Premier Oil plc
("Premier" or the "Group" or the "Company")
Half-Year Results for the six months to 30 June 2020

20 August 2020

Premier today announces its half-year results for the period ended 30 June. Separately, the Group has announced this morning a proposed long-term refinancing of its business.

Tony Durrant, Chief Executive, commented:
"We have taken decisive action to safeguard our people and our assets. We have reduced our expenditure which, together with our hedging programme and the continued underlying performance of our assets, resulted in us generating free cash flow for the period, despite the collapse in commodity prices. The BP Acquisitions and our proposed long-term refinancing will position Premier to benefit from materially rising near-term production, additional free cash flow generation and a strengthening balance sheet, against a backdrop of a recovering oil price."

Operational highlights

- Production of 67.3 kboepd (2019 1H: 84.1 kboepd); 2020 guidance of 65-70 kboepd (before any contribution from the BP Acquisitions) reiterated
- Solan P3 due on-stream in September, forecast to add c.10 kbopd in Q4 to Group production rates; Varadero infill well drilled, supporting Catcher Area oil plateau rates
- Tolmount: platform loaded out, on track to meet Q2 2021 first gas date; adds 20-25 kboepd of net tax-advantaged production once at plateau
- Zama: FEED on track to complete by end Q3; Block 7 partners engaged with Pemex to agree unitisation
- Unsanctioned growth projects put on hold, optionality preserved: Sea Lion and Tuna farm outs agreed, subject to final approvals
- New seismic data interpretations for UK, Indonesia and Mexico confirm highly prospective locations for future drilling
- BP Acquisitions terms revised and creditor approved; adds 19 kboepd (net) of tax-advantaged production
- Commitment to develop all new operated projects on a net zero emissions basis stands the Company in good stead to be carbon-neutral by 2030

Financial highlights

- Operating cash flow of US$324 million (2019 1H: US$545 million); free cash flow was US$25 million (2019 1H: US$188 million) with net debt reduced to US$1.97 billion at end of June (31 December 2019: US$1.99 billion)
- US$32 million loss after tax before one off non-cash charges of US$639 million, resulting in a US$672 million loss after tax (2019 1H: US$121 million profit after tax)
- Forecast 2020 total capex (US$340 million), opex (US$12/boe) and lease costs (US$6/boe), reflecting US$240 million of savings and deferrals secured
- Forecast free cash flow positive for 2020 at current forward curve (before any contribution from the cash generative BP assets)
- Proposed long-term refinancing (announced separately today) resets capital structure and provides runway for the Group to materially reduce debt over time

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Half-Year Results for the six months to 30 June 2020

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We will host a virtual presentation and Q&A session for investors and analysts at 09:00 (BST) today, 20 August 2020, accessible via our website: www.premier-oil.com.

Half-Year Results for the six months to 30 June 2020

Overview

The first half of the year saw significant commodity price weakness and volatility, driven by the unprecedented collapse in global oil demand due to the COVID-19 pandemic. Oil prices recovered to around US$40/bbl towards the end of the period supported by record supply cuts by OPEC and other producers. The global demand and supply position is now more balanced but uncertainty persists around the timing of any further short-term commodity price recovery which depends, among other factors, upon the path of the viral outbreak.

Production operations

Premier's production averaged 67.3 kboepd for the first six months of the year, with the Group ensuring the continued safe operations of its producing assets by reducing manning levels on its installations, significantly reducing the scope of planned shutdowns and establishing pre-mobilisation screening measures and protocols.

Free cash flow through the cycle remains a pre-requisite for the Group and Premier reacted promptly to the collapse in commodity prices by reducing its expenditure to lower its full-year cash cost breakeven. Safety-critical maintenance and capital investments in high-return projects which impacted near-term production were prioritised while discretionary expenditure with longer payback periods was deferred. In addition Premier, together with its joint venture partners, brought forward cessation of production from several of its more mature North Sea assets which were not generating positive free cash flow and were due to be abandoned within the next 12 months.

The continued underlying performance of Premier's assets along with the decisive action taken to reduce costs and preserve cash resulted in the Group's net debt position reducing during the period. Based on the current forward curve, Premier continues to expect to be free cash flow positive (after interest) for the full year 2020.

Production projects and developments

The first half saw the Group successfully and safely execute a number of high-return infill drilling and well intervention campaigns across its producing assets, despite the additional complexity of managing supply chains and delivering projects during a global pandemic. In particular, the third Solan production well is scheduled to be brought on-stream in September and will boost current Group production levels by c.10 kbopd to over 75 kboepd during the fourth quarter (before any contribution from the BP Acquisitions).

The Premier-operated Tolmount development, the Group's only current sanctioned growth project, is on track to deliver first gas in the second quarter of next year. Premier has minimised its share of development capex through an innovative partnership with HGSL, a Kellas Midstream company, who together with Dana Petroleum will jointly own the Tolmount platform and pipeline. The Tolmount field will add 20-25 kboepd (net, Premier 50 per cent) of tax-advantaged production once at plateau rates, later in 2021.

Premier has a highly attractive portfolio of pre-sanction development projects and exploration and appraisal acreage which offer the potential for significant value creation for all of its stakeholders. In light of the current market conditions, Premier has sought to minimise its current expenditure on these projects while at the same time preserving their optionality for future growth. This included temporarily suspending its operated Sea Lion Phase 1 project in the Falkland Islands and deferring all exploration drilling activities by at least one year. Nonetheless, exploration remains a core part of Premier's business model and the Group is particularly encouraged by the recently received seismic data in Indonesia, Mexico and the UK, which confirms the significant resource potential of its acreage.

Acquisitions, disposals and refinancing

Premier continually reviews its portfolio, seeking to progress acquisitions which materially enhance its asset base and create synergies with existing core businesses while selectively disposing of assets to accelerate cash flow. In Mexico, the sales process for Premier's interest in the giant Zama field and the unitisation of the field with the neighbouring block were impacted by the collapse in oil prices and COVID-19. It is Premier's intention to resume discussions with interested parties towards the end of this year, once the unitisation process is further advanced.

In June, Premier announced revised terms for its proposed acquisitions of BP's interests in the Andrew Area and the Shearwater field (the "BP Acquisitions") in the UK North Sea to reflect the material changes in the global commodity markets. The BP Acquisitions, which are expected to be fully funded by equity, are materially value accretive and in line with the Group's stated strategy of acquiring cash generative assets in the UK North Sea, where Premier has strong operating capability and considerable tax losses. This is consistent with the Group's deleveraging objectives.

Post period-end, the Group announced proposed terms of the refinancing of the Group's US$2.9 billion of gross committed debt facilities, which would extend the Group's credit maturities from May 2021 to March 2025. The proposed refinancing, together with the BP Acquisitions, will reset the Group's capital structure and provide a four and a half year runway for the Group to benefit from rising production and additional free cash flow generation. It will also enable Premier to focus on delivering value from its top tier development and exploration portfolio, either through reinvestment or monetisation, and puts Premier in a strong position to refinance the business with a more conventional and lower cost debt structure come 2024.

The proposed refinancing of the Group's debt facilities and the BP Acquisitions and related equity funding remain subject to a number of conditions, including shareholder approval. Creditor approval is also required for the proposed refinancing. Further details are provided in a separate press release issued today.

Sustainability

It remains the Group's highest priority to continue to operate all of its assets in a safe and responsible manner, to ensure the safety of its workforce and to minimise the potential risk to the environment. During the first half, Premier recorded no significant spills and further reduced the Greenhouse Gas intensity of its operated assets, supported by the Group's focus on continuous improvement in its emissions performance and its proactive decision to abandon some of its older fields.

Premier's environmental hopper, which captures all possible projects with the potential to reduce emissions and now forms an integral part of the Company's capital allocation process, together with its industry-leading commitment to develop all of its new operated projects on a net zero emissions basis, stands the Company in good stead for all of its operations to be carbon-neutral by 2030.

Outlook

Completing the proposed BP Acquisitions and the refinancing of Premier's debt facilities remains a key near-term corporate priority for the Group. These proposed transactions will help normalise Premier's balance sheet and allow the Group to benefit from additional free cash flow generation to continue to reduce debt.

With a strengthened balance sheet and strongly rising near-term production, Premier will be well placed to start reinvesting in some of its growth projects to deliver value for all of its stakeholders. However, the Company will remain disciplined and selective in the projects it progresses, realising value from part or full disposal of development assets where appropriate, and balancing growth against its commitment to reduce further its debt.

Operational review

United Kingdom

UK production averaged 45.0 kboepd (2019 1H: 58.1 kboepd) during the period, a reduction on the prior corresponding period due to a temporary Catcher outage and cessation of production from the Huntington and Kyle fields being brought forward. New production from Solan and the BP Acquisitions together with Tolmount at plateau rates will result in Premier's UK tax advantaged production increasing to over 75 kboepd later in the second half of 2021.

The Catcher Area

The Catcher Area fields averaged 28.4 kboepd (net, Premier 50 per cent) (2019 1H: 35.1 kboepd) during the first six months of the year with the fields continuing to produce at plateau oil rates supported by excess well deliverability.

The reduction on the prior corresponding period is attributable to an unplanned 20-day outage during the second quarter driven by the failure of a gas pre-heater (now repaired). It also reflected lower gas sales with some produced gas being re-injected into the reservoir. The wells are being monitored during gas reinjection to evaluate the opportunity for improved oil recovery from the fields and indications to date have been positive. Following the planned shutdown and maintenance work in August, Catcher oil production will return to 66 kbopd with the gas plant fully reinstated and able to export gas.

Drilling operations at the Varadero infill well (VP1) were completed post period-end and the well is scheduled to be brought on-stream in September to help maintain plateau oil rates from the Catcher Area into 2021. Development drilling at Catcher North and Laverda, originally scheduled for this year, was deferred as part of the measures taken to manage the Group's 2020 capex spend.

Beyond Catcher North and Laverda, Premier continues to mature a programme of high return investments to maximise economic recovery from within and around the Catcher Area. The opportunities being matured for consideration include additional targets outside the existing well stock and 4D seismic acquisition to derisk further infill locations.

The Catcher cargoes sold during the period have on average commanded a US$2/bbl premium to Brent.

Other UK producing assets

The non-operated Elgin-Franklin Area, which is the UK's largest producing field group and produced its billionth barrel equivalent during the period, averaged 7.3 kboepd (net, Premier 5.2 per cent) (2019 1H: 6.5 kboepd), materially ahead of budget. This was driven by exceptional uptime and supported by new production from the FIC target infill well which came on-stream at the end of 2019. Post period-end, a four well stimulation campaign commenced which, together with the ongoing infill drilling programme, will help enhance production from the Area. The joint venture partnership is also considering undertaking an additional rig-based intervention campaign on three Franklin wells later in the year.

Production from Premier's operated Solan field averaged 1.7 kboepd (Premier 100 per cent interest) (2019 1H: 4.0 kboepd). Production was impacted by a planned shutdown for P3 platform modifications in May and the second production well (P2) being on free flow from March. In June, the Solan P3 vertical pilot well was successfully side-tracked horizontally, encountering more than 2,300 feet of net sand with reservoir properties at the higher end of expectations. The rig moved off location mid-July following completion of well operations, which included the installation of two electronic submersible pumps. Subsea tie-in activities have now commenced. Once on-stream later this quarter, P3 is expected to boost production rates from the Solan field by c.10 kbopd.

Ravenspurn North averaged 1.2 kboepd (2019 1H: 1.2 kboepd) (net, Premier 28.8 per cent interest). The joint venture partnership took the decision to defer the two well infill programme, originally scheduled to take place in 2020, in light of the current macroeconomic environment. The two wells remain under review pending an improvement in the gas price outlook. In the meantime, additional well intervention activity to support production is under consideration.

Premier's operated Balmoral Area delivered 2.0 kboepd (2019 1H: 1.5 kboepd) (net, Premier) during the period, materially ahead of budget due to high uptime.

In conjunction with its joint venture partners, Premier has taken the decision to cease production from its more mature fields not generating positive cash flows in the current environment. During the first half, Huntington and Kyle ceased production and final production from the operated Balmoral Area is now planned for October 2020. Huntington's subsea infrastructure was flushed, cleaned and disconnected ahead of the Voyageur Spirit FPSO being brought into port post period-end. Abandonment expenditure from these fields which comprise floating production facilities is not expected to be material in the near-term with related well abandonment expenditure spread over a number of future years.

UK unit field operating costs averaged US$13.6/boe, c. 20 per cent below budget reflecting cessation of production from higher cost fields and also savings and deferrals realised in ongoing UK operations.

The Greater Tolmount Area

The 500 BCF (gross) Tolmount gas field (Premier-operated 50 per cent interest) is Premier's only current sanctioned development project and underpins the Group's medium-term UK production profile.

The Tolmount development schedule was impacted by COVID-19 when the Italian yard where the platform was being built entered lockdown at the end of March. Work resumed in early May and the jacket and topsides were successfully loaded onto the Heerema barge ahead of planned sailaway at the end of August. A consequence of the COVID-19 delay and the platform being in the yard for longer is a very high level of completion at sailaway with minimal carryover of work offshore. Offshore installation of the platform remains on track for end September/early October with the rig to mobilise thereafter to drill the four development wells.

The pipeline was successfully laid, trenched and buried over the summer and some rock placement to protect the pipeline crossing points has commenced. The beach remediation work is also well advanced following the completion of the shoreline pull-in. Works on the onshore terminal modifications are progressing to meet planned first gas.

First gas from the Tolmount field is forecast for the second quarter of 2021 with the field expected to add 20-25 kboepd to Group production once up at plateau rates later in the year. Premier's forecast of its share of capex to first gas, which comprises project management and drilling costs, remains unchanged at around US$120 million.

The Tolmount project encapsulates Premier's mission to be low carbon by design and carbon neutral by commitment. The Tolmount facilities have been designed to minimise emissions, deploying the most up to date technologies, and Premier plans to offset any residual emissions with nature-based carbon capture projects, primarily forestry.

FEED on the proposed Tolmount East development, initially comprising a single well subsea tie back to the Tolmount platform, is now complete and Premier is currently evaluating bids for subsea umbilicals, risers, flowlines (SURF), subsea controls and wellheads ahead of being in a position to make a final investment decision in December. Once on-stream Tolmount East (and potentially the neighbouring Mongour discovery which can be drilled from the Tolmount East template) will help extend plateau production from the Tolmount area.

The final processed data from the 3D seismic acquired across the Greater Tolmount Area in 2019 was received post period-end and is being used to further mature the Tolmount Far East prospect and to further assess prospectivity to the east and west of the Tolmount field. While Tolmount is a robust project and the prospectivity in the surrounding area continues to improve, Premier decided not to pursue the acquisition of an additional 25 per cent interest in the project. Rather, the Group prioritised the more strategically material BP Acquisitions which add 19 kboepd of immediately cash generative production and a new hub operatorship.

The BP Acquisitions

In June, Premier announced revised terms for its proposed acquisition of BP's interests in the Andrew Area and the Shearwater field in the UK North Sea to reflect the material developments in the global commodity markets. This included a significantly reduced completion consideration and also changing the decommissioning arrangements with the majority of the obligations now staying with BP. Post period-end and following receipt of creditor approval for the BP Acquisitions, Premier signed the sale and purchase agreements reflecting the amended terms.

The BP Acquisitions provide Premier with operated interests in the Andrew Area and a non-operated interest in the Shearwater field, a significant production and infrastructure hub in the Central North Sea. Both the Andrew Area and the Shearwater field add mid-life production with material upside potential through production optimisation, incremental developments and field life extension projects. The BP Acquisitions, which are expected to be fully funded by equity, will consolidate the Group's position in the UK North Sea, one of Premier's core areas, while at the same time accelerating the use of the Group's US$4.1 billion of tax losses and the deleveraging of its balance sheet.

During the period, production from the Andrew Area and the Shearwater field averaged 16.3 kboepd (net to BP) and 4.4 kboepd (net to BP) respectively. Both assets outperformed Premier's assumptions driven by high operating efficiency.

The Andrew transition work, including the transfer of operatorship from BP to Premier, is well advanced while the requisite regulatory and joint venture approval processes are progressing for both the Andrew Area and the Shearwater field. Post period-end, BP was notified by the Shearwater joint venture partners that they will not be exercising their contractual rights to acquire BP's interests in the Shearwater field. The BP Acquisitions remain conditional on equity funding and customary other approvals, including shareholder approval.

Indonesia

Premier's Indonesian Business Unit generated positive net cash flows during the first six months of the year driven by strong gas demand and high deliverability following the completion of the BIG-P development at the end of 2019.

Production

Production from the Premier-operated Natuna Sea Block A averaged 13.2 kboepd (net, Premier 28.7 per cent interest) (2019 1H: 11.1 kboepd) for the first six months of the year, ahead of budget and higher than the prior corresponding period. This was driven by very high Singapore demand for gas sold under GSA1, Premier's principal gas sales agreement, and high block deliverability following first gas from the BIG-P project.

Singapore demand for gas sold under GSA1 averaged 303 BBtud (gross) (2019 1H: 285 BBtud), ahead of take-or-pay levels and driven by very high offtake during the first four months of the year with the price of GSA1 gas reducing towards that of spot LNG.

Premier's Anoa, Pelikan, Bison and Gajah Puteri fields, which are dedicated to GSA1, delivered 174 BBtud (gross) (2019 1H: 149 BBtud (gross)) during the period and accounted for 57 per cent of GSA1 deliveries (2019 1H: 52 per cent). This was materially above Natuna Sea Block A's 2020 contractual share of 52.5 per cent.

Production from the Gajah Baru, Naga and Iguana gas fields, which supply gas into Singapore under the Group's second gas sales agreement (GSA2) averaged 64 BBtud (gross) (2019 1H: 50 BBtud), slightly ahead of take-or-pay levels.

Premier's Indonesian gas pricing is driven by HSFO prices. In light of the impending implementation of IMO2020 legislation and low oil price environment, Premier hedged a significant proportion of its 2020 Indonesian gas entitlement production at c.US$9/mmscf, significantly above current spot prices.

Preparations are underway for a 2021 jack-up rig campaign which will include an Anoa well workover, an Anoa infill well and a Gajah Baru well workover. Premier continues to evaluate additional incremental investment opportunities, including the potential to drill a well to test the northern flank of Anoa, to support deliverability from its Natuna Sea Block A fields and to backfill its existing gas sales contracts into Singapore which extend to 2028.

Exploration and appraisal

In May, Premier agreed a farm down agreement with Zarubezhneft for a 50 per cent interest in the Group's-operated Tuna discoveries offshore Indonesia. Under the farm down agreement, which remains subject to government approvals, Zarubezhneft will carry Premier for its share of a two well appraisal campaign now expected to take place in 2021. It is anticipated that, post completion and receipt of government approval, Premier will retain operatorship and a 50 per cent interest in the Tuna PSC.

In January 2020, Premier was awarded a one-year extension to the exploration period of the Tuna PSC to allow for appraisal drilling to take place and the subsequent submission of a Plan of Development to the Indonesian government. However, as a result of the COVID-19 pandemic and the ensuing delays to the drilling, a further one year extension to March 2022 will be requested.

Elsewhere in Indonesia, in Premier's highly prospective Andaman Sea licences, the final processed 3D seismic data was received during the second quarter of 2020 and showed a number of low risk, significant gas prospects to be present. Premier plans to drill its first well in the Andaman Sea on its operated Andaman II licence in the first half of 2022 as part of a programme of wells, including drilling on its South Andaman licence, operated by Mubadala Petroleum. Premier's Andaman Sea position has the potential to add a material gas play to the Group's portfolio.

Vietnam

Premier's operated Chim Sáo field continued to deliver a robust production performance during the first six months of the year. This, together with continued low operating costs and Chim Sáo crude continuing to command a premium to Brent, resulted in the asset generating material free cash flow for the Group.

Production from the Premier-operated Block 12W, which contains the Chim Sáo and Dua fields, averaged 9.1 kboepd (net, Premier-operated 53.1 per cent interest) (2019 1H: 12.4 kboepd) and was in line with expectations. The reduction on the prior year reflects natural decline from the existing wells partially offset by active reservoir well management and ongoing well work activities.

The first six months of the year saw two well intervention campaigns, including a water shut off intervention at a production well in the north western part of the field, aimed at maximising the ultimate recovery from the Chim Sáo field. A third campaign, which involved remedial activities within an existing producer, was successfully completed post period-end materially enhancing production. Preparations are underway for further well intervention work later in 2020 and 2021 to mitigate natural decline and optimise offtake from the Chim Sáo field.

A two well infill programme, originally scheduled for 2021, has been deferred to 2022, helping to minimise 2020 capex spend. Premier is currently in the process of seeking regulatory approvals for this programme.

Chim Sáo crude remained in demand during the period, despite the significant collapse in global oil demand due to COVID-19, with cargoes sold during the first half realising an average premium to Brent of over US$5/bbl.

Field operating costs were US$8.9/boe, significantly below budget, as a result of the deferrals of non-critical maintenance programmes and additional savings captured following the COVID-19 pandemic.

Falkland Islands

During the period, Premier temporarily suspended its operated 250 mmbbl Sea Lion Phase 1 project to minimise near-term expenditure and preserve Group cash during the current downturn. Meanwhile, Navitas remains on track to farm in for a 30 per cent interest in the Sea Lion licences.

At the end of the first quarter, Premier took the decision to temporarily suspend its operated Sea Lion Phase 1 project in the Falkland Islands. Technical definition of the project was completed prior to suspension and all work fully documented to enable the project to be reactivated once the macroeconomic outlook improves and Premier's credit position better supports the funding of the project.

A small core team is continuing to progress a number of project, commercial and regulatory work streams. These include the development of Sea Lion's net zero emissions plan to ensure the project will be carbon-neutral, in line with Premier's commitment.

Post period-end, Premier, Rockhopper and Navitas finalised the terms for Navitas to farm in for a 30 per cent interest in the Sea Lion licences. As part of the overall transaction, the previously differing interests between Premier and Rockhopper across the various Sea Lion licences will be harmonised to achieve a Premier 40 per cent, Rockhopper 30 per cent and Navitas 30 per cent distribution of working interests over the Sea Lion licences.

Discussions with the Falklands Islands Government regarding Navitas's entry onto the Sea Lion licences are progressing. Completion of the transaction, which is subject to FIG approval, is targeted for the fourth quarter.

Mexico

At the end of 2019, Premier initiated a sales process for its interest in Mexico's offshore Block 7, which contains the fully-appraised giant Zama field. With an extensive, high quality reservoir containing over 800 million recoverable barrels in shallow water, Zama will be a world-class long-term producing asset. However the subsequent collapse in oil price, together with the ongoing unitisation process with the neighbouring block (Pemex 100 per cent), has interrupted the sales process. It is Premier's intention to resume discussions with interested parties towards the end of this year, once the unitisation process is further advanced.

Unitisation discussions are progressing as per the Mexican regulatory process, which is in line with international best practice. In May, the National Hydrocarbon Commission (CNH) declared Zama a shared reservoir, with the Mexican Ministry of Energy (SENER) issuing the instruction to unitise the Zama field in July. This triggered a defined period of negotiations with Pemex to finalise the Unit Agreement for the Zama field.

Meanwhile, FEED on the selected development concept, which comprises two offshore processing, drilling and accommodation platforms, together with a floating storage and offloading vessel and oil export by tankers, continues apace with a draft FDP expected to be finalised from a technical perspective by the end of the third quarter. It is anticipated that, as soon as unitisation has been resolved, the FDP will be submitted to the Mexican government for approval.

Beyond Zama, Premier retains exposure to exploration upside in Mexico through its other offshore licence interests, each of which has the potential to deliver material future value for Premier. A 3D seismic survey acquisition across Block 30 (Premier 30 per cent interest) was completed in July 2019. The final processed data was received in the second quarter of 2020 and is now being interpreted in order to delineate the full extent of the Wahoo and Cabrilla prospects, as well as to mature other prospectivity on the Block. Drilling of the first well is targeted for the second half of 2022.

Elsewhere in Mexico, on Premier's 100 per cent operated Burgos Blocks 11 and 13, reprocessing of the existing 3D seismic across these blocks is now in part complete and interpretation is underway. Regional play fairway analysis undertaken to date has identified a deeper play in the Mesozoic carbonates that provides additional upside to the prospectivity already identified in the shallower Oligo-Miocene clastic play.

EXPLORATION ACTIVITIES

During the first six months of the year, the COVID-19 pandemic resulted in strict budgetary constraints as a result of which, a number of planned exploration activities were deferred to minimise near-term expenditure. The Group's focus remains on under-explored but proven provinces that have the potential to develop into new business units over the medium term.

Alaska

In March, Premier safely drilled the Charlie-1 well in Area A (Premier 60 per cent interest) on the North Slope of Alaska. While the well successfully extended the Brookian play south recovering hydrocarbons to surface from conventional pay, the reservoir fluid was gas-condensate which is more challenging to commercialise in this area than the light oil the well was targeting. As a result, the well was plugged and abandoned without further testing and Premier is in the final stages of exiting the licence.

Brazil

In Brazil, much of the first quarter was spent preparing for Premier's first in-country exploration well on its operated Block 717 (Premier 50 per cent interest) in the offshore Ceará basin. Premier had contracted the Valaris DS-9 drillship to drill a well targeting the stacked Berimbau/Maraca prospect and the well was due to spud on 1st July. Berimbau is a higher risk, high value prospect with a Pmean to P10 gross unrisked resource estimate of 230-450 mmbbls. Maraca is a lower risk prospect and is estimated to contain 85-165 mmbbls (Pmean-P10) of gross unrisked resource. However, as a result of the COVID-19 pandemic the decision was taken to defer the well and the Valaris contract was terminated.

FINANCIAL REVIEW

Business performance

Production averaged 67.3 kboepd in the period (2019 1H: 84.1 kboepd), which is in line with full year guidance for 2020 which is 65 to 70 kboepd. The reduction when compared to the corresponding prior period was predominantly due to an unplanned 20 day shutdown on Catcher, the disposal of the Pakistan business which completed in 1H 2019 and the cessation of production from Huntington and Kyle in the period.

EBITDAX for the period from continuing operations was US$352.4 million, a reduction of US$327.8 million compared to the prior period EBITDAX of US$680.2 million. The reduced EBITDAX is due to lower realised commodity prices and production, partially offset by higher realised hedging gains of US$111.5 million recognised as revenue in the period.

Business performance (continuing operations)	**2020 1H US$ million**	2019 1H US$ million
Operating (loss)/profit	**(199.3)**	327.5
Add: DD&A	**310.2**	346.5
Add: Exploration and new venture costs	**242.1**	8.7
(Less): Profit on disposal of assets	**(0.6)**	(2.5)
EBITDAX	**352.4**	680.2

Income statement

Production and revenue

Group production on a working interest basis averaged 67.3 kboepd for the period compared to 84.1 kboepd in 2019 1H. Entitlement production for the period was 63.3 kboepd (2019 1H: 79.9 kboepd). Post hedging, Premier realised an average oil price for the period of US$51.5/bbl (2019 1H: US$68.3/bbl) vs an average Brent price of US$40.1/bbl (2019 1H: US$65.7/bbl).

In the UK, Premier achieved average natural gas prices of 35 pence/therm (2019 1H: 44 pence/therm), which included 83.9 million therms which were sold under fixed price master sales agreements. Gas prices in Singapore, indirectly linked with crude oil pricing, averaged US$8.4/mscf (2019 1H: US$11.3/mscf) post-hedging.

Realised prices (post hedging)	2020 1H	2019 1H
Oil price (US$/bbl)	**51.5**	68.3
UK natural gas (pence/therm)	**35**	44
Singapore HSFO (US$/mscf)	**8.4**	11.3

The reduction in production, combined with lower oil and gas prices realised, resulted in a fall in sales revenues from all operations to US$530.6 million compared with US$883.1 million in 2019 1H.

Operating costs

Cost of operations comprise operating costs, changes in lifting positions, inventory movement and royalties. Cost of operations for the Group were US$175.0 million for 2020 1H, compared to US$183.4 million for 2019 1H.

	2020 1H US$ million	2019 1H US$ million
Operating costs		
Continuing operations	**139.8**	154.5
Discontinuing operations (Pakistan)	**-**	2.4
Operating costs	**139.8**	156.9
Operating cost per barrel (US$ per barrel)	**11.4**	10.3

	2020 1H $ million	2019 1H $ million
Amortisation and depreciation		
Total DD&A	**229.1**	344.3
DD&A per barrel (US$ per barrel)	**18.7**	22.6

Total depreciation has reduced year-on-year due to an extension in the assumed field life of the Catcher asset from 2026 to 2029. Included within the depreciation charge is an impairment charge for the Group's production and development assets of US$79.6 million (pre-tax). This charge relates almost entirely to the Solan asset following a reduction in the Group's long-term oil price assumption.

Exploration expenditure and new ventures

Exploration expense and new venture costs amounted to US$242.1 million (2019 1H: US$8.7 million). This includes exploration expenditure of US$194.1 million written off for costs previously capitalised for exploration prospects in the North Falklands basin, which will not be developed as part of the Sea Lion

Phase 1 project. In addition, US$28.1 million of costs for the drilling of the Charlie-1 well in Area A in Alaska have been expensed. The drilling encountered non-commercial gas condensate. In addition, new venture costs include costs associated with the Corporate Actions that have been progressed during the period.

After recognition of these expenditures, the exploration and evaluation asset remaining on the balance sheet at 30 June 2020 amounts to US$742.8 million (31 December 2019: US$934.0 million) which primarily includes the Sea Lion and Tuna projects, as well as the Group's share of expenditure on the Zama prospect in Mexico.

General and administrative expenses

Net G&A costs of 2020 1H of US$4.2 million (2019 1H: US$3.3 million) are broadly consistent with the prior period.

Finance gains and costs

Net finance costs of US$135.5 million have reduced compared to prior year net finance costs of US$207.6 million. The reduction is largely due to a significant fall in value of the Group's outstanding equity warrants at 30 June 2020. In the prior half year period a charge of US$8.1 million was recognised for the change in the equity warrants fair value, whilst in the current half year period a fair value gain of US$23.8 million has been recognised. Cash interest expense in the period was US$105.1 million (2019 1H: US$127.5 million), with the reduction due to lower LIBOR rates and a reduced gross debt balance.

Taxation

The Group has a current tax charge for the period of US$17.8 million (2019 1H: charge of US$36.9 million) and a non-cash deferred tax charge for the period of US$318.9 million (2019 1H: credit of US$29.4 million) which results in a total tax charge for the period of US$336.7 million, from continuing operations (2019 1H: charge of US$7.5 million).

The total tax charge for the period represents an effective tax rate of negative 100.6 per cent (2019 1H: 6.3 per cent). The negative effective tax rate is predominantly driven by the de-recognition of UK ring fence tax losses and allowances due to a reduction in forecast oil and gas price assumptions.

Due to the fall in oil and gas prices and the presence of impairment indicators, the Group re-ran the corporate model to assess whether it is appropriate to continue to recognise the Group's deferred tax losses and allowances as at 30 June 2020. The results of the corporate model concluded that it was no longer appropriate to recognise an amount of US$369.1 million in respect of ring fence tax losses and investment allowances. Premier retains access to these tax losses in the event forecast taxable profits were to increase in the future.

During the period, the Group re-negotiated the terms of the agreed sale and purchase agreements ("SPAs") for the acquisition of the Andrew Area and Shearwater assets from BP (the "BP Acquisitions"). In June 2020, revised terms with BP were agreed, and consent from the Group's lenders received. The revised SPAs were executed in July 2020. Therefore, the Group continues to include the cash flows from the BP Acquisitions in its UK forecasting for the purposes of assessing the recoverability of the Group's UK deferred tax asset.

Loss after tax

Loss after tax for the period was US$671.5 million (2019 1H: profit of US$120.6 million), due to significant non-cash charges in relation to exploration write-off's (US$222.2 million), the partial derecognition of the Group's UK deferred tax asset (US$369.1 million) and impairment of PP&E assets (US$47.8 million, post-tax). Excluding the effect of these non-cash charges, the loss after tax would have been US$32.4 million.

Cash flow

Cash flow from operating activities was US$323.7 million (2019 1H: US$544.6 million) after accounting for tax receipts of US$10.2 million (2019 1H: payments of US$42.1 million) and movement in joint venture cash balances in the period of US$25.1 million. Positive free cash flow in the period was US$24.7 million (2019 1H: US$188.0 million). The reduction of both operating and free cash flow driven by reduced production and realised commodity prices in the period.

Capital expenditure in the period to 30 June 2020 totalled US$140.5 million (2019 1H: US$103.3 million).

Capital expenditure	**2020 1H US$ million**	2019 1H US$ million
Field/development projects	**87.1**	32.4
Exploration and evaluation	**52.4**	69.9
Other	**1.0**	1.0
Total	**140.5**	103.3

The development expenditure mainly relates to the Solan and Tolmount projects in the UK. The largest part of the E&E capital expenditure in the period was the appraisal drilling for the Charlie-1 well in Alaska. In addition, cash expenditure for decommissioning activity in the period was US$21.7 million (2019 1H: US$24.3 million). Further to this, US$3.8 million of cash was funded into long-term abandonment accounts for future decommissioning activities (2019 1H: US$5.2 million).

Net lease payments made in the period were US$80.8 million (2019 1H: US$98.1 million)

Balance sheet position

Net Debt

Accounting net debt at 30 June 2020 amounted to US$1,973.9 million (31 December 2019: US$1,989.8 million), with cash resources of US$139.7 million (31 December 2019: US$198.1 million). The net debt balance excludes the fair value of the cross currency swaps, which hedge non US dollar denominated parts of the Group's borrowings.

During the period, Premier made debt repayments of US$52.3 million. Subsequent to the period end, the Group made a drawing under its RCF facility of US$20 million.

Premier retains significant cash at 30 June 2020 of US$139.7 million and undrawn facilities of US$329.3 million, giving liquidity of US$435.8 million (31 December 2019: US$549.2 million) when excluding cash of US$33.2 million held on behalf of joint venture partners or held as security for performance related letters of credit.

All of Premier's debt facilities are due to mature in May 2021. As this is within 12 months of the balance sheet date, all of the outstanding debt liabilities in relation to these facilities have been presented as current liabilities at 30 June 2020.

Stable Platform Agreement

In June 2020, the Group reached agreement with a subset of its largest lenders on the terms of a "Stable Platform Agreement" which form the basis of the negotiation of the Group's debt facilities. Under the terms of the Stable Platform Agreement, the Company's financial covenants have been waived through to 30 September 2020 whilst discussions continue over the proposed amendments to the Group's existing debt facilities. In July 2020, subsequent to the period end, the Group received formal consent for the terms of the Stable Platform Agreement from the requisite majority of the Group's lenders.

Equity proceeds

In June 2020, Premier entered into a settlement agreement with ARCM, the Group's largest creditor, which provided a comprehensive settlement of all claims relating to the Group's scheme of arrangements and related matters (including costs). The agreement included the following matters:

- ARCM withdrew its appeal of the Court's judgment approving the Group's scheme of arrangements in relation to the BP Acquisitions;
- ARCM undertook to support the proposed BP Acquisitions and also the Stable Platform Agreement through the lender consent process; and,

- Premier issued 82.2 million new shares to ARCM at a fixed price of 26.69 pence per share, resulting in equity proceeds of US$27.0 million.

Following the issuance of the shares to ARCM, as required by the terms of the Group's equity warrant instruments, the exercise price for each equity warrant was reduced from 41.8 pence to 40.8 pence.

Provisions

Total decommissioning provisions at 30 June 2020 are US$1,234.5 million (31 December 2019: US$1,303.4 million), with the reduction driven by expenditure in the period.

Lease liabilities

Total lease liabilities at 30 June 2020 are US$700.1 million (31 December 2019: US$732.5) million, with an associated right of use asset of US$561.3 million (31 December 2019: US$588.0 million).

Non-IFRS measures

The Group uses certain measures of performance that are not specifically defined under IFRS or other generally accepted accounting principles. These non-IFRS measures used within this Interim Report and Accounts are EBITDAX, Free cash flow, Operating cost per barrel, DD&A per barrel, Net Debt and Liquidity and are defined in the glossary.

Financial risk management

Commodity prices

Premier continued to increase its hedging position from 2020 2H until the end of 2022 to protect operating cash flows.

The Group's current hedge position to the end of 31 December 2022 is as follows:

Oil

Swaps / forwards	**2020 2H**
Volume (mmbbls)	1.86
Average price (US$/bbl)	56.6

UK gas

Swaps / forwards / options	**2020 2H**	**2021**	**2022**
Volume (million therms)	27	112	64
Average price (p/therm)	52	41	42

Indonesia gas

Swaps / forwards	**2020 2H**
Volume (HSFO k te)	126
Average price (US$/te)	340

At 30 June 2020, the fair value of the open oil and gas instruments above was an asset of US$65.7 million (31 December 2019: asset of US$37.9 million), which is expected to be released to the income statement during 2020 2H, 2021 and 2022 as the related barrels are lifted or therms delivered.

Foreign exchange

Premier's functional and reporting currency is US dollars. Exchange rate exposures relate only to local currency receipts and expenditures within individual business units. Local currency needs are acquired on a short-term basis. During the period, the Group recorded a mark-to-market loss of US$1.4 million on its outstanding foreign exchange contracts. The Group currently has £150.0 million retail bonds, €60.0 million long-term senior loan notes and £100.0 million term loan in issuance which have been hedged under cross currency swaps in US dollars at average fixed rates of US$1.64:£ and US$1.37:€. The fair value of the cross currency swaps at 30 June 2020 was a liability of US$141.0 million (31 December 2019: US$123.6 million).

Interest rates

The Group has various financing instruments including senior loan notes, UK retail bonds, term loans and revolving credit facilities. Currently, approximately 75 per cent of total borrowings is fixed or has been fixed using the interest rate swap markets. On average, the effective interest on drawn funds for the period, recognised in the income statement, was 7.9 per cent.

Going concern

The Group monitors its capital position and its liquidity risk regularly throughout the year to ensure that it has access to sufficient funds to meet forecast cash requirements. Cash forecasts are regularly produced based on, inter alia, the Group's latest life of field production and expenditure forecasts, management's best estimate of future commodity prices (based on recent forward curves, adjusted for the Group's hedging programme) and the Group's borrowing facilities. Sensitivities are run to reflect different scenarios including, but not limited to, changes in oil and gas production rates, possible reductions in commodity prices and delays or cost overruns on major development projects. This is done to identify risks to liquidity and covenant compliance and enable management to formulate appropriate and timely mitigation strategies in order to manage the risk of funds shortfalls or covenant breaches and to ensure the Group's ability to continue as a going concern.

In July and August 2020, the Group publicly announced that it had agreed to undertake the following corporate actions (together the "Corporate Actions"):

- Signing of sale and purchase agreements ("SPA") for the acquisition of working interests in the Andrew Area and Shearwater assets from BP (together the "BP Acquisitions" or the "Acquired Assets");
- Agreement with its creditors on the "Stable Platform Agreement" under which the testing of the Group's financial covenants is deferred until 30 September 2020;
- Agreement with a subset of the Group's lenders, representing over 45 per cent of the Group's debt facilities on a heads of terms setting out the long-term refinancing of the Group's debt facilities (the "Proposed Refinancing"); and
- A proposed equity raise of US$230 million to fund the proposed BP Acquisitions as previously disclosed and to pay transaction costs. A further US$300 million of new equity is proposed to further reduce debt of which US$205 million will be underwritten by Premier's creditors who will convert existing debt into shares in the event that the equity is not raised from existing shareholders in a pre-emptive offer and new investors (together the "Equity Raise").

The Group's base case going concern assessment includes the completion of the Corporate Actions, including the Proposed Refinancing, with a base case forecast assumed oil price of US$35/bbl in 2H 2020 and US$55/bbl 2021, respectively and production in line with prevailing rates. Under the terms of the Proposed Refinancing agreed with a subset of the Group's lenders, the Group's debt maturity will be extended from May 2021 to March 2025 and the revised financial covenants are expected to be set at a level for which there will be sufficient headroom to ensure compliance at oil prices and production rates below the assumptions made in management's base case.

The BP Acquisitions, the Equity Raise and the Proposed Refinancing are each subject to a number of conditions that must be satisfied to proceed, including shareholder approval for the Equity Raise and the Refinancing being approved by creditors and through Restructuring Plans sanctioned by the court.

Each Restructuring Plan requires approval from 75 per cent by value of at least one class of the Group's creditors. Given the extent and nature of discussions with the Group's lenders, the Directors remain confident that the Proposed Refinancing will complete based on the current agreed terms. However, the Proposed Refinancing is outside of the Group's control and if the Proposed Refinancing did not complete by May 2021, the Group does not consider it will be able to repay its outstanding debt liabilities under its financing facilities.

In addition, since 8 July 2020 the Group's leverage and interest cover financial covenants for the testing period ended on 30 June 2020 have been deferred under the terms of the Stable Platform Agreement. Without the deferrals contained in the Stable Platform Agreement, the Group would have breached the financial covenants contained in its financing agreements in respect of the testing period ended on 30 June 2020. In the event that the Proposed Refinancing is not agreed or finalised by 30 September 2020, if the Group is unable to obtain a further deferral or waiver of the financial covenant testing for the period ended on 30 June 2020, there is a risk that an event of default may arise prior to May 2021. If such an event were to occur, the requisite majority of the Group's creditors would have the right to vote to declare the Group's debt liabilities immediately repayable.

The uncertainties regarding (1) the Proposed Refinancing not completing before the debt becomes payable, and (2) the risk that the Group is unable to obtain a further deferral or waiver of the financial covenant testing in the event that the Proposed Refinancing does not complete before 30 September 2020, or, in the event the Proposed Refinancing does complete, the revised covenants are subsequently breached in downside commodity price and production scenarios; and the impact these could have on the Group's debt facilities becoming repayable on demand in the next 12 months creates material uncertainties which, therefore may cast significant doubt on the Company's ability to continue as a going concern.

However, based on the agreement of heads of terms with a subset of the Group's lenders, the Director's believe that the completion of the Proposed Refinancing is probable and, in the event the Proposed Refinancing does not complete, the Directors remain confident that an alternative agreement with its creditors would be reached. Once the Proposed Refinancing and other Corporate Actions are complete, extending maturity of the Group's debt facilities is extended to March 2025, the Directors would have a reasonable expectation that the Company has adequate resources to continue in operational existence for the foreseeable future. Therefore, the Directors continue to adopt the going concern basis of accounting in preparing these consolidated financial statements and the financial statements do not include the adjustments that would result if the Group were unable to continue as a going concern.

Business risks

Premier's business may be impacted by various risks leading to failure to achieve strategic targets for growth and loss of financial standing, cash flow and earnings, and reputation. Not all of these risks are wholly within the Company's control and the Company may be affected by risks which are not yet manifest or reasonably foreseeable.

Effective risk management is critical to achieving our strategic objectives and protecting our personnel, assets, the communities where we operate and with whom we interact and our reputation. Premier therefore has a comprehensive approach to risk management.

A critical part of the risk management process is to assess the impact and likelihood of risks occurring so that appropriate mitigation plans can be developed and implemented. Risk severity matrices are developed across Premier's business to facilitate assessment of risk. The specific risks identified by project and asset teams, business units and corporate functions are consolidated and amalgamated to provide an oversight of key risk factors at each level, from operations through to business unit management, the Executive Committee and the Board.

For all the known risks facing the business, Premier attempts to minimise the likelihood and mitigate the impact. According to the nature of the risk, Premier may elect to take or tolerate risk, treat risk with controls and mitigating actions, transfer risk to third parties, or terminate risk by ceasing particular activities or operations. Premier has a zero tolerance to financial fraud or ethics non-compliance, and ensures that HSES risks are managed to levels that are as low as reasonably practicable, whilst managing exploration and development risks on a portfolio basis.

The Group's principal risks for the remaining 6 months of the year are set out below:

- Access to capital
- Production and development delivery and decommissioning execution
- Joint venture partner alignment and supply chain delivery
- Organisational capability
- Exploration success and reserves addition
- Commodity price volatility
- Climate change
- Health, safety, environment and security
- Host government: political and fiscal risks

These risks are consistent with those identified at 31 December 2019. The access to capital risk includes the risk of the Group successfully completing a refinancing of its debt facilities before maturity in May 2021, which is also discussed in detail in the going concern section of this finance review.

The Board continues to actively monitor the effect of COVID-19 on global oil and gas markets and the Group's operations. However, in respect to the identification of principal risks, the primary risks associated with COVID-19 are considered to be embedded within the existing principal risks, including the potential impact of the pandemic on commodity price volatility; production and development delivery; and access to capital.

Further information detailing the way in which these risks are mitigated is provided on pages 50 to 57 of the 2019 Annual Report and Financial Statements. This information is also available on Company's website www.premier-oil.com.

STATEMENT OF DIRECTORS' RESPONSIBILITIES

Each of the Directors of the Company confirms that to the best of his or her knowledge:

a) the condensed set of financial statements, which has been prepared in accordance with International Accounting Standard 34 – 'Interim Financial Reporting' as adopted by the European Union gives a true and fair view of the assets, liabilities, financial position and profit of the Company;

b) the half-yearly results statement includes a fair review of the information required by DTR 4.2.7R (indication of important events during the first six months and description of principal risks and uncertainties for the remaining six months of the year); and

c) the half-yearly results statement includes a fair review of the information required by DTR 4.2.8R (disclosure of related parties' transactions and changes therein).

On behalf of the Board

Richard Rose

Finance Director

CONDENSED CONSOLIDATED INCOME STATEMENT

	Note	**Six months to 30 June 2020 Unaudited US$ million**	Six months to 30 June 2019 Unaudited US$ million
Sales revenues	*2*	**530.6**	871.3
Other operating income/(costs)		**1.0**	(4.4)
Cost of operation	*3*	**(175.0)**	(183.4)
Depreciation, depletion, amortisation and impairment		**(310.2)**	(346.5)
Exploration expense and new ventures	*7*	**(242.1)**	(8.7)
Profit on disposal of non-current assets		**0.6**	2.5
General and administration costs		**(4.2)**	(3.3)
Operating (loss)/profit		**(199.3)**	327.5
Interest revenue, finance and other gains		**31.4**	11.1
Finance costs and other finance expenses and losses		**(166.9)**	(218.7)
(Loss)/profit before tax		**(334.8)**	119.9
Tax	*4*	**(336.7)**	(7.5)
(Loss)/profit for the period from continuing operations		**(671.5)**	112.4
Profit for the period from discontinued operations		**-**	8.2
(Loss)/profit after tax		**(671.5)**	120.6
(Loss)/earnings per share (cents)			
From continuing operations			
Basic	*6*	**(78.9)**	13.7
Diluted	*6*	**(78.9)**	12.4
From continuing and discontinued operations			
Basic	*6*	**(78.9)**	14.7
Diluted	*6*	**(78.9)**	13.3

Notes 1 to 12 form an integral part of these condensed financial statements.

CONDENSED CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

	Six months to 30 June 2020 Unaudited US$ million	Six months to 30 June 2019 Unaudited US$ million
(Loss)/profit for the period	**(671.5)**	120.6
Cash flow hedges on commodity swaps		
Gains/(losses) arising during the period	**136.7**	(78.9)
Less: reclassification adjustments for gains in the period	**(111.5)**	(8.8)
	25.2	(87.7)
Cash flow hedges on foreign exchange swaps		
Gains arising during the period	**3.2**	0.4
Less: reclassification adjustments for gains in the period	**-**	(2.0)
	3.2	(1.6)
Tax relating to components of other comprehensive income	**(18.6)**	25.9
Exchange differences on translation of foreign operations	**(20.1)**	11.2
Other comprehensive expense	**(10.3)**	(52.2)
Total comprehensive (expense)/income for the period	**(681.8)**	68.4

All amounts to be reclassified to profit or loss in subsequent periods.

All comprehensive income is attributable to the equity holders of the parent.

CONDENSED CONSOLIDATED BALANCE SHEET

	Note	At 30 June 2020 Unaudited US$ million	At 31 December 2019 Audited US$ million
Non-current assets			
Intangible exploration and evaluation assets	*7*	**742.8**	934.0
Property, plant and equipment	*8*	**2,306.9**	2,481.8
Goodwill		**240.8**	240.8
Other receivables		**230.4**	231.1
Deferred tax assets	*5*	**1,199.1**	1,556.1
		4,720.0	5,443.8
Current assets			
Inventories		**13.3**	16.3
Trade and other receivables		**277.4**	378.9
Derivative financial instruments	*10*	**130.9**	55.3
Cash and cash equivalents		**139.7**	198.1
		561.3	648.6
Total assets		**5,281.3**	6,092.4
Current liabilities			
Trade and other payables		**(394.2)**	(356.2)
Lease liabilities	*11*	**(92.8)**	(149.7)
Short-term provisions		**(93.7)**	(76.8)
Derivative financial instruments	*10*	**(151.0)**	(98.8)
Short-term debt	*9*	**(2,101.8)**	-
Deferred income		**(15.6)**	(15.3)
		(2,849.1)	(696.8)
Net current liabilities		**(2,287.8)**	(48.2)
Non-current liabilities			
Long-term debt		**-**	(2,169.8)
Deferred tax liabilities	*5*	**(114.9)**	(129.9)
Lease liabilities	*11*	**(607.3)**	(582.8)
Deferred income		**(48.1)**	(60.5)
Long-term provisions		**(1,171.7)**	(1,258.8)
Derivative financial instruments	*10*	**-**	(62.3)
		(1,942.0)	(4,264.1)
Total liabilities		**(4,791.1)**	(4,960.9)
Net assets		**490.2**	1,131.5
Equity and reserves			
Share capital		**170.5**	156.5
Share premium account		**516.9**	499.4
Other reserves		**(197.2)**	475.6
		490.2	1,131.5

CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

	Share capital US$ million	Share premium account US$ million	Other reserves US$ million	Total US$ million
At 31 December 2019	156.5	499.4	475.6	1,131.5
Issue of Ordinary Shares	14.0	17.5	1.9	33.4
Net release of ESOP Trust shares	-	-	0.2	0.2
Provision for share-based payments	-	-	6.9	6.9
Loss for the period	-	-	(671.5)	(671.5)
Other comprehensive expense	-	-	(10.3)	(10.3)
At 30 June 2020	**170.5**	**516.9**	**(197.2)**	**490.2**
At 31 December 2018	154.2	491.7	380.1	1,026.0
Issue of Ordinary Shares	1.3	3.1	0.9	5.3
Net release of ESOP Trust shares	-	-	1.0	1.0
Provision for share-based payments	-	-	9.4	9.4
Profit for the period	-	-	120.6	120.6
Other comprehensive expense	-	-	(52.2)	(52.2)
At 30 June 2019	**155.5**	**494.8**	**459.8**	**1,110.1**

CONDENSED CONSOLIDATED CASH FLOW STATEMENT

	Note	Six months to 30 June 2020 Unaudited US$ million	Six months to 30 June 2019 Unaudited US$ million
Net cash from operating activities	*9*	**323.7**	544.6
Investing activities			
Capital expenditure		**(140.5)**	(103.3)
Decommissioning pre-funding		**(3.8)**	(5.2)
Decommissioning expenditure		**(21.7)**	(24.3)
Receipts of sublease income		**13.3**	13.8
(Acquisition)/disposal of oil and gas properties		**(2.6)**	3.1
Net cash used in investing activities		**(155.3)**	(115.9)
Financing activities			
Issuance of Ordinary Shares		**30.2**	3.8
Net release of ESOP Trust shares		**0.2**	1.0
Warrant cash consideration		**-**	(11.9)
Lease payments		**(94.1)**	(111.9)
Repayment of bank loans		**(52.3)**	(169.7)
Interest paid		**(105.1)**	(127.5)
Net cash used in financing activities		**(221.1)**	(416.2)
Currency translation differences relating to cash and cash equivalents		**(5.7)**	(3.6)
Net (decrease)/increase in cash and cash equivalents		**(58.4)**	8.9
Cash and cash equivalents at the beginning of the period		**198.1**	244.6
Cash and cash equivalents at the end of the period	*9*	**139.7**	253.5

NOTES TO THE CONDENSED FINANCIAL STATEMENTS

1. BASIS OF PREPARATION

General information

Premier Oil plc is a limited liability Company incorporated in Scotland and listed on the London Stock Exchange. The address of the registered office is 4th Floor, Saltire Court, 20 Castle Terrace, Edinburgh, EH1 2EN, United Kingdom.

The condensed financial statements for the six months ended 30 June 2020 were approved for issue in accordance with a resolution of a committee of the Board of Directors on 20 August 2020.

The information for the year ended 31 December 2019 contained within the condensed financial statements does not constitute statutory accounts within the meaning of Section 434 of the Companies Act 2006. Statutory accounts for the year ended 31 December 2019 were approved by the Board of Directors on 4 March 2020 and delivered to the Registrar of Companies. The auditor reported on those accounts; the report was unqualified and did not contain any statement under Section 498(2) or 498(3) of the Companies Act 2006.

The financial information contained in this report is unaudited. The condensed consolidated income statement, condensed consolidated statement of comprehensive income, condensed consolidated statement of changes in equity and the condensed consolidated cash flow statement for the six months to 30 June 2020, and the condensed consolidated balance sheet as at 30 June 2020 and related notes, have been reviewed by the auditors. The auditors' report to the Company is attached.

Basis of preparation

The condensed financial statements for the six months ended 30 June 2020 have been prepared in accordance with IAS 34 – 'Interim Financial Reporting', as adopted by the European Union and with the requirements of the Disclosure Guidance and Transparency Rules issued by the Financial Conduct Authority. These condensed financial statements should be read in conjunction with the annual financial statements for the year ended 31 December 2019, which have been prepared in accordance with International Financial Reporting Standards as adopted by the European Union.

The condensed financial statements have been prepared on the going concern basis. Further information relating to the going concern assumption is provided in the Financial Review, including details on the material uncertainties in relation to (1) the Proposed Refinancing not completing before the debt becomes payable, and (2) the risk that the Group is unable to obtain a further deferral or waiver of the

1. BASIS OF PREPARATION *(continued)*

financial covenant testing in the event that the Proposed Refinancing does not complete before 30 September 2020, or, in the event the Proposed Refinancing does complete, the revised covenants are subsequently breached in downside commodity price and production scenarios.

Accounting policies

The accounting policies applied in these condensed financial statements are consistent with those of the annual financial statements for the year ended 31 December 2019.

A number of additional new standards, amendments to existing standards and interpretations were effective from 1 January 2020. The adoption of these amendments did not have a material impact on the Group's condensed financial statements for the half-year ended 30 June 2020.

2. OPERATING SEGMENTS

The Group's operations are located and managed in five business units; namely the Falkland Islands, Indonesia, the United Kingdom, Vietnam and the Rest of the World. The results for Pakistan, the disposal of which was completed in March 2019, are reported as a discontinued operation in the prior year. Some of the business units currently do not generate revenue or have any material operating income.

The Group is only engaged in one business of upstream oil and gas exploration and production, therefore all information is being presented for geographical segments.

	Six months to 30 June 2020 Unaudited US$ million	Six months to 30 June 2019 Unaudited US$ million
Revenue		
United Kingdom	**392.2**	673.7
Indonesia	**87.1**	88.8
Vietnam	**51.3**	108.8
Total Group sales revenue	**530.6**	871.3
Other operating income/(costs) – United Kingdom	**1.0**	(4.4)
Interest and other finance revenue	**0.6**	4.0
Total Group revenue	**532.2**	870.9
Revenue from discontinued operations	**-**	11.8

Group operating (loss)/profit		
United Kingdom	**(3.9)**	225.7
Indonesia	**41.4**	56.5
Vietnam	**6.4**	57.7
Rest of the World	**(219.2)**	(0.2)
Unallocated[1]	**(24.0)**	(12.2)
Group operating (loss)/profit	**(199.3)**	327.5
Interest revenue, finance and other gains	**31.4**	11.1
Finance costs and other finance expenses	**(166.9)**	(218.7)
(Loss)/profit before tax from continuing operations	**(334.8)**	119.9
Tax	**(336.7)**	(7.5)
(Loss)/profit after tax from continuing operations	**(671.5)**	112.4
Profit from discontinued operations	**-**	8.2

[1] Unallocated expenditure include amounts of a corporate nature and not specifically attributable to a geographical segment. These items include corporate general and administration costs, corporate new venture and pre-licence exploration costs.

2. OPERATING SEGMENTS *(continued)*

Of the Group's worldwide revenues of US$530.6 million (2019 1H: US$871.3 million), revenues of US$419.1 million (2019 1H: US$861.6 million) were from contracts with customers. This was increased by hedging gains in the period of US111.5 million (2019 1H: gain of US$9.7 million).

	30 June 2020 Unaudited US$ million	31 December 2019 Audited US$ million
Balance sheet - Segment assets		
United Kingdom[1]	**3,524.5**	4,060.3
Indonesia	**435.0**	481.5
Vietnam	**392.0**	437.8
Falkland Islands	**508.0**	680.0
Rest of the World	**151.2**	179.4
Unallocated[2]	**270.6**	253.4
Total assets	**5,281.3**	6,092.4

[1] Includes goodwill of US$240.8 million.

[2] Unallocated expenditure and assets include amounts of a corporate nature and not specifically attributable to a geographical segment. These include cash and cash equivalents and mark-to market valuations of commodity contracts.

3. COSTS OF SALES

	Six months to 30 June 2020 Unaudited US$ million	Six months to 30 June 2019 Unaudited US$ million
Operating costs	**139.8**	154.5
Gas purchases	**8.1**	14.0
Stock overlift movement	**25.0**	10.0
Royalties	**2.1**	4.9
	175.0	183.4

4. TAX

	Six months to 30 June 2020 Unaudited US$ million	Six months to 30 June 2019 Unaudited US$ million
Current tax		
UK corporation tax on profits	**(10.0)**	-
Overseas tax	**28.2**	49.6
Adjustments in respect of prior years	**(0.4)**	(12.7)
Total current tax charge	**17.8**	36.9
Deferred tax		
UK corporation tax	**333.8**	(24.2)
Overseas tax	**(14.9)**	(5.2)
Total deferred tax charge/(credit)	**318.9**	(29.4)
Tax charge on loss/(profit) on ordinary activities	**336.7**	7.5

The Group has a current tax charge for the period of US$17.8 million (2019 1H: charge of US$36.9 million) and a non-cash deferred tax charge for the period of US$318.9 million (2019 1H: credit of US$29.4 million) which results in a total tax charge for the period of US$336.7 million (2019 1H: charge of US$7.5 million). The deferred tax charge primarily arises due to the de-recognition of UK ring fence tax losses and allowances in the period due to a revision to management's oil and gas price assumptions.

The total tax charge for the period represents an effective tax rate of negative 100.6 per cent (2019 1H: charge of 6.3 per cent). The negative effective tax rate is predominantly driven by the de-recognition of the deferred tax asset in respect of UK ring fence tax losses and allowances. Removing the de-recognition charge would result in a total tax credit for the period of US$32.4 million and an effective tax rate of 9.7 per cent.

The future effective tax rate for the Group is impacted by the mix of jurisdictions in which the Group operates (with corporation tax rates ranging from 20 per cent to 40 per cent), assumptions around future oil prices and changes to tax rates and legislation.

5. DEFERRED TAX

	At 30 June 2020 US$ million	At 31 December 2019 US$ million
Deferred tax assets	**1,199.1**	1,556.1
Deferred tax liabilities	**(114.9)**	(129.9)
	1,084.2	1,426.2

	At 1 January 2020 US$ million	Exchange movements US$ million	(Charged) /credited to income statement US$ million	Charge /(credit) to retained earnings US$ million	At 30 June 2020 US$ million
UK deferred corporation tax					
Fixed assets and allowances	(513.4)	(0.1)	28.9	-	(484.6)
Decommissioning	439.6	(3.6)	(7.8)	-	428.2
Tax losses and allowances	1,536.6	(0.9)	(352.2)	-	1,183.5
Investment allowance	82.5	(0.1)	2.2	-	84.6
Derivative financial instruments	10.8	0.2	(4.9)	(18.6)	(12.5)
Total UK deferred corporation tax	**1,556.1**	**(4.5)**	**(333.8)**	**(18.6)**	**1,199.2**
Overseas deferred tax[1]	**(129.9)**	**-**	**14.9**	**-**	**(115.0)**
Total	**1,426.2**	**(4.5)**	**(318.9)**	**(18.6)**	**1,084.2**

[1] The overseas deferred tax relates mainly to temporary differences associated with fixed asset balances

5. DEFERRED TAX *(continued)*

	At 1 January 2019 US$ million	Exchange movements US$ million	(Charged) /credited to income statement US$ million	Charge /(credit) to retained earnings US$ million	At 31 December 2019 US$ million
UK deferred corporation tax:					
Fixed assets and allowances	(609.2)	0.1	95.7	-	(513.4)
Decommissioning	376.8	2.1	60.7	-	439.6
Tax losses and allowances	1,602.5	0.8	(66.7)	-	1,536.6
Investment allowance	77.8	0.1	4.6	-	82.5
Derivative financial instruments	(13.8)	(0.1)	(0.3)	25.0	10.8
Total UK deferred corporation tax	**1,434.1**	**3.0**	**94.0**	**25.0**	**1,556.1**
Overseas deferred tax[1]	**(139.5)**	**-**	**9.6**	**-**	**(129.9)**
Total	**1,294.6**	**3.0**	**103.6**	**25.0**	**1,426.2**

[1] The overseas deferred tax relates mainly to temporary differences associated with fixed asset balances

The Group's deferred tax assets at 30 June 2020 are recognised to the extent that taxable profits are expected to arise in the future against which the UK ring fence tax losses and allowances can be utilised. In accordance with paragraph 37 of IAS 12 - 'Income Taxes', the Group reassessed the recoverability of its deferred tax assets at 30 June 2020 with respect to UK ring fence tax losses and allowances. The corporate model used to assess the recoverability of the Group's deferred tax losses and allowances was ran assuming oil and gas price assumptions consistent with those used when assessing the Group's underlying assets for impairment (see note 8). The cash flows included in the corporate model are predominantly derived from future revenue from existing UKCS assets. The existing UKCS assets include both existing producing assets and certain future currently unsanctioned assets. The cash flows also include future taxable profits associated with the proposed BP Acquisition as announced on 20 July 2020 on the basis that, at the balance sheet date, management consider it probable that the BP Acquisitions will complete and that the cash flows will arise within Premier's UK ring fence. Future taxable profits associated with the target assets support the recoverability of US$212.2 million of the deferred tax assets recognised at 30 June 2020. The results of the corporate model concluded that it was no longer appropriate to recognise an amount of US$369.1 million in respect of the Group's UK ring fence deferred tax assets relating to tax losses and allowances.

5. Deferred tax *(continued)*

In addition to the above, there are carried forward non-ring fence UK tax losses of approximately US$432.4 million (2019: US$376.4 million) and overseas tax losses of US$303.8 million (2019: US$267.7 million) for which a deferred tax asset has not been recognised.

None of the UK tax losses (ring fence and non-ring fence) have a fixed expiry date for tax purposes.

No deferred tax has been provided on unremitted earnings of overseas subsidiaries, following a change in UK tax legislation in 2009 which exempted foreign dividends from the scope of UK corporation tax, where certain conditions are satisfied.

6. (LOSS)/EARNINGS PER SHARE

The calculation of basic (loss)/earnings per share is based on the (loss)/profit after tax and on the weighted average number of Ordinary Shares in issue during the period. Basic and diluted (loss)/earnings per share are calculated as follows:

	Six months to 30 June 2020 Unaudited US$ million	Six months to 30 June 2019 Unaudited US$ million
(Loss)/earnings		
(Loss)/earnings for the purpose of diluted earnings per share on continuing operations	**(671.5)**	112.4
Profit from discontinued operations	**-**	8.2
Earnings for the purpose of diluted earnings per share on continuing and discontinued operations	**(671.5)**	120.6
Number of shares (millions)		
Weighted average number of Ordinary Shares for the purpose of basic earnings per share	**850.7**	821.6
Effects of dilutive potential Ordinary Shares:		
Contingently issuable shares (2020: anti-dilutive)	**-**	83.0
Weighted average number of Ordinary Shares for the purpose of diluted earnings per share	**850.7**	904.6
(Loss)/earnings per share from continuing operations (cents)		
Basic	**(78.9)**	13.7
Diluted	**(78.9)**	12.4
Earnings per share from discontinued operations (cents)		
Basic	**-**	1.0
Diluted	**-**	0.9

In the prior period, discontinued operations relate to the results of the Group's Pakistan Business Unit for which the disposal completed in March 2019.

7. INTANGIBLE EXPLORATION AND EVALUATION (E&E) ASSETS

	Total US$ million
Cost	
At 1 January 2020	934.0
Exchange movements	(26.8)
Additions during the period	57.8
Exploration expense[1]	(222.2)
At 30 June 2020	**742.8**

[1] Expensed in the income statement with new venture cost of US$19.9 million which include costs incurred in relation to the proposed Corporate Actions.

The amounts for intangible E&E assets represent costs incurred on active exploration projects. These amounts are written off to the income statement as exploration expense unless commercial reserves are established or the determination process is not completed and there are no indications of impairment.

The outcome of ongoing exploration, and therefore whether the carrying value of E&E assets will ultimately be recovered, is inherently uncertain. To the extent that we have an active licence to continue to explore for resources and have an intention to continue exploration activity, the exploration cost associated with the licence will remain capitalised as an E&E asset on the balance sheet. Once exploration activity has completed and we have no further intention to explore the licence for resources, costs capitalised until that point will be expensed and no further costs associated with the licence will be capitalised.

During the period, exploration expenditure of US$194.1 million has been written off for costs previously capitalised for exploration prospects in the North Falklands basin which will not be developed as part of the Sea Lion Phase 1 project. In addition, the drilling of the Charlie-1 well in Area A in Alaska encountered non-commercial gas condensate for which US$28.1 million of costs have been expensed in the period. The balance carried forward is predominantly in relation to the Sea Lion and Tuna projects, as well as our share of expenditure on the Zama prospect in Mexico.

8. PROPERTY, PLANT AND EQUIPMENT

	Oil and gas properties US$ million	Right-of-use-assets US$ million	Other fixed assets US$ million	Total US$ million
Cost				
At 1 January 2020	7,986.6	811.0	61.2	8,858.8
Exchange movements	1.6	(2.3)	(2.0)	(2.7)
Re-measurement of lease liabilities	-	49.3	-	49.3
Additions and changes in decommissioning estimates	87.5	-	1.0	88.5
At 30 June 2020	**8,075.7**	**858.0**	**60.2**	**8,993.9**
Amortisation and depreciation				
At 1 January 2020	6,098.0	223.0	56.0	6,377.0
Exchange movements	1.6	(0.2)	(1.6)	(0.2)
Charge for the year	155.2	73.9	1.5	230.6
Impairment charge	79.6	-	-	79.6
At 30 June 2020	**6,334.4**	**296.7**	**55.9**	**6,687.0**
Net book value:				
At 30 June 2020	**1,741.3**	**561.3**	**4.3**	**2,306.9**
At 31 December 2019	1,888.6	588.0	5.2	2,481.8

Amortisation and depreciation of oil and gas properties is calculated on a unit-of-production basis, using the ratio of oil and gas production in the period to the estimated quantities of proved and probable reserves on an entitlement basis at the end of the period plus production in the period, on a field-by-field basis. Proved and probable reserve estimates are based on a number of underlying assumptions including oil and gas prices, future costs, oil and gas in place and reservoir performance, which are inherently uncertain. Management uses established industry techniques to generate its estimates and regularly references its estimates against those of joint venture partners and external consultants. However, the amount of reserves that will ultimately be recovered from any field cannot be known with certainty until the end of the field's life.

Right-of-use-assets

There were no new leases entered into during the period. The re-measurement above represents the revision to the right-of-use asset for the Catcher FPSO due to the assumed Cessation of Production date being extended by two years to 2029, given positive field performance.

In addition to the above, the Group has a net investment in sublease of US$65.0 million (31 December 2019: US$75.7 million), of which US$51.2 million is classified as a long-term receivable and US$13.8 million as trade and other receivables. The net investment in sublease represents our joint operation partners' share of lease liabilities on lease arrangements which Premier has entered into in its role as operator as sole signatory on behalf of the joint operation and the asset is jointly controlled by the joint operation.

8. PROPERTY, PLANT AND EQUIPMENT *(continued)*

Income of US$2.1 million, which predominantly represents unwinding of the net investment in sublease, has been recognised as finance income in the period.

Impairment charge

The impairment charge in the current period relates almost entirely to the Solan asset in the UK and is due to a reduction in the oil price assumptions used in assessing the future cash flows. The impairment charge of US$79.6 million (pre-tax) (2019 1H: nil) was calculated by comparing the future discounted pre-tax cash flows expected to be derived from production of commercial reserves (the value-in-use) against the carrying value of the asset. In the period, Group-wide indicator of impairment, being a reduction in the long-term oil price assumptions, was identified. When testing producing assets for impairment, future cash flows were estimated using the following oil price assumption: US$35/bbl in 2020, US$55/bbl in 2021, US$65/bbl in 2022 and US$65/bbl in 'real' terms thereafter (2019: US$65/bbl in 2020 and 2021, 2022 at US$70/bbl followed by a long-term price of US$70/bbl (real)) and gas price assumption of 26.5p/therm in 2020, 37.5p/therm in 2021, 42.5p/therm in 2022 and 42.5p/therm in 'real' terms thereafter (2019: 45p/therm in 2020, 50p/therm in 2021 and 2022, 50p/therm in 'real' terms thereafter). The cash flows were discounted using a pre-tax discount rate of 9 per cent for the UK assets (2019: 9 per cent) and 12.5 per cent for the non-UK assets (2019: 12.5 per cent). 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.

Sensitivity

A US$5/bbl reduction in the long-term oil price (to US$60/bbl (real)) would increase the impairment charge by US$22.1 million. An increase in the discount rate to 10 per cent would increase the impairment charge by US$3.5 million. Both of these increases relate almost entirely to the Solan asset.

9. NOTES TO THE CONDENSED CONSOLIDATED CASH FLOW STATEMENT

	Six months to 30 June 2020 Unaudited US$ million	Six months to 30 June 2019 Unaudited US$ million
(Loss)/profit before tax for the period	**(334.8)**	119.9
Adjustments for:		
Depreciation, depletion, amortisation and impairment	**310.2**	346.5
Other operating (income)/costs	**(1.0)**	4.4
Exploration expense	**222.2**	0.3
Provision for share-based payments	**3.2**	6.0
Interest revenue and finance gains	**(31.4)**	(11.1)
Finance costs and other finance expenses	**166.9**	218.7
Profit on disposal of non-current assets	**(0.6)**	(2.5)
Operating cash flows before movements in working capital	**334.7**	682.2
Decrease/(increase) in inventories	**3.0**	(3.7)
Decrease/(increase) in receivables	**26.0**	(16.4)
Decrease in payables	**(26.1)**	(81.4)
Cash generated by operations	**337.6**	580.7
Income taxes received/(paid)	**10.2**	(42.1)
Interest income received	**1.0**	4.6
Net cash from operating activities	**348.8**	543.2
Net cash from discontinued operating activities	**-**	7.2
Net cash from operating activities	**348.8**	550.4
Movement in joint venture cash	**(25.1)**	(5.8)
Total net cash from operating activities	**323.7**	544.6

9. NOTES TO THE CONDENSED CONSOLIDATED CASH FLOW STATEMENT *(continued)*

Analysis of changes in net debt:

	Six months to 30 June 2020 Unaudited US$ million	Six months to 30 June 2019 Unaudited US$ million
a) Reconciliation of net cash flow to movement in net debt		
Movement in cash and cash equivalents	**(58.4)**	8.9
Repayment of bank loans	**52.3**	169.7
Non-cash movements on debt and cash balances (primarily foreign exchange)	**22.0**	0.9
Decrease in net debt in the period	**15.9**	179.5
Opening net debt	**(1,989.8)**	(2,330.7)
Closing net debt	**(1,973.9)**	(2,151.2)

b) Analysis of net debt		
Cash and cash equivalents	**139.7**	253.5
Borrowings[1]	**(2,113.6)**	(2,404.7)
Total net debt	**(1,973.9)**	(2,151.2)

[1] The carrying amounts of the borrowing costs on the balance sheet are stated net of the unamortised portion of the refinancing fees of US$11.8 million (31 December 2019: US$18.2 million). At the period end, as a result of the maturity of the borrowing being May 2021, borrowings have been classified as short-term debt on the balance sheet.

10. FINANCIAL INSTRUMENTS

Derivative financial instruments

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 Chrysaor contingent consideration and the fair value of the equity warrants, which both include estimates based on unobservable inputs and are level 3 in the IFRS 13 hierarchy. There are no non-recurring fair value measurements.

The carrying value of the Group's derivative financial assets and liabilities are:

	At 30 June 2020 US$ million	At 31 December 2019 US$ million
Financial assets		
Oil forward sales contracts[1]	**78.9**	11.9
Gas forward sales contracts[1]	**29.9**	34.7
Gas options	**14.6**	-
Fair value of gas contract acquired from E.ON	**7.5**	4.9
Forward foreign exchange contracts	**-**	3.8
Total	**130.9**	55.3
Financial liabilities		
Oil forward sales contracts	**-**	1.9
Cross currency swaps	**141.0**	123.6
Forward foreign exchange contracts	**1.4**	-
Warrants	**8.6**	35.6
Total	**151.0**	161.1

[1] Includes US$57.7 million receivable from oil and gas forward sales contracts which expired at 30 June 2020.

Fair value is the amount at which a financial instrument could be exchanged in an arm's length transaction, other than in a forced or liquidated sale. Where available, market values have been used to determine fair values. The estimated fair values have been determined using market information and appropriate valuation methodologies. Values recorded are as at the balance sheet date, and will not necessarily be realised. Non-interest bearing financial instruments, which include amounts receivable from customers and accounts payable are also recorded materially at fair value reflecting their short-term maturity.

Equity warrants

The fair value of the warrants includes unobservable inputs and is level 3 in the IFRS 13 hierarchy. The key assumptions underpinning the fair value relate to the expected future share price of the Company, US$:£ exchange rates and the expected date of exercise of the warrants. The fair value has been determined using the Black-Scholes valuation model.

10. FINANCIAL INSTRUMENTS *(continued)*

In June 2020, the Group issued 82.2 million shares to ARCM, the Group's largest creditor, for fixed consideration of 26.69 pence/share. This resulted in cash proceeds of US$27.0 million being received in the period. As part of the requirements under the Group's equity warrant instruments, the warrant exercise price was adjusted to ensure no dilution of value for the holders of the Group's equity warrant instruments. The exercise price was adjusted from 41.8 pence to 40.8 pence per warrant. The equity warrants are exercisable from their issuance until 31 May 2022, at the option of the warrant holder, and are settled with Ordinary Shares of the Company.

During the period, 9.9 million equity warrants were converted, resulting in an allotment of 8.3 million shares. The closing fair value of the open equity at 30 June 2020 was US$8.6 million, resulting in a gain of US$23.8 million being credited in the period as derivative gains within interest revenue, finance and other gains.

Contingent consideration

The contingent consideration is the fair value of the royalty stream payable to Chrysaor for the acquisition of 40 per cent of the Solan asset in May 2015. The estimate of fair value of this contingent consideration includes unobservable inputs and is level 3 in the IFRS 13 hierarchy and is held at fair value though profit and loss. The movement in fair value for the period was US$0.8 million and has been recognised within other operating income with the fair value of the liability within long-term provisions on the balance sheet.

Fair value of financial assets and financial liabilities

The carrying values and fair values of the Group's non-derivative financial assets and financial liabilities (excluding current assets and current liabilities for which carrying values approximate to fair values due to their short-term nature).

	At 30 June 2020		At 31 December 2019	
	Fair value amount US$ million	**Carrying amount US$ million**	Fair value amount US$ million	Carrying amount US$ million
Primary financial instruments held or issued to finance the Group's operations				
Retail bonds	**158.9**	**185.7**	201.6	198.9

The fair value for the bank loans and senior loan notes are considered to be materially the same as the amortised costs of the instruments.

11. LEASES

	Lease liabilities US$ million
At 1 January 2020	732.5
Re-measurement	50.5
Finance costs	18.9
Cash outflows for lease arrangements	(99.6)
Exchange differences	(2.2)
At 30 June 2020	**700.1**
Classified as	
- Short-term	92.8
- Non-current	607.3

Expenses related to both short-term and low value lease arrangements are considered to be immaterial for reporting purposes. During the period variable lease costs of US$1.2 million were expensed, primarily relating to variable expenditure associated with FPSO lease arrangements. Lease liabilities have been classified as either short-term or non-current in the balance sheet according to whether they are expected to be settled within 12 months of the balance sheet date.

The significant portion of the Group's lease liabilities represent lease arrangements for FPSO vessels on the Catcher and Chim Sáo assets. The lease liabilities, and associated right-of-use-assets have been calculated by reference to in-substance fixed lease payments in the underlying agreements incurred throughout the non-cancellable period of the lease along with periods covered by options to extend the lease where the Group is reasonably certain that such options will be exercised. When assessing whether extension options were likely to be exercised, assumptions were consistent with those applied when testing for impairment.

There were no new leases entered into during the period. The re-measurement above represents the revision to the lease liability for the Catcher FPSO due to the assumed Cessation of Production date being extended by two years to 2029, given positive field performance.

Under the modified retrospective transition method, lease payments were discounted at 1 January 2019 using an incremental borrowing rate representing the rate of interest that Premier would have to pay to borrow over a similar term, and with a similar security, the funds necessary to obtain an asset of a similar value to the right-of-use asset in a similar economic environment. The incremental borrowing rate applied to each lease was determined by taking into account the risk-free rate, adjusted for factors such as the credit rating linked to the life of the underlying lease agreement. The weighted average incremental borrowing rate applied by Premier upon transition was 7.2 per cent. Incremental borrowing rates applied to individual leases ranged between 5.4 per cent and 9.2 per cent.

12. SUBSEQUENT EVENTS

In July 2020, Premier announced that it had received consent from a requisite majority of its creditors to proceed with the acquisition of the Andrew Area and Shearwater assets from BP for total up front consideration of US$210 million plus contingent consideration up to a maximum of US$115 million. Premier and BP subsequently signed the SPAs for each of these acquisitions in July 2020.

In addition, Premier received approval for the "Stable Platform Agreement" from its creditors to waive the Company's financial covenants through to 30 September 2020.

INDEPENDENT REVIEW REPORT TO PREMIER OIL PLC

Introduction

We have been engaged by the Company to review the condensed set of financial statements in the half-yearly financial report for the six months ended 30 June 2020 which comprises the interim condensed consolidated income statement, the interim condensed consolidated balance sheet, the interim condensed consolidated statement of changes in equity, the interim condensed consolidated cash flow statement, and the related notes 1 to 12. We have read the other information contained in the half yearly financial report and considered whether it contains any apparent misstatements or material inconsistencies with the information in the condensed set of financial statements.

This report is made solely to the company in accordance with guidance contained in International Standard on Review Engagements 2410 (UK and Ireland) "Review of Interim Financial Information Performed by the Independent Auditor of the Entity" issued by the Auditing Practices Board. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the company, for our work, for this report, or for the conclusions we have formed.

Directors' Responsibilities

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

As disclosed in note 1, the annual financial statements of the Premier Oil plc are prepared in accordance with IFRSs as adopted by the European Union. The condensed set of financial statements included in this half-yearly financial report has been prepared in accordance with International Accounting Standard 34, "Interim Financial Reporting", as adopted by the European Union.

Our Responsibility

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

Scope of Review

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

Emphasis of Matter – Material Uncertainties on Going Concern

In forming our conclusion on our review of the condensed financial statements, we have considered the adequacy of the disclosure made in note 1 of the condensed financial statements concerning the group's ability to continue as a going concern. As disclosed in note 1, the company agreed with their debt holders that the testing of the Group's financial covenants is deferred until 30 September 2020 and the company is in the process of refinancing the Group's debt facilities, which fall due for repayment in May 2021. Should a covenant breach occur, then the group's debt holders on all of the group's facilities will have the right to request repayment of the outstanding debt and to cancel the relevant facilities, if a requisite majority of the Group's debt holders vote in favour of such an action.

We draw attention to note 1 in the financial statements, which indicates that there are uncertainties regarding: (1) the Proposed Refinancing not completing before the debt becomes payable, and (2) the risk that the Group is unable to obtain a further deferral or waiver of the financial covenant testing in the event that the Proposed Refinancing does not complete before 30 September 2020, or, in the event the Proposed Refinancing does complete, the revised covenants are subsequently breached in downside commodity price and production scenarios. As stated in note 1, these conditions indicate that material uncertainties exist that may cast significant doubt on the company's ability to continue as a going concern. Our review conclusion is not modified in respect of this matter.

Conclusion

Based on our review, nothing has come to our attention that causes us to believe that the condensed set of financial statements in the half-yearly financial report for the six months ended 30 June 2020 is not prepared, in all material respects, in accordance with International Accounting Standard 34 as adopted by the European Union and the Disclosure Guidance and Transparency Rules of the United Kingdom's Financial Conduct Authority.

Ernst & Young LLP

London

20 August 2020

Glossary

Non-IFRS measures

The Group uses certain measures of performance that are not specifically defined under IFRS or other generally accepted accounting principles. These non-IFRS measures are EBITDAX, Free cash flow, Operating cost per barrel, Depreciation, depletion and amortisation per barrel, Net Debt and Liquidity are defined below.

- **EBITDAX:** Earnings before interest, tax, depreciation, amortisation, impairment, exploration expenditure and other one-off items in the current period/year as allowed by the Group's financing agreements. Determined by adjusting operating profit/(loss) for the period/year. This is a useful indicator of underlying business performance and is a key metric in the calculation of one of our financial covenants.
- **Free cash flow:** Positive cash flow generation from operating, investing and financing activities excluding drawdowns from and repayments of borrowing facilities and excluding movement in joint venture working capital balances.
- **Operating cost per barrel**: Operating costs for the period/year divided by working interest production. This is a useful indicator of ongoing operating costs from the Group's producing assets.
- **Depreciation, depletion and amortisation per barrel:** Amortisation and depreciation of oil and gas properties and right-of-use assets for the period/year 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:** The net of cash and cash equivalents and long-term debt recognised on the balance sheet. This is an indicator of the Group's indebtedness and capital structure.
- **Liquidity:** The sum of cash and cash equivalents on the balance sheet, and the undrawn amounts available to the Group on our principal facilities, including letter of credit facilities, less our JV partners' share of cash balances. This is a key measure of the Group's financial flexibility and ability to fund day to day operations.

Each of the above non-IFRS measures are presented within the Interim Report and Accounts with detail on how they are reconciled to the statutory financial statements.

Half-Year Results for the six months to 30 June 2020

WORKING INTEREST PRODUCTION BY REGION (unaudited)

	Six months to 30 June 2020 kboepd	Six months to 30 June 2019 kboepd
UK:		
Catcher	28.4	35.1
Balmoral Area[1]	2.0	1.5
Huntington	1.5	6.8
Solan	1.7	4.0
Kyle	1.1	1.4
Elgin-Franklin	7.3	6.5
Other UK	3.0	2.8
	45.0	**58.1**
Indonesia:		
Natuna Sea Block A	13.2	11.1
	13.2	**11.1**
Vietnam:		
Chim Sáo	9.1	12.4
	9.1	**12.4**
Pakistan[2]:		
Bhit/Badhra	-	0.8
Kadanwari	-	0.5
Qadirpur	-	1.0
Zamzama	-	0.2
	-	**2.5**
TOTAL	**67.3**	**84.1**

[1] Includes Balmoral, Brenda, Nicol and Stirling fields.

[2] Pakistan production included until completion of disposal in March 2019.