PremierOil

Annual Results for the year ended 31 December 2016

Press Release

Tony Durrant, Chief Executive, commented:

"Premier has a robust business which continues to deliver excellent operational performance. In 2016 we achieved record production, maintained a low operating cost base and completed the highly value adding acquisition of E.ON's UK upstream portfolio. Significant progress was made on our operated Catcher project which will deliver a further step change in our production levels once on-stream later this year. Our complex refinancing has created uncertainty and volatility but is now nearing completion. Looking forward, our strong and growing cash flows will reduce our debt and in due course allow us to invest in new projects to deliver value for all our stakeholders."

Operational highlights

- Record production of 71.4 kboepd, an increase of 24% on the prior year (2015: 57.6 kboepd)
- High operating efficiency of 91%
- E.ON's UK upstream portfolio outperforming; payback now anticipated in 2017 1H
- Cost base reset; opex of $15.8/boe; Catcher capex reduced by 29%
- 2P reserves and 2C resources increased to 835 mmboe (2015: 758 mmboe)

Financial highlights

- Profit after tax of US$122.6 million (2015: loss after tax US$1.1 billion), including a tax credit of US$522.0 million
- Cash flows from operations of US$431.4 million (2015: US$809.5 million)
- Capex of US$678.1 million, significantly below budget
- Net debt of $2.8 billion as at year-end (2015: $2.2 billion); reduced since peak in Q3 2016
- Cash and undrawn facilities of US$593 million

Refinancing

- Total debt facilities preserved and maturities extended to 2021 and beyond
- Completion of refinancing expected by end of May, as previously guided
- As separately announced today, RCF, Term Loan, USPP and convertible bondholders have locked up to refinancing terms

Outlook

- 2017 production guidance maintained at 75 kboepd, before any contribution from Catcher
- 2017 opex and capex guidance of <$16/boe and US$390 million, respectively
- Catcher on schedule for 2017 first oil; improved field production profile now anticipated
- Greater Tolmount Area value significantly enhanced; offshore FEED commenced
- High impact Zama exploration prospect in Mexico to spud in Q2 2017
- Net cash flow positive at the forward curve in 2017; debt reduction accelerating once Catcher on-stream

ENQUIRIES

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A presentation to analysts will be held at 9am 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.

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CHIEF EXECUTIVE OFFICER'S REVIEW

Against what has been a challenging backdrop, Premier delivered a strong operational performance in 2016, resulting in record production of 71.4 kboepd, up 24 per cent on 2015, with production in the fourth quarter averaging over 80 kboepd. This was driven by contributions from the E.ON UK E&P (E.ON) portfolio and its successful integration into our UK business unit and new production from the Solan field. It was also helped by outperformance from our operated assets in Asia and high operating efficiency of 91 per cent across the portfolio.

UK production doubled during the year to 33.0 kboepd, underpinned by the new contributions from the E.ON portfolio and the Solan field. Production from the E.ON assets exceeded our acquisition case, contributing 17.1 kboepd to Group production over the eight months from 28 April to 31 December 2016. This was driven by outperformance from both the Huntington field and the long life Elgin-Franklin field where there is an ongoing infill drilling programme. Babbage and Wytch Farm also delivered a strong performance in 2016, underpinned by high operating efficiency of over 90 per cent. Profits from UK production continue to be sheltered by Premier's brought forward tax loss and allowance position.

First oil from the Solan field was achieved in April, marking a significant milestone for the Group. The second producer was brought on-stream in August. Production from the field has been lower than anticipated due to poor reservoir performance from the eastern area of the field. Most recently, a decision has been taken to contract a drilling rig to carry out the first planned workover of the first production well (P1) during the summer of 2017. The field is currently producing at around 9 kbopd with the P1 well on free-flow. This will be supplemented by ESP (pump) support following the summer workover.

Singapore demand for our Indonesian gas was strong during 2016. Our operated Natuna Sea Block A again captured a market share within its principal gas sales contract (GSA1) considerably ahead of its contractual share, while there was record demand for our gas under our second gas sales contract (GSA2). Across the border in Vietnam, performance from the Premier-operated Chim Sáo field exceeded expectations, both in terms of reservoir deliverability and operating efficiency, with a successful well intervention programme also helping to mitigate natural decline from the field. Significant upside remains at Chim Sáo and we look forward to executing an infill drilling programme in 2017 to help maximise production levels from the field. Chim Sáo reserves have again been revised upwards.

In 2017, we expect Group production to be higher at 75 kboepd, unchanged from previous guidance and before any contribution from Catcher which we expect to come on-stream later this year. The increase in production from our existing producing assets reflects a full year contribution from the E.ON portfolio and the Solan field, partially offset by natural decline in the Group's Pakistan fields and in certain of our UK fields.

2016 saw us increase our proven and probable (2P) reserves, on a working interest basis, to 353 mmboe (2015: 332 mmboe) and our total 2P reserves and 2C resources to 835 mmboe (2015: 758 mmboe). The increase in our 2P reserves was driven by our acquisition of the E.ON portfolio and an upward revision in our estimate of 2P reserves at Chim Sáo following better than anticipated reservoir performance and an extension to forecast field life. These additions more than offset the impact of 2016 production and a downward revision to our Solan 2P reserve estimates due to poorer than anticipated reservoir performance. The increase in our 2C resources of 56 mmboe was principally as a result of the 50 per cent interest in the Tolmount field acquired with the E.ON portfolio.

Premier's operating costs were US$15.8 boe (2015: US$15.5/boe), significantly below budget as a result of ongoing cost reduction initiatives, successful contract renegotiations and strict management of discretionary spend. With a large portion of our costs Sterling denominated, we also benefitted from the weaker Sterling Dollar exchange rate. Significant reductions in operating costs have been achieved over the last two years. While it is likely to be difficult to push through further contractor rate reductions given current service sector margins, additional cost reductions will come from other approaches such as collaboration and efficiency savings. Premier instigated such initiatives in 2016 and expects to build on these during 2017.

The progress that has been made on the Catcher project during 2016 and the 29 per cent capex reduction secured to date is testament to the hard work, skill and capability of the project team and our contractors. All nine wells drilled to date have come in at or above prognosis and we now expect to deliver an improved production profile from a reduced well count. All of the key elements of the subsea equipment have been installed, ready for the arrival of the FPSO. The construction of the FPSO is largely complete and the focus is now on completing the yard-based pre-commissioning and commissioning work scopes ahead of a mid-year sailaway. Premier continues to target production start-up for later this year. Once on-stream the Catcher field, with an expected plateau rate of over 50 kboepd, will provide another step change in our production levels, generating enhanced, tax-free cash flows for the Group.

With rising production and over 700 mmboe of discovered but undeveloped 2P reserves and 2C resources, we have significant optionality within our portfolio to maintain and grow production and deliver value for our stakeholders. In a depressed commodity price environment, the lower cost projects with a rapid pay-back have been prioritised. For 2017, this includes an infill drilling programme in Vietnam, which has a payback of less than six months, as well as incremental projects in Indonesia, which were sanctioned post period end by Premier's Board, to backfill our existing gas sales contracts.

The Tolmount field is looking increasingly attractive and is likely to provide our next phase of growth. It meets our economic thresholds even at low gas prices, accelerates the use of our UK tax losses and allowances and fits well with our financial profile. There is also significant upside, currently estimated at over 400 Bcf, beyond the main development in the Greater Tolmount Area. The development concept was selected post period end with a nine month front end engineering design (FEED) programme now underway.

Premier's largest pre-development project is Sea Lion Phase 1 in the Falkland Islands. The Sea Lion project as a whole has the potential to be transformational for the Group with around 400 mmboe (net to Premier) to be developed over several phases. FEED on Sea Lion Phase 1 was largely completed in 2016 and saw the breakeven cost of the project lowered significantly from US$55/bbl to less than US$45/bbl, while the capex to first oil was reduced from US$1.8 billion to US$1.5 billion. With the economics of the project considerably improved, Premier is now working to secure a funding solution for the development. Commercial and fiscal discussions with the Falkland Islands Government are also progressing.

In light of current capital allocation priorities, Premier's exploration activities have reduced considerably and our portfolio has become more concentrated on a few key proven but under-explored plays or basins. In particular, we exercised our option to increase our equity stake to 25 per cent in Block 7 in Mexico at the end of 2016 and expect to drill the large amplitude-supported Zama prospect there in Q2 2017. We also exited our 35 per cent interest in Block FZA-M-90 in the Foz do Amazonas Basin in December (subject to ANP approval) enabling us to focus our Brazilian exploration efforts on our core area position in the Ceará basin, where we have acquired 4,000 square kilometres (km^2) of fast track seismic data.

One of the key achievements of the year was our successful acquisition and integration of the E.ON portfolio which builds on our track record of acquiring assets at low points in commodity cycles. The acquisition significantly enhanced the Group's UK North Sea asset base and creates considerable operating, cost and tax synergies within our existing UK business. At a price of US$120 million, the acquisition is expected to reach pay-back in 2017 1H, earlier than anticipated, and we now value the E.ON portfolio at very substantially more than the acquisition cost. This is partly as a result of higher commodity prices but also as a result of improving asset profiles, due to production outperformance or, as in the case of Tolmount, following further work on the project.

We continue to look to dispose of non-core assets, such as our Pakistan business or certain assets from the E.ON portfolio where formal sales processes are ongoing. In addition, we will look to reduce our equity interests in certain projects where we can realise upfront cash to accelerate debt reduction.

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The acquisition of the E.ON portfolio, via debt funding, and the prolonged period of depressed commodity prices saw us enter discussions with our various lending groups in 2016 to undertake a full refinancing of our existing facilities. The number of parties involved and the fact that most of our lenders rank pari passu (which gave rise to complex inter-creditor issues) meant that those negotiations took longer than anticipated. Nonetheless, we are close to locking up all of our lending groups to the amended terms. The lock up of the creditors to the terms of the refinancing marks a major milestone for Premier with the refinancing defining future reduction of debt but also allowing us to plan for future investment in selective new projects. Final completion of the refinancing is targeted for the end of May 2017.

As at year end, we retained cash and undrawn facilities of US$593 million. This was as a result of record production together with the benefit of our hedging programme, low operating costs secured by ongoing cost reduction initiatives and delivery of a capital investment programme below budget. Net debt stood at $2.8 billion at the end of 2016, down from its peak reached in Q3 2016, and we expect to continue to be net cash flow positive (after capex and planned disposals) at current oil prices. This debt reduction will accelerate once the Catcher field is on-stream.

As we enter 2017 with improving commodity prices, our focus is on maintaining our strong production performance and competitive cost base while delivering our operated Catcher project on schedule and below budget. In order to plan and protect our cash flows, we will continue to hedge our oil and gas production with the aim of locking in oil prices at levels at which we will be free cash flow positive. Our positive cash flow will be prioritised towards reducing our debt so as to enable the Group to achieve a leverage ratio of 3x EBITDA by the end of 2018 and, where future cash flows allow, to selectively invest in new projects to deliver future value for all stakeholders.

Tony Durrant
Chief Executive Officer

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BUSINESS UNIT REVIEWS

UNITED KINGDOM

The UK delivered a step change in production in 2016, achieving a year-end exit rate of over 45 kboepd, more than double that of 2015. This was driven by high operating efficiency, a contribution from the E.ON assets (which continue to exceed expectations) and new Solan production. Looking ahead, the Catcher project remains on schedule for first oil in 2017 with total capex now estimated at $1.6 billion, 29 per cent lower than at sanction, while the development scheme for the Tolmount gas project was selected post period end.

Production

Production from Premier's UK fields averaged 33.0 kboepd (2015: 16.7 kboepd), double that of 2015. Production from the E.ON assets exceeded the Group's acquisition case of 15 kboepd, averaging 17.1 kboepd for the eight months from 28 April 2016 to 31 December 2016. Production from the operated Huntington field averaged 10.8 kboepd (2015: 6.2 kboepd) during 2016. The step up in production reflects Premier's increased equity position to 100 per cent (due to the acquisition of the E.ON assets at the end of April 2016 and the default of the minority partners in 2015), high operating efficiency of over 90 per cent and strong reservoir performance. Premier is currently in discussions with Teekay, the owner of the FPSO, to extend the firm charter period beyond April 2018 with a revised rate structure.

Production from the non-operated Elgin-Franklin fields, which was acquired as part of the acquisition of the E.ON assets, increased during the year, benefitting from an ongoing infill drilling campaign and strong winter gas demand, averaging 5.5 kboepd for the eight months from 28 April to 31 December 2016 and 6.5 kboepd in Q4 2016. This strong performance was tempered by periodic oil export restrictions placed on the field over the summer as a result of ongoing maintenance on the Forties Production System (FPS). The non-operated Glenelg field (Premier 18.57 per cent), a satellite field within the Elgin-Franklin area, came back on-stream at the end of May following a successful well workover of the G10 well. The field was producing over 20 kboepd (gross) when not impacted by export restrictions but was subsequently shut in in late September as a result of a blocked scale inhibitor line. A remediation programme is being implemented by the operator to reinstate production. The Premier-operated Babbage field, acquired as part of the acquisition of the E.ON portfolio, also outperformed, producing consistently at rates of above 3 kboepd driven by high uptime of more than 90 per cent and continued good reservoir performance. The platform is in the process of moving to normally unmanned operations which is expected to reduce field operating costs in 2017. Post period end, a successful well intervention campaign was undertaken to maximise production from the Babbage field.

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First oil from the Solan field was achieved on 12 April 2016 and the second producer was brought on-stream on 18 August 2016. Average production for 2016 was impacted by poorer than expected reservoir performance in the eastern part of the field which is limiting water injection and production rates from the second producer (P2). A decision has been taken to contract the Transocean Spitzbergen, which has been working in the area close to Solan, to install two ESPs in P1 following the failure of the existing single ESP during February. The planned work programme will restore P1 production to at least 10 kbopd from mid-year. The field is currently producing around 9 kbopd with P1 on free flow. Meanwhile, a number of options continue to be studied to increase water injection into the reservoir with the aim of supporting higher production levels. Premier has already implemented some of the more short-term, lower capex projects, such as increases to platform pump capacity. While incremental production increases can be gained from such remedial work, it is possible that another well or a side-track would be required in order to gain a more material uplift in production rates and improve recovery. The Solan team are monitoring production behaviour to better delineate recovery from the existing wells and to define the scope of a potential drilling programme for 2018. Operating efficiency of the facilities was good during 2016 and, to date, eight tanker liftings have been successfully completed.

Production from the Premier-operated Balmoral area averaged 2.1 kboepd (2015: 3.1 kboepd), impacted by a commercial disagreement between partners at the start of 2016 (subsequently resolved) and intermittent oil export restrictions due to FPS maintenance. Operating costs were US$49 million (2015: US$64 million), down 23 per cent on the prior period, benefitting from a weaker Sterling Dollar exchange rate and as a result of a focused cost reduction programme, offshore and onshore.

Production from the non-operated Wytch Farm field averaged 5.1 kboepd (2015: 5.2 kboepd), benefitting from the well maintenance work carried out in the second half of 2015 which partially offset modest reservoir decline. The field operator delivered significant cost savings during 2016 which resulted in operating costs of US$26m net (2015: US$32m), down 19 per cent on the prior year. Production from the non-operated Kyle field was maintained at 2.0 kboepd (2015: 2.0 kboepd), slightly ahead of expectations.

UK unit operating costs for the year were US$24/boe (2015: US$ 30/boe), driven by start-up and acquisition of lower opex fields such as Solan, Elgin-Franklin and Babbage and further cost reductions across Premier's existing UK portfolio, particularly at Wytch Farm and Balmoral. This figure includes certain one-off costs following on from the acquisition of the E.ON portfolio. Going forward, UK unit operating costs are expected to trend downwards towards US$20/boe as Premier benefits from a full annual contribution from the lower opex Elgin-Franklin and Solan fields and as higher opex fields are decommissioned.

Development

Catcher

Good progress was made on the Premier-operated Catcher project during 2016 which remains on schedule to deliver first oil in 2017 2H. 2016 saw the total capex estimate for the project reduce to $1.6 billion, a 29 per cent reduction on the original sanctioned estimate. Savings were secured across subsea and drilling activities and as a result of the lower Sterling Dollar exchange rate. Premier's forward cost exposure has reduced significantly with remaining capex to first oil of around $100 million (net to Premier), the majority of which relates to the ongoing drilling programme.

The 2016 subsea installation campaign commenced in April and saw the successful installation of the risers, bundles, towheads, manifolds, midwater arches along with the buoy and mooring system. Hook-up of all of the risers and umbilicals was also completed during 2016. 14 different construction vessels were deployed on the field over several phases while, at the peak of activities in May, there were seven vessels present in the field. Final spool tie-ins were completed in November, concluding the planned 2016 subsea campaign under budget. The major elements of the subsea campaign are now complete with only short campaigns required in 2017 to tie-in wells as they become available from the drilling programme and to support commissioning operations once the FPSO has been installed.

Drilling activities using the Ensco 100 rig have continued to yield positive results. During 2016, CCP3 and CTP1 on the Catcher template, BP3 and BP5 on the Burgman template and VP2 and VP3 on the Varadero template were completed, validating Premier's expected reservoir interpretation from the three drill centres. VP4 on the Varadero template was completed post period end. Based on test results to date, the length of net pay encountered by the seven production wells has been overall 30 per cent longer 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 also forecasts a reduced well count from that envisaged at sanction.

Fabrication of the Catcher FPSO hull and topsides was completed in Asia with the Stern Terra Block and Forward Terra Block successfully delivered to the Keppel Benoi yard in Singapore in June and July respectively. The hull mating operation was carried out and the welding of the two blocks completed in August. Fabrication of all of the topside modules has been completed with the final topside unit lifted onto the vessel in November. The construction phase of the FPSO is now largely complete and the focus is now on final integration and the completion of yard-based pre-commissioning and commissioning work scopes. Sailaway is expected mid-year with Premier continuing to target oil production start-up for later this year.

Pre-development

Premier acquired a 50 per cent operated interest in the Greater Tolmount Area where the Group sees the potential for the development of up to 1 Tcf, including the fully appraised Tolmount main structure of 540 Bcf and upside at Tolmount East and Tolmount Far East, estimated to hold 220 Bcf and 150 Bcf of gas resource respectively. Tolmount will provide the next phase of growth for Premier in the UK, with significantly improved economics benefitting from a higher gas price than the E.ON acquisition case.

During 2016, Premier carried out conceptual studies and engineering work on a number of development options for the Tolmount main structure. This included optimisation of the project from a subsurface, facilities, pipeline, host terminal and commercial perspective. 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. The offshore FEED contracts were awarded post period end and FEED is expected to take 9 months with project sanction targeted for Q1 2018. It is estimated that capex to first gas will be around US$550 million, although Premier is currently engaging with the contractor market with a view to enhancing returns and reducing further upfront capex on the project. In addition, following unsolicited offers of interest from a number of parties, Premier has instigated a process to identify possible investors for a 20 per cent interest in the Tolmount project.

Exploration

The Laverda/Slough prospect, near the Catcher area was drilled in April 2016. The commitment well encountered 13 feet of net oil bearing Tay sands at Laverda, in line with pre-drill expectations, but did not encounter any indications of hydrocarbons in the deeper, high risk Slough prospect.

In July, the Ocean Valiant rig spudded the Bagpuss prospect in the Outer Moray Firth. The well encountered 41 feet of hydrocarbon-bearing sand within a 68 feet hydrocarbon column. The well was plugged and abandoned. Premier subsequently sold its interest in the licence to Reach Halibut Limited.

In December 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; 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.

Premier continues to actively manage its UK exploration portfolio with nine UK licences relinquished or sold in 2016 and associated cost savings realised. While Premier has relinquished much of E.ON's exploration acreage, some of its Southern North Sea prospects are attractive. Premier plans to mature the work programmes on these select licences during 2017, along with further exploration prospects on its current production licences.

INDONESIA

The Premier-operated Natuna Sea Block A fields outperformed in 2016 delivering a robust production performance of 13.0 kboepd, up 6 per cent on 2015, underpinned by an increased market share of 44 per cent within GSA1 and strong Singapore demand for gas deliveries under GSA2. This, together with low operating costs of US$8/boe, resulted in the Indonesian business unit generating strong positive net cash flows for the Group.

Production and development

Net production from Indonesia in 2016 on a working interest basis increased to 14.3 kboepd (2015: 13.9 kboepd), with higher production from the Premier-operated Natuna Sea Block A fields offset, in part, by lower production from the non-operated Kakap fields. Operating efficiency remained high at over 90 per cent.

	Gas supply by contract					
	GSA1		GSA2		GSA5	
BBtud (gross)	**2016**	2015	**2016**	2015	**2016**	2015
Anoa[1]	**132**	133	**–**	–	**–**	–
Gajah Baru[2]	**–**	–	**94**	77	**11**	13
Total Block A	**132**	133	**94**	77	**11**	13
Kakap	**17**	23	**–**	–	**–**	–
Total	**149**	156	**94**	77	**11**	13

[1] Includes production from the Pelikan field.

[2] Includes production from the Naga field.

Premier sold an average of 237 BBtud (gross) (2015: 223 BBtud) from its operated Natuna Sea Block A fields during 2016. Singapore demand for gas sold under GSA1 remained robust, averaging 297 BBtud (2015: 311 BBtud) during 2016. Premier's Anoa and Pelikan fields delivered 132 BBtud, capturing 44 per cent (2015: 43 per cent) of GSA1 deliveries, above Natuna Sea Block A's contractual share of 41 per cent. Natuna Sea Block A's contractual share for 2017 has been increased to 47 per cent.

Gajah Baru and Naga delivered record production of 94 BBtud under GSA2, up 22 per cent on the prior year, representing 100 per cent nomination delivery by Premier. Gas deliveries from Gajah Baru and Naga under the Domestic Swap Agreement (DSA), which resumed in September following an extension of the DSA to end December

2016, averaged 11 BBtud (2015: 13 BBtud). The Gajah Baru compressor reconfiguration project, aimed at maximising deliverability from the Gajah Baru, Pelikan and Naga fields, was successfully completed in December 2016 and will extend plateau production from these fields.

Gas sales from the non-operated Kakap field averaged 17 BBtud (2015: 23 BBtud) while gross liquids production was 2.7 kbopd (2015: 3.5 kbopd), reflecting natural decline from existing wells. Gross liquids production from the Anoa field was stable at 1.4 kbopd (2015: 1.4 kbopd), underpinned by successful well intervention work.

Premier continues to benefit from a low cost base in Indonesia, as a result of an on-going cost reduction campaign. Based on current production levels, Natuna Sea Block A is well placed to deliver operating costs of around US$8/boe into the medium term.

During 2016, FEED was completed on the Bison, Iguana and Gajah Puteri (BIGP) fields which marks the next generation of Natuna Sea Block A projects to support Premier's long-term gas contracts into Singapore. Premier's Board sanctioned BIGP post period end. An invitation to tender for long lead items has been issued and delivery of first gas is targeted for Q3 2019.

Premier has identified several infill drilling candidates at Gajah Baru with drilling currently modelled to commence in 2018 while preparations are underway to recomplete the WL-5x well which made the Lama discovery under Anoa in 2012 and to tie it into production in Q3 2017.

Evaluation of potential development scenarios for the 2014 Kuda Laut and Singa Laut discoveries on the Premier operated Tuna Block is ongoing. These include gas offtakes via the West Natuna Transportation System to Singapore and Indonesia or through existing infrastructure in Vietnam. Post period end, Premier was granted a three-year extension to the exploration period of the licence. This will allow time for Premier to undertake further appraisal drilling and also to establish a commercial development concept for the field, ahead of submitting a Plan of Development.

Exploration and appraisal

Premier continues to mature a number of Lama Play leads and prospects to a drillable status on its operated Natuna Sea Block A acreage and seismic reprocessing is currently scheduled for 2017 to enhance the seismic imaging over the Lama Play area.

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VIETNAM

A robust production performance, combined with continued low operating costs, resulted in the Vietnam business generating net positive operating cash flows during 2016. Further, Chim Sáo's remaining 2P reserves were materially increased at the end of the year as a result of better than expected reservoir performance and the lower lease rate secured for the Chim Sáo vessel resulting in an extended field life.

Production

Production from the Premier-operated Block 12W, which contains the Chim Sáo and Dua fields, averaged 16.2 kboepd (2015: 16.9 kboepd) with high uptime, better than expected reservoir performance and a successful well intervention programme helping to mitigate natural decline from the fields.

Since taking over direct management of production operations in 2015, Premier has prioritised root-cause analysis of all events that lead to loss of production. This knowledge has improved the efficiency of planned maintenance programmes, enhanced the availability of key systems and enabled competency development for the crew. The outcome is that Chim Sáo operating efficiency exceeded 90 per cent in 2016.

The 2016 well intervention programme included bringing a deep reservoir on to production in the Chim Sáo North West area and the reservoir stimulation of three oil wells and a water injector well in the main field area. Planning is underway for a programme of further well stimulations in 2017. In addition, a two-well infill drilling programme, scheduled to commence in August 2017, will further help to maximise the field's production levels.

During 2016, Premier has continued to review all of its contracts with the aim of securing cost reductions and efficiencies throughout its Vietnam operation. Notably, in December 2016, Premier in its capacity as operator of Block 12W completed a revised FPSO charter party agreement securing a reduction in the Chim Sáo FPSO lease rate effective from 1 November 2015 and an extension to the firm charter period.

Strong 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 2016. In addition, as a result of the strong reservoir performance from the field to date and the anticipated extended field life facilitated by a lower FPSO lease rate, Premier has revised upwards its estimates of Chim Sáo's remaining net 2P reserves by 13 mmboe to 31 mmboe.

PAKISTAN

Premier's Pakistan business has performed significantly ahead of forecast in 2016 with net cash flow more than twice the budgeted level. The average realised price was $2.8/mscf while operating costs remained low at around $0.6/mscf.

Production and development

Production in Pakistan averaged 7.5 kboepd (47.4 mmscfd) (2015: 9.7 kboepd (60.2 mmscfd)), from Premier's six non-operated producing gas fields. The fall in production reflects natural decline in all of the gas fields. This was partially offset by a successful well intervention campaign at the Zamzama field which significantly arrested the decline rate of this field. As a result, production from the Zamzama field was significantly ahead of expectations for the period and underpinned the outperformance of the Pakistan business unit.

Mmscfd	**2016**	2015
Bhit	**8.4**	11.4
Badhra	**5.8**	7.7
Qadirpur	**16.1**	17.8
Kadanwari	**5.4**	9.8
Zamzama	**11.3**	13.0
Zarghun South	**0.4**	0.5
Total	**47.4**	60.2

Further work is planned for 2017 to offset the natural decline at the Badhra and Kadanwari fields. A well intervention programme, consisting of three wells, is planned for the Badhra field while a well intervention programme as well as two development wells are planned for the Kadanwari field.

Portfolio management

During 2016, Premier agreed terms with a preferred bidder for the sale of its Pakistan business. However, the bidder was unable to put in place the necessary funding arrangements and the exclusivity period ended. Premier reopened the process to a limited group of potential buyers. The economic date of the transaction is now expected to be 1 January 2017 with Premier retaining 2016 net cash flows.

MAURITANIA

Production and development

Production from the Chinguetti field averaged 368 bopd (2015: 415 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 in 2017. To this end, the operator submitted an abandonment and decommissioning plan to the Government of Mauritania in June 2016.

THE FALKLAND ISLANDS

FEED for the Premier-operated Sea Lion Phase 1 project progressed well during 2016. The estimated breakeven price of the project is now less than $45/bbl, down from $55/bbl at the end of 2015. The focus is now on progressing funding alternatives for the project.

Development

During 2016, Premier undertook FEED on the Sea Lion Phase 1 development. Phase 1 is expected to recover 220 mmbbls from the north-east and north-west sections of the field located in the PL032 licence area. FEED contracts were awarded to SBM Offshore for the FPSO, Subsea 7 for the subsea installation, NOV for the flexible flowlines and One Subsea for the subsea production system.

Over the course of 2016, the four main contractors worked collaboratively with Premier and also with candidate well services and logistics contractors to optimise the facilities design and installation methodology. This included the optimisation of the single drill centre subsea layout to reduce installation costs. As a result of this work, Premier has reduced its pre-first oil capex estimate from $1.8 billion to $1.5 billion.

Premier has also seen significant reductions in its estimates of field support services, including supply boats, helicopters and shuttle tankers. Consequently, field operating costs for Sea Lion are now estimated at $15/bbl, down from over $20/bbl, while the total project breakeven cost has reduced to just below $45/bbl from $55/bbl.

Premier has assembled bid packages for drilling, subsea production systems and certain logistics items, which are ready to be issued to the market when appropriate in order to convert current proposals, derived through extensive market engagement, into binding agreements.

In 2016, Premier secured approval from the Falkland Islands Government for an extension to the Sea Lion Discovery Area licence to April 2020. The focus is now on securing an appropriate funding solution for Phase 1 of the project.

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. A subsequent Phase 2 development will recover a further 300 mmbbls from the remaining reserves in PL032 and the satellite accumulations in the north of the adjacent PL004. There is also a further 250 mmbbls of low risk, near field exploration potential which could be included in either the Phase 1 or Phase 2 developments. Phase 3 will entail the development of the Isobel/Elaine fan complex in the south of PL004, subject to further appraisal drilling.

Exploration

In January 2016, Premier completed its exploration programme in the North Falklands Basin with the successful re-drill of the Isobel Deep well. The well confirmed the oil discovery encountered in the original Isobel Deep well and, in addition, discovered new hydrocarbons in additional sandstones.

EXPLORATION

Premier has continued to reshape and focus its exploration portfolio on under-explored but proven hydrocarbon basins with the potential to develop into new business units in 2018 and beyond. Priority is being given to lower cost operating environments whilst reducing exposure elsewhere. Premier plans to drill the large Zama structure in Mexico in Q2 2017.

MEXICO

During 2016, the Mexico Joint Venture reprocessed the existing 3D seismic data and matured a number of prospects across its Blocks 2 and 7 in the Sureste Basin as candidates to be drilled in 2017 and 2018. In particular, Premier and its partners completed the technical evaluation of their Block 7 acreage including the amplitude-supported Zama prospect which has a well-defined flat spot, an indicator of potential hydrocarbons. A rig has been contracted to drill the low-risk Zama Prospect in the second quarter of 2017 with the overall Zama structure estimated to have a P90-P10 gross unrisked resource range of 100-500 mmboe (the majority of which is on Block 7).

Premier currently holds a carried 10 per cent interest in Block 2, whilst on Block 7 Premier elected to exercise its option to increase its equity to a 25 per cent paying interest in December 2016, subject to the Mexican government (CNH) approval. Premier continues to evaluate opportunities for growth in Mexico.

BRAZIL

Premier received 4,000km^2 of fast-track seismic data across all three of its Ceará Basin blocks in 2016. This data is being interpreted to map promising plays and prospects for future drilling locations on the blocks. Final processed broadband seismic data is due to be delivered in April 2017 and well locations will be selected from this during the course of 2017.

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. In 2016, the installation of offshore buoys and moorings for a collaborative meteorological and oceanographic data campaign was completed to gather the data required for obtaining drilling licences in the basin. This data gathering operation is one of many joint operator initiatives that Premier is either participating in or leading in the Ceara basin, helping to reduce costs.

In August 2016, Premier obtained a licence extension from the Brazilian Government (ANP) to July 2019 on its operated licences CE-M-717 and 665. A similar extension was also obtained by Total, Operator of licence CE-M-661. The extensions will enable Premier to realise further cost synergies with other operators in the Equatorial Margin with drilling operations planned for the first half of 2019.

In the Foz do Amazonas basin, Premier completed its evaluation of new 3D seismic data across block FZA-M-90 and decided to exit. Premier's 35 per cent interest in the block was transferred to operating partner Quieroz Galvão E&P. The farm-out agreement for this block was completed in December 2016 and is awaiting the final approval of the ANP.

Portfolio management

Premier has continued to focus its exploration efforts on under-explored but proven hydrocarbon basins. In light of current capital allocations, Premier's exploration portfolio has become increasingly concentrated. Over the course of 2016, Premier successfully relinquished or sold 16 licences, including a number of licences acquired as part of the acquisition of the E.ON portfolio. A further 11 licences are scheduled for relinquishment subject to government approvals. In particular, Premier exited its 35 per cent interest in Block FZA-M-90 in the Foz do Amazonas Basin in December (subject to ANP approval) enabling the Group to focus its Brazilian exploration efforts on its core licences in the Ceará basin.

Premier has also successfully exited its position in Iraq (subject to final government approval) and the Saharawi Arab Democratic Republic.

PremierOil

Annual Results for the year ended 31 December 2016

Financial Review

Context

Consistent with the last two years, 2016 continued to provide a challenging macro-economic environment. Against this backdrop, however, operational performance remained strong with production for the full year averaging 71.4 kboepd and averaging more than 80kboepd during Q4 2016. This increase was driven by the successful completion of the acquisition of the E.ON portfolio and first oil from the Solan field. We continue to actively manage operating costs which, at $15.8/bbl, are below what had been budgeted for the year, benefitting from tight cost control, a weakened GBP exchange rate and high operating efficiency of over 90 per cent across the portfolio.

In addition, during 2016 we commenced discussions with our lending groups on the terms of our existing finance facilities. In February 2017 we reached an agreement in principle with our lender groups on revised terms. The revised terms include amendments to our financial covenants, deferral of final maturity dates to May 2021 and beyond and a margin uplift on interest payable to the lenders. The process of finalising the revised refinancing and implementation documents is ongoing and completion of the refinancing is expected by the end of May 2017. Once finalised, the agreed terms will give Premier sufficient liquidity to operate in the current oil price environment, deliver our sanctioned projects and to continue to invest in the wider business at appropriate levels of equity interests.

Business Performance

Business performance (US$ million)	**2016**	**2015**
Operating loss	**(145.9)**	(707.8)
Amortisation and depreciation	**340.3**	326.7
Impairment charge on oil and gas properties	**556.2**	1,023.7
Exploration expense and pre-licence costs	**58.4**	109.0
Reduction in decommissioning estimates	**(75.7)**	–
Acquisition of subsidiaries:		
Excess of fair value over consideration	**(228.5)**	–
Costs related to the acquisition	**21.6**	–
EBITDAX	**526.4**	**751.6**

EBITDAX for the year was US$526.4 million compared to US$751.6 million for 2015. The lower EBITDAX is mainly due to lower realised oil prices, including a reduction in the value of our oil hedges settled in the year, partially offset by an increase in volumes lifted following the acquisition of the E.ON assets and first oil from Solan.

Acquisition of the E.ON assets

In April 2016, Premier completed the acquisition of the E.ON assets for cash consideration of US$135.0 million, including working capital adjustments. The acquisition was accounted for as a business combination under the requirements of IFRS 3 Business Combinations and the assets and liabilities acquired have been fair valued on the date of completion utilising Premier's corporate assumptions for oil and gas prices, reserves estimates and discount rates. The fair value of the net assets acquired was US$363.5 million resulting in an excess of fair value over consideration of US$228.5 million. The excess of fair value over consideration has arisen primarily due to E.ON's strategic decision to exit the UK and Norway E&P sectors and Premier's willingness to take over the entire UK upstream operation. Separately, costs related to the acquisition of US$21.6 million have been recognised in the period. This is made up of acquisition costs of US$5.6 million and the recognition of a post-acquisition settlement of US$16.0 million related to redundancy costs.

Income statement

Production and commodity prices

Group production on a working interest basis averaged 71.4 kboepd compared to 57.6 kboepd in 2015. Higher production year-on-year is a result of first oil from the Solan asset and the uplift in production from the E.ON assets acquired in the year. Entitlement production for the period was 66.1 kboepd (2015: 53.4 kboepd).

Premier realised an average oil price for the year of US$44.1/bbl (2015: US$52.6/bbl). Post hedging, realised oil prices increased to US$52.2/bbl (2015: US$79.0/bbl).

In the UK, average prices achieved for National Balancing Point gas ("NBP") were 41.5 pence/therm pre-hedging and 47.6 pence/therm post-hedging. Average gas prices for the Group's non-UK assets were US$4.6 per thousand standard cubic feet (mscf) (2015: US$5.9/mscf). Gas prices in Singapore, linked to high sulphur fuel oil (HSFO) pricing and in turn, therefore, linked to crude oil pricing, averaged US$7.8/mscf (2015: US$8.0/mscf) pre-hedging, and increased to US$8.6mscf 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 (2015: US$3.9/mscf).

Total sales revenue from all operations fell to US$983.4 million (2015: US$1,067.2 million), due to the fall in average realised prices post-hedging, offsetting higher year-on-year production.

Operating costs

Cost of sales comprises cost of operations, change in lifting position, inventory movement, royalties and amortisation and depreciation of property, plant and equipment ('PP&E'). Cost of sales for the Group was US$767.1 million for 2016, compared to US$661.0 million for 2015.

Operating costs	**2016**	**2015**
Cost of operations (US$ million)	**412.8**	323.6
Unit cost of operations ($ per barrel)	**15.8**	15.5
Amortisation of oil and gas properties (US $million)	**332.2**	315.9
Unit amortisation rate ($ per barrel)	**12.7**	14.8

As a result of the weaker sterling exchange rate and continued cost savings across the business, operating costs of $15.8/bbl are 10 per cent below budget. We have maintained costs at these low levels due to improved operating efficiency across several of the Group's assets and continued reductions in underlying cost from further contract reductions with suppliers, including our revised FPSO arrangements on Chim Sáo.

Impairment of oil and gas properties

An impairment charge of US$652.2 million (pre-tax) has been recognised in the income statement relating to the Solan field in the UK North Sea (US$443.7 million post-tax). The impairment charge is driven by a reduction in the 2P reserves expected to be recovered from the asset over its economic life and a US$5/bbl reduction in the Group's long term oil price assumption to US$75 (real)/bbl. The impairment charge is partially offset by the recognition of a reversal of impairment credit of US$96.0 million, pre-tax (US$60.0 million post-tax). The reversal has been recognised on the Huntington and Kyle assets in the UK, the Chim Sáo asset in Vietnam and the Kadanwari asset in Pakistan. The reversal of impairment is principally caused by an increase in the short term oil price assumption, based off the forward curve as at the balance sheet date, and an increase in Chim Sáo 2P reserves. After recognition of a net impairment charge of US$556.2 million (US$383.7 on a post-tax basis) there is US$2,726.2 million capitalised in relation to PP&E assets and US$240.8 million for goodwill.

Revision in decommissioning estimates

The weakness in sterling dollar exchange rate at 31 December has been the principal cause of a US$75.7 million gain being credited to the income statement in respect of revised decommissioning estimates. Whilst any positive foreign exchange revision would generally have been credited to the decommissioning asset in the balance sheet, the majority relates in this case to late life UK assets which have been fully depreciated. As such, a significant portion of this revision has been taken as a credit to the income statement in the period.

Exploration expenditure and pre-licence costs

Exploration expense and pre-licence expenditure costs amounted to US$58.4 million (2015: US$109.0 million). This includes the write-offs relating to the Laverda, Slough and Bagpuss prospects drilled in 2016 and costs that had been capitalised in relation to the Foz licence interest in Brazil. After recognition of these expenditures, the exploration and evaluation asset remaining on the balance sheet at 31 December 2016 is US$1,011.4 million, principally for the Sea Lion and Tolmount assets.

General and administrative expenses

Net G&A costs to the Group of US$24.1 million (2015: US$14.4 million) increased year on year due to the inclusion of E.ON's unallocated G&A for the period since the completion of the acquisition. Underlying G&A, without the acquisition, would have fallen year on year and total net G&A costs to the group in 2017 are expected to return to 2015 levels.

Finance gains and charges

Interest revenue and finance gains reduced to US$13.2 million from US$40.7 million in 2015. The principal reason for this reduction is that, following the acquisition of the remaining share of Solan in 2015, interest receivable is no longer being recognised on the loan to JV partner. Gross finance costs, before interest capitalisation, have increased from US$219.4 million to US$293.7 million. Interest costs capitalised decreased from US$58.8 million to US$34.0 million reflecting the finalisation of the Solan development.

Taxation

The Group's total tax credit for 2016 is US$522.0 million (2015: US$241.1 million charge) which comprises a current tax charge for the period of US$42.0 million and a non-cash deferred tax credit for the period of US$564.0 million. The high effective tax rate for the year is significantly impacted by a number of UK specific items. The most significant of these is a tax credit of US$455.8 million due to recognition of UK tax losses and allowances in the period, driven by an anticipated increase in future profitability from the acquisition of the E.ON assets. This has been partially offset by a charge of US$161.2 million in relation to the supplementary charge rate from 20 per cent to 10 per cent during the year, with the adverse impact of this change mitigated by US$27.1 million as the rate applicable to the reversal of certain temporary differences on decommissioning remained unchanged. A credit of US$61.0m has also been recognised for a ring fence expenditure supplement claim made during the year in the UK.

Finally, an element of the Group's UK impairment charge for the year does not attract a deferred tax offset which reduces the associated credit by approximately US$63.2 million. After adjusting for the net impact of the above items of US$319.1 million, the underlying Group tax charge for the period is a credit of US$202.9 million and an effective tax rate of 52 per cent.

The Group has a net deferred tax asset of US$1,111.4 million at 31 December 2016 (2015: US$678.3 million).

Profit after tax

Profit after tax is US$122.6 million (2015: loss of US$1,103.8 million) resulting in a basic earnings per share of 24.0 cents from continuing and discontinued operations (2015: loss of 216.1 cents).

Cash flows

Cash flow from operating activities was US$431.4 million (2015: US$809.5 million) after accounting for tax payments of US$60.9 million (2015: US$94.0 million).

Capital expenditure in 2016 totalled US$678.1 million (2015: US$1,070.1 million).

Capital expenditure (US$ million)	**2016**	**2015**
Fields/development projects	548.6	847.4
Exploration and evaluation	126.6	216.8
Other	2.9	5.9
Total	**678.1**	**1,070.1**

The principal development projects were the Solan and Catcher fields in the UK. Exploration expenditure mainly related to our exploration campaign in the Falkland Islands, which concluded in Q1 2016, and Brazil. In addition, payments related to decommissioning in the period were US$62.3 million and included a one off US$53 million catch up payment into escrow for future decommissioning of Chim Sáo, the balance of which is held within non-current other receivables.

Balance sheet position

Net debt

Net debt at 31 December 2016, excluding Letters of Credit, amounted to US$2,765.2 million (2015: US$2,242.2 million), with cash resources of US$255.9 million (2015: US$401.3 million).

Net debt (US$ million)	2016	2015
Cash and cash equivalents[1]	255.9	401.3
Convertible bonds[2]	(237.4)	(232.9)
Other debt[2]	(2,783.7)	(2,410.6)
Total net debt	**(2,765.2)**	**(2,242.2)**

[1] Includes JV partners share of cash of US$46.4 million and cash collateral for Mexico exploration of US$6.6 million.

[2] The carrying amounts 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 (2015: US$0.3 million) and debt arrangement fees of US$17.5 million (2015: US$28.1 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 maturing in November 2017 have been classified as short term on the balance sheet. Once the Group's refinancing is completed, maturity of both of these loans will be extended out to May 2021.

Premier retains significant cash, at 31 December 2016, of US$255.9 million and undrawn facilities of US$390.0 million, giving Liquidity of US$592.9 million (31 December 2015: US$1,251.3 million), once cash of US$53.0 million held on behalf of our JV partners is removed from the calculation of Liquidity.

Decommissioning Funding

As part of the E.ON acquisition, Premier entered into a separate Decommissioning Liability Agreement with E.ON, whereby E.ON agreed to part fund Premier's share of decommissioning the Johnston and Ravenspurn North assets. Under the terms of the agreement, E.ON will reimburse 70 per cent of the decommissioning costs between a range of the net decommissioning costs of the two assets above £40 million up to a ceiling of £130 million. This results in a maximum possible funding of £63.0 million from E.ON. At 31 December 2016, a long-term decommissioning funding asset of US$66.7 million has, therefore, been recognised based on the year end sterling dollar exchange rate.

Provisions

The Group's decommissioning provision increased to US$1,325.4 million at 31 December 2016, up from US$1,062.6 million at the end of 2015. The increase is driven by the recognition of a long term provision for decommissioning related to the E.ON assets of US$427.9 million, which has been partially offset by a reduction for the UK assets driven by the weakening of the GBP:USD exchange rate at 31 December 2016.

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, Net Debt and Liquidity and are defined in the glossary.

Financial risk management

Commodity prices

At 31 December 2016, the Group had 1.5 mmbbls of open oil swaps at an average price of $45.8/bbl. The fair value of these oil swaps at 31 December 2016 was a liability of US$18.3 million (2015: asset of US$98.0 million), which is expected to be released to the income statement during 2017 as the related barrels are lifted. Furthermore, in December 2016, the Group paid total premiums of US$4.6 million to enter into oil option agreements for 1.8 mmbls at an average price of $50.7/bbl. These options will be settled during 2017 and are an asset on the Group's balance sheet with a fair value at 31 December 2016 of US$3.5 million. Included within physically delivered oil sales contracts are a further 1.7 mmbls of oil that will be sold for an average fixed price of $55.3/bbl during 2017 as these barrels are delivered.

In addition, the Group has forward UK gas sales for 132 mm therms at an average price of 48 pence/therm at 31 December 2016 that will be physically settled during 2017 and into H1 2018. The fair value of this asset at 31 December 2016 was US$10.0 million.

During 2016, forward oil sales of 5.3 mmbbls, forward gas sales of 36 mm therms and forward fuel oil sales of 72,000 mt expired resulting in a net credit of US$117.0 million (2015: US$278.9 million) which has been included in sales revenue for the year.

Foreign exchange

Premier's functional and reporting currency is US dollars. Exchange rate exposures relate only to local currency receipts, and expenditures within individual business units. Local currency needs are acquired on a short-term basis. At the year end, the Group recorded a mark-to-market loss of US$57.4 million on its outstanding foreign exchange contracts (2015: loss of US$19.1 million). The Group currently has £150.0 million retail bonds, €60.0 million long-term senior loan notes and a £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$1.39:€.

Interest rates

The Group has various financing instruments including senior loan notes, convertible bonds, UK retail bonds, term loans and revolving credit facilities. As at year end, 52 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 year was 4.6 per cent. Mark-to-market credits on interest rate swaps amounted to US$1.0 million (2015: credit of US$7.7 million), which are recorded as movements in other comprehensive income.

Insurance

The Group undertakes a significant insurance programme to reduce the potential impact of physical risks associated with its exploration, development and production activities. Business interruption cover is purchased for a proportion of the cash flow from producing fields for a maximum period of 18 months. During 2016, claims amounting to US$91.0 million (gross) were agreed and settled in relation to exploration drilling in the Falkland Islands.

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 year-end, the Group continued to have significant headroom on its borrowing facilities. However, whilst the Group continues to have sufficient liquidity available under these existing facilities, the Group's projections currently indicate that without an amendment to the covenant limits a breach of one of the financial covenants applicable to the Group's borrowing facilities is likely to arise in respect of the next covenant testing period which, as part of the lender discussions outlined below, has been deferred on a rolling one month basis and is due to be tested for the 12 month period ending 31 March 2017. If there is a breach of a financial covenant, under the existing terms of the Group's financing facilities the Group's debt holders on all of the Group's facilities will have the right to request repayment of the outstanding debt and to cancel the relevant facilities.

Discussions with Premier's lending groups on the terms of a refinancing are substantially progressed and a long form term sheet has been agreed with advisers to the principal lending groups and the Coordinating Committee of the Revolving Credit Facility ("RCF") banks. The terms of the expected refinancing are summarised in note 12 to the financial statements. The process to finalise a lock-up agreement with the lenders in respect of the refinancing is also well advanced. Once this has been agreed the process of a Court Scheme of Arrangement will commence alongside an investment circular process to obtain shareholder approval.

The risk that the expected refinancing will not be approved by Premier's lending groups and shareholders or that the covenant test will not continue to be deferred until approval is received constitutes a material uncertainty that may cast significant doubt upon the use of the going concern basis of accounting. However, the Directors have a reasonable expectation that the refinancing will be completed on the terms that have been negotiated and also that the covenant testing period under the Group's existing facilities will continue to be deferred on a rolling one month basis until the refinancing is finalised. On the assumption that the refinancing of the Group's facilities is finalised as expected, the Group's projections indicate that, unless there are significant falls in prevailing oil prices or forecast production levels, the Group will have sufficient liquidity and will be able to operate within the revised financial covenants for a period of at least 12 months from the date of finalising the 2016 Annual Report and Accounts.

Accordingly, after making enquiries and considering the risks and uncertainties described above, the Directors have a reasonable expectation that the Group and Company will have adequate resources to continue in operational existence for the foreseeable future, being at least the next 12 months and, therefore, 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 significant risks for the next 12 months as being:

- Continued oil price weakness
- Cash generation and ability to fund existing and planned projects
- Loss of value if projects are deferred
- Continued underperformance from the Solan field
- Failure to deliver Catcher to schedule
- Political and security instability in countries of current and planned activity
- Failure to engage constructively with the Oil and Gas Authority and other relevant bodies
- Timing and uncertainty of decommissioning liabilities
- Financial viability of key suppliers and partners
- Ability to maintain core competencies

Further information detailing the way in which these risks are mitigated is provided on the Company's website www.premier-oil.com.

Richard Rose

Finance Director

PremierOil

Annual Results for the year ended 31 December 2016

Consolidated Income Statement
For the year ended 31 December 2016

	2016 $ million	2015 $ million
Continuing operations		
Sales revenues	**983.4**	1,067.2
Other operating (costs) / income	**(6.1)**	31.9
Cost of sales	**(767.1)**	(661.0)
Impairment charge on oil and gas properties	**(556.2)**	(1,023.7)
Reduction in decommissioning estimates	**75.7**	-
Exploration expense	**(48.0)**	(95.4)
Pre-licence exploration costs	**(10.4)**	(13.6)
Excess of fair value over costs of acquisition	**228.5**	-
Costs related to the acquisition of subsidiaries	**(21.6)**	-
Profit on disposal of non-current assets	**-**	1.2
General and administration costs	**(24.1)**	(14.4)
Operating loss	**(145.9)**	(707.8)
Share of profit/(loss) in associate	**1.8**	(1.9)
Interest revenue, finance and other gains	**13.2**	40.7
Finance costs, other finance expenses and losses	**(259.7)**	(160.6)
Loss before tax	**(390.6)**	(829.6)
Tax	**522.0**	(241.1)
Profit/(loss) for the year from continuing operations	**131.4**	(1,070.7)
Discontinued operations		
Loss for the year from discontinued operations[1]	**(8.8)**	(33.1)
Profit/(loss) after tax	**122.6**	(1,103.8)
Earnings/(loss) per share (cents):		
From continuing operations		
Basic	**25.7**	(209.6)
Diluted	**25.4**	(209.6)
From continuing and discontinued operations		
Basic	**24.0**	(216.1)
Diluted	**23.7**	(216.1)

[1] Discontinued operations relate to the disposal of the Norway business unit which completed in December 2015

Annual Results for the year ended 31 December 2016

Consolidated Statement of Comprehensive Income
For the year ended 31 December 2016

	2016 **$ million**	2015 $ million
Profit / (loss) for the year	**122.6**	(1,103.8)
Cash flow hedges on commodity swaps:		
(Losses) / gains arising during the year	**(38.3)**	164.4
Less: reclassification adjustments for gains in the year	**(92.4)**	(278.9)
	(130.7)	(114.5)
Tax relating to components of other comprehensive income	**56.1**	76.0
Cash flow hedges on interest rate and foreign exchange swaps	**3.3**	19.8
Exchange differences on translation of foreign operations	**3.0**	(37.0)
Gains/(losses) on long-term employee benefit plans[1]	**0.2**	(0.1)
Other comprehensive expense	**(68.1)**	(55.8)
Total comprehensive income/(expense) for the year	**54.5**	(1,159.6)

[1] Only item above not expected to be reclassified subsequently to profit and loss account.

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

Annual Results for the year ended 31 December 2016

Consolidated Balance Sheet

As at 31 December 2016

	2016 $ million	2015 $ million
Non-current assets:		
Intangible exploration and evaluation assets	**1,011.4**	749.7
Property, plant and equipment	**2,726.2**	2,611.7
Goodwill	**240.8**	240.8
Investment in associate	**6.2**	5.3
Long-term receivables	**143.4**	12.0
Deferred tax assets	**1,304.0**	871.6
	5,432.0	4,491.1
Current assets:		
Inventories	**22.3**	20.8
Trade and other receivables	**315.1**	274.4
Derivative financial instruments	**34.9**	118.3
Cash and cash equivalents	**255.9**	401.3
	628.2	814.8
Total assets	**6,060.2**	5,305.9
Current liabilities:		
Trade and other payables	**(412.6)**	(472.0)
Short-term provisions	**(56.1)**	(24.8)
Derivative financial instruments *	**(57.2)**	(2.2)
Short-term debt	**(273.0)**	–
Deferred income	**(27.3)**	(20.9)
	(826.2)	(519.9)
Net current (liabilities) / assets	**(198.0)**	294.9

Consolidated Balance Sheet (continued)
As at 31 December 2016

	2016 $ million	2015 $ million
Non-current liabilities:		
Long-term debt	**(2,730.5)**	**(2,615.1)**
Deferred tax liabilities	**(192.6)**	**(193.3)**
Deferred income	**(88.1)**	**(87.6)**
Derivative financial instruments *	**(101.6)**	**(74.3)**
Long-term provisions	**(1,312.1)**	**(1,080.9)**
	(4,424.9)	**(4,051.2)**
Total liabilities	**(5,251.1)**	**(4,571.1)**
Net assets	**809.1**	**734.8**
Equity and reserves:		
Share capital	**106.7**	**106.7**
Share premium account	**275.4**	**275.4**
Merger reserve	**374.3**	**374.3**
Retained earnings	**122.3**	**46.3**
Other reserves	**(69.6)**	**(67.9)**
	809.1	**734.8**

* Includes prior year derivative financial instruments of US$74.3 million which have been reclassified as long-term in the prior year to reflect the maturity of these instruments

Consolidated Statement of Changes in Equity

For the year ended 31 December 2016

					Other reserves			
	Share capital $ million	Share premium account $ million	Retained earnings[2] $ million	Merger reserve $ million	Capital redemption reserve $ million	Translation reserves $ million	Equity reserve $ million	Total $ million
At 1 January 2015	106.7	275.4	1,142.3	374.3	8.1	(48.7)	14.1	1,872.2
Purchase of ESOP Trust shares	-	-	(0.9)	-	-	-	-	(0.9)
Provision for share-based payments	-	-	23.0	-	-	-	-	23.0
Transfer between reserves[1]	-	-	4.5	-	-	-	(4.5)	-
Loss for the year	-	-	(1,103.8)	-	-	-	-	(1,103.8)
Other comprehensive expense	-	-	(18.8)	-	-	(37.0)	-	(55.8)
At 1 January 2016	106.7	275.4	46.3	374.3	8.1	(85.7)	9.6	734.7
Purchase of ESOP Trust shares	-	-	0.2	-	-	-	-	0.2
Provision for share-based payments	-	-	19.7	-	-	-	-	19.7
Transfer between reserves[1]	-	-	4.6	-	-	-	(4.6)	-
Profit for the year	-	-	122.6	-	-	-	-	122.6
Other comprehensive expense	-	-	(71.1)	-	-	3.0	-	(68.1)
At 31 December 2016	**106.7**	**275.4**	**122.3**	**374.3**	**8.1**	**(82.7)**	**5.0**	**809.1**

[1] 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.

PremierOil

Annual Results for the year ended 31 December 2016

Consolidated Cash Flow Statement
For the year ended 31 December 2016

	2016 $ million	2015 $ million
Net cash from operating activities	**431.4**	809.5
Investing activities:		
Capital expenditure	**(678.1)**	(992.2)
Acquisition of subsidiaries	**(135.0)**	-
Cash balance acquired in the period	**24.9**	-
Decommissioning funding	**(62.3)**	-
Disposal of oil and gas properties	**(8.8)**	219.6
Loan to joint venture partner	**-**	(77.9)
Net cash used in investing activities	**(859.3)**	(850.5)
Financing activities:		
Purchase of ESOP Trust shares	**0.2**	(0.9)
Proceeds from drawdown of bank loans	**435.0**	775.0
Debt arrangement fees	**(26.3)**	(9.6)
Repayment of long-term bank loans	**-**	(300.0)
Repayment of senior loan notes	**-**	(209.4)
Interest paid	**(126.3)**	(91.6)
Net cash from financing activities	**282.6**	163.5
Currency translation differences relating to cash and cash equivalents	**(0.1)**	(13.0)
Net (decrease) / increase in cash and cash equivalents	**(145.4)**	109.5
Cash and cash equivalents at the beginning of the year	**401.3**	291.8
Cash and cash equivalents at the end of the year	**255.9**	401.3

Annual Results for the year ended 31 December 2016

NOTES TO THE PRELIMINARY FINANCIAL STATEMENTS
For the year ended 31 December 2016

1. 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. This preliminary announcement was authorised for issue in accordance with a resolution of the Board of Directors on 8 March 2017.

The financial information for the year ended 31 December 2016 set out in this announcement does not constitute statutory accounts within the meaning of section 434 of the Companies Act 2006. Statutory accounts for the year ended 31 December 2015 were approved by the Board of Directors on 24 February 2016 and delivered to the Registrar of Companies and those for 2016 will be delivered following the company's Annual General Meeting (AGM). The auditor has reported on the 2016 accounts; the report was unqualified, but did include a reference to a matter to which the auditor drew attention by way of emphasis of matter around going concern.

Basis of preparation

The financial information has been prepared in accordance with the recognition and measurement criteria of International Financial Reporting Standards (IFRS) adopted for use in the European Union. However, this announcement does not itself contain sufficient information to comply with IFRS. The company will publish full financial statements that comply with IFRS in April 2017.

The financial information has been prepared under the historical cost convention except for the revaluation of financial instruments and certain oil and gas properties at the transition date to IFRS. These financial statements are presented in US dollars since that is the currency in which the majority of the group's transactions are denominated. The financial information has been prepared on the going concern basis. Further information relating to the use of the going concern assumption, including details of a related material uncertainty due to the risk of a covenant breach prior to finalisation of the refinancing process, is provided in the "Going Concern" section of the Financial Review.

Accounting policies

The accounting policies applied in this announcement are consistent with those of the annual financial statements for the year ended 31 December 2015, as described in those annual financial statements. A number of amendments to existing standards and interpretations were applicable from 1 January 2016. The adoption of these amendments did not have a material impact on the group's financial statements for the year ended 31 December 2016.

2. Operating segments

The Group's operations are located and managed in six business units; namely the Falkland Islands, Indonesia, Pakistan (including Mauritania), the United Kingdom, Vietnam and the Rest of the World. The results for Norway, which was sold in 2015 are reported as a discontinued operation in the prior year balances. Some of the business units currently do not generate revenue or have any material operating income.

The Group is engaged in one business of upstream oil and gas exploration and production.

	2016 $ million	2015 $ million
Revenue:		
Indonesia	**141.1**	215.4
Pakistan (including Mauritania)	**52.3**	88.9
Vietnam	**192.0**	227.8
United Kingdom	**598.0**	535.1
Total Group sales revenue	**983.4**	1,067.2
Other operating income - United Kingdom	**-**	31.9
Interest and other finance revenue	**0.7**	29.3
Total Group revenue from continuing operations	**984.1**	1,128.4
Group operating loss:		
Indonesia	**35.6**	62.0
Pakistan (including Mauritania)	**26.7**	12.2
Vietnam	**86.3**	27.0
United Kingdom	**(225.0)**	(721.9)
Rest of the World	**(35.0)**	(59.1)
Unallocated[1]	**(34.5)**	(28.0)
Group operating loss	**(145.9)**	(707.8)
Share of profit / (loss) in associate	**1.8**	(1.9)
Interest revenue, finance and other gains	**13.2**	40.7
Finance costs and other finance expenses	**(259.7)**	(160.6)
Loss before tax from continuing operations	**(390.6)**	(829.6)
Tax	**522.0**	(241.1)
Profit/(loss) after tax from continuing operations	**131.4**	(1,070.7)
Loss from discontinued operations	**(8.8)**	(33.1)

2. Operating segments *(continued)*

	2016 $ million	2015 $ million
Balance sheet		
Segment assets:		
Falkland Islands	**642.9**	591.4
Indonesia	**480.2**	560.3
Pakistan (including Mauritania)	**44.8**	59.3
Vietnam	**399.0**	388.2
United Kingdom	**4,136.5**	3,122.5
Rest of the World	**66.0**	64.6
Unallocated[1]	**290.8**	519.6
Total assets	**6,060.2**	5,305.9
Liabilities:		
Falkland Islands	**(45.6)**	(69.1)
Indonesia	**(244.5)**	(261.0)
Pakistan (including Mauritania)	**(76.3)**	(95.8)
Vietnam	**(202.1)**	(218.4)
United Kingdom	**(1,516.8)**	(1,137.2)
Rest of the World	**(3.5)**	(10.5)
Unallocated[1]	**(3,162.3)**	(2,779.1)
Total liabilities	**(5,251.1)**	(4,571.1)
Other information		
Capital additions and acquisitions:		
Falkland Islands	**59.2**	149.9
Indonesia	**(2.7)**	39.6
Norway	**-**	17.0
Pakistan (including Mauritania)	**0.9**	24.0
Vietnam	**(7.4)**	(23.9)
United Kingdom	**1,247.7**	1,505.5
Rest of the World	**26.4**	38.8
Total capital additions and acquisitions	**1,324.1**	1,750.9
Depreciation, depletion, amortisation and impairment:		
Indonesia	**52.7**	92.6
Pakistan (including Mauritania)	**7.8**	42.9
Vietnam	**45.0**	106.2
United Kingdom	**790.4**	1,107.1
Rest of the World	**0.6**	1.6
Total depreciation, depletion, amortisation and impairment	**896.5**	1,350.4

2. Operating segments *(continued)*

[1] Unallocated expenditure, assets and liabilities include amounts of a corporate nature and not specifically attributable to a geographical segment. These items include corporate general and administration costs, pre-licence exploration costs, cash and cash equivalents, mark-to-market valuations of commodity contracts and interest rate swaps, convertible bonds and other short-term and long-term debt.

Out of the total Group worldwide sales revenues of US$983.4 million (2015: US$1,067.2 million), revenues of US$598.0 million (2015: US$535.1 million) arose from sales of oil and gas to customers located in the UK.

Included in assets arising from the United Kingdom segment are non-current assets (excluding deferred tax assets) of US$2,640.6 million (2015: US$2,137.5 million) located in the UK. Included in depreciation, depletion, amortisation and impairment are impairment charges in relation to the UK (net US$587.8 million) and impairment reversals for Vietnam (US$25.9 million) and Pakistan (US$5.7 million).

Revenue from three customers (2015: two customers) each exceeded 10 per cent of the Group's consolidated revenue and amounted to US$155.4 million and US$157.4 million, arising from sales of crude oil (2015: US$132.5 million) and US$112.0 million arising from sales of gas (2015: US$166.7 million) across all operating segments.

3. Cost of sales

	2016 $ million	2015 $ million
Operating costs	**412.8**	323.6
Gas purchases	**12.4**	-
Stock underlift movement	**(12.1)**	(11.4)
Royalties	**13.7**	22.1
Amortisation and depreciation of property, plant and equipment:		
- Oil and gas properties	**332.2**	315.9
- Other fixed assets	**8.1**	10.8
	767.1	661.0

4. Tax

	2016 $ million	2015 $ million
Current tax:		
UK corporation tax on profits[1]	**(3.0)**	(2.3)
UK petroleum revenue tax	**(0.8)**	19.4
Overseas tax	**53.5**	80.1
Adjustments in respect of prior years	**(7.7)**	1.4
Total current tax	**42.0**	98.6
Deferred tax:		
UK corporation tax	**(544.3)**	187.4
UK petroleum revenue tax	**(14.4)**	(10.6)
Overseas tax	**(5.3)**	(34.3)
Total deferred tax	**(564.0)**	142.5
Tax on profit on ordinary activities	**(522.0)**	241.1

* The UK corporation tax current tax credit of US$3.0 million includes a US$3.3 million UK tax refund relating to decommissioning costs incurred in 2016 and carried back to prior periods.

The tax credit for the year can be reconciled to the loss per the consolidated income statement as follows:

	2016 $ million	2015 $ million
Group loss on ordinary activities before tax	**(390.6)**	(829.6)
Group loss on ordinary activities before tax at 58.4% weighted average rate (2015: 47.4%)	**(228.3)**	(393.2)
Tax effects of:		
Income/expenses that are not taxable/deductible in determining taxable profit	**7.3**	8.0
Financing costs disallowed for UK supplementary charge	**14.4**	20.1
Non-deductible field expenditure	**63.2**	71.0
Tax and tax credits not related to profit before tax (mainly RFES)	**(61.2)**	(144.3)
Unrecognised tax losses	**2.8**	406.2
Adjustments in respect of prior years	**0.7**	10.6
Utilisation and recognition of tax losses not previously recognised	**(392.5)**	(2.5)
Effect of change in tax rates	**161.2**	168.1
Recognition that decommissioning provision will unwind at 50%	**(27.1)**	-
Write down of deferred tax asset previously recognised	**-**	97.1
Recognition of investment allowances not previously recognised	**(62.5)**	-
Tax (credit) / charge for the year	**(522.0)**	241.1
Effective tax rate for the year	**133.6%**	(29.0%)

4. Tax *(continued)*

The weighted average rate is calculated based on the tax rates weighted according to the profit or loss before tax earned by the Group in each jurisdiction. The change in the weighted average rate year-on-year relates to the mix of profit and loss in each jurisdiction. The tax credit not related to profit before tax includes the impact of a UK ring fence expenditure supplement claim in the UK (US$61 million).

The deferred tax credit arises largely as a result of the recognition of UK tax losses and investment allowances (US$455.8 million) after an increase in the estimated future profitability of the group's UK assets following the acquisition of the E.ON North Sea business. This has been partially offset by a charge of US$161.2 million in relation to the supplementary charge rate change from 20 per cent to 10 per cent during the year, with the adverse impact of this change mitigated by US$27.1 million as the rate applicable to the reversal of certain temporary differences on decommissioning remained unchanged.

The future effective tax rate for the Group is impacted by the mix of jurisdictions in which Premier operates (with corporation tax rates ranging from 20 per cent to 55 per cent), assumptions around future oil prices and changes to tax rates and legislation.

5. Deferred tax

	2016 $ million	2015 $ million
Deferred tax assets	**1,304.0**	**871.6**
Deferred tax liabilities	**(192.6)**	**(193.3)**
	1,111.4	**678.3**

	At 1 January 2016 $ million	Exchange movements $ million	Acquisition Accounting 29 April 2016 $ million	(Charged)/ credited to income statement $ million	Credited to retained earnings $ million	At 31 December 2016 $ million
UK deferred corporation tax:						
Fixed assets and allowances	(581.0)	-	(371.2)	232.6	-	(719.6)
Decommissioning	378.8	-	172.3	(156.6)	-	394.5
Deferred petroleum revenue tax	7.2	-	-	(7.2)	-	-
Tax losses and allowances	1,129.4	-	33.5	397.2	-	1,560.1
Other	-	-	(0.7)	65.1	-	64.4
Derivative financial instruments	(49.1)	0.3	(21.2)	13.2	56.1	(0.7)
Total UK deferred corporation tax	**885.3**	**0.3**	**(187.3)**	**544.3**	**56.1**	**1,298.7**
UK deferred petroleum revenue tax[1]	**(14.4)**	**-**	**-**	**14.4**	**-**	**-**
Overseas deferred tax[2]	**(192.6)**	**-**	**-**	**5.3**	**-**	**(187.3)**
Total	**678.3**	**0.3**	**(187.3)**	**564.0**	**56.1**	**1,111.4**

5. Deferred tax *(continued)*

	At 1 January 2015 $ million	Exchange movements $ million	Disposal of asset $ million	(Charged)/ credited to income statement $ million	Credited to retained earnings $ million	At 31 December 2015 $ million
UK deferred corporation tax:						
Fixed assets and allowances	(756.0)	-	-	175.0	-	(581.0)
Decommissioning	329.8	-	-	49.0	-	378.8
Deferred petroleum revenue tax	15.5	-	-	(8.3)	-	7.2
Tax losses and allowances	1,375.3	-	-	(245.9)	-	1,129.4
Investment allowance	157.2	-	-	(157.2)	-	-
Derivative financial instruments	(125.1)	-	-	-	76.0	(49.1)
Total UK deferred corporation tax	996.7	-	-	(187.4)	76.0	885.3
UK deferred petroleum revenue tax[1]	(25.0)	-	-	10.6	-	(14.4)
Overseas deferred tax[2]	(254.2)	4.3	23.0	34.3	-	(192.6)
Total	**717.5**	**4.3**	**23.0**	**(142.5)**	**76.0**	**678.3**

[1] The UK deferred petroleum revenue tax credit reflects the reduction in PRT rate to 0 per cent during the period.

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

The Group's UK deferred tax assets at 31 December 2016 are recognised to the extent that taxable profits are expected to arise in the future against which the ring fence tax losses and allowances can be utilised. In accordance with paragraph 37 of IAS 12 - 'Income Taxes' the group re-assessed its deferred tax assets at 31 December 2016 with respect to ring fence tax losses and allowances. The corporate model used to assess whether it is appropriate to recognise all of the Group's deferred tax assets was re-run, using an oil price assumption of Dated Brent forward curve for two years, followed by US$65/bbl in 2019 and US$75/bbl in 'real' terms therafter. The results of the corporate model demonstrated that as a result of an increase in the Group's estimated future UK profitability arising from the acquisition of assets in the period an additional net amount of US$455.8 million in respect of the Group's UK ring fence deferred tax losses and investment allowances could be recognised, representing full recognition of the associated deferred tax credit.

In addition to the above, there are carried forward non-ring fence UK tax losses of approximately US$363.8 million (2015: US$303.5 million) for which a deferred tax asset has not been recognised on the basis there are insufficient future profits forecast to utilise the losses against.

5. Deferred tax *(continued)*

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

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

During the period it was announced that the rate of supplementary charge to tax on UK ring fence profits is to be further reduced from 20 per cent to 10 per cent with effect from 1 January 2016. The Group's deferred UK tax balances at 31 December 2016 are recognised at the reduced rate which gave rise to a deferred tax charge of US$161.2 million in the income statement to reflect the decrease in the opening deferred tax assets at 1 January 2016.

6. Acquisition of subsidiaries

On 28 April 2016, the Group acquired 100 per cent of the share capital of E.ON E&P UK Ltd ("EPUK"), a wholly owned subsidiary of E.ON SE, a German listed utility. The acquisition of EPUK brings additional high quality assets to Premier's UK North Sea business, the opportunity for cost and operating synergies in the North Sea, more balanced production portfolio and adds significant immediate production and cash flow.

The Group reached agreement on the acquisition on 13 January 2016 and was approved by Premier shareholders on 25 April 2016. Premier paid total cash consideration of US$135.0 million, including working capital adjustments. The acquisition has been accounted for as a business combination. The fair values of the identifiable assets and liabilities acquired were reported as provisional in our half-year report and have now been finalised for the purposes of full year 2016 financial statements.

The fair values of the oil and gas properties and intangible exploration and evaluation assets acquired have been determined using valuation techniques based on discounted cash flows using forward curve commodity prices at the acquisition date, a discount rate based on market observable data and cost and production profiles consistent with the proved and probable reserves acquired with each asset. The financial instruments acquired have been valued using our forward curve oil and gas price assumptions at the date of the acquisition. The decommissioning provisions recognised are based on Premier's internal estimates.

6. Acquisition of subsidiaries *(continued)*

The fair value of the identifiable assets and liabilities of EPUK as at the date of acquisition were:

	Provisional fair value as included in the half-year report $ million	Adjustment $ million	Final fair value $ million
Assets			
Intangible exploration and evaluation assets	105.7	94.1	199.8
Oil and gas properties	600.0	-	600.0
Other fixed assets	7.1	-	7.1
Long-term decommissioning funding asset	85.9	(2.6)	83.3
Inventory	2.7	-	2.7
Trade and other receivables	51.4	-	51.4
Derivative financial instruments	59.4	-	59.4
Cash and cash equivalents	24.9	-	24.9
	937.1	91.5	1,028.6
Liabilities			
Trade and other payables	(50.0)	-	(50.0)
Decommissioning obligations – current	(13.7)	-	(13.7)
Decommissioning obligations – non-current	(565.9)	151.7	(414.2)
Deferred tax liabilities	(65.6)	(121.6)	(187.2)
	(695.2)	30.1	(665.1)
Total identifiable net assets acquired at fair value	241.9	121.6	363.5
Total consideration	(135.0)	-	(135.0)
Excess of fair value over cost (negative goodwill)	**106.9**	**121.6**	**228.5**

The adjustments to the provisional half-year value predominantly relate to an increase in the fair value of the Tolmount field recognised within exploration and evaluation assets and a reduction in the decommissioning estimates for several of the fields acquired to align Premier's estimates either with those of the field operator or E.ON's underlying decommissioning cost estimate. The reduction in the decommissioning estimate for the Ravenspurn North and Johnston fields has resulted in an adjustment to the fair value of the long-term decommissioning funding receivable from E.ON. Deferred tax has been recognised on the above adjustments.

6. Acquisition of subsidiaries *(continued)*

The excess of the fair value of the net assets acquired over the purchase consideration has arisen primarily due to E.ON's strategic decision to exit the UK and Norway E&P sectors, and Premier's willingness to acquire the entire UK business. This been recognised immediately in the consolidated income statement.

From the date of acquisition to 31 December 2016, EPUK contributed US$201.9 million to Group revenue and increased the Group's loss before tax by US$40.9 million. If the acquisition of EPUK had taken place at the beginning of the year, EPUK's contribution to Group revenue for the year ended 31 December 2016 would have been US$336.1 million and it would have increased the Group's loss before tax by US$43.9 million.

Costs related to the acquisition represent transaction costs of US$5.6 million and the recognition of a settlement provision of US$16.0 million in respect of employee costs. This settlement was fully utilised in the second half of 2016.

7. Earnings / (loss) per share

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

	2016 $ million	2015 $ million
Earnings/(loss)		
Earnings/(loss) from continuing operations	**131.4**	(1,070.7)
Effect of dilutive potential Ordinary Shares:		
Interest on convertible bonds	**10.9**	-
Earnings/(loss) for the purpose of diluted earnings/(loss) per share on continuing operations	**142.3**	(1,070.7)
Loss from discontinued operations	**(8.8)**	(33.1)
Earnings/(loss) for the purposes of diluted earnings/(loss) per share on continuing and discontinued operations	**133.5**	(1,103.8)
Number of shares (millions)		
Weighted average number of Ordinary Shares for the purposes of basic earnings per share	**510.8**	510.8
Effects of dilutive potential Ordinary Shares:		
Contingently issuable shares	**48.8**	-
Weighted average number of Ordinary Shares for the purposes of diluted earnings per share	**559.6**	510.8
Earnings/(loss) per share from continuing operations (cents)		
Basic	**25.7**	(209.6)
Diluted	**25.4**	(209.6)
Loss per share from discontinued operations (cents)		
Basic	**(1.7)**	(6.5)
Diluted	**(1.7)**	(6.5)

The inclusion of the contingently issuable shares in 2016 produces diluted earnings per share. In 2015 there were 40.7 million anti-dilutive Ordinary Shares mainly comprising shares to be issued on conversion of convertible bonds.

8. Intangible exploration and evaluation (‘E&E’) assets

	Total $ million
Cost:	
At 1 January 2015	825.7
Exchange movements	(37.2)
Additions during the year	217.9
Disposals	(161.3)
Exploration expense	(95.4)
At 31 December 2015	749.7
Exchange movements	6.1
Additions during the year	103.8
Acquisition of subsidiaries	199.8
Exploration expense	(48.0)
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. Assets written off in the year include costs incurred for drilling the Laverda/Slough and Bagpuss prospects in the North Sea and Foz in Brazil.

The outcome of ongoing exploration, and therefore whether the carrying value of E&E assets will ultimately be recovered, is inherently uncertain. The balance carried forward is predominantly in relation to the Group’s prospects in the Falkland Islands and the Tolmount project in the UK.

The disposal in 2015 is for E&E costs that were held in relation to the Group’s Norway business unit.

9. Property, plant and equipment

	Oil and gas properties $ million	Other fixed assets $ million	Total $ million
Cost:			
At 1 January 2015	5,498.6	59.9	5,558.5
Exchange movements	-	(2.0)	(2.0)
Asset acquisition	614.8	-	614.8
Additions during the year	912.3	5.9	918.2
Disposals	-	(2.4)	(2.4)
At 31 December 2015	7,025.7	61.4	7,087.1
Exchange movements	(8.5)	(4.8)	(13.3)
Acquisition of subsidiaries	600.0	7.1	607.1
Additions during the year	411.4	2.0	413.4
Disposals	-	(1.4)	(1.4)
At 31 December 2016	**8,028.6**	**64.3**	**8,092.9**
Amortisation and depreciation:			
At 1 January 2015	3,091.3	37.2	3,128.5
Exchange movements	-	(1.3)	(1.3)
Charge for the year	315.9	10.8	326.7
Impairment charge	1,023.7	-	1,023.7
Disposals	-	(2.2)	(2.2)
At 31 December 2015	4,430.9	44.5	4,475.4
Exchange movements	(0.4)	(3.4)	(3.8)
Charge for the year	332.2	8.1	340.3
Impairment charge	556.2	-	556.2
Disposals	-	(1.4)	(1.4)
At 31 December 2016	**5,318.9**	**47.8**	**5,366.7**
Net book value:			
At 31 December 2015	2,594.8	16.9	2,611.7
At 31 December 2016	**2,709.7**	**16.5**	**2,726.2**

* Finance costs that have been capitalised within oil and gas properties during the year total US$34.0 million (2015: US$58.8 million), at a weighted average interest rate of 4.6 per cent (2015: 4.4 per cent).

9. Property, plant and equipment *(continued)*

Other fixed assets include items such as leasehold improvements, motor vehicles and office equipment. In April 2016, Premier completed the acquisition of E.ON E&P UK Limited.

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 reserves 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.

Impairment charge

The impairment charge in the current year relates to the Solan asset in the UK. The impairment charge of US$652.2 million was calculated by comparing the future discounted pre-tax cash flows expected to be derived from production of commercial reserves (the value-in-use) against the carrying value of the asset. The future cash flows were estimated using an oil price assumption equal to the Dated Brent forward curve in 2017 and 2018, and US$65/bbl in 2019 and US$75/bbl in 'real' terms thereafter (2015: long-term price of US$80 real/bbl) and were discounted using a pre-tax discount rate of 8 per cent for the UK assets (2015: 8 per cent) and 12.5 per cent for the non-UK assets (2015: 12.5 per cent). Assumptions involved in impairment measurement include estimates of commercial reserves and production volumes, future oil and gas prices, discount rate and the level and timing of expenditures, all of which are inherently uncertain.

The principal cause of the impairment charge being recognised in the year is a reduction in the 2P reserves expected to be recovered from the asset over its economic life and the reduction in the long term oil price assumption to US$75/bbl (real). The recoverable amount of the Solan asset based on its estimated value-in-use assumption set out above is US$570.4 million.

9. Property, plant and equipment *(continued)*

Reversal of previously recognised impairment charges

Under the requirements of IAS 36, if there is an indication that a factor that resulted in an impairment charge may have changed or been reversed, then the previously recognised impairment charge may no longer exist or may have decreased. For a number of assets, due to an increase in the near term oil price assumption (based on the Dated Brent Forward Curve), we have reassessed the recoverable amount of the asset to assess whether an increase in the recoverable amount (value-in-use) is indicative of a reversal of a previously recognised impairment charge. The future cash flows were determined using the same assumptions as those used for the impairment charge outlined above.

A reversal of impairment of US$96.0 million has been credited to the income statement for the year, which has partially offset the impairment charge recognised. The reversal of impairment relates to Huntington (UK, US$50.0 million), Chim Sáo (Vietnam, US$25.9 million), Kyle (UK, US$14.4 million) and Kadanwari (Pakistan, US$5.7 million). An increase in the short term oil price assumption and an increase in the 2P reserves on Chim Sáo have driven the reversal of impairment recognised. The recoverable amounts of the assets at 31 December 2016 were Huntington, US$61.8 million; Chim Sáo, US$583.1 million; Kyle, US$31.9 million; and, Kadanwari, US$9.1 million.

Goodwill

Goodwill of US$240.8 million has been specifically assigned to the Catcher field in the UK, which is considered the cash-generating unit for the purposes of any impairment testing of this goodwill. The Group tests goodwill annually for impairment, or more frequently if there are indications that goodwill might be impaired. The recoverable amounts are determined from value-in-use calculations with the same key assumptions as noted above for the impairment calculations. The discount rate used is 8 per cent (2015: 8 per cent). The value-in-use forecast takes into consideration cash flows which are expected to arise during the life of the Catcher field as a whole, currently expected to be around 2030. This period exceeds five years but is believed to be appropriate as it is underpinned by estimates of commercial reserves provided by in-house reservoir engineers using industry standard reservoir estimation techniques. The headroom between the recoverable amount and the carrying amount, including the goodwill is US$143.2 million. If the discount rate was 1% higher or if the long term oil price assumption was US$5/bbl lower, being reasonably possible changes in key assumptions, no impairment charge would arise.

9. Property, plant and equipment *(continued)*

Sensitivity

A 1 per cent increase in the discount rates used when determining the value-in-use for each oil and gas property would result in a further impairment charge of approximately US$28.3 million. A US$5/bbl reduction in the long-term oil price (to US$70/bbl (real)) would increase the impairment charge by approximately US$58.0 million. The value of the reversal of impairment recognised in the year would be unaffected by either an increase in the discount rate by 1 per cent or a reduction in the long-term oil price assumption to US$70/bbl (real).

10. Deferred income

In June 2015, Premier received US$100.0 million from FlowStream in return for granting them 15 per cent of production from the Solan field until sufficient barrels have been delivered to achieve the rate of return within the agreement. This balance is being released to the income statement within revenue as barrels are delivered to FlowStream from production from Solan. The balance has reduced by US$7.9 million during the year reflecting barrels delivered to FlowStream in the period since first oil from Solan. This has been offset by the finance charge for the year of US$14.9 million.

The portion of the deferred income that is expected to be delivered to FlowStream within the next 12 months has been classified as a current liability.

11. Notes to the cash flow statement

	2016 $ million	2015 $ million
Loss before tax for the year	**(390.6)**	(829.6)
Adjustments for:		
Depreciation, depletion, amortisation and impairment	**896.5**	1,350.4
Other operating costs / (income)	**3.1**	(31.9)
Exploration expense	**48.0**	95.4
Excess of fair value over consideration	**(228.5)**	-
Provision for share-based payments	**8.7**	7.2
Reduction in decommissioning estimates	**(75.7)**	-
Share of profit / loss in associate	**(1.8)**	1.9
Interest revenue and finance gains	**(13.2)**	(40.7)
Finance costs and other finance expenses	**259.7**	160.6
Other gains and losses	**-**	(1.2)
Deferred income (repaid) / received	**(7.9)**	100.0
Operating cash flows before movements in working capital	**498.3**	**812.1**
Decrease in inventories	**1.3**	5.3
Decrease in receivables	**25.1**	382.1
Decrease in payables	**(33.0)**	(297.6)
Cash generated by operations	**491.7**	**901.9**
Income taxes paid	**(60.9)**	(94.0)
Interest income received	**0.6**	1.6
Net cash from operating activities	**431.4**	809.5

11. Notes to the cash flow statement *(continued)*

Analysis of changes in net debt:

	2016 $ million	2015 $ million
a) Reconciliation of net cash flow to movement in net debt:		
Movement in cash and cash equivalents	**(145.4)**	109.5
Proceeds from drawdown of long-term bank loans	**(435.0)**	(775.0)
Repayment of long-term bank loans	**-**	300.0
Repayment of senior loan notes	**-**	209.4
Non-cash movements on debt and cash balances (predominantly FX)	**57.4**	36.1
Increase in net debt in the year	**(523.0)**	(120.0)
Opening net debt	**(2,242.2)**	(2,122.2)
Closing net debt	**(2,765.2)**	(2,242.2)
b) Analysis of net debt:		
Cash and cash equivalents	**255.9**	401.3
Borrowings	**(3,021.1)**	(2,643.5)
Total net debt	**(2,765.2)**	(2,242.2)

12. Subsequent Events

Refinancing

In February 2017, Premier announced the following:

- Agreement of representatives of its Private Lenders to a long form term sheet, subject to credit approvals
- Agreement of revised key terms between Premier and representatives of its convertible bond holders, subject to agreement by the Private Lenders
- Proposed amended terms to its retail bonds

In return the lenders will receive a revised security and covenant package, benefits from enhanced economics and exercise certain governance controls.

The long form term sheet has been circulated to the lenders under the Company's Revolving Credit Facility ("RCF"), term loan, Schuldschein and US Private Placement notes ("USPP") (together the "Private Lenders") for formal credit committee approval with lock-up agreements expected to be received during March 2017. Revised financing documentation will now be finalised with completion of the refinancing currently anticipated by the end of May 2017.

12. Subsequent Events *(continued)*

Key terms of the refinancing

<u>The RCF, term loan, US Private Placement notes (USPP) and Schuldschein notes.</u>

Proposed amendments have been largely agreed with the Co-ordinating Committee of the RCF Group and representatives of the other Private Lenders as follows:

- Confirmation of total existing facilities of US$3.9 billion with drawn capacity preserved
- Alignment of final maturity dates to 31 May 2021
- Amendment of Premier's financial covenants, currently anticipated to be net debt to EBITDA cover ratio test to 9.5x 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

Enhanced economics for lenders, including:

- A margin uplift of 1.5 per cent over existing pricing with an additional 1 per cent for the Schuldschein lenders for conversion of their existing bilateral facilities into an English law-based syndicated facility
- Amendment fees of 1 per cent with an additional 0.5 per cent for the Schuldschein lenders
- Equity warrants representing up to 90 million new shares, being 15 per cent of Premier's issued shares (enlarged for the potential new issue) at a price of 42.75 pence per share, equivalent to 7.6 per cent dilution based on the latest closing share price. The warrants will have a five year term. Alternatively, lenders will have the option to take up synthetic warrants in the form of a deferred fee of comparable value to the equity warrants. Take-up of the synthetic warrants will reduce the number of new shares to be issued under the equity warrants
- Crystallisation of the make-whole on the USPP to be calculated at the completion date of the refinancing

A security package which provides priority over unsecured creditors, in addition a portion of the RCF and certain other debt obligations of up to US$800 million will receive super-senior status.

Certain governance controls including:

- Annual approval of Premier's overall capex and exploration budgets
- Final sanction of significant new projects
- Certain approval rights in respect of acquisitions and disposals

12. Subsequent Events *(continued)*

The retail bonds

Substantially the same economic terms are being offered to the retail bondholders as to the Private Lenders. The key terms proposed 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 per cent and pro-rata participation in the warrant offering as above
- Participation in the security package which gives priority over unsecured creditors, ranking alongside the private debt facilities (with senior status)

Positive feedback has been received from a number of significant retail bondholders who have been consulted on these terms. A prospectus will be issued to retail bondholders to elect between equity warrants and synthetic warrants

Convertible bonds

On 1 March 2017 Premier announced that amended terms to its US$245m convertible bonds had been agreed with all members of an ad hoc committee of convertible bondholders.

The key amended 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 (subject to the terms of an inter-creditor agreement between the Company and its other lenders) in cash
- Conversion price to be reset at a premium of 20 per cent to the higher of the volume weighted average price of Premier's shares over the period from 1 March 2017 to 22 March 2017 (inclusive) or 62 pence
- Equity warrants representing 3 per cent of Premier's issued share capital (enlarged for the issue of equity warrants under the terms of the overall refinancing) at a price of 42.75 pence/share
- 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

Implementation of the proposed refinancing

The proposed RCF, term loan, USPP and Retail Bond amendments will be effected through a Scottish scheme of arrangement of each of Premier and Premier Oil UK Limited (the Schemes), which must be approved by a majority in number and 75 per cent in value of the Scheme creditors attending and voting at meetings arranged for this purpose.

12. Subsequent Events *(continued)*

Schuldschein lenders and the convertible bondholders will each consider and, if they so decide, consent to the terms of the refinancing outside of the Scheme process.

The refinancing will require shareholder approval in respect of the potential issue of the warrant shares and shares that could be issued as a result of the change to the convertible bond conversion price. The approval will be sought at a general meeting.

13. External audit

This preliminary announcement is consistent with the audited financial statements of the group for the year-ended 31 December 2016.

14. Publication of financial statements

It is anticipated that the full Annual Report and Financial Statements will be published in April 2017. Copies will be available from this date at the Company's head office, 23 Lower Belgrave Street, London SW1W 0NR, and on the Company's website (www.premier-oil.com).

15. Annual General Meeting

The Annual General Meeting will be held at the King's Fund, 11-13 Cavendish Square, London W1G 0AN on Wednesday 17 May 2017 at 11:00 am

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, Net Debt and Liquidity and are defined below.

- **EBITDAX:** Earnings before interest, tax, depreciation, amortisation, impairment, exploration spend and reduction in decommissioning estimates. In the current year it also excludes negative goodwill that arose on the E.ON acquisition. Determined by adjusting operating profit / (loss) for the 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.
- **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

PremierOil

Annual Results for the year ended 31 December 2016

OIL AND GAS RESERVES

Working interest reserves at 31 December 2016

Working interest basis													
	Falkland Islands		Indonesia		Pakistan/ Mauritania		UK		Vietnam		Total		
	Oil and NGLs	Gas	Oil and NGLs	Gas	Oil and NGLs	Gas	Oil and NGLs	Gas	Oil and NGLs	Gas	Oil and NGLs	Gas	Oil, NGLs and gas
	mmbbls	bcf	mmbbls	bcf	mmbbls	bcf	mmbbls	bcf	mmbbls	bcf	mmbbls	bcf	mmboe
Group proved plus probable reserves:													
At 1 January 2016	128.0	43.8	2.0	250.4	0.3	79.8	104.1	33.5	17.9	29.4	**252.3**	**436.9**	**331.9**
Revisions[1]	(1.5)	-	(0.1)	19.1	(0.1)	11.9	(5.9)	(7.6)	10.3	13.4	**2.7**	**36.8**	**9.7**
Discoveries and extensions	–	–	–	–	–	–	–	–	–	–	–	–	–
Acquisitions and divestments[1]	–	–	-	-	-	-	14.0	126.7	-	-	**14.0**	**126.7**	**37.8**
Production	-	-	(0.3)	(26.1)	(0.1)	(17.4)	(9.0)	(16.6)	(4.4)	(7.2)	**(13.8)**	**(67.3)**	**(26.1)**
At 31 December 2016	126.5	43.8	1.6	243.4	0.1	74.3	103.2	136.0	23.8	35.6	**255.2**	**533.1**	**353.3**
Total Group developed and undeveloped reserves													
Proved on production	-	-	0.9	127.7	0.1	46.8	33.7	54.4	17.2	23.1	**51.9**	**252.0**	**98.3**
Proved approved/justified for development	102.8	28.5	0.4	47.3	-	-	24.0	33.2	2.3	5.9	**129.5**	**114.9**	**151.1**
Probable on production	-	-	0.1	23.7	-	27.5	20.3	37.3	3.0	2.5	**23.4**	**91.0**	**39.4**
Probable approved/justified for development	23.7	15.3	0.2	44.7	-	-	25.2	11.1	1.3	4.1	**50.4**	**75.2**	**64.5**
At 31 December 2016	**126.5**	**43.8**	**1.6**	**243.4**	**0.1**	**74.3**	**103.2**	**136.0**	**23.8**	**35.6**	**255.2**	**533.1**	**353.3**

Notes:

1 Revisions to reserves are based on re-evaluation of production performance, drilling results and future plans in Chim Sáo and Dua (Vietnam); Anoa, Gajah Baru, Pelikan, Naga & Kakap (Indonesia); Catcher Area, Solan, B-Block, Kyle & Wytch Farm (UK), Bhit and Qadirpur (Pakistan)

2 Discoveries in Laverda are not classified as reserves and do not appear in this table

3 Acquisition of E.ON assets in the UK account for the entire acquisition reserve addition

4 Proved plus portable gas includes 95 bcf of fuel gas reserves

Premier Oil plc categorises petroleum resources in accordance with the 2007 SPE/WPC/AAPG/SPEE Petroleum Resource Management System ('SPE PRMS').

Proved and probable reserves are based on operator, third party reports and internal estimates and are defined in accordance with the Statement of Recommended Practice ('SORP') issued by the Oil Industry Accounting Committee ('OIAC'), dated July 2001.

The Group provides for amortisation of costs relating to evaluated properties based on direct interests on direct interests on an entitlement basis, which incorporates the terms of the PSCs in Indonesia, Vietnam and Mauritania. On an entitlement basis reserves were 332.3 mmboe as at 31 December 2016 (2015: 315.5 mmboe). This was calculated at year-end 2016, using an oil price assumption equal to US$58bbl in 2017, US$58/bbl in 2018, US$65/bbl in 2019 and US$75/bbl in 'real' terms thereafter.