PremierOil

Half Year Results for the six months to 30 June 2017

Press Release

Tony Durrant, Chief Executive, commented:

"Premier continues to deliver excellent operational performance, which will drive free cash flow and the reduction of net debt. The first half saw good progress on the Catcher and Tolmount projects, a world class exploration success in Mexico and the acceleration of cash flow from disposals. Following the successful completion of our refinancing, we are ahead of plans to restore financial strength while progressing a number of exciting projects for future growth."

Operational highlights

- Record production of 82.1 kboepd, an increase of 34.5% on the prior period (1H 2016: 61.0 kboepd)
- Catcher FPSO sailaway to North Sea imminent; positive development drilling results
- Heads of Terms signed for new Infrastructure partnership for Tolmount project
- World class Zama oil discovery, offshore Mexico
- Disposal programme ongoing, including potential sale of interest in Wytch Farm field for US$200 million

Financial highlights

- Cash flows from operations of US$292.0 million (1H 2016: US$108.7 million), up 168% on prior period
- Opex of US$14.7/boe, down 11% on the prior period
- Positive free cash flow in 1H, reducing net debt to US$2.7 billion
- Profit after tax of US$40.7 million (1H 2016: US$167.1 million including one-off non-cash credits)
- Comprehensive refinancing completed

Outlook

- 2017 production guidance increased to 75-80 kboepd, from 75 kboepd
- 2017 opex guidance of <US$16/boe maintained, capex guidance recently lowered to US$325 million
- Catcher on schedule for 2017 first oil; improved field production profile now anticipated
- Further debt reduction forecast at year end at current oil prices including effects of ongoing planned disposals
- Debt reduction accelerating once Catcher on-stream; targeting leverage ratio of 3x EBITDA by end 2018

ENQUIRIES

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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 our website at www.premier-oil.com.

Half Year Results for the six months to 30 June 2017

CHAIRMAN'S STATEMENT

Premier's performance

Premier delivered a strong first half operationally, with record production of 82.1 kboepd, up 34.5 per cent on the first half of 2016. This was driven by high production efficiency across the portfolio, enhanced by a full period of contribution from the former E.ON assets which continue to exceed expectations at the time of the acquisition. UK production, which now represents over half of Group production, saw particular outperformance by the Huntington field, which was the highest net producer in the portfolio. In Asia, demand for our Indonesian gas was strong with our Natuna Sea Block A again capturing a market share within its principal gas contract (GSA1) considerably ahead of its contractual share. In Vietnam, production during the period passed fifty million barrels, in excess of the original total volumes envisaged at the time of sanction of the Chim Sáo project.

As a result of the strong production performance in the first half we now expect production for 2017 to be in the range of 75-80 kboepd, an increase on our previous guidance of 75 kboepd.

At the same time as increasing production, we continue to focus on managing our operating cost base and our committed capital expenditure. Our operating costs in the first half were US$14.7/boe (1H 2016: US$16.5/boe), 11 per cent lower than the corresponding period and our full year capex guidance of US$325 million remains well below our original budget. Significant cost reductions have been achieved over the last two years and we continue to see opportunities for further savings from collaboration initiatives and competitive re-tendering.

Progress on the Catcher development in the UK North Sea has been excellent and the field is on track for first oil before the end of 2017. The FPSO is mechanically complete and is in the final stages of commissioning in Singapore. It is scheduled to leave for the North Sea imminently having completed its marine trials. On the Catcher field itself all the key elements of the subsea equipment have been installed and we have also completed the last of the twelve wells that we planned in advance of first oil. Test flow rates and net pay calculations are above original prognosis and as a result we now expect to deliver an improved peak production profile of 60 kboepd ahead of the sanctioned estimate of 50 kboped (gross). Once on stream the Catcher field will provide a step change in our production levels, generating tax –free cash flows for the Group.

Premier retains considerable optionality within our portfolio to maintain and grow our production and deliver value for all stakeholders. In March 2017, the Board sanctioned an incremental development project in Indonesia (Bison, Iguana, Gajah Puteri ("BIGP")) to back fill our existing gas sales contracts. Alongside this we have made good progress moving forward the next generation of material development projects. FEED is underway on the first phase of our Tolmount gas development in the Southern North Sea and we are pleased to have signed a Heads of Terms to enter into an infrastructure partnership regarding the development of the facilities. Premier's share of the capex required to develop this large gas field is now estimated at only US$100 million. On this basis, Tolmount is a very attractive project, meeting our economic thresholds even at low gas prices, allowing us to use our UK tax losses and with significant further reserve upside. In the Falkland Islands, focus in the first half has been on progressing funding alternatives for the first phase of our Sea Lion project. Good progress has been made and discussions are ongoing with both potential providers of export credit finance and supply chain contractors to secure suitable funding and commercial terms.

In July we were delighted to add to our significant discovered but undeveloped reserves and resources, currently sitting at over 800 mmboe, with a material exploration success in Mexico. The world class oil discovery at the Zama-1 exploration well vindicated our strategy of focusing on under-explored but proven hydrocarbon basins with the ability to deliver a material discovery in a lower cost operating environment. Our initial estimates for the full field are a P90-P10 gross unrisked resource range of 400-800 mmboe. The focus, with our joint venture partners, will now be to appraise and plan the development of this world class discovery.

Active portfolio management remains a key element of our strategy. The successful acquisition and integration of the E.ON portfolio last year looks increasingly beneficial with the producing assets exceeding expectations and the economics of Tolmount continuing to improve. With the acquisition having reached cash pay-back during the first half of the year, our focus is now on delivering our disposal programme of non-core assets in order to accelerate balance sheet deleveraging. The sale of the Pakistan business is expected to conclude by the year end. We have also announced the potential sale of our entire interest in the Wytch Farm field for a consideration of US$200 million. This sale, assuming completion in the second half of 2017, will lead to a material reduction in our debt, including the release of US$75 million of Letters of Credit covering future decommissioning liabilities.

A comprehensive refinancing of all of our debt facilities has now been completed. The refinancing, with our facilities maintained and maturities extended out to 2021 and beyond, marks a major milestone for Premier establishing a solid foundation for us to fulfil our strategic plans going forward. Debt reduction remains a priority, but the refinancing provides the headroom and flexibility to plan for future investment in selective new projects. Net debt stood at US$2.7 billion at the half year, down from the year end as we delivered positive free cash flow in the first half. We expect to continue to be net cash flow positive (after capex and planned disposals) at current oil prices and deleveraging will accelerate as the Catcher field comes on stream and further proceeds are generated from our disposal programme.

Health, Safety, Environment and Security ('HSES') matters will always be of paramount importance to us and, regardless of the external environment, we will not compromise on the integrity and safety of our people and our operations. We continue to set ourselves challenging HSES targets to drive continuous improvement and our HSES performance, as measured against our Group aggregate HSES target, improved in the first six months of the year. In addition, all of our production and drilling operations retain their OHSAS 18001 and ISO 14001 certifications.

Board changes

In accordance with Premier's existing succession planning, Joe Darby and David Lindsell stood down from the Board with effect from the AGM on 17 May 2017. In addition, as I have previously indicated, I will be retiring from the Board on 1 September 2017, having served as Chairman for eight years, and I would like to thank the Company's shareholders and other stakeholders for their considerable support over this time.

I am delighted to welcome Roy Franklin, Dave Blackwood and Mike Wheeler to Premier's Board. Roy will take over the role of Non-Executive Chairman on my retirement, and Dave and Mike have joined the Board following the retirements of Joe Darby and David Lindsell. I am confident that their experience and skills will be of enormous value to the Board and the Company as a whole for the next phase of Premier's development.

Outlook

We now look forward to a rising production profile delivered from our low operating cost base and lower committed capital expenditure as the Catcher field comes on stream. Our focus for the second half of the year is to deliver first oil from Catcher on schedule and under budget, to complete our planned disposals and to bring forward to Board sanction the Tolmount field. Our priority, from the free cash flow generated in the short-term, will be to reduce our debt to enable the Group to achieve a leverage ratio of 3x EBITDA by the end of 2018. The combination of free cash flow and selective investment in new development projects within a strict disciplined framework will deliver future value for all stakeholders.

Mike Welton

Chairman

Half Year Results for the six months to 30 June 2017

OPERATIONAL REVIEW

GROUP PRODUCTION

Group production for the first half averaged 82.1 kboepd (2016 1H: 61.0 kboepd), an increase of 34.5 per cent on the prior corresponding period. This was driven by high production efficiency from our existing assets with all business units performing ahead of the 2017 budget and a full period of contribution from the former E.ON assets. As a result of this strong first half performance and with the summer maintenance programme largely complete, Premier has revised upwards its production guidance for the full year to a range of 75 - 80 kboepd. Pakistan production remains included in the Group's full year production guidance as completion of the sale of the Pakistan business is expected around year end.

kboepd	1H 2017	1H 2016
Indonesia	14.2	13.8
Pakistan & Mauritania	6.8	8.3
UK	45.6	22.2
Vietnam	15.5	16.7
Total	**82.1**	**61.0**

UNITED KINGDOM

The UK continued to deliver a strong production performance in the first half of 2017, more than double that of the same period in 2016. Looking ahead, the Catcher project remains on schedule for first oil by the end of 2017, which will deliver a further step change to UK production in 2018.

Production

Production from Premier's UK fields averaged 45.6 kboepd (1H 2016: 22.2 kboepd), up 105 per cent on the prior corresponding period. Production from the former E.ON assets continues to exceed targets, averaging 19.4 kboepd in the first half. The Premier-operated Huntington field was the highest net producer in the portfolio with production averaging 15.6 kboepd (1H 2016: 8.8 kboepd). This strong performance, 36 per cent ahead of budget, was brought about by improved reservoir management and aided by high FPSO operating efficiency. Discussions with Teekay, the owner of the FPSO, to extend the firm charter period beyond April 2018 with a revised rate structure are expected to be concluded shortly.

Production from the non-operated Elgin-Franklin area was also above budget, averaging 6.5 kboepd, benefitting from an ongoing infill drilling campaign. The non-operated Glenelg field (Premier 18.57 per cent), a satellite field within the Elgin-Franklin area, has produced intermittently due to downhole scaling in the single well which may require an intervention in 2018 to rectify fully.

A successful well intervention programme at the Premier-operated Babbage field was undertaken to maximise production from the field and as a result production was ahead of budget at 3.2 kboepd. The platform was transitioned to a Not Permanently Attended Installation (NPAI) in April, which has delivered a reduction of more than 25 per cent in field operating costs. Premier will continue to undertake production optimisation activities at the field which are expected to add incremental production for low additional expenditure. Similar operations in the Southern North Sea have seen both the re-instatement of the Rita gas field after being shut-in for almost two years, plus successful well re-instatements at the Johnston gas field. These low cost activities deliver cash payback in a few months and have added approximately 1.5 kboepd net to Premier's production capacity in the first half of 2017.

Production from the Premier-operated Solan field averaged 7.3 kboepd, lower than anticipated, as a result of the first production well (P1) being shut in for a period in February following the failure of the existing electric submersible pump (ESP). P1 is currently producing steadily on free flow without the need for workover operations. Production rates from the second producer (P2) remain limited due to poor reservoir performance in the eastern part of the field. Operating efficiency of the Solan facility continues to exceed 90 per cent. The Solan team are monitoring production behaviour to better delineate recovery from the existing wells and a number of options to improve production levels and recovery at Solan continue to be studied. These include increasing water injection rates into the reservoir and a possible further drilling campaign in 2019.

Production from the Premier-operated Balmoral area performed as anticipated delivering 2.6 kboepd (1H 2016: 1.7 kboepd), while production from the non-operated Wytch Farm field averaged 4.5 kboepd (1H 2016: 5.1 kboepd), reflecting modest reservoir decline. This relates to Premier's existing 30.1 per cent interest in the fields which was increased to 33.8 per cent post period end. Production from the rest of Premier's UK portfolio was broadly in line with expectations.

UK unit operating costs for the period were US$19.9/boe (1H 2016: US$31/boe), driven lower by good cost control, aided by a full contribution of lower opex fields such as the former E.ON assets and Solan and by virtue of strong production performance. Premier anticipates UK costs per barrel will remain at this level over the medium-term with the start-up of the Catcher field offsetting natural production decline at other fields.

Development

Catcher

Good progress continues to be made on the Premier-operated Catcher project during the first half of 2017 which remains on track for first oil later this year. Total capex forecast remains at US$1.6 billion, 29 per cent lower than the sanctioned estimate.

All major elements of the subsea activities are complete. During the period a short subsea campaign to tie in the recently completed Varadero wells has been completed and a further campaign to support commissioning operations will be carried out once the FPSO is moored in the field.

Drilling activities using the Ensco 100 rig have continued to yield positive results. The last of the twelve wells scheduled for completion pre-first oil, a Burgman field injection well (BI2), has been drilled and completed. The rig will move back to the Catcher field shortly to drill the next batch of four production wells. The Catcher project has delivered four wells on each of the Catcher, Varadero and Burgman fields (eight producers and four injectors) ahead of schedule. Ten of the twelve wells have been tied-in, with the final two Burgman tie-ins scheduled ahead of first oil from the field. Based on test results to date, the length of net pay encountered by the eight production wells has been overall 30 per cent greater than forecast while the anticipated initial production delivery rate of each well is on average 40 per cent higher than predicted. As a result of these positive well results, Premier remains encouraged about the overall recovery from the Catcher fields and is now forecasting peak plateau production of approximately 60 kboepd (gross), 20 per cent ahead of that envisaged at sanction.

The Catcher FPSO departed the Keppel shipyard on the 10th August and is now undertaking the last of the pre-sail commissioning operations at deep-water anchorage offshore Singapore. The vessel is fully crewed at anchorage with 112 personnel lodged on board, supplemented by additional commissioning personnel as required from on-shore. Departure to the UK is expected imminently.

Pre-development

Good progress has been achieved on the Premier-operated Tolmount project in the Southern Gas Basin. In February 2017, the development concept, comprising a standalone normally unmanned installation (NUI) and a new gas export pipeline to shore, was selected. It is envisaged that the initial phase, which will target the Tolmount main structure, will recover 540 Bcf (P50 estimate) of gas from four producing wells at a plateau production capacity of 300 mmscfd (gross). FEED contracts were awarded for the offshore element of the project, for the beach crossing and for the on-shore receiving terminal modifications. A commercial Heads of Terms has been signed with the operator of the Dimlington terminal to process the Tolmount fluids and to undertake terminal modification works on behalf of the

Tolmount project. Tendering of the major project scopes such as platform, pipeline and drilling rig will commence shortly, with development sanction planned for the first half of 2018.

Alongside the FEED process, Premier has signed a Heads of Terms to enter into an infrastructure partnership regarding the Tolmount development. Under the Heads of Terms, Dana Petroleum and CATS Management Limited (an Antin Infrastructure Partners portfolio company), will jointly construct and own the Tolmount platform and export pipeline as a standalone development, as well as undertaking the on-shore modifications at the Dimlington terminal. The Tolmount field will be tied-in to the platform and a tariff will be paid to the infrastructure owners for the transportation of gas production through the infrastructure over the life of the field. Premier will maintain its 50 per cent equity interest in the licence. Premier's share of capex is estimated at approximately US$100 million and this arrangement enhances future returns from the project. Subsurface studies on Tolmount East and Tolmount Far East continue ahead of any future appraisal drilling.

Exploration

At the end of 2016, the Rowan Gorilla VII jack-up rig spudded the Ravenspurn North Deep well, which is testing the deep Carboniferous play underlying the Ravenspurn North field in the Southern Gas Basin. The vertical pilot hole was completed in May and the subsequent lateral well bore was completed in August ahead of testing. If successful, it could provide material follow-on opportunities for Premier within its Southern Gas Basin portfolio, in addition to helping to prolong the life of the Ravenspurn area fields. Premier is fully carried on its 5 per cent interest in the well.

Portfolio management

During the first half Premier exercised its pre-emption rights to acquire an additional 3.71 per cent of the Wytch Farm field, taking Premier's overall interest in the field to 33.8 per cent. OGA consent has been received and that transaction is expected to complete shortly.

In addition, as announced earlier this week, Premier has reached agreement for the disposal of its entire 33.8 per cent interest in the Wytch Farm field for a proposed consideration of US$200 million. Premier will also expect to release Letters of Credit, amounting to approximately US$75 million, held in conjunction with future field abandonment liabilities. Wytch Farm production to 30 June, net to Premier's pro forma 33.8 per cent interest was 5.0 kboepd and net 2P reserves were 14 mmboe. The transaction is subject to signature of a sale and purchase agreement, to lender approval and if classified as a Class 1 transaction, will require shareholder consent.

Premier's active programme of non-core asset disposals continues including the sale of its 30 per cent interest in the Esmond Transportation System (ETS) and its interest in the Arran field in the Central North Sea, both of which are expected to conclude in the second half of 2017.

INDONESIA

The Premier-operated Natuna Sea Block A fields delivered a robust and stable performance in the first half of 2017 with production of 12.9 kboepd, up 3 per cent on the prior period. This was driven by an increased market share of 49 per cent within GSA1 and strong Singapore demand for gas deliveries under GSA2. Operating costs remained low at less than US$8.7/boe, resulting in the Indonesian business unit generating strong positive net cash flows for the Group.

Production and development

Production from Indonesia in the first half of 2017 on a working interest basis was 14.2 kboepd (1H 2016: 13.8 kboepd), up four per cent on the prior period. The Premier-operated Natuna Sea Block A delivered 12.9 kboepd while production from the non-operated Kakap field averaged 1.3 kboepd.

Singapore demand for gas sold under GSA1 remained robust, averaging 301 BBtud (1H 2016: 297 BBtud). Premier's Anoa and Pelikan fields delivered 149 BBtud (1H 2016: 131 BBtud) and accounted for 49 per cent of GSA1 deliveries (1H 2016: 44 per cent), against a contractual market share of 47 per cent. Sales of Gajah Baru and Naga gas dedicated to GSA2 averaged 85 BBtud (1H 2016: 96 BBtud).

Gas sales from the non-operated Kakap field averaged 18 BBtud (1H 2016: 19 BBtud) over the period while gross liquids production was 2.6 kbopd (1H 2016: 3.0 kbopd), reflecting natural decline from existing wells. Gross liquids production from the Anoa field averaged 1.1 kbopd (1H 2016: 1.4 kbopd).

Premier continues to benefit from a low cost base in Indonesia, and has achieved further cost reductions in the first half with operating costs of below US$8.7/boe.

The Anoa development well (WL-5X) which made the Lama discovery under Anoa in 2012 was completed and the well will be brought on production during August. The well achieved an equipment limited flow rate of 28 mmscf/d, significantly higher than the 18 mmscf/d rate achieved with the original well test. The outcome of long-term production from this well will help to define the potential of these deeper zones within the Anoa field.

The next generation of developments in Natuna Sea Block A to backfill our existing Singapore and domestic market contracts continue to progress. Long lead items have been purchased for the BIGP development project which was sanctioned during the period and delivery of first gas is targeted for 2019.

In January Premier was granted a three-year extension to the exploration period of the Tuna PSC licence where evaluation of potential development scenarios of the 2014 Kuda Laut and Singa Laut gas discoveries, now collectively known as the Tuna Field, is ongoing. Discussions are progressing with the governments of Vietnam and Indonesia regarding connections to existing infrastructure in Vietnam.

Exploration and appraisal

Following the successful flow test on the WL-5X well, Premier continues to mature a number of Lama Play leads and prospects to drillable status on its Natuna Sea Block A acreage and seismic reprocessing is currently scheduled for later in 2017 to enhance the seismic imaging over the Lama Play area.

VIETNAM

A robust production performance, combined with continued low operating costs, resulted in the Vietnam business generating strong operating cash flows. During the period, production passed 50 million barrels in excess of the original volumes envisaged at the project sanction.

Production

Production from the Premier-operated Block 12W, which contains the Chim Sáo and Dua fields, averaged 15.5 kboepd (1H 2016: 16.7 kboepd) underpinned by high operating efficiency, excellent reservoir performance and by a successful well intervention programme helping to mitigate natural decline from the fields. A two well infill drilling programme is scheduled to commence in September and this will further help to maximise the future production levels.

Premier continues to secure cost reductions throughout its Vietnam operation. These include replacing our supply vessels to leverage off depressed market rates and improved vessel management. These cost reductions, together with the reduction in the Chim Sáo FPSO lease rate achieved at the end of last year, meant unit operating costs for the period were maintained at US$9.0/boe (1H 2016: US$9/boe). Robust production performance, low operating costs and the continuing premiums to the Brent oil price commanded by Chim Sáo crude contributed to a positive net operating cash flow from the Vietnam business unit in the period.

PAKISTAN

Premier's Pakistan business continued to generate positive net cash flow during the period. The average realised price was US$2.8/mscf while operating costs remained low at around US$3.8/boe (US$0.52/mscf).

Production and development

Production in Pakistan averaged 6.5 kboepd (40.7 mmscfd) (1H 2016: 7.9 kboepd (49.3 mmscfd)), from Premier's six non-operated producing gas fields. The fall in production reflects natural decline in all of the gas fields.

Mmscfd	**1H 2017**	1H 2016
Bhit	**7.0**	9.0
Badhra	**4.8**	6.1
Qadirpur	**15.1**	16.0
Kadanwari	**4.4**	6.2
Zamzama	**8.8**	11.6
Zarghun South	**0.6**	0.4
Total	**40.7**	49.3

Portfolio management

In April, Premier announced the sale of its Pakistan business to Al-Haj Group for US$65.6 million. To date, Al-Haj has paid deposits of US$23.0 million. The buyer has recently obtained approval from the Competition Commission and engagement with the Pakistani authorities with respect to other approvals is progressing well and completion of the transaction is expected by year end.

MAURITANIA

Production and development

Production from the Chinguetti field averaged 337 bopd (1H 2016: 356 bopd) net to Premier. The fall in production was driven by natural decline from the existing wells. In view of the low oil price and resulting marginal cash flows, the joint venture partners are targeting cessation of production from the field by the end of 2017. FPSO disconnection and demobilisation procedures are being prepared and the field abandonment work will begin from 2018. The field abandonment and decommissioning plan is currently being reviewed by the Government of Mauritania.

THE FALKLAND ISLANDS

Having largely completed FEED for the Premier-operated Sea Lion Phase 1 project in 2016, the focus during the period has been on progressing funding solutions and regulatory approvals for the project.

Development

The Sea Lion project has the potential to be transformational for the Group with around 400 mmboe (net to Premier) to be developed over several phases. The overall strategy to develop the North Falklands Basin remains a phased development solution, starting with Sea Lion Phase 1 which will develop 220 mmbbls in PL032. FEED on Sea Lion Phase 1 was largely completed in 2016 with the focus on optimising the facilities design and installation methodology required. As a result, estimated capex to first oil was reduced from US$1.8 billion to US$1.5 billion. The focus during the first half of 2017 has been on securing appropriate funding and commercial solutions for the project. Good progress has been made and discussions are ongoing with both potential providers of export credit finance and supply chain contractors to secure terms. In parallel, Premier is engaging with the Falkland Islands Government and its agencies on fiscal, environmental and other regulatory matters with a view to obtaining the consents and agreements necessary to be in a position to sanction the development in 2018.

EXPLORATION

In recent years, Premier changed its strategy and rebalanced its exploration portfolio away from traditional but now mature areas to under-explored but proven hydrocarbon basins with the potential to develop into new business units in 2018 and beyond. Priority has been given to lower cost operating environments whilst reducing exposure elsewhere. This strategy has resulted in a major success with the world class oil discovery at the Zama-1 well offshore Mexico.

MEXICO

During 1H 2017 Premier, together with its joint venture partners Talos Energy (Operator) and Sierra Oil & Gas, drilled the Zama prospect in Block 7 in the Sureste Basin, offshore Mexico which resulted in a world class oil discovery. Premier's initial estimate of the gross oil in-place volumes for the overall Zama structure was in excess of 1 billion barrels of oil with a gross oil bearing interval in the Zama-1 well of over 335 metres (1,100 feet). However, after undertaking some further analysis of the data gathered from the Zama-1 well, initial gross oil-in place estimates are now 1.2-1.8 billion barrels, with an estimated recoverable P90-P10 gross unrisked resource range of 400-800 mmboe. These estimates include those volumes that extend into the neighbouring block. The joint venture is now looking to work with the Mexican Government (CNH & SENER) and with PEMEX to move swiftly forward with the appraisal and development of this world class discovery. Premier increased its holding to a 25 per cent paying interest in Block 7 as approved by CNH.

In addition, Premier currently holds a carried 10 per cent interest in Block 2, and the joint venture is evaluating which prospect will be the first to be drilled, potentially targeting a well in 2018. Premier continues to carefully evaluate opportunities for growth in Mexico, from future licensing rounds.

BRAZIL

Premier received 4,000km^2 of final processed broadband seismic data across all three of its Ceará Basin blocks in April 2017. The data is now being interpreted to finalise prospects and well locations will be selected in advance of a potential drilling campaign in 2019. Significant progress has been made on well planning and obtaining of drilling permits as Premier continues to leverage its position as the largest acreage holder in the Ceará Basin, along with its growing experience in Brazil, to coordinate operational synergies.

FINANCIAL REVIEW

Context

2017 continues to provide a challenging macro-economic environment with significant oil price volatility in the period. Brent crude opened the year at US$56.6/bbl falling to a US$44.8/bbl in June, before closing at US$47.9/bbl at 30 June 2017. The average for 2017 1H was US$51.7/bbl against US$39.8/bbl for the corresponding period in 2016.

Against this economic backdrop our production has grown significantly to average 82.1 kboepd (2016 1H: 61.0 kboepd), resulting in total sales revenue from all operations of US$566.3 million compared with US$393.8 million in 2016 1H. In addition, we have also successfully completed the refinancing of all of our debt facilities in July 2017.

Business Performance

EBITDAX for the period from continuing operations was US$325.9 million compared to US$162.7 million for 2016 1H. The increased EBITDAX is mainly due to higher production and higher average oil and gas prices realised during the period.

Business performance (continuing operations)	**2017 Half-year $ million**	**2016 Half-year $ million**
Operating profit	141.4	185.8
Amortisation and depreciation	180.5	148.2
Reduction in decommissioning estimates	-	(100.8)
Exploration expense and pre-licence costs	4.0	14.8
Acquisition of subsidiaries:		
- Excess of fair value over consideration	-	(106.9)
- Costs related to the acquisition of E.ON	-	21.6
EBITDAX *	**325.9**	**162.7**

* Prior year has been restated for results from the Pakistan business unit, which has been reclassified as an asset held for sale in the period

Net debt at 30 June 2017 amounted to US$2,738.5 million (31 December 2016: US$2,765.2 million), with cash resources of US$307.5 million (31 December 2016: US$255.9 million).

	2017 Half-year $ million	2016 Year-end $ million
Cash and cash equivalents [1]	**307.5**	255.9
Convertible bonds [2]	**(239.9)**	(237.4)
Other debt [2]	**(2,806.1)**	(2,783.7)
Net debt	**(2,738.5)**	(2,765.2)

[1] Includes JV partners share of cash of US$49.2 million (31 December 2016: US$46.4 million) and cash collateral for Mexico exploration of US$6.6 million (31 December 2016: US$6.6 million).

[2] The carrying amounts of the convertible bonds, short-term debt and the other long-term debt on the balance sheet are stated net of the unamortised portion of the issue costs of US$0.1 million (31 December 2016: US$0.1 million) and debt arrangement fees of US$12.2 million (31 December 2016: US$17.5 million) respectively.

Long-term borrowings consist of convertible bonds, UK retail bonds, senior loan notes and bank debt. The £100.0 million and US$150.0 million term loans and US$52.8 million of the 2011 USPP notes have been classified as short-term on the balance sheet. As the Refinancing described below was completed after 30 June 2017, these facilities have been classified on the balance sheet as short-term liabilities according to their original maturities of November 2017 and June 2018, respectively. With the Refinancing now completed, the maturity of these loans has been extended to May 2021 and, therefore, they will be reclassified to long-term debt in the year-end balance sheet.

Premier retains significant cash at 30 June 2017, of US$307.5 million and undrawn facilities of US$328.3 million, giving Liquidity of US$580.0 million (31 December 2016: US$592.9 million), once cash of US$55.8 million held on behalf of our joint venture partners is removed from the calculation of Liquidity.

Refinancing

Subsequent to the 30 June 2017 period end, on 28 July 2017, Premier completed a comprehensive refinancing of its debt facilities (the “Refinancing”) with the lenders under the Company’s Revolving Credit Facility (“RCF”), Term Loan, Schuldschein and US Private Placement (“USPP”) notes (together the “Private Lenders”), the retail bonds and the convertible bonds. Completion of the Refinancing provides a solid foundation for Premier to deliver its strategic plans by preserving the Group’s debt facilities, resetting financial covenant headroom and extending maturities to 2021 and beyond.

In connection with the Refinancing, Premier issued 71,012,952 equity warrants and 21,375,852 synthetic warrants to its Private Lenders and retail bondholders and 18,097,019 equity warrants to its convertible bondholders in July 2017. The equity warrants have an exercise price of 42.75 pence and are exercisable from their issuance until 31 May 2022.

As the Refinancing completed after the period end, the impact of the Refinancing has not been recognised in the 2017 1H results but will be captured in the 2017 Annual Report and Accounts of the Group. This includes the classification of the debt on the balance sheet, crystallisation of costs related to the Refinancing and recognition of both the equity and synthetic warrants as financial instruments, however, certain third party costs of US$15.7 million in relation to the Refinancing have been expensed in the period. Further details on the expected impact of the Refinancing are provided in note 12 to the financial statements.

Assets held for sale

In April 2017, Premier announced it has reached agreement and signed a share purchase agreement 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. In 2017 1H, Al-Haj paid a deposit to Premier of US$20.0 million with a further deposit payment of US$3.0 million received in July 2017.

The disposal of the Pakistan business unit is expected to complete by the end of 2017 and, as this is within 12 months of the balance sheet date, the business unit has been 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. Profit after tax for the business unit for the period is US$4.1 million (2016 1H: US$10.9 million). Assets and liabilities held for sale in relation to the Pakistan disposal group are US$43.7 million and US$29.7 million, respectively.

Income statement

Production and revenue

Group production on a working interest basis averaged 82.1 kboepd for the period compared to 61.0 kboepd in 2016 1H. This was driven by high operating efficiency, better than predicted reservoir performance on certain fields and a full period contribution from the E.ON portfolio. Entitlement production for the period was 76.1 kboepd (2016 1H: 57.0 kboepd). Post hedging, Premier realised an average price for the period of US$49.9/bbl (2016 1H: US$48.6/bbl) vs a Brent average price of US$51.7/bbl (2016 1H: US$39.8/bbl).

Gas prices in Singapore, linked to high sulphur fuel oil (HSFO) pricing and in turn, therefore, linked to crude oil pricing, averaged US$8.6/mscf (2016 1H: US$5.8/mscf) post hedging. The average price for Pakistan gas (where only a portion of the contract formulae is linked to energy prices) was US$2.8/mscf (2016 1H: US$3.1/mscf). Average gas price (post hedge) realised from our UK gas assets was 46 pence/therm (2016 1H: 41 pence/therm).

Total sales revenue from all operations (including Pakistan) increased to US$566.3 million (2016 1H: US$393.8 million), primarily due to the increase in production in the period coupled with a small increase in post-hedge realised oil prices. From continuing operations (excluding Pakistan), revenue increased to US$546.1 million from US$367.1 million for the prior period.

Operating costs

Cost of sales comprise cost of operations, changes in lifting positions, inventory movement, royalties and amortisation and depreciation of property plant and equipment ("PP&E"). Cost of sales for the Group was US$399.3 million for 2017 1H, compared to US$339.4 million for 2016 1H (restated for Pakistan).

	2017 Half-year $ million	2016 Half-year $ million
Operating costs		
Continuing operations	214.0	174.3
Discontinuing operations (Pakistan)	4.4	4.8
Operating costs (US$ million)	218.4	179.1
Operating cost per barrel (US$ per barrel)	14.7	16.5
Amortisation and depreciation of oil and gas properties		
Continuing operations	177.3	144.2
Discontinuing operations (Pakistan)	7.3	8.6
Total (US$ million)	184.6	152.8
DD&A per barrel (US$ per barrel)	12.4	13.7

The increase in absolute operating costs reflects a full contribution from the former E.ON assets and the Solan field. Ongoing cost reduction initiatives, successful contract renegotiations and strict management of discretionary spend continue to deliver low and stable operating costs. On a per barrel basis, operating costs fell by 11 per cent due to the strong production performance in the period and the continued focus on cost control mentioned above.

Exploration expenditure and pre-licence costs

Exploration expense and pre-licence expenditure costs amounted to US$4.0 million (2016 1H: US$14.8 million). After recognition of these expenditures, the exploration and evaluation asset remaining on the balance sheet at 30 June 2017, including goodwill attributable to the Catcher asset, is US$1,270.5 million

(31 December 2016: US$1,252.2 million) which includes the Sea Lion and Tolmount 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 1H 2017 to US$4.0 million (2016 1H: US$13.4 million) due to the inclusion of E.ON's unallocated G&A in the prior period. Unallocated G&A continues to fall following the successful integration of E.ON's business into our Aberdeen business unit and ongoing cost reduction initiatives across the Group.

Finance gains and costs

Gross finance costs, before interest capitalisation, which include the unwinding of the discount on decommissioning, of US$166.6 million have increased compared to the prior year (US$121.6 million) principally due to the recognition of certain third party costs for the Refinancing of US$15.7 million and a step up in the interest margin on our facilities. In addition, interest costs capitalised have fallen by US$12.4 million due to the Solan project reaching first oil in April 2016.

Taxation

The Group has a current tax charge for the period of US$28.7 million (2016 1H: US$9.3 million) and a non-cash deferred tax credit for the period of US$68.9 million (2016 1H: US$72.2 million) which results in a total tax credit for the period of US$40.2 million, from continuing operations. (2016 1H: US$62.9 million).

The current tax charge for the period includes a credit adjustment in respect of prior periods of US$7.9 million (2016 1H: US$0.3 million charge), which is predominantly an adjustment for historically over-provided PRT accruals which are no longer required.

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 2016 on the basis that there have been no impairment triggers identified at the balance sheet date of 30 June 2017.

Profit after tax

Profit after tax is US$40.7 million (2016 1H: US$167.1 million), including US$4.1 million for the Pakistan business unit which has been reclassified as a discontinued operation in the period, resulting in a basic profit per share of 7.2 cents (2016 1H: 31.8 cents), from continuing operations. The profit after tax for the prior year included negative goodwill on the E.ON acquisition totalling US$106.9 million and a reduction in decommissioning estimates of US$100.8 million.

Cash flow

Cash flow from operating activities was US$292.0 million (2016 1H: US$108.7 million) after accounting for tax payments of US$44.0 million (2016 1H: US$37.0 million).

Capital expenditure in the period to 30 June 2017 totalled US$129.8 million (2016 1H: US$318.3 million).

Capital expenditure	**2017 Half-year $ million**	**2016 Half-year $ million**
Fields/development projects	106.6	259.3
Exploration and evaluation	22.9	57.7
Other	0.3	1.3
Total	**129.8**	**318.3**

The principal development project was the Catcher field in the UK and exploration drilling on the Zama prospect in Mexico. In addition, cash expenditure for decommissioning activity in the period was US$6.3 million. Further to this, US$7.8 million of cash was funded into long-term abandonment accounts for future decommissioning activities.

During the period, cash receipts included US$20.0 million deposit for the disposal of the Pakistan business and a US$10.0 million deferred receipt from Repsol for the disposal of the CRD prospect in Vietnam in 2013.

Balance sheet position

Decommissioning Funding

Included within long-term receivables, is US$66.6 million for future decommissioning funding receivable from E.ON for the Ravenspurn North and Johnston fields (31 December 2016: US$66.7 million). In addition, other long-term receivables include US$81.2 million for cash held in escrow accounts for expected future decommissioning expenditure (31 December 2016: US$73.4 million).

Provisions

Total decommissioning provisions at 30 June 2017 are US$1,400.0 million, excluding Pakistan, (31 December 2016: US$1,325.4 million), of which US$1,365.5 million are classified as long-term (31 December 2016: US$1,270.4 million). The increase is driven by the strengthening of the GBP:USD exchange rate at 30 June 2017 and unwinding of the discount recognised on the provision. Long-term provisions also include contingent consideration of US$18.4 million payable to Chrysaor (31 December 2016: US$24.0 million).

Non-IFRS measures

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

Financial risk management

Commodity prices

At 30 June 2017, the Group had 0.5 mmbbls of open oil swaps at an average price of US$46.8/bbl. The fair value of these oil swaps at 30 June 2017 was a liability of US$0.9 million (31 December 2016: liability of US$18.3 million), which is expected to be released to the income statement during 2017 H2 as the related barrels are lifted. Furthermore, the Group has open oil put option agreements for 1.8 mmbls at an average price of US$51.1/bbl. These options will be settled during 2017 H2 and are an asset on the Group's balance sheet with a fair value at 30 June 2017 of US$7.7 million (31 December 2016: asset of US$3.5 million). Included within physically delivered oil sales contracts are a further 1.4 mmbls of oil that will be sold for an average fixed price of US$53.9/bbl during 2017 H2 and 2018 Q1 as these barrels are delivered.

The Group has forward UK gas sales of 85 mm therms at an average price of 47 pence/therm at 30 June 2017 that will be physically settled during 2017 H2 and into 2018 1H. The fair value of this asset at 30 June 2017 was US$9.1 million (31 December 2016: asset US$10.4 million).

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. At 30 June 2017, the fair value of the outstanding foreign exchange contracts including cross currency swaps was a liability of US$1.8 million (31 December 2016: asset of US$1.1 million). 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:€ and which at 30 June 2017 had a fair value liability of US$114.9 million (31 December 2016: liability of US$144.0 million).

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 2017, approximately 53 per cent of total borrowings is fixed or has been fixed using the interest rate swap markets. On average, the cost of drawn funds for the period was 5.8 per cent. The fair value of the interest rate swaps at 30 June 2017 was an asset of US$3.7 million (31 December 2016: asset of US$5.1 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 2017 the Group continued to have significant headroom on its financing facilities and cash on hand. In July 2017, the Group finalised the Refinancing of its principal financing facilities with amended covenant profiles therefore, the material uncertainty previously highlighted in the 2016 Annual Report no longer exists. Under the terms of the Refinancing, 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 2017 Interim Report and Accounts. In a scenario where oil and gas prices were to remain materially below those currently being realised or 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 outside of the 12 month going concern assessment period.

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 business unit management to 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 2016, for the remaining 6 months of the year as being:

- Commodity price volatility;
- Financial discipline and governance;
- Production and development delivery and decommissioning execution;
- Joint venture partner alignment and supply chain delivery;
- Organisational capability;
- Exploration success and reserves addition;
- Health, safety, environment and security (HSES); and,
- Host government – political and fiscal risks.

Further information detailing the way in which these risks are mitigated is provided on pages 28 to 35 of the 2016 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 2017

CONDENSED CONSOLIDATED INCOME STATEMENT

	Note	**Six months to 30 June 2017 Unaudited $ million**	Six months to 30 June 2016 Unaudited $ million*
Continuing operations			
Sales revenues	*2*	**546.1**	367.1
Other operating income		**2.6**	0.2
Cost of sales	*3*	**(399.3)**	(339.4)
Reduction in decommissioning estimates		**-**	100.8
Exploration expense	*7*	**(1.1)**	(9.5)
Pre-licence exploration costs		**(2.9)**	(5.3)
Excess of fair value over costs of acquisition		**-**	106.9
Costs related to the acquisition of subsidiaries		**-**	(21.6)
General and administration costs		**(4.0)**	(13.4)
Operating profit		**141.4**	185.8
Interest revenue, finance and other gains	*4*	**9.2**	10.3
Finance costs, other finance expenses and losses	*4*	**(154.2)**	(96.8)
(Loss) / profit before tax		**(3.6)**	99.3
Tax	*5*	**40.2**	62.9
Profit for the period from continuing operations		**36.6**	162.2
Discontinued operations			
Profit for the period from discontinued operations	*11*	**4.1**	4.9
Profit after tax		**40.7**	167.1
Earnings per share (cents):			
From continuing operations			
Basic	*6*	**7.2**	31.8
Diluted	*6*	**7.0**	30.2
From continuing and discontinued operations			
Basic	*6*	**8.0**	32.8
Diluted	*6*	**7.8**	31.1

* restated for discontinued operations, see note 11.

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

PremierOil

Half Year Results for the six months to 30 June 2017

CONDENSED CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

	Six months to 30 June 2017 Unaudited $ million	Six months to 30 June 2016 Unaudited $ million
Profit for the period	**40.7**	167.1
Cash flow hedges on commodity swaps:		
Gains/(losses) arising during the period	**9.9**	(36.9)
Less: reclassification adjustments for losses/(gains) in the period	**6.7**	(47.5)
	16.6	(84.4)
Tax relating to components of other comprehensive income	**(6.6)**	54.3
Cash flow hedges on interest rate and foreign exchange swaps	**1.4**	(14.6)
Exchange differences on translation of foreign operations	**(1.1)**	(10.1)
Other comprehensive income/(expense)	**10.3**	(54.8)
Total comprehensive income for the period	**51.0**	112.3

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

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

Half Year Results for the six months to 30 June 2017

CONDENSED CONSOLIDATED BALANCE SHEET

	Note	At 30 June 2017 Unaudited $ million	At 31 December 2016 Audited $ million
Non-current assets:			
Intangible exploration and evaluation assets	*7*	**1,029.7**	1,011.4
Property, plant and equipment	*8*	**2,678.6**	2,726.2
Goodwill		**240.8**	240.8
Investment in associate		**6.5**	6.2
Long-term receivables		**154.9**	143.4
Deferred tax assets		**1,349.6**	1,304.0
		5,460.1	5,432.0
Current assets:			
Inventories		**19.5**	22.3
Trade and other receivables		**307.9**	315.1
Derivative financial instruments	*10*	**20.3**	34.9
Cash and cash equivalents		**307.5**	255.9
Assets held for sale	*11*	**43.7**	-
		698.9	628.2
Total assets		**6,159.0**	6,060.2
Current liabilities:			
Trade and other payables		**(383.4)**	(412.6)
Short-term debt	*9*	**(332.8)**	(273.0)
Short-term provisions		**(35.1)**	(56.1)
Derivative financial instruments	*10*	**(60.8)**	(57.2)
Deferred income		**(21.1)**	(27.3)
Liabilities held for sale	*11*	**(29.7)**	-
		(862.9)	(826.2)
Net current liabilities		**(164.0)**	(198.0)
Non-current liabilities:			
Long-term debt	*9*	**(2,700.9)**	(2,730.5)
Deferred tax liabilities		**(172.3)**	(192.6)
Deferred income		**(91.3)**	(88.1)
Long-term provisions		**(1,402.5)**	(1,312.1)
Derivative financial instruments	*10*	**(60.0)**	(101.6)
		(4,427.0)	(4,424.9)
Total liabilities		**(5,289.9)**	(5,251.1)
Net assets		**869.1**	809.1

CONDENSED CONSOLIDATED BALANCE SHEET *(continued)*

	At 30 June 2017 Unaudited $ million	At 31 December 2016 Audited $ million
Equity and reserves:		
Share capital	**106.7**	106.7
Share premium account	**275.4**	275.4
Merger reserve	**374.3**	374.3
Retained earnings	**161.8**	109.7
Other reserves	**(49.1)**	(57.0)
	869.1	809.1

Premier Oil

Half Year Results for the six months to 30 June 2017

CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

	Attributable to the equity holders of the parent								
					Other reserves				
	Share capital $ million	Share premium account $ million	Retained earnings $ million	Merger reserve $ million	Hedging reserve $ million	Capital redemption reserve $ million	Translation reserves $ million	Equity reserve $ million	Total $ million
At 1 January 2017	106.7	275.4	109.7	374.3	12.6	8.1	(82.7)	5.0	809.1
Provision for share-based payments	-	-	9.0	-	-	-	-	-	9.0
Transfer between reserves*	-	-	2.4	-	-	-	-	(2.4)	-
Profit for the period	-	-	40.7	-	-	-	-	-	40.7
Other comprehensive income	-	-	-	-	11.4	-	(1.1)	-	10.3
At 30 June 2017	**106.7**	**275.4**	**161.8**	**374.3**	**24.0**	**8.1**	**(83.8)**	**2.6**	**869.1**
At 1 January 2016	106.7	275.4	(37.6)	374.3	83.9	8.1	(85.7)	9.6	734.8
Purchase of ESOP Trust	-	-	0.2	-	-	-	-	-	0.2
Provision for share-based payments	-	-	8.2	-	-	-	-	-	8.2
Transfer between reserves*	-	-	2.2	-	-	-	-	(2.2)	-
Profit for the period	-	-	167.1	-	-	-	-	-	167.1
Other comprehensive expense	-	-	-	-	(44.7)	-	(10.1)	-	(54.8)
At 30 June 2016	**106.7**	**275.4**	**140.1**	**374.3**	**39.2**	**8.1**	**(95.8)**	**7.4**	**855.4**

* The transfer between reserves relates to the non-cash interest on the convertible bonds, less the amortisation of the issue costs that were charged directly against equity.

CONDENSED CONSOLIDATED CASH FLOW STATEMENT

	Note	**Six months to 30 June 2017 Unaudited $ million**	Six months to 30 June 2016 Unaudited $ million
Net cash from operating activities	*9*	**292.0**	108.7
Investing activities:			
Capital expenditure		**(136.1)**	(318.3)
Acquisition of subsidiaries		**-**	(135.0)
Cash balance acquired in the period		**-**	24.9
Decommissioning funding		**(7.8)**	(55.8)
Disposal of oil and gas properties	*11*	**30.0**	-
Net cash used in investing activities		**(113.9)**	(484.2)
Financing activities:			
Proceeds from drawdown of bank loans		**-**	230.0
Debt arrangement fees		**(34.9)**	-
Interest paid		**(89.7)**	(55.3)
Net (used in)/cash from financing activities		**(124.6)**	174.7
Currency translation differences relating to cash and cash equivalents		**(1.9)**	7.2
Net increase/(decrease) in cash and cash equivalents		**51.6**	(193.6)
Cash and cash equivalents at the beginning of the period		**255.9**	401.3
Cash and cash equivalents at the end of the period	*9*	**307.5**	207.7

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 2017 were approved for issue in accordance with a resolution of a committee of the Board of Directors on 23 August 2017.

The information for the year ended 31 December 2016 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 2016 were approved by the Board of Directors on 8 March 2017 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. However, an emphasis of matter with regards to a material uncertainty in the application of the going concern basis of accounting was included in the audit report.

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 2017, and the condensed consolidated balance sheet as at 30 June 2017 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 2017 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 2016, 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 2016, as described in those annual financial statements. A number of new standards, amendments to existing standards and interpretations were effective from 1 January 2017. 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 2017.

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 9, IFRS 15 and IFRS 16 are currently being assessed. IFRS 9 will affect both the measurement of and disclosures relating to financial instruments. IFRS 16 is likely to require a number of significant changes to the treatment of our lease arrangements, in particular the FPSO lease arrangements for Catcher and Chim Sáo, whereby we expect to recognise the leased FPSOs as assets and liabilities from these lease arrangements on our balance sheet from 1 January 2019, with a consequential impact on the profile and phasing of income statement recognition. IFRS 15 may have an impact on revenue recognition and related disclosures.

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 was reclassified as an asset held for sale in the period, are reported as a discontinued operation. The results from Mauritania have been reclassified into 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 2017 Unaudited $ million	Six months to 30 June 2016 Unaudited $ million *
Revenue:		
United Kingdom	**362.6**	204.7
Indonesia	**84.7**	68.0
Vietnam	**97.0**	91.9
Rest of the World	**1.8**	2.5
Total group sales revenue	**546.1**	367.1
Other operating income – United Kingdom	**2.6**	0.2
Interest and other finance revenue	**0.6**	0.5
Total group revenue from continuing operations	**549.3**	367.8
Revenue from discontinued operations	**20.2**	26.7
Group operating profit:		
United Kingdom	**75.8**	97.2
Indonesia	**37.7**	7.5
Vietnam	**38.9**	14.0
Rest of the World	**(4.1)**	0.5
Unallocated[1]	**(6.9)**	66.6
Group operating profit	**141.4**	185.8
Interest revenue, finance and other gains	**9.2**	10.3
Finance costs and other finance expenses	**(154.2)**	(96.8)
(Loss) / profit before tax from continuing operations	**(3.6)**	99.3
Tax	**40.2**	62.9
Profit after tax from continuing operations	**36.6**	162.2
Profit from discontinued operations	**4.1**	4.9

* Restated for discontinued operations

[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)*

	Six months to 30 June 2017 Unaudited $ million	Year to 31 December 2016 Audited $ million
Balance sheet - Segment assets:		
United Kingdom[1]	**4,242.4**	4,136.5
Indonesia	**464.8**	480.2
Vietnam	**372.4**	399.0
Falkland Islands	**628.6**	642.9
Pakistan (including Mauritania)	**-**	44.8
Rest of the World[2]	**79.3**	66.0
Assets held for sale	**43.7**	-
Unallocated[3]	**327.8**	290.8
Total assets	**6,159.0**	6,060.2

[1] Includes goodwill of US$240.8 million.

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

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

3. COST OF SALES

	Six months to 30 June 2017 Unaudited $ million	Six months to 30 June 2016 Unaudited $ million*
Operating costs	**214.0**	174.3
Gas purchases	**3.4**	4.6
Stock overlift/underlift movement	**(2.7)**	7.8
Royalties	**4.1**	4.5
Amortisation and depreciation of property, plant and equipment		
- Oil and gas properties	**177.3**	144.2
- Other fixed assets	**3.2**	4.0
	399.3	339.4

* Restated for discontinued operations

4. INTEREST REVENUE AND FINANCE COSTS

	Note	**Six months to 30 June 2017 Unaudited $ million**	Six months to 30 June 2016 Unaudited $ million*
Interest revenue, finance and other gains:			
Short-term deposits		**0.2**	0.5
Other interest received		**0.4**	-
Gain on forward contracts		**8.6**	-
Exchange differences and others		**-**	9.8
		9.2	10.3
Finance costs:			
Bank loans, overdrafts and bonds		**(72.7)**	(40.4)
Payable in respect of convertible bonds		**(5.5)**	(5.4)
Payable in respect of senior loan notes		**(14.7)**	(14.0)
Long-term debt arrangement fees		**(5.2)**	(5.8)
Exchange differences and others		**(12.2)**	(0.8)
		(110.3)	(66.4)
Other finance expenses:			
Unwinding of discount on decommissioning provision		**(29.9)**	(28.2)
Loss on forward contracts		**(4.7)**	(17.9)
Refinancing fees	*12*	**(15.7)**	-
Finance expense on deferred income		**(6.0)**	(9.1)
		(56.3)	(55.2)
Gross finance costs and other finance expenses		**(166.6)**	(121.6)
Finance costs capitalised during the period		**12.4**	24.8
		(154.2)	(96.8)

* Restated for discontinued operations

5. TAX

	Six months to 30 June 2017 Unaudited $ million	Six months to 30 June 2016 Unaudited $ million *
Current tax:		
UK corporation tax on profits	**(0.2)**	(1.0)
UK petroleum revenue tax	**(0.1)**	0.1
Overseas tax	**36.9**	9.9
Adjustments in respect of prior years	**(7.9)**	0.3
Total current tax charge	**28.7**	9.3
Deferred tax:		
UK corporation tax	**(53.9)**	(68.5)
UK petroleum revenue tax	**-**	1.2
Overseas tax	**(15.0)**	(4.9)
Total deferred tax credit	**(68.9)**	(72.2)
Tax credit on profit/(loss) on ordinary activities	**(40.2)**	(62.9)

* Restated for discontinued operations

The group has a current tax charge for the period of US$28.7 million (2016: charge of US$9.3 million) and a non-cash deferred tax credit for the period of US$68.9 million (2016: credit of US$72.2 million) which results in a total tax credit for the period of US$40.2 million (2016: credit of US$62.9 million).

The current tax charge for the period includes a credit adjustment in respect of prior periods of US$7.9 million (2016 1H: charge of US$0.3 million), which is an adjustment for historically over-provided PRT accruals which are no longer required.

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 2016 on the basis that there have been no impairment triggers identified at the balance sheet date of 30 June 2017.

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 2017 Unaudited	Six months to 30 June 2016 Unaudited
Earnings ($ millions):		
Earnings from continuing operations	**36.6**	162.2
Effect of dilutive potential Ordinary Shares:		
Interest on convertible bonds – (2017 anti-dilutive)	**-**	5.4
Earnings for the purposes of diluted earnings per share on continuing operations	**36.6**	167.6
Profit from discontinued operations	**4.1**	4.9
Earnings for the purpose of diluted earnings per share on continuing and discontinued operations	**40.7**	172.5
Number of shares (millions):		
Weighted average number of Ordinary Shares for the purpose of basic earnings per share	**510.8**	510.8
Effects of dilutive potential Ordinary Shares:		
Contingently issuable shares –dilutive	**12.1**	43.6
Weighted average number of Ordinary Shares for the purpose of diluted earnings per share	**522.9**	554.4
Earnings per share (cents) from continuing operations		
Basic	**7.2**	31.8
Diluted	**7.0**	30.2
Earnings per share (cents) from discontinued operations		
Basic	**0.8**	1.0
Diluted	**0.8**	0.9

Discontinued operations in 2017 relate to the results of the Group's Pakistan business unit which has been reclassified as a held for sale asset in the period. Results for 2016 1H have been restated accordingly. In the prior year, a cost related to the completion of the disposal of Premier's former Norwegian business was also included.

There were 36.1 million anti-dilutive potential Ordinary Shares in 2017 which related to shares to be issued on conversion of the convertible bonds.

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

	Oil and gas properties $ million
Cost:	
At 1 January 2017	1,011.4
Exchange movements	(0.6)
Additions during the period	20.0
Exploration expense	(1.1)
At 30 June 2017	**1,029.7**
At 31 December 2016	1,011.4

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.

8. PROPERTY, PLANT AND EQUIPMENT

	Note	Oil and gas properties $ million	Other fixed assets $ million	Total $ million
Cost:				
At 1 January 2017		8,028.6	64.3	8,092.9
Exchange movements		2.7	1.5	4.2
Additions during the period*		158.0	0.3	158.3
Disposals*		-	(0.7)	(0.7)
Reclassified as asset held for sale	*11*	(329.2)	(0.6)	(329.8)
At 30 June 2017		**7,860.1**	**64.8**	**7,924.9**
Amortisation and depreciation:				
At 1 January 2017		5,318.9	47.8	5,366.7
Exchange movements		-	1.2	1.2
Charge for the period*		184.6	3.2	187.8
Disposals*		-	(0.7)	(0.7)
Reclassified as asset held for sale	*11*	(308.2)	(0.5)	(308.7)
At 30 June 2017		**5,195.3**	**51.0**	**5,246.3**
Net book value:				
At 30 June 2017		**2,664.8**	**13.8**	**2,678.6**
At 31 December 2016		2,709.7	16.5	2,726.2

* Includes costs and charges in the period for the Pakistan business unit which are reclassified as asset held for sale.

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 or 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 2017 Unaudited $ million**	Six months to 30 June 2016 Unaudited $ million*
(Loss) / profit before tax for the period		**(3.6)**	99.3
Adjustments for:			
Depreciation, depletion, amortisation and impairment	*3*	**180.5**	148.2
Other operating income		**(2.6)**	(0.2)
Exploration expense		**1.1**	9.5
Excess of fair value over consideration		**-**	(106.9)
Provision for share-based payments		**5.0**	8.2
Reduction in decommissioning estimates		**-**	(100.8)
Interest revenue and finance gains	*4*	**(9.2)**	(10.3)
Finance costs and other finance expenses	*4*	**154.2**	96.8
Settlement provision		**-**	16.0
Operating cash flows before movements in working capital		**325.4**	159.8
Increase in inventories		**(6.3)**	(2.1)
Decrease/(increase) in receivables		**26.7**	(74.3)
(Decrease) / increase in payables		**(24.0)**	42.0
Cash generated by operations		**321.8**	125.4
Income taxes paid		**(44.0)**	(37.0)
Interest income received		**0.3**	0.5
Net cash from continuing operating activities		**278.1**	88.9
Net cash from discontinued operating activities	*11*	**13.9**	19.8
Net cash from operating activities		**292.0**	108.7

* Restated for discontinued operations

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

Analysis of changes in net debt:

	Six months to 30 June 2017 Unaudited $ million	At 31 December 2016 Audited $ million
a) Reconciliation of net cash flow to movement in net debt:		
Movement in cash and cash equivalents	**51.6**	(145.4)
Proceeds from drawdown of bank loans	**-**	(435.0)
Non-cash movements on debt and cash balances	**(24.9)**	57.4
Decrease/(increase) in net debt in the period	**26.7**	(523.0)
Opening net debt	**(2,765.2)**	(2,242.2)
Closing net debt	**(2,738.5)**	(2,765.2)

b) Analysis of net debt:		
Cash and cash equivalents	**307.5**	255.9
Borrowings*	**(3,046.0)**	(3,021.1)
Total net debt	**(2,738.5)**	(2,765.2)

* Borrowings consist of the convertible bonds, short-term debt and the other long-term debt. The carrying values of the convertible bonds and the other long-term debt on the balance sheet are stated net of the unamortised portion of the issue costs of US$0.1 million (31 December 2016: US$0.1 million) and debt arrangement fees of US$12.2 million (31 December 2016: US$17.5 million) respectively.

10. FINANCIAL INSTRUMENTS

Derivative financial instruments

The group held the following financial instruments at fair value at 30 June 2017. The group has no financial instruments with fair values that are determined by reference to significant unobservable inputs i.e. those that would be classified as level 3 in the fair value hierarchy, nor have there been any transfers of assets or liabilities between levels of the fair value hierarchy.

There are no non-recurring fair value measurements.

	At 30 June 2017 Level 2 $ million	At 31 December 2016 Level 2 $ million
Financial assets:		
Gas forward sale contracts	9.1	10.4
Oil forward sales contracts	-	15.0
Oil put options	7.7	3.5
Forward foreign exchange contracts	-	1.1
Interest rate swaps	3.7	5.1
DVA adjustment	(0.2)	(0.2)
Total	**20.3**	**34.9**

Financial liabilities:		
Oil forward sales contracts	7.6	18.3
Cross currency swaps	114.9	144.0
Forward foreign exchange contracts	1.8	-
CVA adjustment	(3.5)	(3.5)
Total	**120.8**	**158.8**

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

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 2017		At 31 December 2016	
	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	158.4	195.0	147.6	184.5
Convertible bonds	215.5	239.9	177.9	237.5

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

11. DISCONTINUED OPERATIONS

In April 2017, Premier announced it has reached agreement and signed a share purchase agreement 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. In 2017 1H, Al-Haj paid a deposit to Premier of US$20.0 million with a further deposit payment of US$3.0 million received in July 2017. In addition deferred consideration of US$10.0 million was received during the period from Repsol in relation to the disposal of the CRD prospect in Vietnam in 2013.

The disposal of the Pakistan business unit is expected to complete by the end of 2017 and, as this is within 12 months of the balance sheet date, the business unit has been classified as a disposal group held for sale and presented separately in the balance sheet. In the prior year a provision of US$6.0 million was recognised for post-completion finalisation of the disposal of the Group's former Norway business unit, which completed in December 2015.

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

	30 June 2017 $ million	30 June 2016 $ million
Revenue	**20.2**	26.7
Expenses	**(14.0)**	(15.9)
Profit before tax	**6.2**	10.8
Attributable tax (charge) / credit	**(2.1)**	0.1
Net profit for the period from assets held for sale	**4.1**	**10.9**

During the period to 30 June 2017, the Pakistan disposal group contributed US$13.9 million (2016 1H: US$19.8 million) to the Group's net operating cash flows and paid US$1.9 million (2016 1H: US$4.7

million in respect of investing activities. There were no financing cash flows in either the current or the prior period.

The consideration to be received for the Pakistan disposal group is greater than the carrying value of the net assets for the disposal group. Therefore, no impairment has been recognised on reclassification of the disposal group and a profit on disposal is expected to be recognised when the transaction completes. The effect of the disposal group on segment results is disclosed in note 2.

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

	30 June 2017 $ million
Property, plant and equipment	21.1
Long-term receivables	0.4
Deferred tax asset	0.3
Inventory	9.1
Trade and other receivables	12.8
Total assets classified as held for sale	**43.7**
Trade and other payables	(12.4)
Long-term provisions	(17.3)
Total liabilities classified as held for sale	**(29.7)**
Net assets of disposal group	**14.0**

12. SUBSEQUENT EVENTS

Exploration

In July 2017 Premier announced that the Zama-1 exploration well (net 25 per cent interest) in Mexico had made a world class oil discovery with oil in place estimated at in excess of 1bnboe. Costs capitalised of US$8.1 million in relation to the drilling are classified as E&E assets and are expected to remain capitalised at the year end.

Refinancing

Subsequent to the 30 June 2017 period end, on 28 July 2017, Premier completed a comprehensive refinancing of its lending facilities (the "Refinancing") with the lenders under the Company's Revolving Credit Facility ("RCF"), Term Loan, Schuldschein and US Private Placement ("USPP") notes (together the "Private Lenders"), retail bonds and convertible bonds.

<u>The RCF, Term Loan, USPPs and Schuldschein notes.</u>

The Refinancing includes the following key amendments:

- Confirmation of total existing facilities of US$3.9 billion with drawn capacity preserved
- Alignment of final maturity dates to 31 May 2021 for all facilities
- Amendment of Premier's financial covenants, to be net debt to EBITDA cover ratio test to 8.5x until end 2017 reducing to 5.0x at the end of 2018, before returning to 3.0x from the beginning of 2019
- Interest cover ratio reduced to 1.50x before increasing to 3.0x in 2019
- Covenant net debt (which includes issued letters of credit) to be less than US$2.95 billion by end 2018
- A margin uplift of 1.5 per cent over existing pricing with an additional 1.0 per cent for the Schuldschein lenders
- Amendment fees of 1.0 per cent with an additional 0.5 per cent for the Schuldschein lenders
- Issuance of 67,234,316 equity warrants at an exercise price of 42.75 pence per share with a five year term. In addition, 21,186,736 synthetic warrants have been issued, which have a four year term
- Crystallisation of the make-whole on the USPPs on the effective date of the Refinancing totalling US$41.3 million, which will be added to the principal

The retail bonds

Substantially the same economic terms were agreed with the retail bondholders as the Private Lenders. The key terms are:

- Maturity date extended by six months to 31 May 2021
- Enhanced economics comprising an interest rate uplift of 1.5 per cent, amendment fees of 1.0 per cent and pro-rata participation in the warrant offering as above
- Issuance of 3,778,636 equity warrants at an exercise price of 42.75 pence per share with a five year term. In addition, 189,116 synthetic warrants have been issued, which have a four year term. These have been issued on the same terms as those issued to the Private Lenders

Convertible bonds

The terms of Premier's US$245 million convertible bonds were also amended. The key terms are:

- Maturity date extended to 31 May 2022
- Interest rate to remain at 2.5 per cent, to be paid, at the election of the company, either in new shares, or from the proceeds of sale of new shares or in cash
- Conversion price reset to 74.71 pence, with an exchange rate of £1:$1.228
- Issuance of 18,097,019 equity warrants representing 3 per cent of Premier's issued share capital at an exercise price of 42.75 pence/share, on the same terms as those issued to the Private Lenders
- No cash amendment fee
- Issuer right to require conversion at the conversion price at any time after one year if the value of Premier's shares is at least 140 per cent of the conversion price for 25 consecutive dealing days

Substantial modification

All of the above amendments became effective in July 2017 and therefore, the accounting for the above amendments will impact the 2017 full year financial statements but is not reflected in the 2017 Interim Results. It is expected that the above amendments will represent a substantial modification to the USPPs, the Schuldschein notes and the convertible bonds but are not expected to be a substantial modification to the RCF, Term Loan or retail bonds.

Under the requirements of IAS 39, if an existing financial liability is replaced by another from the same lender, on substantially different terms, or the terms of an existing liability are substantially modified, such an exchange or modification is treated as a de-recognition of the original liability and the recognition of a new liability such that the difference in the respective carrying amounts together with any costs or fees incurred are recognised in profit or loss. IAS 39 regards the terms of exchanged or modified debt as 'substantially different' if the net present value of the cash flows under the new terms (including any fees paid net of fees received) discounted at the original effective interest rate is at least 10 per cent different from the discounted present value of the remaining cash flows of the original debt instrument.

Costs and third party fees (expected to be in the region of c.US$150 million, including the USPP make-whole adjustment, amendment fee and adviser fees but excluding the fair value of the warrants), in relation to the Refinancing will be allocated to each individual facility and will be expensed to the income statement to the extent that they relate to the USPPs, Schuldschein notes or the convertible bonds. Certain third party costs in relation to the USPPs, Schuldschein notes and the convertible bonds of US$15.7 million have been recognised within finance costs in 2017 1H, with further costs of approx. US$65 million to be expensed in 2017 H2.

The carrying value of the debt in relation to the USPPs will be increased for the crystallisation of the make whole fee, whilst the carrying value for the Schuldschein will be recognised at its fair value as of the completion date. For the convertible bonds, the carrying value of the debt and equity components will be derecognised from the balance sheet and new debt and equity components will be recognised at their revised fair value as of the completion date to reflect the amended terms and conversion price.

To the extent that costs relate to the RCF, Term Loan and the retail bonds they will be capitalised against the carrying value of the debt and amortised prospectively over the revised maturity of the facility.

<u>Equity and synthetic warrants</u>

In total 89.1 million equity warrants and 21.4 million synthetic warrants have been issued. Both the equity and synthetic warrants will be recognised on the balance sheet at the completion date at their fair value as financial liabilities. To the extent that the warrants relate to debt facilities that will be substantially modified, the cost of issuing the liability will be recognised as an expense in the income statement. The outstanding instruments will be fair valued at each subsequent balance sheet date with gains or losses recognised in the income statement as finance costs. The aggregate fair value at the date of issue was estimated at US$47.7 million. The fair value of the instruments and subsequent changes in fair value will be excluded from financial covenant calculations.

Subsequent to the issue of the warrants, post the balance sheet date, 10.6 million equity warrants have been exercised.

Potential sale of Wytch Farm interests

On 22 August 2017, Premier announced it had reached agreement with a third party for the disposal of its entire 33.8 per cent working interest in the Wytch Farm field for proposed consideration of US$200 million. The transaction is subject to signature of a sale and purchase agreement and to lender approval, a process which is under way. Given the size of the consideration, the transaction is likely to be classified as a Class 1 transaction requiring shareholder consent.

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 2017 which comprises the condensed consolidated income statement, the condensed consolidated statement of comprehensive income, the condensed consolidated balance sheet, the condensed consolidated statement of changes in equity, the 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 Ireland) 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 2017 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

23 August 2017

Glossary

Non-IFRS measures

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

- **EBITDAX:** Earnings before interest, tax, depreciation, amortisation, impairment, exploration expenditure and reduction in decommissioning estimates. In the prior period it also excluded negative goodwill that arose on the E.ON acquisition. 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 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 short and long-term debt recognised on the balance sheet. This is an indicator of the Group's indebtedness, capital structure and a key metric used in the calculation of one of our financial covenants.

- **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

Half Year Results for the six months to 30 June 2017

WORKING INTEREST PRODUCTION BY REGION (unaudited)

	Six months to 30 June 2017 kboepd	Six months to 30 June 2016 kboepd
UK:		
Balmoral area*	2.6	1.7
Huntington**	15.6	8.8
Solan	7.3	0.3
Wytch Farm	4.5	5.1
Kyle	1.9	1.8
Babbage	3.2	1.2
Elgin Franklin	6.5	1.7
Other UK	4.0	1.6
	45.6	**22.2**
Indonesia:		
Natuna Sea Block A	12.9	12.5
Kakap	1.3	1.3
	14.2	**13.8**
Vietnam:		
Chim Sáo	15.5	16.7
	15.5	**16.7**
Pakistan:		
Bhit/Badhra	2.1	2.6
Kadanwari	0.8	1.1
Qadirpur	2.3	2.5
Zamzama	1.3	1.7
Mauritania:		
Chinguetti	0.3	0.4
	6.8	**8.3**
TOTAL	**82.1**	**61.0**

* Includes Balmoral, Brenda, Nicol and Stirling fields.

** Huntington at 100 per cent working interest since completion of the E.ON acquisition in 2016