible Bond embedded derivative	5.1	**(885)**	(36,316)
Decommissioning provisions		**(45,675)**	(43,190)
		(341,436)	(375,795)
Total liabilities		**(391,737)**	(470,149)
Net assets		**66,686**	691,085
Equity			
Share capital		**2,885**	2,883
Share premium		**822,458**	821,910
Share option reserve		**21,443**	20,828
Own shares reserve		**(923)**	(684)
Foreign exchange reserve		**(90,828)**	(90,828)
Accumulated deficit		**(688,349)**	(63,024)
Total equity		**66,686**	691,085

Group Statement of Changes in Equity

	Share capital $'000	Share premium $'000	Share option reserve $'000	Own shares reserve $'000	Foreign exchange reserve $'000	Accumulated deficit $'000	Total $'000
At 1 January 2019	2,843	813,681	24,067	(380)	(90,828)	(121,699)	627,684
Profit for the period	—	—	—	—	—	58,675	58,675
New shares issued under warrants and rights	39	7,743	—	—	—	—	7,782
New shares issued under employee share schemes	1	486	—	(393)	—	—	94
Share-based payments	—	—	(3,239)	89	—	—	(3,150)
At 31 December 2019	2,883	821,910	20,828	(684)	(90,828)	(63,024)	691,085
Loss for the period	**—**	**—**	**—**	**—**	**—**	**(625,325)**	**(625,325)**
New shares issued under employee share schemes	**2**	**548**	**—**	**(445)**	**—**	**—**	**105**
Share-based payments	**—**	**—**	**615**	**206**	**—**	**—**	**821**
At 31 December 2020	**2,885**	**822,458**	**21,443**	**(923)**	**(90,828)**	**(688,349)**	**66,686**

Group Cash Flow Statement

	Notes	**Year ended 31 Dec 2020 $'000**	Year ended 31 Dec 2019 $'000
Cash flows from operating activities			
Operating loss		**(571,059)**	(15,038)
Adjustments for:			
Depreciation of property, plant and equipment	2.3	**97,136**	63,161
Impairment of oil and gas assets	2.3	**519,152**	–
Impairment of intangible exploration and evaluation assets and exploration expense written off	2.4	**47,945**	66,468
Share-based payment charge/(credit)		**821**	(3,150)
Purchase of derivative financial instruments		**(3,420)**	–
Decommissioning spend		**(2,108)**	(12)
Operating cash flow before working capital movements		**88,467**	111,429
Movement in receivables		**159**	(2,559)
Movement in payables		**(10,352)**	8,912
Movement in crude oil, fuel and chemicals inventories	2.2	**1,946**	(5,613)
Net cash inflow from operating activities		**80,220**	112,169
Cash flows from investing activities			
Interest received		**1,227**	1,438
(Increase)/decrease in liquid investments		**(22,811)**	21,668
Expenditure on oil and gas assets		**(23,396)**	(52,878)
Expenditure on other fixed assets		**(69)**	(289)
Expenditure on intangible exploration and evaluation assets		**(35,269)**	(2,265)
Movement in spares and supplies inventories	2.2	**(3,286)**	239
Tax refund relating to R&D expenditure	6.1	**–**	6,235
Net cash used in investing activities		**(83,604)**	(25,852)
Cash flows from financing activities			
Convertible Bond interest paid	5.1	**(17,250)**	(17,250)
Lease repayments	5.2	**(9,658)**	(5,556)
Interest and other finance charges paid		**(15)**	(1,539)
New shares issued under warrants and rights		**–**	7,782
New shares issued under employee share schemes		**105**	94
Net cash used in financing activities		**(26,818)**	(16,469)
(Decrease)/increase in cash and cash equivalents		**(30,202)**	69,848
Cash and cash equivalents at beginning of year	4.1	**171,434**	101,831
Net (decrease)/increase in cash and cash equivalents		**(30,202)**	69,848
Effects of foreign exchange rate changes		**2,471**	(245)
Cash and cash equivalents at end of year	4.1	**143,703**	171,434

Notes

Section 1: General information

1.1 Basis of preparation

The consolidated Financial Statements of Hurricane Energy plc for the year ended 31 December 2020 were authorised for issue by the directors on 24 May 2021. Hurricane Energy plc is a public company, limited by shares, incorporated and domiciled in the United Kingdom and registered in England and Wales under the Companies Act 2006 (registered company number 05245689). The registered office is Ground Floor, The Wharf, Abbey Mill Business Park, Lower Eashing, Godalming, Surrey, GU7 2QN.

The Financial Statements have been prepared under the historical cost convention (except for derivative financial instruments which have been measured at fair value) in accordance with international accounting standards in conformity with the requirements of the Companies Act 2006 and in accordance with the requirements of the AIM Rules.

The Group has applied new accounting standards, amendments and interpretations for the first time, but their adoption has not had any material impact on the disclosure or on the amounts reported in the Financial Statements, nor are they expected to significantly affect future periods:

- Amendments to References to Conceptual Framework in IFRS Standards;
- Amendments to IFRS 3 - 'Definition of a Business'; and
- Interest Rate Benchmark Reform (Amendments to IFRS 9, IAS 39 and IFRS 7)

A number of new and amended accounting standards and interpretations have been published that are not mandatory for the Group's financial year ended 31 December 2020, nor have they been early adopted. These standards and interpretations are not expected to have a material impact on the Group's consolidated Financial Statements:

- Amendments to IFRS 9, IAS 39, IFRS 7, IFRS 4 and IFRS 16 - Interest Rate Benchmark Reform (effective from 1 January 2021);
- Annual Improvements to IFRS Standards 2018-2020 Cycle (effective from 1 January 2022);
- Amendments to IFRS 3 – Reference to Conceptual Framework (effective from 1 January 2022); and
- Amendments to IAS 16 – Proceeds before Intended Use (effective from 1 January 2022).

1.2 Annual report and accounts

The financial information set out within this announcement does not constitute the Company's statutory accounts for the years ended 31 December 2020 or 2019, but is derived from those accounts. A copy of the statutory accounts for 2019 has been delivered to the Registrar of Companies and those for 2020 will be delivered following the Company's annual general meeting. The auditor has reported on the 2020 accounts; their audit report was unqualified, but did draw attention to a material uncertainty that exists which may cast significant doubt on the Group's ability to continue as a going concern. Further information relating to the going concern assumption, including details in respect of the material uncertainty, is provided in the 'Going Concern' section above and in note 1.3 below.

Whilst the financial information included in this announcement has been computed in accordance with IFRS, this announcement does not itself contain sufficient information to comply with IFRS.

1.3 Going concern

The Financial Statements have been prepared in accordance with the going concern basis of accounting.

The presumption of going concern is made on the assumption that the proposed financial restructuring of the Group's existing Convertible Bonds is successfully implemented (see the 'Going Concern' section above and note 7.3 below). Should the proposed financial restructuring not go ahead, the Group is likely to be unable to repay the principal of $230 million due on the Convertible Bonds on maturity in July 2022.

As implementation of the proposed financial restructuring is dependent on all required court and regulatory approval processes being complete and the required percentage of the Group's Bondholders by value having voted in favour, a material uncertainty exists that may cast significant doubt as to the presumption of the Group's ability to continue as a going concern.

1.4 Significant events and changes in the period

In September 2020, following the initial conclusions of its technical review, the Group announced a significant reduction to its unaudited best estimates of Reserves and Contingent Resources from the Lancaster field. These estimates were further revised and refined in an updated CPR, announced in April 2021.

In the first half of 2020, oil prices declined sharply due to supply and demand factors, which included the impact of the COVID-19 pandemic and increases in Saudi Arabian production, with Dated Brent falling from a high of US$69/bbl in early January to a low of US$13/bbl in April, before stabilising to the US$40-$45/bbl range for most of the remainder of the year. As a result, average realised oil price per barrel was significantly lower than 2019 (note 2.1), which in turn has led to pressure on the Group's liquidity and capital resources.

The impact of these events and changes in estimates gave rise to an impairment charge against oil and gas assets of $519.2 million (note 2.3), an impairment charge against intangible exploration and evaluation assets of $35.4 million (note 2.4) and a write-off of deferred tax assets of $54.2 million (note 6.1).

For further discussion about the Group's performance and financial position, see the Chief Executive Officer's Review and Chief Financial Officer's Review above.

Section 2: Oil and gas operations

2.1 Revenue

All revenue is derived from contracts with customers and is comprised of only one category and geographical location, being the sale of crude oil from the Lancaster EPS. All sales were made to one external customer, being BP Oil International Limited.

	Year ended 31 Dec 2020 $'000	Year ended 31 Dec 2019 $'000
Oil sales	**180,083**	170,283
Revenue from contracts with customers	**180,083**	170,283
Cargoes sold	**12**	7
Sales volumes (thousand bbl)	**5,112**	2,874
Average sales price realised ($/bbl)	**$35.2/bbl**	$59.3/bbl

2.2 Cost of sales and inventory

Cost of sales:

	Note	Year ended 31 Dec 2020 $'000	Year ended 31 Dec 2019 $'000
Operating costs		**65,107**	44,915
Depreciation of oil and gas assets – owned	2.3	**84,756**	54,406
Depreciation of oil and gas assets – leased	2.3	**11,828**	8,210
Movement in crude oil inventory		**1,733**	(4,424)
Variable lease payments	5.2	**16,392**	15,346
		179,816	118,453

Inventory:

	31 Dec 2020 $'000	31 Dec 2019 $'000
Crude oil	**2,691**	4,424
Fuel and chemicals	**1,336**	1,549
Spares and supplies	**7,258**	3,972
	11,285	9,945

The amount of crude oil inventory recognised as an expense in the year was $155.2 million (2019: $93.5 million).

2.3 Oil and gas assets

	Note	Leased $'000	Owned $'000	Total $'000
Cost				
At 1 January 2019		–	727,816	727,816
Additions		96,361	26,189	122,550
Changes to decommissioning estimates		4,986	3,419	8,405
At 31 December 2019		101,347	757,424	858,771
Additions		–	**23,652**	**23,652**
Changes to decommissioning estimates		**474**	**3,482**	**3,956**
At 31 December 2020		**101,821**	**784,558**	**886,379**
Depreciation and impairment				
At 1 January 2019		–	–	–
Depreciation charge for the year		(8,210)	(54,406)	(62,616)
At 31 December 2019		(8,210)	(54,406)	(62,616)
Depreciation charge for the year		**(11,828)**	**(84,756)**	**(96,584)**
Provision for impairment	2.3.1	**(60,166)**	**(458,986)**	**(519,152)**
At 31 December 2020		**(80,204)**	**(598,148)**	**(678,352)**
Carrying amount at 31 December 2019		93,137	703,018	796,155
Carrying amount at 31 December 2020		**21,617**	**186,410**	**208,027**

Included within the cost of owned oil and gas assets is $42.8 million of capitalised borrowing costs (31 December 2019: $42.8 million), and $94.7 million (31 December 2019: $92.1 million) of assets not currently subject to depreciation (as they relate to non-producing parts of the Lancaster field).

Oil and gas assets held under leases comprise solely the Aoka Mizu FPSO bareboat charter, which commenced in May 2019 (see note 5.2).

The total amount of depreciation charged to oil and gas assets and other fixed assets was $97.1 million (2019: $63.2 million).

2.3.1 Impairment of oil and gas assets

An impairment charge of $519.2 million was recognised against oil and gas assets in the period, allocated pro-rata to owned and leased assets based on their respective carrying values pre-impairment.

The triggers for the impairment test were the downward revision of estimated Reserves from Lancaster, the decline in oil prices across the first half of 2020 and the market capitalisation of the Company falling below its consolidated net assets. The recoverable amount was determined based on management's best estimate of value in use, using key assumptions, judgements and estimates as outlined below, and taking into account the status of the Group's proposed financial restructuring (see note 7.3) and the potential investment cases under consideration.

The estimate of value in use was made using the expected cash flow approach. Under this approach, the directors considered four scenarios and assigned a probability weighting to each in order to arrive at a risk-adjusted probability cash flow projection. The four scenarios considered, and the percentage probability assigned to each by management for the purposes of the expected cash flow approach, were:

- Wind-down scenario (10%) – whereby the proposed financial restructuring does not complete, and there is a controlled wind-down of production at the Lancaster field, ceasing in June 2022 (at the end of the initial charter term of the Aoka Mizu FPSO);

- No further activity (NFA) scenario (50%) – whereby there is no further investment in the Lancaster field, with operations winding down when production becomes uneconomic;
- ‘P8 2022’ scenario (30%) – whereby an investment case to drill a side-track of the existing 205/21a-7z well is sanctioned, and drilled in spring 2022; and
- ‘P8 + WI 2023’ scenario (10%) – whereby an investment case to drill a water injector well is sanctioned (following completion of the ‘P8 2022’ case) and drilled in summer 2023.

Under the terms of the proposed financial restructuring, the latter three scenarios are predicated, inter alia, on the support of Bondholders and achieving consent from the regulator to permit production with flowing bottom hole pressure up to 300 psi below bubble point. The scenarios also assume renegotiation of some terms of the Aoka Mizu FPSO charter which would mitigate the impact of the early termination fee that would otherwise become payable upon cessation of production outside of contractual option periods. These conditions have been taken into account when assigning the likelihood of outcomes of each scenario.

The key assumptions used within each cash flow projection are based on best estimates using past experience, latest internal technical analysis and external factors, and include:

- production profiles and operating performance primarily based on internal estimates and reservoir simulation models, as these are believed to provide the most accurate forecast of likely future activities. (The production profiles modelled incorporated different oil price and technical assumptions to those included in the ERCE CPR, but were within the ranges of Reserves and Contingent Resources estimated by ERCE);
- the estimated capital cost of a side-track of the 205/21a-7z well to commence production in summer 2022 (both with and without drilling an additional well for the purposes of water injection), based, where possible, on quotes and contracts with key suppliers and contractors;
- subsequent forecast increases in production performance due to the additional volumes (and, under a water injector scenario, additional pressure support) over and above estimated production in a ‘no further activity’ case;
- Dated Brent oil price assumptions (in real terms) of $52/bbl average for 2021, rising to $57/bbl in 2022, $58/bbl in 2023 and $57/bbl in 2024 and thereafter (being management’s best estimate of future oil prices as at 31 December 2020, as required by IAS 36);
- operating cost assumptions based on latest budgets, contracts and information from key suppliers; and
- a pre-tax real discount rate of 9.4%.

The sensitivity of changes to some of these key estimates and assumptions which have a material impact are estimated as follows:

	Decrease/(increase) to impairment charge $’000
Oil price assumption:	
$5/bbl increase to price curve	**44,277**
$5/bbl decrease to price curve	**(44,292)**
Forecast production rates:	
10% increase	**44,802**
10% decrease	**(44,503)**

The sensitivities disclosed are considered in isolation and a result of changing only one variable, and do not take into account any change to the likelihood of a potential scenario occurring as a result of changes to those assumptions.

A $5/bbl increase or decrease to the forecast oil price are considered to be reasonably possible based on oil price volatility, and a 10% increase or decrease to forecast production rates are considered to be reasonably possible based on experienced uptime and production levels.

The impact of assuming the Aoka Mizu FPSO charter continues on its current terms (and thus crystallising an early termination fee in some scenarios) would be to increase the impairment charge by $13.3 million.

The sensitivity of the impairment charge from using an individual scenario instead of the expected cash flow approach is as follows:

	(Increase)/decrease to impairment charge $'000
Wind-down	**(106,836)**
No further activity	**(10,133)**
P8 2022	**20,155**
P8 + WI 2023	**97,037**

2.4 Intangible exploration and evaluation assets

	Note	**Year ended 31 Dec 2020 $'000**	Year ended 31 Dec 2019 $'000
At 1 January		**75,874**	131,526
Additions		**25,623**	6,619
Exploration expenditure written off	2.4.1	**(12,079)**	(66,468)
Provision for impairment	2.4.1	**(35,397)**	–
Changes to decommissioning estimates		**1,369**	4,197
At 31 December		**55,390**	75,874

Intangible exploration and evaluation assets represent the Group's share of the cost of licence interests and exploration and evaluation expenditure within its licensed acreage in the West of Shetland area, which comprise Lincoln (on licence P1368 South), Warwick (licence P2294) and Halifax (licence P2308).

With effect from September 2020, the P2294 licence that holds the Warwick assets was extended into its second term, which expires in August 2023. In November 2020, the P2308 licence which holds the Halifax assets was also extended into its second term, which expires in November 2024.

2.4.1 Impairment and write-off of intangible exploration and evaluation assets

The directors have fully considered and reviewed the potential value of licence interests, including carried forward exploration and evaluation expenditure. The directors have considered the Group's tenure to its licence interests, its plan for further exploration and evaluation activities in relation to these and the likely opportunities for realising the value of the Group's licences, either by farm-out or by development of the assets.

$12.1 million of exploration and evaluation expenditure was written off in the year, comprising the Group's share of standby costs for the Paul B Loyd Jr rig, which was not used for any drilling campaigns during 2020 following the OGA granting an extension to the licence commitments on the Lincoln field in light of the COVID-19 pandemic. See the Chief Executive Officer's Review and Chief Financial Officer's Review above for further details.

A further $0.5 million of exploration expense was written off in the year relating to changes in decommissioning estimates for the Whirlwind well (which was fully written-off in December 2019).

Following the conclusion of the group's technical review and finalisation of the 2021 CPR, provision for impairment of $35.4 million has been recognised in the year, being the full carrying amount of exploration and evaluation expenditure attributable to the Halifax licence, as the revised estimates do not attribute any Reserves or Contingent Resources to Halifax and the Group has no plans or budgets for substantive expenditure on further exploration or evaluation on this licence.

Although the 2021 CPR estimated a reduction in Contingent Resources attributable to the Lincoln subarea (as compared to the December 2017 RPS Energy West of Shetland CPR) the directors have concluded that no impairment to exploration and evaluation assets is necessary at this time as economic analysis shows the potential for its carrying amount to be recovered in full through successful development in conjunction with the Warwick area. However, any appraisal and development activity would involve a significant financial commitment for the Group (and its joint operation partner); and, under the terms of the proposed financial restructuring, the Group would need to seek approval from Bondholders in order to proceed with significant capital expenditure on GWA (including the licence obligation to drill a commitment well on the Lincoln subarea). The directors would also consider their ability to realise value from the licences via sale or farm-out transaction, subject to regulatory, Bondholder and joint operation partner approval. It is a condition of the licence for the Lincoln subarea that, if the Lincoln commitment well is not drilled, the Lincoln subarea be relinquished by the joint venture partners. In the event of a relinquishment, the carrying value of exploration and evaluation assets relating to Lincoln would be written off in full.

On 12 December 2019, the Group executed a deed of variation with the OGA, granting a five-year extension to its P1368 licence (which covered the Lincoln, Lancaster, Whirlwind and Strathmore subareas) to December 2024. As part of this extension agreed with the OGA, the Whirlwind and Strathmore subareas were relinquished resulting in a write-off of $66.5 million for the year ended 31 December 2019, all relating to Whirlwind. The carrying value of intangible exploration and evaluation assets relating to Strathmore was previously fully impaired in 2017.

Section 3: Income Statement

3.1 Earnings per share

	Year ended 31 Dec 2020 $'000	Year ended 31 Dec 2019 $'000
(Loss)/profit attributable to holders of Ordinary Shares in the Company used in calculating basic earnings per share (being (loss)/profit after tax)	**(625,325)**	58,675
Add back impact of:		
Convertible Bond – interest expense not capitalised	**–**	16,417
Convertible Bond – depreciation of interest capitalised in the year	**–**	738
Convertible Bond – fair value gain	**–**	(34,691)
(Loss)/profit attributable to holders of Ordinary Shares in the Company used in calculating diluted earnings per share	**(625,325)**	41,139

	Number	Number
Weighted average number of Ordinary Shares used in calculating basic earnings per share	**1,989,607,524**	1,978,513,120
Potential dilutive effect of:		
Convertible Bond	**–**	442,307,692
Weighted average number of Ordinary Shares and potential Ordinary Shares used in calculating diluted earnings per share	**1,989,607,524**	2,420,820,812

	Cents	Cents
Basic (loss)/earnings per share	**(31.43)**	2.97
Diluted (loss)/earnings per share	**(31.43)**	1.70

The effect of warrants, share awards and options outstanding in 2020 was antidilutive as the Group incurred a loss. The impact of the conversion feature included within the Convertible Bond in 2020 was also antidilutive for the same reason.

The impact of the VCP and PSP awards was antidilutive in 2019 because market-based conditions for both schemes had not been met at the balance sheet date, and the impact of other employee share options was antidilutive in 2019 as the adjusted exercise prices were in excess of the average market price of Ordinary Shares during the relevant periods.

Section 4: Cash

4.1 Cash and cash equivalents and liquid investments

	31 Dec 2020			31 Dec 2019		
	Restricted	**Unrestricted**	**Total**	Restricted	Unrestricted	Total
	$'000	**$'000**	**$'000**	$'000	$'000	$'000
Current cash and cash equivalents	**28,792**	**114,911**	**143,703**	11,778	156,591	168,369
Non-current cash and equivalents	–	–	–	3,065	–	3,065
Cash and cash equivalents (per cash flow statement)	**28,792**	**114,911**	**143,703**	14,843	156,591	171,434
Liquid investments	**22,811**	–	**22,811**	–	–	–
Total cash and cash equivalents and liquid investments	**51,603**	**114,911**	**166,514**	14,843	156,591	171,434

The carrying amounts of cash and cash equivalents and liquid investments are considered to be materially equivalent to their fair values.

The movement in restricted and unrestricted cash, cash equivalents and liquid investments is as follows:

	Year ended 31 Dec 2020			Year ended 31 Dec 2019		
	Restricted	**Unrestricted**	**Total**	Restricted	Unrestricted	Total
	$'000	**$'000**	**$'000**	$'000	$'000	$'000
At 1 January	**14,843**	**156,591**	**171,434**	40,162	83,000	123,162
Operating cash flows	–	**78,272**	**78,272**	–	112,169	112,169
Change in Lancaster EPS decommissioning security arrangements	**22,811**	**(22,811)**	–	(21,668)	21,668	–
Capital expenditure and other investing cash flows	–	**(58,845)**	**(58,845)**	(2,520)	(45,000)	(47,520)
Financing cash flows	–	**(26,818)**	**(26,818)**	(12,938)	(3,531)	(16,469)
Movement in FPSO early termination reserve	**14,807**	**(14,807)**	–	11,735	(11,735)	–
Net release of other restricted funds	**(892)**	**892**	–	(363)	363	–
Foreign exchange rate changes	**34**	**2,437**	**2,471**	435	(343)	92
At 31 December	**51,603**	**114,911**	**166,514**	14,843	156,591	171,434

Included within restricted cash and cash equivalents is $26.5 million (2019: $11.7 million) set aside in relation to the Aoka Mizu FPSO bareboat charter. Under the terms of the contract, the Group is required to ring-fence amounts to ensure it could meet its liability to pay an early termination fee to the lessor if the contract was terminated by the Group earlier than the expiry of an option period. The remaining $2.3 million of restricted cash comprises decommissioning security in place for the suspended Lancaster 205/21a-4z well.

The $22.8 million restricted liquid investment balance comprises decommissioning security in place for the Lancaster EPS. As part of the original Lancaster Field Development Plan approval, the Group was required to provide security of £16.8 million for its decommissioning liability on the Lancaster field, being the estimated post-tax amount to meet future decommissioning obligations. This security was held in trust (classified within restricted liquid investments) until February 2019 when it was transferred into a decommissioning bond, and subsequently released to unrestricted cash during 2019 as the bond conditions were satisfied. Following the downwards revision of Reserves in September 2020 and the ongoing uncertainty with regard to oil prices, the bond provider requested that the Company provide cash collateral for 100% of the bond's value. As the Group would derive no benefit from the bond while still paying fees to the bond provider, the decommissioning bond was terminated by mutual agreement and the required security amount was placed back into trust (classified within restricted liquid investments). In April 2021, the regulator gave notice of its intention to formally request that an additional £11.2 million relating to this decommissioning security be lodged by the Group – see note 7.2.

Section 5: Capital and debt

5.1 Convertible Bond

In July 2017 the Group raised $230 million (gross) from the successful placement of the Convertible Bond. The Convertible Bond was issued at par and carries a coupon of 7.5% payable quarterly in arrears. The Convertible Bond is convertible into fully paid Ordinary Shares with the initial conversion price set at $0.52, representing a 25% premium above the placing price of the concurrent equity placement, being £0.32 (converted into US Dollars at a USD/GBP rate of 1.30). The number of potential Ordinary Shares that could be issued if all the Convertible Bonds were converted is 442,307,692 (assuming conversion at the initial conversion price of $0.52). The impact of these potential Ordinary Shares on diluted earnings per share is shown in note 3.1. Unless previously converted, redeemed or purchased and cancelled, the Convertible Bond will be redeemed at par on 24 July 2022. The Convertible Bond is subject to a covenant which imposes a restriction on the incurrence of certain indebtedness. This restriction shall not apply in respect of:

- any indebtedness in respect of the Convertible Bond (Bond Debt);
- any other indebtedness where the aggregate principal amount of such other indebtedness, when combined with the aggregate principal amount of all other indebtedness of the Group from time to time (excluding the Bond Debt), would not cause the total indebtedness of the Group on a consolidated basis to exceed $45 million (or the equivalent thereof in other currencies at then current rates of exchange); and
- any permitted indebtedness, being:
    - any liability in respect of any lease or hire purchase contract which would, in accordance with IFRS, be treated as a finance or capital lease, with respect to the bareboat charter of the Aoka Mizu FPSO;
    - amounts borrowed, or any guarantee or indemnity given with respect to any security, where required by the Oil and Gas Authority or any other applicable regulator, in relation to suspended wells, decommissioning or other related regulatory obligations of the Group; and
    - any amount raised under any transaction, having the commercial effect of borrowing, in respect of the deferral of payment of invoices due to Technip UK Limited (or any of its affiliated companies) in connection with the agreement for the provision of subsea umbilical risers and flowlines and subsea production systems for the Company's operations in the Lancaster field.

The conversion feature of the Convertible Bonds is classified as an embedded derivative as the Convertible Bonds can be settled by the Group in cash and hence does not meet the 'fixed for fixed' criteria outlined in IAS 32 for recognition as an equity instrument. It has therefore been measured at fair value through profit and loss. The amount recognised at inception in respect of the host debt contract was determined by deducting the fair value of the conversion option at inception (the embedded derivative) from the fair value of the consideration received for the Convertible Bond. The debt component is then recognised at amortised cost, using the effective interest method, until extinguished upon conversion or at maturity. The effective interest rate applicable to the debt component is 13.5%.

Subsequent to the balance sheet date, the Group entered into a lock-up agreement with certain of its Bondholders in order to enter into a proposed financial restructuring which will, if approved, significantly amend the terms of the existing Convertible Bonds; see note 7.3 for further details.

The amounts recognised in the Financial Statements related to the Convertible Bond (which, together with leases as disclosed in note 5.2, are the group's liabilities arising from financing activities) are as follows:

	Debt component $'000	**Derivative component $'000**	**Total $'000**
Carrying value at 1 January 2019	198,364	71,007	269,371
Cash interest paid	(17,250)	–	(17,250)
Fair value gains	–	(34,691)	(34,691)
Interest charged	25,490	–	25,490
Carrying value at 31 December 2019	**206,604**	**36,316**	**242,920**
Cash interest paid	**(17,250)**	–	**(17,250)**
Fair value gains	-	**(35,431)**	**(35,431)**
Interest charged	**26,680**	–	**26,680**
Carrying value at 31 December 2020	**216,034**	**885**	**216,919**
Fair value at 31 December 2019	235,852	36,316	272,168
Fair value at 31 December 2020	**102,615**	**885**	**103,500**

The embedded derivative component of the Convertible Bond is categorised within Level 3 of the fair value hierarchy, as the derivatives themselves are not traded on an active market and their fair values are determined using a valuation technique that uses one key input that is not based on observable market data, being share price volatility.

The key inputs used are share price volatility (calculated as the volatility of one Hurricane Ordinary Share over a period equivalent to the remaining expected term to redemption) and the price of one Ordinary Share at 31 December 2020. In determining the fair value of the embedded derivative, the likelihood of the early redemption option being exercised and the likelihood of a change of control of the Group within the life of the Convertible Bond were considered. The likelihood of each was considered to be nil for the purposes of the valuation.

The fair value calculation at 31 December 2020 used a share price volatility assumption of 118.2% (2019: n/a) and the price of one Hurricane Energy plc Ordinary Share as at the balance sheet date of £0.025 (2019: n/a). The sensitivity of a reasonably possible increase or decrease of those inputs to the Group's profit before tax for the period ended 31 December 2020 is summarised below, assuming all other variables were held constant:

	(Loss)/ gain $'000
Share price volatility assumption:	
20% increase	**(989)**
20% decrease	**605**
Share price at balance sheet date:	
£0.05 increase	**(7,656)**
£0.02 decrease	**871**

Should the proposed financial restructuring be implemented, the existing conversion rights attached to the Convertible Bonds will be amended and the value of the existing embedded derivative reduced to nil at the effective implementation date.

The valuation as at 31 December 2019 was derived by deducting the estimated fair value of the debt component (using an equivalent bond yield of 7.2% estimated from average adjusted bond yields from similar oil and gas E&P companies) from the quoted market value of the Convertible Bond. The valuation methodology has changed due to the previous methodology not being appropriate where the market value of the Convertible Bond is below its par value.

5.2 Leases

The amounts recognised in the Financial Statements relating to lease liabilities (which are liabilities arising from financing activities) are as follows:

	Year ended 31 Dec 2020 $'000	Year ended 31 Dec 2019 $'000
At 1 January	**99,186**	3,323
New leases	**–**	96,361
Cash payments of principal and interest	**(9,658)**	(5,556)
Interest charged	**7,702**	4,972
Foreign exchange movements	**91**	86
At 31 December	**97,321**	99,186
Of which:		
Current	**18,479**	**9,501**
Non-current	**78,842**	**89,685**
	97,321	**99,186**

In May 2019, the Group's bareboat charter of the Aoka Mizu FPSO commenced. Under the contract, the Group makes fixed payments (which are included within the lease liability measurement) and variable payments, which are based on a percentage of the quantity and price of crude oil sold. These variable payments are excluded from the measurement of the lease liability, and instead are recognised as an expense in the period in which sales are made. Should the Group give notice to terminate the lease other than by not exercising extension option periods, significant early termination penalties would apply. The Group is required to set aside amounts to cover a portion of these early termination penalties, which are classified within restricted cash (see note 4.1).

The charges to the income statement in respect of leases during the year included the following:

	Year ended 31 Dec 2020 $'000	Year ended 31 Dec 2019 $'000
Depreciation charge of right-of-use assets:		
Oil and gas assets (included within cost of sales)	**11,828**	8,210
Other fixed assets (included within general and administrative expenses)	**340**	337
	12,168	8,547
Lease interest (included within finance costs)	**7,702**	4,972
Variable lease payments (included within cost of sales)	**16,392**	15,346

The total gross cash outflow for leases for the year was $46.9 million, of which $10.1 million was recovered from the Group's joint operation partner.

The Group's share of the expense relating to the short-term lease of the Paul B Loyd Jr rig was recognised within write-off of exploration and evaluation expenditure (see note 2.4). The expense relating to low-value leases and other short-term leases recognised in the income statement was not material.

Section 6: Tax

6.1 Tax charge for the year

	Year ended 31 Dec 2020 $'000	Year ended 31 Dec 2019 $'000
UK corporation tax		
Current tax – prior years	–	6,259
Total current tax	–	6,259
Deferred tax – current year	**(44,501)**	90,226
Deferred tax – prior year	**(9,732)**	–
Effect of changes in tax rates	–	(35,998)
Total deferred tax	**(54,233)**	54,228
Tax (charge)/credit per income statement	**(54,233)**	60,487
Loss on ordinary activities before tax	**(571,092)**	(1,812)
Loss on ordinary activities multiplied by standard combined rate of corporation tax in the UK applicable to oil and gas companies of 40% (2019: 40%)	**228,437**	725
Effects of:		
R&D tax credit	–	6,259
Expenses not deductible for tax purposes	**(4,656)**	(1,724)
Income not chargeable for tax purposes	**15,138**	4,211
Items taxed at rates other than the standard rate of 40%	**(24)**	(278,873)
Ring-fence expenditure supplement	**22,769**	22,057
Recognition of deferred tax not previously recognised	**–**	307,832
Prior period deferred tax	**(9,732)**	–
Losses not recognised	**(306,165)**	–
Total tax (charge)/credit for the year	**(54,233)**	60,487

Income not chargeable for tax purposes primarily relates to the tax effect of the fair value gain on the Convertible Bond embedded derivative (see note 5.1).

In 2018 the Group made a claim under the SME research and development tax relief scheme in respect of the 2016 and 2017 financial years and has surrendered the resulting losses for a payable tax credit. $6.2 million was received in respect of this in April 2019, classified within cash flows from investing activities as the original expenditure giving rise to the credit was reported within investing activities.

Section 7: Subsequent events

7.1 CPR

In April 2021, an updated CPR on the Group's assets was published, which gave an updated estimate of the hydrocarbon Reserves and Contingent Resources as at 31 December 2020, thus providing additional evidence of conditions that existed as at the balance sheet date. The results of this CPR have therefore been reflected within these Financial Statements, by taking into account these estimates within the impairment test for oil and gas assets (note 2.3.1) and giving rise to a full impairment of exploration and evaluation expenditure attributable to the Halifax licence, as the CPR did not attribute any Reserves or Contingent Resources to that area (note 2.4.1).

7.2 Decommissioning security

In April 2021, the Offshore Petroleum Regulator for Environment and Decommissioning gave notice of its intention to formally request that the Company increase the amount of decommissioning security for the Lancaster field by £11.2 million ($15.7 million), in order for the security to be in place on a pre-tax basis. The Group therefore expects to place this amount into restricted funds shortly after the receipt of the formal request, expected to be in June 2021.

7.3 Proposed financial restructuring

On 30 April 2021, the Group entered into a lock-up agreement (LUA) with an ad hoc group of Bondholders (the Ad Hoc Committee; representing approximately 69% by value of the Group's Convertible Bonds outstanding), pursuant to a proposed financial restructuring plan (the proposed financial restructuring). As at the date of this report, in excess of 75% by value of Bondholders had signed or acceded to the LUA.

As a result of entering into the LUA, an Event of Default has occurred pursuant to the terms and conditions of the Convertible Bonds. As the Company's ability to repay the Convertible Bonds at maturity is dependent on the implementation of the proposed financial restructuring, a Potential Event of Default (as defined in the Trust Deed) has also arisen. The Group has provided notice of the Event of Default and Potential Event of Default to the Trustee. Noting that in excess of 75% by value of Bondholders had signed or acceded to the LUA, and the LUA contains certain forbearances and an agreement not to take or encourage any action which would, or would reasonably be expected to, delay, frustrate, impede or prevent the implementation or consummation of the proposed financial restructuring, the Group does not expect the Bondholders to take action in relation to the Event of Default while the LUA is in effect.

The main components of the proposed financial restructuring are:

- a debt for equity conversion, which entails (amongst other things):
    - a release of approximately $50 million of the outstanding principal amount under the Convertible Bonds in consideration for the allotment and issue of Ordinary Shares in the Company representing in aggregate approximately 95% of the total number of fully diluted issued shares of the Company immediately following the effective date of the proposed financial restructuring; and
    - various amendments to the terms and conditions of the remaining $180 million of Convertible Bonds and associated documents in accordance with the revised terms detailed below, including the provision of security and subsidiary guarantees; and

- a revised business strategy for the Group which contemplates: (i) an extended production case (which would see production from the Lancaster 205/21a-6 well continue until its economic limit is reached); and (ii) subject to approval by the Bondholders, an opportunity for subsequent investments in the Lancaster field (which, at the time of entering into the LUA, envisaged the drilling of a side-track of the existing 205/21a-7z well in 2022, potentially followed by the drilling of a water injector well in 2023).

Amended Bonds

If implemented, the proposed financial restructuring would result in the release of $50 million of the outstanding principal amount of the Convertible Bonds, such that the amount due on maturity of the Amended Bonds will be up to $180 million. Under the terms of the Amended Bonds, the cash coupon on the Convertible Bonds would be increased from 7.5% to 9.4% per annum, an additional payment-in-kind (PIK) interest at a rate of 5% per annum would be introduced and the maturity date would be extended to December 2024. A mandatory prepayment provision, whereby excess cash flow generated by the Group will be applied in mandatory redemption of the Amended Bonds on each interest payment date, and various general, restrictive and information covenants will be added to the Amended Bonds, with a key financial covenant being that the liquidity of the Group (being consolidated cash and cash equivalents of the Group that are not subject to any security interests or held under escrow arrangements) must be no less than $45 million until cessation of production from the Lancaster field.

If implemented, the proposed financial restructuring would result in the removal of the existing conversion options of the Convertible Bonds, and the introduction of a new maturity conversion option exercisable by the Company after December 2024 provided that, amongst other things, all production at Lancaster has ceased permanently and all remaining free cash of the Group has been applied towards outstanding liabilities under the Amended Bonds, all of which is intended to ensure continuing solvency for the Company. This conversion option would, in the circumstances outlined above, allow the Company to convert any remaining outstanding Amended Bonds into Ordinary Shares of the Company. The Amended Bonds will be secured by certain assets, undertakings, property, interests and rights of the Company (Hurricane Energy plc), Hurricane Holdings Limited and Hurricane GLA Limited (both being subsidiaries of the Company), and additional guarantees will be granted by certain Company subsidiaries.

Implementation of the proposed financial restructuring

To implement the proposed financial restructuring, it is proposed that an English Restructuring Plan under Part 26A of the Companies Act 2006 will be utilised, which will require the support of 75% (by value) of the Bondholders voting at a meeting convened by the court. The convening hearing of the court was held on 21 May 2021. The Bondholder plan meeting convened by the court has been scheduled for 11 June 2021. The court has also convened a plan meeting of shareholders, at which shareholders will be asked to vote on the proposed financial restructuring. The shareholder plan meeting will take place on 11 June 2021 following the Bondholder plan meeting. The outcome of those plan meetings will be published by the Company shortly after the conclusion of the meetings.

Subject to the outcome of the Bondholder plan meeting, the Company expects the sanction hearing of the court, at which the court will be asked to sanction the proposed restructuring plan, to commence on or around 21 June 2021. The Company will make an announcement regarding the outcome of the sanction hearing as soon as possible after that hearing concludes.

Unless waived by a 75% majority in value of the Bondholders who are party to or have acceded to the LUA, the implementation of the proposed financial restructuring is conditional on, inter alia, receiving consent from the OGA to amend the Lancaster Field Development Plan to permit production with flowing bottom hole pressure up to 300 psi below the bubble point of the fluid (1,605 psia at 1,240 metres TVDSS).

Failure to implement the proposed financial restructuring

In the event that the proposed financial restructuring (a) is not approved by Bondholders and shareholders at the Bondholder plan meeting and shareholder plan meeting, respectively; or (b) is approved by Bondholders but not by shareholders, and is not sanctioned by the Court; or (c) is approved by Bondholders and shareholders, but is not sanctioned by the Court, the proposed financial restructuring will not be capable of being implemented. In that scenario, given the circumstances, there would be insufficient time to seek, and it is most unlikely that the Company would be able to obtain, the requisite level of Bondholder consent to implement any alternative transaction outside of a controlled wind-down of the Group's operations followed by an insolvent liquidation of the Company and its subsidiaries.

Appendix A: Glossary

1C	Denotes low estimate of Contingent Resources
1P	Denotes low estimate of Reserves (i.e., Proved Reserves). Equal to P1.
2C	Denotes best estimate of Contingent Resources
2P	Denotes the best estimate of Reserves. The sum of Proved plus Probable Reserves.
3C	Denotes high estimate of Contingent Resources
3P	Denotes high estimate of Reserves. The sum of Proved plus Probable plus Possible Reserves.
AIM	The AIM market of the London Stock Exchange
Amended Bond(s)	$180 million of 14.4% convertible bonds due December 2024; being the Convertible Bond(s) amended and restated following completion of the proposed financial restructuring
Aoka Mizu	Aoka Mizu FPSO
bbl	Barrel
Bluewater	Bluewater Energy Services and affiliates
Bondholder	A holder of one or more the Company's Convertible Bonds or, should the proposed financial restructuring proceed, the Company's Amended Bonds
Board	Board of directors of the Company
bopd	Barrels of oil per day
BP	BP Oil International Limited
bubble point	The pressure at which gas begins to come out of solution from oil within the reservoir
CEO	Chief Executive Officer
CFO	Chief Financial Officer
Company	Hurricane Energy plc and/or its subsidiaries
coned	The production of fluids as a result of drawdown pressures during production overcoming the natural buoyancy forces that segregate oil, water and gas
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.
Contingent Resources, Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.
Contingent Resources, Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.
Convertible Bond(s)	$230million of 7.5% convertible bonds issued by the Company in July 2017
COO	Chief Operations Officer
COVID-19	Coronavirus
CPR	Competent Persons Report
E&E	Exploration and Evaluation
E&P	Exploration and Production/Exploration and Production company
EPS	Early Production System
ERCE	ERC Equipoise Limited
ESG	Environmental, Social and Governance
ESP	Electrical submersible pump
FDPA	Field Development Plan Addendum
FPSO	Floating production storage and offloading vessel
FVTPL	Fair value through profit and loss
G&A	General and Administrative costs
GBP	British Pounds Sterling
GHG	Greenhouse Gas (i.e. Carbon Dioxide, Methane, Nitrous Oxide, Chlorofluorocarbon-12, Hydrofluorocarbon-23, Sulphur Hexafluoride, Nitrogen Trifluoride)
GLA	Greater Lancaster Area, comprising the UKCS licences P1368 Central and P2308
Group	Hurricane Energy plc, together with its subsidiaries
GWA	Greater Warwick Area, comprising the Lincoln and Warwick fields located on UKCS licences P1368 South and P2294
Hurricane	Hurricane Energy plc, together with its subsidiaries
IAS	International Accounting Standard
IFRS	International Financial Reporting Standards
IPO	Initial Public Offering
JV	Joint venture
LLIs	Long-Lead Items
LTIP	Long term incentive plan
LUA	Lock-up agreement
Mbbl	Thousand barrels of oil

MMbbl	Million barrels of oil
NFA case	The terms of the proposed financial restructuring agreed between Hurricane and its Bondholders requires implementation of a no further activity case for Lancaster, based on production from the 205/21a-6 well alone, and requires that Hurricane executes a planned wind-down of operations starting when production from the Lancaster field is no longer economic.
OGA	Oil and Gas Authority
OGUK	Oil & Gas trade association for the United Kingdom
Ordinary Shares	Ordinary shares in the Company of £0.001 each
OWC	Oil water contact
P&A	Plug and abandon
P8	The proposed sidetrack to be drilled from the 205/21a-7z horizontal producer well
PRMS	Petroleum Resources Management System
PSP	Performance Share Plan
psia	Pounds per square inch (absolute) unit of pressure
R&D	Research & Development
Regret costs	Amounts that remain payable under contracts on cancellation of a project
Regulator	Oil and Gas Authority, Department for Business Energy and Industrial Strategy, and/or The Health and Safety Executive
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.
Restructuring Plan	Implementation of the proposed financial restructuring announced by Hurricane on 30 April 2021 with holders of its Convertible Bonds under Part 26A of the Companies Act 2006
RPS	RPS Energy Consultants Ltd
SME	Small and medium sized enterprises
SPE	The Society of Petroleum Engineers
Spirit or Spirit Energy	Spirit Energy Limited
stb/d/psi	Stock tank barrels of oil per day per pound per square inch of drawdown
SURF	Subsea, Umbilical, Risers, Flowlines
Tier 1 contractors	Hurricane's major direct contractors
TVDSS	True Vertical Depth Sub Sea
UKCS	United Kingdom Continental Shelf
USD	United States Dollars
VCP	Value Creation Plan
WI	Water injector

Appendix B: Non-IFRS measures

Underlying profit before tax

Underlying profit before tax is defined as profit before tax under IFRS, before fair value gains or losses on the Convertible Bond embedded derivative, fair value gains or losses on unhedged derivative financial instruments, impairment and write-offs of intangible exploration and evaluation assets, impairment of oil and gas assets and gains or losses on disposal of assets or subsidiaries.

Management believes that underlying profit before tax is a useful measure as it provides useful trends on the pre-tax performance of the Group's core business and asset by removing certain items and transactions within the income statement. These are the volatile non-cash impact of the Convertible Bond embedded derivative movement (the valuation of which is largely outside management's control) and gains or losses arising from write-offs and impairments of oil and gas and exploration and evaluation assets, and disposals of assets or subsidiaries which do not reflect the Group's core business. Fair value gains or losses on derivatives not designated as hedging instruments in a hedging relationship have been added to the items excluded from underlying profit before tax as the Group entered into such contracts for the first time during 2020. These fair value movements are excluded from underlying profit before tax as movements are wholly due to movements in oil price which is not within management's control.

	Notes	**Year ended 31 Dec 2020 $'000**	Year ended 31 Dec 2019 $'000
Loss before tax (IFRS measure)		**(571,092)**	(1,812)
Add back:			
Fair value gain on Convertible Bond embedded derivative	5.1	**(35,431)**	(34,691)
Fair value loss on unhedged derivative financial instruments		**3,420**	–
Impairment and write-off of intangible exploration and evaluation assets	2.4	**47,945**	66,468
Impairment of oil and gas assets	2.3	**519,152**	–
Underlying (loss)/profit before tax		**(36,006)**	29,965

Cash production costs

Cash production costs are defined as cost of sales under IFRS, less depreciation of oil and gas assets (including right-of-use assets) and accounting movements of crude oil inventory (including any net realisable value provision movements), plus fixed lease payments payable for leased oil and gas assets. Cash production costs (excluding incentive tariff) are defined as cash production costs less variable lease payments.

Depreciation and movements in crude oil inventory are deducted as they are non-cash accounting adjustments to cost of sales. Fixed lease payments payable for oil and gas assets are added back because, under IFRS 16, the charge relating to fixed lease payments is charged to the income statement within both depreciation of oil and gas assets and interest on lease liabilities. They are therefore included within cash production costs as they are considered by management to be operating costs in nature. Fixed lease payments payable for the purposes of this measure are calculated as the day rate charge multiplied by the number of days in the period. Cash production costs (excluding incentive tariff) deduct variable lease payments, as the latter is directly linked to the price of crude oil sold and thus largely outside of management's control. Cash production cost per barrel measures are defined as the relevant cash production cost measure divided by production volumes.

Management believes that cash production costs and cash production cost per barrel (both including and excluding incentive tariff) are useful measures as they remove non-cash elements from cost of sales, assist with cash flow forecasting and budgeting, and provide indicative breakeven amounts for the sale of crude oil.

	Note	**Year ended 31 Dec 2020 $'000**	Year ended 31 Dec 2019 $'000
Cost of sales (IFRS measure)	2.2	**179,816**	118,453
Less:			
Depreciation of oil and gas assets – owned		**(84,756)**	(54,406)
Depreciation of oil and gas assets – leased	2.3	**(11,828)**	(8,210)
Movements in crude oil inventory		**(1,733)**	4,424
Add:	2.3		
Fixed lease payments payable on oil and gas assets		**9,150**	5,761
Cash production costs	2.2	**90,649**	66,022
Variable lease payments (incentive tariff)		**(16,392)**	(15,346)
Cash production costs (excluding incentive tariff)		**74,257**	50,676
Production volumes		**5,078 kbbl**	3,030 kbbl
Cash production costs per barrel		**$17.9/bbl**	$21.8/bbl
Cash production costs per barrel (excluding incentive tariff)		**$14.6/bbl**	$16.7/bbl

Net free cash and net debt

Net free cash is defined as current unrestricted cash and cash equivalents, plus current financial trade and other receivables (which exclude prepayments) and current oil price derivatives, less current financial trade and other payables.

Management believes that net free cash is a useful measure as it provides a view of the Group's available liquidity and resources after settling all its immediate creditors and accruals and recovering amounts due and accrued from joint operation activities, outstanding amounts from crude oil sales and after settling any other financial trade payables or receivables.

Net debt is defined as net free cash less the par value of the Convertible Bond, being the total amount repayable on maturity of the Bond debt in July 2022 (unless previously converted, redeemed or purchased and cancelled).

Management believes that net debt is a useful measure as it aids stakeholders in understanding the current financial position and liquidity of the Group.

	Note	**31 Dec 2020 $'000**	31 Dec 2019 $'000
Cash and cash equivalents (IFRS measure)	4.1	**143,703**	171,434
Add:			
Trade and other receivables		**14,524**	50,435
Derivative financial instruments		**–**	–
Less:			
Restricted cash and cash equivalents	4.1	**(28,792)**	(14,843)
Prepayments		**(1,644)**	(1,066)
Trade and other payables		**(16,356)**	(72,369)
Net free cash		**111,435**	133,591
Par value of Convertible Bond	5.1	**(230,000)**	(230,000)
Net debt		**(118,565)**	(96,409)