PremierOil

Half-Year Results for the six months to 30 June 2019

Press Release

Tony Durrant, Chief Executive, commented:

"I am pleased to report another strong performance for Premier where we have exceeded our financial and operational targets for the period. The Company's strong cash flow is driving debt reduction and the Zama divestment and Sea Lion farm-down processes are targeting further strengthening of the balance sheet, which remains the Group's highest priority. Premier's operated Tolmount gas project, due on-stream next year, and the addition of good quality exploration and appraisal acreage offer significant low cost opportunities for future value growth."

Operational highlights

- Production of 84.1 kboepd (2018 1H: 76.2 kboepd), a record for 1H
- Catcher Area high plateau rates of 70 kboepd (gross) maintained, operating efficiency of 99%
- Tolmount project on schedule and under budget
- Zama gross resource upgraded to 810 mmboe (P50) following successful appraisal
- Attractive acreage captured: Andaman Sea position increased, entry into a high-impact appraisal project in Alaska
- Climate Change Committee established; review of all operations to reduce emissions initiated

Financial highlights

- Profit after tax of US$121 million (2018 1H: US$98 million)
- EBITDAX of US$680 million (2018 1H: US$488 million, adjusted for impact of IFRS 16)
- Opex of US$10/boe plus lease costs of US$6/boe
- Cash margins 35% higher than 2018 1H
- Free cash flow of US$182 million (2018 1H: US$90 million cash outflow)
- Net debt reduced to US$2.15 billion (31 December 2018: US$2.33 billion)

2019 Outlook

- Production (75-80 kboepd) and expenditure (US$12/boe opex, US$340 million capex) guidance unchanged
- Over 40% of 2019 2H oil production hedged at US$69/bbl
- First gas from Bison, Iguana and Gajah-Puteri (BIG-P) gas fields expected end Q4
- Tolmount East appraisal well results due early Q4
- Sea Lion Phase 1: discussions with senior lenders progressing, farm down process launched
- Formal Zama sale process initiated
- Forecast full year net debt reduction of over US$300 million reiterated (excluding any potential disposal proceeds)

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A presentation to analysts will be held at 9.30am today at the offices of Premier Oil, 23 Lower Belgrave Street, London SW1W 0NR and will be webcast live on the Company's website at www.premier-oil.com. A copy of this announcement is available for download from Premier's website at www.premier-oil.com.

Half-Year Results for the six months to 30 June 2019

Overview

Premier delivered another period of record production, supported by extremely high Group operating efficiency. Together with improved cash margins, this resulted in strong free cash flow delivery.

The Premier-operated Catcher Area (Premier-operated 50 per cent interest) in the UK North Sea was the Group's highest net producer, achieving 99 per cent operating efficiency, validating the new build FPSO design, the delivery capacity of the existing well stock and the operational management of the plant and the reservoir. Following the asset's continued strong subsurface performance, Premier currently expects to increase Catcher Area reserves as part of the Group's formal year-end reserves assessment.

Premier's operated assets in South East Asia – Chim Sáo (Premier-operated 53.1 per cent interest) and Natuna Sea Block A (Premier-operated 28.67 per cent interest) – continue to generate material free cash flow for the Group (after ongoing capital expenditures), producing with high uptime and from a low cost base. Output was lower than the prior corresponding period due to weaker Singapore demand for Premier's Indonesian gas and due to some natural decline from the Chim Sáo oil field.

Across the Group's producing assets, in both the North Sea and South East Asia, Premier has identified numerous opportunities to increase the reserves and field life of its producing assets through incremental investment in infill drilling and well intervention programmes, plant modifications, satellite developments and near field exploration. These projects, which are at various stages of maturity, are typically low cost with high rates of return and a rapid payback period.

On the development side, the Tolmount gas field (Premier-operated 50 per cent interest) is on track for first gas at the end of 2020 and underpins the Group's medium-term UK growth profile. There is considerable upside in the Greater Tolmount Area including at Tolmount East which targets incremental resources of up to 300 BCF (gross).

The conclusion of the appraisal programme at the giant Zama field in Block 7 (Premier non-operated 25 per cent interest) offshore Mexico resulted in Premier upgrading its resource estimates and reaffirming Zama's status as a world-class asset. Progress has also been made on the Group's fully appraised Sea Lion field which, at 250 mmboe (gross) of resource in Phase 1, is a material oilfield development opportunity. Post period end, Premier submitted the Preliminary Information Memorandum, which forms the basis of a loan application for the senior debt component of the project financing structure, to export credit agencies.

The Group's immediate priority is to further strengthen its balance sheet and this, together with significant industry interest, has led to Premier initiating a formal sales process for its interest in the Zama field which, if successful, will result in a material reduction in debt levels. In addition, Premier has launched a formal farm-down process of its 60 per cent operated interest in Sea Lion to optimise its level of participation in the project.

Exploration remains a key component of Premier's strategy. The current environment has provided the opportunity to access highly prospective acreage without compromising the Group's near term deleveraging targets. During the period, Premier increased its position in the emerging South Andaman Sea gas play at low upfront cost and has also entered the North Slope of Alaska, a prolific super basin, by farming into an appraisal project, which is estimated to contain 1 billion barrels (gross) of discovered conventionally reservoired oil-in-place.

The Group's strong operational performance along with continued tight control of its cost base and capital expenditure generated US$182 million of free cash flow during the period. This was directed at reducing debt levels and underpins Premier's expectation of achieving the upper half of its full year 2019 net debt reduction guidance of US$250 million to US$350 million. The Group also continues to reduce its covenant leverage ratio (covenant net debt / EBITDA), which was down from 3.1x at year-end 2018 to 2.4x at the end of the period. Premier's covenant leverage ratio is expected to continue to reduce further by year-end 2019.

Integral to Premier achieving its business objectives is being a responsible operator and the Group adheres to the highest health, environmental and safety standards. The first half saw Premier establish a Climate Change Committee, initiate a review of its operations to identify further opportunities to reduce its emissions and align its Climate Change Policy with the Task Force on Climate-related Financial Disclosures (TCFD) recommendations. Premier's Greenhouse Gas (GHG) intensity was materially lower compared to the prior corresponding period primarily due to a higher production contribution from the Group's Catcher Area, which has a low GHG intensity.

Looking to the remainder of 2019, the Group remains focused on maintaining its strong and safe operating performance and maximising its cash flows, which are protected via a robust hedging programme, and will be prioritised towards improving further the Group's balance sheet. In addition, Premier looks forward to the outcome of the Tolmount East appraisal well, first gas from the BIG-P gas fields, feedback from potential senior lenders and farminees to its Sea Lion project, and progressing the Zama divestment process.

Half-Year Results for the six months to 30 June 2019

OPERATIONAL REVIEW

GROUP PRODUCTION

Group production for the first half averaged 84.1 kboepd, up 10 per cent on the prior corresponding period and a record for Premier. This reflected very high operating efficiency across the portfolio and an increased contribution from the Premier-operated Catcher Area. The Group is on track to meet its previously increased full year production guidance of 75-80 kboepd.

The Group realised 35 per cent higher cash margins for the period, compared to the prior corresponding period, despite lower commodity prices. This was due to higher margin UK oil production accounting for a greater proportion of the Group's output and Premier's hedging programme which provided protection against the fall in commodity prices.

kboepd	2019 1H	2018 1H
UK	**58.1**	**41.3**
Vietnam	**12.4**	**16.2**
Indonesia	**11.1**	**13.4**
Pakistan[1]	**2.5**	**5.3**
Total	**84.1**	**76.2**

[1] sold at 26 March 2019

UNITED KINGDOM

UK production averaged 58.1 kboepd (2018: 41.3 kboepd) and represented almost 70 per cent of the Group's production (2018: 54 per cent) for the period. This increase resulted in a 35 per cent rise in the Group's cash margins. First gas from Premier's operated Tolmount field, the Group's next UK growth project, is on track for the end of 2020. Premier continues to expect UK production to average over 50 kboepd in the medium term.

The Greater Catcher Area

Premier's operated Catcher Area averaged 70.2 kboepd (gross, Premier-operated 50 per cent interest) for the first half, reflecting very high operating efficiency of 99 per cent and strong reservoir performance. The Catcher Area is forecast to reach cash pay back by the end of 2019, only two years after first oil, vindicating the Group's continued investment in the project through the oil price downturn.

Catcher Area production data continues to demonstrate good pressure support provided by the aquifer and injector wells and generally excellent lateral reservoir connectivity. In addition, water cut remains at low levels. Well productivity, supported by the better than expected permeability, remains constrained by the FPSO design capacity and the well stock is being managed to optimise production and ultimate oil recovery. Premier currently expects to increase Catcher Area reserves as part of the Group's formal year-end reserves assessment.

Future infill drilling opportunities along with satellite field tie-backs are being pursued to improve further recovery from the Catcher Area and to keep the FPSO operating at full oil capacity until 2021, materially longer than anticipated at sanction. Premier expects to receive formal approval of the development of the Catcher North and Laverda satellite oil fields imminently. Development drilling is expected to start in mid-2020 with first oil targeted for early 2021.

Premier plans to drill an infill well on the Varadero field immediately before the Catcher North and Laverda drilling programme to target resources beyond the reach of the initial suite of production wells. A 4D seismic survey across the Catcher Area is scheduled for mid-2020 to help confirm additional future infill well locations.

Other producing UK fields

Huntington production averaged 6.8 kboepd (Premier-operated 100 per cent interest), benefitting from high uptime and the newly converted water injector which is providing good pressure support to the whole field. In addition, productivity from the production well H5 increased following a successful squeeze treatment in July.

The non-operated Elgin-Franklin field averaged 6.5 kboepd (net, Premier 5.2 per cent interest) for the first six months of the year. This was ahead of forecast as the area benefitted from successful remedial work on existing wells and continued high operating efficiency. Further intervention work is planned which, together with an ongoing infill drilling programme, is expected to help maintain production from the area.

Production from Premier's operated Solan field averaged 4.0 kboepd (Premier-operated 100 per cent interest), slightly ahead of forecast and driven by excellent plant operating efficiency. A new Solan production well (P3) is planned for Spring 2020 to boost production from the central northern part of the reservoir and to extend field life. Premier has reached agreement with Baker Hughes, a GE company, to align payment with milestone dates, reducing Premier's cash outlay prior to the completion of the well. On the successful completion of the P3 well, excess gas will be used to replace diesel as a fuel for power generation on the facility.

Premier's operated Balmoral Area delivered 1.5 kboepd (net, Premier 79 per cent interest) during the period. Premier currently anticipates cessation of production no earlier than 2021.

Production from the Perenco-operated Ravenspurn North field averaged 1.2 kboepd (net, Premier 28.8 per cent interest), broadly in line with expectations. Perenco plans to drill two infill wells at Ravenspurn North commencing later this year to boost future production from the field.

Production from the rest of Premier's UK portfolio was broadly in line with expectations.

The Greater Tolmount Area

The development of the Premier-operated 500 BCF (gross) Tolmount gas field (Premier 50 per cent interest) in the Southern North Sea is on schedule and, to date, below budget.

The Tolmount field development entails four producer wells tied into a minimal facilities platform, a new gas export pipeline to shore and modifications to an existing onshore gas receiving terminal at Easington. Construction of the topsides steel frame and the jacket continues apace with sailaway of the platform from the Rosetti yard in Italy on track for the second quarter of 2020.

A rig has been contracted to drill the Tolmount development wells, with the first well expected to spud mid-2020. Preparations for the pipeline shore tie-ins are expected to commence shortly while engineering and procurement for the Easington terminal modifications are underway with civil works having commenced at site. Premier continues to expect first gas from the field by the end of 2020 with initial peak production rates of 50 kboepd (gross).

Post-period end, Premier spudded the Tolmount East appraisal well which is targeting 220-300 BCF (P50 to P90) of gross contingent resource. In the success case, Tolmount East will be tied back to Tolmount to ensure the infrastructure is kept at full capacity. Early concept work has been completed so that an accelerated Tolmount East development could be pursued. Data from the Greater Tolmount Area 3D seismic survey, completed in April, is being processed to define additional prospectivity in the area, such as Tolmount Far East, Tolmount West and Mongour.

INDONESIA

Robust production and continued low operating costs resulted in the Indonesian Business Unit generating positive net cash flows for the Group, after ongoing capital expenditures on the BIG-P development. BIG-P remains on track for first gas by the end of the year with positive drilling results achieved to date.

Production from the Premier-operated Natuna Sea Block A averaged 11.1 kboepd (net, Premier 28.67 per cent interest) (2018 1H: 12.8 kboepd) during the first half of the year.

Singapore demand for gas sold under GSA1, the Group's principal gas sales agreement, averaged 285 BBtud (gross) (2018 1H: 269 BBtud), ahead of take-or-pay levels and driven by high offtake early in the year when the LNG spot price was above that of GSA1. Premier's Anoa and Pelikan fields delivered 149 BBtud (gross) (2018 1H: 144 BBtud (gross)) during the period and accounted for 52 per cent of GSA1 deliveries (2018 1H: 53 per cent), above Natuna Sea Block A's contractual share of 51 per cent. In May, Premier completed a successful perforation at WL-6, one of the Anoa West Lobe wells, adding 19 mmscfd (gross) of production delivery from the Lower Gabus reservoir interval.

Production from Gajah Baru and Naga gas under GSA2 averaged 50 BBtud (gross) (2018 1H: 88 BBtud), a reduction on the prior corresponding period and below take-or-pay levels as cheaper spot LNG gas was substituted for Natuna Sea pipeline gas.

The price that Premier achieves for its Indonesian gas is linked to the price of HSFO and, in light of IMO2020, Premier has taken the opportunity to hedge a substantial proportion of its post-tax 2020 Indonesian gas volumes at an average equivalent price c. US$9/BBtu.

Development

The development of the BIG-P gas fields in Natuna Sea Block A involves a three well subsea tie-back to existing infrastructure and is progressing to budget and schedule. Once on-stream, BIG-P will support the Group's long-term contracts into Singapore and help maintain production from Natuna Sea Block A.

The first two out of the three development wells, SBS-1 at Bison and SIG-1 at Iguana, were completed and successfully flow tested. SBS-1 achieved a rate of 23 mmscfd, ahead of pre-drill expectations, due to thicker net sand development and better reservoir properties encountered in the main Middle Arang interval. Additional productive sands were also encountered in the Upper Arang interval. These will be exploited at a later date. SIG-1 flowed at a rate of 20 mmscfd, in line with expectations. The third well, SGP-1 at Gajah-Puteri, is currently being completed.

Onshore fabrication of the subsea structures for BIG-P has been completed with load out imminent. The Iguana-to-Bison-to-Pelikan and the Anoa-to-Gajah-Puteri pipelines have been successfully installed. Installation of the subsea structures and flexible risers will commence in September followed by installation of the umbilicals and final hook up and tie-in of the wells.

VIETNAM

Premier's Vietnam operations delivered a robust production performance. This, together with a continued low cost base, generated material free cash flows for the Group.

Production from the Premier-operated Block 12W, which contains the Chim Sáo and Dua fields, averaged 12.4 kboepd (net, Premier-operated 53.1 per cent interest) (2018 1H: 16.2 kboepd). The reduction on the prior period reflects natural depletion across the existing suite of wells partially offset by skilled reservoir management and ongoing well intervention campaigns which added production from new zones within existing wells. Production was also supported by sustained high operating efficiency in excess of 90 per cent. Demand for Chim Sáo oil remained strong with an average premium to Brent of over US$4/bbl achieved during the first six months of the year.

Three further well intervention campaigns are planned for the remainder of 2019 and a further four are under initial planning for 2020. In addition, preparations are underway for a 2021 two well infill drilling programme aimed at maximizing recovery from the Chim Sáo field. These incremental investments are aimed at extending the productive life of the Chim Sáo field.

Robust production performance, low operating costs and the continuing premiums to the Brent oil price commanded by Chim Sáo crude contributed to a positive net operating cash flow from the Vietnam Business Unit during the period.

THE FALKLAND ISLANDS

During the period, Premier has continued to advance its operated Sea Lion Phase 1 project towards a final investment decision with a focus on progressing the project's financing structure.

The Sea Lion project is a material opportunity for the Group with around 330 mmbbls (net to Premier) to be developed over two phases. Sea Lion Phase 1 will develop 250 mmbbls (gross) resources in PL032 (Premier 60 per cent operated interest), using a conventional FPSO based scheme, similar to Premier's successful Catcher development. The project is at a mature stage of definition and has been substantially de-risked from a technical, cost and schedule perspective.

Premier continues to benefit from a collaborative relationship with its Tier 1 supply chain. Substantive optimisation and value engineering has been achieved during the period with the key service and supply contracts nearing final form in preparation for their execution as the project approaches sanction decision.

The critical path to sanction remains securing the financing for the project. Post-period end, Premier completed a Preliminary Information Memorandum supported by a comprehensive set of independent expert reports on the project. These form the basis of a financing guarantee application package for the senior debt component of the project financing which was submitted to export credit agencies in July. The project is now in a period of lender due diligence which will entail, among other items, finalising the term sheets with potential senior lenders.

A formal farm-down process of Premier's 60 per cent operated interest in Sea Lion Phase 1 has been launched through which the Group proposes to optimise its level of participation in the project.

EXPLORATION AND APPRAISAL

In recent years, Premier has sought to rebalance its exploration portfolio away from traditional but now mature areas to underexplored but proven hydrocarbon basins with the potential to develop into new business units over the medium-term. During the first half of the year, the Group expanded its position in the South Andaman Sea and entered Alaska, consistent with Premier's strategy of focusing on underexplored, emerging plays in proven hydrocarbon provinces.

Indonesia

Post-period end, Premier farmed in for a 20 per cent interest in the South Andaman and Andaman I blocks which are located within the emerging South Andaman Sea gas play fairway directly adjacent to Premier's existing Andaman II acreage. Completion of the transaction is subject to government approvals. This expands Premier's collaboration with Mubadala Petroleum, who are operator of the South Andaman and Andaman I blocks and also the Group's joint venture partner in Andaman II, which Premier operates with a 40 per cent interest.

A 3D seismic acquisition programme across the Andaman I, Andaman II and South Andaman licences was completed during the period and will be used once processed to mature the prospects identified on the existing 2D data, many of which exhibited direct hydrocarbon indicators. Drilling is targeted for early 2021. Premier's Andaman Sea position has the potential to deliver multi-TCF of gas and adds a potentially material gas play to Premier's Indonesia portfolio.

Mexico

The Talos-operated Block 7 Zama appraisal campaign successfully completed in July, on schedule and below budget, and comprised two appraisal wells and a vertical sidetrack which was flow tested. A comprehensive set of data was acquired and demonstrated reservoir properties at the upper end of expectation. This resulted in Premier increasing its gross resource estimate of the Zama structure to 670-810-970 mmboe (P90-P50-P10).

The results from the appraisal programme are being integrated into the pre-FEED and FEED work ahead of the optimal development for the field being selected. In parallel, discussions have commenced around the Zama field resource split between Block 7 (Premier 25 per cent non-operated interest) and the adjacent block which is 100 per cent owned by Pemex. The Block 7 joint venture partnership is aiming to agree an initial tract participation by year-end with formal FDP submission in 2020.

The Group's highest priority is to further strengthen its balance sheet and, given considerable industry interest in shallow water Mexico, this has prompted Premier to initiate a formal sales process for its interest in the Zama field. In the success case, this will lead to a material reduction in the Group's debt levels. 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. The data is now being processed to delineate the full extent of the Wahoo prospect, which exhibits direct hydrocarbon indicators analogous to Zama, as well as to mature other prospectivity on the Block, including the Cabrilla prospect. Drilling is targeted for end 2020. Premier's exploration plan for its 100 per cent operated Burgos Blocks 11 and 13 were approved by CNH in July triggering the start of the four-year initial term for these licences. Reprocessing of the existing 3D seismic has commenced and is expected to be completed in first quarter 2020.

Brazil

In Brazil, Premier is actively engaging with rig contractors with available units in-country to drill a well targeting the stacked Berimbau and Maraca prospects on Block 717 (Premier 50 per cent operated interest) in the offshore Ceara Basin in 2020. Elsewhere in the Ceara basin, on Block 661 (Premier 30 per cent non-operated interest), the joint venture was successful in obtaining a licence extension through to November 2021 and now plans to postpone the drilling of the well to 2021. The joint venture aims to reach alignment on final well location to test the stacked Itarema and Tatajuba prospects shortly. The two wells on Blocks 717 and 661 will test in excess of 500 mmbbls of combined gross prospective resource.

Having fully evaluated the prospectivity on Block 665 (Premier 50 per cent operated interest), Premier and its joint venture partner unanimously decided to relinquish the licence in April 2019.

Alaska

Premier has signed a Sale and Purchase Agreement with 88 Energy and Burgundy Xploration LLC to farm-in for a 60 per cent interest in Area A of their conventional Project Icewine acreage in the proven Alaska North Slope basin. This acreage lies close to the Trans-Alaska Pipeline and the Dalton Highway. The transaction provides Premier with a cost effective entry point into an emerging play, following recent advances in drilling and completion techniques, within a proven oil province and one which has the potential to deliver significant organic growth opportunities for the Group.

Area A contains the Malguk-1 discovery drilled by BP in 1991. This well discovered but never tested 251 feet of light oil pay in turbidite sands in the Torok formation, within the recently emerging Brookian play. Premier estimates an accumulation of more than 1 billion barrels of oil in place, based on the original well data and its evaluation of the existing 3D dataset. There is also considerable upside in the shallower Schrader Bluff formation which has yet to be explored in a play similar to the Pikka/Horseshoe trend. The Alaska North Slope has attracted considerable industry interest recently with technological advances enabling these once stranded resources to now be commercialised. Several similar developments are already underway at various levels of maturity involving operators such as ConocoPhillips, ENI, Repsol and Oil Search.

Under the terms of the SPA, Premier will pay the full costs of an appraisal well up to a total of US$23 million to test the reservoir deliverability of the Malguk-1 discovery. The well will be drilled and tested in Q1 2020 with rig options having already been identified and contracting negotiations underway. On successful completion of the work programme, Premier will have the option to assume operatorship.

FINANCIAL REVIEW

Context

2019 has continued to see oil price volatility with observed prices being as high as US$74.7/bbl and as low as US$50.2/bbl in the period. Brent crude opened the year at US$50.2/bbl before closing at US$63.9/bbl on 30 June 2019. The average for 2019 1H was US$65.7/bbl compared to US$70.6/bbl for the corresponding period in 2018.

Against this economic backdrop our production averaged 84.1 kboepd in the period (2018 1H: 76.2 kboepd), which is ahead of budget for 2019 and is underpinned by very high operating efficiency across the portfolio. The increase when compared to the corresponding prior period was predominantly due to an increased contribution from the Premier-operated Catcher Area, which averaged 35.1 kboepd (net) and achieved 99 per cent operating efficiency. This increased production has underpinned total sales revenue from all operations of US$883.1 million compared with US$643.3 million in 2018 1H.

Business performance

EBITDAX for the period from continuing operations was US$680.2 million, an increase of US$192.4 million compared to the prior period EBITDAX of US$487.8 million, once lease expenses have been added back following the implementation of IFRS 16. The increased EBITDAX, on a like-for-like basis, is due to improved production and realised oil prices post hedging with costs remaining broadly flat due to tight cost control.

Business performance (continuing operations)	**2019 1H $ million**	2018 1H $ million
Operating profit	**327.5**	185.5
Add: DD&A	**346.5**	185.6
Add: Exploration and new venture costs	**8.7**	7.4
(Less)/add: (Profit)/loss on disposal of assets	**(2.5)**	10.4
EBITDAX as reported	**680.2**	388.9
Add: lease expenses	**-**	98.9
EBITDAX adjusted for lease expenses	**680.2**	487.8

Income statement

Production and revenue

Group production on a working interest basis averaged 84.1 kboepd for the period compared to 76.2 kboepd in 2018 1H, due to high operational efficiency across the asset portfolio and the increased contribution from the Catcher Area. Entitlement production for the period was 79.9 kboepd (2018 1H:

69.2 kboepd). Post hedging, Premier realised an average price for the period of US$68.3/bbl (2018 1H: US$61.6/bbl) vs a Brent average price of US$65.7/bbl (2018 1H: US$70.6/bbl).

In the UK, Premier achieved average natural gas prices of 44 pence/therm (2018 1H: 49 pence/therm), which included 21.7 million therms which were sold under fixed price master sales agreements. Gas prices in Singapore, indirectly linked with crude oil pricing, averaged US$11.3/mscf (2018 1H: US$9.7/mscf) post hedging.

Realised prices	**2019 1H**	2018 1H
Oil price (US$/bbl) post hedging	**68.3**	61.6
UK natural gas (pence/therm)	**44**	49
Singapore HSFO (US$/mscf)	**11.3**	9.7

Total sales revenue from all operations (including Pakistan until its disposal in March 2019) increased to US$883.1 million (2018 1H: US$643.3 million), due to an increase in realised oil and HSFO prices in the period combined with higher production. From continuing operations (excluding Pakistan), revenue increased to US$871.3 million compared to US$625.0 million in the prior period.

Operating costs

Cost of operations comprise operating costs, changes in lifting positions, inventory movement and royalties. Cost of operations, which now exclude lease expenses following the adoption of IFRS 16, for the Group was US$183.4 million for 2019 1H, compared to US$132.7 million for 2018 1H, once lease costs of US$98.9 million are removed from the prior period.

	2019 1H $ million	2018 1H $ million
Operating costs		
Continuing operations	**154.5**	232.5
Less: lease expenses	**-**	(98.9)
Discontinuing operations (Pakistan)	**2.4**	4.7
Operating costs	**156.9**	138.3
Operating cost per barrel (US$ per barrel)	**10.3**	10.0

Lease expenses in 2019 1H were US$96.5 million, giving a lease cost per barrel of US$6.3, which is broadly consistent year on year.

	2019 1H $ million	2018 1H $ million
Amortisation and depreciation		
Total DD&A	**344.3**	180.8
DD&A per barrel (US$ per barrel)	**22.6**	13.1

Total depreciation has increased year-on-year due to DD&A charges of US$121.4 million recognised on right-of-use-assets now recorded on the balance sheet as property, plant and equipment following the adoption of IFRS 16 on 1 January 2019. The DD&A charge reflects the positive impact of the revised Catcher reserves estimates.

Exploration expenditure and new ventures

Exploration expense and new venture costs amounted to US$8.7 million (2018 1H: US$7.4 million) primarily related to work performed on potential new ventures. After recognition of these expenditures, the exploration and evaluation asset remaining on the balance sheet at 30 June 2019 amounts to US$870.6 million (31 December 2018: US$812.6 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 2019 1H of US$3.3 million (2018 1H: US$3.0 million) are broadly consistent with the prior period.

Finance gains and costs

Net finance costs of US$207.6 million are broadly in line with the prior year of US$210.2 million. An increase in finance costs due to lease liabilities recognised on adoption of IFRS 16 has been broadly offset by lower finance expenses for changes in the fair value of Premier's equity warrant instruments in the period compared to 2018 1H. Cash interest expense in the period was US$127.5 million (2018 1H: US$125.5 million).

Taxation

The Group has a current tax charge for the period of US$36.9 million (2018 1H: charge of US$46.5 million) and a non-cash deferred tax credit for the period of US$29.4 million (2018 1H: credit of US$161.3 million) which results in a total tax charge for the period of US$7.5 million, from continuing operations (2018 1H: credit of US$114.8 million).

The total tax charge for the period represents an effective tax rate of 6.3 per cent (2018 1H: 464.8 per cent). The low effective tax rate is predominantly driven by prior year adjustments relating to overseas tax disputes found in Premier's favour as well as ring fence expenditure supplement, which continues to be claimed to uplift UK ring fence tax losses carried forward.

The Group continues to recognise its UK deferred tax assets in respect of ring fence tax losses and investment allowances in full in line with the assumptions taken at 31 December 2018 on the basis that there have been no impairment triggers identified at the balance sheet date of 30 June 2019.

Profit after tax

Profit after tax for the period was US$120.6 million (2018 1H: US$98.4 million), including US$8.2 million from the Pakistan Business Unit which was classified as a discontinued operation prior to the completion of its disposal in March 2019, resulting in a basic earnings per share of 14.7 cents (2018 1H: 13.2 cents).

Cash flow

Cash flow from operating activities was US$544.6 million (2018 1H: US$224.6 million) after accounting for tax payments of US$42.1 million (2018 1H: US$62.5 million) and movement in joint venture cash balances in the period of US$5.8 million. The increase is driven by increased production and revenue in the period and due to US$98.1 million of lease cash costs in 2019 1H recorded as financing and not operating cash flows.

Capital expenditure in the period to 30 June 2019 totalled US$103.3 million (2018 1H: US$164.3 million).

Capital expenditure	**2019 1H $ million**	2018 1H $ million
Field/development projects	**32.4**	137.9
Exploration and evaluation	**69.9**	25.8
Other	**1.0**	0.6
Total	**103.3**	164.3

The development expenditure mainly relates to the BIG-P development in Indonesia and the Tolmount project in the UK. The largest part of the E&E capital expenditure in the period was the appraisal drilling for the Zama project in Mexico. In addition, cash expenditure for decommissioning activity in the period was US$24.3 million (2018 1H: US$45.1 million). Further to this, US$5.2 million of cash was funded into long-term abandonment accounts for future decommissioning activities (2018 1H: US$9.8 million).

Disposals

The Group completed the sale of its Pakistan business to the Al-Haj Group in March 2019. In total Premier received the full consideration of US$65.6 million for the sale including deposits and completion payments paid by the buyer and net cash flows collected by Premier since the economic date of the transaction. The Pakistan Business Unit results for the current and prior periods are presented as a discontinued operation.

Balance sheet position

Net Debt

Accounting net debt at 30 June 2019 amounted to US$2,151.2 million (31 December 2018: US$2,330.7 million), with cash resources of US$253.5 million (31 December 2018: US$244.6 million).

During the period, Premier made debt repayments of US$169.7 million. The Group also cancelled US$100.3 million of undrawn capacity of its RCF debt facility.

Premier retains significant cash at 30 June 2019 of US$225.7 million and undrawn facilities of US$419.6 million, giving liquidity of US$645.3 million (31 December 2018: US$569.6 million) when excluding cash of US$27.8 million held on behalf of joint venture partners.

In July 2019, subsequent to the period end, the Group made a further repayment of US$100 million of its RCF debt facility reducing gross debt. The Group also cancelled US$233.5 million of undrawn capacity of this facility, which will reduce commitment fees going forward.

Provisions

Total decommissioning provisions at 30 June 2019 are US$1,186.1 million (31 December 2018: US$1,214.5 million, excluding those associated with assets held for sale), with the reduction driven by expenditure in the period.

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, Cash Margin, Free Cash Flow, Operating cost per barrel, DD&A per barrel, Net Debt and Liquidity and are defined in the glossary.

Impact on key financial metrics on adoption of IFRS 16 Leases

A new IFRS standard on leases came into effect on 1 January 2019. The impact on key financial metrics for the period is shown below.

$ million	Impact of IFRS 16	
Balance Sheet at 30 June 2019 [1]		
Fixed assets	**744.5**	
Net investment in sub-lease	**85.9**	
Lease liabilities	**873.1**	
Income Statement for 2019 1H [2]		
Costs of Production	**96.5**	Decrease
DD&A	**121.4**	Increase
Net finance costs	**19.8**	Increase
Net impact on profit after tax	**44.7**	Decrease
Cash flow for 2019 1H [3]		
Operating cash flow	**98.1**	Increase
Lease payments (within financing cash flows)	**98.1**	Increase
Free cash flow	**Nil**	

1. Balance Sheet

Following the adoption of IFRS 16, US$744.5 million of right-of-use assets, US$85.9 million of net investment in sublease and US$873.1 million of lease liabilities have been included in the Group balance sheet as at 30 June 2019. All of these were previously classified as operating leases as the Group did not have any finance leases under IAS 17. Lease liabilities are now presented separately on the Group balance sheet as both current and non-current liabilities, do not form part of finance debt and are not included in net debt under the terms of the Group's financing facilities.

2. Income Statement

Charges to the income statement due to the adoption of IFRS 16 have increased by US$44.7 million. This represents an increase in depreciation and finance costs recognised on right-of-use assets and lease liabilities, which are partially offset by the absence of operating lease expenses within costs of production. EBITDAX, as previously defined, has increased, due to the absence of operating lease expenses within costs of production. For the purposes of covenant calculations, lease expenses continue to be included within costs of production.

3. Cash flow

In prior years, operating lease payments were presented as operating cash flows. Lease payments are now classified as financing cash flows which has caused operating cash flows to increase. There were

US$98.1 million of lease payments included within financing cash flows for 2019 1H, that would previously have been reported within operating cash flows before the adoption of IFRS 16.

Financial risk management

Commodity prices

Premier continue to take advantage of the improved oil price environment observed at times in 2019 to increase its hedging position in 2019 2H and 2020 to protect free cash flows and covenant compliance.

The Group's current hedge position to the end of 31 December 2020 is as follows:

Oil

Swaps / forwards	**2019 2H**	**2020**
Volume (mmbbls)	4.0	2.2
Average price (US$/bbl)	69	66

UK gas

Swaps / forwards	**2019 2H**	**2020**
Volume (million therms)	16.6	42.3
Average price (p/therm)	62	51

Indonesia gas

Swaps / forwards	**2019 2H**	**2020**
Volume (HSFO k te)	102	252
Average price (US$/te)	381	361

At 30 June 2019, the fair value of the open oil and gas instruments above was an asset of US$37.9 million (31 December 2018: asset of US$119.3 million), which is expected to be released to the income statement during 2019 2H and 2020 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 gain of US$1.9 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:€.

Interest rates

The Group has various financing instruments including senior loan notes, UK retail bonds, term loans and revolving credit facilities. Currently, approximately 66 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 8.3 per cent.

Going concern

The Group monitors its funding position and its liquidity risk throughout the year to ensure 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.

Management's base case forecast assumes an oil price of US$65/bbl in 2019 and 2020, and production in line with prevailing rates. The Group has run downside scenarios, where oil prices are reduced by a flat US$10/bbl throughout the going concern period and where total Group production is forecast to reduce by 10 per cent.

At 30 June 2019, the Group continued to have significant headroom on its financing facilities and cash on hand. The base case forecasts show that the Group will have sufficient financial headroom for the 12 months from the date of approval of the 2019 Interim Report and Accounts. In the individual downside scenarios ran, no covenant breach is forecasted in the going concern period. If both downside scenarios were to materialise immediately and were sustained throughout the going concern period, then, in the absence of any mitigating actions, a breach of one or more of the financial covenants during the 12 month going concern assessment period could arise. This potential breach could be mitigated by non-core asset disposals, such as the Group's interest in the Zama prospect, as well as further hedging activity or deferral of expenditure.

Accordingly, after making enquiries and considering the risks described above, the Directors have a reasonable expectation that the Company has adequate resources to continue in operational existence for the foreseeable future. Accordingly, the Directors continue to adopt the going concern basis of accounting in preparing these consolidated financial statements.

Business risks

Premier's business may be impacted by various risks leading to failure to achieve strategic targets for growth, 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:

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

These risks are consistent with those identified at 31 December 2018, with the addition of a new principal risk related to the impact of climate change.

The potential impact related to the risk of climate change is as follows:

- Adverse investor and lender sentiment towards the oil and gas sector
- Failure to comply with climate change related operational regulations and disclosure requirements
- Disruption to Premier's projects and operations, as a result of changing weather patterns and more frequent extreme weather events
- Longer term reduction in demand for oil and gas products resulting in lower oil and gas prices, as a result of commercial deployment of alternative energy technologies and shifts in consumer preference for lower greenhouse gas emission products

Further information detailing the way in which these risks are mitigated is provided on pages 36 to 41 of the 2018 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

Half-Year Results for the six months to 30 June 2019

CONDENSED CONSOLIDATED INCOME STATEMENT

	Note	**Six months to 30 June 2019 Unaudited $ million**	Six months to 30 June 2018 Unaudited $ million
Continuing operations			
Sales revenues	*2*	**871.3**	625.0
Other operating costs		**(4.4)**	(1.5)
Costs of operation	*3*	**(183.4)**	(231.6)
Depreciation, depletion and amortisation	*8*	**(346.5)**	(185.6)
Exploration and new venture costs	*7*	**(8.7)**	(7.4)
Gain/(loss) on disposal of non-current assets		**2.5**	(10.4)
General and administration costs		**(3.3)**	(3.0)
Operating profit		**327.5**	185.5
Interest revenue, finance and other gains	*4*	**11.1**	3.8
Finance costs, other finance expenses and losses	*4*	**(218.7)**	(214.0)
Profit/(loss) before tax		**119.9**	(24.7)
Tax (charge)/credit	*5*	**(7.5)**	114.8
Profit for the period from continuing operations		**112.4**	90.1
Discontinued operations			
Profit for the period from discontinued operations	*11*	**8.2**	8.3
Profit after tax		**120.6**	98.4
Earnings per share (cents):			
From continuing operations			
Basic	*6*	**13.7**	12.1
Diluted	*6*	**12.4**	10.4
From continuing and discontinued operations			
Basic	*6*	**14.7**	13.2
Diluted	*6*	**13.3**	11.4

Notes 1 to 13 form an integral part of these condensed financial statements.

CONDENSED CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

	Six months to 30 June 2019 Unaudited $ million	Six months to 30 June 2018 Unaudited $ million
Profit for the period	**120.6**	98.4
Cash flow hedges on commodity swaps:		
(Losses) arising during the period	**(78.9)**	(88.4)
Less: reclassification adjustments for (gains)/losses in the period	**(8.8)**	36.4
	(87.7)	(52.0)
Cash flow hedges on interest rate and foreign exchange swaps		
Gains arising during the period	**0.4**	8.6
Less: reclassification adjustments for (gains) in the period	**(2.0)**	(3.9)
	(1.6)	4.7
Tax relating to components of other comprehensive income	**25.9**	16.2
Exchange differences on translation of foreign operations	**11.2**	(7.6)
Other comprehensive expense	**(52.2)**	(38.7)
Total comprehensive income for the period	**68.4**	59.7

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 2019 Unaudited $ million	At 31 December 2018 Audited $ million
Non-current assets:			
Intangible exploration and evaluation assets	*7*	**870.6**	812.6
Property, plant and equipment	*8*	**2,762.9**	2,245.6
Goodwill		**240.8**	240.8
Long-term receivables		**227.2**	159.8
Deferred tax assets		**1,483.9**	1,434.1
		5,585.4	4,892.9
Current assets:			
Inventories		**16.1**	12.5
Trade and other receivables		**393.1**	282.3
Derivative financial instruments	*10*	**39.2**	127.4
Cash and cash equivalents		**253.5**	244.6
Assets held for sale	*11*	**-**	55.2
		701.9	722.0
Total assets		**6,287.3**	5,614.9
Current liabilities:			
Trade and other payables		**(320.4)**	(375.6)
Lease liabilities	*12*	**(161.6)**	-
Short-term provisions		**(57.2)**	(46.0)
Derivative financial instruments	*10*	**(28.7)**	(41.4)
Deferred income		**(9.8)**	(11.0)
Liabilities directly associated with assets held for sale	*11*	**-**	(21.9)
		(577.7)	(495.9)
Net current assets		**124.2**	226.1
Non-current liabilities:			
Long-term debt	*9*	**(2,386.4)**	(2,552.0)
Deferred tax liabilities		**(134.4)**	(139.5)
Lease liabilities	*12*	**(711.5)**	-
Deferred income		**(73.5)**	(76.0)
Long-term provisions		**(1,160.5)**	(1,196.1)
Derivative financial instruments	*10*	**(133.2)**	(129.4)
		(4,599.5)	(4,093.0)
Total liabilities		**(5,177.2)**	(4,588.9)
Net assets		**1,110.1**	1,026.0
Equity and reserves:			
Share capital		**155.5**	154.2
Share premium account		**494.8**	491.7
Other reserves		**459.8**	380.1
		1,110.1	1,026.0

CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

	Share capital $ million	Share premium account $ million	Other reserves $ million	Total $ million
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**

At 31 December 2017	109.0	284.5	223.4	616.9
Adjustment on adoption of IFRS 9[1]	-	-	(82.0)	(82.0)
At 1 January 2018	109.0	284.5	141.4	534.9
Issue of Ordinary Shares	38.5	178.4	(0.2)	216.7
Net release of ESOP Trust shares	-	-	(1.0)	(1.0)
Provision for share-based payments	-	-	8.2	8.2
Release of equity component of convertible bonds	-	-	(54.5)	(54.5)
Profit for the period	-	-	98.4	98.4
Other comprehensive expense	-	-	(38.7)	(38.7)
At 30 June 2018	**147.5**	**462.9**	**153.6**	**764.0**

[1] Refer to the accounting policies in the Premier Oil 2018 Annual Report and Accounts for further information

CONDENSED CONSOLIDATED CASH FLOW STATEMENT

	Note	**Six months to 30 June 2019 Unaudited $ million**	Six months to 30 June 2018 Unaudited $ million
Net cash from operating activities	*9*	**544.6**	224.6
Investing activities:			
Capital expenditure		**(103.3)**	(164.3)
Decommissioning pre-funding		**(5.2)**	(9.8)
Decommissioning expenditure		**(24.3)**	(45.1)
Disposal of oil and gas properties	*11*	**3.1**	22.8
Net cash used in investing activities		**(129.7)**	(196.4)
Financing activities:			
Issuance of Ordinary Shares		**3.8**	8.0
Net release of ESOP Trust shares		**1.0**	(1.0)
Warrant cash consideration		**(11.9)**	-
Lease liability payments		**(98.1)**	-
Proceeds from drawdown of bank loans		**-**	105.0
Repayment of bank loans		**(169.7)**	(199.1)
Interest paid		**(127.5)**	(125.5)
Net cash used in financing activities		**(402.4)**	(212.6)
Currency translation differences relating to cash and cash equivalents		**(3.6)**	(1.0)
Net increase/(decrease) in cash and cash equivalents		**8.9**	(185.4)
Cash and cash equivalents at the beginning of the period		**244.6**	365.4
Cash and cash equivalents at the end of the period	*9*	**253.5**	180.0

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 2019 were approved for issue in accordance with a resolution of a committee of the Board of Directors on 21 August 2019.

The information for the year ended 31 December 2018 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 2018 were approved by the Board of Directors on 6 March 2018 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 2019, and the condensed consolidated balance sheet as at 30 June 2019 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 2019 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 2018, 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.

1. BASIS OF PREPARATION *(continued)*

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 2018, as described in those annual financial statements, except for the adoption of IFRS 16 Leases.

IFRS 16 'Leases'

Premier adopted IFRS 16 Leases ('IFRS 16') with effect from 1 January 2019. IFRS 16 was issued in January 2016 to replace IAS 17 Leases. Further information is included in Premier's 2018 Annual Report and Financial Statements – Accounting Policies.

IFRS 16 sets out the principles for the recognition, measurement, presentation and disclosure of leases and requires lessees to account for all leases, with limited exceptions, under a single on-balance sheet model similar to the accounting for finance leases under IAS 17. Under IFRS 16, at the commencement date of a lease, a lessee is required to recognise a liability to make lease payments ('lease liability') and an asset representing the right to use the underlying asset during the lease term ('right-of-use asset'). Lease liabilities are measured at the present value of future lease payments over the reasonably certain lease term. Variable lease payments that do not depend on an index or a rate are not included in the lease liability. Such payments are expensed as incurred throughout the lease term.

In applying IFRS 16 for the first time the Group has applied the short-term lease practical expedient by not recognising lease liabilities in respect to lease arrangements with a remaining lease term of less than 12 months as at 1 January 2019. The Group adopted the modified retrospective approach to adoption on 1 January 2019, measuring right-of-use assets at an amount based on their respective lease liability on adoption, with the cumulative effect of adopting the standard recognised at the date of initial application without restatement of comparative information.

Lessees are required to separately recognise the interest expense associated with the unwinding of the lease liability and the depreciation expense on the right-of-use asset. These costs replace amounts previously recognised as operating expenditure in respect of operating leases in accordance with IAS 17. Principal payments related to leases are now presented as financing cash flows in the cashflow statement. The replacement of operating lease expenditure with the recognition of interest expense and depreciation in respect to leases liabilities and right-of-use assets, respectively, will result in an increase in Group EBITDAX. The adoption of IFRS 16 will not impact the calculation of the Group's financial debt covenants.

1. BASIS OF PREPARATION *(continued)*

A matter finalised since the release of Premier's 2018 Annual Report and Financial Statements is the determination of the appropriate accounting for a lease arrangement entered into by a lead operator as a sole signatory for the lease of equipment that will be used in a joint operation. The IFRS Interpretations Committee ('IFRIC') issued an agenda decision in respect to this matter in March 2019. Where all partners of a joint operation are considered to share the primary responsibility for lease payments under a lease contract, the Group recognises its share of the respective right-of-use asset and lease liability. This situation is most common where the parties of a joint operation co-sign the lease contract. The Group recognises a gross lease liability for leases entered into on behalf of a joint operation where it has primary responsibility for making the lease payments.

In such instances, if the arrangement between the Group and the joint operation represents a finance sublease, the Group recognises a net investment in sublease for amounts recoverable from non-operators whilst derecognising the respective portion of the gross right-of-use asset. The gross lease liability is retained on the balance sheet. The net investment in sublease is classified as either trade and other receivables or long-term receivables on the balance sheet according to whether or not the amounts will be recovered within 12 months of the balance sheet date.

The assessment as to whether a sublease exists predominantly depends on whether the operator or the joint operation directs the use of the respective right-of-use asset. Where the arrangement between the operator and joint operation does not represent a sublease or the sublease represents an operating sublease, the Group retains the gross lease liability and right-of-use asset on the balance sheet.

The following table provides a reconciliation of the Group's operating lease commitments as at 31 December 2018 to the total lease liability recognised on adoption of IFRS 16. The Group did not recognise any finance leases under IAS 17.

	$ million
Operating lease commitments at 31 December 2018	**1,002.0**
Contracts not in scope of IFRS 16[1]	(85.6)
Effect of discounting[2]	(189.9)
Short term leases	(3.1)
Impact of leases in joint operations[3]	99.0
Lease extension options[4]	77.6
Other	(0.4)
Lease liabilities recognised on adoption of IFRS 16	**899.6**

Notes

[1] Contracts that were considered to be leases under IAS 17 which do not meet the definition of a lease under IFRS 16, principally because the supplier is considered to have substantive substitution rights over the associated assets.

[2] The previously disclosed lease commitments were undiscounted, whilst the IFRS 16 obligations have been discounted based on Premier's incremental borrowing rate.

[3] This represents the gross up of the lease obligations to represent 100 per cent of the liability where the Group has entered into a lease agreement on behalf of the joint operation and its partners and has primary responsibility for lease payments.

[4] Previously, lease commitments only included non-cancellable periods in the lease agreements. Under IFRS 16, the lease term includes periods covered by options to extend the lease where the Group is reasonably certain that such options will be exercised.

A number of additional new standards, amendments to existing standards and interpretations were effective from 1 January 2019. 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 2019.

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. 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 2019 Unaudited $ million	Six months to 30 June 2018 Unaudited $ million
Revenue:		
United Kingdom	**673.7**	395.7
Indonesia	**88.8**	87.6
Vietnam	**108.8**	140.9
Rest of the World	**-**	0.8
Total Group sales revenue	**871.3**	625.0
Other operating costs – United Kingdom	**(4.4)**	(1.5)
Interest and other finance revenue	**4.0**	2.2
Total Group revenue from continuing operations	**870.9**	625.7
Revenue from discontinued operations	**11.8**	18.3
Group operating profit:		
United Kingdom	**225.7**	74.6
Indonesia	**56.5**	42.1
Vietnam	**57.7**	77.5
Rest of the World	**(0.2)**	(3.5)
Unallocated[1]	**(12.2)**	(5.2)
Group operating profit	**327.5**	185.5
Interest revenue, finance and other gains	**11.1**	3.8
Finance costs and other finance expenses	**(218.7)**	(214.0)
Profit/(loss) before tax from continuing operations	**119.9**	(24.7)
Tax (charge)/credit	**(7.5)**	114.8
Profit after tax from continuing operations	**112.4**	90.1
Profit from discontinued operations	**8.2**	8.3

[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 and exploration and new venture costs.

2. OPERATING SEGMENTS *(continued)*

Of the Group's worldwide revenues of US$871.3 million (2018 1H: US$625.0 million), revenues of US$861.6 million (2018 1H: US$661.4 million) were from contracts with customers. This was increased by hedging gains in the period of US$9.7 million (2018 1H: loss of US$36.4 million).

	30 June 2019 Unaudited $ million	31 December 2018 Audited $ million
Balance sheet - Segment assets:		
United Kingdom[1]	**4,263.5**	3,706.1
Indonesia	**451.7**	417.7
Vietnam	**467.8**	312.0
Falkland Islands	**663.9**	648.1
Rest of the World	**147.7**	103.8
Assets held for sale	**-**	55.2
Unallocated[2]	**292.7**	372.0
Total assets	**6,287.3**	5,614.9

[1] Includes goodwill of US$240.8 million.

[2] Unallocated assets include cash and cash equivalents and mark-to-market valuations of commodity contracts and interest rate swaps and options.

3. COSTS OF OPERATION

	Six months to 30 June 2019 Unaudited $ million	Six months to 30 June 2018 Unaudited $ million
Operating costs	**154.5**	232.5
Gas purchases	**14.0**	4.3
Stock overlift/(underlift) movement	**10.0**	(12.5)
Royalties	**4.9**	7.3
	183.4	231.6

4. INTEREST REVENUE AND FINANCE COSTS

	Six months to 30 June 2019 Unaudited $ million	Six months to 30 June 2018 Unaudited $ million
Interest revenue, finance and other gains:		
Lease finance income	**2.8**	-
Short-term deposits	**1.1**	0.6
Other interest received	**0.4**	1.6
Derivative gains	**4.3**	1.6
Exchange differences and others	**2.5**	-
	11.1	3.8
Finance costs:		
Bank loans, overdrafts and bonds	**(101.1)**	(86.7)
Payable in respect of convertible bonds	**-**	(0.6)
Payable in respect of senior loan notes	**(18.9)**	(18.9)
Long-term debt arrangement fees	**(5.0)**	(15.2)
Exchange differences and others	**(29.7)**	(6.6)
	(154.7)	(128.0)
Other finance expenses:		
Lease finance costs	**(22.6)**	-
Unwinding of discount on decommissioning provision	**(26.2)**	(31.7)
Derivative losses	**(14.2)**	(51.6)
Finance expense on deferred income	**(2.6)**	(2.7)
	(65.6)	(86.0)
Gross finance costs and other finance expenses	**(220.3)**	(214.0)
Finance costs capitalised during the period	**1.6**	-
	(218.7)	(214.0)

5. TAX

	Six months to 30 June 2019 Unaudited $ million	Six months to 30 June 2018 Unaudited $ million
Current tax:		
UK corporation tax on profits	**-**	(9.5)
Overseas tax	**49.6**	56.0
Adjustments in respect of prior years	**(12.7)**	-
Total current tax charge	**36.9**	46.5
Deferred tax:		
UK corporation tax	**(24.2)**	(146.4)
Overseas tax	**(5.2)**	(14.9)
Total deferred tax credit	**(29.4)**	(161.3)
Tax charge/(credit) on profit/(loss) on ordinary activities	**7.5**	(114.8)

5. TAX *(continued)*

The Group has a current tax charge for the period of US$36.9 million (2018 1H: US$46.5 million) and a non-cash deferred tax credit for the period of US$29.4 million (2018 1H: US$161.3 million) which results in a total tax charge for the period of US$7.5 million (2018 1H: US$114.8 million credit). The deferred tax credit primarily arises due to ring fence expenditure supplement which is claimed on UK tax losses.

The total tax charge for the period represents an effective tax rate of 6.3 per cent (2018 1H: 464.8 per cent). The low effective tax rate is predominantly driven by ring fence expenditure supplement which continues to be claimed to uplift UK ring fence tax losses carried forward and prior year adjustments relating to overseas tax disputes found in Premier's favour. The Group has not recognised any tax benefit for ongoing tax disputes where a ruling in the Group's favour is not yet considered to be probable.

In addition, during the period, the Group recognised a deferred tax asset and associated tax credit in relation to an expected future tax deduction associated with decommissioning costs funded by E.ON. An offsetting finance cost, which is classified within exchange differences and others (see note 4), has also been recognised as this tax deduction will be reimbursed to E.ON once received by Premier. This finance cost represents the majority of the increase in exchange differences and others when compared to the prior period.

The Group continues to recognise its UK deferred tax assets in respect of ring fence tax losses and investment allowances in full in line with the assumptions taken at 31 December 2018 on the basis that there have been no impairment indicators identified at the balance sheet date of 30 June 2019.

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.

6. EARNINGS PER SHARE

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

	Six months to 30 June 2019 Unaudited	Six months to 30 June 2018 Unaudited
Earnings ($ millions):		
Earnings from continuing operations	**112.4**	90.1
Effect of dilutive potential Ordinary Shares:		
Interest on convertible bonds	**-**	0.6
Earnings for the purposes of diluted earnings per share on continuing operations	**112.4**	90.7
Profit from discontinued operations	**8.2**	8.3
Earnings for the purpose of diluted earnings per share on continuing and discontinued operations	**120.6**	99.0
Number of shares (millions):		
Weighted average number of Ordinary Shares for the purpose of basic earnings per share	**821.6**	745.0
Effects of dilutive potential Ordinary Shares:		
Contingently issuable shares – dilutive	**83.0**	127.2
Weighted average number of Ordinary Shares for the purpose of diluted earnings per share	**904.6**	872.2
Earnings per share (cents) from continuing operations		
Basic	**13.7**	12.1
Diluted	**12.4**	10.4
Earnings per share (cents) from discontinued operations		
Basic	**1.0**	1.1
Diluted	**0.9**	1.0

Discontinued operations relate to the results of the Group's Pakistan Business Unit, which was disposed of in March 2019.

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

	Oil and gas properties $ million
Cost:	
At 1 January 2019	812.6
Exchange movements	1.5
Additions during the period	56.8
Exploration expense	(0.3)
At 30 June 2019	**870.6**

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.

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 $ million	Right-of-use-assets $ million	Other fixed assets $ million	Total $ million
Cost:				
At 1 January 2019	7,807.6	803.3	57.3	8,668.2
Exchange movements	-	(2.0)	-	(2.0)
Additions during the period	(1.8)	64.6	1.0	63.8
Disposals	(1.3)	-	-	(1.3)
At 30 June 2019	**7,804.5**	**865.9**	**58.3**	**8,728.7**
Amortisation and depreciation:				
At 1 January 2019	5,568.2	-	51.1	5,619.3
Charge for the period	222.9	121.4	2.2	346.5
At 30 June 2019	**5,791.1**	**121.4**	**53.3**	**5,965.8**
Net book value:				
At 30 June 2019	**2,013.4**	**744.5**	**5.0**	**2,762.9**
At 31 December 2018	2,239.4	-	6.2	2,245.6

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 additions above represent the revision to the right-of-use asset for the Catcher FPSO due to the assumed COP date being extended to 2028, given positive field performance.

In addition to the above, the Group has a net investment in sublease of US$85.9 million (1 January 2019: US$96.3 million), of which US$64.5 million is classified as a long-term receivable and US$21.4 million as trade and other receivables. The net investment in sublease represents our joint operation partners' share of lease liabilities on lease arrangements for 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.

Income of US$2.8 million, which predominantly represents unwinding of the net investment in sublease, has been recognised as finance income in the year (see note 4).

9. NOTES TO THE CONDENSED CONSOLIDATED CASH FLOW STATEMENT

	Note	**Six months to 30 June 2019 Unaudited $ million**	Six months to 30 June 2018 Unaudited $ million
Profit/(Loss) before tax for the period		**119.9**	(24.7)
Adjustments for:			
Depreciation, depletion and amortisation		**346.5**	185.6
Other operating costs		**4.4**	1.5
Exploration expense	*7*	**0.3**	5.2
Provision for share-based payments		**6.0**	4.2
Interest revenue and finance gains	*4*	**(11.1)**	(3.8)
Finance costs and other finance expenses	*4*	**218.7**	214.0
(Gain)/loss on disposal of non-current assets		**(2.5)**	10.4
Operating cash flows before movements in working capital		**682.2**	392.4
Increase in inventories		**(3.7)**	(4.6)
(Increase)/decrease in receivables		**(16.4)**	48.3
Decrease in payables		**(81.4)**	(113.7)
Cash generated by operations		**580.7**	322.4
Income taxes paid		**(42.1)**	(62.5)
Interest income received		**4.6**	1.8
Net cash from continuing operating activities		**543.2**	261.7
Net cash from discontinued operating activities	*11*	**7.2**	14.9
Net cash from operating activities		**550.4**	276.6
Movement in joint venture cash		**(5.8)**	(52.0)
Total net cash from operating activities		**544.6**	224.6

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

Analysis of changes in net debt:

	Six months to 30 June 2019 Unaudited $ million	Six months to 30 June 2018 Unaudited $ million
a) Reconciliation of net cash flow to movement in net debt:		
Movement in cash and cash equivalents	**8.9**	(185.4)
Proceeds from drawdown of bank loans	**-**	(105.0)
Repayment of bank loans	**169.7**	199.1
Partial conversion of convertible bonds	**-**	154.0
Non-cash movements on debt and cash balances (predominantly foreign exchange)	**0.9**	8.8
Decrease in net debt in the period	**179.5**	71.5
Opening net debt	**(2,330.7)**	(2,724.2)
Closing net debt	**(2,151.2)**	(2,652.7)

b) Analysis of net debt:		
Cash and cash equivalents	**253.5**	180.0
Borrowings[1]	**(2,404.7)**	(2,832.7)
Total net debt	**(2,151.2)**	(2,652.7)

1 Borrowings consist of the convertible bonds and long-term debt. The carrying amounts of the borrowings on the balance sheet are stated net of the unamortised portion of the refinancing fees of US$18.3 million (31 December 2018: US$23.3 million) and the impact of the IFRS 9 adjustment (see accounting policies in the Premier Oil 2018 Annual Report and Accounts).

10. FINANCIAL INSTRUMENTS

Derivative financial instruments

The Group held the following financial instruments at fair value at 30 June 2019. 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 and synthetic 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 2019 $ million	At 31 December 2018 $ million
Financial assets:		
Oil forward sales contracts	28.8	102.0
Gas forward sales contracts	10.4	23.4
Interest rate options	-	1.1
Interest rate swaps	-	0.9
Total	**39.2**	**127.4**
Financial liabilities:		
Oil forward sales contracts	3.6	6.6
Gas forward sales contracts	-	0.6
Cross currency swaps	131.7	125.6
Fair value of gas contract acquired from E.ON	1.5	3.8
Forward foreign exchange contracts	0.5	2.4
Warrants	24.6	31.8
Total	**161.9**	**170.8**

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 and synthetic 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)*

The equity warrants have an exercise price of 41.80 pence and 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. The synthetic warrants are cash settled by the Group when certain net debt and leverage conditions are achieved, linked to the Group's market capitalisation, and expire in May 2021.

During the period, 5.3 million equity warrants were converted, resulting in an allotment of 4.5 million shares. The closing fair value of the open equity at 30 June 2019 was US$24.6 million, resulting in a loss of US$3.4 million being expensed in the period as derivative losses within other finance expenses (see note 4).

During the period, following the Group's leverage ratio being below 3.0x for the 12 month period ended 31 March 2019, the Group exercised its option to settle the synthetic warrants for a cash consideration of £10.8 million. The fair value movement against the opening balance sheet liability of US$4.7 million was expensed as a derivative loss within other finance expenses in the period. As at 30 June 2019, £9.3 million had been paid to warrant holders with the remaining £1.5 million classified within other payables.

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$4.4 million and has been recognised within other operating costs.

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) are shown below.

	At 30 June 2019		At 31 December 2018	
	Fair value amount $ million	**Carrying amount $ million**	Fair value amount $ million	Carrying amount $ million
Primary financial instruments held or issued to finance the Group's operations:				
Retail bonds	**193.6**	**190.4**	181.6	190.5

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. DISCONTINUED OPERATIONS, DISPOSALS AND ASSETS HELD FOR SALE

Disposals

In April 2017, Premier announced it had reached agreement and signed an SPA with Al-Haj Energy Limited ('Al-Haj') for the sale of Premier Oil Pakistan Holdings BV, which comprises Premier's Pakistan Business Unit, for a cash consideration of US$65.6 million. The disposal completed March 2019, following receiving the necessary government approvals and receipt by Premier of the full consideration of US$65.6 million through deposits and completion payments paid by the buyer; and, net cash flows collected by Premier since the economic date of the transaction.

At 31 December 2018, the Pakistan Business Unit was classified as a disposal group held for sale and the assets and liabilities for this disposal group were presented separately in the balance sheet.

The results of the disposal group, until completion, which have been included as discontinued operations in the consolidated income statement were as follows:

	30 June 2019 $ million	30 June 2018 $ million
Revenue	**11.8**	18.3
Expenses	**(3.6)**	(7.4)
Profit before tax	**8.2**	10.9
Attributable tax charge	**(2.0)**	(2.6)
Gain on disposal	**2.0**	-
Net profit attributable to discontinued operations	**8.2**	8.3

During the period to completion, the Pakistan disposal group contributed US$7.2 million (2018 1H: US$14.9 million) to the Group's net operating cash flows and paid US$1.9 million (2018 1H: US$1.5 million in respect of investing activities. There were no financing cash flows in either the current or the prior period.

12. LEASES

	Lease liabilities $ million
At 1 January 2019	899.6
Revisions (note 8)	64.6
Finance costs	22.6
Cash outflows for lease arrangements	(111.6)
Exchange differences	(2.1)
At 30 June 2019	873.1
Classified as:	
- Short-term	161.6
- Non-current	711.5

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$7.6 million were expensed. 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, Chim Sáo and Huntington 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.

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 8.2 per cent.

13. SUBSEQUENT EVENTS

In July 2019, subsequent to the period end, the Group made a further repayment of US$100 million of its RCF debt facility reducing gross debt. The Group also cancelled US$233.5 million of undrawn capacity of this facility, which will reduce commitment fees going forward.

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 2019 which comprises the interim condensed consolidated income statement, the interim condensed consolidated statement of comprehensive income, 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 13. 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 Group are prepared in accordance with IFRSs as adopted by the European Union. The condensed set of financial statements included in this half-yearly financial report has been prepared in accordance with International Accounting Standard 34, "Interim Financial Reporting", as adopted by the European Union.

Our Responsibility

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

Scope of Review

We conducted our review in accordance with International Standard on Review Engagements (UK and Ireland) 2410, "Review of Interim Financial Information Performed by the Independent Auditor of the Entity" issued by the 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.

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 2019 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

21 August 2019

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, Cash margin, Free cash flow, Operating cost per barrel, Depreciation, depletion and amortisation per barrel, Net Debt and Liquidity and 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.
- **Cash margin**: Operating cash flow for the period/year divided by working interest production. This is a useful indicator of cash generation from the Group's producing assets.
- **Free cash flow:** Positive cash flow generation from operating, investing and financing activities excluding drawdowns from and repayments of borrowing facilities.
- **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.

PremierOil

Half-Year Results for the six months to 30 June 2019

WORKING INTEREST PRODUCTION BY REGION (unaudited)

	Six months to 30 June 2019 kboepd	Six months to 30 June 2018 kboepd
UK:		
Catcher	35.1	13.4
Balmoral Area[1]	1.5	1.6
Huntington	6.8	7.3
Solan	4.0	4.5
Kyle	1.4	1.6
Babbage[2]	-	2.7
Elgin-Franklin	6.5	7.0
Other UK	2.8	3.2
	58.1	**41.3**
Indonesia:		
Natuna Sea Block A	11.1	12.8
Kakap[3]	-	0.6
	11.1	**13.4**
Vietnam:		
Chim Sáo	12.4	16.2
	12.4	**16.2**
Pakistan[4]:		
Bhit/Badhra	0.8	1.8
Kadanwari	0.5	0.7
Qadirpur	1.0	2.0
Zamzama	0.2	0.8
	2.5	**5.3**
TOTAL	**84.1**	**76.2**

1 Includes Balmoral, Brenda, Nicol and Stirling fields.

2 Babbage production included until completion of disposal in December 2018.

3 Kakap production included until completion of disposal in April 2018.

4 Pakistan production included until completion of disposal in March 2019.