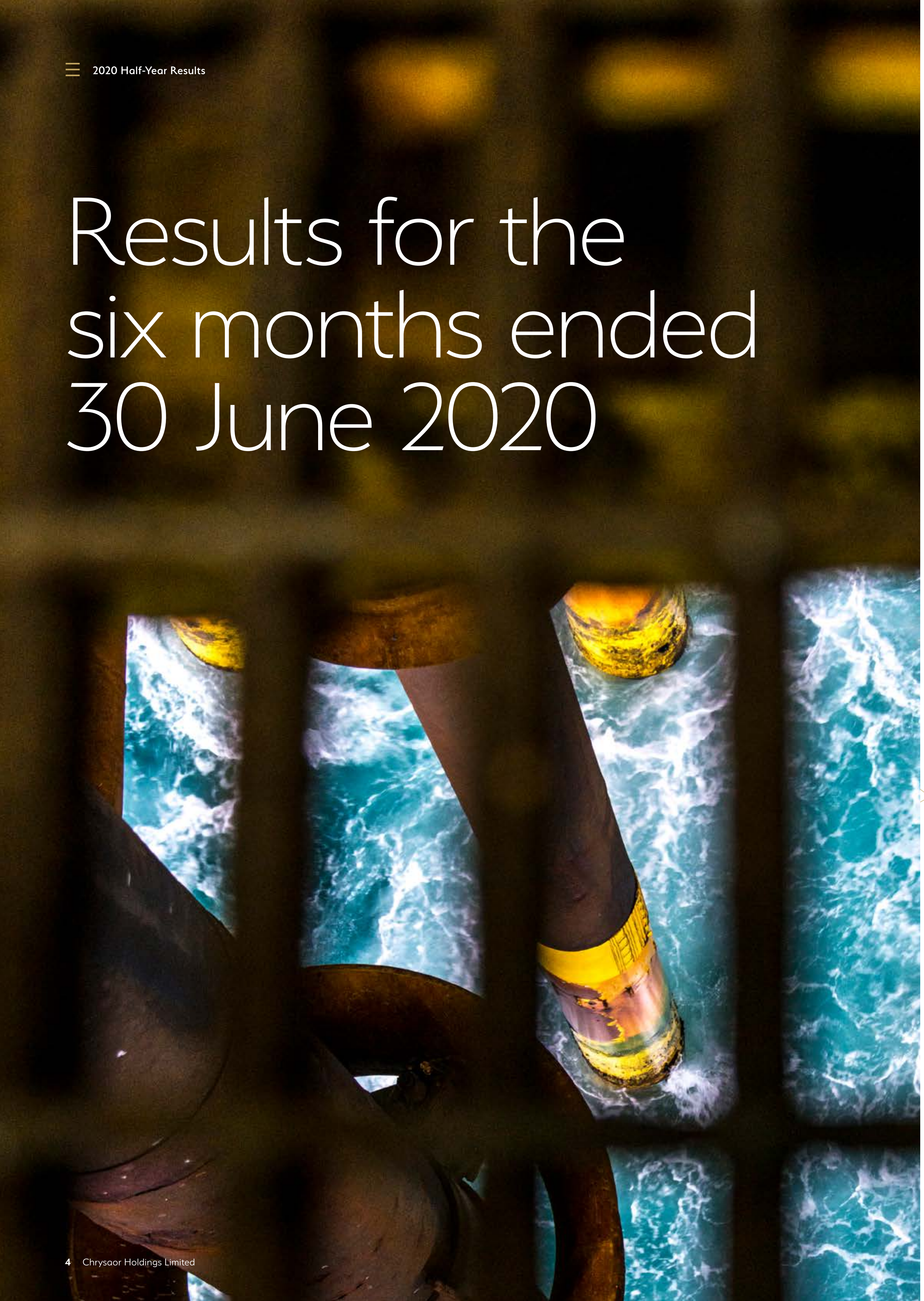
CHRYSAOR

Chrysaor Half-Year Results

30 JUNE 2020

Contents



Results for the six months ended 30 June 2020

CEO foreword

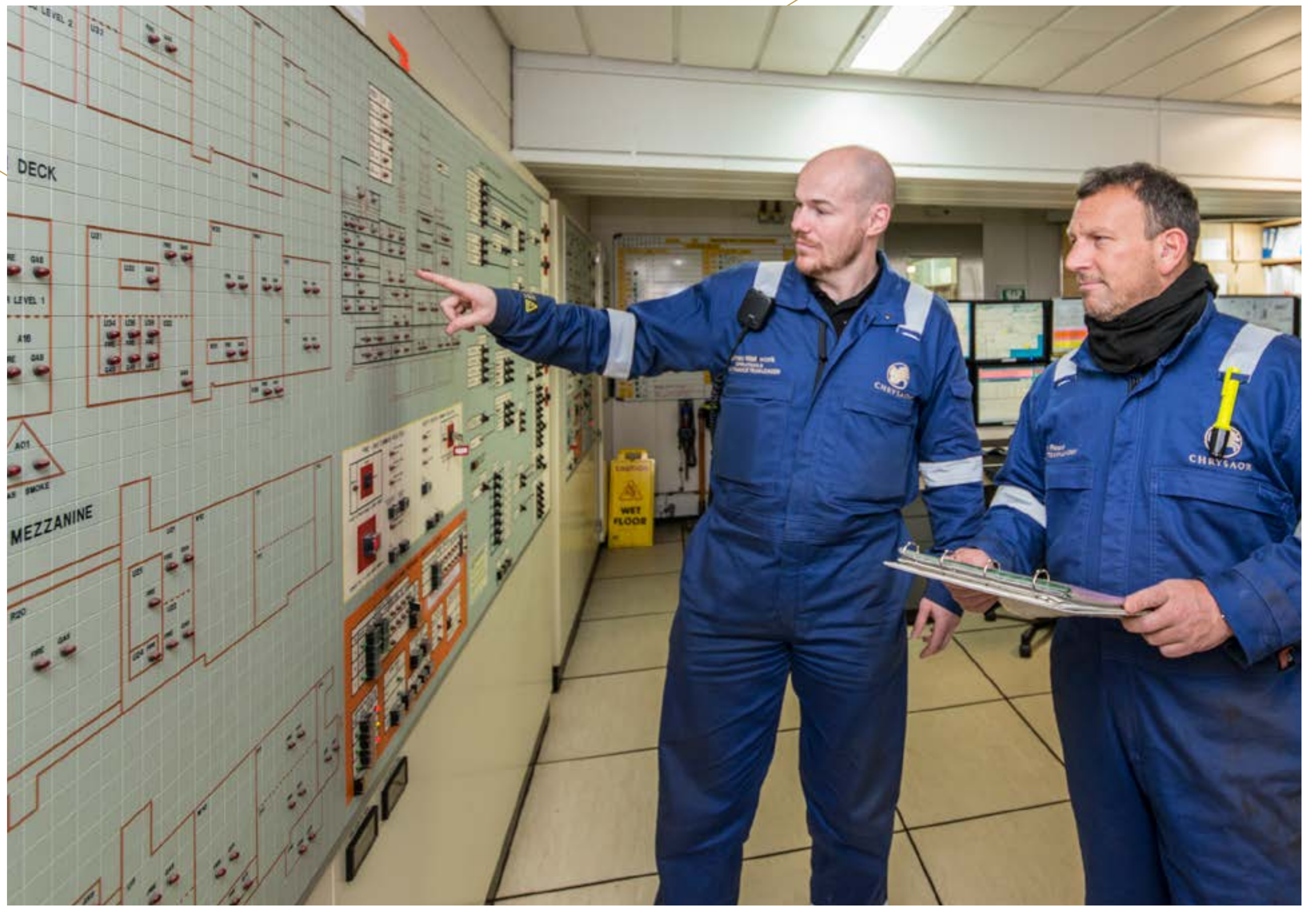
We took early and decisive steps in response to the Covid-19 pandemic and its impact on commodity prices. Our priority has been the safety of our people, and we took a number of decisions to ensure we could continue operations safely. Our onshore staff worked from home, offshore teams were minimised and our core crews supported by pre-mobilisation testing and travel assistance initiatives. We cut back on all non-essential work and also suspended our operated drilling activities for nearly six months.

As a result of these actions, Chrysaor's operational and financial performance in the first half of 2020 was strong, with production averaging 187 mboepd and revenues supported by a significant hedging programme. Costs for the year are also expected to be lower, with the pause in non-essential activity and drilling reducing our forecast capital, decommissioning and operating expenditure for 2020 by around $550 million, with operating costs of $10.20 per barrel.

The integration of the acquired ConocoPhillips UK business is progressing to plan and within budget, with the additional production and cash generation allowing loan repayments and a $0.4 billion reduction in net debt since the 2019-year end. As Chrysaor continues to grow, having a credible plan to reduce our carbon emissions and support UK and Scottish Government initiatives to reach net-zero by 2050 is essential. We have identified a number of near-term material carbon-reduction initiatives for Scope 1 and 2 emissions and, longer term, are investing in early-stage carbon capture and storage (CCS) together with hydrogen production – two potentially critical new businesses for the UK that could help this industry and others take a major step forward in decarbonising their activities.

After the period ended, on the 6 October 2020, we announced that agreement had been reached with Premier Oil and Harbour Energy for the reverse takeover of Premier Oil by Chrysaor. Completion is expected 1Q 2021 and then this transaction would mark the beginning of an exciting new chapter for the company, adding scale in the UK and, for the first time, international production and operations beyond the North Sea. When complete the combined Group will be the largest independent oil and gas company listed on the London Stock Exchange.

Phil Kirk
Chief Executive Officer



2020 half-year highlights*

- On track to achieve a strong operational and safety performance for the year, despite Covid-19 challenges.
- Strong production levels, at 187 mboepd (1H 2019: 123 mboepd). Full-year forecast remains in the 170-180 mboepd range.
- Revenue increased to $1,244 million (1H 2019: $1,055 million) on higher production and realised hedging gains of $474 million.
- A strong hedging book with a positive fair value of $0.9 billion (1H 2019: $0.1 billion).
- EBITDAX of $920 million (1H 2019: $824 million).
- Post-tax impairment on property, plant and equipment of $150 million (1H 2019: $nil) mainly from older AELE hub gas assets, and goodwill impairment of $56 million.
- Capital expenditure of $317 million (1H 2019: $246 million) across all assets, including exploration.
- Continued to implement good cost-control measures, with operating costs of $10.2 per barrel.
- Operating free-cash inflow $592 million (1H 2019: $546 million).
- Net debt reduced to $1.5 billion (Dec 2019: $1.9 billion), with debt repayments of $634 million during the period.
- Completed a significant hedging programme within senior debt requirements for the 2020-2025 period.
- Eight licences, applied for in the 2019 Norwegian Awards in Predefined Areas (APA) Round, were awarded in January 2020.
- Energy transition projects carried out in 1H 2020 will remove between 43-53,000 tonnes of CO_2 a year.

*Comparative figures relate to the same six-month period for 2019 (unless otherwise stated), which excludes the ConocoPhillips UK-acquired business.

Financial overview

	1H 2020	1H 2019
Production (mboepd)	187	123
Revenue and other operating income ($m)	1,243.6	1,055.1
Realised oil price ($/bbl) [2]	63.9	69.1
Realised gas price (p/therm)	30.6	39.1
Operating cost per barrel ($/boe) [3]	10.2	11.5
EBITDAX ($m) [4]	919.8	823.8
(Loss)/profit before tax ($m)	(224.2)	323.7
(Loss)/profit after tax ($m)	(154.5)	174.4
Capital investment ($m)	316.8	246.2
Operating cashflow after capital investment ($m) [5]	591.9	545.8
Net debt ($m)	1,466.3	332.3

(1) Comparative figures relate to the same six-month period for 2019, which excludes the ConocoPhillips UK-acquired business.
(2) Includes realisations from hedging activities
(3) Cost per barrel are direct operating costs including tariff expense less tariff income, excluding movements in over/underlift, divided by working interest production
(4) EBITDAX defined as earnings before tax, interest, depreciation & amortisation, impairments, remeasurements and exploration expenditure
(5) Operating cash flow after capital investment is defined as net cash flows from operating activities less cash outflows on capital investment

First half 2020 overview

After the period ended, on the 6 October 2020, we announced that agreement had been reached with Premier Oil and Harbour Energy for the reverse takeover of Premier Oil by Chrysaor. Completion is expected 1Q 2021 and then this transaction would mark the beginning of an exciting new chapter for the company, adding scale in the UK and, for the first time, international production and operations beyond the North Sea. When complete the combined Group will be the largest independent oil and gas company listed on the London Stock Exchange.

Operational performance

Our production stood at 187 mboepd for the six-month period (1H 2019: 123 mboepd), reflecting additional volumes from the UK business acquired from ConocoPhillips. This was split 87 mboepd from liquids (1H 2019: 72 mboepd) and 100 mboepd from gas (1H 2019: 51 mboepd); operated assets 119 mboepd (1H 2019: 40 mboepd) and non-operated assets 68 mboepd (1H 2019: 83 mboepd). For the remainder of the year, our production will reflect reduced levels of drilling and operational activities, offset by a shortening of planned shutdowns. We continue to expect full-year production to be in the range of 170-180 mboepd. The deferral of the Forties Pipeline System (FPS) triennial shutdown to 2021 will however result in additional platform shutdowns in 2021 to complete maintenance work originally scheduled for 2020.

Before the Covid-19 drilling break, operated well activity was focused on the J-Area and the Armada hub. In September as operations resume, drilling recommences on Callanish and back in the J-Area with the Joanne S16 well.

On non-operated assets, drilling continued in the Beryl Area with the development platform and subsea wells, including Callater. The partnership drilled Solar, the first tertiary exploration well, and this is now under technical review, whilst the next target, Gamma, is currently drilling. On Buzzard, activities progressed with the completion of the DC1 in-fill drilling programme and continued drilling on the DC2 Northern Terraces.

Our decommissioning team is making good progress on wells and facilities across our southern North Sea assets, with all activity going to plan. At the end of June 2020, we had completed plugging and making safe a total of 108 out of the 145-well programme (74%). During the Summer, we also safely completed our heavy lift programme and have now removed 19 out of 38 platforms.

Covid-19

Covid-19 had a significant impact on the Chrysaor Group in the first half of 2020, but our early actions to address and mitigate its effect meant the Group continued to perform well during the period.

In response to the Covid-19 outbreak, we mobilised our Crisis Management and Business Continuity Teams to oversee business operations. These remain in place throughout the early easing of the lockdown period. We also set up a Recovery Team, whose priorities are the safety and wellbeing of our workforce and ensuring adherence with both Governments' legislation and guidance. We continue to prioritise and manage the recovery phase to ensure all our facilities are ready to support our increase in offshore activity.

Our onshore personnel predominantly continued to work from home, with a small volunteer group representing around 20% of the workforce in the offices. We reduced offshore activities to managing base operations and safety-critical maintenance. This, in turn, reduced our platform manpower levels. We implemented a 'barrier' approach, with numerous, systematic measures to prevent the virus reaching our offshore installations and, on the few occasions it did, to remove it swiftly. This included pre-mobilisation screening and testing for our offshore workforce, deploying isolation tracking, adjusting rota patterns and contracting a dedicated medical evacuation helicopter to minimise potential Covid-19 contact time on the platforms. We decided to temporarily suspend operated drilling activities for up to six months across our three active rigs. The rig carrying out decommissioning activities continued to operate throughout the period.

HSEQ

Our Health, Safety, Environment and Quality (HSEQ) performance is central to Chrysaor and how we approach our operations. During the period, we made good progress on our annual group HSEQ plan, CO2 emissions were on target and the number and severity of incidents were reduced. However, we did unfortunately have four process-safety incidents, including one Tier-2 hydrocarbon release.

Responding to this, we spent considerable effort to ensure we learned the lessons from the incidents and also held 'time out for safety' sessions focused on encouraging the use of safety intervention tools and re-focusing the organisation. After this, we have seen a marked decrease in recordable injuries, regulatory-reportable and process-safety incidents. We also carried out various audit and regulatory inspection programmes in the period, all with generally favourable results.

Our operated total recordable case frequency (TRCF) for the period was at 1.2 per million man-hours. Whilst this is an improvement on 2019, it is still too high. The non-operated TRCF is 3.4 and we are actively working with operators to influence their HSEQ performance.

Our Covid-19 activity pause has directly increased our maintenance hours backlog. This has also been exacerbated by the deferral of the Forties Pipeline System (FPS) shutdown to 2021. Some elements of our shutdowns have therefore also been rescheduled to 2021. This has then affected our maintenance targets, but our robust risk assessment processes and forward plans mean we are comfortable with the deferred work.

Energy transition

As part of a comprehensive energy-transition and carbon-emissions-reduction strategy, we have established future milestones and identified targeted categories of initiatives. We are near to selecting a concept for the Acorn carbon capture and storage project, and the basis-of-design is underway for the hydrogen project.

During the period, we carried out several initiatives to reduce CO2 emissions. The most significant were operational changes in the Greater Britannia Area to run one of two export compressors and changing the coolers on the Erskine production module.

These projects together are expected to remove between 43-53,000 tonnes of CO_2 over the full year. Looking ahead, projects deferred from 2020 by Covid-19 will be carried out in 2021 and pump and compressor re-wheeling initiatives are underway. To complement our strategy, we have enhanced and externally assured our emissions forecasting methods and improved performance visibility.

We are continuing to review other carbon reduction opportunities, to refine Scope 1 initiatives that we have identified, and to engage in the feasibility of full or partial electrification options.

Recognising the important role we play in energy transition, we have incorporated a Reserve Based Loan facility margin adjustment in our debt facility, linked to reducing carbon emissions. We will continue to work closely with regulatory bodies and other industry participants, particularly as the legislative framework evolves. We have also carried out a Task Force on Climate-related Financial Disclosures (TCFD) gap analysis.

Commodity prices

Commodity prices fell significantly in the first quarter as a result of increased oil supply from OPEC combined with the dramatic fall in global demand caused by Covid-19. In response, we reduced our 2020 capital, decommissioning and operating expenditure by around $550 million versus the approved plans. The majority of this spend has been deferred into 2021 or 2022.

Hedging

Our hedging programme had a positive fair value of $890.4 million at period end (1H 2019: $100.0 million). Under this programme we have approximately two-thirds of 2020 production volumes hedged above $60/bbl for oil and 45p/therm for gas, with further volumes hedged out to 2025. We have met all our hedging commitments under the Reserves Based Lending (RBL) debt facility.

Integration

The integration of the acquired ConocoPhillips business is progressing well, and we expect to complete it in 4Q 2021. We have finalised the new organisational structure and implementation is underway, with completion expected at the end of September 2020. The consolidation of information systems and business processes into a single business-management system continue to progress as planned but will continue into 2021.

Exploration

In early September, we were offered 14 licences by the Oil and Gas Authority (OGA) in the 32nd UK Licensing Round. These cover 25 blocks or parts thereof, with nine as operator and five as non-operator. This will secure quality acreage around our existing infrastructure, enabling our teams to fully evaluate the remaining potential in the area and assess the impact of any future exploration opportunities.

In Norway, we were awarded eight licences in the 2019 Awards in Predefined Areas (APA) Round. Three licences are operated and five are non-operated, covering 15 blocks. Our average working interest is over 40 percent, with gross un-risked recoverable resources of over one billion barrels of oil equivalent.

Financial performance

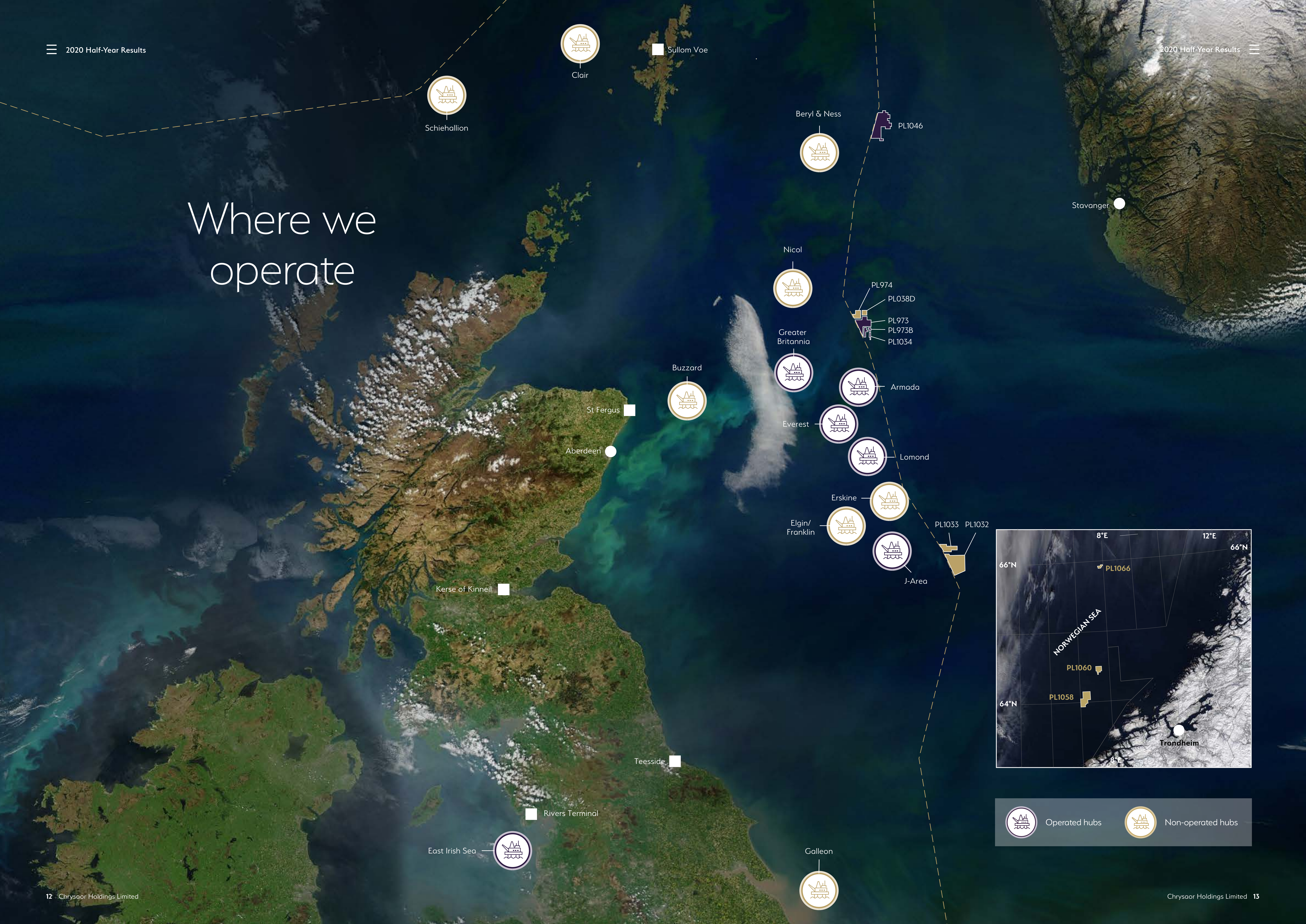
Our good production levels, rigorous cost control and contribution from the acquired business resulted in operating costs per barrel for the period improving to $10.2/boe (1H 2019: $11.5/boe), below the benchmark of $15/boe. For the first half of 2020, EBITDAX was $919.8 million (1H 2019: $823.8 million), driven by higher production, offset by lower crude prices.

In addition to this, our effective hedging programme supported operating cash flow after capital expenditure, of $592 million (1H 2019: $546 million). This allowed us to make voluntary repayments totalling $634 million under the senior RBL debt facility, with net debt (excluding letters of credit) at the end of the period $1.5 billion (Dec 2019: $1.9 billion and 1H 2019 $0.3 billion).

We completed an amendment of the RBL facility at the start of June, increasing debt availability and revising governance requirements in line with peers. As part of these amended terms, Chrysaor is the first independent European exploration and production company to incorporate an RBL facility margin adjustment linked to reducing its carbon emissions.

Operations review

Where we operate



2020 Half-Year Results

UK operated production assets

Our UK assets comprise five operated complexes in the central North Sea, which we run as three business units or hubs: The Armada, Everest, Lomond and Erskine fields comprise one hub, and the J-Area and Greater Britannia Area the other two.

We have carried out significant development activities to maximise sustainable production across these hubs.

We temporarily suspended operated drilling for up to six months from March but continued to decommission wells. We expect to resume operated drilling in September 2020.

Armada, Everest, Lomond and Erskine (AELE) Hub

Production for the AELE hub was 34.0 mboepd during the period (1Q 2020 34.7 mboepd, 1H 2019 39.7 mboepd).

Despite good production from Everest and Lomond, Armada volumes were below expectation due to delays bringing on the Hawkins and Seymour Horst wells.

We have reduced the scope of the mid-year shutdowns for all fields and deferred them to either later in the summer of 2020, or for completion in extended shutdowns in 2Q 2021.

Development

On Armada, we commissioned the Hawkins well and completed and flow-tested Seymour Horst. Both wells are now shut-in for topside construction works, which is nearing completion. Both wells are expected to be brought online after the annual shutdown.

On Armada, we are also reviewing the North West Seymour area with the possibility of drilling further wells. There are also development tie-in opportunities from the Norwegian Jerv and potentially Ilder exploration wells due to be drilled in 2021. Further development drilling opportunities are being matured.

Both Everest and Lomond have late-life compression projects to increase recoverable reserves and extend field life. These have progressed well, with both projects due for completion on or before 2022. They will also deliver a reduction in CO_2 emissions.

J-Area

J-Area produced net 33.4 mboepd in the period (1Q 2020: 34.0 mboepd, 1H 2019: 15.2 mboepd).

The platform's recurring produced-water quality issues were brought under control during the period, but power generation challenges and a glycol system defect, affected production.

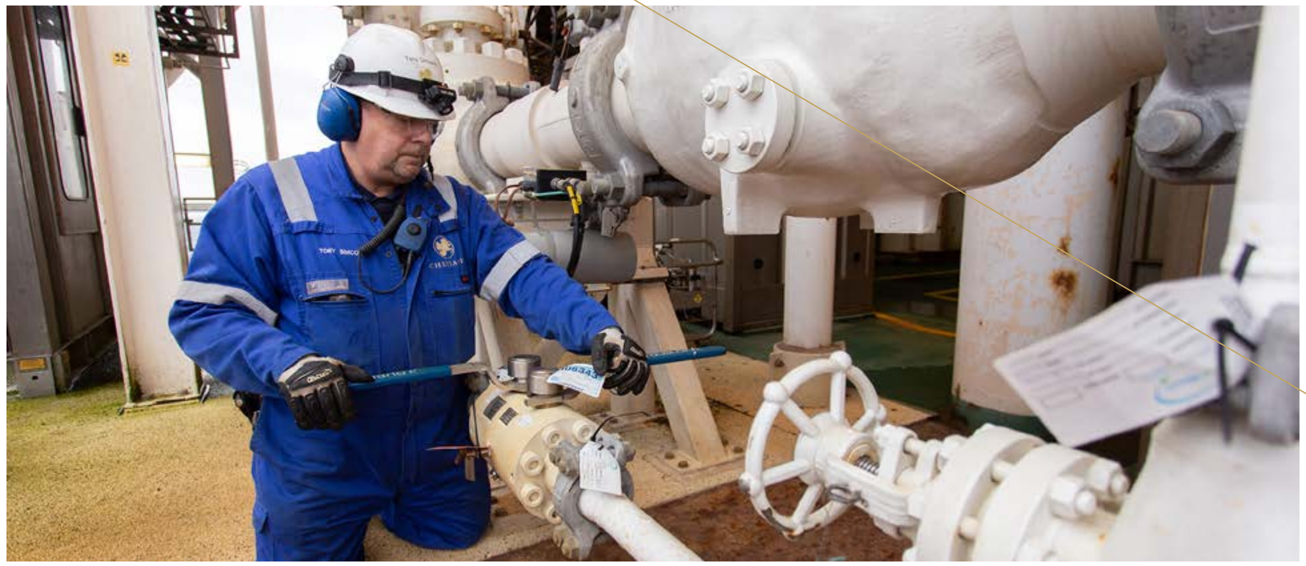
We continued the drilling programme until the Jasmine S14 well was completed and brought onstream. In the first quarter we also completed a further re-perforation on the well-intervention programme and the Judy accommodation-upgrade project. The Summer shutdown for essential testing and maintenance was safely achieved across the J-Area fields.

Development

The 2020 well-intervention campaign continued in Q1 2020, with acid washing and re-perforation techniques to maintain and enhance production rates. We suspended the J-Area drilling programme in March but re-started in September. Further activity is planned on Jasmine, Judy and Jade in the second half of the year. These include drilling of the S16 well, followed by the West Limb.

Work is continuing in preparation for our drilling activity in 2021, 2022 and beyond, with development wells planned from Judy and Jade, and exploration and appraisal wells on the Dunnottar, Talbot and Jade South opportunities.

Compressor re-wheel options are being considered for Judy, which would reduce emissions from around 2025.



Greater Britannia Area (GBA)

The Greater Britannia Area produced 42.9 mboepd in the period (1Q 2020: 39.2 mboepd).

Production at GBA was high, despite planned losses from the H4 well flow trial and the well-intervention campaign. We have deferred the 40-day Britannia shutdown scheduled for June and July, to 2021, aligning with the deferral of the Forties Pipeline System (FPS) shutdown. A short, re-planned, annual outage was safely executed in 3Q 2020.

Development

We plan to start drilling on the Callanish F5 well in September, with first production expected in Q1 2021.

We will carry out the long-term compression re-wheel project in 3Q 2021, following completion of the FPS outage in May 2021. This is expected to reduce CO2 emissions by 10-15,000 tonnes per year. Other re-wheel options are being reviewed for the export train and medium pressure compressors.

The Finlaggan tie-in prospect is progressing safely offshore as per plan with work ongoing on the subsea campaign.

East Irish Sea (EIS)

The EIS area produced 8.5 mboepd in the period (1Q 2020: 8.4 mboepd).

Production in 1H 2020 was below expectations. Operating performance was affected by control-system issues at Calder, the Rivers Terminal and unplanned compressor maintenance onshore at the North Morecambe Terminal. Performance for the Millom field was stable. Plans for 2H 2020 include a two-week shutdown, with the focus being to increase reliability levels.

Development and appraisal

Planning continues for the 2021 Calder and Millom field-barge campaigns, and potential future helideck upgrades. Work is progressing to evaluate and progress the development of several Chrysaor-owned satellite fields within an Area Plan.

UK operated exploration

Despite the suspension of drilling caused by Covid-19, work continued on our exploration programme.

In September, we were offered a total of 14 licences in the 32nd UK Licensing Round, covering 25 blocks or part-blocks thereof. Of these, nine licences are operated and five are non-operated. We were successful in being offered 25 of the 27 blocks we applied for. Overall, Chrysaor won the highest number of operated awards in this round, and the highest number of licences in total. Formal acceptance of these awards and ratification by the Oil and Gas Authority (OGA) is expected by early 1Q 2021.

We have continued preparing several wells to ensure they are ready for drilling when operational conditions allow. Our large portfolio allows us to prioritise capital allocation and the timing of what we drill, effectively.

Our other 30th Round Licences across the central North Sea, near to existing production facilities, have been moving forward, with encouraging signs. We received new seismic data in mid-July, and we will now start loading the fast-track volume. Thereafter, we will proceed with interpretation work.

We continued with seismic interpretation work on our 30th and 31st Round Licence Awards. On Licence P2330 (Mid North Sea High), we received the first fast-track volume of the 2019 3D Multi-Client Survey, and we have started work to build the new interpretation and velocity models.

UK non-operated production assets

We are continuing to use our non-operated relationships to influence and promote improved performance, and to add value to our portfolio.

Beryl

The Beryl Area produced 17.8 mboepd in the period (1Q 2020: 18.8 mboepd, 1H 2019: 15.9 mboepd).

Production continued to be strong in 1H 2020, despite various production curtailments due to adverse weather causing tanker offload delays and plant-trip challenges.

Development and exploration

The partnership continued platform drilling and brought producer well BEB online in 2Q 2020, with rates above expectations. The Bravo injector well (BTI) re-entry was completed and this is due to come online in Q3 2020. A second Storr target opportunity is also being reviewed. Strong performance continued with Buckland BK7. The Callater well CC3 was completed, and it is due to come online imminently.

Three well interventions are planned for 2H 2020. One has been deferred to 1H 2021. In a back-to-back platform drilling sequence, two additional targets will be completed, plus one rig-based workover in 2H 2020.

The partnership completed the Solar exploration well, and its data is now under evaluation. Following this, a three-leg exploration and appraisal target will be drilled in 2H 2020 to access the Gammas and Losgann tertiary prospects.

Chrysaor joined Apache on the UK 32nd Licensing Round, and in September we were awarded additional acreage in Quadrant 9 around the Greater Beryl Area.

Buzzard

Buzzard produced 19.6 mboepd in the period (1Q 2020: 21.8 mboepd, 1H 2019: 26.4 mboepd).

Buzzard reached the production milestone of 750 million barrels. Field production has been good, albeit performance has been hampered with various outages, including power-management issues.

Development

We concluded the Buzzard infill platform drilling campaign in 2Q 2020.

The Buzzard Phase 2 (BP2) campaign schedule was affected by the postponement of the Cruden Bay FPS shutdown from summer 2020 to 2021. We deferred the BP2 shutdown and will accelerate the significant 2022 asset turnaround into a combined schedule in 2021. This will defer key elements of the project from 2020 to 2021, with first oil moving from March to December 2021.

Clair

The Clair field produced 5.3 mboepd in the period (1Q 2020: 5.2 mboepd).

Production on Clair Phase-1 was good, though affected by failure of the downhole safety valves on two wells.

Clair Ridge production was also good, though affected by water production. We brought production well B06 on stream in 1Q 2020. We completed a second water-injector well B07, and the platform drilling team is currently working on the next production well, B08. The LoSal water injection system reliability has been strong, and plans are in place for further system testing in 3Q 2020.

Development

On Ridge, we will continue to drill the production and water-injection well sequence throughout the remainder of 2020. We will also begin upgrades to the main oil-line pumps in 4Q 2020 on Phase 1, to increase offtake capacity.

Elgin/Franklin

Elgin/Franklin had strong uptime and well performance and produced 19.7 mboepd in the period (1Q 2020: 20.3 mboepd, 1H 2019: 17.4 mboepd).

We had scheduled a significant fabric maintenance campaign and shutdown scopes for 2020 but have now deferred much of this into 2021. We are planning only safety-critical and regulatory compliance work scopes for this year.

Development

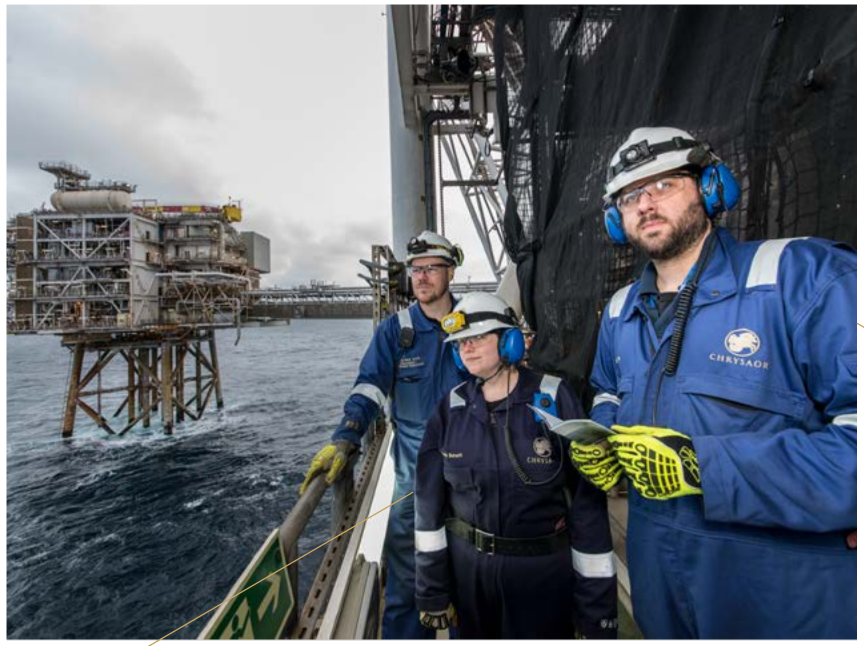
The Elgin/Franklin infill drilling campaign completed a Franklin well earlier than anticipated in December 2019 and started the next sanctioned Franklin well. We expect this to complete in 4Q 2020. The next Elgin infill well is likely to start drilling in early 2021.

Schiehallion

The Schiehallion field produced net 5.6 mboepd in the period (1Q 2020: 5.3 mboepd, 1H 2019: 8.2 mboepd).

Development

Work covered installation of trees and the tie-in of four previously completed wells. We brought the wells online in May 2020, and activity moved to drilling a water injection well, which was completed and brought online in August 2020.



UK decommissioning

Operated

In the Caister Murdoch System (CMS) area, we decommissioned eight wells on the Murdoch complex during the period and moved the facility into cold suspension. We also removed the Caister platform.

We will abandon the nine remaining wells through to 2022 and continue platform removals through to 2024.

In the LOGGS area, we removed the Ganymede platform. Decommissioning work will continue to remove the platforms and 26 wells through to 2023.

At Viking, we removed two platforms and will remove the remaining three platforms over the summer. The final two subsea wells will be plugged and abandoned in 2021-22.

We began demolition on the Theddlethorpe gas terminal site in 1Q 2020. This will take approximately 18 months to complete. Land remediation and restoration is planned to follow into 2023.

MacCulloch area operations were suspended. Well-decommissioning activities should restart in late 2020 or early 2021 depending on rig scheduling. We will remove the remaining subsea infrastructure between 2022 and 2024.

Non-operated

The Hewett field decommissioning works were suspended. The restart of decommissioning operations is planned for 3Q 2020 and is expected to continue through to 2025.

The Thistle field well-abandonment activities were suspended while the operator seeks approval for cessation of production. Well-abandonment and topside-decommissioning activities are expected to restart in 2021 and continue through to 2026.

The Miller field planned decommissioning works include the removal of the subsea infrastructure and pipework remediation. This is expected in 2022-2025.

Norway

In January 2020, Chrysaor was awarded eight further production licences on the Norwegian Continental Shelf by the Ministry of Petroleum & Energy (MPE) in relation to the Awards in Pre-Defined Areas (APA) 2019 Offshore Licensing Round. We now hold working interests in 11 licences over 18 blocks with an average working interest of 42%, comprising un-risked recoverable resources of more than 1.4 billion boe.

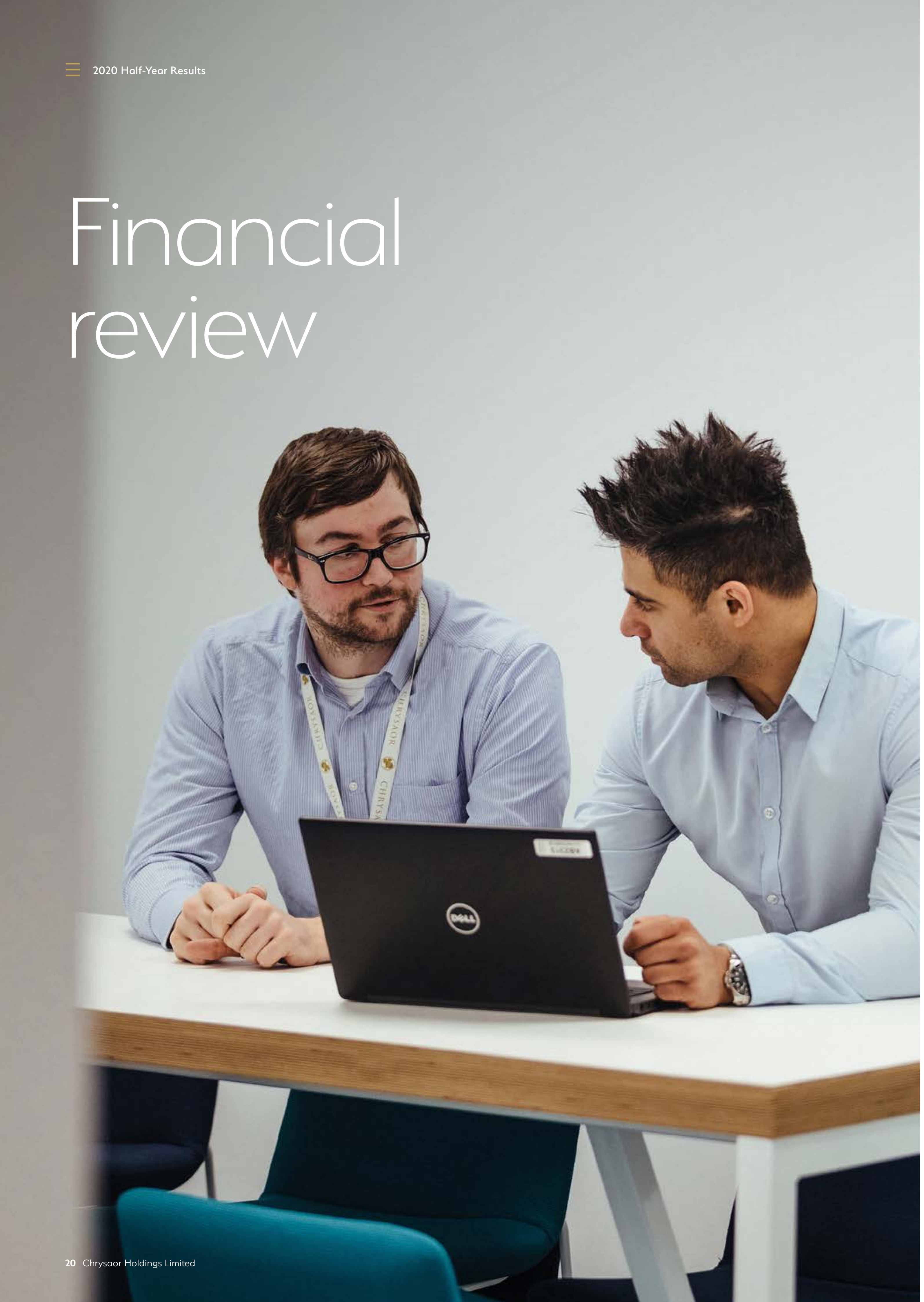
These new awards, of which three are operated by Chrysaor, are across a variety of work programmes, including one 'firm well' and additional 'drill-or-drop' commitments. The operators of the other five licences are Equinor, AkerBP, Lundin or OMV.

In response to the Covid-19 outbreak, the PL 973 licence partners postponed the start of the planned drilling campaign, including up to three wells, from 4Q 2020 to 1Q 2021. The COSL Innovator, pictured above, will be used for the Chrysaor-operated drilling campaign.

In June, the Norwegian Parliament made a temporary change to the fiscal regime on the Norwegian Continental Shelf, to mitigate the combined effect on the offshore industry of Covid-19 and low commodity prices. This allows companies to offset 100% of all investments against the special tax base of 56% in the year of investment and utilise the uplift of 24% against the special tax base. These measures apply to all investments made in 2020 and 2021 as well as investments where a plan for development and operation (PDO) and a plan for installation and operation (PIO) is sanctioned and submitted by the end of 2022. These must be approved by Parliament by the end of 2023 and until first production (as defined in the PDO).

For the rest of 2020, we plan to secure value-creating activity in the licences awarded in the APA 2019 Offshore Licensing Round, participate in the APA 2020 Offshore Licensing Round and further grow the licence portfolio through a combination of organic and acquisition-based growth.

Financial review



Background

The macroeconomic environment for the oil and gas industry deteriorated significantly in the six-month period to 30 June 2020. This was caused by persistent global oversupply and reducing demand due to the worldwide economic impact of Covid-19. These, in turn, led to a sharp decline in commodity prices. Despite an agreement in April between OPEC and material non-OPEC producers to remove almost 10 million barrels of oil equivalent per day from production in May and June (the equivalent of around 10 percent of the world's oil supply), oil prices have only partially recovered, and are subject to continued oversupply concerns.

Brent crude at the end of 2019 was approximately $67 per barrel and closed lower at around $41 per barrel at 30 June 2020. For the half-year period, Brent crude averaged $40 per barrel, compared to $65.95 per barrel for the same period in 2019. NBP gas prices were 30 p/therm at the end of 2019, and closed at 15 p/therm at June 2020, averaging 19 p/therm for the period. This compared to 40 p/therm for the half-year period to 30 June 2019.

Despite this, the Group is in a very healthy financial position. We have strong cash balances and access to undrawn liquidity provided by our senior debt facility. We expect that, even in the current depressed commodity price environment, we will continue to generate positive free cash flow after interest and tax in 2020. This is due to the strength of our hedge book, combined with a significant cost-reduction programme across both capital investment and operating expenses.

The 2019 comparative figures reflect the corresponding half-year period to 30 June 2019. For clarity, they include no contribution from the acquired ConocoPhillips UK business, which completed on 30 September 2019.

Production and revenue

Our production for the first half of 2020 averaged 187 mboepd (2019: 123 mboepd). This year-on-year increase came wholly from our operated assets, with increased equity in the J-Area, equity in the Greater Britannia Area, and excellent production levels. Everest also had excellent production, and Elgin/Franklin produced high volumes due to their strong uptime levels and well performance.

Some of our hydrocarbon production is sold pursuant to fixed-price contracts, as described below under 'derivative financial instruments'. The rest is sold at market values, subject to standard quality and basis adjustments.

Total revenue, before lease-accounting recoveries from partners, earned from production amounted to $1,230.0 million (1H 2019: $1,055.1 million) after realised hedging gains of $474.1 million (1H 2019: $37.6 million hedging losses). Crude oil sales amounted to $722.6 million (1H 2019: $703.4 million), with a post-hedge realised price of $63.9/boe (1H 2019: $69.1/boe), and gas revenue of $413.4 million (1H 2019: $268.2 million), with a post-hedge realised price of 30.6p/therm (1H 2019: 39.1p/therm). Condensate sales and tariff and other revenue amounted to $70.4 million (1H 2019: $74.2 million) and $23.6 million (1H 2019: $9.2 million) respectively.

Cost of sales

Cost of sales (see note 5), which includes field-operating costs, transportation tariffs and depreciation, depletion and amortisation (DD&A) amounted to $1,018.0 million (1H 2019: $568.3 million). Field-operating costs, including production costs, insurance and transportation costs, totalled $370.1 million (1H 2019: $263.2 million). Group depreciation, depletion and amortisation (DD&A) charges on oil and gas assets (including capacity rights), amounted to $697.4 million (1H 2019: $352.3 million), and $13.4 million (1H 2019: nil) on right-of-use leased assets.

Cost of sales also includes a $62.9 million credit (1H 2019: $47.2 million credit) in respect of movements in overlift/underlift and movement in hydrocarbon inventories.

	30 June 2020 $million	30 June 2019 $million
Operating costs		
Field operating costs less tariff income	347.5	256.4
Field operating costs per barrel (US$ per barrel)	$10.2	$11.5
DD&A (before impairment charges)		
Depreciation of oil and gas properties	709.9	351.2
Amortisation of intangible assets	0.9	1.1
Total	710.8	352.3
DD&A (before impairment charges) per barrel	$20.8	$15.8

The decrease in operating costs per barrel is largely due to increased production volumes, disciplined cost control and higher tariff income in the Beryl hub, from the new third-party Garten field.

Impairment

Following an impairment review of the Group's assets, we have recognised a pre-tax impairment charge, mainly on the Group's older oil and gas assets, of $250.6 million ($150.4 million post-tax) (1H 2019: nil) as a result of changing our long-term commodity price assumptions to crude oil $60 per barrel and gas 45p per therm. The pre-tax impairment charge on these oil and gas assets is net of an impairment credit of $89.8 million (post-tax $53.9 million) (1H 2019: nil) in respect of reductions to decommissioning estimates on the Group's non-producing assets. In addition, a goodwill impairment charge of $55.7 million has been recorded in the period (1H 2019: $nil), also attributable to changes in the Group's assessment of long-term commodity prices.

Provision for onerous service contracts

The Group has recorded a $27.9 million onerous-contract provision for long-term standby costs on the *Deepsea Aberdeen* rig, which has been operating within the Schiehallion field, whereby no future approved activities have resulted in the rig potentially remaining on standby until the end of the contract in April 2022. We, and the operator, are continuing initiatives to pursue sublet opportunities.

EBITDAX

For the first half of 2020, EBITDAX was $919.8 million (1H 2019: $823.8 million), driven by higher production, offset by lower crude prices.

General and administration costs

General and administration expenses for the period amounted to $29.2 million (1H 2019: $22.3 million). This increase is primarily due to increased business development activity and the materially larger organisation size.

Exploration and evaluation expenditure

During the period, the Group expensed $43.0 million (1H 2019: $8.2 million) of exploration and appraisal activities, comprising $38.8 million (1H 2019: $0.1 million) of licence relinquishments and uncommercial evaluations and $4.2 million (1H 2019: $8.1 million) of pre-licence expenditure. This was mainly related to business development mergers and acquisition (M&A) spend, Norwegian regional seismic and time-writing costs.

Net financing costs

Financing expenses totalled $148.8 million (1H 2019: $121.4 million), including debt facilities and shareholder loan-note interest expenses of $72.4 million (1H 2019: $78.8 million). Also, facility fees of $22.4 million (1H 2019: $20.7 million) and the unwinding of discount on provisions, primarily associated with future decommissioning obligations, of $48.6 million (1H 2019: $20.6 million).

Of the interest expense, $13.4 million (1H 2019: $45.1 million) relates specifically to shareholder loan notes, which have been accumulated within borrowings for future settlement in accordance with the terms of the loan-note agreements. The comparative reduction in loan-notes interest is mainly due to the conversion of E loan notes into equity in August 2019.

The financing costs also include a lease interest charge of $3.9 million (1H 2019: $0.6 million) associated with lease creditors recognised under IFRS 16 Leases, and other interest of $1.5 million (1H 2019: $0.3 million).

Finance income of $105.1 million (1H 2019: $10.2 million) includes bank and other interest of $3.5 million (1H 2019: $10.2 million) and foreign exchange gains of $101.6 million (1H 2019: $0.4 million loss). These primarily arise on intercompany balances between entities with different functional currencies.

Taxation

The credit from taxation amounted to $69.7 million (1H 2019: $149.3 million charge), split between a current tax expense of $211.0 million (1H 2019: $6.7 million credit), and a deferred tax credit of $280.7 million (1H 2019: $156.0 million expense). The total tax credit for the six-month period represents an effective tax rate of 31 percent (2019: 46 percent). The lower effective tax rate is predominantly driven by the impacts of profits subject to tax at different rates, mainly related to the non-taxable expense of the goodwill impairment, the impact of investment allowance and because of movements in unrecognised deferred tax.

Earnings

The loss after tax was $154.5 million (1H 2019: $174.4 million profit), primarily due to the impairments on oil and gas assets and goodwill, and exploration write-offs

Capital Investment

	30 June 2020 $ million	30 June 2019 $ million
Additions to oil and gas assets	(236.5)	(197.4)
Additions to fixtures and fittings, office equipment & IT software	(35.5)	(5.5)
Additions to exploration and evaluation assets	(44.8)	(43.3)
Total capital investment	(316.8)	(246.2)
Movement in working capital	(45.6)	17.8
Capitalised lease payments	8.2	-
Cash capital expenditure per the cash flow statement	(354.2)	(228.4)

Capital investment is defined as additions to property, plant and equipment, fixtures and fittings and intangible exploration and evaluation assets, less decommissioning asset additions.
It is a useful indicator of the Group's organic expenditure on oil and gas assets, and exploration and appraisal assets, incurred during a period.

During the period, the Group incurred capital expenditure of $316.8 million (2019: $246.2 million). This mainly consisted of spending on operated assets including: frac operations and subsequent clean up on the Seymour Horst well in the Armada hub, drilling of the Joanne SO Chalk well in the J-Area prior to suspension caused by Covid-19, project FEED and long leads on the Talbot project, and expenditure on the Callanish F5 well. The major non-operated capital expenditure relates to Beryl platform drilling, completion of the Callater CC3 and Storr development wells, drilling the Solar (spudded in 2019) and Gamma Tertiary exploration wells in the Beryl Area, and continuation of the Buzzard Phase 2 drilling and infill drilling campaigns. The Beryl Tertiary exploration wells are subject to a 'carry' arrangement under which Chrysaor funds Apache's share of up to $33 million spend (gross) over two wells. The 'carry' was fully paid in early August 2020.

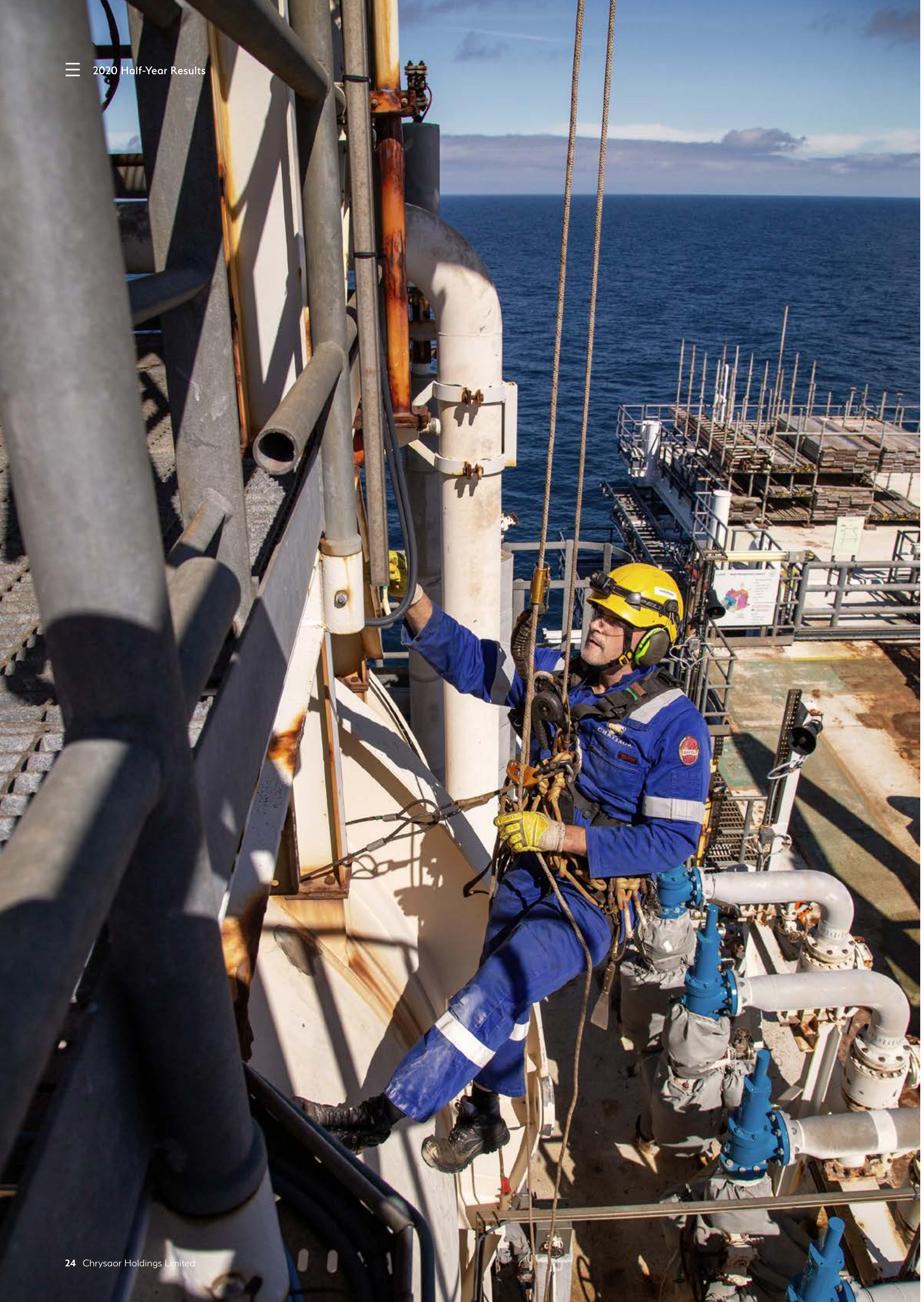
Cash flow

Net cash from operating activities amounted to $946.1 million (1H 2019: $774.2 million) after working capital movements. This operating cash flow was used in investing activities on capital expenditure of $354.2 million (1H 2019: $228.4 million) and expenditure on business combinations and acquisitions of $12.5 million for a contingent consideration payment made to Shell. This was dependent upon commodity price performance throughout 2019 (1H 2019: $302.6 million, including $35.1 million for a contingent consideration payment to Shell and $267.5 million representing a deposit for the acquisition of the ConocoPhillips UK business). Interest received in the period amounted to $3.5 million (1H 2019: $4.7 million).

Operating free cash flow of $591.9 million (1H 2019: $545.8 million) indicates the Group's ability to generate organic cash flow to fund operational and capital investment activities, and subsequently fund and repay debt, as well as grow our business through acquisition.

Financing activities cash flow includes the repayment of $634.0 million of our senior debt under the RBL facility (1H 2019: $200.0 million), interest paid of $75.3 million (1H 2019: $44.8 million) including $59.8 million on the senior and junior debt facilities (1H 2019: $33.4 million) and $14.8 million on charges and fees (1H 2019: $11.4 million). Also, arrangement and underwriting fees of $0.7 million (1H 2019: $44.9 million) for amendments made to the RBL facility in conjunction with the normal redetermination process. During the period, a partial redemption of both the C Loan Notes and D Loan Notes took place, of $4.9 million and $42.0 million respectively.

Cash balances decreased by $203.8 million (1H 2019: $26.9 million decrease) to $369.4 million (2019: $289.4 million) at the end of the period.



Derivative financial instruments

We carry out hedging activity to manage commodity price risk, to ensure we comply with the requirements of the RBL facility. Also, to ensure there is enough funding for future investments.

We have entered into a series of fixed-price sales agreements and a financial hedging programme for both oil and gas, consisting of swap and option instruments. Our future production volumes are hedged under the physical and financial arrangements in place at 30 June. These are set out in the following table. Hedges realised to date are in respect of crude oil only.

Hedge position	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Oil						
Volume hedged (mmboe)	12.74	12.34	1.1	-	-	-
Average price hedged ($/bbl)	62.10	62.52	60.07	-	-	-
Gas						
Volume hedged (mmboe)	6.78	11.84	17.22	9.05	4.05	1.03
Average priced hedged (p/therm)	46.2	48.8	46.0	45.1	44.2	44.4

At 30 June 2020, our financial hedging programme on commodity derivative instruments showed a positive fair value of $890.4 million (2019: $100.0 million), with no ineffectiveness charge to the income statement.

Capital structure

Analysis of net borrowings	**30 Jun 2020 $million**	**31 Dec 2019 $million**
Cash and cash equivalents	(369)	(573)
Senior debt under the RBL facility	1,440	2,067
Junior debt	396	396
Net Debt	1,467	1,890
Shareholder loan notes	283	317
Exploration financing facility	11	9
Financing arrangement with BHGE	35	34
Total net borrowings	1,796	2,250

Net debt reduced from $1,889.8 million to $1,466.3 million during the period, with repayments on the RBL facility of $634 million offset by a reduction in cash balances of $203.8 million. Total net borrowings (note 14) mainly consisted of senior debt and junior debt less cash balances and amounted to $1,795.8 million (2019: $2,249.5 million).

Insurance

We have significant and appropriate insurance in place to minimise risk to our operational and investment programmes. This includes business interruption insurance.

Going concern

The Directors have adopted a going-concern basis of accounting for the preparation of the financial statements. Management reviews cash flow forecasts and sensitivities on a regular basis. Sensitivities are typically run for changes in commodity prices and asset performance. These models and sensitivities provide assurance that we will be able to meet our cash flow and funding requirements, as well as adhere to financial and liquidity covenants.

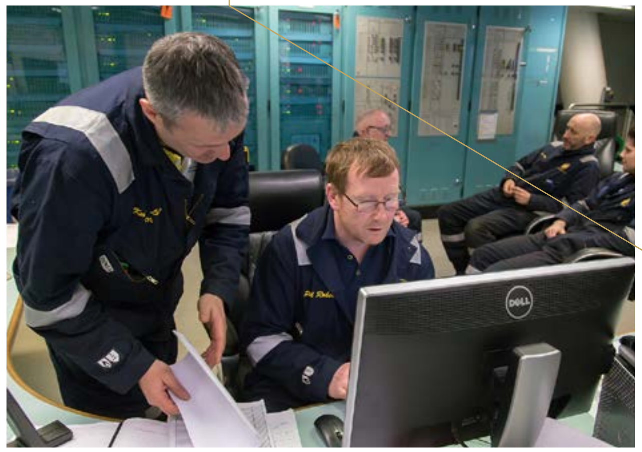
Our management forecasts show that, for the next 12 months and the foreseeable future, the Group will be able to operate and generate sufficient operating cash flow to sustain investment in discretionary capital projects, as well as repay debt as it falls due.

Post Balance Sheet Events

On the 6 October 2020, we announced that agreement had been reached with Premier Oil plc and Harbour Energy regarding a proposed reverse takeover all share merger between Premier and Chrysaor and the reorganisation of Premier's existing debt and cross-currency swaps. Completion of the transaction is subject to regulatory approvals, approval by Premier's shareholders, the existing creditors and expected in 1Q 2021.

The transaction will create the largest independent oil and gas company listed on the London Stock Exchange with combined production of over 250 mboepd as at 30 June 2020 and 2P reserves of 717 mmboe as at 31 December 2019. The combined Group will be of significant scale and diversification with a strong balance sheet and significant international growth opportunities.

In September 2020, the Group put in place a new Long-Term Incentive Plan ('LTIP') scheme for senior employees. The LTIP is a cash settled scheme based on a number of notional shares multiplied by a notional share price. The scheme has a maximum number of notional shares that can vest. Performance conditions determine the final number of vesting notional shares and there are three performance measures covering absolute and relative total shareholder return and return on capital employed. The vesting period is three years from the scheme grant date with cash settlement to the employees twelve months after the vesting period provided the individual remains in employment.



Principal risks

Our business could be affected by a variety of risks, leading to failure to achieve our strategic targets for growth, as well as loss of financial standing, cash flow, earnings and reputation. Not all of these are wholly within our control, and we may be affected by risks yet to materialise or that are reasonably foreseeable. To achieve our strategic objectives, including protecting our people, assets and reputation, we need an effective risk-management process in place. We therefore apply a comprehensive and integrated approach to risk management. A critical part of this is to assess the impact and likelihood of risks occurring, so we can develop, implement and monitor plans regularly. We continually assess all types of risk using a single risk matrix across the business, where we measure and rank identified risks as listed below. Being able to understand the issues facing Chrysaor is a critical component in running our business safely and reliably.

For all the known risks facing the Group, we try to minimise the likelihood of them occurring, and mitigate their impact. Our Board has adopted a rigorous environment for risk management and control, which includes identifying, assessing and monitoring. This means our management gains a clear and prioritised picture of the risks we are exposed to, and that we must address, balancing stakeholder risk and return.

Our senior management oversee accountability for the principal risks while we delegate the lower-level risks to operational and functional leadership. Their activities are subject to regular audit and assurance through the process for risk and opportunity management.

We have identified our principal risks. For further information on how we mitigate these, please see Section 11, Principal Risks, in our 2019 Annual Report and Accounts.

Responsibility statement

The Directors confirm that, to the best of their knowledge, the condensed set of financial statements has been prepared in accordance with IAS 34 'Interim Financial Reporting'.

Consolidated
Income statement

For the six months ended 30 June	Note	2020 Audited $000	2019 Unaudited $000
Revenue	4	1,230,054	1,055,064
Other income	4	13,570	-
		1,243,624	1,055,064
Cost of sales	5	(1,018,015)	(568,336)
Gross Profit		225,609	486,728
Impairment of property, plant and equipment	12	(250,629)	-
Impairment of goodwill	10	(55,735)	-
Provision for onerous service contracts	21	(27,943)	-
Exploration and evaluation expenses	5	(4,190)	(8,077)
Exploration costs written-off	5	(38,851)	(132)
Loss on disposal of exploration and evaluation asset	26	(55)	-
Re-measurements	5	473	(21,336)
General and administrative expenses		(29,201)	(22,255)
Operating (loss)/profit	5	(180,522)	434,928
Finance income	7	105,068	10,190
Finance expenses	7	(148,768)	(121,413)
(Loss)/profit before taxation		(224,222)	323,705
Income tax credit/(expense)	9	69,771	(149,327)
(Loss)/profit for the half-year		(154,451)	174,378

Consolidated
Statement of comprehensive income

For the six months ended 30 June	2020 Audited $000	2019 Unaudited $000
(Loss) / profit for the half year	(154,451)	174,378
Items that may be classified to income statement in subsequent periods:		
Fair value gains/(losses) on cash flow hedges	520,306	(283,255)
Tax (expense)/credit on cash flow hedges	(210,167)	113,302
Currency exchange differences	(135,216)	(911)
Total other comprehensive income/(expense) for the half-year, net of tax	174,923	(170,864)
Total comprehensive profit for the half-year	20,472	3,514
Total comprehensive profit attributable to:		
Equity holders of the parent	20,472	3,514

2020 Half-Year Results

Consolidated
Balance sheet

Assets	Note	30 Jun 2020 Audited $000	31 Dec 2019 Audited $000
Non-current assets			
Goodwill	10	1,343,616	1,404,334
Other intangible assets	11	492,119	430,528
Property, plant and equipment	12	6,519,213	7,679,606
Right of use assets	13	144,016	221,223
Other receivables	17	2,871	2,604
Other financial assets	23	313,531	202,230
Total non-current assets		8,815,366	9,940,525
Current assets			
Inventories	16	153,044	146,881
Trade and other receivables	17	269,432	474,118
Other financial assets	23	614,390	193,888
Cash and cash equivalents	18	369,391	573,182
Total current assets		1,406,257	1,388,069
Total assets		10,221,623	11,328,594
Equity and liabilities			
Equity			
Share capital	25	71	71
Share premium		910,020	910,020
Cash flow hedge reserve		494,048	176,123
Costs of hedging reserve		8,503	16,289
Currency translation reserve		(58,611)	76,605
Retained earnings		575,393	729,844
Total equity		1,929,424	1,908,952
Non-current liabilities			
Borrowings	22	2,170,189	2,205,322
Provisions	21	3,368,416	3,766,739
Deferred tax	9	1,564,731	1,649,290
Trade and other payables	20	46,420	52,375
Lease creditor	13	96,384	145,403
Other financial liabilities	23	14,547	3,663
Total non-current liabilities		7,260,687	7,822,792
Current liabilities			
Trade and other payables	20	556,103	676,436
Lease creditor	13	53,782	79,525
Current tax liabilities		202,926	-
Borrowings	22	11,886	617,363
Provisions	21	206,704	183,081
Other financial liabilities	23	111	40,445
Total current liabilities		1,031,512	1,596,850
Total liabilities		8,292,199	9,419,642
Total equity and liabilities		10,221,623	11,328,594

The notes on pages 32 to 77 form part of these financial statements.

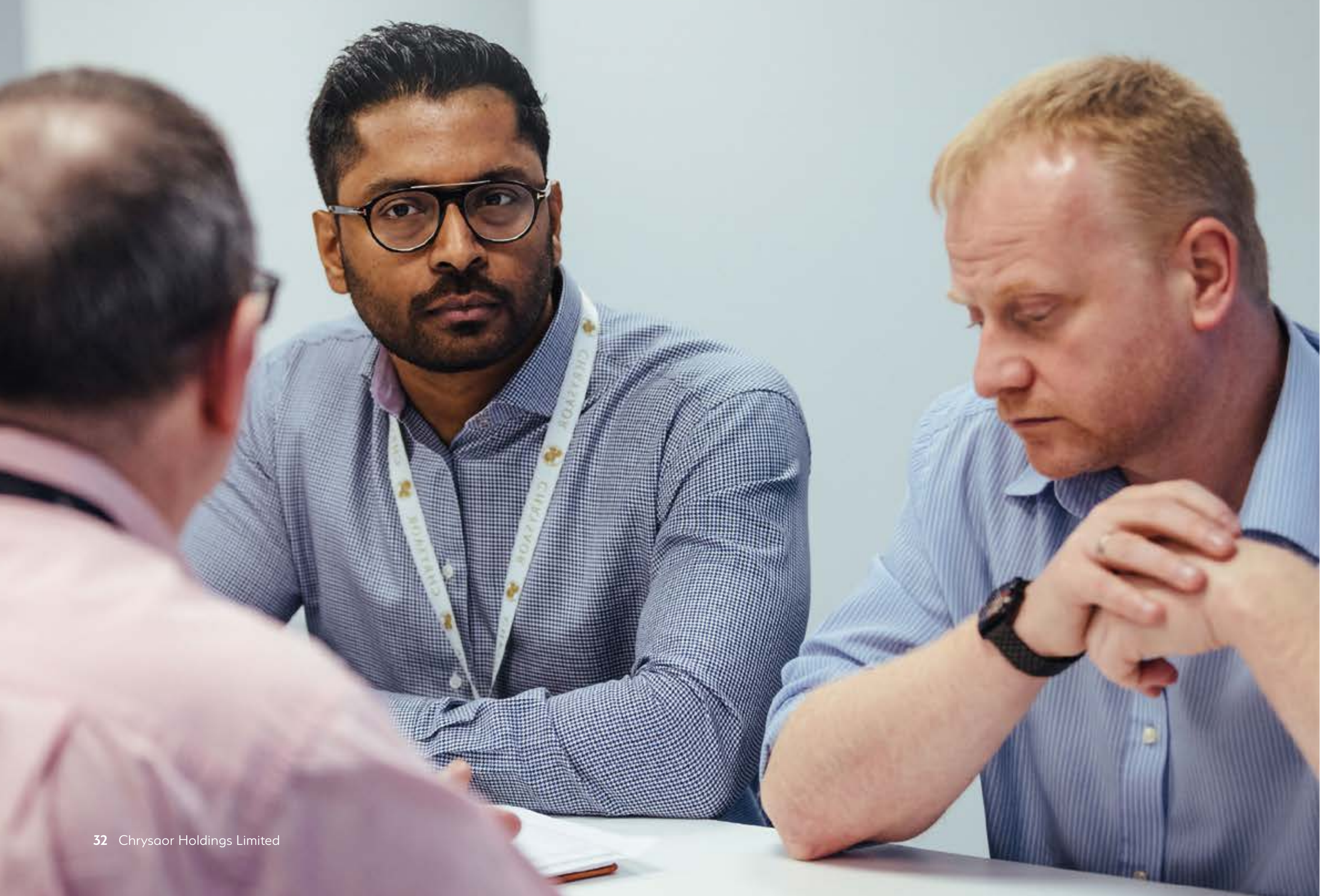
Consolidated
Statement of changes in equity

	Share capital $000	Share premium $000	Cash flow hedge reserve $000	Costs of hedging reserve $000	Currency translation reserve $000	Retained earnings $000	Total equity $000
As at 1 January 2019 (audited)	22	234,801	219,678	4,831	(23,182)	500,092	936,242
Profit for the half year	-	-	-	-	-	174,378	174,378
Total comprehensive loss	-	-	(169,445)	(508)	(911)	-	(170,864)
At 30 June 2019 (unaudited)	22	234,801	50,233	4,323	(24,093)	674,470	939,756
Profit for the half year	-	-	-	-	-	44,469	44,469
Issue of new shares	49	675,219	-	-	-	-	675,268
Share-based payments	-	-	-	-	-	10,905	10,905
Total comprehensive income	-	-	125,890	11,966	100,698	-	238,554
As at I January 2020 (audited)	71	910,020	176,123	16,289	76,605	729,844	1,908,952
Loss for the half-year	-	-	-	-	-	(154,451)	(154,451)
Total comprehensive profit/(loss)	-	-	317,925	(7,786)	(135,216)	-	174,923
At 30 June 2020 (audited)	71	910,020	494,048	8,503	(58,611)	575,393	1,929,424

Consolidated
Statement of cash flows

For the 6 months ended 30 June	Note	2020 Audited $000	2019 Unaudited $000
Net cash flows from operating activities	26	946,096	774,222
Cash flows from investing activities			
Expenditure on exploration and evaluation assets		(46,519)	(43,266)
Expenditure on property, plant and equipment		(274,820)	(180,722)
Expenditure on non-oil and gas intangible assets		(32,882)	(4,394)
Proceeds from sale of exploration and evaluation asset		20	-
Expenditure on business combinations and acquisitions		(12,495)	(302,579)
Interest received		3,460	4,662
Net cash flows from investing activities		(363,236)	(526,299)
Cash flows from financing activities			
Proceeds from new financing arrangements		-	15,000
Proceeds from new borrowings		2,596	-
Lease payments		(32,649)	(471)
Repayment of borrowings		(634,000)	(200,000)
Redemption of loan notes		(46,860)	-
Interest paid and bank charges		(75,332)	(89,709)
Net cash flows from financing activities		(786,245)	(275,180)
Net decrease in cash and cash equivalents		(203,385)	(27,257)
Effect of exchange rates on cash and cash equivalents		(406)	359
		(203,791)	(26,898)
Cash and cash equivalents at 1 January		573,182	316,311
Cash and cash equivalents as at 30 June		369,391	289,413

Notes to the half-year condensed financial statements



1. General information

The consolidated financial statements of Chrysaor Holdings Limited for the six month period ended 30 June 2020 which comprise the parent company, Chrysaor Holdings Limited and all its subsidiaries, were approved for issue by the Board of Directors on 16 December 2020. Chrysaor Holdings Limited is a private company limited by share capital incorporated in the Cayman Islands and domiciled in the United Kingdom. The Company's registered office is Ugland House, South Church Crescent, George Town, Grand Cayman.

The Group's principal activities are the acquisition, exploration, development and production of oil and gas reserves on the UK and Norwegian Continental Shelves.

2. Accounting policies

Basis of preparation

The consolidated financial statements of the Group have been prepared on a going concern basis in accordance with International Financial Reporting Standards (IFRSs) as issued by the International Accounting Standards Board (IASB) and as adopted by the European Union. The Group financial statements are presented in US Dollars (USD) and all values are rounded to the nearest thousand dollars ($'000) except when otherwise stated.

The Financial Statements have been prepared on the historical cost basis, except for certain financial assets and liabilities (including derivative financial instruments) which have been measured at fair value and assets classified as held for sale which are carried at fair value less cost to sell.

The accounting policies which follow set out those policies which apply in preparing the financial statements for the six-month period ended 30 June 2020. All accounting policies have been applied consistently other than where new policies have been adopted.

Basis of Consolidation

The Group financial statements consolidate the financial statements of the Company and its subsidiary undertakings drawn up to 30 June 2020. Subsidiaries are those entities over which the Group has control. Control is achieved where the Company has the power over the subsidiary, is exposed, or has rights to variable returns from the subsidiary and has the ability to use its power to affect its returns. All subsidiaries are 100 percent owned by the Company and therefore the Group does not have any non-controlling interests.

All intercompany balances have been eliminated on consolidation.

Segment Reporting

The Group's activities consist of one class of business - the acquisition, exploration, development and production of oil and gas reserves and related activities in two geographical area presently being the UK North Sea and the Norwegian North Sea.

Pensions

Contributions made to defined contribution pension schemes are recognised in the income statement in the period in which they become payable.

Joint Arrangements

Exploration and production operations are usually conducted through joint arrangements with other parties. The Group reviews all joint arrangements and classifies them as either joint operations or joint ventures depending on the rights and obligations of each party to the arrangement and whether the arrangement is structured through a separate vehicle. All interests in joint arrangements held by the Group are classified as joint operations.

In relation to its interests in joint operations, the Group recognises its:

- Assets, including its share of any assets held jointly
- Liabilities, including its share of any liabilities incurred jointly
- Revenue from the sale of its share of the output arising from the joint operation
- Share of the revenue from the sale of the output by the joint operation, and
- Expenses, including its share of any expenses incurred jointly

Foreign Currency Translation

Each entity in the Group determines its own functional currency, being the currency of the primary economic environment in which the entity operates, and items included in the financial statements of each entity are measured using that functional currency.

The consolidated financial statements are presented in US Dollars.

Transactions recorded in foreign currencies are initially recorded in the entity's functional currency by applying an average rate of exchange. Monetary assets and liabilities denominated in foreign currencies are retranslated at the functional currency rate of exchange ruling at the reporting date. All differences are taken to the income statement, except when hedge accounting is applied. Non-monetary assets and liabilities denominated in foreign currencies are measured at historic cost based on exchange rates at the date of the transaction and subsequently not retranslated.

On consolidation, the assets and liabilities of the Group's operations are translated at exchange rates prevailing on the balance sheet date. Income and expense items are translated at the average monthly exchange rates for the period. Equity is held at historic costs and are not retranslated. The resulting exchange differences are recognised as other comprehensive income or expense and are transferred to the Group's translation reserve.

2020 Half-Year Results

Business Combinations

Business combinations are accounted for using the acquisition method. The cost of an acquisition is measured as the fair value of the assets transferred, equity instruments issued and liabilities incurred or assumed at the date of completion of the acquisition. Acquisition costs incurred are expensed and included in administrative expenses. Where applicable, the consideration for the acquisition includes any asset or liability resulting from a contingent consideration arrangement, measured at its fair value at acquisition.

The identifiable assets, liabilities and contingent liabilities acquired that meet the conditions for recognition under IFRS 3 are recognised at their fair value at the acquisition date, except that:

- Deferred tax assets or liabilities and liabilities or assets related to employee benefit arrangements are recognised and measured in accordance with IAS 12 Income Taxes and IAS 19 Employee Benefits respectively.
- Liabilities or equity instruments related to the replacement by the Group of an acquirer's share-based payment awards are measured in accordance with IFRS 2 Share-based Payment, and
- Assets (or disposal groups) that are classified as held for sale in accordance with IFRS 5 Non-current Assets Held for Sale and discontinued operations are measured in accordance with that Standard.

If the initial accounting for a business combination is incomplete by the end of the reporting period in which the combination occurs, the Group reports provisional amounts for the items for which the accounting is incomplete. Those provisional amounts are adjusted during the measurement period, or additional assets or liabilities are recognised to reflect new information obtained about facts and circumstances that existed as of the acquisition date that, if known, would have affected the amounts recognised as of that date. The measurement period is the period from the date of acquisition to the date the Group obtains complete information about facts and circumstances that existed as of the acquisition date, subject to a maximum of one year.

Goodwill

In the event of a business combination or acquisition of an interest in a joint operation in which the activity constitutes a business, as defined in IFRS 3 Business Combinations, the acquisition method of accounting is applied. Goodwill represents the difference between the aggregate of the fair value of purchase consideration transferred at the acquisition date and the fair value of the identifiable assets, liabilities and contingent liabilities acquired. Goodwill is initially measured at cost. Following initial recognition, goodwill is measured at cost less any accumulated impairment. Goodwill is treated as an asset of the relevant entity to which it relates and accordingly non-US Dollar goodwill is translated into US Dollars at the closing rate of exchange at each reporting date.

Goodwill, as disclosed in note 10, is reviewed for impairment at least annually by assessing the recoverable amount of the cash generating units to which the goodwill relates. Where the carrying amount of the cash generating unit and related goodwill is higher than the recoverable amount of the cash generating unit, an impairment loss is recognised.

Intangible Assets - Exploration and Evaluation Assets

Exploration and evaluation expenditure is accounted for using the successful efforts method of accounting.

(a) Pre-Licence Costs

Pre-licencing costs are expensed in the period in which they are incurred.

(b) Licencing and Property Acquisition Costs

Licence and property acquisition costs paid in connection with a right to explore in an existing exploration area are capitalised as exploration and evaluation costs within intangible assets.

Licence and property acquisition costs are reviewed at each reporting date to confirm that there is no indication that the carrying amount exceeds the recoverable amount. If no future activity is planned or the related licence has been relinquished or has expired, the carrying value of the property acquisition costs is written off through the income statement. Upon recognition of proved reserves and internal approval for development, the relevant expenditure is transferred to oil and gas properties within development and production assets.

(c) Exploration and Evaluation Costs

Once the legal right to explore has been acquired, costs directly associated with the exploration are capitalised as exploration and evaluation intangible non-current assets until the exploration is complete and the results have been evaluated. If no potential commercial resources are discovered, the exploration asset is written off.

All such capitalised costs are subject to technical, commercial and management review, as well as review for indicators of impairment at least annually. This is to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are written off through the income statement.

When proved reserves of oil or natural gas are identified and development is sanctioned by management, the relevant capitalised expenditure is first assessed for impairment and (if required) any impairment loss is recognised, then the remaining balance is transferred to oil and gas properties within development and production assets. No amortisation is charged during the exploration and evaluation phase.

(d) Farm-Outs – In the Exploration and Evaluation Phase

The Group does not record any expenditure made by the farmee on its account. It also does not recognise any gain or loss on its exploration and evaluation farm-out arrangements but re-designates any costs previously capitalised in relation to the whole interest as relating to the partial interest retained. Any cash consideration received directly from the farmee is credited against costs previously capitalised in relation to the whole interest with any excess accounted for by the farmor as a gain on disposal.

Property, Plant and Equipment – Oil and Gas Development and Production Assets

Expenditure on the construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of development wells including unsuccessful development or delineation wells, is capitalised as oil and gas properties within development and production assets.

The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of the decommissioning obligation and, for qualifying assets (where relevant), borrowing costs. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. Until the adoption of IFRS 16 Leases, the capitalised value of a finance lease was included within property, plant and equipment within the Group's financial statements.

All costs relating to a development are accumulated and not depreciated until the commencement of production. Depreciation is provided using the unit of production method based on proven and probable reserves. When there is a change in the estimated total recoverable proven and probable reserves of a field, that change is accounted for prospectively in the depreciation charge over the revised remaining proven and probable reserves.

An item of development and production expenditure and any significant part initially recognised is derecognised upon disposal or when no future economic benefits are expected from its use or disposal. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the asset) is included in the income statement.

Expenditure on major maintenance refits, inspections or repairs comprises the cost of replacement assets or parts of assets, inspection costs and overhaul costs. Where an asset, or part of an asset that was separately depreciated and is now written off is replaced and it is probable that future economic benefits associated with the item will flow to the Group, the expenditure is capitalised. All other day-to-day repairs and maintenance costs are expensed as incurred.

Fixtures and Fittings and Office Equipment

Fixtures and fittings and office equipment (non-oil and gas property, plant and equipment) is stated at cost less accumulated depreciation and impairment. Depreciation is provided for on a straight-line basis at rates sufficient to write off the cost of the asset less any residual value over their estimated useful economic lives. The depreciation periods for the principal categories of assets are as follows:

Fixtures and fittings – Up to 10 years

Office equipment – Up to 5 years

Intangible assets

Intangible assets, which principally comprise IT software, are carried at cost less any accumulated amortisation. These assets are amortised on a straight-line basis over their useful economic lives of up to three years.

Impairment of Non-Current Assets (excluding goodwill)

The Group assesses, at each reporting date, whether there is an indication that an asset may be impaired. If any indication exists, the Group estimates the recoverable amount of the associated asset or cash generating unit, being the higher of the fair value less costs of disposal and value-in-use. When the carrying amount of an asset or cash generating unit exceeds its recoverable amount, the difference is recognised in the income statement as an impairment charge.

Financial Instruments

(a) Financial Assets

The Company uses two criteria to determine the classification of financial assets: the Company's business model and contractual cash flow characteristics of the financial assets. Where appropriate the Company identifies three categories of financial assets: amortised cost, fair value through profit or loss (FVTPL), and fair value through other comprehensive income (FVOCI).

Financial Assets held at Amortised Cost

Financial assets held at amortised cost are initially measured at fair value except for trade debtors which are initially measured at cost. Both are subsequently carried at amortised cost using the effective interest rate (EIR) method, less impairment. The EIR amortisation is presented within finance income in the Income statement.

Cash and Cash Equivalents

Cash at bank and in hand in the balance sheet comprise cash deposits with banks and in hand.

Impairment of Financial Assets

The Company recognises an allowance for expected credit losses (ECLs) for all debt instruments not held at fair value through profit or loss. ECLs are based on the difference between the contractual cash flows due in accordance with the contract and all the cash flows that the Company expects to receive, discounted at an approximation of the original effective interest rate.

ECLs are recognised in two stages. For credit exposures for which there has not been a significant increase in credit risk since initial recognition, ECLs are provided for credit losses that result from default events that are possible within the next 12-months (a 12-month ECL). For those credit exposures for which there has been a significant increase in credit risk since initial recognition, a loss allowance is required for credit losses expected over the remaining life of the exposure, irrespective of the timing of the default (a lifetime ECL).

For trade receivables and contract assets, the Group applies a simplified approach in calculating ECLs. Provision rates are calculated based on estimates including the probability of default by assessing counterparty credit ratings, as adjusted for forward-looking factors specific to the debtors and the economic environment and the Group's historical credit loss experience.

Credit Impaired Financial Assets

At each reporting date, the Group assesses whether financial assets carried at amortised cost and debt financial assets carried at FVOCI are credit impaired. A financial asset is 'credit-impaired' when one or more events that have a detrimental impact on the estimated future cash flows of the financial asset have occurred. Evidence that a financial asset is credit-impaired includes the following observable data:

- Significant financial difficulty of the borrower or issuer
- A breach of contract such as default or past due event
- The restructuring of a loan or advance by the Group on terms that the Group would otherwise not consider
- It is becoming probable that the borrower will enter bankruptcy or other financial reorganisation, or
- The disappearance of an active market for a security because of financial difficulties

(b) Financial Liabilities

Financial liabilities are classified, at initial recognition, as financial liabilities at fair value through profit or loss, loans and borrowings, payables, or as derivatives designated as hedging instruments in an effective hedge, as appropriate. All financial liabilities are recognised initially at fair value and, in the case of loans and borrowings and payables, net of directly attributable transaction costs.

Borrowings and Loans

Interest-bearing bank loans and overdrafts are recorded at the proceeds received, net of direct issue costs. Finance charges, including premiums payable on settlement or redemption and direct issue costs, are accounted for on an accrual basis in the income statement using the effective interest method and are added to the carrying amount of the instrument to the extent that they are not settled in the year in which they arise.

Derecognition

A financial liability is derecognised when the obligation under the liability is discharged or cancelled or expires. When an existing financial liability is replaced by another from the same lender on substantially different terms, or the terms of an existing liability are substantially modified, such an exchange or modification is treated as the derecognition of the original liability and the recognition of a new liability. The difference in the respective carrying amounts is recognised in the income statement.

(c) Derivative Financial Instruments

Derivative financial instruments are initially recognised and subsequently re-measured at fair value. Certain derivative financial instruments are designated as cash flow hedges in line with the Company's risk management policies. When derivatives do not qualify for hedge accounting or are not designated as accounting hedges, changes in the fair value of the instrument are recognised within the income statement.

Cash Flow Hedges

The effective portion of gains and losses arising from the remeasurement of derivative financial instruments designated as cash flow hedges are deferred within other comprehensive income and subsequently transferred to the income statement in the period the hedged transaction is recognised in the income statement. When a hedging instrument is sold or expires, any cumulative gain or loss previously recognised in other comprehensive income remains deferred until the hedged item affects profit or loss or is no longer expected to occur. Any gain or loss relating to the ineffective portion of a cash flow hedge is immediately recognised in the income statement. Hedge ineffectiveness could arise if volumes of the hedging instruments are greater than the hedged item of production, or where the credit worthiness of the counterparty is significant and may dominate the transaction and lead to losses.

(d) Fair Values

The fair value of financial instruments that are traded in active markets at the reporting date is determined by reference to quoted market prices or dealer price quotations, without any deduction for transaction costs.

For financial instruments not traded in an active market, the fair value is determined using appropriate valuation techniques.

Equity

Share Capital

Share capital includes the total net proceeds, both nominal and share premium, on the issue of ordinary and preference shares of the Company.

Cash Flow Hedge Reserves

The cash flow hedge and cost of hedging reserves represents gains and losses on derivatives classified as effective cash flow hedges.

Currency Translation Reserve

This reserve comprises exchange differences arising on consolidation of the Group's operations with a functional currency other than the USD.

Share Based Payments

The Group has applied the requirements of IFRS 2 Share-based Payments. The Group has share-based awards that are equity and cash settled as defined by IFRS 2. The fair value of the equity settled awards has been determined at the date of grant of the award allowing for the effect of any market-based conditions. For cash-settled awards, a liability is recognised for the goods or service acquired. This is measured initially at the fair value of the liability. The fair value of the liability is subsequently remeasured at each balance sheet date until the liability is settled, and at the date of settlement, with any changes in fair value recognised in the income statement.

Inventories

Hydrocarbon inventories are stated at net realisable value with movements recognised in the income statement. All other inventories are stated at the lower of cost and net realisable value. The cost of materials is the purchase cost, determined on a first-in, first-out basis.

Provisions for Liabilities

A provision is recognised when the Group has a legal or constructive obligation as a result of a past event; it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation.

The expense relating to any provision is presented in the income statement net of any reimbursement. If the effect of the time value of money is material, provisions are discounted using a current pre-tax rate that reflects, where appropriate, the risk specific to the liability. Where discounting is used, the increase in the provision due to the passage of time is recognised as part of finance costs in the income statement.

The estimated cost of dismantling and restoring the production and related facilities at the end of the economic life of each field is recognised in full at the commencement of oil and gas production. The amount provided is the present value of the estimated future restoration cost. A non-current asset is also recognised. Any changes to estimated costs or discount rates are dealt with prospectively.

Trade Payables

Initial recognition of trade payables is at fair value. Subsequently they are stated at amortised cost.

Taxes

(a) Current Tax

Current tax assets and liabilities for the current and prior periods are measured at the amount expected to be recovered from or paid to the taxation authorities. The tax rates and laws used to compute the amount are those that are enacted or substantively enacted at the reporting date in the countries where the Group operates and generates taxable income.

Current income tax related to items recognised directly in other comprehensive income or equity is recognised in other comprehensive income or directly in equity not in the income statement.

(b) Deferred Tax

Deferred taxation is recognised in respect of all timing differences arising between the tax bases of the assets and liabilities and their carrying amounts in the financial statements with the following exceptions:

- Deferred income tax assets are recognised only to the extent that it is probable that the taxable profit will be available against which the deductible temporary difference, carried forward tax credits or tax losses can be utilised.
- Deferred income tax assets and liabilities are measured on an undiscounted basis at the tax rates that are expected to apply when the related asset is realised or liability is settled, based on tax rates and laws enacted or substantively enacted at the reporting date. The carrying amount of the deferred income tax asset is reviewed at each reporting sheet date.
- Deferred income tax assets and liabilities are offset, only if a legally enforceable right exists to offset current assets against current tax liabilities, the deferred income tax relates to the same tax authority and that same tax authority permits the Group to make a single net payment.

Revenue from Contracts with Customers

Revenue from contracts with customers is recognised when the Company satisfies a performance obligation by transferring a good or service to a customer. A good or service is transferred when the customer obtains control of that good or service. Revenue associated with the sale of crude oil, natural gas, and natural gas liquids ("NGLs") is measured based on the consideration specified in contracts with customers with reference to quoted market prices in active markets, adjusted according to specific terms and conditions as applicable according to the sales contracts. The transfer of control of oil, natural gas, natural gas liquids and other items sold by the Company occurs when title passes at the point the customer takes physical delivery. The Company principally satisfies its performance obligations at this point in time.

2020 Half-Year Results

Over/Underlift

Revenues from the production of oil and natural gas properties in which the Group has an interest with partners are recognised based on the Group's working interest in those properties (the entitlement method). Differences between the production sold and the Group's share of production result in an overlift or an underlift. Overlift and underlift are valued at market value and included within payables or receivables respectively. Movements during the accounting period are recognised within cost of sales in the income statement such that gross profit is recognised on an entitlement basis.

Interest Income

Interest income is recognised on an accruals basis, by reference to the principal outstanding and at the effective interest rate method.

Borrowing Costs

Borrowing costs directly attributable to the acquisition, construction or production of an asset that necessarily takes a substantial period of time to get ready for its intended use or sale (a qualifying asset) are capitalised as part of the cost of the respective assets.

New Accounting Standards and Interpretations

The Group adopted new and revised accounting standards and interpretations relevant to its business and effective for accounting periods beginning on or after 1 January 2020, including:

Amendments to IFRS 3: Definition of a Business

In October 2018, the IASB issued amendments to the definition of a business in IFRS 3 Business Combinations to help entities determine whether an acquired set of activities and assets is a business or not. They clarify the minimum requirements for a business, remove the assessment of whether market participants are capable of replacing any missing elements, add guidance to help entities assess whether an acquired process is substantive, narrow the definitions of a business and of outputs, and introduce an optional fair value concentration test. New illustrative examples were provided along with the amendments. This amendment is effective for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after 1 January 2020, and to asset acquisitions that occur on or after the beginning of that period. Application of this amendment will be effective post EU endorsement.

Since the amendments apply prospectively to transactions or other events that occur on or after the date of first application, the Group has not been affected by these amendments on the date of transition.

Amendments to IAS 1 and IAS 8: Definition of Material

In October 2018, the IASB issued amendments to IAS 1 Presentation of Financial Statements and IAS 8 Accounting Policies, Changes in Accounting Estimates and Errors to align the definition of 'material' across the standards and to clarify certain aspects of the definition. The new definition states that, 'Information is material if omitting, misstating or obscuring it could reasonably be expected to influence decisions that the primary users of general purpose financial statements make on the basis of those financial statements, which provide financial information about a specific reporting entity.'

The amendments to the definition of material has not had a significant impact on the Group's consolidated financial statements.

The other pronouncements did not have any impact on the Group's accounting policies and did not require retrospective adjustments.

Accounting Standards Issued but Not Yet Effective

The new and amended standards and interpretations that are issued, but not yet effective, up to the date of issuance of the Group's financial statements are disclosed below. The Group intends to adopt these new and amended standards and interpretations, if applicable, when they become effective.

IFRS 17 Insurance Contracts

IFRS 17 is effective for annual reporting periods beginning on or after 1 January 2023 with earlier application permitted as long as IFRS 9 is also applied. The standard combines current measurement of the future cash flows with the recognition of profit over the period that services are provided under the contract. Insurance service results (including presentation of insurance revenue) are presented separately from insurance finance income or expenses. It also requires an entity to make an accounting policy choice of whether to recognise all insurance finance income or expenses in profit or loss or to recognise some of that income or expenses in other comprehensive income. The Group does not expect any existing contracts to be impacted by the new standard however, this will be assessed closer to adoption of 1 January 2023.

Amendments to IAS 1, 'Presentation of financial statements' – Classification of liabilities as current or non-current

On 23 January 2020, the IASB issued a narrow-scope amendment to IAS 1 to clarify that liabilities are classified as either current or non-current, depending on the rights that exist at the end of the reporting period. Liabilities are classified as non-current if the entity has a substantive right to defer settlement for at least 12 months at the end of the reporting period. The Group will consider if its liabilities are either current or non-current when the standard is effective from 1 January 2022.

IBOR reform and the effects on financial reporting

The International Accounting Standards Board (Board) issued Interest Rate Benchmark Reform—Phase 2, which amends IFRS 9 Financial Instruments, IAS 39 Financial Instruments: Recognition and Measurement, IFRS 7 Financial Instruments: Disclosures, IFRS 4 Insurance Contracts and IFRS 16 Leases. The Board identified two groups of accounting issues that could have financial reporting implications. In 2019, the Board issued its initial amendments in Phase 1 of the project, applicable to 2020 reporting, it covers reporting in the period before the replacement of an existing interest rate benchmark with an alternative RFR (Risk Free Rate). This addressed hedge accounting requirements: the highly probable requirement; prospective assessments; and separately identifiable risk components. The Group has assessed the requirements of Phase 1 which apply for the first time in 2020, none of which impact the financial statements of the Group because there is no material hedge accounting of interest rate exposures. Phase 2 addresses financial reporting when an existing interest rate benchmark is replaced with an alternative RFR, including the effects of changes to contractual cash flows or hedging relationships arising from the replacement of an interest rate benchmark with an alternative benchmark rate (replacement issues). The group has not early adopted Phase 2 requirements.

Critical Accounting Judgements and Estimates

The preparation of the Group's financial statements in conformity with IFRS requires management to make judgements, estimates and assumptions at the date of the financial statements. Estimates and assumptions are continuously evaluated and are based on management experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. Uncertainty about these assumptions and estimates could result in outcomes that require a material adjustment to the carrying amount of the assets or liabilities affected in future periods. In particular, the Group has identified the following areas where significant judgement, estimates and assumptions are required.

Exploration and Evaluation Expenditure

As at 30 June 2020, the Group held a balance of $439.8 million (2019: $425.3 million) relating to expenditure on unproved hydrocarbon resources within other intangible assets which represent active exploration and evaluation activities. The application of the Group's accounting policy for exploration and evaluation expenditure requires judgement to determine whether future economic benefits are likely, from either exploitation or sale, or whether activities have not reached a stage which permits a reasonable assessment of the existence of commercial reserves. The determination of reserves and resources is itself an estimation process that requires varying degrees of uncertainty depending on how the resources are classified. If, after expenditure is capitalised, information becomes available suggesting that the recovery of the expenditure is unlikely, the relevant capitalised amount is written off in the income statement in the period when the new information becomes available.

Goodwill

The Group tests goodwill annually for impairment, or more frequently if there are indications that goodwill might be impaired. Impairment is determined for goodwill by assessing the recoverable amount of each CGU to which the goodwill relates. Where the recoverable amount of the CGU is less than its carrying amount, an impairment loss is recognised in the income statement. Impairment losses relating to goodwill cannot be reversed in future periods.

Key Sources of Estimation Uncertainty

Recoverability of Oil and Gas Assets

The Group assesses each asset or cash generating unit each reporting period to determine whether any indication of impairment exists. Where an indicator of impairment exists, a formal estimate of the recoverable amount is made, which is considered to be the higher of the fair value less costs of disposal and value-in-use. The assessments of fair value less cost of disposal requires the use of estimates and assumptions on uncontrollable parameters such as long-term oil prices (considering current and historical prices, price trends and related factors, foreign exchange rates and discount rates.

The Group's estimate of the recoverable value of its assets is sensitive to commodity prices and discount rates. A change in the long-term price assumptions of 10 percent, and a 2 percent change in the post-tax discount rate are considered to be reasonably possible for the purposes of sensitivity analysis, the result of which can be found in notes 10 and 12.

Decommissioning Costs

Decommissioning costs will be incurred by the Group at the end of the operating life of most of the Group's facilities and properties. The Group assesses its decommissioning provision at each reporting date. The ultimate decommissioning costs are uncertain and cost estimates can vary in response to many factors including the expected timing, extent and amount of expenditure. On the basis that all other assumptions in the calculation remain the same a 10 percent increase in the cost estimates, and a 10 percent decrease in the discount rates used to assess the final decommissioning obligation, would result in increases to the decommissioning provision of approximately $440 million and $62 million respectively. This change would be principally offset by a change to the value of the associated asset.

Climate Change

The Group recognises that there may be potential financial implications in the future from climate change risk. The Group expects that climate change policies, legislation and regulation will increase, and likely on accelerating timelines which, although will result in intended benefits, is likely to increase associated costs and administration requirements as well as potentially limiting the investment capital available to the industry. These in due course may well have an impact across a number of areas of accounting including impairment, fair values, increased costs, onerous contracts, contingent liabilities. However as at the balance sheet date the Group believes there is no material impact on balance sheet carrying values of assets or liabilities. Although this is an estimate, it is not considered a critical estimate, as management's view is that at the end of the current reporting period there is no significant risk of climate change resulting in a material adjustment to the carrying amounts of assets and liabilities, within the next financial year.

3. Segment information

The Group's activities consist of one class of business, being the acquisition, exploration, development and production of oil and gas reserves and related activities and are split geographically and managed in two regions - the UK North Sea and the Norwegian North Sea. The Norwegian business unit currently does not generate revenue or have any material operating income and, as such, all revenues are attributable to the UK.

Income statement	**6 months ended 30 June 2020 $000**	**6 months ended 30 June 2019 $000**
UK	(177,397)	442,992
Norway	(3,125)	(8,064)
Group operating (loss)/profit	(180,522)	434,928
Finance income	105,068	10,190
Finance expenses	(148,768)	(121,413)
(Loss)/profit before income tax	(224,222)	323,705
Income tax credit/(expense)	69,771	(149,327)
(Loss)/profit for the financial period	(154,451)	174,378

Balance sheet	**30 June 2020 $000**	**31 Dec 2019 $000**
Segment assets		
UK	10,178,260	11,296,039
Norway	43,363	32,555
Total assets	10,221,623	11,328,594
Segment liabilities		
UK	(8,262,232)	(9,404,440)
Norway	(29,967)	(15,202)
Total liabilities	(8,292,199)	(9,419,642)

3. Segment information (continued)

Other information	**6 months ended 30 June 2020 $000**	**6 months ended 30 June 2019 $000**
Capital expenditure		
UK	305,600	244,894
Norway	11,200	1,353
Total capital expenditure	316,800	246,247
Depreciation, depletion and amortisation		
UK	723,222	359,102
Norway	246	205
Total depreciation, depletion and amortisation	723,468	359,307
Exploration and evaluation expenses		
UK	1,990	743
Norway	2,200	7,334
Total exploration and evaluation expenses	4,190	8,077

All exploration costs written-off of $38.9 million (2019: $0.1 million) relate to the UK business unit.

4. Revenue

	6 months ended 30 June 2020 $000	6 months ended 30 June 2019 $000
Crude oil sales	722,584	703,412
Gas sales	413,438	268,247
Condensate sales	70,385	74,247
Hydrocarbon revenue	1,206,407	1,045,906
Tariff income	22,685	6,865
Other revenue	962	2,293
Total revenue from production activities	1,230,054	1,055,064
Other income – IFRS16 lease accounting-partner recovery	13,570	-
Total revenue and other income	1,243,624	1,055,064

Revenues of $755.9 million (1H 2019: $1,017.5 million) were from contracts with customers. This was prior to realised hedging gains on crude and gas sales in the period of $474.1 million (1H 2019: $37.6 million). Approximately 96 percent (2019: 96 percent) of the revenues were attributable to energy trading companies of the Shell group.

5. Operating (loss)/profit

	6 months ended 30 June 2020 $000	6 months ended 30 June 2019 $000
Cost of sales		
Production, insurance and transportation costs	370,141	263,231
Depreciation of oil and gas properties	696,504	351,178
Capitalisation of IFRS16 lease depreciation	(15,426)	-
Depreciation of right of use assets	28,776	-
Amortisation of intangible assets	870	1,089
Movement in over/underlift balances and hydrocarbon inventories	(62,850)	(47,162)
Total cost of sales	1,018,015	568,336
Impairment of property, plant and equipment	250,629	-
Impairment of goodwill	55,735	-
Provision for onerous service contract	27,943	-
Exploration costs written-off	38,851	132
Exploration and evaluation expenditure	4,190	8,077
Re-measurement of commodity-based derivative instruments	-	22,460
Re-measurement of exploration contingent consideration	-	276
Re-measurement of acquisition-completion adjustments	391	-
Re-measurement of royalty valuation	(280)	(1,400)
Re-measurement – gain on termination of lease	(584)	-
General and administrative expenses		
Depreciation of right-of-use assets	3,141	1,149
Depreciation of other fixed assets	3,077	2,159
Amortisation of intangible assets	6,526	3,732
Other administrative costs	16,457	15,215
Total general and administrative expenses	29,201	22,255

During 2015, the Group sold its entire interest in a pre-production development. Part of the consideration received was a beneficial interest in a royalty agreement. The remeasurement of this interest of $0.3 million (June 2019: $1.4 million represents the updated valuation of the contingent consideration in respect of the royalty payments due to the Group (note 23).

The contingent consideration was fully settled in March 2020 and as a result there are no movements on the fair value of crude based derivative instruments reported through the income statement since the year ended 31 December.

6. Staff Costs

	6 months ended 30 June 2020 $000	6 months ended 30 June 2019 $000
Wages and salaries	73,182	32,329
Social security costs	11,945	4,923
Pension costs	9,096	3,735
Other staff costs including benefits	10,015	2,664
	104,238	43,651

	6 months ended 30 June 2020 No.	6 months ended 30 June 2019 No.
Offshore based	398	177
Office and administration	646	245
	1,044	422

Staff costs above are recharged to joint venture partners or are capitalised to the extent that they are directly attributable to capital or decommissioning projects.

Employment contracts are held by three subsidiaries of the Group, Chrysaor E&P Services Limited, Chrysaor Norge AS and from 1 October 2019, Chrysaor Production (U.K.) Limited.

All employees were engaged in the acquisition, exploration, development and production of oil and gas reserves.

The Group operates a defined contribution pension plan and the amounts charged to the income statement represent the contributions payable in the period.

7. Finance income and finance expenses

	6 months ended 30 June 2020 $000	6 months ended 30 June 2019 $000
Finance income		
Bank interest	2,390	4,662
Other interest	1,070	5,528
Foreign exchange gains	101,608	-
	105,068	10,190

Finance expenses		
Interest payable on Reserves Based Loan and junior facility	58,995	33,703
Interest payable on loan notes	13,419	45,055
Other interest	1,532	328
Lease interest	3,853	570
Foreign exchange losses	-	424
Bank and financing fees	22,412	20,704
Unwinding of discount on deferred consideration payable	92	-
Unwinding of discount on decommissioning and other provisions	48,465	20,629
	148,768	121,413

Bank and financing fees include an amount of $7.6 million (June 2019: $8.1 million) relating to the amortisation of transaction costs capitalised against the Group's long-term borrowings (note 23).

Net other interest expense of $0.5 million (2019: $5.2 million credit) includes a $1.1 million charge (June 2019: $5.2 million credit) which represents interest under a financing arrangement (note 23).

2020 Half-Year Results

8. Directors' remuneration

	6 months ended 30 June 2020 $000	6 months ended 30 June 2019 $000
Directors' remuneration	1,420	1,233
Payments made in lieu of pension contributions	106	87
Pension costs	7	10
	1,533	1,330

Included above are the emoluments of the two Executive Directors of the Group. The payments made in lieu of pension contributions were made at the same rate as pension contributions made to employees. The other Directors who served during the period received no emoluments from Group companies in respect of their services.

The directors did not receive any other remuneration.

The above amounts for remuneration include the following in respect of the highest paid director:

	6 months ended 30 June 2020 $000	6 months ended 30 June 2019 $000
Directors' remuneration	809	696
Payments made in lieu of pension contributions	64	51
Pension costs	4	5
	877	752

9. Income tax

	6 months ended 30 June 2020 $000	6 months ended 30 June 2019 $000
Current income tax expense/(credit):		
UK corporation tax	214,847	-
Overseas tax	(11,273)	(6,595)
Adjustment in respect of prior years	7,383	(140)
Total current income tax expense/(credit)	210,957	(6,735)
Deferred tax (credit)/expense:		
Origination and reversal of temporary differences	(282,074)	158,262
Overseas tax	8,708	235
Adjustment in respect of prior years	(7,362)	(2,435)
Total deferred tax (credit)/expense	(280,728)	156,062
Tax (credit)/expense in the income statement	(69,771)	149,327
The tax (credit)/expense in the income statement is disclosed as follows:		
Income tax (credit)/expense on continuing operations	(69,771)	149,327
	(69,771)	149,327

The origination of and reversal of temporary differences are, as shown in the next table, related primarily to movement in the carrying amounts and tax base values of expenditure and Group losses for the current and prior year and the timing of when these items are charged and/or credited against accounting and taxable profit.

9. Income Tax (continued)

A reconciliation between total tax charge/(credit) and the accounting profit multiplied by the standard rate of corporation tax and supplementary charge applying to UK oil and gas production operations for the six months ended 30 June 2020 and 2019 is as follows:

	6 months ended 30 June 2020 $000	6 months ended 30 June 2019 $000
(Loss)/profit before taxation	(224,222)	323,705
(Loss)/profit before taxation at 40.0% (2019: 40.0%)	(89,689)	129,482
Effects of:		
Expenses not deductible for tax purposes	28,918	18,567
Interest not deductible for supplementary charge	4,135	4,728
Adjustment in respect of prior years	21	(2,575)
Income not taxable	(5)	-
Movement in unrecognised deferred tax assets	3,507	2,361
Impact of profits/losses relieved at different rates	(1,931)	9,854
Investment allowance	(13,009)	(13,090)
Petroleum revenue tax (net of corporation tax)	(1,656)	-
Currency translation adjustment	(62)	-
Total tax (credit) expense reported in the consolidated income statement	(69,771)	149,327

The origination of and reversal of temporary differences are, as shown in the next table, related primarily to movement in the carrying amounts and tax base values of expenditure and Group losses for the current and prior year and the timing of when these items are charged and/or credited against accounting and taxable profit.

Deferred tax

Deferred tax is presented net on the Group balance sheet is as follows:

	Accelerated Capital Allowances $000	Abandonment $000	Losses $000	Fair Value On Derivatives $000	Other $000	Total $000
As at 1 January 2020	(3,164,408)	1,588,824	1,960	(128,795)	53,129	(1,649,290)
Deferred tax (expense)/credit	365,445	(92,791)	255	(1,481)	9,300	280,728
Comprehensive (expense)				(210,167)	-	(210,167)
Foreign exchange	88,554	(70,976)	(186)	1,185	(4,579)	13,998
As at 30 June 2020	(2,710,409)	1,425,057	2,029	(339,258)	57,850	(1,564,731)

9. Income Tax (continued)

The Norwegian related tax losses are not expected to be recovered within the next twelve months. Companies operating on the Norwegian Continental Shelf under the offshore tax regime can claim the tax value of any unused tax losses or other tax credits related to its offshore activities to be paid in cash (including interest) from the tax authorities when operations cease. Deferred tax assets that are based on offshore tax losses carried forward are therefore normally recognised in full. There is no time limit on the right to carry tax losses forward in Norway.

Deferred tax assets are recognised to the extent that the future benefit from the underlying tax losses carried forward is probable. Relevant tax law is considered as to the availability of the tax losses to offset future income. To determine the future taxable income from which the losses may be deducted, reference was made to the profit forecasts for the Group as at 30 June 2020. These profit forecasts showed sufficient future taxable income to recognise the deferred tax asset.

The Group has tax losses, mainly from non-ring fence activities, of $135.6 million (2019: $132.4 million), a portion of which may potentially be available for offset against future taxable profits in the companies in which the losses arose. An associated deferred tax asset of $28.0 million (2019: $27.7 million) has not been recognised in respect of these losses as they may not be used to offset taxable profits elsewhere in the Group due to uncertainty of recovery. The Group has recognised a deferred tax asset of $2.0 million (2019: $2.0 million) in relation to tax losses only to the extent of anticipated future taxable profits.

The Group has not recognised a deferred tax asset of $5.6m (2019: $2.8m) in relation to accelerated capital allowances, or a deferred tax asset of $0.8 million (2019: nil) in relation to fair value movements on derivatives, on the basis that these deferred tax assets will not be recoverable in the foreseeable future.

Changes in tax rate

Legislation introduced in Finance Bill 2020, which was substantively enacted on 17 March 2020, retained the main rate of UK corporation tax for non-ring fence profits at 19 percent from 1 April 2020. This has no material impact on the Group.

10. Goodwil

Group	2020 $000	2019 $000
Cost:		
At 1 January	1,404,334	493,084
Additions (note 15)	-	908,359
Impairment charge	(55,735)	-
Currency translation adjustment	(4,983)	2,891
At 30 June	1,343,616	1,404,334

2020 Half-Year Results

10. Goodwil (continued)

Goodwill represents the difference between the aggregate of the fair value of purchase consideration transferred at the acquisition date and the fair value of the identifiable assets.

The goodwill balance arose on the acquisition of the ConocoPhillips UK business which completed on 30 September 2019, the acquisition of UK North Sea assets from Shell which completed on 1 November 2017, and on the acquisition of additional equity in the Armada, Maria and Seymour fields from Spirit Energy, which completed on 1 June 2018. During 2018, under the two Sale and Purchase Agreements (SPA) pertaining to the acquisition that completed in 2017, Chrysaor agreed the full and final settlement with Shell. See note 15 for further details.

Goodwill acquired through business combinations has been allocated to a single cash generating unit ('CGU'), the UK Continental Shelf ('UKCS'), and this is therefore the lowest level at which goodwill is reviewed.

Impairment Testing of Goodwill

In accordance with 'IAS 36: Impairment of Assets', goodwill has been reviewed for impairment at the period-end. In assessing whether goodwill has been impaired, the carrying amount of the CGU for goodwill is compared with its recoverable amount.

The Group tests goodwill annually for impairment, or more frequently if there are indications that goodwill might be impaired. At the period-end, the Group tested for impairment in accordance with accounting policy, and following changes to the Group's long-term commodity price assumptions linked to the significant deterioration in the macroeconomic environment for the oil and gas industry, a goodwill impairment of $55.7 million was recognised.

Determining Recoverable Amount

The recoverable amounts of the CGU and fields have been determined on a fair value less costs to sell basis. The key assumptions used in determining the fair value are often subjective, such as the future long-term oil price assumption, or the operational performance of the assets. Discounted cash flow models comprising asset-by-asset life of field projections using Level 3 inputs (based on IFRS 13 fair value hierarchy) have been used to determine the recoverable amounts. The cash flows have been modelled on a post-tax and post-decommissioning basis at the Group's post-tax discount rate of 6 percent (2019: 6 percent). Risks specific to assets within the CGU are reflected within the cash flow forecasts. Risks specific to assets within the CGU are reflected within the cash flow forecasts.

Key Assumptions Used in Calculations

Assumptions involved in impairment measurement include estimates of commercial reserves and production volumes, future oil and gas prices, discount rates and the level and timing of expenditures, all of which are inherently uncertain.

Oil and gas prices are based on an internal view of management expectations derived from external financial analysts view of current prices for the first three years transitioning to a flat long term price from 2023 - the long-term commodity prices used were $60 per barrel for crude and 45p per therm for gas. Management's long-term assumptions are benchmarked against a range of external forward price curves on a regular basis. Individual field price differentials are then applied.

Production volumes are based on life of field production profiles for each asset within the CGU. Proven and probable reserves are estimates of the amount of oil and gas that can be economically extracted from the Group's oil and gas assets. The Group estimates its reserves using standard recognised evaluation techniques and is assessed at least annually by management and by an independent consultant. Proven and probable reserves are determined using estimates of oil and gas in place, recovery factors and future commodity prices.

Operating expenditure, capital expenditure and decommissioning costs are derived from the Group's Business Plan.

The discount rate reflects management's estimate of the Group's Weighted Average Cost of Capital (WACC), considering both debt and equity. The cost of equity is derived from an expected return on investment by the Group's investors, and the cost of debt is based on its interest-bearing borrowings. Segment risk is incorporated by applying a beta factor based on publicly available market data. The discount rate is based on an assessment of a relevant peer group's post-tax WACC.

Foreign exchange rates are based on management's long-term rate assumptions, with reference to a range of underlying economic indicators.

Sensitivity to Changes in Assumptions Used in Calculations

The Group has run sensitivities on its long-term commodity price assumptions, which have been based on long range forecasts from external financial analysts, using alternate long-term price assumptions and discount rates. These are considered to be reasonably possible changes for the purposes of sensitivity analysis. Sensitivity analysis indicates that a 10 percent reduction in the oil and gas price deck applied in the impairment test would result in a further impairment to goodwill of $666.6 million, and a 2 percent increase in the discount rate would result in a further impairment to goodwill of $222.3 million.

11. Other intangible assets

Cost	Oil and gas assets $000	Non-oil and gas assets $000	Capacity rights $000	Total $000
At 1 January 2019	52,543	-	9,634	62,177
Additions	81,792	820	-	82,612
Additions from business combinations and joint arrangements	325,880	-	-	325,880
Transfers to property, plant & equipment	(39,002)	-	-	(39,002)
Unsuccessful exploration written-off	(222)	-	-	(222)
Currency translation adjustment	4,262	-	374	4,636
At 31 December 2019	425,253	820	10,008	436,081
Additions	44,763	33,362	-	78,125
Transfers from property, plant and equipment	33,273	39,153	-	72,426
Reduction in decommissioning asset	(5,295)	-	-	(5,295)
Disposals	(75)	-	-	(75)
Unsuccessful exploration written-off	(38,851)	-	-	(38,851)
Currency translation adjustment	(19,219)	(2,982)	(645)	(22,846)
At 30 June 2020	439,849	70,353	9,363	519,565
Accumulated amortisation				
At 1 January 2019	-	-	3,248	3,248
Charge for the year	-	-	2,097	2,097
Currency translation adjustment	-	-	208	208
At 31 December 2019	-	-	5,553	5,553
Charge for the period	-	6,526	870	7,396
Transfers from property, plant and equipment	-	16,077	-	16,077
Currency translation adjustment	-	(1,197)	(383)	(1,580)
At 30 June 2020	-	21,406	6,040	27,446
Net book value				
At 30 June 2020	439,849	48,947	3,323	492,119
At 31 December 2019	425,253	820	4,455	430,528
At 1 January 2019	52,543	-	6,386	58,929

Exploration costs written-off relates to costs associated with licence relinquishments and uncommercial well evaluations.

Non-oil and gas assets relate to expenditure on IT software and the Acorn project, a project focussed on carbon dioxide (CO_2) capture and storage which is planned to use existing technology to this new area of application. The costs are held within intangible assets until an assessment of its economic commerciality is determined.

The capacity rights represent National Transmission System (NTS) entry capacity at Bacton and Teesside acquired as part of the business combination completed in 2017. These rights have a remaining useful life of three years and are amortised on a contractual volume basis.

12. Property, plant and equipment

Cost	Oil and gas assets $000	Fixtures and fittings & office equipment $000	Total $000
At 1 January 2019	4,437,097	33,529	4,470,626
Additions	480,448	16,952	497,400
Additions from business combinations and joint arrangements	4,248,567	7,518	4,256,085
Reduction in decommissioning asset	(4,327)	-	(4,327)
Transfer of intangible assets	39,002	-	39,002
Currency translation adjustment	57,532	2,308	59,840
At 31 December 2019	9,258,319	60,307	9,318,626
Additions	236,525	2,150	238,675
Reduction in decommissioning asset	(189,620)	-	(189,620)
Transfers to intangible assets	(33,273)	(39,153)	(72,426)
Currency translation adjustment	(224,870)	(1,434)	(226,304)
At 30 June 2020	9,047,081	21,870	9,068,951

Depreciation			
At 1 January 2019	716,042	10,759	726,801
Charge for the year	889,226	14,180	903,406
Currency translation adjustment	7,873	940	8,813
At 31 December 2019	1,613,141	25,879	1,639,020
Charge for the period	696,504	3,077	699,581
Transfer to intangible assets	-	(16,077)	(16,077)
Impairment charge	250,629	-	250,629
Currency translation adjustment	(22,718)	(697)	(23,415)
At 30 June 2020	2,537,556	12,182	2,549,738

Net book value			
At 30 June 2020	6,509,525	9,688	6,519,213
At 31 December 2019	7,645,178	34,428	7,679,606
At 1 January 2019	3,721,055	22,770	3,743,825

12. Property, plant and equipment (continued)

During the period, the Group recognised a net pre-tax impairment charge of $250.6 million (post-tax $150.5 million) within the income statement. This represents a write-down of $340.4 million on the Group's older gas assets as a result of the Group's revised view of long-term commodity prices, and a pre-tax impairment credit of ($89.8 million) in respect of reductions to decommissioning estimates on the Group's non-producing assets (see note 21).

The Group uses the fair value less cost of disposal method (FVLCD) to calculate the recoverable amount of the cash generating units (CGU) consistent with a level 3 fair value measurement. In determining FVLCD, appropriate discounted-cash-flow valuation models were used, incorporating market-based assumptions. Oil and gas prices are based on an internal view of management expectations derived from external financial analysts view of current prices for the first three years transitioning to a flat long term price from 2023 - the long-term commodity prices used were $60 per barrel for crude and 45p per therm for gas.

A reduction or increase in oil and gas prices of 10% are considered to be reasonably possible changes for the purpose of sensitivity analysis. Decreases to oil and gas prices specified above would result in a further post-tax impairment of $117.1 million. A 10 percent rise in the oil and gas price deck would lead to a reduction in the post-tax impairment of $132.4 million. Considering the discount rates, a 2 percent decrease in the post-tax rate would lead to a further post-tax impairment of $35.3 million, whereas a 2 percent increase in the post-tax rate would lead to a reduction in the post-tax impairment of $34.1 million. The Group believes a 2 percent change in the pre-tax discount rate to be a reasonable possibility for the purpose of sensitivity analysis. The impairment was calculated as detailed above.

Included within property, plant and equipment additions of $238.7 million (June 2019: $211.1 million) are associated cash flows of $274.8 million (June 2019: $180.7 million) and non-cash flow items of ($36.1) million (June 2019: $30.4 million), represented by ($44.3) million (June 2019: $17.9 million) of non-cash working capital movements, decommissioning asset revisions of $nil (June 2019: $12.5 million) and $8.2 million of capitalised leased payments (June 2019: nil).

13. Leases - right-of-use assets

(i) This note provides information for leases where the Group is a lessee.

Right-of-use assets	6 months ended 30 June 2020 $000	Year ended 31 Dec 2019 $000
Group		
Land and buildings	54,299	58,092
Drilling rigs	87,666	159,945
Equipment	2,051	3,186
	144,016	221,223

Lease creditors		
Group		
Current	53,782	79,525
Non-current	96,384	145,403
	150,166	224,928

13. Leases - right-of-use assets (continued)

During the period, a lease liability in relation to the Transocean 712 drilling rig was terminated, resulting in a gain of $0.6 million. In addition, a cost revision to the right-of-use asset and lease liability was made, resulting in reductions of $10.0 million.

There were no additions to the right-of-use assets during the period (2019: $19.0 million).

(ii) The consolidated income statement includes the following amounts relating to leases:

Depreciation charge of right-of-use assets		
Group	**6 months ended 30 June 2020 $000**	**6 months ended 30 June 2019 $000**
Land and buildings	3,644	1,149
Drilling rigs	27,576	-
Equipment	697	-
	31,917	1,149
Capitalisation of IFRS16 lease depreciation		
Drilling rigs	(14,991)	-
Equipment	(435)	-
Depreciation charge included within Consolidated Income Statement	16,491	1,149

Of the $15.4 million capitalised IFRS16 lease depreciation, $8.2 million has been capitalised within property, plant and equipment and $7.2 million within provisions.

Lease interest (included in finance expenses – note 7)	3,853	570

The total cash outflow for leases in 1H 2020 was $32.6 million (1H 2019: $0.5 million).

14. Investments

At 30 June 2020, the subsidiary undertakings of the Company which were all wholly owned were:

Name of company	Country of incorporation	Main activity
Chrysaor E&P Limited	UK	Holding company
Chrysaor Production Holdings Limited (i)	UK	Holding company
Chrysaor Resources (UK) Holdings Limited (i)	UK	Holding company
Chrysaor E&P Finance Limited (i)	UK	Financing company
Chrysaor E&P Services Limited (i)	UK	Service company
Chrysaor North Sea Limited (i)	UK	Oil and gas
Chrysaor Limited (i)	UK	Oil and gas
Chrysaor CNS Limited (i)	UK	Oil and gas
Chrysaor Norge AS (i)	Norway	Oil and gas
Chrysaor Resources (Irish Sea) Limited (ii)	UK	Oil and gas
Chrysaor Marketing Limited (i)	UK	Dormant company
Chrysaor Production Limited (iii)	UK	Holding company
Chrysaor Production (U.K.) Limited (v)	UK	Oil and gas
Chrysaor Petroleum Company U.K. Limited (iii)	UK	Oil and gas
Chrysaor (U.K.) Theta Limited (vii)	UK	Oil and gas
Chrysaor (U.K.) Alpha Limited (vi)	UK	Oil and gas
Chrysaor (U.K.) Beta Limited (xi)	UK	Oil and gas
Chrysaor Developments Limited (vi)	UK	Oil and gas
Chrysaor Petroleum Limited (vi)	UK	Oil and gas
Chrysaor (U.K.) Sigma Limited (viii)	UK	Oil and gas
Chrysaor (Glen) Limited (vi)	UK	Non-trading
Chrysaor (U.K.) Zeta Limited (vi)	UK	Non-trading holding company
Chrysaor (U.K.) Eta Limited (x)	UK	Non-trading
Chrysaor (U.K.) Delta Limited (vi)	UK	Non-trading holding company
Chrysaor Supply and Trading Limited (iii)	UK	Non-trading
Chrysaor (U.K.) Lambda Limited (ix)	ROI	Dormant company
Chrysaor Investments Limited (vi)	UK	Dormant company
Chrysaor Production Oil (GB) Limited (iv)	UK	Dormant company
Chrysaor Petroleum Chemicals U.K. Limited (iv)	UK	Dormant company
Chrysaor (U.K.) Britannia Limited (vi)	UK	Dormant company

(i) Held by Chrysaor E&P Limited
(ii) Held by Chrysaor Resources (UK) Holdings Limited
(iii) Held by Chrysaor Production Holdings Limited
(iv) Held by Chrysaor Petroleum Company U.K. Limited
(v) Held by Chrysaor Production Limited
(vi) Held by Chrysaor Production (U.K.) Limited
(vii) Held by Chrysaor (U.K.) Sigma Limited
(viii) 98.04% held by Chrysaor Production (U.K.) Limited and 1.96% held by Chrysaor (U.K.) Delta Limited
(ix) 99.999% held by Chrysaor (U.K.) Theta Limited and 0.001% held by Chrysaor (U.K.) Eta Limited
(x) Held by Chrysaor (U.K.) Zeta Limited
(xi) Held by Chrysaor (U.K.) Alpha Limited

14. Investments (continued)

The Company holds 100% of the share capital and voting rights in each of the companies above, unless otherwise stated.

All the subsidiaries are registered in England and Wales, with the exception of Chrysaor Norge AS, which is registered in Norway, and Chrysaor (U.K.) Lambda Limited, which is registered in the Republic of Ireland. The registered office of all subsidiaries noted above is Brettenham House, Lancaster Place, London, United Kingdom, WC2E 7EN, apart from Chrysaor Norge AS whose registered office is Haakon VII's gate 1, 4th Floor, 0161 Oslo, Norway, and Chrysaor (U.K.) Lambda Limited whose registered office is Riverside One, Sir John Rogerson's Quay, Dublin 2, Ireland.

15. Business Combinations and Acquisition of Interests in Joint Arrangements

Business Combinations During the Year Ended 31 December 2019

In April 2019, Chrysaor entered into an agreement to acquire the ConocoPhillips UK business for a headline consideration of $2.675 billion.

The transaction completed on 30 September 2019 and adds two new operated hubs to Chrysaor's portfolio in the UK Central North Sea, Greater Britannia Area and J-Area, in addition to a non-operated interest in the Clair Field area. The fair values of the net identifiable assets acquired from the transaction are as follows:

	Total $000
Exploration, evaluation and other intangible assets	325,880
Property, plant and equipment – oil and gas assets	4,248,567
Property, plant and equipment – non-oil and gas assets	7,518
Property, plant and equipment – right of use assets	206,978
Total fixed assets	4,788,943
Inventories	54,203
Cash	247,034
Trade and other receivables	223,884
Trade and other payables	(324,753)
Deferred tax	(760,983)
Provision for decommissioning	(2,408,211)
IFRS16 lease liabilities	(206,978)
Fair value of identifiable net assets acquired	1,613,139
Cash consideration	2,430,049
Additional completion adjustments	91,449
Total consideration	2,521,498
Goodwill Recognised	908,359

15. Business Combinations and Acquisition of Interests in Joint Arrangements (continued)

In November 2019, $38.2 million of additional completion adjustments were paid to ConocoPhillips US, representing the first of four annual payments to be made during 2019 to 2022.

Acquisition related costs of $7.6 million were incurred during 2019 and recognised as an expense within General and Administrative costs.

The cash consideration was funded from existing cash resources and additional RBL funding of $1.68 billion from the upsized $3 billion debt facility.

Goodwill of $908.4 million, which has arisen principally due to the requirement to recognise deferred tax on the difference between the assigned fair values and the tax bases of assets and liabilities acquired in a business combination, has been recognised on the acquisition, representing the excess of the total consideration transferred over the fair value of the net assets acquired.

The fair values for the oil and gas assets recognised as property, plant and equipment were determined by reference to commodity forward price curves for the first three years following the acquisition date and, for subsequent years, based on a market consensus. None of the goodwill is deductible for corporation tax.

From the date of acquisition, the business contributed $264.6 million of revenue and ($88 million) to the profit before tax from continuing operations of the Group. Had the acquisition been affected at 1 January 2019, the business would have contributed revenue of $1.0 billion in the year to 31 December 2019, and $32.4 million of a loss towards profit before taxation.

As at the date of this report and financial statements, pursuant to the terms of the Put and Call Options Agreement (PCOA), negotiations were ongoing as to the final consideration payable as a result of the review of the interim and pre-effective date period transactions.

16. Inventories

	30 June 2020 $000	**31 Dec 2019 $000**
Hydrocarbons	36,954	35,170
Consumables and subsea supplies	116,090	111,711
	153,044	146,881

Hydrocarbon inventories are measured at net realisable value. Inventories of consumables and subsea supplies include a provision of $9.6 million (2019: $9.7 million) where it is considered that the net realisable value is lower than the original cost.

Inventories recognised as an expense during the period ended 30 June 2020 amounted to $1.8 million (2019: $0.4 million). These expenses are included within production costs.

17. Trade and Other Receivables

Current	30 June 2020 $000	31 Dec 2019 $000
Trade debtors	131,906	186,593
Under-lift position	37,050	34,358
Other debtors	86,661	177,072
Prepayments and accrued income	13,815	60,417
Corporation tax receivable	-	15,678
	269,432	474,118

Trade debtors are non-interest bearing and are generally on 20 to 30 days' terms. As at 30 June 2020, there were no credit loss provisions (2019: $nil).

Other debtors mainly relate to amounts due from joint venture partners.

The carrying value of the trade and other receivables are equal to their fair value as at the balance sheet date.

Non–Current	30 June 2020 $000	31 Dec 2019 $000
Other receivables	2,871	2,604
	2,871	2,604

18. Cash and Cash Equivalents

Current	30 June 2020 $000	31 Dec 2019 $000
Cash at bank and in hand	369,391	573,182

Cash at bank earns interest at floating rates based on daily bank deposit rates. The Group only deposits cash with major banks of high-quality credit standing.

19. Commitments

Capital Commitments

As at 30 June 2020, the Group had commitments for future capital expenditure amounting to $359.0 million (2019 $420.5 million). Where the commitment relates to a joint arrangement, the amount represents the Group's net share of the commitment. Where the Group is not the operator of the joint arrangement then the amounts are based on the Group's net share of committed future work programmes.

20. Trade and Other Payables

Current	30 June 2020 $000	31 Dec 2019 $000
Trade payables	131,387	116,221
Overlift position	25,208	83,370
Other payables	79,399	40,970
Accruals and deferred income	320,109	435,875
	556,103	676,436
Non-Current		
Other payables	46,420	52,375
	46,420	52,375

Other payables, within both current ($18.8 million) (2019: $19.9 million) and non-current ($37.5 million) (2019: $39.7 million) 'trade and other payables', includes the present value of additional completion payments payable to ConocoPhillips Company as part of the acquisition of the ConocoPhillips UK business. The amounts are payable in 3 further instalments between October 2020 and October 2022.

21. Provisions

	Decommissioning provision $000	Other provisions $000	Total $000
At 1 January 2019	1,468,044	7,690	1,475,734
Additions from business combinations and joint arrangements (note 15)	2,408,211	-	2,408,211
Additions	28,389	-	28,389
Changes in estimates – decrease to decommissioning asset	(4,327)	-	(4,327)
Remeasurements	-	(7,773)	(7,773)
Amounts used	(46,816)	-	(46,816)
Interest on decommissioning lease	(1,076)	-	(1,076)
Depreciation, depletion & amortisation on decommissioning right-of-use leased asset	(4,821)	-	(4,821)
Unwinding of discount	57,629	83	57,712
Currency translation adjustment	44,587	-	44,587
At 31 December 2019	3,949,820	-	3,949,820
Additions	9,753	27,943	37,696
Changes in estimates – decrease to decommissioning asset	(114,908)	-	(114,908)
Changes in estimates – credit to income statement	(89,760)	-	(89,760)
Amounts used	(82,406)	-	(82,406)
Unwinding of discount	48,465	-	48,465
Currency translation adjustment	(173,787)	-	(173,787)
At 30 June 2020	3,547,177	27,943	3,575,120

Classified within:	Non-current liabilities	Other provisions $000	Total $000
At 30 June 2020	3,368,416	206,704	3,575,120
At 31 December 2019	3,776,739	183,081	3,949,820
At 1 January 2019	1,475,734	-	1,475,734

21. Provisions (continued)

The Group provides for the estimated future decommissioning costs on its oil and gas assets at the balance sheet date. The payment dates of expected decommissioning costs are uncertain and are based on economic assumptions of the fields concerned. The Group currently expects to incur decommissioning costs over the next 40 years, the majority of which we anticipate will be incurred between the next 10 to 20 years. Decommissioning provisions are discounted at a risk-free rate of between 1.8 percent and 2.5 percent (2019: 2.3 percent to 2.8 percent), and the unwinding of the discount is presented within finance expenses (note 7).

These provisions have been created based on internal and third-party estimates. Assumptions based on the current economic environment have been made, which management believe are a reasonable basis upon which to estimate the future liability. These estimates are reviewed regularly to consider any material changes to the assumptions. However, actual decommissioning costs will ultimately depend upon market prices for the necessary decommissioning work required, which will reflect market conditions at the relevant time. In addition, the timing of decommissioning liabilities will depend upon the dates when the fields become economically unviable, which in itself will depend on future commodity prices, which are inherently uncertain.

Other provisions relate to a provision for an onerous contract in respect of long-term standby costs on the Deepsea Aberdeen rig, which has been operating within the Schiehallion field, whereby no future approved activities have resulted in the rig potentially remaining on standby until the end of the contract in April 2022.

22. Borrowings and facilities

	30 Jun 2020 $000	31 Dec 2019 $000
Reserves Based Loan facility	1,439,706	2,067,339
Junior facility	396,014	395,613
10% Unsecured C loan notes 2027	30,845	34,355
10% Unsecured D loan notes 2027	252,220	282,151
Exploration finance facility	11,088	8,999
Other loans	35,284	34,228
	2,165,157	2,822,685
Classified within:		
Non-current liabilities	2,170,189	2,205,322
Current liabilities	11,886	617,363
	2,182,075	2,822,685
Current assets (deferred fees)	(16,918)	-
	2,165,157	2,822,685

2020 Half-Year Results

2020 Half-Year Results

22. Borrowings and facilities (continued)

Interest of $10.9 million (2019: $11.7 million) on the Reserves Based Loan (RBL) and junior facilities had accrued by the balance sheet date and have been classified within accruals and deferred income.

In June 2019, the Group extended the terms of the RBL facility to 31 December 2025, and increased the syndicate to 19 banks, and facility size to $3.0 billion (with an option for a further $1 billion accordion), to assist the financing of the ConocoPhillips UK acquisition. Subject to the maximum size of the facility, which reduces every six months on a straight-line basis from 1 January 2022 to the maturity date of 31 December 2025, the amount available under the facility is determined based on a valuation of the Group's borrowing base assets under certain forward-looking assumptions. The facility was also amended to carry interest at USD LIBOR plus a margin of 3.25 percent, rising to a margin of 3.5 percent after four years. Certain fees are also payable, including fees on available commitments at 40 percent of the applicable margin and commission on letters of credit issued at 50 percent of the applicable margin. The junior facility of $400 million was extended and amended at the same time as the RBL facility to carry interest at six-month USD LIBOR plus a margin of 5.25 percent, rising to a margin of 5.5 percent after four years, and is repayable in semi-annual instalments between 30 June 2022 and 30 June 2026.

In June 2020, certain other amendments were made to the RBL facility in conjunction with the normal redetermination process. No changes were made to the existing $3.0 billion facility size, but the debt availability grew to $2.5 billion, to be redetermined now on an annual basis. Other amendments included the revision of certain governance requirements to be in line with peers, and the incorporation of a margin adjustment linked to carbon-emission reductions. The syndication group now stands at 18 banks.

During 2019, Chrysaor entered into a NOK 750 million exploration finance facility (EFF) with Skandinaviska Enskilda Banken in relation to part-financing the exploration activities of Chrysaor Norge AS. At the balance sheet date, the amount drawn down on the facility was NOK 110 million (2019: NOK 83 million).

Incremental transaction costs of $45.9 million were capitalised when the terms of the RBL were extended in June 2019 and amended in June 2020. These amounts are being amortised over the term of the relevant arrangement. During the period, $7.5 million (2019: $8.1 million) of transaction costs have been amortised and are included within financing costs. At the period end, $16.9 million of transaction costs, due to be amortised within the next 12 months, have been reclassified to current assets.

At the balance sheet date, the outstanding RBL and junior-loan balances, excluding incremental transaction costs, were $1,500 million and $400 million respectively (2019: $2,134 million and $400 million). At 30 June 2020, the junior facility remained fully drawn and $1,030 million remained available for drawdown under the RBL facility.

The unsecured loan notes were issued in 2017 and are listed on The International Stock Exchange (formerly the Channel Islands Securities Exchange). They incur interest of 10 percent per annum which, at the election of the Company, is capitalised and added to the principal amount each 31 December. The C loan notes and D loan notes rank junior to any senior bank debt. None of the loan notes carry voting rights. In February 2020, a partial cash redemption of the C Loan Notes of $4.9 million and D Loan Notes of $42.0 million took place.

The Group has Letters of Credit facilities of $528 million (Dec 2019: $599 million) held in respect of future abandonment liabilities.

Other loans represent a commercial financing arrangement with BHGE, covering a 3-year work programme for drilling, completion and subsea tie-in of development wells on Chrysaor's operated assets. As part of the deal, BHGE contribute to the costs of the work programme by funding a portion of the capital expenditure, in exchange for a greater exposure to returns, as well as risks, should certain targets and success criteria, both operational and geological, be met. Interest on this financing arrangement has been calculated using the effective interest method with reference to the expected cash flows, using an estimated reserve case.

22. Borrowings and facilities (continued)

The table below details the change in the carrying amount of the Group's borrowings arising from financing cash flows.

	Group $000
Total borrowings as at 1 January 2019	1,804,889
Repayment of senior debt	(200,000)
Proceeds from drawdown of borrowing facilities	1,834,000
Proceeds from financing arrangement	29,600
Proceeds from exploration financing facility	9,275
Conversion of E loan notes to equity	(675,264)
Transaction costs capitalised	(45,134)
Transaction costs on exploration financing facility paid and capitalised	(507)
Currency translation adjustments	174
Loan notes interest capitalised	69,767
Financing arrangement interest (receivable)	(19,696)
Amortisation of transaction costs	15,581
Total borrowings as at 31 December 2019	2,822,685
Proceeds from exploration financing facility	2,596
Loan notes redemption	(46,860)
Transaction costs capitalised	(765)
Debt repayments	(634,000)
Currency translation adjustments	(578)
Loan notes interest capitalised	13,419
Financing arrangement interest payable	1,055
Amortisation of transaction costs	7,605
Total borrowings as at 30 June 2020	2,165,157

2020 Half-Year Results

23. Other financial assets and liabilities

The Group held the following financial instruments at fair value at 30 June 2020. The fair values of all derivative financial instruments are based on estimates from observable inputs and are all level 2 in the IFRS 13 hierarchy, except for the royalty valuation and the Shell contingent consideration, which both include estimates based on unobservable inputs and are level 3 in the IFRS 13 hierarchy.

	30 June 2020		31 Dec 2019	
	Assets $000	**Liabilities $000**	**Assets $000**	**Liabilities $000**
Measured at fair value through profit and loss				
Royalty consideration	4,920	-	3,000	-
Commodity derivatives – contingent consideration	-	-	-	(12,495)
	4,920	-	3,000	(12,495)
Measure at fair value through other comprehensive income				
Commodity derivatives – cash flow hedges	608,069	(111)	190,888	(27,950)
Foreign exchange derivatives – cash flow hedges	924	-	-	-
Carbon swaps – cash flow hedges	477	-	-	-
	609,470	(111)	190,888	(27,950)
Total current	614,390	(111)	193,888	(40,445)
Measured at fair value through profit and loss				
Royalty consideration	6,380	-	9,100	-
Measured at fair value through other comprehensive income				
Commodity derivatives – cash flow hedges	292,150	(9,688)	193,130	(3,663)
Interest rate derivatives – cash flow hedges	-	(4,859)	-	-
Carbon swaps – cash flow hedges	15,001	-	-	-
	307,151	(14,547)	193,130	(3,663)
Total non-current	313,531	(14,547)	202,230	(3,663)
Total current and non-current	927,921	(14,658)	396,118	(44,108)

23. Other financial assets and liabilities (continued)

All financial instruments initially recognised and subsequently re-measured at fair value have been classified in accordance with the hierarchy described in IFRS 13 'Fair Value Measurement'. The hierarchy groups fair-value measurements into the following levels, based on the degree to which the fair value is observable.

Level 1: fair-value measurements are derived from unadjusted quoted prices for identical assets or liabilities.

Level 2: fair-value measurements include inputs, other than quoted prices included within level 1, which are observable directly or indirectly.

Level 3: fair-value measurements are derived from valuation techniques that include significant inputs not based on observable data.

	Financial assets		Financial liabilities	
As at 30 June 2020	**Level 2 $000**	**Level 3 $000**	**Level 2 $000**	**Level 3 $000**
Royalty valuation	-	11,300	-	-
Commodity derivatives – cash flow hedges	900,219	-	(9,799)	-
Foreign exchange derivatives – cash flow hedges	924	-	-	-
Carbon swaps – cash flow hedges	15,478	-	-	-
Interest rate derivatives – cash flow hedges	-	-	(4,859)	-
	916,621	11,300	(14,658)	-
As at 31 December 2019				
Royalty valuation	-	12,100	-	-
Commodity derivatives – cash flow hedges	384,018	-	(31,613)	-
Commodity derivatives – contingent consideration	-	-	-	(12,495)
	384,018	12,100	(31,613)	(12,495)

There were no transfers between fair value levels in the period. The movements in the period associated with financial assets and liabilities measured in accordance with level 3 of the fair value hierarchy are shown below:

	Financial assets		Financial liabilities	
	2020 $000	**2019 $000**	**2020 $000**	**2019 $000**
Fair value as at 1 January	12,100	12,700	(12,495)	(39,354)
Additions	-	-	-	-
Settlements	(1,080)	(3,000)	12,495	35,079
Gains and losses recognised in the income statement	280	1,400	-	(22,460)
Currency translation adjustments	-	-	-	-
Fair value as at 30 June	11,300	11,100	-	(26,735)

23. Other financial assets and liabilities (continued)

Part of the consideration received on the sale of the Group's interest in a pre-production development in 2015 was a royalty interest, which is recognised on the balance sheet as a financial asset. At 30 June 2020, the Group valued the outstanding consideration receivable at $11.3 million (June 2019: $11.1 million; Dec 2019: $12.1 million) of which $4.9 million (June 2019: $1.9 million; Dec 2019: $3.0 million) is considered to be receivable within one year.

The agreement with the sellers of the UK North Sea assets purchased by the Group in 2017 included contingent consideration dependent on future commodity prices over the four-year period ended 31 December 2021. These contingent payments and receipts represented a series of option contracts. In the period to 31 December 2019, the fair value of the contingent payments was presented as a financial liability and estimated using valuation techniques, the key inputs for which included future commodity prices and volatility. The contingent consideration in relation to the 2019 calendar year was fully settled in March 2020 and as a result there are no further movements on the fair value of crude based derivative instruments reported through the income statement.

Fair value movements recognised in the income statement on financial instruments are shown below.

	6 months ended 30 June 2020 $000	6 months ended 30 June 2019 $000
Income/(expense) included in the income statement		
Remeasurement of royalty valuation	280	1,400
Remeasurement of commodity price contingent consideration	-	(22,460)
	280	(21,060)

Fair Values of Other Financial Instruments

The following financial instruments are measured at amortised cost and are considered to have fair values different to their book values.

	2020		2019	
	Book value	**Fair value**	**Book value**	**Fair value**
Long-term borrowings – loan notes	(283,065)	(388,335)	(316,506)	(357,676)

The fair values of the loan notes are within level 2 of the fair value hierarchy and have been estimated by discounting all future cash flows by the relevant market yield curve at the balance sheet date adjusted for an appropriate credit margin. The fair values of other financial instruments not measured at fair value including cash and short-term deposits, trade receivables, trade payables and floating rate borrowings approximate their carrying amounts.

23. Other financial assets and liabilities (continued)

Cash Flow Hedge Accounting

The Group uses a combination of fixed price physical sales contracts and cash-settled fixed price commodity swaps, and options to manage the price risk associated with its underlying oil and gas revenues. As at 30 June 2020, all of the Group's cash-settled fixed price commodity swap derivatives have been designated as cash flow hedges of highly probable forecast sales of oil and gas.

The following table indicates the volumes, average hedged price and timings associated with Group's financial commodity derivatives. Volumes hedged through fixed price contracts with customers for physical delivery are excluded.

Position as at 30 June 2020	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Oil volume hedged (thousand bbls)	12,742	12,341	1,095	-	-	-
Weighted average hedged price ($/bbl)	62.10	62.52	60.07	-	-	-
Gas volume hedged (million therms)	393	687	999	525	235	60
Weighted average hedged price (p/therm)	46p	49p	46p	45p	44p	44p

As at 30 June 2020, the fair value of net financial commodity derivatives designated as cash flow hedges was $890.4 million (June 2019: $100.0 million; December 2019: $352.4 million) and net unrealised pre-tax gains of $829.8 million (June 2019: $91.3 million; December 2019: gains $320.9 million) was deferred in other comprehensive income in respect of the effective portion of the hedge relationships. Amounts deferred in other comprehensive income will be released to the income statement as the underlying hedged transactions occur. As at 30 June 2020, net deferred pre-tax gains on commodity derivatives of $607.9 million (December 2019: gains $162.9 million) are expected to be released to the income statement within one year.

24. Financial risk factors and risk management

The Group's principal financial assets and liabilities comprise trade and other receivables, cash and short-term deposits accounts, trade payables, interest bearing loans and derivative financial instruments. The main purpose of these financial instruments is to manage short-term cash flow and price exposures and raise finance for the Group's expenditure programme. Further information on the Group's financial instrument risk management objectives, policies and strategies are set out in Section 11, Principal Risks, in our 2019 Annual Report and Accounts.

Risk Exposures and Responses

The Group manages its exposure to key financial risks in accordance with its financial risk management policy. The objective of the policy is to support the delivery of the Group's financial targets while protecting future financial security. The main risks that could adversely affect the Group's financial assets, liabilities or future cash flows are: market risks comprising commodity price risk, interest rate risk and foreign currency risk, liquidity risk, and credit risk. Management reviews and agreed policies for managing each of these risks are summarised in this note.

The Group's senior management oversees the management of financial risks. The Group's senior management ensures that financial risk-taking activities are governed by appropriate policies and procedures and that financial risks are identified, measured and managed in accordance with Group policies and risk objectives. All derivative activities for risk management purposes are carried out by specialist teams that have the appropriate skills, experience and supervision. It is the Group's policy that no trading in derivatives for speculative purposes shall be undertaken.

Market Risk

Market risk is the risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk comprises three types of risk: commodity price risk, interest rate risk and foreign currency risk. Financial instruments mainly affected by market risk include loans and borrowings, deposits and derivative financial instruments.

The sensitivity analyses in the following sections relate to the position as at 30 June 2020 and 31 December 2019.

The sensitivity analyses have been prepared on the basis that the number of financial instruments are all constant. The sensitivity analyses are intended to illustrate the sensitivity to changes in market variables on the composition of the Group's financial instruments at the balance sheet date and show the impact on profit or loss and shareholders' equity, where applicable.

The following assumptions have been made in calculating the sensitivity analyses:

- The sensitivity of the relevant profit before tax item and/or equity is the effect of the assumed changes in respective market risks for the full year based on the financial assets and financial liabilities held at the balance sheet date.
- The sensitivities indicate the effect of a reasonable increase in each market variable. Unless otherwise stated, the effect of a corresponding decrease in these variables is considered approximately equal and opposite.
- Fair value changes from derivative instruments designated as cash flow hedges are considered fully effective and recorded in shareholders' equity, net of tax.
- Fair value changes from derivatives and other financial instruments not designated as cash flow hedges are presented as a sensitivity to profit before tax only and not included in shareholders' equity.

(a) Commodity Price Risk

The Group is exposed to the risk of fluctuations in prevailing market commodity prices on the mix of oil and gas products. On a rolling basis, the Group's policy is to hedge the commodity price exposure associated with 50 to 70 percent of the next 12 months' production, between 40 and 60 percent in the following 12-month period, between 30 and 50 percent in the following 12-month period and up to 40 percent in the subsequent 12-month period. The Group manages these risks through the use of fixed priced contracts with customers for physical delivery and derivative financial instruments including fixed priced swaps and options.

The following table summarises the impact on the Group's pre-tax profit and equity from a reasonably foreseeable movement in commodity prices on the fair value of commodity based derivative instruments held by the Group at the balance sheet date. There were no derivative financial instruments held by the Company in the current year or in the previous year.

24. Financial risk factors and risk management (continued)

As at 30 June 2020	Market Movement	Effect on profit before tax $000	Effect on equity $000
Brent oil price	USD10/bbl increase	-	(150,497)
Brent oil price	USD10/bbl decrease	-	150,497
NBP gas price	GBP 0.1/therm increase	-	(123,883)
NBP gas price	GBP 0.1/therm decrease	-	123,883
As at 31 December 2019			
Brent oil price	USD10/bbl increase	-	(208,370)
Brent oil price	USD10/bbl decrease	-	208,370
NBP gas price	GBP 0.1/therm increase	-	(135,893)
NBP gas price	GBP 0.1/therm decrease	-	135,893

Note: the contingent consideration in relation to the 2019 calendar year was fully settled in March 2020 and as a result there are no movements on the fair value of crude based derivative instruments reported through the income statement since the year ended 31 December.

(b) Interest Rate Risk

Floating rate borrowings comprise bank loans under the RBL and junior facilities which incur interest fixed six months in advance at USD Libor plus a margin of 3.25 to 5.25 percent. Fixed rate borrowings comprise a series of shareholder loan notes which incur interest at 10 percent per annum. At the option of the Company, interest on the shareholder loan notes can be capitalised into the principal amount and settled at maturity. Floating rate financial assets comprise cash and cash equivalents which earn interest at the relevant market rate. The Group monitors its exposure to fluctuations in interest rates and uses interest rate derivatives to manage the fixed and floating composition of its borrowings.

The below represents interest rate financial instruments in place at 30 June 2020:

Derivative	Currency	Period of hedge	Terms
Interest rate swaps	$700 million	Jun 20 – Jun 25	Average 0.5561%

There were no interest rate financial instruments in place at 31 December 2019.

The interest rate and currency profile of the Group's interest-bearing financial assets and liabilities is shown below.

24. Financial risk factors and risk management (continued)

As at 30 June 2020	Cash at bank $000	Fixed rate borrowings $000	Floating rate borrowings $000	Total $000
US Dollars	328,396	(283,065)	(1,871,004)	(1,825,673)
Pound Sterling	39,545	-	-	39,545
Norwegian Krone	1,413	-	(11,088)	(9,675)
Other	37	-	-	37
	369,391	(283,065)	(1,882,092)	(1,795,766)
As at 31 December 2019				
US Dollars	510,109	(316,506)	(2,497,180)	(2,303,577)
Pound Sterling	53,694	-	-	53,694
Norwegian Krone	15	-	(8,999)	(8,984)
Other	9,364	-	-	9,364
	573,182	(316,506)	(2,506,179)	(2,249,503)

The following table illustrates the indicative pre-tax effect on profit and equity of applying a reasonably foreseeable increase in interest rates to the Group's financial assets and liabilities at the balance sheet date. The Company had no significant floating rate asset or liabilities in the current or previous year.

2020	Market Movement	Effect on profit before tax $000	Effect on equity $000
US Interest Rates	+100 basis points	(15,716)	-
2019			
US Interest Rates	+100 basis points	(20,239)	-

24. Financial risk factors and risk management (continued)

(c) Foreign Currency Risk

The Group is exposed to foreign exchange risks to the extent it transacts in various currencies, while measuring and reporting its results in US Dollars. Since time passes between the recording of a receivable or payable transaction and its collection or payment, the Group is exposed to gains or losses on non-USD amounts and on balance sheet translation of monetary accounts denominated in non-USD amounts upon spot rate fluctuations from period to period. To mitigate exposure to movements in exchange rates, wherever possible financial assets and liabilities are held in currencies that match the functional currency of the relevant entity. The Group has subsidiaries with functional currencies of Pounds Sterling, US Dollar and Norwegian Krone. Exposures can also arise from sales or purchases denominated in currencies other than the functional currency of the relevant entity, and such exposures are monitored and hedged with agreement from the Board.

The Group enters into forward contracts as a means of hedging its exposure to foreign exchange rate risks. As at 30 June 2020, the Group had £125.0 million hedged at forward rates of between $1.2311 and $1.2413: £1 for the period July 2020 to January 2021, and EUR 13,777,750 hedged at forward rates of between $1.1039 and $1.1061: EUR for the period July 2020 to December 2020.

As at 31 December 2019, the Group had not entered into any exchange rate derivatives.

The following table demonstrates the sensitivity to a reasonably foreseeable change in US Dollar against Pounds Sterling with all other variables held constant, of the Group's profit before tax (due to foreign exchange translation of monetary assets and liabilities). The impact of translating the net assets of foreign operations into US Dollars is excluded from the sensitivity analysis.

2020	Market Movement	Effect on profit before tax $000	Effect on equity $000
US dollar/Sterling	10% strengthening	140,922	-
US dollar/Sterling	10% weakening	(140,922)	-
2019			
US dollar/Sterling	10% strengthening	133,595	-
US dollar/Sterling	10% weakening	(133,595)	-

(d) Credit Risk

Credit risk is the risk that a counterparty will not meet its obligations under a financial instrument or customer contract, leading to financial loss. The Group is exposed to credit risk from its operating activities (primarily for trade receivables) and from its financing activities, including deposits with banks and derivative financial instruments.

The Group only sells hydrocarbons to recognised and creditworthy parties, typically the trading arm of large, international oil and gas companies. An indication of the concentration of credit risk on trade receivables is shown in note 4, whereby the revenue from one customer exceeds 96 percent of the Group's consolidated revenue.

The credit risk on liquid funds and derivative financial instruments is limited because the counterparties are internationally recognised banking institutions and are considered to represent minimal credit risk.

There are no significant concentrations of credit risk within the Group unless otherwise disclosed, and credit losses are expected to be near to zero. The maximum credit risk exposure relating to financial assets is represented by carrying value as at the balance sheet date.

(e) Liquidity Risk

The Group monitors the amount of borrowings maturing within any specific period and proposes to meet its financing commitments from the operating cash flows of the business and existing committed lines of credit.

The table below summarises the maturity profile of the Group's financial liabilities at 30 June 2020 and 31 December 2019 based on contractual undiscounted payments.

2020 Half-Year Results

24. Financial risk factors and risk management (continued)

As at 30 June 2020	Within one year $000	1 to 2 years $000	2 to 5 years $000	Over 5 years $000	Total $000
Non-derivative Financial Liabilities					
Reserves Based Loan facility	55,778	57,422	1,285,698	339,578	1,738,476
Junior facility	22,770	111,570	272,398	74,479	481,217
Loan notes	-	-	-	561,840	561,840
Exploration finance facility	8,624	2,805	-	-	11,429
Other loans	606	15,519	35,834	7,849	59,808
Trade and other payables	733,821	27,673	18,747	-	780,241
Lease obligations	53,634	53,555	30,145	33,916	171,250
	875,233	268,544	1,642,822	1,017,662	3,804,261
Derivative Financial Liabilities					
Net-settled commodity derivatives	109	-	9,688	-	9,797
Net-settled interest rate derivatives	-	-	-	4,859	4,859
Total as at 30 June 2020	875,342	268,544	1,652,510	1,022,521	3,818,917

As at 31 December 2019					
Non-derivative Financial Liabilities					
Reserves Based Loan facility	713,412	580,844	1,030,513	79,060	2,403,829
Junior facility	29,154	29,075	354,062	105,674	517,965
Loan notes	-	-	-	660,052	660,052
Exploration finance facility	9,732	-	-	-	9,732
Other loans	16,046	13,290	23,856	-	53,192
Trade and other payables	593,066	32,575	19,800	-	645,441
Lease obligations	80,045	72,220	54,938	30,302	237,505
	1,441,455	728,004	1,483,169	875,088	4,527,716
Derivative Financial Liabilities					
Net-settled commodity derivatives	40,445	1,330	2,333	-	44,108
Total as at 31 December 2019	1,481,900	729,334	1,485,502	875,088	4,571,824

The maturity profile in the above tables reflect only one side of the Group's liquidity position. Interest bearing loans and borrowings and trade payables mainly originate from the financing of assets used in the Group's ongoing operations such as property, plant and equipment and working capital such as inventories. These assets are considered part of the Group's overall liquidity risk.

25. Share Capital

Allotted, called up and fully paid	No.	2020 $000	No.	2019 $000
F Ordinary shares of £0.01 each	4,994,624	61	4,994,625	61
G Ordinary shares of £0.40 each	18,900	10	18,900	10
M Ordinary shares of £0.01 each	9,865	-	9,865	-
		71		71

As at 30 June 2020, the share capital comprised of three classes of ordinary shares. Each F and G ordinary share carries equal voting and dividend rights.

M ordinary shares carry no voting rights and are subordinate to both F and G ordinary shares regarding rights to dividend and other distributions.

2020 Half-Year Results

26. Notes to the statement of cash flows

Net cash flows from operating activities consist of	6 months ended 30 June 2020 $000	6 months ended 30 June 2019 $000
(Loss)/profit before taxation	(224,222)	323,705
Finance cost, excluding foreign exchange	148,768	123,470
Finance income, excluding foreign exchange	(3,460)	(10,190)
Depreciation, depletion and amortisation	723,468	359,307
Impairment of property, plant and equipment	250,629	-
Impairment of goodwill	55,735	-
Exploration write-off	38,851	132
Movement in realised cash-flow hedges not yet settled	(34,691)	(8,082)
Remeasurement on commodity-price-contingent consideration	-	22,460
Remeasurement of acquisition-completion adjustments	391	-
Onerous contract provision	27,943	-
Decommissioning expenditure	(96,636)	(5,260)
Unrealised foreign-exchange gain	(104,662)	(2,057)
Decrease in royalty consideration receivable	800	1,600
Gain on termination of IFRS16 lease	(584)	-
Remeasurement on exploration-contingent consideration	-	276
Net tax receipts	6,583	-
Loss on disposal of exploration and evaluation asset	55	-
Working-capital adjustments		
Increase in inventories	(9,738)	(4,743)
Decrease/(increase) in trade and other receivables	202,875	(50,387)
(Decrease)/increase in trade and other payables	(36,009)	23,991
Net cash inflow from operating activities	946,096	774,222

26. Notes to the statement of cash flows (continued)

Reconciliation of net cash flow to movement in net borrowings	6 months ended 30 June 2020 $000	Year ended 31 December 2019 $000
Proceeds from drawdown of borrowing facilities	-	(1,834,000)
Proceeds from financing arrangement	-	(29,600)
Conversion of E loan notes to equity	-	675,264
Proceeds from exploration-financing facility loan	(2,596)	(9,275)
Repayment of senior debt	634,000	200,000
Transaction costs capitalised	765	45,641
Loan notes partial redemption	46,860	-
Financing-arrangement interest (payable)/receivable	(1,055)	19,696
Amortisation of transaction costs capitalised	(7,605)	(15,581)
Currency translation adjustment on EFF loan	617	(175)
Currency translation adjustment on transaction costs	(39)	1
Loan notes interest capitalised	(13,419)	(69,767)
Movement in total borrowings	657,528	(1,017,796)
Movement in cash and cash equivalents	(203,791)	256,871
Decrease/(increase) in net borrowings in the period	453,737	(760,925)
Opening net borrowings	(2,249,503)	(1,488,578)
Closing net borrowings	(1,795,766)	(2,249,503)

Analysis of net borrowings	6 months ended 30 June 2020 $000	Year ended 31 December 2019 $000
Cash and cash equivalents	369,391	573,182
Reserves Based Loan facility	(1,439,706)	(2,067,339)
Junior facility	(396,014)	(395,613)
Net debt	(1,466,329)	(1,889,770)
Shareholder loan notes	(283,065)	(316,506)
Exploration financing facility	(11,088)	(8,999)
Financing arrangement	(35,284)	(34,228)
Closing net borrowings	(1,795,766)	(2,249,503)

Borrowings consist of unsecured loan notes, short-term debt and long-term debt. The carrying values on the balance sheet are stated net of the unamortised portion of the issue costs and bank fees of $64.3 million (2019: $71.1 million).

2020 Half-Year Results

27. Related Party Disclosures

The consolidated financial statements include the financial statements of the Company and its subsidiaries, a list of which is contained in note 14.

The Group's main related parties comprise members of key management personnel and Harbour Energy Ltd (Harbour Energy) along with affiliated persons and entities. Harbour Energy is an energy investment vehicle formed by EIG Global Energy Partners and is the Group's primary private equity investor. Transactions with these related parties are disclosed below.

Share Capital

On 31 August 2019, the 10 percent Unsecured E Loan notes held by Harbour Energy, with a principal and accrued interest value of $675.3 million, were exchanged for 4,013,524 F ordinary shares of £0.01 each. In November 2019, 225 M ordinary shares of £0.01 each were issued to certain members of key management for a cash consideration of £10 per share.

Shareholder Loan Notes

At the end of 2018, Harbour Energy held E loan notes with a principal value of $566.9 million plus accrued interest. On 31 August 2019, all the E Loan Notes including accrued interest were exchanged for F ordinary shares, at a value of $675.3 million. The main impact of the exchange is that Harbour Energy's direct equity interest in CHL increased to 89.6 percent from 48 percent. In February 2020, a partial redemption of both the C Loan Notes and D Loan Notes took place, of $4.9 million and $42.0 million respectively.

As at 30 June 2020, the carrying amount of D loan notes due to Harbour Energy was $252.2 million (Dec 2019: $282.2 million) and the value of C loan notes due to key management personnel was $1.8 million (Dec 2019: $2.0 million). The amount of interest charged to the income statement associated with all loan notes payable to Harbour Energy and key management was $12.1 million and $0.1 million respectively (6 months to 30 June 2019: $43.5 million and $0.2 million respectively).

The Company also pays governance and monitoring fees to its institutional shareholders. For the six months to 30 June 2020, the total fees payable to Harbour Energy amounted to $4.3 million (2019: $4.3 million) and to other shareholders $0.5 million (2019: $0.5 million) with $0.5 million outstanding as at the balance sheet date (2019: $0.5 million).

Controlling Party

The immediate parent undertaking is Harbour Chrysaor Equity Holdings Ltd (Cayman). The ultimate parent undertaking and the largest and smallest group to consolidate these financial statements is Harbour Energy Holdings Ltd (Cayman). Copies of the Harbour Energy Holdings Ltd consolidated financial statements can be obtained from the company secretary at 7th Floor, 20 St. James's Street, London, SW1A 1ES.

Key Management Compensation

Remuneration of key management personnel of the Group is shown below. The remuneration of the Non-Executive Chairman is wholly paid by EIG Management Company. The remuneration of the Harbour-appointed directors for their board roles of the Company is wholly paid by Harbour Energy.

27. Related Party Disclosures (continued)

Group	6 months ended 30 June 2020 $000	6 months ended 30 June 2019 $000
Salaries and short-term benefits	4,937	3,526
Payments made in lieu of pension contributions	356	244
Pension benefits	55	63
	5,348	3,833

28. Post Balance Sheet Events

On the 6 October 2020, we announced that agreement had been reached with Premier Oil plc and Harbour Energy regarding a proposed reverse takeover all share merger between Premier and Chrysaor and the reorganisation of Premier's existing debt and cross-currency swaps. Completion of the transaction is subject to regulatory approvals, approval by Premier's shareholders, the existing creditors and expected in 1Q 2021.

The transaction will create the largest independent oil and gas company listed on the London Stock Exchange with combined production of over 250 mboepd as at 30 June 2020 and 2P reserves of 717 mmboe as at 31 December 2019. The combined Group will be of significant scale and diversification with a strong balance sheet and significant international growth opportunities.

In September 2020, the Group put in place a new Long-Term Incentive Plan ('LTIP') scheme for senior employees. The LTIP is a cash settled scheme based on a number of notional shares multiplied by a notional share price. The scheme has a maximum number of notional shares that can vest. Performance conditions determine the final number of vesting notional shares and there are three performance measures covering absolute and relative total shareholder return and return on capital employed. The vesting period is three years from the scheme grant date with cash settlement to the employees twelve months after the vesting period provided the individual remains in employment.

2020 Half-Year Results

Glossary	
2C	Contingent Resources
2P	Proven And Probable Reserves
bbl	Barrel
boe	Barrels Of Oil Equivalent
boepd	Barrels Of Oil Equivalent Per Day
AELE	Armada, Everest, Lomond and Erskine
AFE	Authorisation For Expenditure
APA	Awards In Pre-Defined Areas
BCT	Business Continuity Team
BP2	Buzzard Phase 2
CATS	Central Area Transmission System
CMT	Crisis Management Team
CO_2	Carbon Dioxide
E&A	Exploration and Appraisal
E&P	Exploration and Production
EEE	Everest East Expansion
EFF	Exploration Finance Facility
FPS	Forties Pipeline System
FPV	Floating Production Vessel
FPSO	Floating Production Storage Offloading
HLV	Heavy-Lift Vessel
HUC	Hook Up and Commissioning
HSEQ	Health, Safety, Environmental and Quality
KPI	Key Performance Indicators
OGA	Oil and Gas Authority
OPEC	Organisation Of The Petroleum Exporting Countries
P&A	Plug and Abandon
POB	Persons On Board
POD	Plan For Development and Operation
TCFD	Task Force On Climate-Related Financial Disclosures
TGT	Theddlethorpe Gas Terminal
TRCF	Total Recordable Rate Frequency
UKCS	Uk Continental Shelf

Non-IFRS measures

Chrysaor uses certain measures of performance that are not specifically defined under IFRS or other generally accepted accounting principles. These non-IFRS measures, which are presented within the Financial Review, are EBITDAX, cost per barrel, depreciation, depletion and amortisation per barrel, free cash flow and net debt, and are defined below:

- **EBITDAX:** is defined as earnings before tax, interest, depreciation and amortisation, impairments, remeasurements, onerous contracts and exploration expenditure. This is a useful indicator of underlying business performance.
- **Depreciation, depletion and amortisation per barrel (DD&A):** depreciation and amortisation of oil and gas properties for the period divided by working interest production. This is a useful indicator of ongoing rates of depreciation and amortisation of the Group's producing assets.
- **Net debt:** total senior and junior debt less cash and cash equivalents recognised on the consolidated balance sheet. This is an indicator of the Group's indebtedness and contribution to capital structure.
- **Operating free cash flow** is defined as net cash flows from operating activities less cash outflows on capital investment.
- **Operating cost per barrel:** direct operating costs (excluding over/underlift) for the period, including tariff expense and insurance costs less tariff income, divided by working interest production. This is a useful indicator of ongoing operating costs from the Group's producing assets.