PremierOil

Half-Year Results for the six months to 30 June 2018

Press Release

Tony Durrant, Chief Executive, commented:
"Premier met its operational targets for the period. The Catcher Area is now at plateau production rates which, together with higher commodity prices, is driving free cash flow generation and net debt reduction. We have progressed our development projects while maintaining strict capital discipline. We can also look forward to a high-graded exploration and appraisal programme which has the potential to deliver very significant value for the business."

Operational highlights
- Production of 76.2 kboepd (2017 1H: 82.1 kboepd) reflecting Catcher Area production ramp up offset by asset sales and natural decline
- Production averaged 86.2 kboepd in July (July 2017: 76.7 kboepd), despite ongoing summer maintenance
- Catcher Area now at plateau production; day rates of up to 70 kboepd (gross) achieved
- Tolmount project sanctioned post period end; key contracts awarded
- Exploration acreage significantly enhanced with new licence awards in Mexico and Indonesia
- Sale of Babbage Area announced; ETS (UK) and Kakap (Indonesia) disposals completed

Financial highlights
- Profit after tax more than doubled to US$98.4 million (2017 1H: US$40.7 million)
- EBITDA of US$388.9 million (2017 1H: US$325.9 million), up 19 per cent
- Cash flows from operations of US$276.6 million (2017 1H: US$282.7 million)
- Opex of US$17.2/boe, 5 per cent below budget
- Net debt reduced to US$2.65 billion (2017: US$2.72 billion)

2018 Outlook
- Production guidance unchanged at 80-85 kboepd
- Forecast opex of US$17-US$18/boe and capex of US$380 million unchanged
- Tolmount platform construction to start in December
- Zama appraisal programme to commence in Q4
- Completion of Pakistan and Babbage Area sales transactions
- Forecast full year net debt reduction of US$300 to US$400 million with covenant leverage ratio expected to fall to 2.5x by end Q1 2019, in line with previous guidance

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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 2018

OVERVIEW

Premier again delivered a strong operational performance in the first half of the year. The ramp up in production from the Catcher Area (Catcher, Varadero and Burgman) and high uptime across our other producing assets enabled us to maintain production at year-end levels despite material asset sales. At the same time, we remain focused on maintaining our low cost base and continued to secure savings against budgeted expenditure.

The Catcher Area has been producing at plateau rates since May which, along with higher commodity prices, resulted in a step change in our production and our free cash flow generation, substantially de-risking our debt reduction forecasts. We also see the potential for considerable upside from the Catcher Area as a result of better than expected initial production rates and the opportunity to maintain and extend plateau production through infill drilling and the tie-back of near field discoveries.

Premier remains focused on delivering the highest return projects from its portfolio. The sanction of our operated Tolmount Main gas project marks a major milestone. It secures our medium-term UK production profile and realises further value from the 2016 E.ON transaction. Tolmount Main is one of the largest undeveloped gas discoveries in the Southern North Sea and, in barrel of oil equivalent terms, is of similar size to our Catcher Area. We have also secured an innovative financing structure for the project which minimises our capital expenditure whilst maintaining our exposure to the upside in the Greater Tolmount Area. The development of the Bison, Iguana and Gajah Puteri (BIG-P) gas fields, an incremental gas project in Indonesia, is also proceeding well, on budget, and scheduled to deliver first gas next year.

Beyond Tolmount Main and BIG-P, the portfolio contains a number of projects to maintain and grow our production, delivering value over the longer term. The first half saw us award Letters of Intent (LOIs) to the key contractors for our Sea Lion project which, at 220 mmboe (gross) of reserves in Phase 1 alone, represents a material opportunity for Premier. The focus for the second half remains on securing senior debt funding for the project. In Mexico, the programme for appraisal of our world-class Zama discovery is scheduled to start later this year while in Indonesia we are seeking to farm-down our interest in the Tuna discoveries ahead of a two well appraisal programme. The majority of the spend for these projects will be from 2020 by which time we will have restored balance sheet strength after a period of forecast material free cash flow generation.

Over the last few years we have re-focused our exploration portfolio on high-graded proven petroleum systems in emerging basins. This resulted in the Zama discovery last year and will see us drill the high value Tolmount East well in 2019 and two potential high impact wells in the Ceará Basin, offshore Brazil, targeted for 2020. We have also continued to enhance and replenish our exploration portfolio for future drilling. We were particularly excited to capture Block 30, south west of our Zama discovery, in Mexico's Round 3.1, and the Andaman II licence offshore Indonesia where we see the potential for over 2 TCF of gas.

Potential acquisition opportunities that enhance our asset base and create synergies with our existing core businesses continue to be evaluated while our non-core disposal programme progressed over the period. In April we announced the sale of our interests in the Babbage Area which will immediately reduce our net debt and our committed exploration spend in 2019. We also completed the disposal of our interests in Kakap, offshore Indonesia, and the Esmond Transportation System (ETS) in the North Sea.

Debt reduction remains our key corporate priority in the near-term. We anticipate considerable debt reduction for the full year 2018 of US$300 to US$400 million, driven by increasing cash flow generation from our producing portfolio, cash proceeds from announced disposals and the early exchange of the convertible bond. As a result, at current oil prices, we anticipate our covenant leverage ratio falling to 3x EBITDA by the year-end and to 2.5x by the end of the first quarter of 2019.

Health, Safety, Environment and Security (HSES) matters will always be of paramount importance to us. We will not compromise on the integrity and safety of our people and our operations and we continue to set ourselves challenging HSES targets to drive continuous improvement.

Half-Year Results for the six months to 30 June 2018

OPERATIONAL REVIEW

GROUP PRODUCTION

Group production for the first half averaged 76.2 kboepd (2017 1H: 82.1 kboepd) with new production from the Catcher Area and outperformance from the Chim Sáo field in Vietnam offset by asset sales, natural decline and the re-phasing of planned maintenance into the first half. Post period end, production averaged 86.2 kboepd in July (2017 July: 76.7 kboepd) reflecting strong production from the Catcher Area and despite ongoing summer maintenance elsewhere in the portfolio.

Premier's full year production guidance of 80-85 kboepd remains unchanged with completion of the sale of the Pakistan business and the Babbage Area assets expected later this year.

kboepd	2018 1H	2017 1H
Indonesia	**13.4**	14.2
Pakistan	**5.3**	6.8[1]
UK	**41.3**	45.6
Vietnam	**16.2**	15.5
Total	**76.2**	82.1

[1] Includes 335 boepd from the Chinguetti field in Mauritania which ceased production in December 2017

UNITED KINGDOM

Premier's UK operations delivered increasing operating cash flows in the first half of the year driven by new Catcher Area production and higher commodity prices. The Catcher Area reached contracted plateau production rates in May, increasing delivery capacity from Premier's UK assets to in excess of 60 kboepd (net). Post period end, the Tolmount project was sanctioned with first gas scheduled for 2020. Production from the UK is expected to average around 50 kboepd (net) over the next five years with new Catcher Area and Tolmount production offsetting natural decline from elsewhere in the UK portfolio.

Catcher Area

Premier's operated Catcher Area averaged 26.6 kboepd (gross) for the first half, reflecting constrained production as commissioning of the gas and the water injection plants was completed. The Catcher Area reached contracted plateau production rates of 60 kbopd (gross) in May with day rates of up to 70 kboepd (gross) having been achieved post period end. Plant availability has continued to increase as commissioning of the secondary systems completes.

Production data from the Catcher Area continues to demonstrate good pressure support and connectivity between the reservoirs. Delivery potential from the available wells remains significantly in excess of the FPSO design capacity. As a result, preliminary discussions have started with the FPSO provider BW Offshore about sustaining production rates above the currently contracted 60 kbopd (gross).

Post period end, the DSV Falcon successfully tied into production four additional wells, further increasing deliverability from the Catcher Area. The 17th well, a Burgman producer, was completed in August with the 18th well, also a Burgman producer, scheduled to complete in October. These two wells will be available for production by November. This will mark completion of the current phase of the Catcher Area development.

Premier has identified several near field discoveries as potential high value subsea tie-backs to the Catcher Area FPSO to maintain and extend plateau production. In particular, the development concepts for the Laverda and Catcher North oil accumulations have been selected and will comprise two development wells drilled from a common drill centre tied back to the Varadero manifold. Project sanction is targeted for the first quarter of 2019.

In addition, Premier has identified potential infill well locations targeting resources beyond the reach of the initial production wells. Premier also plans to acquire 4D seismic to help define future infill drilling locations.

In February, Premier was awarded two blocks adjacent to the Catcher Area in the UK 30th Offshore Licensing Round. One of the blocks lies to the south of the Catcher field and contains the Bonneville discovery, a potential future tie-back to the Catcher Area infrastructure.

Other UK producing fields

Huntington production averaged 7.3 kboepd during the period, reflecting natural decline in line with expectations and planned shutdowns. Post period end, a light well intervention vessel was mobilised in field to carry out the first phase of converting a former production well into a water injection well to increase reservoir pressure and enhance recovery from the field. The conversion will be finalised with modifications to the subsea pipework in the fourth quarter of this year. This, together with the underlying reservoir performance of the field, has resulted in Premier agreeing commercial terms with Teekay to extend the Huntington Voyageur FPSO contract by a further year to mid-April 2020. At the end of July the field closed for summer maintenance. The programme includes modifications to the FPSO to enable gas import to increase operational efficiency. Production is on track to restart at the end of August.

The Elgin-Franklin Area produced 7 kboepd during the first six months of the year. This was ahead of expectations as the area benefited from a new production well coming on-stream in January and flush production following the extended Forties Pipeline System shutdown at the end of 2017.

Production from Premier's operated Solan field averaged 4.5 kboepd. This was driven by high operating efficiency offset by a planned shutdown being accelerated from July to June. Premier continues to plan for a 2020 infill drilling programme to improve recovery of reserves from the Central Northern part of the Solan field. The programme will entail a new producer-injector pair targeting known thicker sands in the adjacent Northern Fault Terrace, up dip from an existing water injector (W1). The new producer (P3) will be tied back to existing subsea infrastructure while the injector will be drilled as a side track from W1. Alternative financing strategies for this programme are under consideration and an investment decision is scheduled for the fourth quarter of 2018.

As a result of higher commodity prices, cost control and asset performance, field life has been extended at Premier's operated Balmoral Area as well as at the Kyle field where Premier has a non-operated 40 per cent interest. Premier anticipates that cessation of production from the Balmoral Area will now be no earlier than 2021 while at the Kyle field CNR and Teekay have agreed to extend the lease of the Banff FPSO, which handles Kyle's production, to August 2019.

The Greater Tolmount Area

Post period end, the development of the initial phase of the Greater Tolmount Area (Tolmount Main) in the Southern Gas Basin was sanctioned by the joint venture and infrastructure partners. The Premier-operated Tolmount Main field will produce around 500 Bcf (96 mmboe) (gross) of gas with peak production of up to 300 mmscfd (58 kboepd) (gross).

The Tolmount Main development will entail a minimal facilities platform and a new gas export pipeline to shore. The EPCIC (Engineering, Procurement, Construction, Installation and Commissioning) contract was awarded to Rosetti Marino, who are now placing the contracts for the long lead items. This includes the award of the contract for the transportation and installation of the platform to Heerema. First steel for the platform will be cut in December 2018. Sailaway of the platform from Rosetti's Ravenna yard in Italy is scheduled for the second quarter of 2020 with offshore installation of the platform planned for mid-2020.

Commercial agreements have been signed with Centrica Storage Limited for upgrades to the Easington terminal and for the processing of Tolmount gas. The Easington terminal was selected as the host facility after the reclassification of Rough as a producing field, rather than a storage facility, resulted in gas processing capacity being made available at Easington on competitive terms. Saipem has been selected as the pipeline EPCI contractor. Landfall construction will start over the winter of 2019/2020 in anticipation of the offshore pipelay campaign in the second half of 2020. Ensco has been awarded an LOI for the development drilling programme comprising four development wells with the first well scheduled to come on-stream in the fourth quarter of 2020.

In an innovative financing structure, Premier's share of the capex required to develop this large gas field is estimated at only US$120 million, comprising project management and development drilling costs. The infrastructure joint venture between Humber Gathering System Limited (a member of the CATS Management Limited group of companies) and Dana Petroleum will own and pay for the platform and pipeline capex as well as pay for upgrades to the onshore terminal. In return, Premier will pay a tariff for the transportation and processing of Tolmount gas through the infrastructure. This arrangement significantly enhances Premier's future returns from the project.

Significant upside exists within the Greater Tolmount Area. Premier plans to drill the Tolmount East appraisal well, which is targeting 220-400 Bcf (Pmean to P10) (gross) of additional gas resource, in mid-2019. The aim of the well is to test the Eastern extension of the Tolmount field area that sits above the gas water contact but is structurally separated from Tolmount Main and viewed as low risk. It is anticipated that the well will be suspended for use as a future producer which would be tied back to Tolmount Main infrastructure. Furthermore, a successful Tolmount East appraisal could facilitate the tie-back of the existing Mongour discovery, in which Premier also has a 50 per cent interest.

Premier plans to acquire 3D seismic across the Greater Tolmount Area in 2019 to enable maturation of the Tolmount Far East well location with a view to drilling the prospect in 2021. This could potentially add a further 150 Bcf (gross) of resource and would likely be developed as a subsea tie-back to the Tolmount Main field facilities via Tolmount East.

Portfolio management

In April, Premier announced the sale of its interests in the Babbage Area to Verus Petroleum. Production from the Babbage Area averaged 2.7 kboepd during the period. Premier expects to receive net cash proceeds of US$64.3 million, before customary working capital adjustments. Verus will also take on exploration commitments estimated at US$23.8 million. Completion of the transaction is expected in the fourth quarter of 2018. In addition, Premier completed the previously announced sale of its 30 per cent non-operated interest in ETS for total cash proceeds of US$22.9 million (after working capital adjustments). There is also a future potential payment of up to US$3.5 million linked to the achievement of certain key milestones in respect of any future development of the nearby Pegasus field.

INDONESIA

Production from Premier's operated Natuna Sea Block A fields averaged 12.8 kboepd (net), in line with the prior period and expectations. The development of BIG-P continues and remains on budget and to schedule for first gas in 2019. Continued low operating costs resulted in the Indonesian Business Unit generating material positive net cash flows for the Group.

Half-Year Results for the six months to 30 June 2018

Production

Production from Indonesia in the first half of 2018 was 13.4 kboepd (net) (2017 1H: 14.2 kboepd). The Premier-operated Natuna Sea Block A delivered 12.8 kboepd (net) (2017 1H: 12.9 kboepd) while production from the non-operated Kakap field (now sold) averaged 0.6 kboepd (net).

Singapore demand for gas sold under GSA1 averaged 269 BBtud (gross) (2017 1H: 301 BBtud), a reduction on the prior corresponding period as a result of the re-phasing of end-buyer maintenance into the first half of the year from the second half. Premier's Anoa and Pelikan fields delivered 144 BBtud (gross) (2017 1H: 149 BBtud (gross)) during the period and accounted for 53 per cent of GSA1 deliveries (2017 1H: 49 per cent), an increased market share on the prior period and above Natuna Sea Block A's contractual share of 52 per cent.

Sales of Gajah Baru and Naga gas dedicated to GSA2 averaged 88 BBtud (gross) (2017 1H: 85 BBtud). Gross liquids production from the Anoa field was 1.2 kbopd (2017 1H: 1.1 kbopd).

Gas sales from the non-operated Kakap field averaged 7 BBtud (gross) (2017 1H: 18 BBtud (gross)) while gross liquids production was 1.4 kbopd (2017 1H: 2.6 kbopd). The reduction on the prior corresponding period reflects the sale of Kakap to Batavia Oil for US$3.2 million, before working capital adjustments, which completed in April.

Premier continues to benefit from a low cost base in Indonesia with operating costs averaging US$6.8/boe for the period.

Development

The development of BIG-P is proceeding to schedule and on budget. Onshore fabrication of the Naga and Pelikan deck extensions and the Pelikan and AGX platform spools was completed in the Batam yard in July and offshore installation has commenced with numerous service vessels in field.

The offshore installation campaign, including the installation of the deck extensions at Naga and Pelikan and the topsides components of the subsea control system at Gajah Baru and Anoa, will be completed by the end of the third quarter.

Fabrication of the subsea structures will commence in September. They will be installed along with the flowlines, flexible risers and umbilicals during the second offshore installation campaign planned to begin in the second quarter of 2019. A DSV will then complete the final hook up and tie-ins over the summer of 2019.

Drilling of the BIG-P development wells will commence in the first half of 2019 ahead of first gas which remains on schedule for the third quarter of 2019. Once on-stream, the BIG-P gas fields will help backfill the Group's contracts into Singapore and maintain production from Natuna Sea Block A.

Exploration and appraisal

Premier and its joint venture partners have agreed, subject to contract, a farm-in offer to the Tuna PSC ahead of a two well appraisal campaign targeted for 2019. In addition, further seismic evaluation of the associated prospects and leads on the remainder of the Tuna PSC provide an opportunity to add further value once the Tuna field is developed.

In January 2018, Premier was awarded a 40 per cent operated interest in the Andaman II licence in North Sumatra basin offshore Aceh, Indonesia. Premier has identified numerous prospects and leads which exhibit direct hydrocarbon indicators on existing 2D seismic across the licence. Premier is in discussions with seismic contractors with a view to initiating the acquisition of 1,850 square kilometres of 3D seismic across the licence. The forward plan is to mature these prospects, ahead of possible drilling in 2021. The licence has the potential to deliver significant gas volumes into North Sumatra and adds a potentially material new gas play to Premier's Indonesian portfolio.

On Natuna Sea Block A, the exploration team is reprocessing existing Anoa 3D datasets and analysing production data from the WL-5X well to assess the ultimate potential of the Lama play beneath the Anoa field and also to identify potential infill drilling locations within the Anoa main field.

VIETNAM

Chim Sáo has maintained high levels of production during the period averaging 16.2 kboepd and generating material free cash flow for the Group. Post period end, the Chim Sáo field lifted its 200th cargo of oil, with every cargo since first oil having been sold at a premium to Brent.

Production

Production from the Premier-operated Block 12W, which contains the Chim Sáo and Dua fields, averaged 16.2 kboepd (2017 1H: 15.5 kboepd) net to Premier, up on the prior corresponding period and ahead of budget. This strong performance was underpinned by the successful infill drilling campaign in 2017, which completed in December, and a two well intervention programme during the first six months of the year which brought on-stream new reservoir zones within existing wells adding over 1 kboepd (gross) of production. Two more well intervention campaigns are planned for the third quarter aimed at offsetting the natural decline from the existing wells. Operating efficiency was also high for the period at 94 per cent while underlying reservoir performance continues to exceed expectations.

Vietnam operating costs remain low and stable at US$9.6/boe (2017 1H: US$9.0/boe) and below budget. This, together with the robust production performance and the continuing premiums to the Brent oil price commanded by Chim Sáo crude, resulted in the Vietnam Business Unit contributing gross operating cash flow of over US$100 million during the period.

THE FALKLAND ISLANDS

The focus for the period has been on securing LOIs with key contractors and progressing the funding structure for the project.

Sea Lion

The Sea Lion project represents a material opportunity for the Group with around 400 mmboe (net to Premier) to be developed over several phases. The initial phase, Sea Lion Phase 1, will commercialise 220 mmbbls (gross) in PL032. The development concept entails subsea wells tied back to a leased FPSO. Premier plans to leverage the knowledge and skills successfully deployed on the Catcher Area project, as well as more generally its track record of developing medium sized offshore oil fields using FPSOs, to deliver the Sea Lion project.

Premier is in the process of completing the selection of contractors and has put in place LOIs for the provision of key services, including an FPSO, the drilling rig, well services, SURF, subsea production systems and installation services and helicopter services, as well as vendor funding.

The focus for the second half of the year remains on securing senior debt funding for the project, ahead of a final investment decision.

PAKISTAN

Premier's Pakistan business continued to generate positive net cash flow during the period. The average realised gas price was US$3.2/mscf while operating costs remained low at US$0.78/mscf (US$4.9/boe).

Net production averaged 5.3 kboepd (33.4 mmscfd) (2017 1H: 6.5 kboepd (40.1 mmscfd)) from Premier's six non-operated producing gas fields. The fall in production reflects natural decline in all of the gas fields.

Completion of the US$65.6 million sale of Premier's Pakistan business to Al-Haj Group remains subject to final approvals from the Pakistan authorities. To date, Al-Haj has paid deposits of US$25 million and Premier continues to collect the positive cash flows generated from these assets.

EXPLORATION AND APPRAISAL

Premier's exploration team continues to focus its efforts on high-graded proven petroleum systems in emerging basins which have the potential to deliver material resource additions for the Group whilst maintaining strict capital discipline.

MEXICO

In Mexico, pre-unitisation terms have been agreed by all potential partners in the field. The Block 7 appraisal programme has also been agreed with final government approval expected shortly. As a result, the appraisal of the Zama discovery in Block 7 is scheduled to commence in the fourth quarter of this year. The appraisal programme will comprise two back-to-back wells and one side track with the objective to confirm the oil water contact as defined by the seismic flat spot and to prove the detailed distribution of the reservoir. Premier also plans to carry out a comprehensive logging and coring programme as well as to flow test the side track of the first Zama appraisal well. Maturation of low risk, high value tie-back opportunities elsewhere on Block 7 remains ongoing.

In March, Premier successfully participated in Mexico's Round 3.1. Premier, together with its joint venture partners (DEA and Sapura), secured Block 30 which is directly to the south west of Premier's Zama discovery in the prolific, shallow water Sureste Basin. The forward plan includes block wide 3D seismic acquisition, including across the Wahoo prospect, which exhibits a flat spot analogous to the Zama discovery, and the Cabrilla prospect. Drilling activities are targeted to start before the end of 2020.

In Round 3.1, Premier also secured Blocks 11 and 13 in the Burgos Basin, which is directly inshore from the deep water Perdido fold belt. Premier will undertake an environmental base line study across its two new blocks prior to reprocessing the existing 3D seismic data during 2019.

On Block 2 in the Sureste Basin, Premier's option to participate and convert to a paying interest of up to 25 per cent equity or to withdraw was triggered in May 2018. Premier has decided to exit the block ahead of drilling.

BRAZIL

In Brazil, Premier is focussed on the Ceará Basin where it has developed an industry leading database and knowledge to maximise its chances of delivering a significant discovery. During the period, the ANP approved a revised well plan for Block 717 (Premier, 50 per cent operator), comprising a single deeper dual-target well to test the Berimbau and deeper Maraca prospects. This replaces the original two well commitments associated with Block 717. On Block 661, the joint venture partnership (Premier, 30 per cent) plans to target the stacked reservoir Itarema/Tatajuba prospect. The forward plan is to fulfil the remaining single well commitments on Blocks 717 and 661 via a two well drilling programme in the first half of 2020. The two wells will test an aggregate mean resource estimate in excess of 500 mmbbls (gross, unrisked).

FINANCIAL REVIEW

Context

2018 has seen a general improvement in the macro-economic environment for the sector, albeit with continued oil price volatility being observed in the period. Brent crude opened the year at US$66.9/bbl before closing at US$77.9/bbl on 30 June 2018. The average for 2018 1H was US$70.6/bbl compared to US$51.7/bbl for the corresponding period in 2017.

Against this economic backdrop our production averaged 76.2 kboepd in the period, (2017 1H: 82.1 kboepd), representing a reduction when compared to the corresponding prior period due to asset sales, natural field decline and planned shutdowns, partially offset by production from the Catcher field. This has resulted in total sales revenue from all operations of US$643.3 million compared with US$566.3 million in 2017 1H. Following the ramp up of Catcher production, recent Group production rates have been in excess of 90 kboepd.

Business performance

EBITDA for the period from continuing operations was US$388.9 million compared to US$325.9 million for 2017 1H. The increased EBITDA is mainly due to higher average oil and gas prices realised during the period offsetting lower production. With higher production forecast in 2018 2H as Catcher production reaches plateau, at current oil prices EBITDA is expected to increase significantly in the second half of this year.

Business performance (continuing operations)	**2018 Half-year $ million**	2017 Half-year $ million
Operating profit	**185.5**	141.4
Add: Amortisation and depreciation	**185.6**	180.5
Add: Exploration expense and pre-licence costs	**7.4**	4.0
Add: Loss on disposal of assets	**10.4**	-
EBITDA	**388.9**	325.9

Income statement

Production and revenue

Group production on a working interest basis averaged 76.2 kboepd for the period compared to 82.1 kboepd in 2017 1H, due to asset sales and natural field decline. First half production was also impacted by planned shutdowns at the Huntington and Solan fields and lower Singapore gas demand due to end-buyer maintenance. This was offset by the ramp up of Catcher production and outperformance from the Chim Sáo field. Entitlement production for the period was 69.2 kboepd (2017 1H: 76.1 kboepd). Post hedging, Premier realised an average price for the period of US$61.6/bbl (2017 1H: US$49.9/bbl) vs a Brent average price of US$70.6/bbl (2017 1H: US$51.7/bbl).

In the UK, Premier achieved average natural gas prices of 49 pence/therm (2017 1H: 46 pence/therm), which included 39.4 million therms which were sold under fixed price master sales agreements. Gas prices in Singapore, indirectly linked with crude oil pricing, averaged US$9.7/mscf (2017 1H: US$8.6/mscf) post hedging.

Total sales revenue from all operations (including Pakistan) increased to US$643.3 million (2017 1H: US$566.3 million), primarily due to the increase in realised oil and gas prices in the period offsetting lower production. From continuing operations (excluding Pakistan), revenue increased to US$625.0 million compared to US$546.1 million in the prior period.

Operating costs

Cost of operations comprise operating costs, changes in lifting positions, inventory movement and royalties. Cost of operations for the Group was US$231.6 million for 2018 1H, compared to US$218.8 million for 2017 1H.

	2018 Half-year $ million	2017 Half-year $ million
Operating costs		
Continuing operations	**232.5**	214.0
Discontinuing operations (Pakistan)	**4.7**	4.4
Operating costs (US$ million)	**237.2**	218.4
Operating cost per barrel (US$ per barrel)	**17.2**	14.7
Amortisation and depreciation of oil and gas properties		
Continuing operations	**180.8**	177.3
Discontinuing operations (Pakistan)	**-**	7.3
Total (US$ million)	**180.8**	184.6
DD&A per barrel (US$ per barrel)	**13.1**	12.4

The increase in absolute operating costs reflects commencement of production from the Catcher field towards the end of 2017. On a per barrel basis, operating costs increased compared to the prior period but were 5 per cent lower than budget. The increase was primarily due to the commencement of FPSO payments for Catcher whilst production was constrained in the period as final facilities commissioning was being completed.

Exploration expenditure and pre-licence costs

Exploration expense and pre-licence expenditure costs amounted to US$7.4 million (2017 1H: US$4.0 million) primarily relating to historical costs incurred on the Block 2 licence in Mexico and the Sunbeam prospect in the UK. After recognition of these expenditures, the exploration and evaluation asset remaining on the balance sheet at 30 June 2018 amounts to US$1,081.3 million (31 December 2017: US$1,061.9 million) which includes the Sea Lion, Tolmount and Tuna projects, as well as our share of expenditure on the Zama prospect in Mexico.

General and administrative expenses

Net G&A costs have fallen for 2018 1H to US$3.0 million (2017 1H: US$4.0 million) due to ongoing cost control and overhead allocation.

Finance gains and costs

Net finance costs of US$210.2 million have increased compared to the prior year (US$145.0 million), principally due to a step up in the interest margin on our financing facilities following the completion of the refinancing in July 2017 and an increase in the fair value of the Group's outstanding equity and synthetic warrants to US$100.7 million from US$59.8 million at 31 December 2017 as a result of strong share price performance. Cash interest expense in the period was US$125.5 million (2017 1H: US$89.7 million).

Taxation

The Group has a current tax charge for the period of US$46.5 million (2017 1H: charge of US$28.7 million) and a non-cash deferred tax credit for the period of US$161.3 million (2017 1H: credit of US$68.9 million) which results in a total tax credit for the period of US$114.8 million, from continuing operations (2017 1H: credit of US$40.2 million).

The total tax credit for the period represents an effective tax rate of 464.8 per cent (2017 1H: negative 1,116.7 per cent). The high 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.

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 2017 on the basis that there have been no impairment triggers identified at the balance sheet date of 30 June 2018.

Profit after tax

Profit after tax for the period was US$98.4 million (2017 1H: profit of US$40.7 million), including US$8.3 million from the Pakistan Business Unit which is classified as a discontinued operation at the balance sheet date, resulting in a basic earnings per share of 13.2 cents (2017 1H: 8.0 cents).

Cash flow

Cash flow from operating activities was US$224.6 million (2017 1H: US$292.0 million) after accounting for tax payments of US$62.5 million (2017 1H: US$44.0 million) and movement in joint venture cash balances in the period of US$52.0 million. Before the movement in the joint venture cash balances, underlying operating cash flows were US$276.6 million.

Capital expenditure in the period to 30 June 2018 totalled US$164.3 million (2017 1H: US$129.8 million).

Capital expenditure	**2018 Half-year $ million**	2017 Half-year $ million
Field/development projects	**137.9**	106.6
Exploration and evaluation	**25.8**	22.9
Other	**0.6**	0.3
Total	**164.3**	129.8

The principal development project was the Catcher field in the UK. The largest part of the E&E capital expenditure in the period was the signature bonus for the Block-30 exploration licence in Mexico. In addition, cash expenditure for decommissioning activity in the period was US$45.1 million (2017 1H: US$6.3 million). Further to this, US$9.8 million of cash was funded into long-term abandonment accounts for future decommissioning activities (2017 1H: US$7.8 million).

Discontinued operations, disposals and assets held for sale

In April 2018, Premier entered into a sale and purchase agreement (SPA) to sell its interest in the Babbage Area to Verus Petroleum SNS Limited (Verus) for £62.9 million (US$88.1 million). In addition, Verus will take on exploration commitments valued at £17 million (US$23.8 million), resulting in net cash proceeds of £45.9 million (US$64.3 million) to Premier, before customary working capital adjustments. Further cash payments of up to £5.5 million (US$7.7 million) are due to Premier if the Cobra discovery is developed. The effective date of the transaction is 1 January 2018. Disposal proceeds will be used to pay down Premier's existing debt. Completion of the transaction is expected in 2018 2H. Accordingly, the assets and liabilities of the Babbage Area interests have been classified as assets held for sale on the balance sheet at 30 June 2018.

During the period, Premier completed the previously announced sales of its interests in the Kakap field and its 30 per cent non-operated interest in the Esmond Transportation System (ETS) for total cash proceeds of US$22.8 million (after working capital adjustments).

Completion of the sale of Premier's Pakistan business to Al-Haj Group remains subject to final approvals from the Pakistan authorities. In the meantime, Premier continues to collect the positive cash flows generated from these assets. The disposal of the Pakistan Business Unit is expected to complete in the second half of 2018 and, as this is within 12 months of the balance sheet date, the business unit remains classified as a disposal group held for sale and presented separately in the balance sheet. Results for the disposal group in both the current and prior periods have been presented as a discontinued operation.

Balance sheet position

Net Debt

Accounting net debt at 30 June 2018 amounted to US$2,652.7 million (31 December 2017: US$2,724.2 million), with cash resources of US$180.0 million (31 December 2017: US$365.4 million).

Following completion of the Wytch Farm disposal in December 2017, net cash proceeds received of US$176 million were used to pay down and cancel the equivalent value of the RCF debt facility in January 2018. This reduced the total available RCF facility from US$2,050 million to US$1,874 million.

In January 2018, Premier invited convertible bondholders to exercise their exchange rights in respect of any and all of their bonds. 87.5 per cent or US$205.8 million of the US$235.2 million bonds outstanding were accepted for early exchange with an incentive amount of US$50 per US$1,000 in principal of bonds. The exchange resulted in the issue of 231,882,091 Ordinary Shares, which included 7,578,343 incentive shares. This resulted in a convertible bond liability of US$27.8 million on the balance sheet at 30 June 2018.

Subsequent to the period end, Premier announced its intention to exercise the mandatory conversion option in its convertible bonds. The exercise of such option will automatically and mandatorily convert all of the US$28.8 million outstanding convertible bonds into approximately 31.4 million new Ordinary Shares of Premier.

Premier retains significant cash at 30 June 2018 of US$147.6 million and undrawn facilities of US$156.1 million, giving Liquidity of US$303.7 million (31 December 2017: US$541.2 million) when excluding cash of US$32.4 million held on behalf of joint venture partners.

Provisions

Total decommissioning provisions excluding those associated with assets held for sale at 30 June 2018 are US$1,339.1 million (31 December 2017: US$1,432.1 million). The reduction is driven by decommissioning expenditure during the period and the reclassification of the decommissioning provision associated with the Babbage Area.

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 Financial Review are EBITDA, Operating cost per barrel, DD&A per barrel, Net Debt and Liquidity and are defined in the glossary.

Financial risk management

Commodity prices

Premier continues to take advantage of the improved oil price environment to increase its hedging position in 2019 to protect future free cash flows and covenant compliance. The Company's current hedge position to the end of 2019 is as follows:

Oil swaps/forwards	2018 2H	2019 1H	2019 2H
Volume (mmbbls)	4.0	2.6	1.5
Average price	$60/bbl	$66/bbl	$69/bbl

At 30 June 2018, the fair value of the open oil swaps was a liability of US$81.8 million (31 December 2017: liability of US$31.7 million), which is expected to be released to the income statement during 2018 2H and 2019 as the related barrels are lifted.

Furthermore, the Group has open oil put option agreements for 0.7 mmbbls at an average price of US$60.5/bbl. These options will be settled during 2018 2H. Included within physically delivered oil sales contracts are 0.8 mmbbls of oil that will be sold for an average fixed price of US$51.2/bbl during 2018 2H and 2019 as these barrels are delivered (these volumes are included in the above table). In addition, the Group currently has forward UK gas sales of 46 mm therms at an average price of 51 pence/therm that will be physically settled during 2018 2H and 2019 1H.

After the period end, Premier hedged part of its Indonesian gas production through the sale of 120,000 MT of HSFO Sing 180 in 2019 at an average price of US$394/MT.

Foreign exchange

Premier's functional and reporting currency is US dollars. Exchange rate exposures relate only to local currency receipts and local currency expenditures within individual business units. Local currency needs are acquired on a short-term basis. During the period, the Group recorded a mark-to-market loss of US$3.7 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, convertible bonds, UK retail bonds, term loans and revolving credit facilities. As 30 June 2018, approximately 49 per cent of total borrowings is fixed or has been fixed using the interest rate swap markets. On average, the effective interest on drawn funds for the period, recognised in the income statement, was 7.1 per cent. Mark-to-market gains on interest rate swaps amounted to US$1.0 million.

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.

At 30 June 2018 the Group continued to have significant headroom on its financing facilities and cash on hand. The Group's forecasts show that, at currently observed oil and gas prices and prevailing production, the Group will have sufficient financial headroom for the 12 months from the date of approval of the 2018 Interim Report and Accounts. In downside scenarios where oil and gas prices were to remain materially below those currently being realised and if production levels were to be significantly below current performance then, in the absence of any mitigating actions, a breach of one or more of the financial covenants may arise during the 12 month going concern assessment period. Potential mitigating actions could include further non-core asset disposals, additional 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 has identified its principal risks, which have not changed since 31 December 2017, for the remaining 6 months of the year as being:

- Oil price weakness and volatility.
- Underperformance of existing assets.
- Failure of new Catcher asset to fully deliver to expectations.
- Execution of planned corporate actions.
- Ability to fund existing and planned growth projects.
- Breach of new banking covenants if oil prices fall or assets underperform.
- Ability to maintain core competencies.
- Timing and uncertainty of decommissioning liabilities.
- Political and security instability in countries of current and planned activity.
- Rising costs if oil prices recover could limit access to services.

Further information detailing the way in which these risks are mitigated is provided on pages 22 to 29 of the 2017 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 2018

CONDENSED CONSOLIDATED INCOME STATEMENT

	Note	**Six months to 30 June 2018 Unaudited $ million**	Six months to 30 June 2017 Unaudited $ million
Continuing operations			
Sales revenues	*2*	**625.0**	546.1
Other operating (costs)/income		**(1.5)**	2.6
Costs of operation	*3*	**(231.6)**	(218.8)
Depreciation, depletion and amortisation		**(185.6)**	(180.5)
Exploration expense and pre-licence costs	*7*	**(7.4)**	(4.0)
Loss on disposal of non-current assets	*11*	**(10.4)**	-
General and administration costs		**(3.0)**	(4.0)
Operating profit		**185.5**	141.4
Interest revenue, finance and other gains	*4*	**3.8**	9.2
Finance costs, other finance expenses and losses	*4*	**(214.0)**	(154.2)
Loss before tax		**(24.7)**	(3.6)
Tax	*5*	**114.8**	40.2
Profit for the period from continuing operations		**90.1**	36.6
Discontinued operations			
Profit for the period from discontinued operations	*11*	**8.3**	4.1
Profit after tax		**98.4**	40.7
Earnings per share (cents):			
From continuing operations			
Basic	*6*	**12.1**	7.2
Diluted	*6*	**10.4**	7.0
From continuing and discontinued operations			
Basic	*6*	**13.2**	8.0
Diluted	*6*	**11.4**	7.8

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

Half-Year Results for the six months to 30 June 2018

CONDENSED CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

	Six months to 30 June 2018 Unaudited $ million	Six months to 30 June 2017 Unaudited $ million
Profit for the period	**98.4**	40.7
Cash flow hedges on commodity swaps:		
(Losses)/gains arising during the period	**(88.4)**	9.9
Less: reclassification adjustments for losses in the period	**36.4**	6.7
	(52.0)	16.6
Cash flow hedges on interest rate and foreign exchange swaps		
Gains/(losses) arising during the period	**8.6**	(19.6)
Less: reclassification adjustments for (gains)/losses in the period	**(3.9)**	21.0
	4.7	1.4
Tax relating to components of other comprehensive income	**16.2**	(6.6)
Exchange differences on translation of foreign operations	**(7.6)**	(1.1)
Other comprehensive (expense) / income	**(38.7)**	10.3
Total comprehensive income for the period	**59.7**	51.0

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 2018 Unaudited $ million**	At 31 December 2017 Audited $ million
Non-current assets:			
Intangible exploration and evaluation assets	*7*	**1,081.3**	1,061.9
Property, plant and equipment	*8*	**2,177.5**	2,381.0
Goodwill		**240.8**	240.8
Long-term receivables		**165.1**	160.8
Deferred tax assets		**1,619.9**	1,461.5
		5,284.6	5,306.0
Current assets:			
Inventories		**18.5**	13.5
Trade and other receivables		**307.0**	340.6
Derivative financial instruments	*10*	**14.3**	14.5
Cash and cash equivalents		**180.0**	365.4
Assets held for sale	*11*	**64.8**	96.6
		584.6	830.6
Total assets		**5,869.2**	6,136.6
Current liabilities:			
Trade and other payables		**(310.7)**	(572.9)
Short-term provisions		**(61.9)**	(91.2)
Derivative financial instruments	*10*	**(209.4)**	(99.8)
Deferred income		**(14.4)**	(13.1)
Liabilities directly associated with assets held for sale	*11*	**(58.3)**	(46.6)
		(654.7)	(823.6)
Net current (liabilities)/assets		**(70.1)**	7.0
Non-current liabilities:			
Long-term debt	*9*	**(2,802.3)**	(2,972.6)
Deferred tax liabilities		**(148.6)**	(164.0)
Deferred income		**(72.7)**	(80.3)
Long-term provisions		**(1,306.2)**	(1,370.9)
Derivative financial instruments	*10*	**(120.7)**	(108.3)
		(4,450.5)	(4,696.1)
Total liabilities		**(5,105.2)**	(5,519.7)
Net assets		**764.0**	616.9
Equity and reserves:			
Share capital		**147.5**	109.0
Share premium account		**462.9**	284.5
Other reserves		**153.6**	223.4
		764.0	616.9

CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

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

At 1 January 2017	106.7	275.4	427.0	809.1
Provision for share-based payments	-	-	9.0	9.0
Profit for the period	-	-	40.7	40.7
Other comprehensive income	-	-	10.3	10.3
At 30 June 2017	**106.7**	**275.4**	**487.0**	**869.1**

[1] Refer to note 1 for detail on IFRS 9 adjustment.

PremierOil

Half-Year Results for the six months to 30 June 2018

CONDENSED CONSOLIDATED CASH FLOW STATEMENT

	Note	**Six months to 30 June 2018 Unaudited $ million**	Six months to 30 June 2017 Unaudited $ million
Net cash from operating activities	*9*	**224.6**	292.0
Investing activities:			
Capital expenditure		**(164.3)**	(129.8)
Decommissioning pre-funding		**(9.8)**	(7.8)
Decommissioning expenditure		**(45.1)**	(6.3)
Disposal of oil and gas properties	*11*	**22.8**	30.0
Net cash used in investing activities		**(196.4)**	(113.9)
Financing activities:			
Issuance of Ordinary Shares		**8.0**	-
Net release of ESOP Trust shares		**(1.0)**	-
Proceeds from drawdown of bank loans		**105.0**	-
Repayment of bank loans		**(199.1)**	-
Debt arrangement fees		**-**	(34.9)
Interest paid		**(125.5)**	(89.7)
Net used in financing activities		**(212.6)**	(124.6)
Currency translation differences relating to cash and cash equivalents		**(1.0)**	(1.9)
Net (decrease)/increase in cash and cash equivalents		**(185.4)**	51.6
Cash and cash equivalents at the beginning of the period		**365.4**	255.9
Cash and cash equivalents at the end of the period	*9*	**180.0**	307.5

NOTES TO THE CONDENSED FINANCIAL STATEMENTS

1. BASIS OF PREPARATION

General information

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

The condensed financial statements for the six months ended 30 June 2018 were approved for issue in accordance with a resolution of a committee of the Board of Directors on 22 August 2018.

The information for the year ended 31 December 2017 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 2017 were approved by the Board of Directors on 7 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 2018, and the condensed consolidated balance sheet as at 30 June 2018 and related notes, have been reviewed by the auditors and their report to the Company is attached.

Basis of preparation

The condensed financial statements for the six months ended 30 June 2018 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 2017, 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.

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 2017, as described in those annual financial statements, except for the adoption of IFRS 9 Financial Instruments and IFRS 15 Revenue from Contracts with Customers.

IFRS 9 'Financial Instruments'

The overall impact on transition to IFRS 9 was an US$82 million increase in long-term debt and corresponding reduction in net assets. This adjustment relates entirely to an adjustment to the Group's accounting for its refinancing that completed in July 2017. On adoption of IFRS 9, additional interest charges for facilities that were not deemed to be substantially modified have been expensed at the point of completion of the refinancing. Under the previous accounting policies these additional interest charges had been expected to be amortised to the income statement on an effective interest rate basis over the life of the facilities. Under IFRS 9, this would have increased the interest charge recognised in 2017 by US$82 million, with a corresponding reduction in net assets at 31 December 2017. Going forward, this reduces Premier's forecast interest charges by c.US$20 million per annum. The impact on the current period balance sheet is to increase long-term debt and reduce retained earnings by US$82 million. As permitted by IFRS 9 comparatives have not been restated.

For certain line items in the balance sheet the closing balance at 31 December 2017 as previously reported and the opening balance at 1 January 2018 therefore differ (see statement of changes in equity). The Group's accounting policy has been revised to reflect the requirements of IFRS 9. However, excluding the impact on the accounting treatment applied to the Group's 2017 refinancing, the standard has not had a significant impact. The Group's accounting policy for IFRS 9 is set out below:

(a) Classification of financial assets and financial liabilities

IFRS 9 requires the use of two criteria to determine the classification of financial assets: the entity's business model for the financial assets and the contractual cash flow characteristics of the financial assets. The Standard goes on to identify three categories of financial assets - amortised cost; fair value through profit or loss (FVTPL); and fair value through other comprehensive income (FVOCI). The accounting for the Group's financial liabilities remains largely the same as it was under IAS 39. Similar to the requirements of IAS 39, IFRS 9 requires contingent consideration liabilities to be treated as financial instruments measured at fair value, with the changes in fair value recognised in the statement of profit or loss.

1. BASIS OF PREPARATION *(continued)*

Under IFRS 9, embedded derivatives are no longer separated from a host financial asset. Instead, financial assets are classified based on their contractual terms and the Group's business model. The accounting for derivatives embedded in financial liabilities and in non-financial host contracts has not changed from that required by IAS 39.

(b) Impairment

IFRS 9 mandates the use of an expected credit loss model to calculate impairment losses rather than an incurred loss model, and therefore it is not necessary for a credit event to have occurred before credit losses are recognised. The new impairment model applies to the Group's financial assets and loan commitments. No changes to the impairment provisions were made on transition to IFRS 9.

The IFRS 9 impairment model requiring the recognition of 'expected credit losses', in contrast to the requirement to recognise 'incurred credit losses' under IAS 39, has not had a material impact on the Group's financial statements.

Trade receivables are generally settled on a short time frame and the Group's other financial assets are due from counterparties without material credit risk concerns at the time of transition.

(c) Hedge accounting

The hedge accounting requirements of IFRS 9 have been simplified and are more closely aligned to an entity's risk management strategy. Under IFRS 9 all existing hedging relationships will qualify as continuing hedging relationships and the group also intends to apply hedge accounting prospectively to certain of its commodity price risk management activities for which hedge accounting was not possible under IAS 39. This had no impact on the 2018 opening balance sheet.

<u>IFRS 15 'Revenue from Contracts with Customers'</u>

Premier has elected to apply the 'modified retrospective' approach to transition permitted by IFRS 15 under which comparative financial information is not restated. The standard did not have a material effect on the Group's financial statements as at 1 January 2018 and so no transition adjustment has been made. The standard has not had a material impact on the Group's accounting policy in respect to revenue as previously disclosed in the 2017 financial statements.

1. BASIS OF PREPARATION *(continued)*

Revenue from contracts with customers for the 2018 1H period is presented in Note 2. Amounts presented for comparative periods in 2017 include revenues determined in accordance with the Group's previous accounting policies relating to revenue. The total amounts presented do not, therefore, represent the revenue from contracts with customers that would have been reported for those periods had IFRS 15 been applied using a fully retrospective approach to transition but the differences are not material.

The Group’s accounting policy for IFRS 15 is set out below:

Under IFRS 15, revenue from contracts with customers is recognized when or as the group satisfies a performance obligation by transferring a promised good or service to a customer. A good or service is transferred when the customer obtains control of that good or service. The transfer of control of oil, natural gas, natural gas liquids, and other items sold by the group usually coincides with title passing to the customer and the customer taking physical possession. The group principally satisfies its performance obligations at a point in time and the amounts of revenue recognized relating to performance obligations satisfied over time are not significant.

A number of additional new standards, amendments to existing standards and interpretations were effective from 1 January 2018. 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 2018.

Changes to accounting policies and the impact on financial statements resulting from new accounting standards and amendments to existing standards that have been issued, but are not yet effective, including IFRS 16, are currently being assessed. IFRS 16 is likely to require a number of significant changes to the treatment of the Group’s lease arrangements, in particular the FPSO lease arrangements for Catcher and Chim Sáo. We expect to recognise right of use assets and liabilities associated with the leased FPSOs on our balance sheet from 1 January 2019, with a consequential impact on the profile and phasing of income statement recognition.

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, which remains classified as an asset held for sale, are reported as a discontinued operation. The results from Mauritania continue to be included in the Rest of the World Business Unit.

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 2018 Unaudited $ million	Six months to 30 June 2017 Unaudited $ million
Revenue:		
United Kingdom	**395.7**	362.6
Indonesia	**87.6**	84.7
Vietnam	**140.9**	97.0
Rest of the World	**0.8**	1.8
Total Group sales revenue	**625.0**	546.1
Other operating (costs)/income – United Kingdom	**(1.5)**	2.6
Interest and other finance revenue	**2.2**	0.6
Total Group revenue from continuing operations	**625.7**	549.3
Revenue from discontinued operations	**18.3**	20.2
Group operating profit:		
United Kingdom	**74.6**	75.8
Indonesia	**42.1**	37.7
Vietnam	**77.5**	38.9
Rest of the World	**(3.5)**	(4.1)
Unallocated[1]	**(5.2)**	(6.9)
Group operating profit	**185.5**	141.4
Interest revenue, finance and other gains	**3.8**	9.2
Finance costs and other finance expenses	**(214.0)**	(154.2)
Loss before tax from continuing operations	**(24.7)**	(3.6)
Tax	**114.8**	40.2
Profit after tax from continuing operations	**90.1**	36.6
Profit from discontinued operations	**8.3**	4.1

[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 pre-licence exploration costs.

2. OPERATING SEGMENTS *(continued)*

Of the Group's worldwide revenues of US$625.0 million (2017 1H: US$546.1 million), revenues of US$661.4 million (2017 1H: US$552.7 million) were from contacts with customers. This was offset by hedging losses in the period of US$36.4 million (2017 1H: US$6.6 million).

	30 June 2018 Unaudited $ million	31 December 2017 Audited $ million
Balance sheet - Segment assets:		
United Kingdom[1]	**4,097.7**	4,116.2
Indonesia	**428.6**	440.4
Vietnam	**340.9**	374.4
Falkland Islands	**635.6**	633.1
Rest of the World[2]	**107.3**	96.0
Assets held for sale	**64.8**	96.6
Unallocated[3]	**194.3**	379.9
Total assets	**5,869.2**	6,136.6

[1] Includes goodwill of US$240.8 million.

[2] Segmental assets for Mauritania have been included within Rest of the World.

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

3. COSTS OF OPERATION

	Six months to 30 June 2018 Unaudited $ million	Six months to 30 June 2017 Unaudited $ million
Operating costs	**232.5**	214.0
Gas purchases	**4.3**	3.4
Stock underlift movement	**(12.5)**	(2.7)
Royalties	**7.3**	4.1
	231.6	218.8

4. INTEREST REVENUE AND FINANCE COSTS

	Six months to 30 June 2018 Unaudited $ million	Six months to 30 June 2017 Unaudited $ million
Interest revenue, finance and other gains:		
Short-term deposits	**0.6**	0.2
Other interest received	**1.6**	0.4
Derivative gains	**1.6**	8.6
	3.8	9.2
Finance costs:		
Bank loans, overdrafts and bonds	**(86.7)**	(72.7)
Payable in respect of convertible bonds	**(0.6)**	(5.5)
Payable in respect of senior loan notes	**(18.9)**	(14.7)
Long-term debt arrangement fees	**(15.2)**	(5.2)
Exchange differences and others	**(6.6)**	(12.2)
	(128.0)	(110.3)
Other finance expenses:		
Unwinding of discount on decommissioning provision	**(31.7)**	(29.9)
Derivative losses	**(51.6)**	(4.7)
Refinancing fees	**-**	(15.7)
Finance expense on deferred income	**(2.7)**	(6.0)
	(86.0)	(56.3)
Gross finance costs and other finance expenses	**(214.0)**	(166.6)
Finance costs capitalised during the period	**-**	12.4
	(214.0)	(154.2)

5. TAX

	Six months to 30 June 2018 Unaudited $ million	Six months to 30 June 2017 Unaudited $ million
Current tax:		
UK corporation tax on profits	**(9.5)**	(0.2)
UK petroleum revenue tax	**-**	(0.1)
Overseas tax	**56.0**	36.9
Adjustments in respect of prior years	**-**	(7.9)
Total current tax charge	**46.5**	28.7
Deferred tax:		
UK corporation tax	**(146.4)**	(53.9)
Overseas tax	**(14.9)**	(15.0)
Total deferred tax credit	**(161.3)**	(68.9)
Tax credit on loss on ordinary activities	**(114.8)**	(40.2)

5. TAX *(continued)*

The Group has a current tax charge for the period of US$46.5 million (2017: charge of US$28.7 million) and a non-cash deferred tax credit for the period of US$161.3 million (2017: US$68.9 million) which results in a total tax credit for the period of US$114.8 million (2017: credit of US$40.2 million). The deferred tax credit primarily arises due to ring fence expenditure supplement which is claimed on UK tax losses.

The Group's full year forecast effective tax rate (ETR), which was applied to the half-year results to calculate the interim tax credit, is heavily impacted by the effect of the ring fence expenditure supplement (RFES) to be claimed in the UK. Removing the impact of RFES from the full year ETR calculation would reduce the Group's half-year ETR to 172 per cent and would therefore, reduce the tax credit recognised by the Group for the six months ended 30 June 2018. With higher production forecast in the second half of 2018 as Catcher production reaches plateau, at current oil prices EBITDA is expected to increase significantly in the second half of the year, which is likely to result in a partial release of the tax credit recognised at 30 June 2018 by the end of 2018.

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 2017 on the basis that there have been no impairment triggers identified at the balance sheet date of 30 June 2018.

The weighted average rate is calculated based on the tax rates weighted according to the profit or loss before tax earned by the Group in each jurisdiction. The change in the weighted average rate year-on-year relates to the mix of profit and loss in each jurisdiction.

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 55 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 2018 Unaudited	Six months to 30 June 2017 Unaudited
Earnings ($ millions):		
Earnings from continuing operations	**90.1**	36.6
Effect of dilutive potential Ordinary Shares:		
Interest on convertible bonds – (2017 anti-dilutive)	**0.6**	-
Earnings for the purposes of diluted earnings per share on continuing operations	**90.7**	36.6
Profit from discontinued operations	**8.3**	4.1
Earnings for the purpose of diluted earnings per share on continuing and discontinued operations	**99.0**	40.7
Number of shares (millions):		
Weighted average number of Ordinary Shares for the purpose of basic earnings per share	**745.0**	510.8
Effects of dilutive potential Ordinary Shares:		
Contingently issuable shares – dilutive	**127.2**	12.1
Weighted average number of Ordinary Shares for the purpose of diluted earnings per share	**872.2**	522.9
Earnings per share (cents) from continuing operations		
Basic	**12.1**	7.2
Diluted	**10.4**	7.0
Earnings per share (cents) from continuing and discontinued operations		
Basic	**13.2**	8.0
Diluted	**11.4**	7.8

Discontinued operations in 2018 relate to the results of the Group's Pakistan Business Unit which continue to be classified as a held for sale asset.

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

	Oil and gas properties $ million
Cost:	
At 1 January 2018	1,061.9
Exchange movements	(6.7)
Additions during the period	32.9
Exploration expense	(5.2)
Assets classified as held for sale	(1.6)
At 30 June 2018	**1,081.3**
At 31 December 2017	1,061.9

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, Tolmount and Tuna projects, as well as our share of expenditure on the Zama prospect in Mexico.

8. PROPERTY, PLANT AND EQUIPMENT

	Note	Oil and gas properties $ million	Other fixed assets $ million	Total $ million
Cost:				
At 1 January 2018		7,589.4	66.7	7,656.1
Exchange movements		0.5	(1.1)	(0.6)
Additions during the period		(2.6)	0.7	(1.9)
Disposals		(0.1)	(0.1)	(0.2)
Assets classified as held for sale	*11*	(20.6)	-	(20.6)
At 30 June 2018		**7,566.6**	**66.2**	**7,632.8**
Amortisation and depreciation:				
At 1 January 2018		5,220.3	54.8	5,275.1
Exchange movements		1.1	(0.6)	0.5
Charge for the period		180.8	4.8	185.6
Disposals		-	(0.1)	(0.1)
Assets classified as held for sale	*11*	(5.8)	-	(5.8)
At 30 June 2018		**5,396.4**	**58.9**	**5,455.3**
Net book value:				
At 30 June 2018		**2,170.2**	**7.3**	**2,177.5**
At 31 December 2017		2,369.1	11.9	2,381.0

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.

9. NOTES TO THE CONDENSED CONSOLIDATED CASH FLOW STATEMENT

	Note	**Six months to 30 June 2018 Unaudited $ million**	Six months to 30 June 2017 Unaudited $ million
Loss before tax for the period		**(24.7)**	(3.6)
Adjustments for:			
Depreciation, depletion and amortisation		**185.6**	180.5
Other operating costs/(income)		**1.5**	(2.6)
Exploration expense	*7*	**5.2**	1.1
Provision for share-based payments		**4.2**	5.0
Interest revenue and finance gains	*4*	**(3.8)**	(9.2)
Finance costs and other finance expenses	*4*	**214.0**	154.2
Loss on disposal of non-current assets		**10.4**	-
Operating cash flows before movements in working capital		**392.4**	325.4
Increase in inventories		**(4.6)**	(6.3)
Decrease in receivables		**48.3**	26.7
Decrease in payables		**(113.7)**	(33.3)
Cash generated by operations		**322.4**	312.5
Income taxes paid		**(62.5)**	(44.0)
Interest income received		**1.8**	0.3
Net cash from continuing operating activities		**261.7**	268.8
Net cash from discontinued operating activities	*11*	**14.9**	13.9
Net cash from operating activities		**276.6**	282.7
Movement in joint venture cash		**(52.0)**	9.3
Total net cash from operating activities		**224.6**	292.0

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

Analysis of changes in net debt:

	Six months to 30 June 2018 Unaudited $ million	Six months to 30 June 2017 Unaudited $ million
a) Reconciliation of net cash flow to movement in net debt:		
Movement in cash and cash equivalents	**(185.4)**	51.6
Proceeds from drawdown of bank loans	**(105.0)**	-
Repayment of bank loans	**199.1**	-
Partial conversion of convertible bonds	**154.0**	-
Non-cash movements on debt and cash balances (predominantly foreign exchange)	**8.8**	(24.9)
Decrease in net debt in the period	**71.5**	26.7
Opening net debt	**(2,724.2)**	(2,765.2)
Closing net debt	**(2,652.7)**	(2,738.5)

b) Analysis of net debt:		
Cash and cash equivalents	**180.0**	307.5
Borrowings[1]	**(2,832.7)**	(3,046.0)
Total net debt	**(2,652.7)**	(2,738.5)

[1] Borrowings consist of the convertible bonds, short-term debt 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$101.8 million (31 December 2017: US$117.0 million) and the impact of the IFRS 9 adjustment (see note 1).

10. FINANCIAL INSTRUMENTS

Derivative financial instruments

The Group held the following financial instruments at fair value at 30 June 2018. 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 2018 $ million	At 31 December 2017 $ million
Financial assets:		
Oil put options	-	0.2
Fair value of gas contracts acquired from E.ON	8.7	9.1
Forward foreign exchange contracts	-	0.6
Interest rate swaps	5.6	4.6
Total	**14.3**	**14.5**
Financial liabilities:		
Oil forward sales contracts	105.9	36.1
Gas forward sales contracts	1.8	-
Cross currency swaps	114.8	108.4
Forward foreign exchange contracts	6.9	3.8
Warrants	100.7	59.8
Total	**330.1**	**208.1**

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 (2017: 42.75 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.

As at 31 December 2017, 75.2 million equity warrants and 21.4 million synthetic warrants were recognised on the balance sheet as derivative financial instruments. During the period, 14.5 million equity warrants were converted, resulting in an allotment of 14.3 million shares. The closing fair value of the open equity and synthetic warrants at 30 June 2018 was US$74.5 million and US$26.2 million respectively, giving a total of US$100.7 million after the exercise of warrants and resulting in a loss of US$40.9 million being expensed in the period as derivative losses within other finance expenses (see note 4).

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$1.5 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 2018		At 31 December 2017	
	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	**201.6**	**198.0**	196.1	202.5
Convertible bonds	**53.2**	**27.8**	266.9	180.5

10. FINANCIAL INSTRUMENTS *(continued)*

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.

Convertible bonds

In January 2018, Premier invited convertible bondholders to exercise their exchange rights in respect of any and all of their bonds. 87.5 per cent or US$205.8 million of the US$235.2 million bonds outstanding were accepted for early exchange with an incentive amount of US$50 per US$1,000 in principal of bonds. The exchange resulted in the issue of 231,882,091 Ordinary Shares, which included 7,578,343 incentive shares. This resulted in a reduction in the convertible bond liability from US$180.5 million to US$27.8 million on the balance sheet at 30 June 2018. The exchange also resulted in a release of US$54.5m from other reserves in the period to 30 June 2018.

11. DISCONTINUED OPERATIONS, DISPOSALS AND ASSETS HELD FOR SALE

	30 June 2018 $ million	31 December 2017 $ million
Assets held for:		
- Pakistan Business Unit	**49.2**	52.2
- Babbage	**15.6**	-
- Esmond Transportation System (ETS)	**-**	27.0
- Kakap field	**-**	17.4
Total assets classified as held for sale	**64.8**	96.6
Liabilities held for:		
- Pakistan Business Unit	**(26.8)**	(25.4)
- Babbage	**(31.5)**	-
- Esmond Transportation System (ETS)	**-**	(7.0)
- Kakap field	**-**	(14.2)
Total liabilities classified as held for sale	**(58.3)**	(46.6)

<u>Disposals</u>

During the period, Premier completed the previously announced sales of its interests in the Kakap field and its 30 per cent non-operated interest in the Esmond Transportation System (ETS) for total cash proceeds of US$22.8 million (after working capital adjustments). A net loss on disposal of US$4.8 million had been recognised in the income statement for the period. In addition, US$5.6m contingent consideration receivable from Kris Energy in relation to the Aceh disposal by Premier in 2014 has been written off in the period.

11. DISCONTINUED OPERATIONS, DISPOSALS AND ASSETS HELD FOR SALE *(continued)*

Assets held for sale – Babbage interests

In April 2018, Premier entered into a sale and purchase agreement (SPA) to sell its interest in the Babbage Area to Verus Petroleum SNS Limited (Verus) for £62.9 million (US$88.1 million). In addition, Verus will take on exploration commitments valued at £17 million (US$23.8 million), resulting in net cash proceeds of £45.9 million (US$64.3 million) to Premier, before customary working capital adjustments. Further cash payments of up to £5.5 million (US$7.7 million) are due to Premier if the Cobra discovery is developed. The effective date of the transaction is 1 January 2018. Disposal proceeds will be used to pay down Premier's existing debt. Completion of the transaction is expected in 2018 2H. Accordingly, the assets and liabilities of the Babbage Area interests have been classified as assets held for sale in the balance sheet at 30 June 2018.

The consideration to be received for the Babbage interests is greater than the carrying value of the net assets of Babbage. Therefore, no impairment has been recognised on reclassification of the asset and a profit on disposal is expected to be recognised when the transaction completes.

Discontinued operations

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. During 2017 Al-Haj paid a deposit to Premier of US$25 million.

The disposal of the Pakistan Business Unit is expected to complete by the end of 2018 and, as this is within 12 months of the balance sheet date, the business unit continues to be classified as a disposal group held for sale and presented separately in the balance sheet.

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

	30 June 2018 $ million	30 June 2017 $ million
Revenue	**18.3**	20.2
Expenses	**(7.4)**	(14.0)
Profit before tax	**10.9**	6.2
Attributable tax charge	**(2.6)**	(2.1)
Net profit for the period from assets held for sale	**8.3**	4.1

11. DISCONTINUED OPERATIONS, DISPOSALS AND ASSETS HELD FOR SALE *(continued)*

During the period to 30 June 2018, the Pakistan disposal group contributed US$14.9 million (2017 1H: US$13.9 million) to the Group's net operating cash flows and paid US$1.5 million (2017 1H: US$1.9 million in respect of investing activities. There were no financing cash flows in either the current or the prior period.

The major classes of assets and liabilities comprising the disposal group classified as held for sale are as follows:

	30 June 2018 $ million	31 December 2017 $ million
Property, plant and equipment	**23.4**	23.3
Long-term receivables	**0.3**	0.4
Deferred tax asset	**1.2**	0.8
Inventory	**8.3**	9.0
Trade and other receivables	**15.3**	17.8
Cash	**0.7**	0.9
Pakistan assets classified as held for sale	**49.2**	52.2
Trade and other payables	**(10.3)**	(7.8)
Long-term provisions	**(16.5)**	(17.6)
Pakistan liabilities classified as held for sale	**(26.8)**	(25.4)
Net assets of disposal group	**22.4**	26.8

Contingent liabilities

At 30 June 2018, the Group had a contingent liability for a potential contractual payment of £13.3 million (US$17.6 million) payable in relation to an overseas tax matter. Whilst there is a possible risk that a cash payment may be required in 2018 2H, the Group continues to engage with the overseas tax authorities and is confident that no payment will be made.

12. SUBSEQUENT EVENTS

In July 2018, Premier announced its intention to exercise the mandatory conversion option in its convertible bonds. The exercise of such option will automatically and mandatorily convert all of the remaining US$28.8 million outstanding convertible bonds into approximately 31.4 million new Ordinary Shares of Premier.

In August 2018, the joint venture and the Group's infrastructure partners on the Tolmount project sanctioned the development of the gas field.

INDEPENDENT REVIEW REPORT TO PREMIER OIL PLC

Introduction

We have been engaged by Premier Oil plc (the 'Company') to review the condensed set of financial statements in the half-yearly financial report for the six months ended 30 June 2018 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 12. We have read the other information contained in the half-yearly financial report and considered whether it contains any apparent misstatements or material inconsistencies with the information in the condensed set of financial statements.

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

Directors' Responsibilities

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

As disclosed in note 1, the annual financial statements of the Group are prepared in accordance with International Financial Reporting Standards (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 2018 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

22 August 2018

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 EBITDA, Operating cost per barrel, Depreciation, depletion and amortisation per barrel, Net Debt and Liquidity are defined below.

- **EBITDA:** 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.

- **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 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 Financial Review with detail on how they are reconciled to the statutory financial statements

PremierOil

Half-Year Results for the six months to 30 June 2018

WORKING INTEREST PRODUCTION BY REGION (unaudited)

	Six months to 30 June 2018 kboepd	Six months to 30 June 2017 kboepd
UK:		
Catcher	13.4	-
Balmoral Area[1]	1.6	2.6
Huntington	7.3	15.6
Solan	4.5	7.3
Wytch Farm[2]	-	4.5
Kyle	1.6	1.9
Babbage	2.7	3.2
Elgin-Franklin	7.0	6.5
Other UK	3.2	4.0
	41.3	**45.6**
Indonesia:		
Natuna Sea Block A	12.8	12.9
Kakap[3]	0.6	1.3
	13.4	**14.2**
Vietnam:		
Chim Sáo	16.2	15.5
	16.2	**15.5**
Pakistan:		
Bhit/Badhra	1.8	2.1
Kadanwari	0.7	0.8
Qadirpur	2.0	2.3
Zamzama	0.8	1.3
Mauritania:		
Chinguetti	-	0.3
	5.3	**6.8**
TOTAL	**76.2**	**82.1**

1 Includes Balmoral, Brenda, Nicol and Stirling fields.

2 Disposal of Wytch Farm completed in December 2017.

3 Kakap production included until completion of disposal on 10 April 2018.