Full Year Results for the year ended 31 December 2019

Premier Oil plc
"Premier" or the "Company" or the "Group"
5 March 2020

Press Release

Tony Durrant, Chief Executive Officer, commented:

"Premier made significant progress against its strategic targets during 2019. Strong operational performance resulted in record free cash flows and reducing debt levels. We took material steps to commercialise our reserve and resource base and added to our exploration acreage position. The proposed acquisitions will add material cash-generative UK production. Premier is committed to being a responsible operator and today announces that all operated projects will be developed on a net zero emissions basis."

Operational highlights

- Production of 78.4 kboepd, at upper end of guidance; 2020 guidance of 70-75 kboepd (before any contribution from the announced UK acquisitions)
- Catcher (UK) project payback reached; Catcher North and Laverda developments sanctioned
- BIG-P (Indonesia) first gas delivered on schedule and below budget
- Tolmount (UK) on track for first gas by year-end 2020, adding 20-25 kboepd (net, Premier 50 per cent); Tolmount East development planning underway targeting 2020 2H sanction
- Positive Zama (Mexico) appraisal campaign; unitisation and sales process underway
- Heads of Terms signed for Sea Lion (Falkland Islands) and Tuna (Indonesia) farm downs
- Accretive and strategic UK acquisitions, underwritten financing and proposed extension of credit facilities announced; court sanction hearing scheduled for 17-20 March 2020
- New prospective acreage captured in Alaska and Indonesia; high value near-term E&A wells planned with Charlie-1 (Alaska) drilling ahead and Berimbau/Maraca (Brazil) to spud in Q3

Financial highlights

- Increased profit after tax of US$164 million (2018: US$133 million)
- Record free cash flow of US$327 million (2018: US$251 million); US$31/bbl cash margin (2018: US$26/bbl)
- EBITDAX increased to US$1,230 million (2018: US$1,091 million, adjusted for the impact of IFRS16)
- 2019 expenditure (opex of US$11/boe, total capex of US$273 million) below guidance
- Net debt reduced to US$1.99 billion (2018: US$2.33 billion) and covenant leverage ratio to 2.3x (2018: 3.1x)
- Free cash flow generation forecast for 2020, driving continued debt reduction

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A presentation to analysts will be held at 9.30am today at Premier Oil's offices at 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 2019

CEO REVIEW

2019 was another year of strong operational and financial delivery by Premier with significant progress made against the Company's strategic objectives.

Commodity prices were slightly weaker during 2019 driven by global trade tensions and ongoing concerns about the balance of supply and demand. Despite this, the Group reported record free cash flows and increased net profits.

Production

Group production averaged 78.4 kboepd (2018: 80.5 kboepd), at the upper end of market guidance. This was driven by exceptionally high uptime across the portfolio and outperformance from Premier's operated flagship Catcher Area in the UK, which reached cash payback in October.

Production by business unit (kboepd)	**2019**	**2018**
Indonesia	11.5	13.2
Pakistan[1]	1.3	5.3
United Kingdom	54.2	46.8
Vietnam	11.4	15.2
Total	**78.4**	**80.5**

[1] sold on 26 March 2019

Increased tax advantaged production from the UK offset lower output from the Group's Asian assets. This change in production mix, together with higher price realisations, continued tight cost control and prudent management of capital investment, resulted in increased cash margins year-on-year.

In South East Asia and the UK, Premier's two core producing areas, the teams have continued to mature and execute incremental investment opportunities to increase the reserves and field life of the Group's assets. In December, Premier achieved first gas from its operated Bison, Iguana and Gajah Puteri (BIG-P) fields increasing deliverability from the Natuna Sea Block A PSC and enabling the Group to meet increased Singapore demand for its Indonesian gas. The safe and successful execution of BIG-P on schedule and below budget builds on Premier's track record of project delivery.

In the UK, a significant amount of activity is planned for 2020. This includes the drilling of a third producer on the Solan field West of Shetland, the development of two Catcher Area satellites in the Central North Sea together with a Varadero infill well, and infill drilling at Ravenspurn North in the Southern Gas Basin. These investments have high returns and quick payback periods and will help boost production in the second half of 2020 and early 2021.

Growth projects

The Premier-operated Tolmount development is on track for first gas by the end of 2020 and underpins the Group's medium-term production profile. As a conventional platform serving four wells tied back to an established onshore terminal, Tolmount requires modest capital expenditure and will have low production costs, ensuring the project's robust economics. Premier has also partnered with infrastructure group, Kellas Midstream, who will partially fund and own the infrastructure element of the development.

The Group's positive view of the upside within the Greater Tolmount Area was confirmed with the successful Tolmount East appraisal well in October which, as well as extending plateau production from the Tolmount Area, unlocks the potential development of the Mongour discovery to the north. Further potential exists at the nearby prospect, Tolmount Far East and to the south and west of the Tolmount field.

Premier has continued to optimise its level of participation in its future development projects. In the Falkland Islands, Premier has signed a Heads of Terms with Navitas Petroleum to farm in for a 30 per cent interest in the Group's fully appraised 250 mmbbls (gross) Sea Lion project. This marks a significant step forward for the Sea Lion development with Navitas Petroleum sharing the pre-first oil funding and bringing additional sources of senior debt financing to the project. In Indonesia, Premier has signed a Heads of Terms with Zarubezhneft to farm in for a 50 per cent interest in its operated Tuna PSC. The new investor will carry Premier for its share of a two-well appraisal campaign targeted to commence in 2020.

Exploration within a disciplined capital framework remains a key part of Premier's business model and 2019 saw the Group continue to capture highly-prospective international acreage in proven basins. Premier deepened its position in the emerging Andaman Sea gas play, an area which has significant long-term potential, and also entered the Alaska North Slope. Premier's first well in Alaska, which spudded post period-end, is targeting an accumulation of over 1 billion barrels of oil-in-place (gross).

Free cash flow through the cycle remains a pre-requisite for the Group and Premier will remain disciplined and selective in the projects it progresses, realising value from part or full disposal of development assets where appropriate. In August, Premier initiated a sales process for its stake in the Zama field offshore Mexico, following the successful appraisal of the field earlier in the year. Premier expects those discussions to reach conclusion later in 2020 once the unitisation process with the neighbouring block is further advanced.

Reserves and resources

As at 31 December 2019, the Group's proven and probable (2P) reserves, on a working interest basis, were 175 mmboe (2018: 194 mmboe) and total 2P and 2C resources were 847 mmboe (2018: 867 mmboe).

	2P reserves (mmboe)	2P reserves and 2C resources (mmboe)
1 January 2019	194	867
Production	(28)	(28)
Net additions, revisions, discoveries	15	16
Disposals, relinquishments	(5)	(8)
31 December 2019	175[1]	847

[1] Due to rounding, total 2P reserves does not correspond to the sum of the individual line items

The reduction in 2P reserves is driven by the impact of 2019 production and the sale of the Pakistan business, partially offset by a 15 mmboe upward revision in the Group's 2P reserves, principally related to the Catcher Area and Natuna Sea Block A. Premier now anticipates a higher overall recovery from the Catcher Area, following excellent reservoir performance and maturation of production infill well targets. In Indonesia, strong performance from the Gajah Baru Upper Arang reservoir and maturation of incremental projects in the Anoa field resulted in increased Natuna Sea Block A's 2P reserves. The Group's 2C resources were broadly flat year-on-year.

Premier also seeks to increase its reserve and resource base through acquisitions. Post period-end, the Group announced the proposed acquisitions of the Andrew Area and Shearwater assets from BP and an additional 25 per cent interest in its operated Tolmount Area from Dana Petroleum. These acquisitions, once completed, will materially increase the Group's UK reserves and resources. They are materially value accretive and in line with the Group's stated strategy of acquiring cash-generative assets in the UK North Sea, where Premier has strong operating capability and considerable tax assets. It is expected that the final consideration will be fully funded from the proceeds of the new equity issuance.

Finance

During 2019, the Group generated US$327.4 million of positive free cash flow which was directed towards debt reduction and further strengthening the balance sheet. At year-end 2019, net debt was US$1.99 billion bringing total debt reduction since October 2017 to over US$900 million, significantly ahead of the Group's forecasts. This is primarily due to operational outperformance, supplemented by non-core asset disposals.

The Group has also announced the proposed extension of the maturities of its credit facilities to 2023. By the end of 2021, the Group will have benefitted from more than 12 months of production from Tolmount and the acquired UK assets will have been fully integrated into the business. Premier believes that this, together with its balance sheet benefitting from two further years of debt reduction, will put the Company in a strong position to refinance the business with a more conventional, and lower cost, debt structure.

The Court Schemes of Arrangement (the Schemes) required to implement the announced acquisitions, related funding arrangements and extension of the Group's credit facilities commenced post year-end. The requisite majority of Premier's creditors approved the Schemes in February and the court sanction hearing is scheduled to commence on 17 March 2020.

Environmental, Social and Governance (ESG)

A Company's success is not only measured in terms of financial performance, but also in terms of environment and social performance. It is the Group's highest priority to continue to operate all of its assets in a safe and responsible manner, to ensure the safety of its workforce and to minimise the potential risk to the environment. In 2019, Premier recorded no serious injuries, no spills and reduced its carbon footprint, achieving a historic low Greenhouse Gas intensity at its operated assets.

Premier recognises the urgent need to respond to Climate Change and the key role the energy industry needs to play in addressing the environmental challenges faced by society today. As such, Premier has committed to ensuring that all of its operated projects will be developed on a carbon neutral basis in respect of Scope 1 and Scope 2 emissions. We can therefore commit, based on expected future profiles, that Premier will be more than 65 per cent carbon neutral by 2025 and 100 per cent by 2030.

Outlook

In the first quarter of 2020, oil prices have fallen significantly due to fears over the spread of COVID-19 and the impact this may have on global demand for oil. The current volatile macro environment serves to highlight the importance of the business being sustainably free cash flow positive and ensuring that future growth can be funded through the commodity price cycle without compromising the balance sheet. The Group's immediate priority remains to reduce its debt levels and covenant leverage ratio towards 1x, a process which will be accelerated by the acquisition of the UK assets announced post period-end. At the same time, Premier will continue to maintain its capital discipline investing selectively in new international projects and exploration to create material value for all of its stakeholders over the longer term.

Full Year Results for the year ended 31 December 2019

Board changes

As announced separately, Premier is pleased to announce that Elisabeth Proust will join the Company's Board as an independent Non-executive Director and member of the Health, Safety, Environment and Security Committee and Nomination Committee with effect from 1 April 2020.

Elisabeth has a strong technical and operational background and joins the Board after a distinguished career within Total's upstream business.

Robin Allan, Director, North Sea and Exploration, will be leaving the Board at the close of the Group's Annual General Meeting in May. Robin will continue to work for Premier on a part-time consultancy basis, with a particular focus on ESG matters and Premier's response to the Climate Change agenda.

BUSINESS UNIT REVIEW

UK

Premier achieved record production from its UK assets of 54.2 kboepd in 2019. This 16 per cent increase on the prior year was driven by a full-year contribution from the Catcher Area at increased rates. First gas from Premier's operated Tolmount project, which is scheduled to come on-stream by year end 2020, will help sustain the Group's UK production at over 50 kboepd, before any contribution from the proposed UK acquisitions.

Catcher Area

Production from the Catcher Area exceeded expectations during 2019 averaging 33.6 kboepd (net, Premier 50 per cent operated interest), underpinned by exceptionally high operating efficiency and reservoir outperformance.

The Catcher Area FPSO continues to produce beyond sanctioned plateau rates supported by excess well deliverability. This resulted in the Group again increasing its Catcher Area recoverable reserves. Premier is also working with the FPSO provider and its joint venture partners to increase oil rates on a short term trial basis. The Catcher Area achieved a low GHG intensity during 2019, benefitting from the high plant uptime and the new build FPSO with modern gas recovery and treatment systems.

Premier received formal approval of the development of the Catcher North and Laverda fields in August. The requisite contracts have been placed and fabrication of the flexibles and umbilicals is underway. Catcher North and Laverda, together with the Varadero infill well, which will also be drilled during 2020, will help offset natural decline as the existing Catcher Area production wells come off plateau. Development drilling is scheduled to start in May 2020 with first oil scheduled for the first quarter of 2021.

The Group continues to work up additional well targets within and around the Catcher Area to maximise economic recovery. Two Burgman infill production wells are under evaluation for 2021 with long lead items ordered and the rig contracting process underway. The 4D seismic to be acquired during 2020 will further calibrate Premier's existing reservoir models, help high grade future opportunities and provide better imaging of the potential oil-bearing reservoirs beyond the existing discoveries to evaluate near-field tie-back opportunities.

Other UK producing assets

2019 production from the Elgin-Franklin Area, which is the UK's largest producing field, averaged 6.0 kboepd (net, Premier 5.2 per cent interest), ahead of expectations. Production was supported by well intervention campaigns and infill drilling, including the F12 well, which was placed on-stream in December. Further infill drilling is planned for 2020, including the F5 well, which is expected to be drilled in the second quarter and tied into production before year-end. In addition, post period-end the joint venture partners approved a four-well stimulation campaign to take place in 2020 to help improve production performance from the existing wells.

Production from Premier's operated Solan field averaged 3.5 kboepd (Premier 100 per cent interest), slightly ahead of forecast and driven by excellent plant operating efficiency. Preparations continued throughout 2019 for the drilling of a new Solan production well (P3) which will boost production from the central part of the reservoir and extend field life. The well is expected to spud in March 2020 with first oil anticipated in the third quarter of 2020. Premier has reached agreement with Baker Hughes to align payment with milestone dates, reducing Premier's cash outlay prior to the completion of the well. On the successful completion of the P3 well, excess gas will be used to replace diesel as a fuel for power generation on the facility.

Active well management at the Premier-operated Huntington field underpinned high uptime from the facility with production averaging 5.8 kboepd (Premier 100 per cent interest). Post period-end, water cut in the highest producing well increased. This prompted Premier to submit a draft decommissioning programme for the removal of the leased Huntington FPSO from the field to the Secretary of State for Business, Energy and Industrial Strategy in February 2020. Premier expects that the last Huntington cargo will be lifted from the field in April 2020. Since 2016, when Premier became operator, the field has outperformed expectations, with proactive reservoir management resulting in the deferral of cessation of production and reserve upgrades over the last few years.

During 2019, Premier installed the Ocean Power Technologies (OPT) PowerBuoy® (PB3) for trial on the Huntington field. The PB3 has demonstrated its ability to harness wave energy to power site-monitoring systems designed for the protection of subsea infrastructure following FPSO sailaway. Premier intends to work with the Oil and Gas Technology Centre and OPT to further develop the system for future use during the decommissioning phases of the Group's assets.

Premier's operated Balmoral Area delivered 1.3 kboepd (net, Premier 79.2 per cent interest) during the period. Production was impacted by the failure of the Brenda multi-phase-pump, partially offset by the restart of the B29 well in April.

In 2019, production from Ravenspurn North averaged 1.2 kboepd (net, Premier 28.7 per cent interest). Uptime from the field improved significantly following the summer shut down, averaging in excess of 95 per cent. The Borr Prospector-5 jack up rig has been contracted to drill two horizontal wells on Ravenspurn North, commencing in March 2020. The wells will access gas in undrained areas of the field with the aim of extending field life and derisking further infill opportunities.

Production from the Kyle field, which is exported via the Petrojarl Banff FPSO, averaged 1.4 kboepd (net, Premier 40 per cent interest). The Kyle joint venture partners are working closely with the Banff owners towards the safe and cost efficient decommissioning of the Kyle facilities, with sailaway of the Petrojarl Banff FPSO anticipated in the summer of 2020.

UK unit field operating costs were stable at US$13/boe (2018: US$13/boe) while lease costs reduced to US$8/boe (2018: US$10/boe). This reflects a full year of production at increased rates from the Catcher FPSO offsetting natural decline on more mature, fixed cost assets such as Huntington and Kyle.

The Greater Tolmount Area

The Premier-operated Tolmount development is on schedule for first gas before year-end 2020 and is tracking below budget. Construction and fit-out of the platform in Rosetti's yard continued during 2019. Jacket roll up was achieved in December and final welding and riser installation is nearing completion. The fit out of all major topsides equipment packages has been substantially completed and final piping, electrical installation and pre-commissioning continues ahead of platform sailaway, which is scheduled for late-April 2020.

Saipem continue to progress the offshore pipeline work scope on behalf of the joint venture partners. The offshore pre-anchor route survey was concluded in November and coating of the linepipe was completed post period-end. Onshore, the shaft from cliff top to beach level has been constructed and preparations are underway for the beach crossing. Laying of the 20 inch gas export pipeline is planned for the summer of 2020. The Easington terminal works are also progressing and the installation of the pre-assembled units commenced post period-end.

Preparations for the 2020 development drilling campaign are well underway. All long lead items have been ordered and contracts placed. The first of the four development wells is expected to spud in the second quarter of 2020 after the jacket is installed. There is also a plan to drill a fifth well at the end of the programme to improve overall recovery from the field. Premier continues to expect first gas before year-end, with Tolmount adding 20-25 kboepd (net, Premier 50 per cent interest) to Group production once on plateau.

In October 2019, Premier announced the success of the Tolmount East well in an undrilled area four kilometres east of the Tolmount gas field. Premier is undertaking FEED studies for both platform and subsea concepts to develop the Tolmount East gas field via the Tolmount infrastructure. Premier plans to select the optimal field development concept during the second quarter of 2020. Final product from the 3D seismic acquired across the Greater Tolmount Area in 2019 is expected in April 2020 and will further-inform the concept select decision. Project sanction of Tolmount East is targeted for the second half of the year and will be brought on-stream to ensure Tolmount infrastructure is kept at full utilisation.

The success at Tolmount East unlocks the potential development of the Mongour discovery to the north which is expected to be developed with Tolmount East. Total resource at Tolmount East, including Mongour, is 160-300 BCF (P50 to P10). These estimates will be further refined as FEED progresses and the processing of the 3D seismic data is completed and integrated into the evaluation.

There is considerable upside within the Greater Tolmount Area. The success at Tolmount East with the new 3D seismic survey reduces the uncertainty of the Tolmount Far East prospect which Premier is currently maturing ahead of drilling in 2022. Further potential also exists to the south and west of the Tolmount field.

Proposed UK acquisitions

Post period-end, Premier announced the proposed acquisitions of the Andrew Area and Shearwater assets from BP and an additional 25 per cent interest in its operated Tolmount Area from Dana Petroleum.

The acquisitions provide Premier with material operated interests in the Andrew Area and a non-operated interest in Shearwater, a significant production and infrastructure hub in the Central North Sea. Both the Andrew Area and the

Shearwater field add mid-life production with material upside potential through production optimisation, incremental developments and field life extension projects. The Tolmount acquisition enables Premier to deepen its position in one of its core UK development assets which has significant upside and, as outlined above, is on track for first gas by the end of 2020.

Combined with existing assets, the proposed acquisitions add cash-generative, rising production out to 2024 with pro forma 2019 UK production in excess of 75 kboepd and no decommissioning security burden. All of the proposed acquisitions are expected to have completed by the end of the third quarter of 2020.

INDONESIA

Premier's Indonesian Business Unit generated material positive net cash flows, after ongoing capital expenditures on the BIG-P development. Safe delivery of BIG-P first gas on schedule and below budget is testament to the team's strong project execution skills and supports the Company's long-term gas sales contracts into Singapore.

Production and development

Production from the Premier-operated Natuna Sea Block A averaged 11.5 kboepd (net, Premier 28.7 per cent interest) (2018: 12.9 kboepd). The slight reduction on 2018 reflects weaker Singapore demand during the second and third quarters of 2019 with Singapore customers substituting cheaper spot LNG for Natuna Sea pipeline gas.

Singapore demand for Premier's Indonesian gas strengthened into year-end with production from Natuna Sea Block A averaging 16.1 kboepd (net to Premier) in December, as the price of Natuna Sea Block A pipeline gas and spot LNG converged. This strong production has continued into 2020 with Natuna Sea Block A production averaging 15.6 kboepd (net to Premier) to the end of February with Singapore demand significantly above take or pay levels.

Premier's Indonesian gas pricing is driven by HSFO prices. In light of the impending implementation of IMO2020 legislation, Premier hedged a significant proportion of its 2020 Indonesian gas entitlement production at c.US$9/mmscf, significantly above current spot prices.

Gross gas deliveries under GSA1 and GSA2 (BBtud)	**GSA1**		**GSA2**	
	2019	**2018**	**2019**	**2018**
Anoa, Pelikan, Bison, Gajah Puteri	147	153	-	-
Gajah Baru, Naga, Iguana	-	-	55	80
Kakap	-	4	-	-
Total	**147**	**157**	**55**	**80**

Premier sold an average of 202 BBtud (gross) (2018: 233 BBtud) from its Natuna Sea Block A fields to Singapore under its two Gas Sales Agreements (GSA1 and GSA2) during 2019. Gross liquids production from the Natuna Sea Block A averaged 1.4 kbopd in 2019.

Singapore demand for Indonesian gas under GSA1 averaged 285 BBtud (2018: 292 BBtud), slightly ahead of take or pay levels. Premier's Natuna Sea Block A fields dedicated to GSA 1 – Anoa, Pelikan, Bison and Gajah Puteri – delivered 147 BBtud (gross) (2018: 153 BBtud), capturing 52 per cent (2018: 52 per cent) of GSA1 deliveries, above Natuna Sea Block A's contractual share of 51 per cent.

Premier's Natuna Sea Block A fields dedicated to GSA2 – Gajah Baru, Naga and Iguana – delivered 55 BBtud (2018: 80 BBtud), in line with take or pay levels.

During 2019, Premier successfully executed a series of high value investments aimed at boosting deliverability from Natuna Sea Block A. Premier achieved first gas from its operated BIG-P project in December, on schedule and significantly below budget. With further production history, Premier expects BIG-P recoverable reserves to increase to in excess of the 93 BCF (gross) estimated at sanction. This is as a result of the successful three-well drilling campaign in 2019 which encountered additional productive sands. Natuna Sea Block A deliverability was also boosted by a successful perforation of an Anoa West Lobe well in May and the tie-in of a Gajah Baru infill well in December.

Further intervention activities are planned for 2020 to maximise gas delivery from the Natuna Sea Block A fields and preparations are underway for a 2021 rig campaign which will include Anoa well workovers and side-tracks, infill drilling on the Pelikan field and an appraisal well to test the northern flank of the producing Anoa field.

Exploration and appraisal

During 2019, Premier continued to progress its operated Tuna discoveries, which are estimated to contain 100 mmboe (gross) and are located in the Natuna Sea close to the Indonesian and Vietnamese maritime boundary.

In December, Premier signed a Heads of Terms with Zarubezhneft, a Russian company with upstream interests primarily in Vietnam, to farm in for a 50 per cent non-operated interest in the Tuna PSC. A farm down agreement is expected to be signed by the end of the first quarter of 2020. Under the farm down agreement, Zarubezhneft will carry Premier for its share of a two-well appraisal campaign which is planned for 2020. It is anticipated that, post completion and receipt of government approval, Premier will retain operatorship and a 50 per cent interest in the Tuna PSC.

In January 2020, Premier was awarded a one-year extension to the exploration period of the Tuna PSC to allow for appraisal drilling to take place and the subsequent submission of a Plan of Development to the Indonesian government by March 2021.

Elsewhere in Indonesia, Premier expanded its acreage position in the South Andaman Sea during 2019, farming in for a 20 per cent interest in South Andaman and Andaman I PSCs. A 3D seismic acquisition programme across parts of the Andaman Sea blocks was completed during the first half of 2019. The fast track data was received in September and confirmed the prospective nature of the acreage with the fully-processed seismic data across all three blocks to be delivered in the first quarter of 2020. Premier plans to drill its first well in the Andaman Sea on its operated Andaman II licence in the first half of 2021. Premier's Andaman Sea position has the potential to deliver multi-TCF of gas and adds a potentially material gas play to the Group's Indonesia portfolio.

VIETNAM

Premier's operated Chim Sáo field delivered a robust production performance in 2019. Together with continued low operating costs, this resulted in the asset generating over US$80 million of free cash flow. A two-well infill programme is being planned for 2021 to help offset natural decline from the existing production wells with regulatory approvals in progress.

Production from the Premier-operated Block 12W, which contains the Chim Sáo and Dua fields, averaged 11.4 kboepd (net, Premier-operated 53.1 per cent interest) (2018: 15.2 kboepd) and was ahead of expectations. The reduction on the prior year reflects natural decline from the existing wells partially offset by active reservoir management and ongoing well intervention activities.

2019 saw four well intervention campaigns aimed at maximising the ultimate recovery from the Chim Sáo field. This included improved utilisation of gas lift across the Chim Sáo well stock and the perforation of new zones within existing wells. Further well intervention work is planned for 2020 to help slow natural decline and optimise offtake from the Chim Sáo field. Preparations are also underway for a two-well infill programme scheduled for 2021. Premier is currently seeking regulatory approvals for the programme ahead of going out for tender for a rig.

Chim Sáo cargoes were well bid, especially in the second half of the year, with an average premium to Brent of more than US$4.70/bbl realised for cargoes lifted during 2019. Demand for Chim Sáo crude continued to strengthen post period-end with January to April 2020 loading cargoes sold at an average premium to Brent of US$7.20/bbl.

Field operating costs were US$9/boe (2018: US$5/boe), significantly below budget driven by production outperformance.

FALKLAND ISLANDS

The Premier-operated Sea Lion Phase 1 project has been substantially derisked from a technical and cost perspective and, post period-end, Navitas Petroleum agreed to farm in for a 30 per cent interest in the project. The Group's focus is now on securing senior debt support for the project.

The 530 mmbbls (gross) Sea Lion project, which will be developed over two phases, represents a material opportunity for the Group.

Sea Lion Phase 1 will develop 250 mmbbls (gross) using a conventional FPSO and subsea well development scheme, similar to Premier's operated Catcher development. FEED has been completed and the development concept further optimised with the addition of a drill centre to the south and the well count increased to 29 wells (20 producers, eight water injectors and one gas injector). 12 wells will be drilled pre-first oil supporting ramp up to plateau production rates of 85 kboepd (gross).

Premier continues to benefit from a collaborative relationship with its Tier 1 supply chain companies. All of the key service and supply contracts, including for the provision of the FPSO, drilling rig, well services, flexible flowlines and risers, subsea production systems and SURF installation, are being finalised in preparation for their execution as the project approaches sanction decision.

The Environmental Impact Statement was updated in 2019 to reflect further project optimisation and was issued for public consultation in the Falkland Islands, which concluded post period-end. The Environmental Impact Statement will be submitted along with the Field Development Plan (FDP) for government approval as part of the project sanction process.

Premier has made a public commitment that all operated projects will be developed on the basis that they will be net zero in respect of Scope 1 and Scope 2 emissions. A number of engineering features have been designed into the Sea Lion project using best-available technology to minimise emissions at source. It is anticipated that these will be supplemented by carbon offsets to ensure net zero emissions from Sea Lion is achieved.

During 2019, Premier launched a farm down process to bring in an additional equity partner into the Sea Lion project to optimise the Group's level of participation in the development. In January 2020, Premier and Rockhopper agreed a detailed Heads of Terms with Navitas Petroleum to farm in for a 30 per cent interest in Sea Lion. Finalisation of a farm out agreement is expected during the first half of 2020 with completion subject to regulatory and lender approval. Together with the vendor funding for the project by the contractors and the senior debt financing component, this reduces Premier's share of pre-first oil capex from c.US$500 million to below US$300 million spread over the project investment period.

The critical path item to sanction remains securing senior debt support for the project. In 2019, Premier completed a Preliminary Information Memorandum supported by a comprehensive set of independent expert reports on the project. These formed the basis for the financing guarantee application process for the senior debt component of the project financing. While engagement with senior debt providers is constructive, feedback received highlights the need for Premier to complete its announced corporate actions and extension of its credit facilities to provide certainty over its medium- to long-term funding position before financial guarantees for the project can be provided.

EXPLORATION ACTIVITIES

During 2019, Premier's exploration teams continued to invest selectively in its international exploration portfolio within strict budgetary constraints. The Group's focus remains on underexplored but proven provinces which have the potential to develop into new business units over the medium term.

Alaska

2019 saw a new country entry for Premier, with the Group farming in for a 60 per cent interest in the conventional Area A Icewine project in the Alaska North Slope. Area A contains the Malguk-1 discovery drilled by BP in 1991. This well discovered but never tested 251 feet of light oil pay in turbidite sands in the Torok formation, within the emerging Brookian play where a number of developments are currently underway. Premier estimates an accumulation of more than 1 billion barrels (gross) of oil-in-place. The Charlie-1 (Malguk-1 appraisal) well spudded post period-end on 2 March and is currently drilling ahead. Premier plans to flow test the well with the results expected in April. On successful completion of the work programme, Premier will have the option to assume operatorship and to opt-in to Icewine Area B or C.

Brazil

In Brazil, much of 2019 was spent preparing for Premier's first in-country exploration well on its operated Block 717 (Premier 50 per cent interest) in the offshore Ceará basin. Premier has contracted the Valaris DS-9 drillship to drill a well targeting the stacked Berimbau/Maraca prospect. Berimbau is the higher risk, high value prospect with a Pmean to P10 gross unrisked resource estimate of 230-450 mmbbls. Maraca is a lower risk prospect and is estimated to contain 85-165 mmbbls (Pmean-P10) of gross unrisked resource. The well is expected to spud in the third quarter of 2020.

Elsewhere in the Ceará basin, on Block 661 (Premier 30 per cent non-operated interest), the joint venture successfully obtained an initial term licence extension through to November 2021.

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

Mexico

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

In June, the Block 7 joint venture partnership agreed the main elements of a full field development plan to maximise overall recovery from the Zama field. The Zama field will be developed using two offshore processing, drilling and accommodation platforms, together with a floating, storage and offloading vessel and oil export by tankers. FEED is now underway with submission of the FDP for government approval expected in the third quarter of 2020. FDP approval is subject to conclusion of the unitisation of the field between Block 7 and the neighbouring block (Pemex 100 per cent interest).

Unitisation discussions are progressing as per the Mexican regulatory process, which is in line with international best practice. If the Block 7 partners and Pemex cannot reach agreement, then an independent expert will be appointed in the second quarter of 2020 to determine the initial tract participation of the Zama field as per the process detailed in the Government-approved Pre-unitisation Agreement.

Following the successful appraisal of the Zama field, Premier initiated a sales process for its interest in Block 7. Discussions with interested parties are ongoing and are expected to conclude once the unitisation process is further advanced.

Premier retains exposure to exploration upside in Mexico through its other offshore licence interests, each of which has the potential to deliver material future value for Premier. A 3D seismic survey acquisition across Block 30 (Premier

30 per cent interest) was completed in July. The data is now being processed to delineate the full extent of the Wahoo and Cabrilla prospects, as well as to mature other prospectivity on the Block. Drilling is targeted for 2021.

Premier's exploration plan for its 100 per cent operated Burgos Blocks 11 and 13 were approved by CNH in July, triggering the start of the four-year initial term for these licences. Reprocessing of the existing 3D seismic across Premier's Burgos blocks is ongoing and regional play fairway analysis has identified a deeper play in the Cretaceous and Jurassic carbonates that provides additional upside to that previously identified in the Oligocene-Miocene clastic play.

Full Year Results for the year ended 31 December 2019

FINANCIAL REVIEW

Business performance

Production averaged 78.4 kboepd in 2019 (2018: 80.5 kboepd), which, coupled with improved crude differentials, higher post hedged realisations and a higher oil vs gas mix, resulted in total revenue from all operations of US$1,597 million compared with US$1,438 million in 2018.

EBITDAX for the period from continuing operations was US$1,230 million, an increase of US$139 million compared to the prior period EBITDAX of US$1,091 million, once lease expenses have been added back following the implementation of IFRS 16. The increased EBITDAX, on a like-for-like basis, is due primarily to improved realised oil prices post hedging and a higher oil vs gas production mix with underlying operating costs remaining broadly stable due to tight cost control.

Business performance (continuing operations)	**2019 $ million**	2018 $ million
Operating profit	**455.0**	531.0
Add: DD&A	**757.9**	358.4
Add: Exploration and new venture costs	**21.3**	35.2
(Less): (Profit) on disposal of assets	**(4.2)**	(42.3)
EBITDAX as reported	**1,230.0**	882.3
Add: lease expenses	**-**	208.7
EBITDAX adjusted for lease expenses	**1,230.0**	1,091.0

In addition, we have reduced Net Debt to US$1,989.8 million, following strong cash flow generation in the year.

Income statement

Production and commodity prices

Group production on a working interest basis averaged 78.4 kboepd compared to 80.5 kboepd in 2018. Production is at the upper end of guidance previously given but is slightly lower than prior year due to the disposal of the Pakistan business unit, which completed in March 2019, and natural decline in other fields. This was partially offset by high operational efficiency across the asset portfolio and the increased contribution from Catcher. Average entitlement production for the period was 73.9 kboepd (2018: 73.8 kboepd).

Premier realised an average oil price for the year of US$66.3/bbl (2018: US$67.9/bbl). Including the effect of oil swaps which settled during 2019, the realised oil price was US$68.1/bbl (2018: US$63.5/bbl). Premier benefitted from improving differentials for its crude oil sales relative to the underlying Brent oil price.

In the UK, average natural gas prices achieved were 42 pence/therm (2018: 57 pence/therm), which included 24.5 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$10.2/mscf (2018: US$11.2/mscf).

Realised prices	**2019**	2018
Oil price (US$/bbl) post hedging	**68.1**	63.5
UK natural gas (pence/therm)	**42**	57
Singapore HSFO (US$/mscf)	**10.2**	11.2

Total revenue from all operations (including Pakistan) increased to US$1,596.5 million (2018: US$1,438.3 million). From continuing operations (excluding Pakistan), sales revenue increased to US$1,584.7 million from US$1,397.5 million for the prior year.

Cost of operations

Cost of operations comprise operating costs, changes in lifting positions, inventory movement and royalties. Cost of operations, which now exclude lease expenses following the adoption of IFRS 16, for the Group was US$342.8 million for 2019, compared to US$291.3 million for 2018, once lease costs of US$208.7 million are removed from the prior period.

	2019 $ million	2018 $ million
Operating costs		
Continuing operations	**322.6**	487.5
Less: lease expenses	**-**	(208.7)
Discontinuing operations (Pakistan)	**2.4**	9.5
Operating costs	**325.0**	288.3
Operating cost per barrel (US$ per barrel)	**11.4**	9.8

Lease expenses in 2019 were US$196.4 million, giving a lease cost per barrel of US$6.9, which is broadly consistent year on year.

The increase in absolute operating costs reflects additional payments made to reflect high uptime from the Catcher field. Ongoing cost reduction initiatives, successful contract renegotiations and strict management of discretionary spend continue to deliver low and stable operating costs. Operating costs per barrel, excluding lease costs, are expected to be c.$15/bbl in 2020 reflecting lower year on year production rather than any increase in underlying operating costs.

	2019 $ million	2018 $ million
Amortisation and depreciation		
Total DD&A	**742.9**	386.5
DD&A per barrel (US$ per barrel)	**26.4**	13.2

Total depreciation has increased year-on-year due to DD&A charges of US$223.0 million recognised on right-of-use-assets now recorded on the balance sheet as property, plant and equipment following the adoption of IFRS 16 on 1 January 2019. The DD&A charge reflects the positive impact of the revised Catcher reserves estimates. Included within the depreciation charge for the year are charges of US$30.5 million related to an increase in the Group's UK decommissioning provisions for assets which are carried at nil book value. The increase is driven by a reduction in the discount rate used to determine the net present value of the decommissioning provision, following the reduction in US treasury rates observed in 2019 and not by any material change in the underlying decommissioning cost estimates.

Exploration expenditure and new ventures

Exploration expense and new venture costs amounted to US$21.3 million (2018: US$35.2 million), primarily related to work performed on potential new licences and acquisitions. After recognition of these expenditures, the exploration and evaluation assets remaining on the balance sheet at 31 December 2019 amount to US$934.0 million, principally for the Sea Lion asset, our share of the Zama prospect and Block 30 in Mexico and the Tuna PSC in Indonesia.

General and administrative expenses

Net G&A costs fell to US$9.0 million from US$14.0 million in 2018.

Finance gains and charges

Net finance gains and charges of US$352.5 million, have reduced compared to the prior year (US$372.8 million). An increase in finance costs due to lease liabilities recognised on adoption of IFRS 16 has been broadly offset by a reduction in the unwinding of the decommissioning provision due to the change in discount rate and mark to market gains on open hedging instruments. Cash interest expense in the period was US$251.9 million (2018: US$228.7 million), reflecting the timing of Revolving Credit Facility ("RCF") rollovers. Cash interest expense is expected to fall in

2020 on an underlying basis reflecting reduced net debt, excluding the impact of any amendment fees relating to the proposed amendment and extension of our existing facilities.

Taxation

The Group's total tax credit for 2019 from continuing operations is US$52.5 million (2018: charge of US$53.1 million) which comprises a current tax charge for the period of US$51.1 million and a non-cash deferred tax credit for the period of US$103.6 million.

The total tax credit represents an effective tax rate credit of 51.2 per cent (2018: charge of 33.5 per cent). The effective tax rate for the year is primarily impacted by ring fence expenditure supplement claims in the UK during the year (US$88.1 million credit). For the Group's principal UK North Sea operating subsidiary, 2019 represented the final ring fence expenditure supplement claim. After adjusting for this, the underlying Group tax charge for the period is US$35.6 million and an effective tax rate of 34.7 per cent. The Group has a net deferred tax asset of US$1,426.2 million at 31 December 2019 (2018: US$1,294.6 million).

Profit after tax

Profit after tax is US$164.3 million (2018: US$133.4 million) resulting in a basic earnings per share of 19.9 cents from continuing and discontinued operations (2018: 17.3 cents). The profit after tax in the year is driven principally by the increased sales revenue and the Group's tax loss position in the UK, partially offset by the increase in lease related costs in the income statement following implementation of IFRS 16 on 1 January 2019.

Cash flows

Cash flow from operating activities was US$1,080.0 million (2018: US$777.2 million) after accounting for tax payments of US$61.2 million (2018: US$128.8 million) and before the movement in joint venture cash balances in the period of US$28.7 million. The increase is driven by increased production and revenue in the period and due to US$204.5 million of lease cash costs (net) in 2019 recorded as financing and not operating cash flows.
Capital expenditure in 2019 totalled US$241.4 million (2018: US$279.8 million).

Capital expenditure	**2019 $ million**	2018 $ million
Fields/development projects	**101.7**	234.3
Exploration and evaluation	**136.9**	43.6
Other	**2.8**	1.9
Total	**241.4**	279.8

The development expenditure mainly relates to the BIG-P development in Indonesia and the Tolmount project in the UK. The largest part of the E&E capital expenditure in the period was the appraisal drilling for the Zama project in Mexico. In addition, cash expenditure for decommissioning activity in the period was US$35.3 million (2018: US$72.7 million). Further to this, US$9.9 million of cash was funded into long-term abandonment accounts for future decommissioning activities (2018: US$17.8 million).

Total development and E&E expenditure in 2020 is estimated at US$410 million principally related to development drilling on Tolmount, Catcher and Solan and exploration and appraisal activities in Alaska, Brazil, Mexico and Indonesia. Decommissioning spend is estimated at US$60 million reflecting the recent decision to cease production at Huntington, although the impact on full year cash flow generation is offset by the assumption that Huntington would have generated negative operating cash flow in 2H 2020.

Discontinued operations, disposals and assets held for sale

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

Balance sheet position

Net debt

Net debt at 31 December 2019 amounted to US$1,989.8 million (31 December 2018: US$2,330.7 million), with cash resources of US$198.1 million (31 December 2018: US$244.6 million). The maturity of all of Premier's facilities is May 2021. During the year, Premier made debt repayments of US$399.7 million. Further, the Group cancelled US$333.8 million of its RCF debt facility.

Premier retains significant cash at 31 December 2019 of US$151.0 million and undrawn facilities of US$398.2 million, giving liquidity of US$549.2 million (31 December 2018: US$569.6 million) when excluding cash of US$47.1 million held on behalf of joint venture partners or as security for letters of credit.

Subsequent to the year-end, in January 2020, a further US$129.5 million of the Group's RCF debt facility was cancelled by Premier, which will result in reduced commitment fee costs for the Group in 2020.

Provisions

The Group's decommissioning provision increased to US$1,303.4 million at 31 December 2019, up from US$1,214.5

million at the end of 2018. The increase is driven by a reduction in the discount rate used to determine the net present value of the decommissioning provision, following the reduction in US treasury rates observed in 2019 and not by any material change in the underlying decommissioning costs estimates.

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

Impact on key financial metrics on adoption of IFRS 16 Leases

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

$ million	Impact of IFRS 16	
Balance Sheet at 31 December 2019 [1]		
Fixed assets	**588.0**	
Net investment in sub-lease	**75.7**	
Lease liabilities	**(732.5)**	
Income Statement for 2019 [2]		
Costs of Production	**196.4**	Decrease
DD&A	**223.0**	Increase
Net finance costs	**44.7**	Increase
Net impact on profit after tax	**71.3**	Decrease
Cash flow for 2019 [3]		
Operating cash flow	**204.5**	Increase
Net lease payments (within financing and investing)	**204.5**	Increase
Free cash flow	**Nil**	

1. Balance Sheet

Following the adoption of IFRS 16, US$588.0 million of right-of-use assets, US$75.7 million of net investment in sublease and US$732.5 million of lease liabilities have been included in the Group balance sheet as at 31 December 2019. All of these were previously classified as operating leases as the Group did not have any finance leases under IAS 17. Lease liabilities are now presented separately on the Group balance sheet as both current and non-current liabilities, do not form part of finance debt and are not included in net debt under the terms of the Group's financing facilities.

2. Income Statement

Charges to the income statement due to the adoption of IFRS 16 have increased by US$71.3 million. This represents an increase in depreciation and finance costs recognised on right-of-use assets and lease liabilities, which are partially offset by the absence of operating lease expenses within costs of production. EBITDAX, as previously defined, has increased, due to the absence of operating lease expenses within costs of production. For the purposes of covenant calculations, lease expenses continue to be included within costs of production.

3. Cash flow

In prior years, operating lease payments were presented as operating cash flows. Lease payments are now classified as financing cash flows which has caused operating cash flows to increase. There were US$204.5 million of lease payments (net) included within financing and investing cash flows for 2019, that would previously have been reported within operating cash flows before the adoption of IFRS 16.

Financial risk management

Commodity prices

Premier continued to take advantage of the improved oil price environment observed at times in 2019 to increase its hedging position to protect free cash flows and covenant compliance. [1]

The Group's current hedge position is as follows:

Oil

Swaps / forwards	**2020 1H**	**2020 2H**
Volume (mmbbls)	3.4	1.3
Average price (US$/bbl)	64	63

UK gas

Swaps / forwards / options	**2020 1H**	**2020 2H**	**2021**	**2022**
Volume (million therms)	35	28	89	64
Average price (p/therm)	55	52	42[1]	42[1]

(1) 2021 average price is a mixture of swap and option floor pricing whilst 2022 is average option floor pricing only. Excludes impact of deferred option premiums

Indonesia gas

Swaps / forwards	2020 1H	2020 2H
Volume (HSFO k te)	126	126
Average price (US$/te)	382	340

At 31 December 2019, the fair value of the open oil and gas instruments above was an asset of US$29.2 million (31 December 2018: asset of US$119.3 million), which is expected to be released to the income statement during 2020 and 2021 as the related barrels are lifted or therms delivered.

During 2019, expiration of forward oil swaps resulted in a net credit of US$35.9 million (2018: charge of US$71.2 million) which has been included in sales revenue for the year.

Foreign exchange

Premier's functional and reporting currency is US dollars. Exchange rate exposures relate only to local currency receipts, and expenditures within individual business units. Local currency needs are acquired on a short-term basis. At the year-end, the Group recorded a mark-to-market gain of US$6.2 million on its outstanding foreign exchange contracts (2018: loss of US$17.2 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:€. The fair value of the cross currency swap liability at 31 December 2019 is US$123.6 million, which is split between current and long term liabilities (2018: liability of US$125.6 million).

Interest rates

The Group has various financing instruments including senior loan notes, UK retail bonds, term loans and revolving credit facilities. Currently, approximately 73 per cent of total borrowings is fixed or capped using interest rate options. On average, the effective interest on drawn funds for the period, recognised in the income statement, was 8.2 per cent.

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 2019, US$2.3 million of cash proceeds were received (net to Premier) in relation to settled insurance claims (2018: US$1.4 million).

Going concern

The Group monitors its funding position and its liquidity risk throughout the year to ensure it has access to sufficient funds to meet forecast cash requirements. Cash forecasts are regularly produced based on, inter alia, the Group's latest life of field production and expenditure forecasts, management's best estimate of future commodity prices (based on recent forward curves, adjusted for the Group's hedging programme) and the Group's borrowing facilities. Sensitivities are run to reflect different scenarios including, but not limited to, changes in oil and gas production rates, possible reductions in commodity prices and delays or cost overruns on major development projects. This is done to identify risks to liquidity and covenant compliance and enable management to formulate appropriate and timely mitigation strategies.

Management's base case forecast assumed an oil price of US$65/bbl in 2020 and 2021, respectively and production in line with prevailing rates. In January 2020, the Group publicly announced the agreement it had reached to undertake the following corporate actions (together the "Corporate Actions"):

- an amend and extend ("A&E") of all of the Group's financing facilities, including extension of maturity from May 2021 to November 2023;
- the proposed acquisition of a 25 per cent working interest in Tolmount from Dana and interests in Andrew and Shearwater from BP (together the "Acquisitions" or the "Acquired Assets");
- entering into of a US$300 million bridge facility to partly finance the Acquisitions (the "Bridge Facility"). Based on current forecasts we do not expect to utilise the Bridge Facility; and,
- raising equity from shareholders via a combination of a placing and a rights issue (the "Equity Raise"), which is fully underwritten.

The above actions are expected to be approved via a court scheme of arrangement in March 2020. Assuming approval is obtained, the Group will request that shareholders approve the Equity Raise and Acquisitions in Q2 2020. In February 2020, more than 75 per cent of the Group's creditors voted to support the Group's scheme of arrangement. Accordingly, management expect the above Corporate Actions to be approved and completed in Q3 2020. The expected completion of Corporate Actions is reflected in the base case forecast. However, as sanction of the scheme of arrangement is subject to court approval, and particularly given the scheme is currently being opposed by one creditor, approval is not yet certain.

At 31 December 2019, the Group continued to have significant headroom on its financing facilities and cash on hand. The Group has run downside scenarios, where oil and gas prices are reduced by a flat US$10/bbl throughout the going concern period and where total Group production is forecast to reduce by 10 per cent. In the downside scenarios applied to the base case forecast, individually and in combination, there would be no forecast covenant breach during the 12 month going concern assessment period.

In addition, the Group has run downside scenarios where the Corporate Actions do not complete either because of a rejection of the Scheme by the court or due to rejection by shareholders. In the event that the Corporate Actions do not complete, and applying the base case assumptions to Premier's existing assets, the forecasts show that the Group will have sufficient financial headroom for the 12 months from the date of approval of the 2019 Annual Report and Accounts, even if the Corporate Actions do not complete. However, if the Corporate Actions do not complete and downside price and or production scenarios materialise, in the absence of any mitigating actions, a breach of one or more of the financial covenants during the 12 month going concern assessment period would arise and the Group's financing facilities would be classified as current liabilities in subsequent reporting periods. This potential breach could be mitigated by asset disposals, such as the Group's interest in the Zama prospect, as well as further hedging activity or deferral of expenditure.

Currently, due to fears over the spread of COVID-19 and the impact this may have on global demand for oil, oil prices have fallen to levels not seen since early 2016 and below the sensitised case above. If oil prices were to remain at these levels, and the Corporate Actions described above did not complete, the Directors believe that the mitigating actions identified above would prevent a breach from occurring.

Based on management's expectation that the completion of the Corporate Actions is probable, and considering the downside scenarios run, including the Corporate Actions not completing, the Directors have a reasonable expectation that the Company has adequate resources to continue in operational existence for the foreseeable future. Therefore, the Directors continue to adopt the going concern basis of accounting in preparing these consolidated financial statements.

In the remote scenario whereby the Corporate Actions do not complete, there is a sustained fall in the oil price, and management is unable to deliver any mitigating actions, in the event of a forecast covenant breach, management has an expectation that either a covenant waiver or forbearance from the required number of lenders would be received, which would avoid an acceleration of repayment of the Group's financing facilities during the going concern period.

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:

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

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

Richard Rose

Finance Director

PremierOil

Full Year Results for the year ended 31 December 2019

Consolidated Income Statement
For the year ended 31 December 2019

	2019 US$ million	2018 US$ million
Continuing operations		
Sales revenues	**1,584.7**	1,397.5
Other operating costs	**(2.9)**	(1.2)
Costs of operation	**(342.8)**	(500.0)
Depreciation, depletion, amortisation and impairment	**(757.9)**	(358.4)
Exploration expenses and new ventures	**(21.3)**	(35.2)
Profit on disposal of non-current assets	**4.2**	42.3
General and administration costs	**(9.0)**	(14.0)
Operating profit	**455.0**	531.0
Interest revenue, finance and other gains	**31.4**	27.8
Finance costs, other finance expenses and losses	**(383.9)**	(400.6)
Profit before tax from continuing operations	**102.5**	158.2
Tax credit/(charge)	**52.5**	(53.1)
Profit for the year from continuing operations	**155.0**	105.1
Discontinued operations		
Profit for the year from discontinued operations	**9.3**	28.3
Profit after tax	**164.3**	133.4
Earnings per share (cents):		
From continuing operations		
Basic	**18.8**	13.6
Diluted	**17.2**	12.2
From continuing and discontinued operations		
Basic	**19.9**	17.3
Diluted	**18.2**	15.5

Consolidated Statement of Comprehensive Income
For the year ended 31 December 2019

	2019 US$ million	2018 US$ million
Profit for the year	**164.3**	133.4
Cash flow hedges on commodity swaps:		
(Losses)/gains arising during the year	**(50.8)**	85.7
Add: reclassification adjustments for (gains)/losses in the year	**(45.6)**	71.2
	(96.4)	156.9
Cash flow hedges on interest rate and foreign exchange swaps:		
(Losses)/gains arising during the year	**(13.4)**	21.5
Less: reclassification adjustments for losses/(gains) in the year	**10.3**	(11.4)
	(3.1)	10.1
Tax relating to components of other comprehensive income	**25.0**	(33.8)
Exchange differences on translation of foreign operations	**(3.8)**	7.4
Gain on long-term employee benefit plans*	**0.2**	-
Other comprehensive (expenses)/income	**(78.1)**	140.6
Total comprehensive income for the year	**86.2**	274.0

* Not expected to be reclassified subsequently to income statement.

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

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Full Year Results for the year ended 31 December 2019

Consolidated Balance Sheet
As at 31 December 2019

	2019 US$ million	2018 US$ million
Non-current assets:		
Intangible exploration and evaluation assets	**934.0**	812.6
Property, plant and equipment	**2,481.8**	2,245.6
Goodwill	**240.8**	240.8
Long-term receivables	**231.1**	159.8
Deferred tax assets	**1,556.1**	1,434.1
	5,443.8	4,892.9
Current assets:		
Inventories	**16.3**	12.5
Trade and other receivables	**378.9**	282.3
Derivative financial instruments	**55.3**	127.4
Cash and cash equivalents	**198.1**	244.6
Assets held for sale	**-**	55.2
	648.6	722.0
Total assets	**6,092.4**	5,614.9
Current liabilities:		
Trade and other payables	**(356.2)**	(375.6)
Lease liabilities	**(149.7)**	-
Short-term provisions	**(76.8)**	(46.0)
Derivative financial instruments	**(98.8)**	(41.4)
Deferred income	**(15.3)**	(11.0)
Liabilities directly associated with assets held for sale	**-**	(21.9)
	(696.8)	(495.9)
Net current (liabilities)/assets	**(48.2)**	226.1
Non-current liabilities:		
Long-term debt	**(2,169.8)**	(2,552.0)
Deferred tax liabilities	**(129.9)**	(139.5)
Lease liabilities	**(582.8)**	-
Deferred income	**(60.5)**	(76.0)
Derivative financial instruments	**(62.3)**	(129.4)
Long-term provisions	**(1,258.8)**	(1,196.1)
	(4,264.1)	(4,093.0)
Total liabilities	**(4,960.9)**	(4,588.9)
Net assets	**1,131.5**	1,026.0
Equity and reserves:		
Share capital	**156.5**	154.2
Share premium account	**499.4**	491.7
Other reserves	**475.6**	380.1
	1,131.5	1,026.0

Consolidated Statement of Changes in Equity
For the year ended 31 December 2019

	Share capital US$ million	Share premium account US$ million	Other reserves US$ million	Total US$ million
At 1 January 2018	109.0	284.5	141.4	534.9
Issue of Ordinary Shares	45.2	207.2	7.7	260.1
Purchase of ESOP Trust shares	-	-	(1.5)	(1.5)
Provision for share-based payments	-	-	14.6	14.6
Conversion of convertible bonds	-	-	(56.1)	(56.1)
Profit for the year	-	-	133.4	133.4
Other comprehensive income	-	-	140.6	140.6
At 1 January 2019	154.2	491.7	380.1	1,026.0
Issue of Ordinary Shares	2.3	7.7	0.9	10.9
Purchase of ESOP Trust shares	-	-	(3.6)	(3.6)
Provision for share-based payments	-	-	12.0	12.0
Profit for the year	-	-	164.3	164.3
Other comprehensive expense	-	-	(78.1)	(78.1)
At 31 December 2019	**156.5**	**499.4**	**475.6**	**1,131.5**

Consolidated Cash Flow Statement
For the year ended 31 December 2019

	2019 US$ million	2018 US$ million
Net cash from operating activities	**1,108.7**	722.8
Investing activities:		
Capital expenditure	**(241.4)**	(279.8)
Decommissioning pre-funding	**(9.9)**	(17.8)
Decommissioning expenditure	**(35.3)**	(72.7)
Receipts from sub-lease income	**20.2**	-
Proceeds from disposal of oil and gas properties	**4.2**	73.4
Net cash used in investing activities	**(262.2)**	(296.9)
Financing activities:		
Issuance of Ordinary Shares	**4.7**	13.8
Net release/(purchase) of ESOP Trust shares	**1.1**	(1.5)
Warrant cash consideration	**(13.8)**	-
Proceeds from drawdown of long-term bank loans	**-**	105.0
Repayment of long-term bank loans	**(399.7)**	(415.3)
Lease liability payments	**(224.7)**	-
Interest paid	**(251.9)**	(228.7)
Net cash from financing activities	**(884.3)**	(526.7)
Currency translation differences relating to cash and cash equivalents	**(8.7)**	(20.0)
Net decrease in cash and cash equivalents	**(46.5)**	(120.8)
Cash and cash equivalents at the beginning of the year	**244.6**	365.4
Cash and cash equivalents at the end of the year	**198.1**	244.6

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the year ended 31 December 2019

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 4 March 2020.

The financial information for the year ended 31 December 2019 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 2018 were approved by the Board of Directors on 6 March 2019 and delivered to the Registrar of Companies and those for 2019 will be delivered following the Company's Annual General Meeting ('AGM'). The auditor has reported on the 2019 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 2020.

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 these condensed financial statements are consistent with those of the annual financial statements for the year ended 31 December 2018, as described in those annual financial statements, except for the adoption of IFRS 16 Leases.

1. General information *(continued)*

IFRS 16 'Leases'

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

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

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

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

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

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

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

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

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

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

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

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

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

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.

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

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

	2019 US$ million	2018 US$ million
Revenue:		
Indonesia	**172.2**	192.8
Vietnam	**198.6**	272.4
United Kingdom	**1,213.9**	931.5
Rest of the World	**-**	0.8
Total Group sales revenue	**1,584.7**	1,397.5
Interest and other finance revenue	**2.4**	7.6
Total Group revenue from continuing operations	**1,587.1**	1,405.1
Group operating profit:		
Indonesia	**90.9**	111.8
Vietnam	**96.2**	142.2
United Kingdom	**291.7**	326.2
Rest of the World	**(0.9)**	(29.6)
Unallocated [1]	**(22.9)**	(19.6)
Group operating profit	**455.0**	531.0
Interest revenue, finance and other gains	**31.4**	27.8
Finance costs and other finance expenses	**(383.9)**	(400.6)
Profit before tax from continuing operations	**102.5**	158.2
Tax	**52.5**	(53.1)
Profit after tax from continuing operations	**155.0**	105.1
Profit from discontinued operations	**9.3**	28.3

2. Operating segments *(continued)*

	2019 US$ million	2018 US$ million
Balance sheet		
Segment assets:		
Falkland Islands	**680.0**	648.1
Indonesia	**481.5**	417.7
Vietnam	**437.8**	312.0
United Kingdom	**4,060.3**	3,706.1
Rest of the World	**179.4**	103.8
Assets held for sale	**-**	55.2
Unallocated[1]	**253.4**	372.0
Total assets	**6,092.4**	5,614.9
Liabilities:		
Falkland Islands	**(13.0)**	(12.8)
Indonesia	**(216.5)**	(174.0)
Vietnam	**(324.3)**	(174.1)
United Kingdom	**(2,041.7)**	(1,431.9)
Rest of the World	**(34.5)**	(51.4)
Liabilities directly associated with assets held for sale	**-**	(21.9)
Unallocated[1]	**(2,330.9)**	(2,722.8)
Total liabilities	**(4,960.9)**	(4,588.9)
Other information		
Capital additions and acquisitions:		
Falkland Islands	**30.0**	15.1
Indonesia[2]	**72.1**	24.5
Pakistan	**1.3**	4.1
Vietnam[2]	**5.0**	(0.1)
United Kingdom[2]	**142.6**	(50.3)
Rest of the World[2]	**61.2**	37.2
Total capital additions and acquisitions	**312.2**	30.5

2. Operating segments *(continued)*

	2019 US$ million	2018 US$ million
Depreciation, depletion, amortisation and impairment: [3]		
Indonesia	**44.5**	46.6
Vietnam	**60.0**	55.6
United Kingdom	**652.6**	254.8
Rest of the World	**0.8**	1.4
Total DD&A and impairment (continuing operations)	**757.9**	358.4

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

[2] Includes revisions to decommissioning estimates in the year.

[3] Includes DD&A in respect of right-of-use assets.

Out of the total Group worldwide sales revenues of US$1,584.7 million (2018: US$1,397.5 million), revenues of US$1,213.9 million (2018: US$931.5 million) arose from sales of oil and gas to customers located in the UK. Included within the total revenues were revenues of US$1,539.1 million (2018: US$1,468.7 million) from contracts with customers. This was in addition to hedging gains of US$45.6 million (2018: US$71.2 million loss).

Included in assets arising from the United Kingdom segment are non-current assets (excluding deferred tax assets) of US$2,286.3 million (2018: US$2,090.5 million). Included in depreciation, depletion, amortisation and impairment is a net impairment charge in relation to the UK of US$41.5 million (2018: US$35.2 million net credit).

Revenue from three customers (2018: three customers) each exceeded 10 per cent of the Group's consolidated revenue. Sales to two customers in the UK amounted to US$318.8 million and US$187.3 million (2018: two customers at US$312.4 million and US$142.3 million). Sales to one customer in Indonesia totalled US$160.4 million (2018: one customer amounting to US$186.5 million).

3. Cost of operation

	2019 US$ million	2018 US$ million
Operating costs	**322.6**	487.5
Gas purchases	**21.6**	9.6
Stock overlift/underlift movement	**(10.5)**	(11.1)
Royalties	**9.1**	14.0
	342.8	500.0

4. Tax

	2019 US$ million	2018 US$ million
Current tax:		
UK corporation tax on profits	**(6.0)**	(23.2)
Overseas tax	**81.6**	120.7
Adjustments in respect of prior years	**(24.5)**	(6.9)
Total current tax	**51.1**	90.6
Deferred tax:		
UK corporation tax	**(94.0)**	(13.5)
Overseas tax	**(9.6)**	(24.0)
Total deferred tax	**(103.6)**	(37.5)
Tax (credit)/charge on profit on ordinary activities	**(52.5)**	53.1

4. Tax *(continued)*

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

	2019 US$ million	2018 US$ million
Group profit on ordinary activities before tax	**102.5**	158.2
Group profit on ordinary activities before tax at 46.0% weighted average rate (2018: 44.7%)	**47.2**	70.8
Tax effects of:		
Income/expenses that are not taxable/deductible in determining taxable profit	**16.2**	(8.7)
Financing costs disallowed for UK supplementary charge	**19.4**	22.6
Non-deductible field expenditure	**11.3**	6.1
Tax and tax credits not related to profit before tax (mainly Ring Fenced Expenditure Supplement)	**(89.2)**	(46.1)
Group relief	**-**	2.7
Unrecognised tax losses	**10.0**	14.8
Effect of change in foreign exchange	**0.3**	17.8
Adjustments in respect of prior years	**(40.3)**	(31.2)
Utilisation and recognition of tax losses not previously recognised	**-**	-
Effect of differences in tax rates	**-**	(0.4)
Recognition that decommissioning provision will unwind at 50%	**(8.0)**	4.7
Recognition of deferred tax asset	**(19.4)**	-
Tax (credit)/charge for the year	**(52.5)**	53.1
Effective tax rate for the year	**(51.2%)**	33.5%

The UK deferred tax credit arises due to Ring Fence Expenditure Supplement and is offset by other items impacting deferred tax. The overseas deferred tax credit arises on fixed asset balances.

The prior year adjustments include overseas tax disputes found in Premier's favour. The Group has not recognised any tax benefit for ongoing tax disputes where a ruling in the Group's favour is not yet considered to be probable.

In addition, during the year, the Group recognised a deferred tax asset and associated tax credit in relation to an expected future tax deduction associated with decommissioning costs funded by E.ON. An offsetting finance cost, which is classified within exchange differences and others, has also been recognised as this tax deduction will be reimbursed to E.ON once received by Premier.

4. Tax *(continued)*

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

The 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 19 per cent to 55 per cent), assumptions around future oil prices and changes to tax rates and legislation.

5. Deferred tax

	2019 US$ million	2018 US$ million
Deferred tax assets	**1,556.1**	1,434.1
Deferred tax liabilities	**(129.9)**	(139.5)
	1,426.2	1,294.6

	At 1 January 2019 US$ million	**Exchange movements US$ million**	**(Charged) /credited to income statement US$ million**	**Charge to retained earnings US$ million**	**Disposal of asset US$ million**	**At 31 December 2019 US$ million**
UK deferred corporation tax:						
Fixed assets and allowances	(609.2)	0.1	95.7	-	-	(513.4)
Decommissioning	376.8	2.1	60.7	-	-	439.6
Tax losses and allowances	1,602.5	0.8	(66.7)	-	-	1,536.6
Investment allowance	77.8	0.1	4.6	-	-	82.5
Derivative financial instruments	(13.8)	(0.1)	(0.3)	25.0	-	10.8
Total UK deferred corporation tax	**1,434.1**	**3.0**	**94.0**	**25.0**	**-**	**1,556.1**
Overseas deferred tax[1]	**(139.5)**	**-**	**9.6**	**-**	**-**	**(129.9)**
Total	**1,294.6**	**3.0**	**103.6**	**25.0**	**-**	**1,426.2**

5. Deferred tax *(continued)*

	At 1 January 2018 US$ million	Exchange movements US$ million	(Charged) /credited to income statement US$ million	Charge to retained earnings US$ million	Disposal of asset US$ million	At 31 December 2018 US$ million
UK deferred corporation tax:						
Fixed assets and allowances	(737.4)	(0.3)	133.0	-	(4.5)	(609.2)
Decommissioning	476.9	(1.5)	(99.1)	-	0.5	376.8
Tax losses and allowances	1,639.8	(1.0)	(36.3)	-	-	1,602.5
Investment allowance	71.2	(0.1)	6.7	-	-	77.8
Derivative financial instruments	10.9	(0.1)	9.2	(33.8)	-	(13.8)
Total UK deferred corporation tax	**1,461.4**	**(3.0)**	**13.5**	**(33.8)**	**(4.0)**	**1,434.1**
Overseas deferred tax[1]	**(163.9)**	**-**	**24.0**	**-**	**0.4**	**(139.5)**
Total	**1,297.5**	**(3.0)**	**37.5**	**(33.8)**	**(3.6)**	**1,294.6**

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

The Group's deferred tax assets at 31 December 2019 are recognised to the extent that taxable profits are expected to arise in the future against which the UK ring fence tax tax losses and allowances can be utilised. In accordance with paragraph 37 of IAS 12 - 'Income Taxes', the Group reassessed its deferred tax assets at 31 December 2019 with respect to UK ring fence tax losses and allowances. The corporate model used to assess whether it is appropriate to recognise the Group's deferred tax losses and allowances was re-run, using an oil price assumption of US$65/bbl in 2020 and 2021, US$70/bbl in 2020 and US$70/bbl in 'real' terms thereafter. These price assumptions are consistent with that used when assessing the Group's underlying assets for impairment. The cash flows included in the corporate model are predominantly derived from future revenue from existing UKCS assets. The existing UKCS assets include both existing producing assets and certain future currently unsanctioned assets. The cash flows also include future revenue from the proposed acquisition assets announced on 7 January 2020 on the basis that, at the balance sheet date, management consider it probable that the acquisitions will complete and that the cash flows will arise within Premier's UK ring-fence. The acquisitions represent approximately US$267 million of the deferred tax assets recognised at 31 December 2019. The results of the corporate model concluded that it was appropriate to continue to recognise the Group's deferred tax assets in respect of UK ring fence tax losses and allowances with the exception of US$18.1 million of tax losses and US$24.4 million of allowances relating to supplementary charge.

5. Deferred tax *(continued)*

In addition to the above, there are carried forward non-ring fence UK tax losses of approximately US$376.4 million (2018: US$359.1 million) and overseas tax losses of US$267.7 million (2018: US$154.8 million) for which a deferred tax asset has not been recognised. None of the UK tax losses (ring fence and non-ring fence) have a fixed expiry date for tax purposes. No deferred tax has been provided on unremitted earnings of overseas subsidiaries, following a change in UK tax legislation in 2009 which exempted foreign dividends from the scope of UK corporation tax, where certain conditions are satisfied.

6. Earnings per share

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

	2019 US$ million	2018 US$ million
Earnings		
Earnings for the purpose of diluted earnings per share on continuing operations	**155.0**	105.1
Profit from discontinued operations	**9.3**	28.3
Earnings for the purposes of diluted earnings per share on continuing and discontinued operations	**164.3**	133.4
Number of shares (millions)		
Weighted average number of Ordinary Shares for the purposes of basic earnings per share	**826.2**	774.0
Effects of dilutive potential Ordinary Shares:		
Contingently issuable shares	**76.9**	88.3
Weighted average number of Ordinary Shares for the purposes of diluted earnings per share	**903.1**	862.3
Earnings per share from continuing operations (cents)		
Basic	**18.8**	13.6
Diluted	**17.2**	12.2
Earnings per share from discontinued operations (cents)		
Basic	**1.1**	3.7
Diluted	**1.0**	3.3

The inclusion of the contingently issuable shares in the current and prior year produces diluted earnings per share for both continuing and discontinued operations. At 31 December 2019 there were 76.9 million potential Ordinary Shares in the Company that are underlying the Company's equity warrants and share options that may dilute earnings per share in the future. These have been included in the calculation of diluted earnings per share.

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

Oil and Gas Properties	Total US$ million
Cost:	
At 1 January 2018	1,061.9
Exchange movements	(5.6)
Additions during the year	62.1
Transfer to PP&E	(274.2)
Disposals	(1.4)
Assets classified as held for sale	(0.6)
Exploration expense[1]	(29.6)
At 31 December 2018	812.6
Exchange movements	1.3
Additions during the year	129.3
Transfer to PP&E	(1.9)
Exploration expense[1]	(7.3)
At 31 December 2019	934.0

[1] Expensed in the income statement with pre-licence expenses of US$14.0 million in 2019 (2018: US$5.6 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 the Ibu Lembu prospect in Indonesia following management's decision to no longer pursue the prospect.

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, Tuna in Indonesia and the non-operated Zama prospect and Block 30 in Mexico.

8. Property, plant and equipment

	Oil and gas properties US$ million	Right-of-use assets US$ million	Other fixed assets US$ million	Total US$ million
Cost:				
At 1 January 2018	7,589.4	-	66.7	7,656.1
Exchange movements	1.2	-	(2.1)	(0.9)
Additions and changes in decommissioning estimates	(33.5)	-	1.9	(31.6)
Transferred from E&E	274.2	-	-	274.2
Assets classified as held for sale	(4.1)	-	-	(4.1)
Disposals	(19.6)	-	(9.2)	(28.8)
At 31 December 2018	7,807.6	-	57.3	7,864.9
Implementation of IFRS 16	-	803.3	-	803.3
At 1 January 2019	7,807.6	803.3	57.3	8,668.2
Exchange movements	(1.7)	(0.6)	1.1	(1.2)
Re-measurement of lease liabilities	-	8.3	-	8.3
Additions and changes in decommissioning estimates	180.1	-	2.8	182.9
Transferred from E&E	1.9	-	-	1.9
Disposals	(1.3)	-	-	(1.3)
At 31 December 2019	**7,986.6**	**811.0**	**61.2**	**8,858.8**
Amortisation, depreciation and impairment:				
At 1 January 2018	5,220.3	-	54.9	5,275.2
Exchange movements	2.1	-	(1.7)	0.4
Charge for the year	386.5	-	7.1	393.6
Net impairment credit	(35.2)	-	-	(35.2)
Disposals	(5.5)	-	(9.2)	(14.7)
At 31 December 2018	5,568.2	-	51.1	5,619.3
Exchange movements	(1.1)	-	0.9	(0.2)
Charge for the year	489.4	223.0	4.0	716.4
Net impairment charge	41.5	-	-	41.5
At 31 December 2019	**6,098.0**	**223.0**	**56.0**	**6,377.0**
Net book value:				
At 31 December 2018	2,239.4	-	6.2	2,245.6
At 31 December 2019	**1,888.6**	**588.0**	**5.2**	**2,481.8**

Finance costs that have been capitalised within oil and gas properties during the year total US$4.3 million (2018: US$1.2 million), at a weighted average interest rate of 8.2 per cent (2018: 7.6 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 to UK assets. The impairment charge of US$41.5 million (pre-tax) (2018: net impairment reversal of US$35.2 million) was calculated by comparing the future discounted pre-tax cash flows expected to be derived from production of commercial reserves (the value-in-use) against the carrying value of the asset. In the period, Group-wide indicators of impairment, being a reduction in both the long-term oil price and decommissioning discount rate assumptions, were identified. US$30.5 million of the current year charge relates to the net effect of changes in decommissioning estimates on assets previously depreciated to nil net book value. The remainder relates primarily to Solan. When testing producing assets for impairment, future cash flows were estimated using the following oil price assumption: US$65/bbl in 2020 and 2021, US$70/bbl in 2022 and US$70/bbl in 'real' terms thereafter (2018: US$60/bbl in 2019, US$65/bbl in 2020, 2021 at US$70/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 (2018: 9 per cent) and 12.5 per cent for the non-UK assets (2018: 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.

Sensitivity

A US$5/bbl reduction in the long-term oil price (to US$65/bbl (real)) would increase the impairment charge by US$13.4 million, all on the UK Solan asset. No other assets would be impaired.

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

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 (2018: 9 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 2026. 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 of the Catcher cash generating unit, including the goodwill, is US$203.8 million (2018: US$166.8 million).

The key assumptions applied in the measurement of the 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 these key assumptions would cause the asset's carrying amount to exceed its recoverable amount.

Right-of-use assets

There were no new leases entered into during the period. The re-measurement above represents the net impact of re-measurements of the Catcher FPSO lease which were driven by changes in assumed COP dates during the year based on field performance.

In addition to the above the Group has a net investment in sublease of US$75.7 million (1 January 2019: US$96.3 million), of which US$54.1 million is classified as a long-term receivable and US$21.6 million as trade and other receivables. The net investment in sublease represents our joint operations partners' share of lease liabilities on lease arrangements for which Premier has entered into in its role as operator as sole signatory on behalf of the joint operation and the asset is controlled by the joint operation.

Income of US$5.3 million, which predominantly represents unwinding of the net investment in sublease, has been recognised as finance income in the year.

9. Leases

	Lease liabilities US$ million
At 1 January 2019	899.6
Re-measurement	8.3
Finance costs	50.0
Cash outflows for lease arrangements	(224.7)
Exchange differences	(0.7)
At 31 December 2019	**732.5**
Classified as:	
- short-term	149.7
- non-current	582.8

Expenses related to both short-term and low value lease arrangements are considered to be immaterial for reporting purposes. During the period variable lease costs of US$23.3 million were expensed. Lease liabilities have been classified as either short-term or non-current in the balance sheet according to whether they are expected to be settled within 12 months of the balance sheet date.

The significant portion of the Group's lease liabilities represent lease arrangements for FPSO vessels on the Catcher, Chim Sáo and Huntington assets. The lease liabilities, and associated right-of-use-assets have been calculated by reference to in-substance fixed lease payments in the underlying agreements incurred throughout the non-cancellable period of the lease along with periods covered by options to extend the lease where the Group is reasonably certain that such options will be exercised. When assessing whether extension options were likely to be exercised, assumptions are consistent with those applied when testing for impairment.

Under the modified retrospective transition method, lease payments were discounted at 1 January 2019 using an incremental borrowing rate representing the rate of interest that Premier would have to pay to borrow over a similar term, and with a similar security, the funds necessary to obtain an asset of a similar value to the right-of-use asset in a similar economic environment. The incremental borrowing rate applied to each lease was determined by taking into account the risk-free rate, adjusted for factors such as the credit rating linked to the life of the underlying lease agreement. The weighted average incremental borrowing rate applied by Premier upon transition was 7.2 per cent. Incremental borrowing rates applied to individual leases ranged between 5.4 per cent and 8.2 per cent.

10. Notes to the cash flow statement

	2019 US$ million	2018 US$ million
Profit before tax for the year	**102.5**	158.2
Adjustments for:		
Depreciation, depletion, amortisation and impairment	**757.9**	358.4
Other operating costs	**2.9**	1.2
Exploration expense	**7.3**	29.6
Provision for share-based payments	**7.1**	10.8
Interest revenue and finance gains	**(31.4)**	(27.8)
Finance costs and other finance expenses	**383.9**	400.6
Profit on disposal of non-current assets	**(4.2)**	(42.3)
Operating cash flows before movements in working capital	**1,226.0**	888.7
(Increase)/decrease in inventories	**(3.8)**	1.2
(Increase)/decrease in receivables	**(74.9)**	72.6
(Decrease) in payables	**(19.5)**	(93.0)
Cash generated by operations	**1,127.8**	869.5
Income taxes paid	**(61.2)**	(128.8)
Interest income received	**6.2**	7.5
Net cash from continuing operating activities	**1,072.8**	748.2
Net cash from discontinued operating activities	**7.2**	29.0
Net cash from operating activities	**1,080.0**	777.2
Movement in JV cash	**28.7**	(54.4)
Total net cash from operating activities	**1,108.7**	722.8

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

Analysis of changes in net debt:

	2019 US$ million	2018 US$ million
a) Reconciliation of net cash flow to movement in net debt:		
Movement in cash and cash equivalents	**(46.5)**	(120.8)
Proceeds from drawdown of long-term bank loans	**-**	(105.0)
Repayment of long-term bank loans	**399.7**	415.3
Conversion of convertible bonds	**-**	181.9
Non-cash movements on debt and case balances (primarily, FX)	**(12.3)**	22.1
Reduction in net debt in the year	**340.9**	393.5
Opening net debt	**(2,330.7)**	(2,724.2)
Closing net debt	**(1,989.8)**	(2,330.7)
b) Analysis of net debt:		
Cash and cash equivalents	**198.1**	244.6
Borrowings	**(2,187.9)**	(2,575.3)
Total net debt	**(1,989.8)**	(2,330.7)

The carrying amounts of the borrowings on the balance sheet are stated net of the unamortised portion of the refinancing fees of US$18.1 million (2018: US$23.3 million).

11. Subsequent Events

Debt Reduction

Subsequent to year-end, US$129.5 million of the RCF debt facility was cancelled and a further US$50 million was repaid, which will result in a reduction in commitment fee costs in 2020.

Corporate actions

In January 2020, the Group publicly announced the agreement it had reached to undertake the following corporate actions (together the 'Corporate Actions'):

- an amend and extend ('A&E') of all the Group's refinancing facilities, including extension of maturities from May 2021 to November 2023;
- the proposed acquisition of a 25 per cent working interest in Tolmount from Dana and interests in Andrew and Shearwater (together the 'Acquisitions' or 'Acquired Assets');
- entering into a US$300 million bridge facility to partly finance the Acquisitions ('the Bridge Facility'). Based on current forecasts it is not expected that the Bridge Facility will be unitised; and
- raising equity from shareholders via a combination of a placing and a rights issue (the 'Equity Raise') which is fully underwritten.

Lender consents were obtained from the required proportion of lenders for the above Corporate Actions, prior to their announcement. As part of this consent process, pending the Schemes becoming effective, sufficient lenders have provided forbearances in respect of any defaults that may be argued to have arisen under Premier's existing credit facilities by virtue of the implementation of the Schemes and other aspects of the Corporate Actions. Accordingly, no resulting action can be taken to accelerate, or prevent drawings being made under, the Group's existing credit facilities in respect of the Scheme or Corporate Actions.

In February 2020, more than 75 per cent of the Group's creditors voted to support the Group's scheme of arrangement. Therefore, management believes it is probable that the above actions will be approved via a court scheme of arrangement in March 2020.

Non-adjusting post balance sheet event

Premier are exposed to macro-economic risks, including pandemic diseases that could have a material adverse effect on our operations. We continue to monitor the recent coronavirus COVID 19 outbreak, which is causing economic disruption in China and elsewhere and may impact our performance in 2020. However, at present, it is not possible to predict whether or not the COVID-19 outbreak will have a material adverse effect on our earnings, cash flows and financial condition.

12. External audit

This preliminary announcement is consistent with the audited financial statements of the Group for the year-ended 31 December 2019.

13. Publication of financial statements

It is anticipated that the full Annual Report and Financial Statements will be published in April 2020. 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).

14. Annual General Meeting

The Annual General Meeting will be held at the King's Fund, 11-13 Cavendish Square, London W1G 0AN on Tuesday 12th May 2020 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, 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.
- **Cash margin:** Operating cash flow for the year divided by working interest production. This is a useful indicator of cash generation from the Group's producing assets.
- **Free cash flow:** Positive cash flow generation from operating, investing and financing activities excluding drawdowns from and repayments of borrowing facilities and equity issuances.
- **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 and right-of-use assets 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.
- **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.

PremierOil

Full Year Results for the year ended 31 December 2019

OIL AND GAS RESERVES

Working interest reserves at 31 December 2019

Working interest basis															
	Falkland Islands		Indonesia		Pakistan/ Mauritania		UK		Vietnam		Mexico		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 and NGLs	Gas	Oil and NGLs and Gas
	mmbbls	bcf	mmbbls	bcf	mmbbls	bcf	mmbbls	bcf	mmbbls	bcf	mmbbls	bcf	mmbbls	bcf	mmboe
Group proved plus probable reserves:															
At 1 January 2019	-	-	1.03	160.76	0.05	34.89	68.04	342.17	17.62	23.27	-	-	86.74	561.09	193.7
Revisions	-	-	0.2	16.42	-	-	5.46	32.96	-0.15	0.42	-	-	5.51	49.8	14.58
Discoveries and extensions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions and divestments	-	-	-	0.26	-0.05	-32.12	-	-	-	-	-	-	-0.05	-31.86	-5.05
Production	-	-	-0.14	-20.65	-	-2.77	-16.67	-17.83	-3.31	-4.31	-	-	-20.12	-45.56	-28.49
At 31 December 2019	-	-	1.09	156.79	-	-	56.83	357.3	14.16	19.38	-	-	72.08	533.47	174.74
Total Group developed and undeveloped reserves															
Proved on production	-	-	0.82	116.72	-	-	23.25	57.95	12.53	16.45	-	-	36.6	191.12	73.74
Proved approved/justified for development	-	-	0.08	17.48	-	-	12.21	156.84	0.2	0.46	-	-	12.49	174.78	45.93
Probable on production	-	-	0.18	9.53	-	-	14.89	17.85	1.12	1.78	-	-	16.19	29.16	21.8
Probable approved/justified for development	-	-	0.01	13.06	-	-	6.48	124.66	0.31	0.69	-	-	6.8	138.41	33.27
At 31 December 2019	-	-	1.09	156.79	-	-	56.83	357.3	14.16	19.38	-	-	72.08	533.47	174.74

Notes:

1. Both the Zama discovery and Sea Lion remained as contingent resources awaiting FID/Sanction and do not appear in this table.
2. All assets in Pakistan have been divested as of April 2019.
3. Proved plus probable gas includes fuel gas

Premier Oil plc categorises petroleum resources in accordance with the June 2018 SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE 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 164.4 mmboe as at 31 December 2019 (2018: 181.5 mmboe). This was calculated at year-end 2019, using the following oil price assumption: US$65/bbl in 2020 and 2021, US$70/bbl in 2022, US$70/bbl in 'real' terms thereafter (2018: Dated Brent forward curve of US$60/bbl in 2019, US$65/bbl in 2020, US$70/bbl in 2021 and US$75/bbl in 'real' terms thereafter).