PremierOil

Full Year Results for the year ended 31 December 2017

Press Release

Tony Durrant, Chief Executive, commented:

"2017 was a successful year for Premier with the refinancing completed, our producing portfolio performing well, the Catcher field brought on-stream and the notable Zama oil discovery in Mexico. 2018 will see further production growth, allowing us to deliver on our plans for reducing net debt to restore balance sheet strength while also progressing projects that deliver the highest financial returns."

2017 Operational highlights

- Production of 75 kboepd (2016: 71.4 kboepd)
- Catcher first oil achieved in December, on schedule and under budget
- Tolmount funding secured
- World class discovery offshore Mexico, estimated 600 mmbbls (gross)
- US$300 million of non-core asset disposals
- Reserves and resources of 902 mmboe (2016: 835 mmboe)

2017 Financial highlights

- Comprehensive refinancing completed; cash and undrawn facilities at year-end of US$541.2 million
- Cash flows from operations of US$496.0 million up 15% (2016: US$431.4 million)
- Opex of US$16.4/boe, maintaining low cost base
- Development and exploration capex of US$275.6 million, down 58%
- Positive free cash flow of US$71.2 million, net debt reduced to US$2.7 billion
- EBITDAX increased to US$589.7 million (2016: US$494.1 million)
- US$253.8 million post-tax loss after previously disclosed impairments and refinancing costs

2018 Outlook

- Production guidance of 80-85 kboepd
- Opex and capex guidance of US$17-18/boe and US$300 million, respectively
- Catcher expected to reach 60 kbopd (gross) in April ahead of plan
- Tolmount project sanction anticipated
- Material progress on Sea Lion towards final investment decision
- Zama: rig contracting in progress for 2H appraisal
- Significant covenant headroom forecast by year-end
- Rising free cash flow, driving debt reduction through 2018 and 2019

ENQUIRIES

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

Full Year Results for the year ended 31 December 2017

CHIEF EXECUTIVE OFFICER'S REVIEW

2017 saw continued volatility in commodity prices contributing to economic and market uncertainty for the industry. For Premier, the year contained three very significant highlights with a world class oil discovery at Zama offshore Mexico, first oil from the Catcher development, and the completion of our comprehensive debt refinancing. These events, together with a strong production performance from the existing business, continuing cost control and selective disposals of non-core assets, mean that Premier is already delivering ahead of its strategic plan agreed at the time of the refinancing. More recently the outlook has improved with oil prices closing 2017 at a two-year high of US$66.9/bbl.

Regardless of the external environment, Health, Safety, Environment and Security ('HSES') matters will always be of paramount importance to us and we will not compromise on the integrity and safety of our people and our operations. We continue to set ourselves challenging HSES targets to drive continuous improvement. Our HSES performance in 2017, as measured against our Group aggregate HSES targets, improved. In addition, all of our production and drilling operations retain their OHSAS 18001 and ISO 14001 certifications. More broadly, our corporate responsibility efforts continue to be guided by the Ten Principles of the UN Global Compact, to which we remain committed.

In the near-term Premier's focus is on reducing debt by utilising the Group's cash flow generated from our low cost stable production base. In 2017, Premier delivered production of 75.0 kboepd, in line with full year guidance and up five per cent on 2016. This increase in production was driven by a record first half underpinned by high operating efficiency across the portfolio and a full year contribution from the ex-E.ON assets.

Production (kboepd)	**Working interest**		**Entitlement**	
	2017	2016	**2017**	2016
Indonesia	**14.1**	14.3	**10.3**	10.1
Pakistan and Mauritania	**6.5**	7.9	**6.4**	7.9
UK	**39.5**	33.0	**39.5**	33.0
Vietnam	**14.9**	16.2	**13.0**	15.1
Total	**75.0**	71.4	**69.2**	66.1

Our South East Asia assets performed well during 2017. In Indonesia, demand from Singapore for our gas was strong and our operated Natuna Sea Block A fields secured an increased market share within its principal gas sales contract ('GSA1') of 49.6 per cent against a contractual share of 47.25 per cent. It also delivered record production under the second gas sales contract ('GSA2'). Across the border in Vietnam, gross production from the Premier-operated Chim

Sáo field passed 50 million barrels, in excess of the original total sanctioned volumes. The field exceeded expectations both in terms of operating efficiency and better than expected reservoir performance, with a successful well intervention programme helping to mitigate natural decline from the field. Year-end production levels were also boosted by a further 6.5 kboepd (gross) after completing a low cost, two well infill drilling programme.

UK production, which represents over half of Group production, grew 20 per cent from 2016 principally as a result of a full year's contribution from the ex-E.ON assets, which continue to exceed expectations at the time of acquisition. The Huntington field saw particular outperformance, contributing 13.0 kboepd, and it remains the highest net producer in our UK portfolio prior to the ramp up of production from the Catcher Area. The continuing strong reservoir performance, together with an improved lease rate structure on the FPSO agreed with Teekay, means that we expect Huntington to continue to produce longer than previously envisaged. The long-life Elgin-Franklin field continued to benefit from an ongoing infill drilling programme and our Babbage gas field delivered a strong performance in 2017 underpinned by well intervention and optimisation of the existing well stock. Production from the Solan field was lower than originally expected due to poorer performance in the East reservoir. This has resulted in a write down in recoverable reserves leading to a non-cash impairment charge in the year. Current production from Solan is performing in line with our revised expectations and we continue to evaluate options to improve production levels and recovery. Profits from UK production continue to be sheltered by Premier's brought forward cumulative tax loss and allowance position.

In December we were delighted to safely deliver first oil from the Catcher Area, marking a significant milestone for Premier. The successful execution of this project on schedule, and with total project costs expected to be some 30 per cent below the original sanctioned budget, is testament to the hard work, skill and capability of the project team and our contractors. We are bringing the development on-stream in a phased manner from the three fields that make up the Catcher Area, firstly from the Catcher field, then Varadero and shortly from Burgman, as the final commissioning activities on the FPSO are completed. Once the field is fully operational we will be producing at a plateau production rate of 60 kbopd (gross) which we expect to achieve during April. Development drilling throughout the project has been encouraging with 14 wells now completed and a further 4 wells to be drilled by September 2018. Catcher is an example of Premier's capability to deliver full cycle FPSO projects from exploration through to production and the increased cash flows it generates will play an important role in our debt reduction plans in 2018 and beyond.

During 2018, we expect Group production to increase to 80-85 kboepd reflecting the phased ramp up from the Catcher Area, offset by natural decline in certain of our fields and the impact of disposals.

Full Year Results for the year ended 31 December 2017

Strict management of our operating cost base and our committed capital expenditure have remained a key focus for Premier in 2017. Our operating costs were US$16.4/boe (2016: US$15.8/boe) in line with budget, reflecting changes in the production portfolio and ongoing cost saving initiatives. We continue to see opportunities for further savings from collaboration initiatives and competitive re-tendering, and expect to maintain a low cost base for the medium-term. 2017 capital expenditure was well below our original guidance as we secured further savings on the Catcher project and on our drilling campaign in Mexico. As the current phase of the Catcher development completes in the middle of 2018, Premier's forward committed capex will fall significantly.

Alongside increasing production and cost control discipline, our selective disposal programme of non-core assets announced in 2017 has enabled us to start deleveraging our balance sheet. These disposals included the sale of our Pakistan business that will complete after the receipt of Pakistani authorities approval, the ongoing rationalisation of assets acquired with the E.ON portfolio and the disposal of our non-operated interest in the Wytch Farm field which completed in December. These disposals, which will generate consideration of US$300 million, are an important part of meeting our debt reduction targets.

In the medium-term Premier intends to invest selectively in our portfolio of future projects to maintain and grow our production in the 2019-2021 timeframe and deliver value for all stakeholders. In July we were delighted to announce a material exploration success in Mexico. The world class oil discovery at the Zama-1 exploration well vindicated our strategy of focusing on under-explored but proven hydrocarbon basins and our initial estimates for the full field are a P90-P10 gross unrisked resource range of 400-800 mmbbls, well ahead of pre-drill expectations. Premier continues to work with both our joint venture partners and PEMEX in the neighbouring block to secure a pre-unitisation agreement to progress the appraisal of this significant discovery. Discussions are underway to secure an option on a rig to undertake the appraisal programme which is expected to commence in the second half of 2018 or early 2019.

Our next development is an incremental gas project in Indonesia, which was sanctioned by the Board in March 2017. Bison, Iguana, Gajah Puteri ('BIGP'), which is designed to back fill our existing Singapore and domestic gas sales contracts, is proceeding well and is on budget and scheduled to deliver first gas in 2019.

Our Tolmount Main gas development in the Southern North Sea, which will provide the next significant phase of our growth, is targeted for project sanction in 2018. This initial phase is targeting gross resources of 540 Bcf (100 mmboe) and is an economically robust project for Premier even at low gas prices. There is also significant resource upside, currently estimated at a further 400 Bcf (gross) in the Greater Tolmount Area. Front End Engineering Design ('FEED') work is progressing well, the environmental assessments for the project are underway and a draft field development plan has been submitted to the OGA. We are pleased to have agreed an innovative financing arrangement for the project, establishing an infrastructure partnership for the field facilities. The impact of this arrangement is to reduce Premier's share of the capex required to develop this large gas field to approximately US$100 million.

Our Sea Lion project in the Falkland Islands is Premier's largest pre-development project with around 400 mmboe reserves and resources (net to Premier) to be developed over several phases. With considerable progress made in 2016 to optimise the project economics for the first phase of the development, work in 2017 focused on the commercial, regulatory and fiscal work streams and on securing a financing solution. Discussions are ongoing with senior debt providers and supply chain contractors to secure suitable funding and commercial terms. Letters of Intent have now been signed with contractors for the provision of a range of services including vendor financing. Premier is working towards a final investment decision by the end of 2018.

At 31 December 2017 group proven and probable (2P) reserves, on a working interest basis, were 302 mmboe (2016: 353 mmboe) and total 2P reserves and 2C resources increased to 902 mmboe (2016: 835 mmboe).

	Proven and probable 2P reserves (mmboe)	**2P reserves and 2C contingent resources (mmboe)**
1 January 2017	353	835
Production	(27)	(27)
Net additions, revisions, discoveries	(12)	120
Disposals, relinquishments	(12)	(26)
31 December 2017	**302**	**902**

The decrease in 2P reserves is driven by the impact of 2017 production, a downward revision to our Solan 2P reserve estimates and the disposal of our Wytch Farm interests. This is partially offset by upward revisions to our estimates of 2P reserves at both Huntington and Babbage. The increase in our 2C resources of 118 mmboe was principally a result of the Zama oil discovery offshore Mexico, the addition of Tolmount East as a contingent resource and upward revision to the Sea Lion Phase 2 resources including the 2015 Zebedee discovery.

The completion of the refinancing of our debt facilities in July marked a major milestone for Premier and has established a solid foundation for us to fulfil our strategic plans. Debt reduction remains our top priority, but the refinancing provides the headroom and flexibility to plan for future investment in selective new projects. At year-end net debt stood at US$2.7 billion. Positive free cash flow including disposals was offset by adjustments to reflect the terms and costs of the refinancing and non-cash foreign exchange movements. Post year-end Premier invited our convertible bondholders to accelerate the conversion of their bonds. Approximately US$200 million was converted resulting in a further reduction in net debt.

As we enter 2018, our stable production delivered from a competitive operating cost base and lower capital commitments will generate increasing free cash flows, which in the short-term will be directed at reducing our debt. Looking forward, we will selectively invest in new development projects within a strict capital discipline framework to provide growth in the medium-term and deliver future value for all stakeholders.

Tony Durrant

Chief Executive Officer

Full Year Results for the year ended 31 December 2017

OPERATIONAL REVIEW

UNITED KINGDOM

The UK delivered 20 per cent higher production in 2017, with a full year's contribution from the E.ON assets acquired during 2016 and high operating efficiency across the portfolio. First oil from the Catcher Area, which was delivered on 23 December on schedule and with total forecast project costs some 30 per cent below the sanctioned budget, will deliver a further increase to UK production in 2018. Looking forward, we expect to sanction the Tolmount gas project during 2018, providing the next phase of growth for the UK business, which is expected to average around 50 kboepd (net) over the next five years.

Production

Production from Premier's UK fields averaged 39.5 kboepd (net) (2016: 33.0 kboepd (net)), up 20 per cent on 2016. Following delivery of first oil from Catcher at the end of the year, there will be a further production growth in 2018, despite the impact of the Wytch Farm disposal in December. Production from the Catcher Area is currently ramping up and is expected to reach plateau rates during April.

The Premier-operated Huntington field (100 per cent interest) was the highest producer in the UK portfolio in 2017 with production averaging 13.0 kboepd (2016: 10.8 kboepd), 28 per cent higher than budget. This strong performance was achieved by improved reservoir management and high FPSO operating efficiency. The lease agreement with Teekay, the owner of the Voyageur Spirit FPSO, has been extended beyond April 2018 for a minimum of a year with a revised lower lease cost structure. The combination of better than expected reservoir performance and a lower FPSO lease rate has led Premier to increase its estimate of Huntington's remaining net 2P reserves by 4 mmboe.

Production from the non-operated Elgin-Franklin field (5.2 per cent interest) was marginally below budget, averaging 5.4 kboepd (net). Strong underlying field performance as a result of an ongoing infill drilling campaign was offset by an extended summer maintenance shutdown required to replace a large platform riser shutdown valve, and by downtime of the Forties Pipeline System ('FPS') export pipeline during the fourth quarter of 2017. 2018 production to the end of February has averaged 7.7 kboepd (net), above expectations, due to contributions from infill drilling and high operating efficiency. The non-operated Glenelg field (18.75 per cent interest), a satellite field within the Elgin-Franklin area, produced intermittently during 2017 due to downhole scaling in the single well. This is likely to require an intervention in 2018/19 to rectify fully.

A successful well intervention programme and continued production optimisation of the existing well stock led to the Premier-operated Babbage field (47 per cent interest) delivering 3.1 kboepd (net), ahead of budget. In addition, field operating costs were reduced by more than 20 per cent as a result of the platform being transitioned to a Not

Permanently Attended Installation ('NPAI') in April. Premier will continue to undertake production optimisation activities at the field which are expected to add incremental production for low additional expenditure in coming years. As a result of the improved production performance and lower operating costs, Premier now expects a longer than expected field life beyond 2030 and has revised upwards its estimates of Babbage's remaining net 2P reserves.

In the Southern North Sea, similar well optimisation efforts, including re-instatement of inactive wells and interventions in existing well stock, have seen production restart at the Rita gas field (74 per cent interest) after being shut in for almost two years. There have also been successful well re-instatements at the Johnston gas field (50.1 per cent interest). These low cost activities typically deliver short-term cash payback in less than 12 months.

Production from the Premier-operated Solan field (100 per cent interest) averaged 5.9 kboepd, lower than originally expected, as a result of the first production well ('P1') being shut in for a period in February following the failure of the existing electric submersible pump ('ESP'). P1 is currently producing as expected on free flow and as a result the Company has no immediate requirement for workover operations. Production rates from the second producer ('P2') remain limited due to poor reservoir performance in the eastern part of the field. During the year further topside enhancements were completed with the successful installation and commissioning of a water injection upgrade and produced water handling projects. Options to improve production levels and recovery at Solan continue to be evaluated including a possible further drilling campaign starting in 2019 or 2020. Premier has reduced its estimates of Solan's remaining net 2P reserves, reflecting lower expected recovery from the asset over its economic life. This reduction does not take account of any potential upside from the deeper Triassic play on the Solan licence or the impact of any potential third-party volumes across the Solan infrastructure, which are currently being assessed.

Production from the Premier-operated Balmoral Area performed as expected delivering 2.2 kboepd (net) (2016: 2.1 kboepd (net)). Previous plans for cessation of production at Balmoral by April 2019 have been re-evaluated, driven by the asset's performance and improving market oil prices. Planning for the decommissioning of the area is well advanced, including the disposal and sale of the Balmoral Floating Production Vessel ('FPV'). Some decommissioning work has started and during the fourth quarter, the Helix Well Op's Seawell intervention vessel entered four old suspended Balmoral water injection wells to gather information on well status and to prepare the wells for later abandonment. Premier is now considering moving cessation of production out to 2021, subject to partner and Government approvals. In order to do this, some modest further investment on wells, subsea and topsides may be required to maintain performance and asset integrity, whilst a lower but appropriate level of decommissioning planning works would also continue.

Production from the non-operated Wytch Farm field (33.8 per cent interest) averaged 4.4 kboepd (net) (2016: 5.1 kboepd (net), reflecting natural reservoir decline and a reduced contribution following disposal of the asset in December.

UK unit operating costs for the year were US$23/boe (2016: US$24/boe) as a result of favourable asset uptime, continued cost control measures and a full year's contribution from the E.ON assets. In 2018, Premier expects a further reduction in the UK operating costs per barrel with increased production from the start-up of the Catcher Area and the lower leased FPSO rates at Huntington, offsetting natural decline at certain fields.

Development

Catcher

First oil was successfully delivered on schedule on the Premier-operated Catcher project on 23 December. The Catcher Area (50 per cent interest) comprises three fields - Catcher, Varadero and Burgman - with production initially started from the Catcher field. Total forecast capex remains at US$1.6 billion, 30 per cent lower than the sanctioned estimate.

Following successful final construction and pre-commissioning activity during the period, the Catcher FPSO departed the Keppel shipyard in Singapore on 10 August and completed its journey to the UK via the Suez Canal without incident and ahead of schedule. The vessel then completed a planned stop at Nigg Port, Scotland for preparatory work ahead of arrival at the Catcher field location on 18 October. By 20 October it was successfully connected in-field to the pre-installed buoy and had completed the initial rotation test. The installation, hook-up and commissioning ('IHUC') work has proceeded to plan. All production and injection risers were permanently hung-off, shutdown valving installed and subsea control umbilicals attached. The remaining offshore construction period of work was complete by the end of November, when the focus switched to final commissioning of subsea systems and the interfaces with the vessel. A trial for oil tanker offloading completed successfully in the third week of November ahead of first oil in December.

The initial production wells from the Catcher field were cleaned up and tested at rates in excess of 20 kbopd (gross) each, in line with expectations and reflecting initial high productivity. As planned, production is being ramped up in phases with first oil from Varadero brought on in early January, to be followed by Burgman shortly. Production levels have had to be deliberately constrained during the ramp up phase while commissioning of the full gas processing modules and the water injection systems on the FPSO are carried out. Water injection was brought on in mid-February and the final gas compression commissioning is underway. Following this, full production from the Catcher Area of 60 kbopd (gross) is expected during April. The first two export cargos of over 500,000 barrels each were lifted on 23 January and 18 February and both were sold at a premium to Brent.

Drilling activities using the Ensco 100 rig have continued with operations ahead of schedule and under budget. Fourteen production and injection wells have now been drilled and completed with consistently positive reservoir results, with 12 of these wells being tied-in ahead of first oil. The rig is currently drilling the CCP6 well on the second Catcher template and will drill a further Catcher well before moving to the Burgman field. A total of 18 wells will be drilled by September 2018 before a planned drilling break. As a result of initial production from the field and these positive well results to date, Premier is encouraged about the potential overall recovery from the Catcher Area and continues to target peak plateau production of approximately 60 kbopd (gross), 20 per cent higher than that envisaged at sanction.

Premier and its joint venture partners are already examining future Catcher Area development opportunities to make full use of the newly commissioned facilities. Studies are underway for the future development of the 2016 Laverda discovery in conjunction with an infill well in the northern area of the Catcher field. These future activities, amongst others, are planned to provide incremental production from 2020 onwards.

Pre-development

Good progress has been achieved on the Premier-operated Tolmount project (50 per cent interest) in the Southern Gas Basin. It is envisaged that the initial phase, which will target the Tolmount main structure, will recover 540 Bcf (gross) of gas from four producing wells at a production capacity of up to 300 mmscfd (gross).

In February 2017, the development concept, comprising a standalone normally unmanned installation (‘NUI’) and a new gas export pipeline to shore, was selected. A commercial Heads of Terms was also signed with a terminal operator to process the Tolmount fluids and to undertake terminal modification works on behalf of the Tolmount project. Front End Engineering & Design (‘FEED’) work is progressing well, with platform and pipeline FEED completed and tenders received for the project scopes under evaluation. Bids are also being evaluated from drilling rig providers to cover the development drilling programme, and the earlier drilling of the Tolmount East appraisal well in 2019.

Alongside the FEED process, Premier signed a Heads of Terms to enter into an infrastructure partnership for the Tolmount development with Dana Petroleum and CATS Management Limited, whereby they will jointly finance, construct and own the Tolmount platform and export pipeline as a standalone development, as well as undertaking the onshore modifications at the onshore gas receiving terminal. The Tolmount field will be tied-in to the platform and a tariff will be paid to the infrastructure owners by the upstream partners for the transportation of gas production through the infrastructure over the life of the field. As a result, Premier’s share of capex is estimated to be approximately US$100 million. Fully termed agreements are being progressed ahead of project sanction which is scheduled during 2018.

Exploration

During 2017, well operations on the Ravenspurn North Deep well (five per cent carried interest), which was testing the deep Carboniferous play underlying the Ravenspurn North field in the Southern Gas Basin, were completed. The well was plugged and abandoned.

Premier continues to actively manage its UK exploration portfolio. In September, Premier exited the P2184 Licence which carried a commitment well obligation on the Ekland prospect and a further four licences were relinquished by the end of the year. This includes the P2136 Artemis Licence, where a well commitment was offset against other activity in the UKCS.

Portfolio management

During the first half of the year Premier exercised its pre-emption rights to acquire an additional 3.71 per cent of the Wytch Farm field for approximately US$15 million, taking Premier's overall interest in the field to 33.8 per cent. Subsequently, Premier agreed to dispose of its entire 33.8 per cent interest in the Wytch Farm field to Perenco UK Limited for a cash consideration of US$200 million, realising an attractive valuation in excess of that implied from the previous transaction and above Premier's internal valuation. Premier was also able to release Letters of Credit, amounting to approximately US$75 million, held in respect of future field abandonment liabilities. The sale completed in December, generating a pre-tax profit on disposal of approximately US$133 million.

Premier continued its programme of non-core asset disposals in 2017 principally from the E.ON portfolio acquired in 2016. It disposed of its interests in the Austen and Arran fields in the Central North Sea during the year and in December announced the disposal of its 30 per cent interest in the Esmond Transportation System ('ETS') pipeline for up to US$31.6 million. These disposals, together with the relinquishment of other licences, has meant that Premier has actively managed its current UK licence position down from 63 blocks in 2016 to 39 blocks today, and this rationalisation activity is expected to continue in 2018.

INDONESIA

The Premier-operated Natuna Sea Block A fields delivered a robust and stable performance in 2017 with production of 12.9 kboepd (net), underpinned by supplying an increased market share of 49.6 per cent within GSA1 and strong Singapore demand for gas deliveries under GSA2. This, together with continued low operating costs of US$9.6/boe, once again led to the Indonesian business unit generating material positive net cash flows for the Group.

Production and development

Production from Indonesia in 2017 on a working interest basis was in line with budget at 14.1 kboepd (net) (2016: 14.3 kboepd (net)). The Premier-operated Natuna Sea Block A fields (28.67 per cent interest) delivered 12.9 kboepd (net) while production from the non-operated Kakap field (18.75 per cent interest) averaged 1.2 kboepd (net). Operating efficiency remained high at over 99 per cent.

Gas supply by contract						
	GSA1		GSA2		GSA5	
BBtud (gross)	**2017**	2016	**2017**	2016	**2017**	2016
Anoa (Pelikan field)	**143**	132	**–**	–	**–**	–
Gajah Baru (Naga field)	**–**	–	**91**	94	**–**	11
Total Block A	**143**	132	**91**	94	**–**	11
Kakap	**17**	17	**–**	–	**–**	–
Total	**160**	149	**91**	94	**–**	11

Premier sold an average of 234 BBtud (gross) (2016: 237 BBtud) from its operated Natuna Sea Block A fields during 2017. Singapore demand for gas sold under GSA1 remained robust, averaging 286 BBtud (2016: 297 BBtud). Premier's Anoa and Pelikan fields delivered 143 BBtud (gross) (2016: 132 BBtud (gross)), capturing 49.6 per cent (2016: 44.4 per cent) of GSA1 deliveries, above Natuna Sea Block A's contractual share of 47.2 per cent. Natuna Sea Block A's contractual share for 2018 has been increased to 51.7 per cent.

Gajah Baru and Naga delivered production of 91 BBtud (gross) (2016: 94 BBtud (gross)) under GSA2, representing 100 per cent nomination delivery by Premier. There were no deliveries under GSA5 (2016: 11 BBtud (gross)) following the expiry of the Domestic Gas Supply Agreement.

Gas sales from the non-operated Kakap field averaged 17 BBtud (gross) (2016: 17 BBtud (gross)) while gross liquids production was 2.6 kbopd (2016: 2.7 kbopd). Gross liquids production from the Anoa field was 1.1 kbopd (2016: 1.4 kbopd), underpinned by successful well intervention work.

Premier continues to benefit from a low cost base in Indonesia, delivering further cost reductions in 2017. Based on current production levels, Natuna Sea Block A remains well placed to deliver operating costs of around US$9/boe into the medium-term.

The Anoa development well ('WL-5X'), which made the Lama discovery under Anoa in 2012, was re-completed in August 2017. The well was brought on-stream to carry out a long-term production test which will help to define the potential of these deeper zones within the Anoa field.

The development of the Bison, Iguana and Gajah Puteri ('BIGP') gas fields was sanctioned in 2017 which marks the next generation of Natuna Sea Block A projects to support Premier's long-term gas contracts into Singapore. The EPCI contract for BIGP, which will be developed as subsea tiebacks to existing infrastructure, was executed in October 2017 and development drilling is planned for early 2019. First gas remains on budget and on schedule for the second half of 2019.

In January Premier was granted a three-year extension to the exploration period of the Premier-operated Tuna PSC licence where the evaluation of potential development scenarios for the 2014 Kuda Laut and Singa Laut discoveries, now collectively known as the Tuna field (65 per cent interest), is ongoing. In November a Memorandum of Understanding between PetroVietnam, SKK Migas (on behalf of the Indonesian Government) and Premier for future gas sales from the Tuna field in Indonesia into Vietnam was signed, enhancing future commercialisation. In 2018, a farm-out process has been launched with a view to funding Premier's share of an appraisal campaign in 2019.

Exploration and appraisal

As a result of the production performance from the Anoa development well WL-5X, brought on-stream in August, Premier is reprocessing 3D seismic over the Anoa field to enhance the seismic imaging across the Lama Play area. Premier will use this reprocessed data to identify and mature Lama Play leads and prospects on its Natuna Sea Block A acreage.

Since the year-end, Premier together with its joint venture partners has been awarded the Andaman II licence (40 per cent, operated interest) in the North Sumatra basin offshore Aceh, Indonesia. The licence has the potential to deliver significant gas volumes into North Sumatra and adds a potentially material gas play to Premier's Indonesian portfolio.

Portfolio management

In December, Premier signed a sale and purchase agreement with Batavia Oil to sell its entire 18.75 per cent non-operated interest in the Kakap field for a cash consideration of US$3.2 million. Completion is subject to approval from the Government of Indonesia.

VIETNAM

The Vietnam business generated strong operating cash flows in 2017 due to a higher than budgeted production performance combined with continued low operating costs. During the period, gross cumulative production surpassed 50 million barrels, in excess of the original volumes estimated at project sanction.

Production

Production from the Premier-operated Block 12W (53.13 per cent interest), which contains the Chim Sáo and Dua fields, was ahead of budget, averaging 14.9 kboepd (net) (2016: 16.2 kboped (net)) underpinned by high operating efficiency, excellent reservoir performance and a successful well intervention programme which helped to mitigate natural decline from the fields.

A two well infill drilling programme completed in December 2017 proved highly successful, adding incremental net production of 3.3 kboepd and further extending the long-term potential from the field. The infill drilling programme comprised two low cost wells. The first well was a side-track of a water injector well no longer required which was re-completed as a production well while the second well was drilled from the final unused slot on the Chim Sáo wellhead platform. Using lessons learnt from previous drilling campaigns, reservoir performance has been improved and production increased, with some further zones remaining unperforated. This will allow us to target bringing further incremental production on-stream in 2018.

Overlying the two main reservoirs in the Chim Sáo field are several smaller but significant hydrocarbon bearing sandstones which are intersected by the production wells. In 2017, as the rate of hydrocarbon flow from the main reservoirs reduced, the shallower reservoirs of selected wells were perforated to access new zones. In addition, producing zones in several wells were worked over to accelerate hydrocarbon production. This intervention programme on existing wells reduced the rate of natural production decline and contributed 1.0 kboepd (net) to Premier's 2017 production at a cost of only US$4/barrel.

Chim Sáo's operating efficiency remained at over 90 per cent in 2017. This was the result of safe and reliable operations and maintenance services, minimal unplanned events, and planned shutdown and slowdown campaigns being completed on schedule.

During 2017 Chim Sáo operating costs remained low at US$9.8/boe (2016: US$8.7/boe). Low costs were maintained by replacing the supply vessel contract at depressed market rates, improved vessel management, and the impact of the lower Chim Sáo FPSO lease rate agreed at the end of 2016. These savings, along with Chim Sáo crude continuing to sell at premiums to the Brent oil price, contributed to a positive net operating cash flow from the Vietnam business unit in 2017 despite the cost of the infill programme.

PAKISTAN

Premier's Pakistan business continued to generate positive and stable net cash flows for the Group. During 2017, the average realised gas price was US$3.0/mscf while operating costs remained low at US$4.2/boe (US$0.6/mscf).

Production and Development

Net production in Pakistan averaged 6.2 kboepd (39.1 mmscfd) (2016: 7.5 kboepd (47.4 mmscfd)) from Premier's six non-operated producing gas fields. The fall in production reflects natural decline in the main gas fields which was partially offset by successful well intervention campaigns at the Bhit and Badhra fields.

Mmscfd (net)	Production 2017	2016	Equity interest %
Bhit	**7.0**	8.4	6.0
Badhra	**4.6**	5.7	6.0
Qadirpur	**14.9**	16.1	4.75
Kadanwari	**4.1**	5.5	15.79
Zamzama	**7.9**	11.3	9.38
Zarghun South	**0.6**	0.4	3.75
Total	**39.1**	47.4	

Portfolio management

In April, Premier announced the sale of its Pakistan business to Al-Haj Group for US$65.6 million. To date, Al-Haj has paid deposits of US$25.0 million. Completion of the sale is awaiting final approvals from the Pakistani authorities and in the meantime Premier continues to collect the cash flows generated from the Pakistan assets.

MAURITANIA

Production and development

Production from the Chinguetti field (8.12 per cent interest) averaged 257 bopd (2016: 368 bopd) net to Premier during 2017. The fall in production was driven by natural decline from the existing wells. As a result of these low production volumes and resulting marginal cash flows, the joint venture partners ceased production from the field on 30 December 2017 and the FPSO is being prepared for sail away. A drill ship has now been mobilised to the Chinguetti field to start a six-month campaign for temporary suspension of wells starting with the water injection wells. The permanent abandonment of the wells is scheduled for 2019. The field abandonment and decommissioning plan is awaiting approval by the Government of Mauritania. In addition, plans are being prepared for the abandonment of the suspended exploration and appraisal wells on the previously relinquished Banda and Tiof discoveries.

THE FALKLAND ISLANDS

The focus in 2017 for the Premier-operated Sea Lion Phase 1 project has been on progressing commercial and regulatory work streams and on securing commitments from key contractors for the project.

Pre - development

The Sea Lion project and the wider North Falklands Basin, has the potential to be significant for Premier and the strategy is to develop the discovered resources in several phases. Sea Lion Phase 1 (60 per cent interest), which is targeting gross reserves of over 220 mmbbls in PL032, will utilise a conventional FPSO based scheme, very similar to Premier's successful Catcher development. Engineering design work which was largely completed in 2016, focused on optimising the facilities design and installation methodology required reducing the estimated gross capex to first oil to US$1.5 billion.

During 2017, Premier focused on securing agreement with key supply chain contractors for the project. Good progress was made in this respect with Letters of Intent signed with a number of contractors for the provision of a range of services and vendor financing. Further discussions with senior debt providers including commercial banks and export credit finance agencies will progress in 2018.

Alongside this, Premier continued to engage with the Falkland Islands Government ('FIG') on environmental, fiscal and other regulatory matters with a view to obtaining the consents and agreements necessary to be in a position to reach a final investment by the end of 2018. As part of this process the latest drafts of the Field Development Plan and Environmental Impact Statement ('EIS') for Sea Lion Phase 1 were submitted to FIG and the formal public consultation of the EIS commenced in January 2018.

It is estimated that a subsequent Phase 2 development will recover over 300 mmbbls (gross) from the remaining volumes in PL032 and the satellite accumulations in the north of the adjacent PL004. During 2017 further technical analysis carried out on Phase 2, including the 2015 Zebedee discovery in PL004, has resulted in an increase in net 2C resources at the year-end.

EXPLORATION

In recent years, Premier's strategy has been to focus its exploration portfolio on under-explored but proven hydrocarbon basins rather than traditional but now mature areas, with priority given to lower cost operating environments. This strategy resulted in a major success with the world class oil discovery at the Zama-1 well offshore Mexico during 2017, capitalising on Premier's first mover advantage as the country opened up to foreign investment.

MEXICO

During 2017 Premier, together with its joint venture partners Talos Energy (Operator) and Sierra Oil & Gas, drilled the Zama prospect in Block 7 in the Sureste Basin, offshore Mexico which resulted in a significant oil discovery. The Zama-1 well encountered a continuous oil bearing interval of over 335 metres (1,100 feet) with up to 200 metres of net oil bearing reservoir in upper Miocene sandstones with no water contact. Initial tests of hydrocarbon samples recovered to the surface showed light oil with API gravities between 28 and 30 degrees. Premier's initial gross oil-in-place estimates are 1.2-1.8 billion barrels, with an estimated recoverable P90-P10 gross resource range of 400-800 mmbbls. These estimates include those volumes that extend into the neighbouring block which is operated by PEMEX. The joint venture is now working with PEMEX to secure a pre-unitisation agreement in order to progress the appraisal programme which is expected to commence on Premier's block in the second half of 2018 or in early 2019. Our joint venture is close to securing an option on a rig to complete the appraisal programme on Block 7 and PEMEX has indicated that they intend to appraise the Zama discovery on their licence with a well scheduled to spud in the second quarter of 2018. In addition to appraisal well planning, pre-FEED scoping studies have been received from seven vendors aiding appraisal planning and identifying additional data to be acquired in the up and coming drilling programme. Premier holds a 25 per cent paying interest in Block 7.

Premier also currently holds a carried 10 per cent interest in Block 2, with an option to increase to 25 per cent or to exit. The joint venture is evaluating which prospect will be the first to be drilled, targeting a well in 2019. Premier continues to evaluate opportunities for growth in Mexico, from future licensing rounds.

BRAZIL

Premier received 4,000 km^2 of final processed broadband seismic data across all three of its Ceará Basin blocks in April 2017. The data has now been interpreted, the best prospects selected and the wells are being planned in advance of a potential drilling campaign in 2019 or 2020. Significant progress has been made on obtaining environmental and drilling permits as Premier continues to leverage its position as the largest acreage holder in the Ceará Basin, along with its growing experience in Brazil, to coordinate operational synergies. In October the ANP, the Brazilian Government regulator, published an option to all Round 11 awards that entitles Premier to request extension of its licences by a further two years to at least July 2021.

Full Year Results for the year ended 31 December 2017

FINANCIAL REVIEW

Overview

2017 saw continuing oil price volatility. Brent crude opened the year at US$56.6/bbl before falling to US$44.8/bbl in June and then strengthening considerably in the second half of the year to close at US$66.9/bbl at 31 December 2017. The average for 2017 was US$54.2/bbl against US$43.7/bbl for 2016. Subsequent to the year-end, prices improved during January reaching a high of US$71.3/bbl, before falling to US$64.2/bbl on 7 March 2018, below the year end observed price.

Against this economic backdrop we have achieved our best ever full year of production, averaging 75.0 kboepd (2016: 71.4 kboepd), resulting in total revenue from all operations of US$1,102 million compared with US$983.4 million in 2016 and Free Cash Flow after disposals of US$71 million (2016: US$580 million cash outflow). In addition, we successfully completed the refinancing of all of our debt facilities in July 2017 and reached first oil on the Catcher field in the UK North Sea in December 2017.

Business performance

EBITDAX for the year from continuing operations was US$589.7 million compared to US$494.1 million for 2016. The increase in EBITDAX is mainly due to higher production and sales volumes realised during the year.

Business Performance (continuing operations)	**2017 $ million**	2016 $ million
Operating profit / (loss)	**33.8**	(170.1)
Add: Amortisation and depreciation	**415.6**	326.4
Add: Impairment charge on oil and gas properties	**252.2**	561.9
Add: Exploration expense and pre-licence costs	**17.1**	58.5
Less: Gain on disposal of assets	**(129.0)**	-
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[1]	**589.7**	494.1

1. Prior year has been restated for results from the Pakistan business unit, which has been reclassified as a discontinued operation in the year.

Full Year Results for the year ended 31 December 2017

Income statement

Production and commodity prices

Group production on a working interest basis averaged 75.0 kboepd compared to 71.4 kboepd in 2016. This was driven by high operating efficiency, better than predicted reservoir performance on certain fields and a full period contribution from the E.ON UK portfolio acquired in April 2016. Average entitlement production for the period was 69.2 kboepd (2016: 66.1 kboepd).

Premier realised an average oil price for the year of US$52.9/bbl (2016: US$44.1/bbl). Including the effect of oil swaps which settled during 2017, the realised oil price was US$52.1/bbl (2016: US$52.2/bbl).

In the UK, average natural gas prices achieved were 47.2 pence/therm (2016: 47.6 pence/therm), which included 95.8 million therms which were sold under fixed price master sales agreements. Gas prices in Singapore, linked to high sulphur fuel oil ('HSFO') pricing and in turn, therefore, linked to crude oil pricing, averaged US$8.4/mscf (2016: US$7.8/mscf).

Total revenue from all operations (including Pakistan) increased to US$1,102 million (2016: US$983.4 million). From continuing operations (excluding Pakistan), sales revenue increased to US$1,043.1 million from US$937.0 million for the prior year.

Cost of operations

Cost of operations comprises operating costs, changes in lifting positions, inventory movements and royalties. Cost of operations for the Group from continuing operations was US$455.4 million for 2017, compared to US$412.7 million for 2016.

Operating Costs	**2017 $ million**	2016 $ million
Continuing operations	**438.4**	402.7
Discontinuing operations (Pakistan)	**9.6**	10.1
Operating costs	**448.0**	412.8
Operating costs per barrel	**16.4**	15.8

Amortisation and depreciation of oil and gas properties	**2017 $ million**	2016 $ million
Continuing operations	**409.0**	318.3
Discontinuing operations (Pakistan)	**7.2**	13.9
Total	**416.2**	332.2
Depreciation, depletion and amortisation ('DD&A') per barrel	**15.2**	12.7

The increase in absolute operating costs reflects a full year contribution from the former E.ON assets and the Solan field. Ongoing cost reduction initiatives, successful contract renegotiations and strict management of discretionary spend continue to deliver low and stable operating costs. On a per barrel basis, operating costs increased by 4 per cent due to portfolio mix effects in the production base.

The DD&A charge has increased to US$15.2 per barrel reflecting the accelerated DD&A charge attributable to Solan in the UK.

Impairment of oil and gas properties

A non-cash net impairment charge of US$252.2 million (pre-tax) (US$170.9 million post-tax) has been recognised in the income statement. This relates principally to the Solan field in the UK North Sea as a result of a reduction in the 2P reserves expected to be recovered from the asset over its economic life, partially offset by the recognition of a reversal of impairment for the Huntington asset in the UK. The reversal of impairment is principally caused by a 12 month extension in the life of the asset and a reduction in the lease rate payable for the FPSO. After recognition of the net impairment charge there is US$2,381.0 million capitalised in relation to PP&E assets and US$240.8 million for goodwill.

Exploration expenditure and pre-licence costs

Exploration expense and pre-licence expenditure costs amounted to US$17.1 million (2016: US$58.5 million). After recognition of these expenditures, the exploration and evaluation assets remaining on the balance sheet at 31 December 2017 amount to US$1,061.9 million, principally for the Sea Lion and Tolmount assets, as well as our share of drilling costs for the Zama prospect in Mexico.

General and administrative expenses

Net G&A costs of US$16.8 million (2016: US$24.1 million) reduced year-on-year. 2016 included E.ON's unallocated G&A costs which fell significantly post integration of the E.ON operations into the Group's UK business unit. Underlying gross G&A has fallen in 2017 and is broadly in line with 2015 levels.

Finance gains and charges

Finance costs, other finance expenses and losses of US$329.0 million, have increased compared to the prior year (US$258.8 million), principally due to a step up in the interest margin on our financing facilities following the completion of the refinancing.

Taxation

The Group's total tax credit for 2017 is US$96.1 million (2016: US$522.6 million restated for the exclusion of the Pakistan business unit) which comprises a current tax charge for the period of US$74.8 million and a non-cash deferred tax credit for the period of US$170.9 million.

The total tax charge represents an effective tax rate of 26.2 per cent (2016: 126.3 per cent). The low effective tax rate for the year is primarily impacted by two UK specific deferred tax items. The first is the impact of ring fence expenditure supplement claims in the UK during the year (US$69.1 million credit) and the second is the element of the UK impairment charge for the year that does not attract a deferred tax offset (US$19.6 million charge). After adjusting for the net impact of the above items of US$49.5 million, the underlying Group tax charge for the period is a credit of US$145.6 million and an effective tax rate of 40 per cent.

The Group has a net deferred tax asset of US$1,297.5 million at 31 December 2017 (2016: US$1,111.4 million). The increase in deferred tax asset primarily arises due to new UK tax losses and allowances generated in the year. The Group continues to recognise its deferred tax assets in respect of UK tax losses and allowances in full.

Loss after tax

Loss after tax is US$253.8 million (2016: profit of US$122.6 million) resulting in a basic loss per share of 49.4 cents from continuing and discontinued operations (2016: earning of 24.0 cents). The loss after tax in the year is driven by the non-cash impairment charges recognised and the one-time fees expensed in relation to the Group's refinancing, partially offset by the gain on disposal of the Wytch Farm interests.

Cash flows

Cash flow from operating activities was US$496.0 million (2016: US$431.4 million) after accounting for tax payments of US$69.6 million (2016: US$60.9 million). The increase in operating cash flows was largely driven by higher production and sales volumes.

Capital expenditure in 2017 totalled US$275.6 million (2016: US$662.6 million).

Capital expenditure	2017 $ million	2016 $ million
Fields/development projects	**236.8**	533.1
Exploration and evaluation	**37.6**	126.6
Other	**1.2**	2.9
Total	**275.6**	662.6

The principal development project was the Catcher field in the UK and the majority of exploration spend was related to the drilling programme on the Zama prospect in Mexico. In addition, cash expenditure for decommissioning activity in the period was US$25.7 million. Further to this, US$16.7 million of cash was placed into long-term abandonment escrow accounts for future decommissioning activities.

In 2018 development and exploration spend is expected to be around US$300 million, of which US$170 million relates to the Catcher development (including a one off contractual first oil payment made to the FPSO provider BW Offshore) and US$45 million to exploration. Capex will be weighted to the first half of 2018 as spending on the Catcher project completes with the drilling programme on the asset due to finish by the end of the third quarter. Abandonment spend is expected to be approximately US$80 million in 2018, before taking into account the benefits of cost recovery and tax relief.

Discontinued operations, disposals and assets held for sale

During the year, Premier signed a share purchase agreement with Al-Haj Energy Limited ('Al-Haj') for the sale of Premier Oil Pakistan Holdings BV, which comprises Premier's Pakistan business unit, for a cash consideration of US$65.6 million. During the year, Al-Haj paid a cash deposit to Premier of US$25.0 million.

The disposal of the Pakistan business unit is expected to complete in 2018 and, as this is within 12 months of the balance sheet date, the business unit has been classified as a disposal group held for sale and presented separately in the balance sheet. Results for the disposal group in both the current and prior periods have been presented as a discontinued operation. Profit after tax for the business unit for the year is US$16.4 million (2016: US$22.7 million). Assets and liabilities held for sale in relation to the Pakistan disposal group are US$52.2 million and US$25.4 million, respectively.

In September 2017, Premier entered into a sale and purchase agreement to sell its entire interests in Licences PL089 and P534, which contain the Wytch Farm field ('Wytch Farm'), to Verus Petroleum SNS Limited ('Verus') for a cash consideration of US$200 million, subject to certain customary financial adjustments. The disposal included the additional 3.71 per cent equity interest Premier acquired in September 2017 for US$9.8 million.

The disposal was subject to the pre-emption rights of existing joint venture partners and Premier subsequently received notification from Perenco UK Limited ('Perenco') of its intention to exercise those rights. Therefore, in November 2017, Premier entered into a sale and purchase agreement with Perenco on materially the same terms as those agreed with Verus.

The disposal to Perenco completed in December 2017, with Premier receiving final cash consideration, after working capital adjustments, of US$177.1 million. This resulted in a gain on disposal of US$133.0 million and enabled Premier to release letters of credit totalling approximately US$75 million which had been issued in relation to future decommissioning liabilities that were transferred as part of the disposal.

In December 2017, Premier entered into separate sale and purchase agreements ('SPAs') to dispose of its entire equity interest in the ETS pipeline in the UK for total consideration of US$31.6 million (including a potential future payment of US$3.5 million linked to the future development of the Pegasus field) and its entire non-operated interest in the Kakap field in Indonesia for US$3.2 million. The assets and liabilities for both of these interests have been classified as assets held for sale in the balance sheet at 31 December 2017.

Refinancing

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

During the year it was determined that the refinancing represented a substantial modification of the terms of the USPPs, the SSL and the convertible bonds. Accordingly, extinguishment accounting has been applied for the USPPs, SSL and convertible bonds, resulting in the de-recognition of the carrying amount of the financial liability and the recognition of a new financial liability for each of these revised facilities at their fair value. The de-recognition includes costs in relation to the refinancing of US$83.7 million.

Furthermore, it was determined that the refinancing did not represent a substantial modification of the terms of the RCF, the Term Loan or the retail bonds. Therefore refinancing costs in relation to the RCF, the Term Loan and the retail bonds of US$121.6 million have been deducted from the carrying amount of these financial liabilities in the balance sheet. These costs, along with previous unamortised arrangement fees, will be amortised over the revised term of these facilities.

The total refinancing costs include the recognition of the USPP make-whole adjustment, amendment and adviser fees, including the recognition of the equity and synthetic warrants at fair value. In connection with the refinancing, Premier issued 71.0 million equity warrants and 21.4 million synthetic warrants to its Private Lenders and retail bondholders and 18.1 million equity warrants to its convertible bondholders in July 2017. At issue the equity warrants had an exercise price of 42.75 pence and are exercisable from their issuance until 31 May 2022. The fair value liability for the equity and synthetic warrants recognised on the date of issue was US$47.7 million. Prior to the end of the year, 13.9 million equity warrants had been exercised by warrant holders. The closing fair value at 31 December 2017 was US$59.8 million.

Balance sheet position

Net debt

Net debt at 31 December 2017 amounted to US$2,724.2 million (31 December 2016: US$2,765.2 million), with cash resources of US$365.4 million (31 December 2016: US$255.9 million). With the refinancing completed, the maturity of all of Premier's facilities has been extended to May 2021, except for the convertible bonds which are May 2022. Therefore, all of Premier's facilities have been classified as long-term debt on the year-end balance sheet.

At 31 December 2017, Premier retained significant cash of US$297.2 million, once cash of US$68.2 million held on behalf of our joint venture partners is excluded, and undrawn facilities of US$244.0 million, giving Liquidity of US$541.2 million (31 December 2016: US$592.9 million).

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

Provisions

The Group's decommissioning provision increased to US$1,432.1 million at 31 December 2017, up from US$1,325.3 million at the end of 2016. The increase is driven by the addition of provisions relating to the new Catcher field.

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

Financial risk management

Commodity prices

At 31 December 2017, the Group had 3.6 mmbbls of open oil swaps at an average price of US$55.9/bbl. The fair value of these oil swaps at 31 December 2017 was a liability of US$31.7 million (2016: liability of US$18.3 million), which is expected to be released to the income statement during 2018 as the related barrels are lifted. Furthermore, during the year, the Group paid total premiums of US$6.3 million to enter into oil option agreements for 2.9 mmbls at an average price of US$53.5/bbl. Out of these options, 1.1 mmbls expired in 2017 and 1.8 mmbls will mature during 2018 and are an asset on the Group's balance sheet with a fair value at 31 December 2017 of US$0.2 million (2016: asset of US$3.5 million). Included within physically delivered oil sales contracts are a further 1.8 mmbls of oil that will be sold for an average fixed price of US$54.6/bbl during 2018 as these barrels are delivered.

During 2017, forward oil swaps of 1.5 mmbbls expired resulting in a net charge of US$11.4 million (2016: US$104.9 million credit) 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 gain of US$28.2 million on its outstanding foreign exchange contracts (2016: loss of US$58.6 million). The Group currently has £150.0 million retail bonds, €63.0 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$1.37:€.

Interest rates

The Group has various financing instruments including senior loan notes, convertible bonds, UK retail bonds, term loans and revolving credit facilities. As at year-end, 51 per cent of total borrowings are fixed or has been fixed using the interest rate swap markets. On average, the cost of drawn funds for the year was 7.3 per cent. Mark-to-market credits on interest rate swaps amounted to US$4.6 million (2016: credit of US$1.0 million).

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 2017, US$7.2 million of cash proceeds were received (net to Premier) in relation to settled insurance claims.

Full Year Results for the year ended 31 December 2017

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.

As part of the refinancing completed in 2017, the Group amended its financial covenants. These progressively tighten over the next 12 months with the Net Debt/EBITDA and EBITDA/Interest covenants returning to 3.0x for the twelve months ended 31 March 2019. At year-end, the Group continued to have significant liquidity and headroom on the financial covenants within its borrowing facilities. The Group's forecasts show that, at currently observed oil and gas prices and prevailing production, the Group will have sufficient financial headroom for the 12 months from the date of approval of the 2017 Annual Report and Financial Statements. In downside scenarios, where oil and gas prices were to fall and remain significantly below those currently being realised or production levels were to be significantly below current performance then in the absence of any mitigating actions, a breach of one or more of the financial covenants might arise outside of the 12 month going concern assessment period. Potential mitigating actions could include further non-core asset disposals, additional hedging activity or deferral of expenditure.

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

Business risks

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

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

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

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

The Group has identified its principal risks for the next 12 months as being:

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

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

Richard Rose

Finance Director

Full Year Results for the year ended 31 December 2017

Consolidated Income Statement
For the year ended 31 December 2017

	2017 $ million	2016 $ million Restated [1]
Continuing operations		
Sales revenues	**1,043.1**	937.0
Other operating income/costs	**18.8**	(6.1)
Costs of operation	**(455.4)**	(412.7)
Depreciation, depletion, amortisation and impairment	**(667.8)**	(888.3)
Reduction in decommissioning estimates	**-**	75.7
Exploration expense and pre-licence costs	**(17.1)**	(58.5)
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	**129.0**	-
General and administration costs	**(16.8)**	(24.1)
Operating profit/(loss)	**33.8**	(170.1)
Interest revenue, finance and other gains	**12.6**	15.0
Finance costs, other finance expenses and losses	**(329.0)**	(258.8)
Loss on substantial modification	**(83.7)**	-
Loss before tax from continuing operations	**(366.3)**	(413.9)
Tax	**96.1**	522.6
(Loss)/profit for the year from continuing operations	**(270.2)**	108.7
Discontinued operations		
Profit for the year from discontinued operations	**16.4**	13.9
(Loss)/profit after tax	**(253.8)**	122.6
(Loss)/earnings per share (cents):		
From continuing operations		
Basic	**(52.6)**	21.3
Diluted	**(52.6)**	20.8
From continuing and discontinued operations		
Basic	**(49.4)**	24.0
Diluted	**(49.4)**	23.5

[1] Restated for the classification of the Pakistan business unit as a discontinued operation and certain line items to match current year classification

Full Year Results for the year ended 31 December 2017

Consolidated Statement of Comprehensive Income
For the year ended 31 December 2017

	2017 $ million	2016 $ million
		Restated [1]
(Loss)/profit for the year	**(253.8)**	122.6
Cash flow hedges on commodity swaps:		
Losses arising during the year	**(25.6)**	(38.3)
Less: reclassification adjustments for losses (gains) in the year	**11.4**	(92.4)
	(14.2)	(130.7)
Cash flow hedges on interest rate and foreign exchange swaps:		
(Losses)/gains arising during the year	**(33.9)**	60.9
Less: reclassification adjustments for losses / (gains) in the year	**23.1**	(57.6)
	(10.8)	3.3
Tax relating to components of other comprehensive income	**7.5**	56.1
Exchange differences on translation of foreign operations	**(4.9)**	3.0
Gains on long-term employee benefit plans[2]	**-**	0.2
Other comprehensive expense	**(22.4)**	(68.1)
Total comprehensive (expense)/income for the year	**(276.2)**	54.5

[1] Restated for the classification of the Pakistan business unit as a discontinued operation
[2] 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.

PremierOil

Full Year Results for the year ended 31 December 2017

Consolidated Balance Sheet
As at 31 December 2017

	2017 $ million	2016 $ million
Non-current assets:		
Intangible exploration and evaluation assets	**1,061.9**	1,011.4
Property, plant and equipment	**2,381.0**	2,726.2
Goodwill	**240.8**	240.8
Long-term receivables	**160.8**	149.6
Deferred tax assets	**1,461.5**	1,304.0
	5,306.0	5,432.0
Current assets:		
Inventories	**13.5**	22.3
Trade and other receivables	**340.6**	315.1
Derivative financial instruments	**14.5**	34.9
Cash and cash equivalents	**365.4**	255.9
Assets held for sale	**96.6**	-
	830.6	628.2
Total assets	**6,136.6**	6,060.2
Current liabilities:		
Trade and other payables	**(572.9)**	(412.6)
Short-term provisions	**(91.2)**	(56.1)
Derivative financial instruments	**(99.8)**	(57.2)
Short-term debt	**-**	(273.0)
Deferred income	**(13.1)**	(27.3)
Liabilities directly associated with assets held for sale	**(46.6)**	-
	(823.6)	(826.2)
Net current assets/(liabilities)	**7.0**	(198.0)
Non-current liabilities:		
Long-term debt	**(2,972.6)**	(2,730.5)
Deferred tax liabilities	**(164.0)**	(192.6)
Deferred income	**(80.3)**	(88.1)
Derivative financial instruments	**(108.3)**	(101.6)
Long-term provisions	**(1,370.9)**	(1,312.1)
	(4,696.1)	(4,424.9)
Total liabilities	**(5,519.7)**	(5,251.1)
Net assets	**616.9**	809.1
Equity and reserves:		
Share capital	**109.0**	106.7
Share premium account	**284.5**	275.4
Other reserves	**223.4**	427.0
	616.9	809.1

Consolidated Statement of Changes in Equity

For the year ended 31 December 2017

	Share capital $ million	Share premium account $ million	Other reserves $ million	Total $ million
At 1 January 2016	106.7	275.4	352.6	734.7
Purchase of ESOP Trust shares	-	-	0.2	0.2
Provision for share-based payments	-	-	19.7	19.7
Profit for the year	-	-	122.6	122.6
Other comprehensive expense	-	-	(68.1)	(68.1)
At 1 January 2017	106.7	275.4	427.0	809.1
Issue of Ordinary Shares	2.3	9.1	1.1	12.5
Net release of ESOP Trust Shares	-	-	(0.2)	(0.2)
Provision for share-based payments	-	-	14.5	14.5
Incremental equity component of revised convertible bonds	-	-	57.2	57.2
Loss for the year	-	-	(253.8)	(253.8)
Other comprehensive expense	-	-	(22.4)	(22.4)
At 31 December 2017	**109.0**	**284.5**	**223.4**	**616.9**

Full Year Results for the year ended 31 December 2017

Consolidated Cash Flow Statement
For the year ended 31 December 2017

	2017 $ million	2016 $ million
		Restated [1]
Net cash from operating activities	**496.0**	431.4
Investing activities:		
Capital expenditure	**(275.6)**	(662.6)
Acquisition of subsidiaries	**-**	(135.0)
Cash balance acquired in the period	**-**	24.9
Decommissioning pre-funding	**(16.7)**	(62.3)
Decommissioning expenditure	**(25.7)**	(15.5)
Proceeds from disposal of oil and gas properties	**202.3**	(8.8)
Net cash used in investing activities	**(115.7)**	(859.3)
Financing activities:		
Issuance of Ordinary shares	**0.8**	-
Net (release) / purchase of ESOP Trust shares	**(0.2)**	0.2
Proceeds from drawdown of long-term bank loans	**45.0**	435.0
Debt arrangement fees	**(86.0)**	(26.3)
Interest paid	**(223.7)**	(126.3)
Net cash from financing activities	**(264.1)**	282.6
Currency translation differences relating to cash and cash equivalents	**(6.7)**	(0.1)
Net increase / (decrease) in cash and cash equivalents	**109.5**	(145.4)
Cash and cash equivalents at the beginning of the year	**255.9**	401.3
Cash and cash equivalents at the end of the year	**365.4**	255.9

[1] Restated for certain line items to match current year classification

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the year ended 31 December 2017

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 7 March 2018.

The financial information for the year ended 31 December 2017 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 2016 were approved by the Board of Directors on 8 March 2017 and delivered to the Registrar of Companies and those for 2017 will be delivered following the company's Annual General Meeting ('AGM'). The auditor has reported on the 2017 accounts and their audit report was unqualified.

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.

Accounting policies

The accounting policies applied in this announcement are consistent with those of the annual financial statements for the year ended 31 December 2016, as described in those annual financial statements. A number of amendments to existing standards and interpretations were applicable from 1 January 2017. The adoption of these amendments did not have a material impact on the Group's financial statements for the year ended 31 December 2017.

2. Operating segments

The Group's operations are located and managed in five business units; namely the Falkland Islands, Indonesia, Vietnam, the United Kingdom, and the Rest of the World. The results for Pakistan are reported as a discontinued operation. The results for Mauritania have been reclassified into the Rest of the World business unit.

Some of the business units currently do not generate revenue or have any material operating income.

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

	2017 $ million	2016 $ million
		Restated
Revenue:		
Indonesia	**171.8**	141.1
Vietnam	**210.7**	192.0
United Kingdom	**655.9**	598.0
Rest of the World	**4.7**	5.9
Total Group sales revenue	**1,043.1**	937.0
Other operating income - United Kingdom	**18.8**	-
Interest and other finance revenue	**1.7**	0.7
Total Group revenue from continuing operations	**1,063.6**	937.7
Group operating profit/(loss):		
Indonesia	**65.3**	35.6
Vietnam	**82.6**	86.3
United Kingdom	**(86.4)**	(225.0)
Rest of the World	**(5.0)**	(32.2)
Unallocated [2]	**(22.7)**	(34.8)
Group operating profit/(loss)	**33.8**	(170.1)
Interest revenue, finance and other gains	**12.6**	15.0
Finance costs and other finance expenses	**(329.0)**	(258.8)
Loss on substantial modification	**(83.7)**	-
Loss before tax from continuing operations	**(366.3)**	(413.9)
Tax	**96.1**	522.6
(Loss)/profit after tax from continuing operations	**(270.2)**	108.7
Profit from discontinued operations	**16.4**	13.9

2. Operating segments *(continued)*

	2017 $ million	2016 $ million
Balance sheet		
Segment assets:		
Falkland Islands	**633.1**	642.9
Indonesia	**440.4**	480.2
Pakistan (including Mauritania)	**-**	44.8
Vietnam	**374.4**	399.0
United Kingdom	**4,116.2**	4,136.5
Rest of the World	**96.0**	66.0
Assets held for sale	**96.6**	-
Unallocated[2]	**379.9**	290.8
Total assets	**6,136.6**	6,060.2
Liabilities:		
Falkland Islands	**(8.2)**	(45.6)
Indonesia	**(223.9)**	(244.5)
Pakistan (including Mauritania)	**-**	(76.3)
Vietnam	**(203.4)**	(202.1)
United Kingdom	**(1,802.1)**	(1,516.8)
Rest of the World	**(54.8)**	(3.5)
Liabilities directly associated with assets held for sale	**(46.6)**	-
Unallocated[2]	**(3,180.7)**	(3,162.3)
Total liabilities	**(5,519.7)**	(5,251.1)
Other information		
Capital additions and acquisitions:		
Falkland Islands	**12.9**	59.2
Indonesia	**7.4**	(2.7)
Pakistan (including Mauritania)	**10.5**	0.9
Vietnam	**20.2**	(7.4)
United Kingdom	**444.3**	1,247.7
Rest of the World	**25.3**	26.4
Total capital additions and acquisitions	**520.6**	1,324.1

2. Operating segments *(continued)*

	2017 $ million	2016 $ million
Depreciation, depletion, amortisation and impairment:		
Indonesia	**57.2**	52.7
Vietnam	**64.5**	45.0
United Kingdom	**542.9**	790.4
Rest of the World	**3.2**	0.2
Total DD&A and impairment (continuing operations)	**667.8**	888.3
Total DD&A and impairment (discontinued operations)	**7.3**	8.2

1 Segmental income, assets, liabilities and capital addition as for Mauritania have been included within the Rest of the World for the current year.

2 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, warrants and other short-term and long-term debt.

3 DD&A for the Pakistan business unit was charged until 30 June 2017, which was the date of reclassification of an asset held for sale.

Out of the total Group worldwide sales revenues of US$1,043.1 million (2016: US$937.0 million restated), revenues of US$655.9 million (2016: US$598.0 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$2,455.7 million (2016: US$2,640.6 million) located in the UK. Included in depreciation, depletion, amortisation and impairment are net impairment charges in relation to the UK of US$252.2 million (2016: US$587.9 million).

Revenue from three customers (2016: three customers) each exceeded 10 per cent of the Group's consolidated revenue and amounted to US$240.3 million arising from sales of crude oil (2016: two customers amounting to US$155.4 million and US$157.4 million) and US$121.4 million and US$168.3 million arising from sales of gas (2016: one customer US$112.0 million).

3. Cost of operation

	2017 $ million	2016 $ million
		Restated[1]
Operating costs	**438.4**	402.7
Gas purchases	**5.5**	12.4
Stock overlift/underlift movement	**1.3**	(12.1)
Royalties	**10.2**	9.7
	455.4	412.7

1 Restated for the classification of the Pakistan business unit as a discontinued operation

4. Tax

	2017 $ million	2016 $ million
		Restated[1]
Current tax:		
UK corporation tax on profits	**(0.8)**	(3.0)
UK petroleum revenue tax	**(8.2)**	(0.8)
Overseas tax	**75.6**	44.6
Adjustments in respect of prior years	**8.2**	0.7
Total current tax	**74.8**	41.5
Deferred tax:		
UK corporation tax	**(146.2)**	(544.4)
UK petroleum revenue tax	**-**	(14.4)
Overseas tax	**(24.7)**	(5.3)
Total deferred tax	**(170.9)**	(564.1)
Tax on (loss) on ordinary activities	**(96.1)**	(522.6)

1 Restated for the classification of the Pakistan business unit as a discontinued operation

4. Tax *(continued)*

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

	2017 $ million	2016 $ million
		Restated[1]
Group loss on ordinary activities before tax	**(366.3)**	(413.9)
Group loss on ordinary activities before tax at 29.1 per cent weighted average rate (2016: 58.1 per cent)	**(106.6)**	(240.6)
Tax effects of:		
Income/expenses that are not taxable/deductible in determining taxable profit	**40.6**	9.4
Financing costs disallowed for UK supplementary charge	**16.4**	14.4
Non-deductible field expenditure	**36.1**	63.2
Tax and tax credits not related to profit before tax (mainly Ring Fenced Expenditure Supplement)	**(69.9)**	(60.7)
Unrecognised tax losses	**6.1**	2.8
Adjustments in respect of prior years	**(3.2)**	8.6
Utilisation and recognition of tax losses not previously recognised	**(0.8)**	(392.5)
Effect of change in tax rates	**(0.5)**	161.5
Recognition that decommissioning provision will unwind at 50%	**(14.3)**	(27.1)
Recognition of investment allowances not previously recognised	**-**	(61.6)
Tax credit for the year	**(96.1)**	(522.6)
Effective tax rate for the year	**26.2%**	126.3%

1 Restated for the classification of the Pakistan business unit as a discontinued operation

The deferred tax credit primarily arises due to UK specific deferred tax items. This includes the deferred tax credit associated with the UK impairment charge for the period (US$101.8 million), which is partially offset by an element of the UK impairment charge for the year that does not attract a deferred tax offset (US$19.6 million). This also includes the deferred tax credit which arises on the generation of new UK ring fence tax losses, allowances and ring fence expenditure supplement which are recognised in full for deferred tax purposes.

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

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

5. Discontinued operations, disposals and assets held for sale

	2017 $ million	2016 $ million
Net profit for the year attributable to Pakistan business unit	**16.4**	22.7
Completion of disposal of Norway business unit	**-**	(8.8)
Net profit for the year from discontinued operations	**16.4**	13.9

The disposal of the Norway business unit completed in December 2015

	2017 $ million
Assets held for:	
- Pakistan business unit	**52.2**
- Esmond Transportation System ('ETS')	**27.0**
- Kakap field	**17.4**
Total assets classified as held for sale	**96.6**
Liabilities held for:	
- Pakistan business unit	**(25.4)**
- Esmond Transportation System ('ETS')	**(7.0)**
- Kakap field	**(14.2)**
Total liabilities classified as held for sale	**(46.6)**

Disposals – Wytch Farm interests

The disposal completed in December 2017, with Premier receiving final cash consideration, after working capital adjustments, of US$177.1 million. This resulted in a gain on disposal of US$133.0 million.

5. Discontinued operations, disposals and assets held for sale *(continued)*

Assets held for sale

ETS

In December 2017, Premier signed an SPA to sell its entire equity interest in the ETS pipeline to CATS Management Limited and the disposal is expected to be completed within the next 12 months. Therefore, the assets and liabilities for Premier's ETS interest have been classified as assets held for sale in the balance sheet at 31 December 2017, as the disposal is expected to complete within the next 12 months. An impairment charge has not been recognised at the time of this reclassification, as the initial upfront consideration of US$28.1 million is greater than the carrying value of the ETS assets and liabilities held on Premier's Group balance sheet.

Kakap

In December 2017, Premier signed an SPA with Batavia Oil to sell its entire 18.75 per cent non-operated interest in the Kakap field for a consideration of US$3.2 million. Completion is subject to receiving approval from the Government of Indonesia. Completion is expected to be achieved within the next 12 months, therefore, the assets and liabilities for Kakap have been classified as assets held for sale in the balance sheet at 31 December 2017. On reclassification an impairment charge of US$4.2 million has been recognised so that the carrying value of Premier's interest in the Kakap field is equal to the agreed consideration. This charge has been recognised in the income statement against the gain on disposal recognised for Wytch Farm.

Discontinued operations – Pakistan business unit

In April 2017, Premier announced it had reached agreement and signed an SPA with Al-Haj Energy Limited ('Al-Haj') for the sale of Premier Oil Pakistan Holdings BV, which comprises Premier's Pakistan business unit, for a cash consideration of US$65.6 million. In 2017, Al-Haj paid a deposit to Premier of US$25.0 million.

The disposal of the Pakistan business unit is expected to complete in 2018 and, as this is within 12 months of the balance sheet date, the business unit was classified as a disposal group held for sale on 30 June 2017 and presented separately in the balance sheet.

5. Discontinued operations, disposals and assets held for sale *(continued)*

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

	2017 $ million	**2016 $ million**
Revenue	**40.8**	46.4
Expenses	**(22.4)**	(23.1)
Profit before tax	**18.4**	23.3
Attributable tax (charge)	**(2.0)**	(0.6)
Net profit for the period from assets held for sale	**16.4**	22.7

During the year to 31 December 2017, the Pakistan disposal group contributed US$16.8 million (2016 US$29.4 million) to the Group's net operating cash flows and paid US$6.8 million (2016 US$8.5 million in respect of investing activities). There were no financing cash flows in either the current or the prior years. The major classes of assets and liabilities comprising the disposal group classified as held for sale are as follows:

	2017 $ million
Property, plant and equipment	**23.3**
Long-term receivables	**0.4**
Deferred tax asset	**0.8**
Inventory	**9.0**
Trade and other receivables	**17.8**
Cash	**0.9**
Pakistan assets classified as held for sale	**52.2**
Trade and other payables	**(7.8)**
Long-term provisions	**(17.6)**
Pakistan liabilities classified as held for sale	**(25.4)**
Net assets of disposal group	**26.8**

Following completion of the disposal, Premier have retained a provision of US$16.4 million in relation to potential costs in relation to the business unit for the period of ownership by Premier prior to the disposal. The provision is not included in the discontinued operations assets and liabilities in the table above.

6. (Loss)/earnings per share

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

	2017 $ million	2016 $ million
		Restated[1]
Loss/(earnings)		
Loss/earnings from continuing operations	**(270.2)**	108.7
Effect of dilutive potential Ordinary Shares:		
Interest on convertible bonds – anti-dilutive	**-**	-
(Loss)/earnings for the purpose of diluted (loss)/earnings per share on continuing operations	**(270.2)**	108.7
Profit from discontinued operations	**16.4**	13.9
(Loss)/earnings for the purposes of diluted (loss)/earnings per share on continuing and discontinued operations	**(253.8)**	122.6
Number of shares (millions)		
Weighted average number of Ordinary Shares for the purposes of basic earnings per share	**513.7**	510.8
Effects of dilutive potential Ordinary Shares:		
Contingently issuable shares – anti-dilutive	**-**	-
Weighted average number of Ordinary Shares for the purposes of diluted earnings per share	**612.0**	523.5
(Loss)/earnings per share from continuing operations (cents)		
Basic	**(52.6)**	21.3
Diluted	**(52.6)**	20.8
Earnings per share from discontinued operations (cents)		
Basic	**3.2**	2.7
Diluted	**3.2**	2.7

1 Restated for the classification of the Pakistan business unit as a discontinued operation

There are 98.3 million potentially dilutive contingently issuable shares related to unexercised Equity warrants and Share Options and the inclusion of these contingently issuable shares gives rise to an anti-dilutive loss and earnings per share for both continuing and discontinued operations. Furthermore, there are 259.3 million potentially dilutive shares related to the convertible bonds at 31 December 2017. The inclusion of the convertible bond interest and shares to be issued on conversion of convertible bonds, also produces an anti-dilutive loss and earnings per share for both continuing and discontinued operations.

7. Intangible exploration and evaluation ('E&E') assets

Oil and Gas Properties	Total $ million
At 1 January 2016	749.7
Exchange movements	6.1
Additions during the year	103.8
Acquisition of subsidiaries	199.8
Exploration expense [1]	(48.0)
At 31 December 2016	1,011.4
Exchange movements	(0.9)
Additions during the year	63.1
Assets classified as held for sale in the year	(0.5)
Exploration expense [1]	(11.2)
At 31 December 2017	**1,061.9**

1 Expensed in the income statement with pre-licence expenses of US$5.9 million in 2017 (2016: US$10.5 million)

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 on the Ekland licence in the UK.

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

The balance carried forward is predominantly in relation to the Group's prospects in the Falkland Islands and the Tolmount project in the UK. We continue to progress both Sea Lion and Tolmount projects and are aiming to reach an investment decision on Sea Lion and to sanction Tolmount during 2018.

E&E assets transferred to held for sale in the year related to the Kakap entity in Indonesia.

8. Property, plant and equipment

	Oil and gas properties $ million	Other fixed assets $ million	Total $ million
Cost:			
At 1 January 2016	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
Exchange movements	4.6	2.4	7.0
Additions during the year	445.4	2.3	447.7
Asset acquisition	9.8	-	9.8
Assets transferred as held for sale	(489.6)	(1.7)	(491.3)
Disposals	(409.4)	(0.6)	(410.0)
At 31 December 2017	**7,589.4**	**66.7**	**7,656.1**
Amortisation and depreciation:			
At 1 January 2016	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
Net impairment charge	556.2	-	556.2
Disposals	-	(1.4)	(1.4)
At 31 December 2016	5,318.9	47.8	5,366.7
Exchange movements	(0.3)	1.8	1.5
Charge for the year	416.2	6.7	422.9
Net impairment charge	252.2	-	252.2
Assets classified as held for sale	(434.6)	(0.9)	(435.5)
Disposals	(332.1)	(0.6)	(332.7)
At 31 December 2017	**5,220.3**	**54.8**	**5,275.1**
Net book value:			
At 31 December 2016	2,709.7	16.5	2,726.2
At 31 December 2017	**2,369.1**	**11.9**	**2,381.0**

Finance costs that have been capitalised within oil and gas properties during the year total US$41.3 million (2016: US$34.0 million), at a weighted average interest rate of 7.3 per cent (2016: 4.6 per cent).

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

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

Impairment charge

The impairment charge in the current year relates entirely to UK fields and predominantly comprises of Solan (US$268.1 million), the Balmoral Area (US$20.7 million) and Glenelg (US$7.4 million). The impairment charge of US$296.6 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 2018 and 2019, US$70/bbl in 2020 and US$75/bbl in 'real' terms thereafter (2016: two years at forward curve, year three at US$65/bbl followed by a long-term price of US$75/bbl (real)) and were discounted using a pre-tax discount rate of 9 per cent for the UK assets (2016: 8 per cent) and 12.5 per cent for the non-UK assets (2016: 12.5 per cent). Assumptions involved in impairment measurement include estimates of commercial reserves and production volumes, future oil and gas prices, discount rates and the level and timing of expenditures, all of which are inherently uncertain.

The principal cause of the impairment charge being recognised in the year is a reduction in the 2P reserves expected to be recovered from Solan over its economic life, a reduction in the expected residual value of the Balmoral Area FPV and a delayed workover for Glenelg. The recoverable amount of the impaired assets based on the value-in-use assumptions set out above is US$246.1 million (Solan), US$18.6 million (Balmoral) and US$35.0 million (Glenelg). The recoverable amount for Glenelg assumes that a workover of the G10 well is performed in 2019 which is management's current expectations based on discussions with the operator. If the workover is delayed or not performed, it is likely to reduce the recoverable amount of the asset, which would have the effect of increasing the impairment charge.

8. 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$44.4 million has been credited to the income statement for the year, which has partially offset the impairment charge recognised. The reversal of impairment relates entirely to Huntington in the UK. An increase in the short term oil price assumption and an increase in the life of the field have driven the increase in the value-in-use. The recoverable amount of Huntington at 31 December 2017 was US$78.8 million.

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$8.3 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$41.2 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).

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 9 per cent (2016: 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 2025. This period exceeds five years but is believed to be appropriate as it is underpinned by estimates of commercial reserves provided by our 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$305.7 million. The key assumptions to which the calculation of value-in-use of the Catcher asset are discount rate, oil prices, forecasted recoverable reserves and estimated future costs. No reasonably possible change in any of the key assumptions would cause the asset's carrying amount to exceed its recoverable amount.

9. 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$22.0 million during the year reflecting barrels delivered to FlowStream and a credit to finance costs of US$6.8 million. The finance credit is due to a revision in the settlement profile of the deferred income balance following the revision to Solan reserves. 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.

10. Borrowings

The Group's loans are carried at amortised cost as follows:

	2017 $ million			2016 $ million		
	Carrying value	Fees	Total	Carrying value	Fees	Total
Bank loans	2,165.0	(106.9)	2,058.1	2,108.0	(12.1)	2,095.9
Senior loan notes	541.6	-	541.6	491.1	(3.7)	487.4
Retail bonds	202.5	(10.1)	192.4	184.5	(1.7)	182.8
Convertible bonds	180.5	-	180.5	237.5	(0.1)	237.4
Total borrowings	3,089.6	(117.0)	2,972.6	3,021.1	(17.6)	3,003.5
Due within one year			-			273.0
Due after more than one year			2,972.6			2,730.5
Total borrowings			2,972.6			3,003.5

At the year-end, the Group's principal credit facilities comprised:

- Bank loans: US$2.5 billion revolving and letter of credit facility ('RCF'), US$150 million and £100 million term loans (together the 'Term Loan')
- Senior loan notes: US$335 million and €63.6 million of US Private Placement ('USPP') notes and US$130 million Schuldschein ('SSL');
- £150 million of retail bonds; and,
- US$237.9 million of convertible bonds.

All of the above facilities mature in May 2021, except for the convertible bonds which, for those not already converted, mature in May 2022.

10. Borrowings *(continued)*

Refinancing

In July 2017, Premier completed a comprehensive refinancing of its lending facilities with all the lenders under each facility.

Under the requirements of IAS 39, if an existing financial liability is replaced by another from the same lender, on substantially different terms, or the terms of an existing liability are substantially modified, such an exchange or modification is treated as a de-recognition of the original liability and the recognition of a new liability, measured at its fair value, such that the difference in the respective carrying amounts together with any costs or fees incurred are recognised in profit or loss. IAS 39 regards the terms of exchanged or modified debt as 'substantially different' if the net present value of the cash flows under the new terms (including any fees paid net of fees received) discounted at the original effective interest rate is at least 10 per cent different from the discounted present value of the remaining cash flows of the original debt instrument. Where an exchange or modification of financial liabilities is not considered substantial, no gain or loss is recognised, the fees are capitalised against the carrying value of the liability and any changes to the cash flows are recognised as interest over the remaining term.

After applying the 10 per cent test, as required by IAS 39, it was determined that the refinancing amendments represented a substantial modification of the USPP notes, the SSL and the convertible bonds. However, the refinancing amendments did not represent a substantial modification of the RCF, Term Loans or the retail bond notes.

Costs and third-party fees, which include the USPP make-whole adjustment, amendment fee and adviser fees paid and recognition of the warrants at fair value, have been allocated to each facility as follows:

	2017 $ million
Bank Loans	**111.8**
Senior loan notes	**70.2**
Retail bonds	**9.8**
Convertible bonds	**13.5**
Total costs in relation to the refinancing	**205.3**

Of the total fees above, US$83.7 million in relation to the senior loan notes and convertible bonds have been expensed to the income statement in the year. The fees in relation to the bank loans and retail bonds of US$121.6 million have been capitalised against the carrying value of the debt and are being amortised over the revised maturity of the facility.

11. Notes to the cash flow statement

	2017 $ million	2016 $ million
		Restated[1]
Loss before tax for the year	**(366.3)**	(413.9)
Adjustments for:		
Depreciation, depletion, amortisation and impairment	**667.8**	888.3
Other operating (income) / costs	**(18.8)**	6.1
Exploration expense	**11.2**	48.0
Excess of fair value over consideration	**-**	(228.5)
Provision for share-based payments	**8.6**	8.7
Reduction in decommissioning estimates	**-**	(75.7)
Interest revenue and finance gains	**(12.6)**	(15.0)
Finance costs and other finance expenses	**412.7**	258.8
Profit on disposal of non-current assets	**(129.0)**	-
Operating cash flows before movements in working capital	**573.6**	476.8
(Increase)/decrease in inventories	**(1.2)**	1.3
(Increase)/decrease in receivables	**(161.3)**	25.1
Increase/(decrease) in payables	**136.6**	(40.9)
Cash generated by operations	**547.7**	462.3
Income taxes paid	**(69.6)**	(60.9)
Interest income received	**1.1**	0.6
Net cash from operating activities	**479.2**	402.0
Net cash from discontinued operating activities	**16.8**	29.4
Total net cash from operating activities	**496.0**	431.4

1 Restated for the classification of the Pakistan business unit as a discontinued operation

Full Year Results for the year ended 31 December 2017

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

Analysis of changes in net debt:

	2017 $ million	2016 $ million
a) Reconciliation of net cash flow to movement in net debt:		
Movement in cash and cash equivalents	**109.5**	(145.4)
Proceeds from drawdown of long-term bank loans	**(45.0)**	(435.0)
USPP make-whole adjustment	**(41.3)**	-
Adjustment to revised fair value of convertible bonds	**58.6**	-
Partial conversion of convertible bonds	**5.5**	-
Non-cash movements on debt and cash balances (predominantly FX)	**(46.3)**	57.4
Decrease/(Increase) in net debt in the year	**41.0**	(523.0)
Opening net debt	**(2,765.2)**	(2,242.2)
Closing net debt	**(2,724.2)**	(2,765.2)
b) Analysis of net debt:		
Cash and cash equivalents	**365.4**	255.9
Borrowings	**(3,089.6)**	(3,021.1)
Total net debt	**(2,724.2)**	(2,765.2)

The carrying amounts of the borrowings on the balance sheet are stated net of the unamortised portion of the refinancing fees of US$117.0 million (2016: US$17.6 million).

12. Subsequent Events

Convertible bonds

In January 2018, Premier invited convertible bondholders to exercise their exchange rights in respect of any and all of their bonds. 87.5 per cent or US$205.8 million bonds outstanding were accepted for early exchange with an incentive amount of US$50 per US1,000 in principal of bonds. The exchange resulted in the issue of 231,882,091 Ordinary Shares, including 7,578,343 of incentive shares. It is expected that the value of the incentive shares will be expensed in the 2018 income statement.

Equity Warrants

Subsequent to the year-end until the date of this report, 8,117,546 equity warrants have been exercised into 7,951,992 Ordinary Shares.

Debt Reduction

Net cash proceeds received for the Wytch Farm disposal of US$176 million in December 2017 were used to pay down and cancel the RCF debt facility in January 2018. This reduced the total available RCF facility from US$2,050 million to US$1,874 million. As a result of this disposal US$75 million of letters of credit were released. In addition the US$16.4 million letters of credit held for the Zama exploration well in Mexico, which was included within the covenant Net Debt at 31 December 2017, was also released in January 2018.

13. External audit

This preliminary announcement is consistent with the audited financial statements of the Group for the year-ended 31 December 2017.

14. Publication of financial statements

It is anticipated that the full Annual Report and Financial Statements will be published in April 2018. 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 16 May 2018 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, DD&A per barrel, Free cash flow, Net Debt and Liquidity and are defined below.

- **EBITDAX:** Earnings before interest, tax, depreciation, amortisation, impairment, exploration spend and other one off items. In the current year it also excludes the gain on disposal recognised in the income statement. This is a useful indicator of underlying business performance.
- **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.
- **DD&A per barrel:** Amortisation and depreciation of oil and gas properties for the year divided by working interest production. This is a useful indicator of ongoing rates of depreciation and amortisation of the Group's producing assets.
- **Free cash flow:** Positive cash flow generation from operating, investing and financing activities excluding drawdowns from borrowing facilities.
- **Net Debt:** The net of cash and cash equivalents and long-term debt recognised on the balance sheet. This is an indicator of the Group's indebtedness and capital structure.
- **Liquidity:** The sum of cash and cash equivalents on the balance sheet, and the undrawn amounts available to the Group on our principal facilities, including letters 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.

Full Year Results for the year ended 31 December 2017

OIL AND GAS RESERVES

Working interest reserves at 31 December 2017

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 2017	126.5	43.8	1.7	243.5	0.1	74.3	103.1	136.0	23.8	35.6	**255.2**	**533.2**	**353.3**
Revisions[1]	-	-	0.1	(18.1)	-	(8.7)	(13.0)	33.7	(0.3)	(3.7)	**(13.2)**	**3.3**	**(12.4)**
Discoveries and extensions[2]	-	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions and divestments[3]	-	-	-	-	-	-	(11.2)	(1.3)	-	-	**(11.3)**	**(1.4)**	**(11.7)**
Production	-	-	(0.3)	(26.0)	-	(14.4)	(9.9)	(24.0)	(4.3)	(5.4)	**(14.5)**	**(69.7)**	**(27.4)**
At 31 December 2017	126.5	43.8	1.5	199.4	0.1	51.2	69.0	144.4	19.2	26.5	**216.2**	**465.4**	**301.8**
Total Group developed and undeveloped reserves													
Proved on production	-	-	0.8	121.1	0.1	34.9	20.0	80.2	15.8	18.2	**36.6**	**254.5**	**83.3**
Proved approved/justified for development	102.8	28.5	0.4	36.5	-	-	21.2	26.5	0.5	6.2	**124.7**	**97.7**	**143.3**
Probable on production	-	-	0.1	9.9	-	16.3	5.6	32.4	2.8	1.7	**8.6**	**60.3**	**19.1**
Probable approved/justified for development	23.7	15.3	0.2	31.9	-	-	22.2	5.3	0.1	0.4	**46.3**	**52.9**	**56.1**
At 31 December 2017	**126.5**	**43.8**	**1.5**	**199.4**	**0.1**	**51.2**	**69.0**	**144.4**	**19.2**	**26.5**	**216.2**	**465.4**	**301.8**

Notes:

1 Revisions to reserves are based on re-evaluation of production performance, drilling results and future plans in Dua (Vietnam); Anoa and Gajah-Baru (Indonesia); Solan, Babbage and Huntington (UK); Qadirpur (Pakistan)

2 The Zama discovery in Mexico is classified as contingent resource and does not appear in this table

3 Divestment of Wytch Farm (UK)

4 Proved plus probable 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 an entitlement basis, which incorporates the terms of the PSCs in Indonesia and Vietnam. On an entitlement basis reserves were 284.9 mmboe as at 31 December 2017 (2016: 332.3 mmboe). This was calculated at year-end 2017, using an oil price assumption equal to US$65/bbl in 2018, US$61.5/bbl in 2019, US$70/bbl in 2020 and US$75/bbl in 'real' terms thereafter (2016: Dated Brent, 2017 US$58/bbl, 2018 US$58/bbl, US$65/bbl in 2019 and US$75/bbl in 'real' terms thereafter).

In 2018, it is anticipated that there will be changes to the SPE Petroleum Resource Management System standards which are likely to include revised commercial requirements for reserve classification. If the Sea Lion development, which is currently booked with 2P reserves of 134 mmboe does not pass through the Sanction Gate currently planned during 2018, there would be potential for these resources to be recategorised as contingent at the end of 2018.