EnQuest PLC

Results for the year ended 31 December 2019 and 2020 outlook

24% production growth; material debt reduction with net debt:EBITDA at 1.4x

Decisive action being taken to position EnQuest to manage in a sustained low oil price environment

9 April 2020

Unless otherwise stated, all figures are on a Business performance basis and are in US Dollars.

2019 performance – delivered targets

- Group production averaged 68,606 Boepd in 2019, up 23.7% on 2018
- Revenue of $1,711.8 million (2018: $1,201.0 million) and EBITDA of $1,006.5 million (2018: $716.3 million)
- Cash generated from operations of $994.6 million (2018: $788.6 million), reflecting higher EBITDA
- Cash capital expenditure of $237.5 million (2018: $220.2 million)
- Cash and available bank facilities amounted to $288.6 million at 31 December 2019, with net debt of $1,413.0 million (2018: $1,774.5 million); net debt:EBITDA at 1.4x
- Net 2P reserves of 213 MMboe and net 2C resources of 173 MMboe at the end of 2019 (2018: 2P reserves of 245 MMboe; 2C resources of 198 MMboe); lower 2P reserves driven by production and downward revisions at Heather/Broom and Thistle, partially offset by increases at Magnus, Kraken and PM8/Seligi
- Non-cash post-tax impairments of $562.3 million, including tangible fixed assets of $397.5 million, mainly reflecting changes in oil price and production profiles, primarily at Heather/Broom, Thistle and the Dons, and $149.6 million impairment of goodwill

2020 performance and outlook – well positioned for a low oil price environment

Operations

- Year to date production performance remains good with the Group's day-to-day operations continuing without being materially affected by COVID-19

Financial position

- No senior credit facility amortisations due in 2020 following voluntary early repayments; the Group's outstanding credit facility[1] is $425.0 million at the end of February
- Cash and available facilities at the end of February were $268.2 million, with net debt of $1,368.1 million

Prioritising operational excellence, cost control and capital discipline

- Targeting further in-year savings by removing discretionary activities given the prevailing oil price environment
  - Full year operating expense savings of c.$190 million; revised full year guidance of c.$335 million
  - Full year capital expense savings of c.$110 million; revised full year guidance of c.$120 million
  - Directors and senior management have agreed an interim voluntary reduction in salary of 20%
- Full year production guidance remains at 57,000 to 63,000 Boepd
- Forecast free cash flow[2] breakeven reduced to c.$33/Boe for 2020 and c.$27/Boe for 2021, subject to achieving savings
- Future portfolio opportunities focused on three largest, low-cost assets: Magnus, Kraken and PM8/Seligi

[1] Excludes interest capitalised as payment in kind of $15.8 million

[2] Free cash flow: net change in cash and cash equivalents less net (repayments)/proceeds from loan facilities. $/Boe based on working interest production

EnQuest PLC

EnQuest Chief Executive, Amjad Bseisu, said:

"During 2019, EnQuest again delivered on its targets. The combination of improved Kraken performance, a full year contribution at Magnus and strong performances at Scolty/Crathes and PM8/Seligi, drove significant production growth and free cash flow generation, which facilitated a material reduction in the Group's net debt.

"Given the prevailing low oil price environment, we have taken decisive action to lower our cost base, targeting $190 million of operating cost savings in 2020, equating to unit operating expenses of c.$15/Boe. With these significant cost reductions, cash flow breakeven is estimated at c.$33/Boe in 2020. With realisations in the first quarter of 2020, the cash flow breakeven falls to c.$25/bbl for the remainder of the year. 2021 cash flow breakeven is now forecast at c.$27/Boe, with unit operating expense of around $12/Boe. With these significant reductions, we are well positioned to manage through a sustained low oil price environment.

"Our three largest assets continue to generate meaningful operating cash flows, even at low oil prices, and, in the medium to long-term, offer low-cost resource maturation opportunities which are aligned with our proven differential capabilities."

Production and financial information

	2019	2018	Change %
Production (Boepd)	68,606	55,447	23.7
Revenue and other operating income ($m)[1]	1,711.8	1,201.0	42.5
Realised oil price ($/bbl)[1, 2]	65.3	64.2	1.7
Gross profit ($m)	468.3	275.0	70.3
Profit before tax & net finance costs ($m)	442.2	290.0	52.5
EBITDA ($m)[2]	1,006.5	716.3	40.5
Cash generated from operations ($m)	994.6	788.6	26.1
Reported (loss)/profit after tax ($m)	(449.3)	127.3	-
Reported basic (loss)/earnings per share (cents)	(27.4)	9.2	-
Cash capex ($m)[2]	237.5	220.2	7.9
	End 2019	**End 2018**	
Net (debt)/cash ($m)[2]	(1,413.0)	(1,774.5)	(20.4)

Notes:

[1] Including gains of $24.8 million (2018: losses of $93.0 million) associated with EnQuest's oil price hedges

[2] See reconciliation of alternative performance measures within the 'Glossary – Non-GAAP measures' starting on page 69

Production details

Average daily production on a net working interest basis (Boepd)	1 Jan' 2019 to 31 Dec' 2019	1 Jan' 2018 to 31 Dec' 2018
Northern North Sea	27,237	19,293[1]
Central North Sea	7,544	6,353
Kraken	25,172	21,369
Total UKCS	**59,953**	**47,015**
Total Malaysia	**8,653**	**8,432**
Total EnQuest	**68,606**	**55,447**

Notes:

[1] Includes net production related to 25% interest in Magnus until 30 November 2018 and 100% interest of Magnus from 1 December 2018, averaged over the 12 months to the end of December 2018

2019 performance summary

EnQuest's operational focus for 2019 was to improve and stabilise production at Kraken, deliver the Group's sub-sea pipeline projects and drilling programmes, while maintaining strong production efficiency across its asset base. All of these were achieved with the Group again performing better than, or in line, with external guidance. This operational delivery combined with ongoing cost control, has enabled the Group to continue to strengthen the balance sheet by significantly reducing net debt.

EnQuest's average production increased by 23.7% to 68,606 Boepd, towards the top end of the guidance range, primarily reflecting the contributions from Magnus, Kraken, Scolty/Crathes and PM8/Seligi, partially offset by the shutdowns at Thistle and Heather and natural declines across the portfolio.

EBITDA and cash generated by operations increased materially in 2019 compared to 2018, reaching $1,006.5 million and $994.6 million, respectively, reflecting the combination of significantly higher production, higher realised oil price and the Group's focus on cost control.

Cash capital expenditure of $237.5 million was focused on executing the Group's drilling programmes at Kraken, Magnus and PM8/Seligi and the sub-sea pipeline projects at Scolty/Crathes and the Dunlin bypass for Thistle and the Dons.

Liquidity and net debt

At 31 December 2019, net debt was $1,413.0 million, down $361.5 million from $1,774.5 million at 31 December 2018, reflecting a strong operational performance and higher realised oil prices. Total cash and available facilities were $288.6 million, including ring-fenced funds held in operational accounts associated with Magnus, the Sculptor Capital facility (previously known as the Oz Management facility) and other joint venture accounts totalling $74.0 million.

Strong free cash flow generation enabled the Group to make early voluntary repayments of the senior credit facility, which was reduced by $325.0 million during the year, including $120.0 million associated with the April 2020 scheduled amortisation. A further $35.0 million was repaid in January 2020 as an accelerated voluntary payment of the October 2020 amortisation. No further amortisation payments are due in 2020. At the end of March, the senior credit facility, excluding payment in kind interest, totalled $425.0 million

Reserves and resources

Net 2P reserves at the end of 2019 were 213 MMboe (2018: 245 MMboe) and have been audited on a consistent basis with prior years. During the year, the Group produced 9.6% of its year-end 2018 2P reserves base, with downward revisions at Heather/Broom and Thistle almost entirely offset by increases at Magnus, Kraken and PM8/Seligi. Net 2C resources at the end of 2019 were 173 MMboe (2018: 198 MMboe) as a result of transfers to 2P reserves at Magnus and PM8/Seligi and revisions at Heather/Broom, partially offset by the addition of resources associated with the award of the PM409 Production Sharing Contract in Malaysia.

A sustainable business - 2020 performance and additional outlook details

The Group is materially better placed to deal with the reduced oil price than historically with a much reduced level of debt and no payments of the Group's senior credit facility due in 2020. In addition, the Group is taking decisive action to further reduce operating and capital expenditure in 2020 and beyond, with a view to targeting cash flow breakeven of c.$33/Boe in 2020 and c.$27/Boe in 2021.

The Group is now targeting operating expenditure savings of c.$190 million, which would lower operating costs by c.35% to c.$335 million, equating to unit operating expense of c.$15/Boe. In 2021, the Group is targeting unit operating expenditures of c.$12/Boe. These savings will be driven primarily by cost savings at Heather and Thistle/Deveron, but also through the removal of non-critical and discretionary operating expenditures and support costs.

Cash capital expenditure is also expected to be further reduced, now down c.$110 million to c.$120 million. The majority of the Group's 2020 programme relates to the recently concluded drilling programme at Magnus and the two-well programme now underway at Kraken, with approximately $50 million of 2020 cash capital expenditure relating to the phasing of cash payments into 2020. The Group's 2021 capital expenditure programme is expected to reduce further, which will also impact production.

EnQuest's updated working assumption is not to re-start production at the Heather and Thistle/Deveron fields. As a result, full year production guidance is expected to be in the range of 57,000 to 63,000 Boepd, with forecast Kraken gross production remaining unchanged between 30,000 and 35,000 Bopd. The two-well drilling programme in Kraken's western area is underway and expected to contribute production in the second half of the year, partially offsetting the impacts of the planned maintenance shutdown and natural declines. As previously announced, the Group's current expectation is for economic production at Alma/Galia to cease in the second half of 2020.

EnQuest has hedged c.20% of 2020 entitlement production with c.2.9 MMbbls of oil at an average floor price of c.$65/bbl and, in accordance with the Sculptor Capital facility agreement, c.1.1 MMbbls hedged at an average floor price of c.$52/bbl.

While no further repayments of the Group's senior credit facility are due in 2020, debt repayment remains the financial priority for the Group.

COVID-19 update

As a responsible operator, EnQuest has been monitoring the evolving situation, and consequent emerging risk, with regards to the spread of COVID-19. The Group has been working with a variety of stakeholders, including industry and medical organisations, to ensure its operational response and advice to its workforce is appropriate and commensurate with the prevailing expert advice and level of risk. Appropriate restrictions on offshore travel have been implemented, such as self-declaration by, and isolation of, individuals who have been to affected areas and pre-mobilisation temperature checking in operation at most locations. EnQuest's normal communicable disease process has been updated specifically in respect of COVID-19, with additional offshore isolation capability and agreements in place to transport impacted individuals back onshore in dedicated helicopters. At the Sullom Voe Terminal, the same processes have also been implemented, with isolation capability at the local accommodation block. Non-essential down-manning has been implemented, with many of the Group's onshore workforce working remotely.

While it is difficult to forecast the impact of COVID-19, at the time of publication of EnQuest's full year results, the Group's day-to-day operations continue without being materially affected. The situation will continue to be monitored.

Summary financial review of 2019

(all figures quoted are in US Dollars and relate to Business performance unless otherwise stated)

Revenue for 2019 was $1,711.8 million, 42.5% higher than in 2018 ($1,201.0 million), reflecting the increase in production, the onward sale of third-party gas purchases not required for injection activities at Magnus, and the favourable impact of the Group's commodity hedge programme, offset by slightly lower market prices. The Group's commodity hedge programme resulted in realised gains of $24.8 million in 2019 (2018: losses of $93.0 million).

The Group's average realised oil price excluding the impact of hedging was $64.2/bbl, compared to $69.4/bbl for 2018. The Group's average realised oil price including the impact of hedging was $65.3/bbl in 2019, 1.7% higher than in 2018 ($64.2/bbl).

Revenue is predominantly derived from crude oil sales which totalled $1,548.2 million, 25.1% higher than in 2018 ($1,237.6 million), reflecting the increase in volumes. Revenue from the sale of condensate and gas was $120.2 million (2018: $43.1 million), mainly reflecting gas sales from Magnus, which includes the combination of produced gas sales and the onward sale of third-party gas purchases not required for injection activities, for which the costs are included in other cost of sales.

Total cost of sales were $1,243.6 million for the year ended 31 December 2019, 34.3% higher than in 2018 ($926.0 million).

The Group's operating expenditures of $518.1 million were 11.2% higher than in 2018 ($465.9 million), reflecting the full year of additional equity interest in Magnus. Unit operating costs decreased by 10.4% to $20.6/Boe (2018: $23.0/Boe) as a result of increased production.

Total cost of sales also included non-cash depletion expense of $525.1 million, 20.1% higher than in 2018 ($437.1 million), mainly reflecting a full year of 100% equity interest in Magnus.

The charge relating to the Group's lifting position and inventory was $102.9 million (2018: $25.1 gain). This reflects a switch to a $28.6 million net overlift position at 31 December 2019 from a $68.3 million net underlift position at 31 December 2018. This switch reflected the closing positions on Thistle and Heather and the unwind of underlift on Magnus in the year.

Other cost of sales of $97.5 million were higher than in 2018 ($48.1 million), principally reflecting the cost of additional Magnus related third-party gas purchases not required for injection activities of $72.0 million.

EBITDA for 2019 was $1,006.5 million, up 40.5% compared to 2018 ($716.3 million), primarily as a result of increased production and revenue.

The tax charge for 2019 of $23.6 million (2017: $20.9 million tax credit), excluding exceptional items, is mainly due to Malaysian tax and the utilisation of UK losses offset by the Ring Fence Expenditure Supplement on UK activities generated in the year. UK corporate tax losses at the end of the year reduced to $2,903.4 million (2018: $3,225.3 million) as the Group generated taxable profits on increased production which were offset against existing tax losses.

Post-tax exceptional items for 2019 were a loss of $663.6 million (2018: gains of $49.1 million). The Group recognised pre-tax non-cash impairment charges on its tangible oil and gas assets of $637.5 million (2018: $126.0 million), mainly in respect of Heather, Thistle and the Dons, $149.6 million (2018: $nil) on goodwill and $25.4 million (2018: $0.4 million) on intangible oil and gas assets. In addition, a non-cash increase in fair value of contingent consideration relating to the Magnus asset of $15.5 million, non-cash other finance costs relating to the unwinding of contingent consideration of $57.2 million and unrealised losses on commodity contracts of $65.4 million. A tax credit of $303.5 million (2018: $12.4 million) has been presented as exceptional, representing the tax impact of the above items.

Net debt at 31 December 2019 was $1,413.0 million, a decrease of 20.4% compared to 2018 ($1,774.5 million), primarily as a result of the improved cash generating capability of the Group. This includes $133.3 million of interest that has been capitalised to the principal of the facilities pursuant to the terms of the Group's November 2016 refinancing (31 December 2018: $132.0 million).

Ends

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Presentation to Analysts and Investors
A presentation to analysts and investors will be held at 09:00 today – London time. The presentation will be accessible via an audio webcast, available on the investor relations section of the EnQuest website at www.enquest.com.
A conference call facility will also be available at 09:00 on the following numbers:

Conference call details:

UK: +44 (0) 800 376 7922 or +44 (0) 844 571 8892

International: +44 (0) 207 192 8000

Confirmation Code: EnQuest

Notes to editors

This announcement has been determined to contain inside information. The person responsible for the release of this announcement is Stefan Ricketts, General Counsel and Company Secretary.

ENQUEST

EnQuest is an independent production and development company with operations in the UK North Sea and Malaysia. The Group's strategic vision is to be the operator of choice for maturing and underdeveloped hydrocarbon assets, by focusing on operational excellence, differential capability, value enhancement and financial discipline.

EnQuest PLC trades on both the London Stock Exchange and the NASDAQ OMX Stockholm. Its UK operated assets include Thistle/Deveron, Heather/Broom, the Dons area, Magnus, the Greater Kittiwake Area, Scolty/Crathes Alma/Galia and Kraken; EnQuest also has an interest in the non-operated Alba producing oil field. At the end of December 2019, EnQuest had interests in 17 UK production licences and was the operator of 15 of these licences. EnQuest's interests in Malaysia include the PM8/Seligi and PM409 Production Sharing Contracts, both of which the Group operates.

Forward-looking statements: This announcement may contain certain forward-looking statements with respect to EnQuest's expectations and plans, strategy, management's objectives, future performance, production, reserves, costs, revenues and other trend information. These statements and forecasts involve risk and uncertainty because they relate to events and depend upon circumstances that may occur in the future. There are a number of factors which could cause actual results or developments to differ materially from those expressed or implied by these forward-looking statements and forecasts. The statements have been made with reference to forecast price changes, economic conditions and the current regulatory environment. Nothing in this announcement should be construed as a profit forecast. Past share price performance cannot be relied upon as a guide to future performance.

Chief Executive's report

Overview
EnQuest's operational focus for 2019 was to improve and stabilise production at Kraken, deliver the Group's sub-sea pipeline projects and drilling programmes, while maintaining strong production efficiency across its asset base. All of these were achieved, with the Group again performing better than, or in line with, its external guidance. This operational delivery combined with ongoing cost control enabled the Group to continue to strengthen the balance sheet by significantly reducing net debt.

Operational performance
EnQuest's average production increased by 23.7% to 68,606 Boepd, towards the top end of the Group's guidance. The increase was driven by the contributions from Magnus, Kraken, Scolty/Crathes and PM8/Seligi, partially offset by the shutdowns at Thistle and Heather and natural declines across the portfolio. The improved performance of the Kraken FPSO vessel is particularly pleasing. This was the result of targeted improvement initiatives and the collaborative efforts by our people and those of our partner and the vessel operator. At Magnus, the team also delivered a good operational performance, which, along with a revised reservoir management strategy that lowered operating costs, resulted in the reimbursement of EnQuest's $100 million cash consideration in a year, earlier than originally expected. The project teams delivered an excellent performance in our sub-sea pipeline replacement projects at Scolty/Crathes and the Dunlin bypass in respect of Thistle and the Dons, with both being completed ahead of budget and schedule.

During the year, the Group produced 9.6% of its year-end 2018 2P reserves base. The Group's revised life-of-field expectations at Heather/Broom and Thistle resulted in downward reserves revisions which were almost entirely offset by increases at the Group's growth assets, Magnus, Kraken and PM8/Seligi. Overall, net 2P reserves reduced to 213 MMboe at the end of 2019, down 13.3% on the 245 MMboe at the end of 2018. Since the Company was formed with around 81 MMboe of 2P reserves, the Group has achieved a compound average reserves growth of 10.2%. The Group continues to have substantial 2C resources of around 173 MMboe, primarily located at Magnus, Kraken and PM8/Seligi, and include the addition of 2C resources associated with the Group's Production Sharing Contract ('PSC') at PM409, offshore Malaysia.

Financial performance
The Group's EBITDA increased by 40.5% to $1,006.5 billion, reflecting the material increase in production and higher realised prices, while the Group's ongoing focus on cost control kept operating expenditure to $518.1 million, with unit operating costs reduced to around $20.6/Boe. As a result, cash generated by operations increased significantly to $994.6 million, up 26.1% compared to 2018, with free cash flow of $368.5 million.

This strong performance facilitated a material reduction in the Group's net debt, which ended the year at $1,413.0 million, down $361.5 million from the end of 2018, with EnQuest's net debt to EBITDA ratio at 1.4x, materially ahead of the initial target of being below 2x. A combination of scheduled and voluntary early repayments of the Group's senior credit facility, including a $35.0 million payment in January 2020, has seen the outstanding balance reduce to $425.0 million with no further amortisations due in 2020.

At the year end, the Group recognised non-cash post-tax impairments of $562.3 million, including tangible fixed assets of $397.5 million, mainly reflecting changes in oil price and production profiles, primarily at Heather/Broom, Thistle and the Dons, and $149.6 million impairment of goodwill.

Health, Safety, Environment and Assurance ('HSEA')
As always, SAFE Results is our number one priority. Across the Group, good progress was made with the leading metrics in areas such as safety-critical maintenance backlog, leadership site visits and close out of actions from incidents and audits, demonstrating our commitment to be proactive with regard to HSEA. In both Malaysia and the UK, positive
feedback from the respective regulators was received regarding the levels of transparency and trust that have been generated.

However, in occupational safety, our Lost Time Incident ('LTI') performance was mixed. During the year, our teams at Kittiwake and PM8/Seligi recorded 14 and nine years LTI free, respectively, while our Thistle and Northern Producer assets in the UK North Sea and the Tanjong Baram asset in Malaysia all recorded an LTI-free year. These are great achievements considering the ongoing backdrop of high activity levels and the age of our assets. Our team at Thistle demonstrated EnQuest's proactive approach to safety when they decided to shut down and down-man the platform following the results of a routine inspection programme. However, there was an increase in the number of minor injuries in the UK and there was a high-potential incident associated with the KT03 compressor lube oil system at Heather. Such issues highlight the need for everyone to remain focused at all times on delivering SAFE Results. We continue to learn from these events through extensive root cause analysis and the subsequent development and sharing of any required improvements across EnQuest's assets in an effort to limit the chance of reoccurrence.

While there were no major hydrocarbon releases in Malaysia, a significant improvement on hydrocarbon loss of containment events from 2018, reportable hydrocarbon releases across the Group's UK operated assets increased to 11 from six in 2018. During 2019, the UK team published its environmental compliance manual which, along with training and awareness sessions, has been designed to inform the workforce of our environmental responsibilities and help to improve environmental performance.

The Company's place within the wider energy transition is to improve performance and efficiencies at already producing assets through short-cycle investments, avoiding the need for costly, carbon intensive and long-dated new developments. As part of this efficiency drive, the Group recognises that it must endeavour to minimise carbon emissions from its operations as far as practicable and play its part in the UK's legal requirement to be net carbon neutral by 2050. With its low-sulphur content, demand for Kraken oil increased through 2019 and into 2020 as buyers in the maritime industry recognised it is playing a valuable part in reducing sulphur emissions in accordance with the International
Maritime Organisation's new regulations that limit the sulphur content of bunker fuel. By selling directly to the fuel oil market, Kraken cargoes also avoid refining-related emissions. In 2020, a systematic programme of work is being undertaken to put in place plans that will include specific, measurable emissions reduction targets, supported by specific projects, which will form the basis of our 2021 corporate targets.

UK North Sea operations

Magnus continued to perform strongly throughout 2019, achieving production efficiency of 81%, driven by enhanced reservoir management, well interventions and plant debottlenecking. During the year, the Group also further improved the facility's water handling capabilities, a key enabler to the field's revised reservoir management strategy, which itself has driven a material reduction in operating costs. In the first quarter of 2020, new production wells on Magnus were completed and came onstream, with further production optimisation activities underway.

Safety-related shutdowns in the fourth quarter at Heather and Thistle impacted performance. While shutdown for repairs, there was a small fire in one of the compressor modules at Heather that was quickly extinguished. At Thistle, the team initiated a precautionary shutdown and down-man following the identification of a deterioration in a metal plate connecting a redundant storage tank to the platform's leg. The Group no longer expects to restart production at either of Heather or Thistle, with extensive analysis of the costs and risks of remediation and restarting production outweighing the economic benefits of doing so.

At Kraken, performance of the FPSO vessel significantly improved through the year as a result of targeted improvement initiatives, focusing on the main power engines, topside power water pumps and the hydraulic submersible pumps, combined with changes to the offshore spares management and FPSO maintenance processes. The completion of the drill centre ('DC') 4 drilling programme in March marked the end of the field's original development plan. Overall subsurface and wells performance has remained strong, with water cut levels stable and below the Group's assumptions that underpinned the year-end 2018 2P reserves estimates, providing increased confidence in long-term production. In May 2019, the Group sanctioned the Worcester development in Kraken's western area, where drilling of a producer-injector pair through spare capacity in the existing DC2 sub-sea infrastructure began in the first quarter of 2020. Further areas in the western area, including the Maureen sands which lie directly beneath the existing reservoirs, are being evaluated to identify economic, drillable targets to develop its estimated 70 to 130 MMbbls of STOIIP.

During the year, our projects teams delivered an excellent performance in our two sub-sea pipeline replacement projects at Scolty/Crathes and at the Dunlin bypass in respect of Thistle and the Dons, with both being completed ahead of budget and schedule. Thistle production was transferred to the new export route at the end of June without incurring any production downtime, while production at Scolty/Crathes restarted in September.

While production efficiency at Alma/Galia remained high at over 95% throughout the year, natural declines meant production was lower than in 2018. The decommissioning programme has recently been finalised, with the Group expecting production to cease in the second half of 2020.

At the Sullom Voe Terminal, the Group achieved high plant availability and delivered safe and stable operations during the year. In July, the Group announced essential organisational changes to the terminal to ensure that it remains competitive for existing and future business. Many of these changes were implemented in early 2020.

Malaysia operations

Production in 2019 was slightly higher than in 2018, primarily reflecting high production efficiency of 92% at PM8/Seligi and better than expected performance from the Group's idle well restoration programme. The Group successfully completed the 2019 compressor maintenance programme and systematic and wide-scale asset inspection and maintenance campaign during the fourth quarter.

In December, the Group was awarded the Block PM409 Production Sharing Contract ('PSC') offshore Malaysia. The block is in a proven hydrocarbon area containing several undeveloped discoveries and is contiguous to the Group's existing PM8/Seligi PSC, providing low-cost tie-back opportunities to the Group's existing Seligi main production hub.

The Group will continue to execute its idle well restoration activities during 2020. It will also continue to assess the development potential of the large number of low-cost drilling and workover targets that have been identified at PM8/Seligi and identify suitable drilling and tie-back opportunities within Block PM409.

2020 performance and outlook

We have been monitoring the evolving situation with regards to the spread of COVID-19 and been working with a variety of stakeholders, including industry and medical organisations, to ensure its operational response and advice to its workforce is appropriate and commensurate with the prevailing expert advice and level of risk. We have implemented a number of actions to keep our people safe and maintain safe operations, such as offshore travel restrictions, non-essential workforce down-manning and access to specialised evacuation transport for our operated assets.

Given the prevailing low oil price environment, the Group has reviewed each of its assets and related spending plans. EnQuest's no longer plans to re-start production at the Heather and Thistle/Deveron fields. At the same time, the Group is taking decisive action and implementing a material operating cost and capital expenditure reduction programme to significantly lower EnQuest's cost base, with Group free cash flow breakeven targeted at c.$33/Boe in 2020 and c.$27/Boe in 2021.

As a result of the field shutdowns outlined above, full year production is expected to be in the range of 57,000 to 63,000 Boepd. Kraken gross production remains unchanged at 30,000 to 35,000 Bopd. The two-well drilling programme in Kraken's western area is underway and expected to contribute production in the second half of the year, partially offsetting the impacts of the planned maintenance shutdown and natural declines. As previously announced, the Group's current expectation is for economic production at Alma/Galia to cease in the second half of 2020.

For 2020, the Group is targeting base operating expenditure savings of c.$190 million, which would lower operating costs by c.35% to c.$335 million and unit operating expense to c.$15/Boe. In 2021, the Group is targeting unit operating expenditures of c.$12/Boe. These savings are driven primarily by cost savings at Heather and Thistle/Deveron, but also through the removal of non-critical and discretionary operating expenditures and support costs.

2020 cash capital expenditure is also expected to be reduced by c.$110 million to c.$120 million. The majority of the Group's 2020 programme relates to the recently concluded drilling programme at Magnus and the two-well programme now underway at Kraken, with approximately $50 million of 2020 cash capital expenditure relating to the phasing of cash payments into 2020. The Group's 2021 capital expenditure programme is expected to reduce further, which will also impact production.

While no further repayments of the Group's senior credit facility are due in 2020, further debt repayment remains the financial priority for the Group.

Longer-term development

Lowering the Group's cost base now will enable our experienced and capable teams to utilise our proven differential capabilities to develop EnQuest's material opportunity set to deliver future value to its stakeholders. We will continue to reduce our debt and dependent on price conditions and Company performance, our capital allocation will balance investment to develop our asset base, returns to shareholders and the acquisition of suitable growth opportunities, which will be aligned with our proven differential capabilities in managing maturing and underdeveloped hydrocarbon assets.

Operating review

NORTHERN NORTH SEA OPERATIONS

2019 performance summary

Production in 2019 of 27,237 Boepd was 41.2% higher than in 2018, reflecting additional equity interest in, and a continued strong performance from, Magnus, partially offset by safety-related shutdowns at Heather and Thistle and natural declines across the Northern North Sea area assets.

Magnus has continued to perform strongly throughout 2019, achieving production efficiency of 81%, driven by enhanced reservoir management, well interventions and plant debottlenecking. During the year, the Group further improved the facility's water handling capabilities through the return to service of a second deaeration tower and successfully completed a planned three-week shutdown of the facility to undertake safety-critical maintenance. The planned two-well drilling programme commenced during the fourth quarter and continued through the end of the year and into 2020.

Single compressor train outages and an extended shutdown impacted production at Heather during the year. In October, while shut down to undertake repair work on the compressors, the facility suffered a small fire in one of the compressor modules which was extinguished quickly. With safety being a top priority for the Company, the facility remained shut down while Company and regulatory investigations into the incident were undertaken and necessary repairs fully assessed.

On Thistle, production and water injection efficiency averaged over 90% during the first half of the year and the drilling team successfully executed the well abandonment programme in line with the Group's asset strategy. However, in October production stopped following a proactive safety-related shutdown as a result of a deterioration in the condition of a metal plate connecting one of the redundant sub-sea storage tanks to the facility's legs being identified during the ongoing sub-sea monitoring and inspection programme. The Group had already planned to remove the tanks on behalf of the decommissioning partners during the summer of 2020, with initial tendering having started earlier in 2019. This programme was accelerated, with contracts for the sub-sea and heavy lift operations awarded in late 2019.

At the Dons fields, production was slightly below the Group's expectations reflecting lower than expected water injection efficiency as a result of water injection pump failures and gas lift interruptions.

The Dunlin bypass project was successfully completed in June, 18 days ahead of schedule, with final commissioning work undertaken during the Dons planned annual maintenance shutdown. Modifications on the Thistle, Northern Producer and Magnus facilities were also completed on schedule, with Thistle production being transferred to the new export route without incurring any production downtime.

At the Sullom Voe Terminal ('SVT'), the Group has achieved high plant availability and delivered safe and stable operations during the year. The Oil & Gas Authority endorsed the revised SVT Owner's strategy to extend the life of the facility in support of maximising economic recovery for the 33 offshore fields that currently export crude oil through the terminal. In July, the Group announced essential organisational changes to the terminal to ensure that it remains competitive for existing and future business. These changes form an essential part of SVT's future and as a direct consequence of EnQuest's demonstrable progress in safely reducing SVT's underlying cost basis, there are now a number of ongoing enquiries for the provision of additional services from the terminal.

2020 performance and outlook

In the first quarter of 2020, new production wells on Magnus were completed and brought onstream. During the year, the test separator will be enhanced, which will enable more robust testing and improved optimisation. Chemical trials will also be conducted to investigate methods to reduce well slugging and increase oil flow. A two-week maintenance shutdown on Magnus is planned during the third quarter.

In the medium term, the Group has substantial 2C resources of 38 MMboe to develop, primarily through low-cost drilling. In addition, the Group will continue to evaluate the estimated c.250 MMbbls of additional remaining mobile oil in place to identify future drilling targets to maximise recovery from this field.

At Thistle, the Group no longer expects to restart production. Adverse weather conditions have restricted progress on the tank removal project, although where possible, sub-sea and platform surveys to assess the condition of the tanks, their connection to the facilities legs and the condition of the topsides to assist project planning have been undertaken. The tank removal project will continue, with further platform remediation activity also required, although timing of these activities remains subject to weather and detailed execution plans.

In February, having carefully reviewed all options, EnQuest decided not to restart production from the Heather field and intends to seek the necessary regulatory approvals from the UK Oil & Gas Authority in respect of cessation of production. This decision was taken following extensive analysis, which clearly demonstrated the costs and risks of remediation and resuming production outweighed the economic benefits of doing so.

Following remediation of the water injection efficiency and gas lift repair issues experienced during 2019, the Dons fields have ramped up during the first quarter of 2020. A three-week maintenance shutdown is planned during the third quarter.

CENTRAL NORTH SEA OPERATIONS

2019 performance summary

Production in 2019 of 7,544 Boepd was 18.8% higher than in 2018, driven by increased volumes from Scolty/Crathes following the successful completion of the pipeline replacement project in September. This project, which was delivered during the third quarter planned maintenance shutdown, was completed ahead of budget and schedule. Production restarted in early September, initially with production from the Crathes well. After Crathes declined as expected, the well was temporarily shut in to allow production to begin from Scolty. From December, both the Scolty and Crathes wells have been online and performing strongly, supported by optimisation activities.

On the Greater Kittiwake Area, high levels of production and water injection efficiency of 95% have delivered a strong production performance in 2019, partially mitigating the impact of natural declines. The team has delivered another solid HSEA performance, reaching 14 years without a LTI.

At Alma/Galia, average production in 2019 was 1,900 Boepd, a decrease of 8.1% compared to 2018, reflecting the natural decline of the field. Production efficiency at Alma/Galia remained high at over 95% during the year, while preparatory decommissioning programmes commenced.

Output from Alba during the year has been in line with expectations.

2020 performance and outlook

Performance to the end of February has been good. Production continues to decline at Alma/Galia, where the Group's focus remains on production optimisation and cost reduction. Decommissioning is expected to commence following cessation of production, currently forecast to be in the second half of 2020 with the FPSO vessel moving off-station thereafter.

At both Scolty/Crathes and the Greater Kittiwake Area, a four-week shutdown is planned for the summer, as required by the outage at the Forties Production System oil export route.

A two-day shutdown is planned at Alba during the third quarter.

THE KRAKEN DEVELOPMENT

2019 performance summary

Average gross production was 35,704 Bopd, above the top end of the Group's 2019 guidance range of 30,000 to 35,000 Bopd and 17.8% higher than 2018. Performance at the FPSO vessel has significantly improved through the year. This follows a programme of targeted improvement initiatives, focusing on the main power engines, topside power water pumps and the hydraulic submersible pumps, combined with changes to the offshore spares management and FPSO maintenance processes. Over the summer, pipework repairs on the FPSO required short unplanned production shutdowns, however production efficiency quickly returned to high levels, averaging more than 95% in the fourth quarter, compared to around 58% in the first quarter of 2019.

In March, the Group completed the DC4 drilling programme which marked the conclusion of the original Kraken field development plan. Overall subsurface and well performance remains strong and the Group continues to optimise production through improved injector-producer well management. The aggregate field water cut has remained stable and has evolved on a lower trajectory than was anticipated in the year end 2018 2P reserves estimates, providing increased confidence in long-term production. In May, the Group sanctioned the drilling programme at Worcester within the western area, commencing the next phase of the Kraken development. A rig contract was placed to drill the producer-injector pair through spare capacity in the existing DC2 sub-sea infrastructure.

Between first production and the end of 2019, more than 26 million barrels of oil had been produced and 52 cargoes offloaded from the FPSO, with 25 of these cargoes offloaded in the year. Pricing was robust, with some cargoes achieving premiums to Brent.

2020 performance and outlook

Production and cargo pricing remained strong in the first two months of the year. The Group continues to sell Kraken cargoes directly to the shipping market, as a key component of IMO 2020 compliant low-sulphur fuel oil.

The Group has commenced the two-well drilling programme at Worcester in the western area. In total, the western area provides a near-field, economic, development opportunity, with between 70 and 130 MMbbls of STOIIP. The Pembroke, Antrim and Barra areas continue to be evaluated and the Group is also reviewing the potential for developing the Maureen sands, which lie directly beneath the existing reservoir.

MALAYSIA OPERATIONS

2019 performance summary

Average production in Malaysia during the year was 8,653 Boepd, which was 2.6% higher than in 2018, driven by high production efficiency of 92% at PM8/Seligi and better than expected performance from the Group's idle well restoration programme. The idle well restoration programme commenced ahead of schedule and resulted in 11 wells restored to production, helping mitigate underlying natural decline. In September, the Group completed its two-well drilling programme, with one well online.

A structured compressor maintenance and repair programme resulted in significantly improved compressor uptime performance during the fourth quarter, supporting enhanced gas reinjection and oil production. The systematic and wide-scale asset inspection and maintenance campaign to help ensure long-term facilities integrity was successfully concluded in the fourth quarter.

Production at Tanjong Baram decreased materially in the period, reflecting natural decline and the inability of well A2 to naturally flow. Under the terms of the Small Field Risk Service Contract ('SFRSC'), following two consecutive quarters of allocated revenue being below operating expenditures, the field is deemed uneconomic and EnQuest has the right to issue a contract termination notice. In December, this notice was issued to PETRONAS and the SFRSC was terminated on 3 March 2020. As a result, EnQuest will receive the outstanding capital expenditure of around $50 million over a period of three quarters, with the first repayment due in June 2020.

In December, the Group was awarded the Block PM409 Production Sharing Contract ('PSC') offshore Malaysia. Under the terms of the PSC, EnQuest will operate the block with a participating interest of 85.0%, with PETRONAS Carigali Sdn Bhd owning the remaining 15.0%. Block PM409 measures approximately 1,700 km2 and is located offshore Peninsular Malaysia in water depths of 70 to 100 metres. The block is in a proven hydrocarbon area containing several undeveloped discoveries and is contiguous to the Group's existing PM8/Seligi PSC, providing low-cost tie-back opportunities to the Group's existing Seligi main production hub. Within the initial four-year exploration term of the PSC, the partners are committed to the drilling of one well.

2020 performance and outlook

Aggregate production has been in line with the Group's expectations for the first two months of 2020, with the Tanjong Baram SFRSC terminating in March.

A planned shutdown of the PM8/Seligi facilities is anticipated in Q3 2020, with a similar duration to 2019.

At PM8/Seligi, further investment in idle well restoration and facility improvements will continue throughout the year.

EnQuest has c.22 MMboe of 2P reserves and c.76 MMboe of 2C resources in Malaysia. A large number of low-cost drilling and workover targets have been identified at PM8/Seligi, with multi-well drilling programmes being assessed for future development. At PM409, the Group will undertake subsurface studies to assess the existing discovered resources to identify suitable drilling and sub-sea tie-back opportunities for future development.

Financial review

Financial overview
All figures quoted are in US Dollars and relate to Business performance unless otherwise stated.

The Group delivered on its operational and financial targets for 2019, growing production by 24% and lowering unit operating expenditure to $20.6/Boe. The material increase in EBITDA and free cash flow facilitated accelerated repayments of the Group's credit facility, to strengthen the balance sheet further. The Group's year-end net debt to EBITDA ratio was 1.4x, significantly ahead of the original target of below 2.0x. The Group has now repaid the entire 2020 senior credit facility amortisation early, following the voluntary repayment of $35 million in January 2020.

Production on a working interest basis increased by 23.7% to 68,606 Boepd, compared to 55,447 Boepd in 2018.

This increase reflected a significant improvement in performance at the FPSO vessel at Kraken, increased volumes from Scolty/Crathes following the successful completion of the pipeline replacement, high production efficiency at PM8/Seligi and a full year's contribution at 100% equity interest at Magnus. These increases were partially offset by shutdowns at Heather and Thistle, lower than expected production and water injection efficiency at the Dons and natural declines across other assets.

Revenue for 2019 was $1,711.8 million, 42.5% higher than in 2018 ($1,201.0 million) reflecting the increase in production, the onward sale of third-party gas purchases not required for injection activities at Magnus, and the favourable impact of the Group's commodity hedge programme, partially offset by lower market prices. The Group's commodity hedge programme resulted in realised gains of $24.8 million in 2019 (2018: losses of $93.0 million).

The Group's operating expenditures of $518.1 million were 11.2% higher than in 2018 ($465.9 million), reflecting the full year of additional equity interest in Magnus. Unit operating costs decreased by 10.4% to $20.6/Boe (2018: $23.0/Boe) as a result of increased production.

Other cost of sales of $97.5 million were higher than in 2018 ($48.1 million), principally reflecting the cost of additional Magnus related third-party gas purchases not required for injection activities of $72.0 million.

EBITDA for 2019 was $1,006.5 million, up 40.5% compared to 2018 ($716.3 million), primarily as a result of increased revenue.

	2019 $ million	2018 $ million
Profit from operations before tax and finance income/(costs)	**442.1**	290.0
Depletion and depreciation	**533.4**	442.4
Change in well inventories	**14.6**	5.8
Net foreign exchange (gain)/loss	**16.4**	(21.9)
EBITDA	**1,006.5**	716.3

EnQuest's net debt decreased by $361.5 million to $1,413.0 million at 31 December 2019 (31 December 2018: $1,774.5 million). This includes $133.3 million of interest that has been capitalised to the principal of the facilities pursuant to the terms of the Group's November 2016 refinancing ('Payable in Kind' or 'PIK') (31 December 2018: $132.0 million) (see note 18 for further details).

	Net debt/(cash)[1]	
	31 December 2019 $ million	31 December 2018 $ million
Bonds	**971.9**	965.1
Multi-currency revolving credit facility ('RCF')	**475.1**	799.4
Sculptor Capital facility[2]	**122.9**	178.5
Tanjong Baram Project Finance Facility	**31.7**	31.7
Mercuria Prepayment Facility	**–**	22.2
SVT Working Capital Facility	**31.9**	15.7
Other loans	**–**	2.5
Cash and cash equivalents	**(220.5)**	(240.6)
Net debt	**1,413.0**	1,774.5

Notes:
1 See reconciliation of net debt within the 'Glossary – Non-GAAP measures' starting on page 69
2 Sculptor Capital facility was previously known as the Oz Management facility

During the year, the Group's improved cash generation enabled repayments of $325.0 million relating to the RCF, more than the scheduled amortisation requirement. In January 2020, EnQuest voluntarily repaid an additional $35.0 million early, with the Group having now repaid the entire senior credit facility amortisation due in 2020. Strong performance at Kraken drove repayments of the Sculptor Capital facility, totalling $55.6 million in the period. Following the termination of the Tanjong Baram Small Field Risk Service Contract on 3 March 2020, the Group anticipates repaying the Tanjong Baram Project Finance Facility during 2020.

UK corporate tax losses at the end of the year reduced to $2,903.4 million (2018: $3,225.3 million). The Group generated taxable profits on increased production which were offset against existing tax losses. In the current environment, no significant corporation tax or supplementary charge is expected to be paid on UK operational activities for the foreseeable future. The Group paid cash corporate income tax on the Malaysian assets which will continue throughout the life of the Production Sharing Contract.

Income statement

Revenue

On average, market prices for crude oil in 2019 were lower than in 2018. The Group's average realised oil price excluding the impact of hedging was $64.2/bbl, 7.5% lower than in 2018 ($69.4/bbl). Revenue is predominantly derived from crude oil sales which totalled $1,548.2 million, 25.1% higher than in 2018 ($1,237.6 million), reflecting the increase in volumes. Revenue from the sale of condensate and gas was $120.2 million (2018: $43.1 million), as a result of gas sales from Magnus, which includes the combination of produced gas sales and the onward sale of third-party gas purchases not required for injection activities, for which the costs are included in other cost of sales. Tariffs and other income generated $18.7 million (2018: $13.4 million). The Group's commodity hedges and other oil derivatives generated $24.8 million of realised gains (2018: losses of $93.0 million), including gains of $4.9 million of non-cash amortisation of option premiums (2018: losses of $17.2 million) as a result of the timing at which the hedges were entered into and the decrease in market prices. The Group's average realised oil price including the impact of hedging was $65.3/bbl in 2019, 1.7% higher than 2018 ($64.2/bbl).

Note: For the reconciliation of realised oil prices see 'Glossary – Non-GAAP measures' starting on page 69

Cost of sales[1]

	2019 $ million	2018 $ million
Production costs	**441.6**	396.9
Tariff and transportation expenses	**74.8**	68.4
Realised (gain)/loss on derivatives related to operating costs	**1.7**	0.6
Operating costs	**518.1**	465.9
(Credit)/charge relating to the Group's lifting position and inventory	**102.9**	(25.1)
Depletion of oil and gas assets	**525.1**	437.1
Other cost of sales	**97.5**	48.1
Cost of sales	**1,243.6**	926.0
Operating cost per barrel[2]	**$/Boe**	$/Boe
– Production costs	**17.6**	19.6
– Tariff and transportation expenses	**3.0**	3.4
Average unit operating cost	**20.6**	23.0

Note:
1 See reconciliation of alternative performance measures within the 'Glossary – Non-GAAP measures' starting on page 69
2 Calculated on a working interest basis

Cost of sales were $1,243.6 million for the year ended 31 December 2019, 34.3% higher than in 2018 ($926.0 million).

Operating costs increased by $52.2 million, reflecting a full year of 100% equity interest in Magnus. The Group's average unit operating cost decreased by 10.4% to $20.6/Boe as a result of increased production.

The charge relating to the Group's lifting position and inventory was $102.9 million (2018: $25.1 million gain). This reflects a switch to a $28.6 million net overlift position at 31 December 2019 from a $68.3 million net underlift position at 31 December 2018. This switch reflected the closing positions on Thistle and Heather and the unwind of underlift on Magnus in the year.

Depletion expense of $525.1 million was 20.1% higher than in 2018 ($437.1 million), mainly reflecting a full year of 100% equity interest in Magnus.

Other cost of sales of $97.5 million were higher than in 2018 ($48.1 million), principally reflecting the cost of additional Magnus-related third-party gas purchases not required for injection activities of $72.0 million.

Other income and expenses

Net other expenses of $18.4 million (2018: net other income of $19.1 million) primarily comprises net foreign exchange losses, which relate to the revaluation of Sterling-denominated amounts in the balance sheet following the strengthening of Sterling against the Dollar.

Finance costs

Finance costs of $206.6 million were 12.5% lower than in 2018 ($236.1 million). The decrease was primarily driven by a reduction of $27.3 million in bond and loan interest charges (2019: $130.4 million; 2018: $157.7 million). Other finance costs included lease liability interest of $55.7 million (2018: $55.8 million), $14.1 million on unwinding of discount on decommissioning provisions and other liabilities (2018: $14.0 million), $5.7 million amortisation of arrangement fees for financing facilities and bonds (2018: $8.5 million) and other financial expenses of $2.1 million (2018: $1.7 million), primarily the cost for surety bonds principally to provide security for decommissioning liabilities.

Taxation
The tax charge for 2019 of $23.6 million (2018: $20.9 million tax credit), excluding exceptional items, is mainly due to Malaysian tax and the utilisation of UK losses offset by RFES generated in the year.

Remeasurement and exceptional items
Revenue included unrealised losses of $65.4 million in respect of the mark-to-market movement on the Group's commodity contracts (2018: unrealised gains of $97.4 million).

Non-cash impairment charges of: $637.5 million (2018: $126.0 million) on the Group's tangible oil and gas assets arises from a reduction in the long-term oil price, revisions to production profiles in Heather/Broom, Thistle/Deveron and the Dons fields, and the anticipated cessation of production at Alma/Galia;$149.6 million (2018: $nil) on the Group's goodwill; and $25.4 million (2018: $0.4 million) on the Group's intangible oil and gas assets reflecting the write-off of historical exploration and appraisal expenditures.

Other income and expense included a $15.5 million expense in relation to the fair value recalculation of the Magnus contingent consideration reflecting the improved performance and outlook at the asset, and $15.6 million in relation to the KUFPEC settlement agreement. Other finance costs mainly relates to the unwinding of contingent consideration from the acquisition of Magnus and associated infrastructure of $57.2 million.

A tax credit of $303.5 million (2018: $12.4 million) has been presented as exceptional, representing the tax impact of the above items.

Earnings per share
The Group's Business performance basic profit per share was 13.1 cents (2018: 5.7 cents) and diluted profit per share was 13.0 cents (2018: 5.5 cents).

The Group's reported basic loss per share was 27.4 cents (2018 profit per share: 9.2 cents) and reported diluted loss per share was 27.4 cents (2018 profit per share: 9.0 cents).

Cash flow and liquidity
Net debt at 31 December 2019 amounted to $1,413.0 million, including PIK of $133.3 million, compared with net debt of $1,774.5 million at 31 December 2018, including PIK of $132.0 million. The Group has remained in compliance with financial covenants under its debt facilities throughout the year. The movement in net debt was as follows:

	$ million
Net debt 1 January 2019	**(1,774.5)**
Operating cash flows	962.3
Cash capital expenditure	(237.5)
Net interest and finance costs paid	(147.0)
Finance lease payments	(135.1)
Repayments on Magnus financing and profit share	(74.2)
Non-cash capitalisation of interest	(5.2)
Other movements, primarily net foreign exchange on cash and debt	(1.8)
Net debt 31 December 2019[1]	**(1,413.0)**

Note:
1 See reconciliation of alternative performance measures within the 'Glossary – Non-GAAP measures' starting on page 69

The Group's reported operating cash flows for the year ended 31 December 2019 were $962.3 million, up 21.1% compared to 2018 ($794.4 million). The main drivers for this increase were the increase in volumes and a gain on realised hedging at year end.

Cash outflow on capital expenditure is set out in the table below:

	Year ended 31 December 2019 $ million	Year ended 31 December 2018 $ million
North Sea	**224.4**	200.2
Malaysia	**13.0**	19.5
Exploration and evaluation	**0.1**	0.5
	237.5	220.2

Cash capital expenditure primarily relates to the Kraken DC4 programme, pipeline projects, licence to operate capital expenditure and agreed deferrals brought into 2019.

Balance sheet
The Group's total asset value has decreased by $885.3 million to $4,776.6 million at 31 December 2019 (2018: $5,661.9 million), mainly due to the impairment charge on the Group's tangible and intangible oil and gas assets and depletion of oil and gas assets offset by the recognition of the IFRS 16 Leases right-of-use assets. Net current liabilities have decreased to $282.7 million as at 31 December 2019 (2018: $301.2 million). Included in the Group's net current liabilities are $178.7 million of estimated future obligations where settlement is subject to the financial performance at Kraken and Magnus (2018: $134.8 million).

Property, plant and equipment ('PP&E')
PP&E has decreased by $899.0 million to $3,450.9 million at 31 December 2019 from $4,349.9 million at 31 December 2018 (see note 10). This decrease encompasses the capital additions to PP&E of $177.4 million, initial recognition of new right-of-use assets under IFRS 16 Leases of $60.5 million, a net increase of $34.2 million for changes in estimates for decommissioning and other provisions, offset by non-cash impairments of $637.5 million and depletion and depreciation charges of $533.4 million.

The PP&E capital additions during the period, including capitalised interest, are set out in the table below:

	2019 $ million
Kraken	**29.0**
Northern North Sea	**63.9**
Central North Sea	**68.7**
Malaysia	**15.8**
	177.4

Goodwill
Goodwill decreased due to non-cash impairment of $149.6 million, mainly reflecting the impairment of assets relating to PP&E.

Intangible oil and gas assets
Intangible oil and gas assets decreased by $24.2 million to $27.6 million at 31 December 2019 (31 December 2018: $51.8 million), mainly reflecting the write-off of historical exploration and appraisal expenditures.

Trade and other receivables
Trade and other receivables increased by $3.7 million to $279.5 million at 31 December 2019 compared with $275.8 million at 31 December 2018.

Cash and net debt
The Group had $220.5 million of cash and cash equivalents at 31 December 2019 and $1,413.0 million of net debt, including PIK and capitalised interest of $140.7 million (2018: $240.6 million, $1,774.5 million and $135.5 million, respectively).

Net debt comprises the following liabilities:
- $225.7 million principal outstanding on the £155.0 million retail bond, including interest capitalised as PIK of $22.1 million (2018: $218.9 million and $21.5 million, respectively);
- $746.1 million principal outstanding on the high yield bond, including interest capitalised as PIK of $96.1 million (2018: $746.1 million and $96.1 million, respectively);
- $475.1 million of credit facility, comprising amounts drawn down of $460.0 million and interest capitalised as PIK of $15.1 million (2018: $799.4 million, $785.0 million and $14.4 million, respectively);
- $122.9 million on the Sculptor Capital facility, comprising amounts drawn down of $115.5 million and capitalised interest of $7.4 million (2018: $178.5 million, $175.0 million and $3.5 million, respectively);
- $31.9 million relating to the SVT Working Capital Facility (2018: $15.7 million);
- $31.7 million relating to the Tanjong Baram Project Finance Facility (2018: $31.7 million); and
- In 2018, $22.2 million relating to the Mercuria Prepayment Facility and $2.5 million outstanding from a trade creditor loan.

Provisions
The Group's decommissioning provision increased by $40.2 million to $711.9 million at 31 December 2019 (2018: $671.7 million). The movement is due to an increase in changes in estimates of $37.9 million and $13.4 million unwinding of discount, partially offset by utilisation of $11.1 million for decommissioning carried out in the period. During 2019, the Group commissioned Wood Group PSN to estimate the costs involved in decommissioning each operated field. The estimates were reviewed by operations personnel and adjustments were made where necessary to reflect management's view of the estimates.

Other provisions increased by $11.1 million in 2019 to $51.1 million (2018: $40.0 million). Other provisions includes EnQuest's obligation to make payments to BP by reference to 7.5% of BP's decommissioning costs of the Thistle and Deveron fields and the KUFPEC settlement agreement.

Contingent consideration
The contingent consideration related to the Magnus acquisition increased by $3.2 million. In 2019, EnQuest repaid $88.4 million to BP, including repaying the remaining $34.8 million in the year associated with the initial 25% interest vendor loan, with the remainder reflecting the partial repayment of the 75% interest vendor loan and interest, and BP's entitlement to share in the cash flows from the 75% interest. A change in fair value estimate charge of $15.5 million and an unwinding of discount of $57.2 million was recognised in the year.

Income tax
The Group had an income tax liability of $4.1 million (2018: $15.3 million) related to corporate income tax on Malaysian assets.

Deferred tax
The Group's net deferred tax asset has increased from $258.9 million at 31 December 2018 to $555.1 million at 31 December 2019. The increase primarily relates to the combined tax impact from each of the impairment of the Group's oil and gas assets, the Group's hedging activities and the Magnus acquisition contingent consideration. Total UK tax losses carried forward at the year end amounted to $2,903.4 million (2018: $3,225.3 million).

Trade and other payables
Trade and other payables of $419.9 million at 31 December 2019 are $82.1 million lower than at 31 December 2018 ($502.0 million). The full balance of $419.9 million is payable within one year (2018: $483.8 million within one year and $18.2 million after more than one year). The decrease in current payables mainly reflects other working capital movements and the change in VAT position.

Leases obligations
As at 31 December 2019, the Group held a lease liability of $716.2 million. Six additional leases with a combined liability of $60.5 million were recognised on transition to IFRS 16 on 1 January 2019. The main lease continues to relate to the Kraken FPSO, with a liability of $635.0 million at 31 December 2019 and undiscounted contractual cash flows of $115.5 million payable within one year.

Financial risk management
Oil price
The Group is exposed to the impact of changes in both Brent crude oil price and gas prices on its revenue and profits. EnQuest's policy is to manage the impact of commodity prices to protect against volatility and allow availability of cash flow for repayment of debt and investment in capital programmes.

During the year ended 31 December 2019, commodity derivatives generated a total loss of $40.6 million; (realised gains of $24.8 million and unrealised losses of $65.4 million) mostly in respect of the mark-to-market of swaps and calls, and the amortisation of premiums on calls.

Foreign exchange
EnQuest's functional currency is US Dollars. Foreign currency risk arises on purchases and the translation of assets and liabilities denominated in currencies other than US Dollars. To mitigate the risks of large fluctuations in the currency markets, the hedging policy agreed by the Board allows for up to 70% of the non-US Dollar portion of the Group's annual capital budget and operating expenditure to be hedged. For specific contracted capital expenditure projects, up to 100% can be hedged.

EnQuest continually reviews its currency exposures and, when appropriate, looks at opportunities to enter into foreign exchange hedging contracts. During the year ended 31 December 2019, losses totalling $1.0 million (2018: losses of $0.4 million) were recognised in the income statement. This included losses totalling $2.7 million realised on contracts maturing during the year (2018: $0.6 million).

Surplus cash balances are deposited as cash collateral against in-place letters of credit as a way of reducing interest costs. Otherwise, cash balances can be invested in short-term bank deposits and AAA-rated liquidity funds, subject to Board-approved limits and with a view to minimising counterparty credit risks.

Going concern disclosure
The Group closely monitors and manages its funding position and liquidity risk throughout the year, including monitoring forecast covenant results, to ensure that it has access to sufficient funds to meet forecast cash requirements. Cash forecasts are regularly produced and sensitivities considered for, but not limited to, changes in crude oil prices (adjusted for hedging undertaken by the Group), production rates and costs. These forecasts and sensitivity analyses allow management to mitigate liquidity or covenant compliance risks in a timely manner. Management has also repaid the term loan on or ahead of schedule, with no further scheduled payments now due in 2020.

The Group is actively monitoring the impact on operations from COVID-19 and has implemented a number of mitigations to minimise the impact. The Group has been working with a variety of stakeholders, including industry and medical organisations, to ensure its operational response and advice to its workforce is appropriate and commensurate with the prevailing expert advice and level of risk. Appropriate restrictions on offshore travel have been implemented, such as self-declaration by, and isolation of, individuals who have been to affected areas and pre-mobilisation temperature checking is in operation. EnQuest's normal communicable disease process has been updated specifically in respect of COVID-19, with additional offshore isolation capability and agreements in place to transport impacted individuals back onshore in dedicated helicopters. Non-essential down-manning has been implemented, with many of the Group's onshore workforce working remotely.

While it is difficult to forecast the impact of COVID-19, at the time of publication of EnQuest's full year results, the Group's day-to-day operations continue without being materially affected.

The Group has reviewed each of its assets and related spending plans in light of the current lower oil price environment. EnQuest's updated working assumption is not to re-start production at the Heather and Thistle/Deveron fields. At the same time, the Group is implementing a material operating cost and capital expenditure reduction programme. This significantly lowers EnQuest's cost base and successful delivery of this programme is assumed in the Base case.

The Base case uses an oil price assumption of $40/bbl from March 2020 through to the end of the first quarter 2021, based on recent research analyst projections for the period. This has been sensitised under a plausible downside case ('Downside case'). The Base case and Downside case indicate that the Company is covenant compliant and able to operate within the headroom of its existing borrowing facilities for 12 months from the date of approval of the Annual Report and Accounts. Given the extreme volatility in current oil prices, the Directors have also performed reverse stress testing with the breakeven price for liquidity being c. $10/bbl.

The quarterly liquidity covenant in the facility (the "Liquidity Test") requires that the Group has sufficient funds available to meet all liabilities of the Group when due and payable for the period commencing on each quarter and ending on the date falling 12 months after the final maturity date which is 1 October 2021. The Liquidity Test assumptions include a price deck of the average forward curve oil price, minus a 10% discount, of 15 consecutive business days starting from approximately in the middle of the previous quarter. The Base case uses $45/bbl for the remainder of 2021, with a longer-term price assumption of $60/bbl. Under these prices the Group forecasts no breaches in the Liquidity Test. Applying the 10% discount stipulated in the Liquidity Test and a further reduction in excess of 15% on Base case prices across all periods, the Group would breach this covenant, prior to any mitigations such as further cost reductions or other funding options. Given the extreme volatility in current oil prices, there is a risk of a potential covenant breach, which would therefore require a covenant waiver to be obtained. The Directors are confident that obtaining waivers from the facility providers would be forthcoming. However, the risk of not obtaining a waiver represents a material uncertainty that may cast doubt upon the Group's ability to continue to apply the going concern basis of accounting.

Notwithstanding the material uncertainty described above, after making enquiries and assessing the progress against the forecast, projections and the status of the mitigating actions referred to above, the Directors have a reasonable expectation that the Group will continue in operation and meet its commitments as they fall due over the going concern period. Accordingly, the Directors continue to adopt the going concern basis in preparing the financial statements.

Viability statement

The Directors have assessed the viability of the Group over a three-year period to March 2023. This assessment has taken into account the Group's financial position as at March 2020, forecasts that reflect the current market volatility and the Group's principal risks and uncertainties. The Directors' approach to risk management, their assessment of the Group's principal risks and uncertainties, and the actions management are taking to mitigate these risks are outlined on pages 17 to 25. The Directors recognise that such future assessments are subject to a level of uncertainty that increases with time and, therefore, future outcomes cannot be guaranteed or predicted with certainty. The impact of these risks and uncertainties, including their combined impact, has been reviewed by the Directors and the effectiveness and achievability of the potential mitigating actions have been considered.

The period of three years is deemed appropriate as it is the time horizon across which management constructs a detailed plan against which business performance is measured and also covers the period within which the Group's term loan and revolving credit facility is expected to be repaid. Based on the Group's projections, the Directors have a reasonable expectation that the Group can continue in operation and meet its liabilities as they fall due over the period to end March 2023.

The Group's going concern Base case also underpins this assessment and takes account of the Group's principal risks and uncertainties. The viability assessment uses the same oil price assumptions as for the going concern assessment, $45/bbl for the remainder of 2021, with a longer term price assumption of $60/bbl based on recent research analyst projections for the period.

The Base case has been sensitised by considering the impact of the following plausible downside risks on a combined basis:

- a 10% discount to the Base case oil price assumptions; and
- a 5% decrease in 2020 and 2021 production.

The Base case and sensitised case indicate that the Company is covenant compliant and able to operate within the headroom of its existing borrowing facilities during the three-year viability period from the date of approval of the Annual Report and Accounts.

For the current assessment, the Directors also draw attention to the specific principal risks and uncertainties (and mitigants) identified below, which, individually or collectively, could have a material impact on the Group's viability during the period of review.

Oil price volatility

A further decline in oil and gas prices from those assumed in the Base and Downside cases would adversely affect the Group's operations and financial condition. In partial mitigation to oil price volatility, the Group has hedged approximately 2.9 MMbbls at an average floor price of around $65/bbl in the first quarter of 2020. In accordance with the Sculptor Capital facility agreement, the Group has a further approximately 1.1 MMbbls hedged across 2020 with an average floor price of around $52/bbl. In line with Group policy, EnQuest will continue to pursue hedging at the appropriate time and price.

Access to funding
The Group's credit facility contains certain covenants (based on the ratio of indebtedness incurred under the term loan and revolving credit facility to EBITDA, finance charges to EBITDA, and a requirement for liquidity testing). Prolonged low oil prices, cost increases and production delays or outages could further threaten the Group's liquidity and/or ability to comply with relevant covenants. In assessing viability the Directors recognise the material uncertainty identified in the going concern period (see above) and the conclusion that a waiver for any potential covenant breach would be forthcoming.

The maturity dates of the existing $746 million High Yield Bond and the £172 million Retail Notes (both figures at year end 2019 and inclusive of the PIK notes) are in April 2022, with a mandatory extension to the maturity date to October 2023 if the existing facility is not fully repaid or refinanced by October 2020. The Directors recognise that refinancing of the High Yield Bond and Retail Notes is expected to be required beyond the viability period in 2023 and, based on recent research analyst projections for oil prices, and believe this would be achievable subject to other market conditions at that time.

Notwithstanding the principal risks and uncertainties described above, after making enquiries and assessing the progress against the forecast, projections and the status of the mitigating actions referred to above, the Directors have a reasonable expectation that the Group can continue in operation and meet its commitments as they fall due over the viability period ending March 2023. Accordingly, the Directors therefore support this viability statement.

Risks and uncertainties

Management of risks and uncertainties
Consistent with the Company's purpose, the Board has articulated EnQuest's strategic vision to be the operator of choice for maturing and underdeveloped hydrocarbon assets. EnQuest is focused on delivering on its targets, driving future growth and managing its capital structure and liquidity.

EnQuest seeks to balance its risk position between investing in activities that can achieve its near-term targets and drive future growth with the appropriate returns, including any appropriate market opportunities that may present themselves, and the continuing need to remain financially disciplined. This combination drives cost efficiency and cash flow generation, facilitating the continued reduction in the Group's debt. In this regard, the Board has developed certain guiding strategic tenets that link with EnQuest's strategy and appetite for risk. Broadly, these reflect a focus by the Company on:

- Maintaining discipline across metrics such as financial headroom, leverage ratio and gearing;
- Enhancing diversity within our portfolio of assets, with a focus on underdeveloped producing assets and maturing assets with investment potential; and
- Ensuring the quality of the investment decision-making process.

In pursuit of its strategy, EnQuest has to manage a variety of risks. Accordingly, the Board has established a Risk Management Framework ('RMF') to enhance effective risk management within the following Board-approved overarching statement of risk appetite:

- We make investments and manage the asset portfolio against agreed key performance indicators consistent with the strategic objectives of enhancing net cash flow, reducing leverage, minimising emissions, managing costs and diversifying our asset base;
- We seek to embed a risk culture within our organisation corresponding to the risk appetite which is articulated for each of our principal risks;
- We seek to avoid reputational risk by ensuring that our operational and HSEA processes, policies and practices reduce the potential for error and harm to the greatest extent practicable by means of a variety of controls to prevent or mitigate occurrence; and
- We set clear tolerances for all material operational risks to minimise overall operational losses, with zero tolerance for criminal conduct.

The Board reviews the Company's risk appetite annually in light of changing market conditions and the Company's performance and strategic focus. The Executive Committee periodically reviews and updates the Group Risk Register based on the individual risk registers of the business. The Group Risk Register, along with an assurance mapping and controls review exercise; a risk report (focused on identifying and mitigating the most critical and emerging risks through a systematic analysis of the Company's business, its industry and the global risk environment); and a continuous improvement plan, is periodically reviewed by the Board (with senior management), to ensure that key issues are being adequately identified and actively managed. In addition, the Group's Safety and Risk Committee (a sub-Committee of the Board) provides a forum for the Board to review selected individual risk areas in greater depth.

As part of its strategic, business planning and risk processes, the Group considers how a number of macro-economic themes may influence its principal risks. These are factors about which the Company should be cognisant in developing its strategy, including long-term supply and demand trends. They include, for example, developments in technology, demographics, climate change and how markets and the regulatory environment may respond, and the decommissioning of infrastructure in the UK North Sea and other mature basins. These themes are relevant to the Group's assessments across a number of its principal risks. The Group will continue to monitor these themes and the relevant developing policy environment at an international and national level and will adapt its strategy accordingly. For example, EnQuest remains conscious of the potential for a number of aspects of climate change to amplify certain principal risks over time (e.g. in relation to access to capital markets – see 'Financial' risk on page 22 – and oil price – see 'Oil and gas prices' risk on page 20). The Group is also conscious that as an operator of mature producing assets with limited appetite for exploration, it has limited exposure to investments which do not deliver near-term returns and is therefore in a position to adapt and calibrate its exposure to new investments according to developments in relevant markets.

As part of its evolution of the Group's Risk Management Framework, the Safety and Risk Committee has refreshed its views on all risk areas faced by the Group (categorising these into a 'Risk Library' of 18 overarching risks). For each risk area, the Committee reviewed 'Risk Bowties' that identified risk causes and impacts and mapped these to preventative and containment controls used to manage the risks to acceptable levels. In the first quarter of 2020, as a responsible operator, EnQuest has been monitoring the evolving situation, and consequent emerging risk, with regards to the spread of COVID-19. The Group has been working with a variety of stakeholders, including industry and medical organisations, to ensure its operational response and advice to its workforce is appropriate and commensurate with the prevailing expert advice and level of risk. While it is difficult to forecast the impact of COVID-19, at the time of publication of EnQuest's full year results, the Group's day-to-day operations continue without being materially affected. The situation will continue to be monitored.

The Board, supported by the Audit Committee and the Safety and Risk Committee, has reviewed the Group's system of risk management and internal control for the period from 1 January 2019 to the date of this report and carried out a robust assessment of the Company's emerging and principal risks and the procedures in place to identify and mitigate these risks. The Board confirms that the Group complies in this respect with the Financial Reporting Council's 'Guidance on Risk Management, Internal Control and Related Financial and Business Reporting'.

Key business risks

The Group's principal risks (identified from the 'Risk Library') are those which could prevent the business from executing its strategy and creating value for shareholders or lead to a significant loss of reputation. The Board has carried out a robust assessment of the principal risks facing the Company, including those that would threaten its business model, future performance, solvency or liquidity.

Cognisant of the Group's purpose and strategy, the Board is satisfied that the Group's risk management system works effectively in assessing and managing the Group's risk appetite and has supported a robust assessment by the Directors of the principal risks facing the Group.

Set out on the following pages are:

- the principal risks and mitigations;
- an estimate of the potential impact and likelihood of occurrence after the mitigation actions, along with how these have changed in the past year; and
- an articulation of the Group's risk appetite for each of these principal risks.

Amongst these, the key risks the Group currently faces are a sustained decline in oil prices (see 'Oil and gas prices' risk on page 20), a lack of growth opportunities and/or a materially lower than expected production performance for a prolonged period (see 'Production' risk on page 20, 'Subsurface risk and reserves replacement' on page 24).

RISK

HEALTH, SAFETY & ENVIRONMENT ('HSE')

Oil and gas development, production and exploration activities are by their nature complex with HSE risks covering many areas, including major accident hazards, personal health and safety, compliance with regulatory requirements, asset integrity issues and potential environmental impact, including those associated with climate change.

Potential impact – Medium (2018 Medium)
Likelihood – Medium (2018 Low)

There has been no material change in the potential impact. However, we have increased the likelihood of this risk, reflecting the possibility of hydrocarbon releases given the age of many of the Group's assets. We have made an absolute commitment to ensure that exposures are known and recognise that there was a high-potential incident on the Heather platform resulting in the shutdown of production. There was an extensive investigation to determine root causes and implement actions to address shortcomings to prevent re-occurrence. The Group's overall record on HSE remains robust.

The availability of competent people given the potential impacts of COVID-19, could impact the operations of the Group.

APPETITE

The Group's principal aim is SAFE Results with no harm to people and respect for the environment. Should operational results and safety ever come into conflict, employees have a responsibility to choose safety over operational results. Employees are empowered to stop operations for safety-related reasons, as demonstrated in 2019 with the precautionary down-man of Thistle due to integrity uncertainty in relation to the unused storage tanks based upon findings from the planned inspection programme.

2019 had challenges that have allowed EnQuest to learn and reinforce its HSE culture. The Group's desire is to maintain upper quartile HSE performance measured against suitable industry metrics.

MITIGATION

The Group maintains, in conjunction with its core contractors, a comprehensive programme of assurance activities and has undertaken a series of deep dives into the RMF bowties that have demonstrated the robustness of the management process and identified opportunities for improvement. A HSE continual improvement programme is in place, promoting a culture of engagement and transparency in relation to HSE matters. HSE performance is discussed at each Board meeting and the mitigation of HSE risk has been enhanced through further emphasising the role of HSE oversight within the Safety and Risk Committee's terms of reference. During 2019, the Group continued to focus on control of major accident hazards and 'SAFE Behaviours'.

In addition, the Group has a positive and transparent relationship with the UK Health and Safety Executive and Department for Business, Energy & Industrial Strategy, and the Malaysian regulator, Malaysia Petroleum Management.

EnQuest's HSE Policy is now fully integrated across our operated sites and this has enabled an increased focus on Health, Safety and the Environment. There is a strong assurance programme in place to ensure EnQuest complies with its Policy and Principles and regulatory commitments.

The Group continues to monitor the evolving situation with regard to the impacts of COVID-19 in conjunction with a variety of stakeholders, including industry and medical organisations. Appropriate actions will continue to be implemented in accordance with expert advice.

RISK

REPUTATION

The reputational and commercial exposures to a major offshore incident, including those related to an environmental incident, or non-compliance with applicable law and regulation, are significant.

Potential impact – High (2018 High)
Likelihood – Low (2018 Low)

There has been no material change in the potential impact or likelihood.

APPETITE

The Group has no tolerance for conduct which may compromise its reputation for integrity and competence.

MITIGATION

All activities are conducted in accordance with approved policies, standards and procedures. Interface agreements are agreed with all core contractors.

The Group requires adherence to its Code of Conduct and runs compliance programmes to provide assurance on conformity with relevant legal and ethical requirements.

The Group undertakes regular audit activities to provide assurance on compliance with established policies, standards and procedures.

All EnQuest personnel and contractors are required to pass an annual anti-bribery, corruption and anti-facilitation of tax evasion course.

All personnel are authorised to shut down production for safety-related reasons: for example, in 2019, prioritising safety, we shut down production at the Heather and Thistle fields, please see page 7 for further details.

RISK

PRODUCTION

The Group's production is critical to its success and is subject to a variety of risks including: subsurface uncertainties; operating in a mature field environment; potential for significant unexpected shutdowns; and unplanned expenditure (particularly where remediation may be dependent on suitable weather conditions offshore).

Lower than expected reservoir performance or insufficient addition of new resources may have a material impact on the Group's future growth.

The Group's delivery infrastructure in the UK North Sea is, to a significant extent, dependent on the Sullom Voe Terminal.

Longer-term production is threatened if low oil prices or prolonged field shutdowns requiring high-cost remediation bring forward decommissioning timelines.

Potential impact – High (2018 High)
Likelihood – Low (2018 Low)

There has been no material change in the potential impact or likelihood.

The Group has delivered on its 2019 production target, reflecting the improved FPSO performance at Kraken, the contribution from additional equity interest in Magnus and the successful pipeline replacement at Scolty/Crathes. However, the completion of the Dunlin bypass export project sees volumes from Thistle and the Dons exported via the Magnus facility and Ninian Pipeline System, therefore further increasing reliance on the Sullom Voe Terminal.

APPETITE

Since production efficiency and meeting production targets are core to our business and the Group seeks to maintain a high degree of operational control over production assets in its portfolio, EnQuest has a very low tolerance for operational risks to its production (or the support systems that underpin production).

MITIGATION

The Group's programme of asset integrity and assurance activities provide leading indicators of significant potential issues which may result in unplanned shutdowns or which may in other respects have the potential to undermine asset availability and uptime. The Group continually assesses the condition of its assets and operates extensive maintenance and inspection programmes designed to minimise the risk of unplanned shutdowns and expenditure. The Group monitors both leading and lagging KPIs in relation to its maintenance activities and liaises closely with its downstream operators to minimise pipeline and terminal production impacts.

Production efficiency is continually monitored with losses being identified and remedial and improvement opportunities undertaken as required. A continual, rigorous cost focus is also maintained.

Life of asset production profiles are audited by independent reserves auditors. The Group also undertakes regular internal reviews. The Group's forecasts of production are risked to reflect appropriate production uncertainties.

The Sullom Voe Terminal has a good safety record and its safety and operational performance levels are regularly monitored and challenged by the Group and other terminal owners and users to ensure that operational integrity is maintained. Further, EnQuest has begun transforming the Sullom Voe Terminal, including lowering operating costs, to ensure it remains competitive and well placed to maximise its useful economic life and support the future of the North Sea.

The Group actively continues to explore the potential of alternative transport options and developing hubs that may provide both risk mitigation and cost savings.

The Group also continues to consider new opportunities for expanding production.

RISK

OIL AND GAS PRICES

A material decline in oil and gas prices adversely affects the Group's operations and financial condition.

Potential impact – High (2018 High)
Likelihood – High (2018 Medium)

The potential impact remains high, with the likelihood increased to high as a result of the significant decline in oil price in March 2020. This decline was driven by a combination of OPEC and Russia failing to agree limits on supply and the impact of COVID-19 on global oil demand.

The Group recognises that climate change concerns and related regulatory developments are likely to reduce demand for hydrocarbons over time. This may be mitigated by correlated constraints on the development of new supply.

APPETITE

The Group recognises that considerable exposure to this risk is inherent to its business.

MITIGATION

This risk is being mitigated by a number of measures including hedging oil price, renegotiating supplier contracts, reducing costs and commitments and institutionalising a lower cost base.

The Group monitors oil price sensitivity relative to its capital commitments and has a policy (see page 61) which allows hedging of its production. As at 8 April 2020, the Group had hedged approximately 4.0 MMbbls. This ensures that the Group will receive a minimum oil price for its production.

In order to develop its resources, the Group needs to be able to fund the required investment. The Group will therefore regularly review and implement suitable policies to hedge against the possible negative impact of changes in oil prices while remaining within the limits set by its term loan and revolving credit facility.

The Group has established an in-house trading and marketing function to enable it to enhance its ability to mitigate the exposure to volatility in oil prices.

Further, as described previously, the Group's focus on production efficiency supports mitigation of a low oil price environment.

RISK

HUMAN RESOURCES

The Group's success continues to be dependent upon its ability to attract and retain key personnel and develop organisational capability to deliver strategic growth. Industrial action across the sector, or the availability of competent people given the potential impacts of COVID-19, could also impact the operations of the Group.

Potential impact – Medium (2018 Medium)
Likelihood – High (2018 High)

The impact and likelihood are unchanged but reflect the level of competition in the sector, particularly in the UK.

APPETITE

As a low-cost, lean organisation, the Group relies on motivated and high-quality employees to achieve its targets and manage its risks.

The Group recognises that the benefits of a lean and flexible organisation require agility to assure against the risk of skills shortages.

MITIGATION

The Group has established an able and competent employee base to execute its principal activities. In addition to this, the Group seeks to maintain good relationships with its employees and contractor companies and regularly monitors the employment market to provide remuneration packages, bonus plans and long-term share-based incentive plans that incentivise performance and long-term commitment from employees to the Group.

We recognise that our people are critical to our success and so are continually evolving our end-to-end people management processes, including recruitment and selection, career development and performance management. This ensures that we have the right person for the job and that we provide appropriate training, support and development opportunities, with feedback to drive continuous improvement whilst delivering SAFE Results. The culture of the Group is an area of ongoing focus and an employee survey was completed at the end of 2019. Its results were encouraging and the Company is now developing its responses to the findings.

The Group also maintains market-competitive contracts with key suppliers to support the execution of work where the necessary skills do not exist within the Group's employee base.

The Group recognises that there is a gender pay gap within the organisation but that there is no issue with equal pay for the same tasks. EnQuest aims to attract the best talent, recognising the value of diversity.

Executive and senior management retention, succession planning and development remain important priorities for the Board. It is a Board-level priority that executive and senior management possess the appropriate mix of skills and experience to realise the Group's strategy; succession planning therefore remains a key priority.

EnQuest introduced a Group employee forum during 2019 to add to its employee communication and engagement strategy. This forum has improved engagement and interaction between the workforce and the Board.

The Group continues to monitor the evolving situation with regard to the impacts of COVID-19 in conjunction with a variety of stakeholders, including industry and medical organisations. Appropriate actions will continue to be implemented in accordance with expert advice.

RISK

FINANCIAL

Inability to fund financial commitments or maintain adequate cash flow and liquidity and/or reduce costs.

The Group's term loan and revolving credit facility contains certain financial covenants (based on the ratio of indebtedness incurred under the term loan and revolving facility to EBITDA, finance charges to EBITDA and a requirement for liquidity testing). Prolonged low oil prices, cost increases, including those related to an environmental incident, and production delays or outages, could threaten the Group's liquidity and/or ability to comply with relevant covenants.

Potential impact – High (2018 High)
Likelihood – High (2018 Medium)

The potential impact remains high, with the likelihood raised to high following the significant decline in oil price in March 2020. The Group has made material progress in reducing its term loan facility ahead of schedule, with no further amortisations due in 2020. However, there remains a further $440 million (including payment in kind interest) to be repaid or refinanced during 2021. Significant reductions in the oil price or material reductions in production, will likely have a material impact on the Group's ability to repay or refinance the loan facility in 2021. Further information is contained in the Financial Review, particularly within the going concern and viability disclosures on pages 15 and 16. In addition, there is potential for the cost of capital to increase and insurance availability to erode, as factors such as climate change concerns and oil price volatility may reduce investors' and insurers' acceptable levels of oil and gas sector exposure and the cost of emissions trading certificates may trend higher.

APPETITE

The Group recognises that significant leverage was required to fund its growth, as low oil prices impacted revenues. However, it is intent on further reducing its leverage levels, maintaining liquidity, enhancing profit margins, controlling costs and complying with its obligations to finance providers while delivering shareholder value, recognising that reasonable assumptions relating to external risks need to be made in transacting with finance providers.

MITIGATION

Debt reduction is a strategic priority. During the year, the Group repaid a total of $325 million of the term facility, with an additional $35 million repaid in January 2020.

These steps, together with other mitigating actions available to management, are expected to provide the Group with sufficient liquidity to strengthen its balance sheet for longer-term growth.

Ongoing compliance with the financial covenants under the Group's term loan and revolving credit facility is actively monitored and reviewed.

EnQuest generates operating cash inflow from the Group's producing assets. The Group reviews its cash flow requirements on an ongoing basis to ensure it has adequate resources for its needs.

The Group is continuing to enhance its financial position through maintaining a focus on controlling and reducing costs through supplier renegotiations, assessing counterparty credit risk, hedging and trading, cost-cutting and rationalisation. Where costs are incurred by external service providers, the Group actively challenges operating costs. The Group also maintains a framework of internal controls.

With the decline in oil price in March 2020, the Group announced it is taking quick and decisive action to reduce operating and capital expenditure in 2020 and beyond, with a view to targeting cash flow breakeven of c.$33/Boe in 2020 and c.$27/Boe in 2021.

RISK

FISCAL RISK AND GOVERNMENT TAKE

Unanticipated changes in the regulatory or fiscal environment can affect the Group's ability to deliver its strategy/business plan and potentially impact revenue and future developments.

Potential impact – High (2018 High)
Likelihood – Medium (2018 Medium)

There has been no material change in the potential impact or likelihood, although the exit of the United Kingdom from the European Union may impact the regulatory environment going forward, for example by affecting the cost of emissions trading certificates.

APPETITE

The Group faces an uncertain macro-economic and regulatory environment. Due to the nature of such risks and their relative unpredictability, it must be tolerant of certain inherent exposure.

MITIGATION

It is difficult for the Group to predict the timing or severity of such changes. However, through Oil & Gas UK and other industry associations, the Group engages with government and other appropriate organisations in order to keep abreast of expected and potential changes; the Group also takes an active role in making appropriate representations.

All business development or investment activities recognise potential tax implications and the Group maintains relevant internal tax expertise.

At an operational level, the Group has procedures to identify impending changes in relevant regulations to ensure legislative compliance.

RISK

PROJECT EXECUTION AND DELIVERY

The Group's success will be partially dependent upon the successful execution and delivery of development projects.

Potential impact – Medium (2018 Medium)
Likelihood – Low (2018 Low)

The potential impact and likelihood remain unchanged. As the Group focuses on reducing its debt, its current appetite is to pursue short-cycle development projects.

APPETITE

The efficient delivery of new project developments has been a key feature of the Group's long-term strategy. The Group's current appetite is for short-cycle development projects such as infill drilling and near-field tie-backs.

While the Group necessarily assumes significant risk when it sanctions a new development (for example, by incurring costs against oil price assumptions), it requires that risks to the efficient implementation of the project are minimised.

MITIGATION

The Group has project teams which are responsible for the planning and execution of new projects with a dedicated team for each development. The Group has detailed controls, systems and monitoring processes in place, notably the Capital Projects Delivery Process, to ensure that deadlines are met, costs are controlled and that design concepts and the Field Development Plan are adhered to and implemented. These are modified when circumstances require and only through a controlled management of change process and with the necessary internal and external authorisation and communication. The Group also engages third-party assurance experts to review, challenge and, where appropriate, make recommendations to improve the processes for project management, cost control and governance of major projects. EnQuest ensures that responsibility for delivering time-critical supplier obligations and lead times are fully understood, acknowledged and proactively managed by the most senior levels within supplier organisations. EnQuest also supports its partners and suppliers through the provision of appropriate secondees if required.

RISK

PORTFOLIO CONCENTRATION

The Group's assets are primarily concentrated in the UK North Sea around a limited number of infrastructure hubs and existing production (principally oil) is from mature fields. This amplifies exposure to key infrastructure (including ageing pipelines and terminals), political/fiscal changes and oil price movements.

Potential impact – High (2018 High)
Likelihood – High (2018 High)

The Group is currently focused on oil production and does not have significant exposure to gas or other sources of income.

APPETITE

Although the extent of portfolio concentration is moderated by production generated internationally, the majority of the Group's assets remain relatively concentrated in the UK North Sea and therefore this risk remains intrinsic to the Group.

MITIGATION

This risk is mitigated in part through acquisitions. For all acquisitions, the Group uses a number of business development resources to evaluate and transact acquisitions in a commercially sensitive manner. This includes performing extensive due diligence (using in-house and external personnel) and actively involving executive management in reviewing commercial, technical and other business risks together with mitigation measures.

The Group also constantly keeps its portfolio under rigorous review and, accordingly, actively considers the potential for making disposals and divesting, executing development projects, making international acquisitions, expanding hubs and potentially investing in gas assets or export capability where such opportunities are consistent with the Group's focus on enhancing net revenues, generating cash flow and strengthening the balance sheet.

RISK

JOINT VENTURE PARTNERS

Failure by joint venture parties to fund their obligations.

Dependence on other parties where the Group is not the operator.

Potential impact – Medium (2018 Medium)
Likelihood – Low (2018 Medium)

There has been no material change in the potential impact. We have reduced the likelihood in line with the reduction in the Group's exposure to capital-intensive projects requiring funding from third parties.

APPETITE

The Group requires partners of high integrity. It recognises that it must accept a degree of exposure to the credit worthiness of partners and evaluates this aspect carefully as part of every investment decision.

MITIGATION

The Group operates regular cash call and billing arrangements with its co-venturers to mitigate the Group's credit exposure at any one point in time and keeps in regular dialogue with each of these parties to ensure payment. Risk of default is mitigated by joint operating agreements allowing the Group to take over any defaulting party's share in an operated asset and rigorous and continual assessment of the financial situation of partners.

The Group generally prefers to be the operator. The Group maintains regular dialogue with its partners to ensure alignment of interests and to maximise the value of joint venture assets.

RISK

SUBSURFACE RISK AND RESERVES REPLACEMENT

Failure to develop its contingent and prospective resources or secure new licences and/or asset acquisitions and realise their expected value.

Potential impact – High (2018 High)
Likelihood – Medium (2018 Medium)

There has been no material change in the potential impact or likelihood. During the year, EnQuest was awarded the Block PM409 PSC in Malaysia. This block is contiguous to the Group’s existing PM8/Seligi PSC, providing low-cost tie-back opportunities to the Group's existing Seligi main production hub.

Low oil prices or prolonged field shutdowns requiring high-cost remediation which accelerate cessation of production can potentially affect development of contingent and prospective resources and/or reserves certifications.

APPETITE

Reserves replacement is an element of the sustainability of the Group and its ability to grow. The Group has some tolerance for the assumption of risk in relation to the key activities required to deliver reserves growth, such as drilling and acquisitions.

MITIGATION

The Group puts a strong emphasis on subsurface analysis and employs industry-leading professionals. The Group continues to recruit in a variety of technical positions which enables it to manage existing assets and evaluate the acquisition of new assets and licences.

All analysis is subject to internal and, where appropriate, external review and relevant stage gate processes. All reserves are currently externally reviewed by a Competent Person. In addition, EnQuest has active business development teams, both in the UK and internationally, developing a range of opportunities and liaising with vendors/government.

The Group continues to consider potential opportunities to acquire new production resources that meet its investment criteria.

RISK

COMPETITION

The Group operates in a competitive environment across many areas, including the acquisition of oil and gas assets, the marketing of oil and gas, the procurement of oil and gas services and access to human resources.

Potential impact – High (2018 High)
Likelihood – High (2018 High)

The potential impact and likelihood have remained unchanged, with a number of competitors assessing the acquisition of available oil and gas assets.

APPETITE

The Group operates in a mature industry with well-established competitors and aims to be the leading operator in the sector.

MITIGATION

The Group has strong technical and business development capabilities to ensure that it is well positioned to identify and execute potential acquisition opportunities.

The Group maintains good relations with oil and gas service providers and constantly keeps the market under review.

RISK

INTERNATIONAL BUSINESS

While the majority of the Group's activities and assets are in the UK, the international business is still material. The Group's international business is subject to the same risks as the UK business (e.g. HSEA, production and project execution); however, there are additional risks that the Group faces, including security of staff and assets, political, foreign exchange and currency control, taxation, legal and regulatory, cultural and language barriers and corruption.

Potential impact – Medium (2018 Medium)
Likelihood – Medium (2018 Medium)

There has been no material change in the impact or likelihood.

During 2019, EnQuest was awarded the Block PM409 PSC in Malaysia. Within the initial four-year exploration term of the PSC, the partners are committed to the drilling of one well.

APPETITE

In light of its long-term growth strategy, the Group seeks to expand and diversify its production (geographically and in terms of quantum); as such, it is tolerant of assuming certain commercial risks which may accompany the opportunities it pursues.

However, such tolerance does not impair the Group's commitment to comply with legislative and regulatory requirements in the jurisdictions in which it operates. Opportunities should enhance net revenues and facilitate strengthening of the balance sheet.

MITIGATION

Prior to entering a new country, EnQuest evaluates the host country to assess whether there is an adequate and established legal and political framework in place to protect and safeguard first its expatriate and local staff and, second, any investment within the country in question.

When evaluating international business risks, executive management reviews commercial, technical and other business risks together with mitigation and how risks can be managed by the business on an ongoing basis.

EnQuest looks to employ suitably qualified host country staff and work with good-quality local advisers to ensure it complies with national legislation, business practices and cultural norms while at all times ensuring that staff, contractors and advisers comply with EnQuest's business principles, including those on financial control, cost management, fraud and corruption.

Where appropriate, the risks may be mitigated by entering into a joint venture with partners with local knowledge and experience.

After country entry, EnQuest maintains a dialogue with local and regional government, particularly with those responsible for oil, energy and fiscal matters, and may obtain support from appropriate risk consultancies. When there is a significant change in the risk to people or assets within a country, the Group takes appropriate action to safeguard people and assets.

RISK

IT SECURITY AND RESILIENCE

The Group is exposed to risks arising from interruption to, or failure of, IT infrastructure. The risks of disruption to normal operations range from loss in functionality of generic systems (such as email and internet access) to the compromising of more sophisticated systems that support the Group's operational activities. These risks could result from malicious interventions such as cyber-attacks.

Potential impact – Medium (2018 Medium)
Likelihood – Low (2018 Low)

APPETITE

The Group endeavours to provide a secure IT environment that is able to resist and withstand any attacks or unintentional disruption that may compromise sensitive data, impact operations, or destabilise its financial systems; it has a very low appetite for this risk.

MITIGATION

The Group has established IT capabilities and endeavours to be in a position to defend its systems against disruption or attack.

The Safety and Risk Committee undertook additional analyses of cyber-security risks in 2019. Recognising that it is one of the Group's key focus areas, the Group now employs a cyber-security manager. Work on assessing the cyber-security environment and implementing improvements as necessary will continue during 2020.

Stefan Ricketts
Company Secretary

The Strategic Report was approved by the Board and signed on its behalf by the Company Secretary on 8 April 2020.

KEY PERFORMANCE INDICATORS

	2019	2018	2017
UK North Sea Lost Time Incident Frequency ('LTIF')[1]	**0.89**	0.61	0.70
Malaysia LTIF[1]	**0.00**	0.00	0.00
Group LTIF[1]	**0.57**	0.43	0.46
Production (Boepd)	**68,606**	55,447	37,405
Net 2P reserves (MMboe)	**213**	245	210
Business performance data:			
Revenue and other operating income ($ million) [2]	**1,711.8**	1,201.0	627.5
Realised average oil price per barrel ($)[2, 3]	**65.3**	64.2	52.2
Opex per barrel (production and transportation costs) ($)[3]	**20.6**	23.0	25.6
EBITDA ($ million) [3]	**1,006.5**	716.3	303.6
Cash capex on property, plant and equipment oil and gas assets ($ million) [3]	**237.5**	220.2	367.6
Reported data:			
Cash generated from operations ($ million)	**994.6**	788.6	327.0
Net debt including PIK ($ million)[3]	**1,413.0**	1,774.5	1,991.4

[1] Lost time incident frequency represents the number of incidents per million exposure hours worked (based on 12 hours for offshore and 8 hours for onshore)
[2] Including realised gain of $24.8 million in 2019 associated with EnQuest's oil price hedges (2018: realised losses of $93.0 million; 2017: realised loss of $20.6 million)
[3] See reconciliation of alternative performance measures within the 'Glossary – Non-GAAP measures' starting on page 69

OIL AND GAS RESERVES AND RESOURCES

EnQuest oil and gas reserves and resources as at 31 December 2019

	UKCS		Other regions		Total
	MMboe	MMboe	MMboe	MMboe	MMboe
Proven and probable reserves[1, 2, 3 and 6]					
At 31 December 2018		225		20	245
Revisions of previous estimates		(14)		5	(9)
Acquisitions and disposals		–		–	–
Production:					
Export meter	(22)		(3)		
Volume adjustments[5]	–		1		
		(22)		(2)	(24)
Total at 31 December 2019[8]		**190**		**22**	**213**
Contingent resources[1, 2 and 4]					
At 31 December 2018		131		68	198
Revisions of previous estimates		(21)		(13)	(35)
Acquisitions and disposals [7]		–		28	28
Promoted to reserves[9]		(13)		(5)	(18)
Total contingent resources at 31 December 2019		**97**		**76**	**173**

Notes:
1 Reserves are quoted on a net entitlement basis, resources are quoted on a working interest basis
2 Proven and probable reserves and contingent resources have been assessed by the Group's internal reservoir engineers, utilising geological, geophysical, engineering and financial data
3 The Group's proven and probable reserves have been audited by a recognised Competent Person in accordance with the definitions set out under the 2018 Petroleum Resources Management System and supporting guidelines issued by the Society of Petroleum Engineers
4 Contingent resources relate to technically recoverable hydrocarbons for which commerciality has not yet been determined and are stated on a best technical case or '2C' basis
5 Correction of export to sales volumes
6 All UKCS volumes are presented pre-SVT value adjustment
7 Contingent resources: Award of Block PM409 PSC
8 The above proven and probable reserves include 7 MMboe that will be consumed as fuel gas on Magnus and the Dons fields
9 Magnus reflects additional drilling opportunities and maturing the low-pressure operations project; PM8/Seligi reflects the continued success of the idle well restoration programme and new infill drilling and workover opportunities
10 The above table excludes Tanjong Baram in Malaysia
11 Rounding may apply

GROUP STATEMENT OF COMPREHENSIVE INCOME

For the year ended 31 December 2019

	Notes	2019 Business performance $'000	2019 Remeasurements and exceptional items (note 4) $'000	2019 Reported in year $'000	2018 Business performance $'000	2018 Remeasurements and exceptional items (note 4) $'000	2018 Reported in year $'000
Revenue and other operating income	5(a)	**1,711,834**	**(65,375)**	**1,646,459**	1,201,005	97,432	1,298,437
Cost of sales	5(b)	**(1,243,570)**	**(378)**	**(1,243,948)**	(926,020)	1,718	(924,302)
Gross profit/(loss)		**468,264**	**(65,753)**	**402,511**	274,985	99,150	374,135
Net impairment (charge)/reversal to oil and gas assets	4	**–**	**(812,448)**	**(812,448)**	–	(126,046)	(126,046)
General and administration expenses	5(c)	**(7,661)**	**–**	**(7,661)**	(4,018)	–	(4,018)
Other income	5(d)	**3,446**	**–**	**3,446**	22,428	78,316	100,744
Other expenses	5(e)	**(21,881)**	**(31,735)**	**(53,616)**	(3,362)	(14,715)	(18,077)
Profit/(loss) from operations before tax and finance income/(costs)		**442,168**	**(909,936)**	**(467,768)**	290,033	36,705	326,738
Finance costs	6	**(206,596)**	**(57,165)**	**(263,761)**	(236,114)	(28)	(236,142)
Finance income	6	**2,416**	**–**	**2,416**	3,389	–	3,389
Profit/(loss) before tax		**237,988**	**(967,101)**	**(729,113)**	57,308	36,677	93,985
Income tax	7	**(23,648)**	**303,460**	**279,812**	20,887	12,406	33,293
Profit/(loss) for the year attributable to owners of the parent		**214,340**	**(663,641)**	**(449,301)**	78,195	49,083	127,278
Other comprehensive income							
Items that may be reclassified to profit or loss:							
Transfers to income statement of cash flow hedges				**–**			(36)
Other comprehensive income for the year, net of tax				**–**			(36)
Total comprehensive income for the year, attributable to owners of the parent				**(449,301)**			127,242
Earnings per share	8	**$**		**$**	$		$
Basic		**0.131**		**(0.274)**	0.057[(i)]		0.092[(i)]
Diluted		**0.130**		**(0.274)**	0.055[(i)]		0.090[(i)]

(i) Restated to reflect the recalculated weighted average number of Ordinary shares as a result of the 2018 rights issue

The attached notes 1 to 31 form part of these Group financial statements.

GROUP BALANCE SHEET

At 31 December 2019

	Notes	**2019 $'000**	2018 $'000
ASSETS			
Non-current assets			
Property, plant and equipment	10	**3,450,929**	4,349,913
Goodwill	11	**134,400**	283,950
Intangible oil and gas assets	12	**27,553**	51,803
Deferred tax assets	7	**576,038**	286,721
Other financial assets	19	**11**	5,989
		4,188,931	4,978,376
Current assets			
Inventories	13	**78,644**	100,532
Trade and other receivables	16	**279,502**	275,809
Current tax receivable		**–**	20
Cash and cash equivalents	14	**220,456**	240,604
Other financial assets	19	**9,083**	66,575
		587,685	683,540
TOTAL ASSETS		**4,776,616**	5,661,916
EQUITY AND LIABILITIES			
Equity			
Share capital and premium	20	**345,420**	345,331
Merger reserve		**662,855**	662,855
Share-based payment reserve		**(1,085)**	(6,884)
Retained earnings		**(448,129)**	(17,750)
TOTAL EQUITY		**559,061**	983,552
Non-current liabilities			
Borrowings	18	**493,424**	735,470
Bonds	18	**966,231**	990,282
Leases liability	24	**614,818**	615,781
Contingent consideration	22	**545,550**	591,343
Provisions	23	**706,190**	714,749
Trade and other payables	17	**–**	18,209
Deferred tax liabilities	7	**20,919**	27,815
		3,347,132	3,693,649
Current liabilities			
Borrowings	18	**165,589**	311,261
Leases liability	24	**101,348**	93,169
Contingent consideration	22	**111,711**	69,093
Provisions	23	**56,769**	11,957
Trade and other payables	17	**419,855**	483,781
Other financial liabilities	19	**11,073**	142
Current tax payable		**4,078**	15,312
		870,423	984,715
TOTAL LIABILITIES		**4,217,555**	4,678,364
TOTAL EQUITY AND LIABILITIES		**4,776,616**	5,661,916

The attached notes 1 to 31 form part of these Group financial statements.

The financial statements were approved by the Board of Directors on 8 April 2020 and signed on its behalf by:

Jonathan Swinney
Chief Financial Officer

GROUP STATEMENT OF CHANGES IN EQUITY

For the year ended 31 December 2019

	Share capital and share premium $'000	Merger reserve $'000	Cash flow hedge reserve $'000	Share-based payments reserve $'000	Retained earnings $'000	Total $'000
Balance at 31 December 2017 (as previously reported)	210,402	662,855	36	(5,516)	(106,911)	760,866
Adjustment on adoption of IFRS 9 (see note 2)	–	–	–	–	(38,117)	(38,117)
Balance at 1 January 2018	210,402	662,855	36	(5,516)	(145,028)	722,749
Profit/(loss) for the year	–	–	–	–	127,278	127,278
Other comprehensive income	–	–	(36)	–	–	(36)
Total comprehensive income for the year	–	–	(36)	–	127,278	127,242
Issue of share capital	128,916	–	–	–	–	128,916
Share-based payment	–	–	–	4,645	–	4,645
Shares issued on behalf of Employee Benefit Trust	6,013	–	–	(6,013)	–	–
Balance at 31 December 2018 (as previously reported)	**345,331**	**662,855**	**–**	**(6,884)**	**(17,750)**	**983,552**
Adjustment on adoption of IFRS 9/IFRS 16 (see note 2)	**–**	**–**	**–**	**–**	**18,922**	**18,922**
Balance at 1 January 2019	**345,331**	**662,855**	**–**	**(6,884)**	**1,172**	**1,002,474**
Profit/(loss) for the year	**–**	**–**	**–**	**–**	**(449,301)**	**(449,301)**
Total comprehensive income for the year	**–**	**–**	**–**	**–**	**(449,301)**	**(449,301)**
Share-based payment	**–**	**–**	**–**	**5,888**	**–**	**5,888**
Shares issued on behalf of Employee Benefit Trust	**89**	**–**	**–**	**(89)**	**–**	**–**
Balance at 31 December 2019	**345,420**	**662,855**	**–**	**(1,085)**	**(448,129)**	**559,061**

The attached notes 1 to 31 form part of these Group financial statements.

GROUP STATEMENT OF CASH FLOWS

For the year ended 31 December 2019

	Notes	2019 $'000	2018 $'000
CASH FLOW FROM OPERATING ACTIVITIES			
Cash generated from operations	29	**994,618**	788,629
Cash received/(paid) on sale/(purchase) of financial instruments		**4,936**	(16,363)
Proceeds from exercise of Thistle decommissioning option		**–**	50,000
Decommissioning spend	23	**(11,131)**	(10,036)
Income taxes paid		**(26,152)**	(17,798)
Net cash flows from/(used in) operating activities		**962,271**	794,432
INVESTING ACTIVITIES			
Purchase of property, plant and equipment		**(234,241)**	(220,213)
Purchase of intangible oil and gas assets		**(3,241)**	–
Consideration on exercise of Magnus acquisition option		**–**	(100,000)
Repayment of Magnus contingent consideration – Profit share		**(21,581)**	–
Interest received		**1,225**	1,600
Net cash flows (used in)/from investing activities		**(257,838)**	(318,613)
FINANCING ACTIVITIES			
Proceeds from loans and borrowings		**–**	219,900
Repayment of loans and borrowings		**(394,025)**	(402,008)
Repayment of Magnus contingent consideration – Vendor loan		**(52,669)**	(48,642)
Gross proceeds from issue of shares		**–**	138,926
Shares purchased by Employee Benefit Trust		**–**	(6,013)
Share issue and debt restructuring costs paid		**–**	(3,997)
Repayment of obligations under leases	24	**(135,125)**	(144,820)
Interest paid		**(146,047)**	(136,482)
Other finance costs paid		**(2,130)**	(20,425)
Net cash flows from/(used in) financing activities		**(729,996)**	(403,560)
NET INCREASE/(DECREASE) IN CASH AND CASH EQUIVALENTS		**(25,563)**	72,258
Net foreign exchange on cash and cash equivalents		**6,562**	(4,726)
Cash and cash equivalents at 1 January		**237,200**	169,668
CASH AND CASH EQUIVALENTS AT 31 DECEMBER		**218,199**	237,200
Reconciliation of cash and cash equivalents			
Cash and cash equivalents per statement of cash flows		**218,199**	237,200
Restricted cash	14	**2,257**	3,404
Cash and cash equivalents per balance sheet		**220,456**	240,604

The attached notes 1 to 31 form part of these Group financial statements.

NOTES TO THE GROUP FINANCIAL STATEMENTS

For the year ended 31 December 2019

1. Corporate information

EnQuest PLC ('EnQuest' or the 'Company') is a limited liability company incorporated and registered in England and is listed on the London Stock Exchange and on the Stockholm NASDAQ OMX.

The principal activities of the Company and its subsidiaries (together the 'Group') are to enhance hydrocarbon recovery and extend the useful lives of mature and underdeveloped assets and associated infrastructure in a profitable and responsible manner.

The Group's financial statements for the year ended 31 December 2019 were authorised for issue in accordance with a resolution of the Board of Directors on 8 April 2020.

A listing of the Group's companies is contained in note 28 to these Group financial statements.

2. Summary of significant accounting policies

Basis of preparation

The Group financial information has been prepared in accordance with International Financial Reporting Standards ('IFRS') as adopted by the European Union as they apply to the financial statements of the Group for the year ended 31 December 2019 and applied in accordance with the Companies Act 2006. The accounting policies which follow set out those policies which apply in preparing the financial statements for the year ended 31 December 2019.

The Group financial information has been prepared on an historical cost basis, except for the fair value remeasurement of certain financial instruments, including derivatives, as set out in the accounting policies. The presentation currency of the Group financial information is US Dollars ('$') and all values in the Group financial information are rounded to the nearest thousand ($'000) except where otherwise stated.

The financial statements have been prepared on the going concern basis. The Directors' assessment of going concern concludes that the use of the going concern basis is appropriate and that the Directors have a reasonable expectation that the Group will be able to continue in operation and meet its commitments as they fall due over the going concern period.

The Group closely monitors and manages its funding position and liquidity risk throughout the year, including monitoring forecast covenant results, to ensure that it has access to sufficient funds to meet forecast cash requirements. Cash forecasts are regularly produced and sensitivities considered for, but not limited to, changes in crude oil prices (adjusted for hedging undertaken by the Group), production rates and costs. These forecasts and sensitivity analyses allow management to mitigate liquidity or covenant compliance risks in a timely manner. Management has also repaid the term loan on or ahead of schedule, with no further scheduled payments now due in 2020.

The Group is actively monitoring the impact on operations from COVID-19 and has implemented a number of mitigations to minimise the impact. The Group has been working with a variety of stakeholders, including industry and medical organisations, to ensure its operational response and advice to its workforce is appropriate and commensurate with the prevailing expert advice and level of risk. Appropriate restrictions on offshore travel have been implemented, such as self-declaration by, and isolation of, individuals who have been to affected areas and pre-mobilisation temperature checking is in operation. EnQuest's normal communicable disease process has been updated specifically in respect of COVID-19, with additional offshore isolation capability and agreements in place to transport impacted individuals back onshore in dedicated helicopters. Non-essential down-manning has been implemented, with many of the Group's onshore workforce working remotely.

While it is difficult to forecast the impact of COVID-19, at the time of publication of EnQuest's full year results, the Group's day-to-day operations continue without being materially affected.

The Group has reviewed each of its assets and related spending plans in light of the current lower oil price environment. EnQuest's updated working assumption is not to re-start production at the Heather and Thistle/Deveron fields. At the same time, the Group is implementing a material operating cost and capital expenditure reduction programme. This significantly lowers EnQuest's cost base and successful delivery of this programme is assumed in the Base case.

The Base case uses an oil price assumption of $40/bbl from March 2020 through to the end of the first quarter 2021, based on recent research analyst projections for the period. This has been sensitised under a plausible downside case ('Downside case'). The Base case and Downside case indicate that the Company is covenant compliant and able to operate within the headroom of its existing borrowing facilities for 12 months from the date of approval of the Annual Report and Accounts. Given the extreme volatility in current oil prices, the Directors have also performed reverse stress testing with the breakeven price for liquidity being c. $10/bbl.

The quarterly liquidity covenant in the facility (the "Liquidity Test") requires that the Group has sufficient funds available to meet all liabilities of the Group when due and payable for the period commencing on each quarter and ending on the date falling 12 months after the final maturity date which is 1 October 2021. The Liquidity Test assumptions include a price deck of the average forward curve oil price, minus a 10% discount, of 15 consecutive business days starting from approximately in the middle of the previous quarter. The Base case uses $45/bbl for the remainder of 2021, with a longer term price assumption of $60/bbl. Under these prices the Group forecasts no breaches in the Liquidity Test. Applying the 10% discount stipulated in the Liquidity Test and a further reduction in excess of 15% on Base case prices across all periods, the Group would breach this covenant, prior to any mitigations such as further cost reductions or other funding options. Given the extreme volatility in current oil prices, there is a risk of a potential covenant breach which would therefore require a covenant waiver to be obtained. The Directors are confident that obtaining waivers from the facility providers would be forthcoming. However, the risk of not obtaining a waiver represents a material uncertainty that may cast doubt upon the Group's ability to continue to apply the going concern basis of accounting.

Notwithstanding the material uncertainty described above, after making enquiries and assessing the progress against the forecast, projections and the status of the mitigating actions referred to above, the Directors have a reasonable expectation that the Group will continue in operation and meet its commitments as they fall due over the going concern period. Accordingly, the Directors continue to adopt the going concern basis in preparing the financial statements.

2. Summary of significant accounting policies (continued)

New standards and interpretations

The Group applied IFRS 16 Leases from 1 January 2019 and IFRS 9 Financial Instruments from 1 January 2018. The nature and effect of the changes as a result of adoption of these new accounting standards are described below. Other new standards are also effective from 1 January 2019 but they do not have a material effect on the Group's financial statements.

IFRS 16 Leases

The Group has adopted IFRS 16 Leases from 1 January 2019, using the modified retrospective method, which resulted in changes in accounting policies and opening balance sheet adjustments, as recognised in these financial statements. The comparative information has not been restated and continues to be reported under IAS 17 and IFRIC 4.

IFRS 16 introduces a single, on-balance sheet lease accounting model for lessees. As at 1 January 2019 for each identified lease, the Group has recognised a right-of-use asset, representing its right to use the underlying asset, and a lease liability, representing its obligation to make lease payments.

The Group has applied the practical expedient to grandfather the definition of a lease on transition. On application of IFRS 16, all contracts entered into before 1 January 2019 which had been identified as leases in accordance with IAS 17 are accounted for in line with IFRS 16. Contracts which have not been identified as a lease continue to be accounted for in line with their historical treatment. The Group has also elected to use the recognition exemptions proposed for lease contracts for which the lease terms ends within 12 months as of the date of initial application and lease contracts for which the underlying asset is of low value.

For leases within joint ventures, the Group has assessed on a lease-by-lease basis the facts and circumstances. This relates mainly to leases of vessels. Where all parties to a joint operation jointly have the right to control the use of the identified asset and all parties have a legal obligation to make lease payments to the lessor, the Group's share of the right-of-use asset and its share of the lease liability will be recognised on the Group balance sheet. This may arise in cases where the lease is signed by all parties to the joint operation or the joint operation partners are named within the lease. However, in cases where EnQuest is the only party with the legal obligation to make lease payments to the lessor, the full lease liability and right-of-use asset will be recognised on the Group balance sheet. This may be the case if, for example, EnQuest, as operator of the joint operation, is the sole signatory to the lease. If the underlying asset is used for the performance of the joint operating agreement, EnQuest will recharge the associated costs in line with the joint operating agreement.

At 1 January 2019, the Group recognised new right-of-use assets and lease liabilities of $60.5 million, mainly in relation to property and oil and gas vessels. This has decreased from $79.5 million reported in the half year condensed financial statements for the period ended 30 June 2019 due to recalculation of lease effective interest rates, decreasing the recognition value, and clarification on joint venture vessel leases held in Malaysia, resulting in the recognition of the leases increasing from the working interest percentage to 100% recognition as EnQuest is the only party with legal obligations. When measuring lease liabilities, the lease payments were discounted using the applicable company's incremental borrowing rate at 1 January 2019. The weighted-average incremental borrowing rate applied by EnQuest upon transition was 8.0%.

The difference between the IFRS 16 lease liability recognised at 1 January 2019, discounted at the Group's weighted-average incremental borrowing rate, versus those leases disclosed at 31 December 2018 under IAS 17 are driven by: identified operating leases at 31 December 2018 recognised as lease liability on transition; exempt leases (low-value and short-term); and extension options reasonably certain to be extended that were not included in the previously disclosed lease commitment.

The Group sub-leases part of Annan House, its Aberdeen office. The Group classifies the sub-lease as an operating lease, because it does not transfer substantially all the risks and rewards incidental to the ownership of the right-of-use asset. On the adoption of IFRS 16, the impact of the surplus lease provision held for Annan House was assessed and an adjustment for $2.3 million was taken through opening reserves and against the previously recognised provision. The Group will continue to assess the recovery of the asset and will take any provision for impairment directly to the right-of-use asset.

On 1 January 2019, the existing Kraken FPSO lease asset was transferred out of oil and gas assets and into right-of-use assets, at a net book value of $690.7 million. There was no change in the accounting policy for this existing lease on transition to IFRS 16.

The Group reassesses the judgements and estimates for leases as disclosed above at each reporting period, and has assessed, for the year ended 31 December 2019, these are not significant risks that could result in a material adjustment to the carrying amounts of assets and liabilities within the next financial year.

2. Summary of significant accounting policies (continued)

The following table shows the adjustment recognised for each individual line item. Line items that were not affected by the changes have not been included. The adjustments are recognised in the opening balance sheet on 1 January 2019.

Group balance sheet (extract)	1 January 2019 As originally presented $'000	Impact of change in accounting policy under IFRS 16 $'000	1 January 2019 Adjusted balance $'000
Non-current assets			
Property, plant and equipment			
Oil and Gas assets	4,331,719	(690,742)	3,640,977
Office furniture, fixtures and fittings	18,194	-	18,194
Right-of-use assets	-	751,269	751,269
Total	**4,349,913**	**60,527**	**4,410,440**
Equity			
Retained earnings	(17,750)	2,344	(15,406)
Non-current liabilities			
Obligations under leases	615,781	60,527	676,308
Current liabilities			
Obligations under leases	93,169	-	93,169
Surplus lease provision	2,344	(2,344)	-
Total	**693,544**	**60,527**	**754,071**

The adoption of IFRS 16 in the year ended 31 December 2019 resulted in an increase in depreciation of $9.0 million and finance costs of $4.7 million. Operating expenses decreased by $8.6 million.

IFRS 9 Financial Instruments
On 1 January 2018, the Group adopted the new accounting standard IFRS 9 Financial Instruments. This resulted in an accounting adjustment to opening reserves of $38.1 million; $22.7 million against the retail bond and $15.4 million against the high yield bond.

At 1 January 2019, upon review of further information and clarification, this adjustment was updated. This resulted in an accounting adjustment taken through opening reserves of $16.6 million and $33.4 million through the amortised value of the bonds (reduction of $18.9 million against the retail bond and $14.5 million against the high yield bond) offset by a charge of $16.6 million against the bond interest accrual. There was no change in effective interest rate. These adjustments have been taken through this year's financial statements. The Directors believe these adjustments are not material to the prior year financial statements and would not have a material influence on the users of the financial statements.

Group balance sheet (extract)	1 January 2019 (Post IFRS 16 adjustment) $'000	Impact of change in accounting policy under IFRS 9 $'000	1 January 2019 Adjusted balance $'000
Non-current liabilities			
Bonds	998,331	(33,407)	964,924
Trade and other payables: Bond accrual	-	16,596	16,596
Current liabilities			
Bonds	-	-	-
Trade and other payables: Bond accrual	16,810	-	16,810
Total	**1,015,141**	**(16,811)**	**998,330**
Equity			
Retained earnings (brought forward after impact of IFRS 16)	(15,406)	16,578	1,172
Profit and loss: Interest and foreign exchange in 2019	-	233	233
Total	**(15,406)**	**16,811**	**1,405**

Standards issued but not yet effective
Standards issued and relevant to the Group, but not yet effective up to the date of issuance of the Group's financial statements, are listed below. This listing is of standards and interpretations issued, which the Group reasonably expects to be applicable at a future date. The Group has not early adopted any standards, interpretations or amendments early and intends to adopt these standards when they become effective. The Directors do not anticipate that the adoption of these standards will have a material impact on the Group's financial statements in the period of initial application.

- Amendments to References to Conceptual Framework in IFRS Standards
- Definition of a Business (Amendments to IFRS 3)
- Definition of Material (Amendments to IAS 1 and IAS 8)

2. Summary of significant accounting policies (continued)

Basis of consolidation

The consolidated financial statements incorporate the financial statements of EnQuest PLC and entities controlled by the Company (its subsidiaries) made up to 31 December each year. Control is achieved when the Company:

- has power over the investee;
- is exposed, or has rights, to variable returns from its involvement with the investee; and
- has the ability to use its power to affect its returns.

The Company reassesses whether or not it controls an investee if facts and circumstances indicate that there are changes to one or more of the three elements of control listed above. Consolidation of a subsidiary begins when the Company obtains control over the subsidiary and ceases when the Company loses control of the subsidiary. Specifically, the results of subsidiaries acquired or disposed of during the year are included in profit or loss from the date the Company gains control until the date when the Company ceases to control the subsidiary.

Where necessary, adjustments are made to the financial statements of subsidiaries to bring the accounting policies used into line with the Group's accounting policies. All intragroup assets and liabilities, equity, income, expenses and cash flows relating to transactions between the members of the Group are eliminated on consolidation.

Joint arrangements

Oil and gas operations are usually conducted by the Group as co-licensees in unincorporated joint operations with other companies. Joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities require the consent of the relevant parties sharing control. The joint operating agreement is the underlying contractual framework to the joint arrangement, which is historically referred to as the joint venture ('JV'). The Annual Report and Accounts therefore refers to 'joint ventures' as standard terms used in the oil and gas industry, which is used interchangeably with joint operations.

Most of the Group's activities are conducted through joint operations, whereby the parties that have joint control of the arrangement have the rights to the assets, and obligations for the liabilities relating to the arrangement. The Group reports its interests in joint operations using proportionate consolidation – the Group's share of the production, assets, liabilities, income and expenses of the joint operation are combined with the equivalent items in the consolidated financial statements on a line-by-line basis. During 2019, the Group did not have any material interests in joint ventures or in associates.

Foreign currencies

Items included in the financial statements of each of the Group's entities are measured using the currency of the primary economic environment in which the entity operates (functional currency). The Group's financial statements are presented in US Dollars, the currency which the Group has elected to use as its presentation currency.

In the accounts of the Company and its individual subsidiaries, transactions in currencies other than a company's functional currency are recorded at the prevailing rate of exchange on the date of the transaction. At the year end, monetary assets and liabilities denominated in foreign currencies are retranslated at the rates of exchange prevailing at the balance sheet date. Non-monetary assets and liabilities that are measured at historical cost in a foreign currency are translated using the rate of exchange at the dates of the initial transactions. Non-monetary assets and liabilities measured at fair value in a foreign currency are translated using the rate of exchange at the date the fair value was determined. All foreign exchange gains and losses are taken to profit and loss in the statement of comprehensive income.

Critical accounting judgements

The Group assesses critical accounting judgements annually. The following are the critical judgements, apart from those involving estimations which are dealt with in the policy 'Key sources of estimation uncertainty' below, that the Directors have made in the process of applying the Group's accounting policies, which have the most significant effect on the amounts recognised in the financial statements.

Oil and gas reserves

The business of the Group is to enhance hydrocarbon recovery and extend the useful lives of mature and underdeveloped assets and associated infrastructure in a profitable and responsible manner. The process in determining the estimates of oil and gas reserves requires critical judgement. The judgements, which inform the estimates of oil and gas reserves, result in different future production profiles affecting prospectively the discounted cash flows used in impairment testing and the calculation of contingent consideration, the anticipated date of decommissioning and the depletion charges in accordance with the unit of production method, as well as the going concern assessment.

The Group uses proven and probable ('2P') reserves (see page 26) in calculations based on expected future cash flows from underlying assets. Third-party audits of EnQuest's reserves and resources are conducted annually.

Key sources of estimation uncertainty

The key sources of estimation uncertainty concerning the future, and other major sources of estimation uncertainty at the end of the reporting period, that have a significant risk of resulting in a material adjustment to the carrying amounts of assets and liabilities within the next financial year are discussed below:

Future oil prices

Future oil prices are a key driver of estimation affecting several areas of the financial statements. Oil and gas price assumptions are reviewed and, where necessary, adjusted on a periodic basis. The estimates take into account existing prices, historical trends and variability and other macroeconomic factors. Review includes benchmarking and analysis against forward curves from available market data and other third-party forecasts, as well as review and challenge by the Audit Committee.

A reduction or increase in future oil prices of 10%, based on the approximate volatility of historical oil prices, are considered to be reasonably possible changes for the purposes of sensitivity analysis.

Oil price assumptions based on an internal view of forward curve prices at 31 December 2019 are $63.0/bbl (2020), $65.0/bbl (2021), $67.0/bbl (2022) and $70.0/bbl real thereafter, inflated at 2.0% per annum from 2024 (2018: $60.0/bbl (2019), $65.0/bbl (2020), $65.0/bbl (2021) and $75.0/bbl real thereafter).

2. Summary of significant accounting policies (continued)

Impairment testing of oil and gas assets and goodwill and valuation of Magnus contingent consideration
Determination of whether oil and gas assets or goodwill have suffered any impairment requires an estimation of the fair value less costs to dispose of the cash generating units ('CGU') to which oil and gas assets and goodwill have been allocated. The calculation requires the entity to estimate the future cash flows expected to arise from the CGU using discounted cash flow models comprising asset-by-asset life of field projections using Level 3 inputs (based on the IFRS 13 fair value hierarchy).

Determination of the Magnus contingent consideration valuation requires an estimation of the fair value less costs to dispose of the cash generating unit, the Magnus asset. The calculation requires the entity to estimate the future cash flows expected to arise from the CGU using discounted cash flow models comprising the asset life of field projections using Level 3 inputs (based on the IFRS 13 fair value hierarchy).

Key assumptions and estimates used in the impairment and contingent consideration models are stated in 'Key assumptions used in calculations' below. As the production and related cash flows can be estimated from EnQuest's experience, management believes that the estimated cash flows expected to be generated over the life of each field are the appropriate basis upon which to assess goodwill and individual assets for impairment.

Decommissioning provision
Provisions for decommissioning and restoration costs are estimates based on current legal and constructive requirements, current technology and price levels for the removal of facilities and plugging and abandoning of wells. These parameters are based on information and estimates deemed to be appropriate by the Group at the current time. The present value is calculated using amounts discounted over the useful economic life of the assets. The effect of changes resulting from these items, along with the change in expected timing, work scope and amount of expenditure, to the timing or the amount of the original estimate of the decommissioning provision, could result in a material adjustment of these provisions and is reflected on a prospective basis. Due to the significant estimates and assumptions, the carrying amounts of decommissioning provisions are reviewed on a regular basis.

In estimating decommissioning provisions, the Group applies an annual inflation rate of 2.0% (2018: 2.0%) and an annual discount rate of 2.0% (2018: 2.0%).

Deferred taxation
The Group recognises deferred tax assets on unused tax losses where it is probable that future taxable profits will be available for utilisation. This requires management to make assumptions and estimates relating to future oil prices and oil and gas reserves (as discussed above) and the estimated future costs, to assess the amount of deferred tax that can be recognised.

Key assumptions used in calculations
The key assumptions required for the calculation of the discounted cash flow models are:
- Oil prices (see above);
- Oil and gas reserves (see above);
- Production profiles based on life of field internal estimates including assumptions on performance of assets;
- Related life of field opex, capex and decommissioning costs derived from the Group's Business Plan adjusted for changes in timing based on the production profiles used as above;
- Discount rates driven by the Group's post-tax weighted average cost of capital; and
- Currency exchange rates based on management's estimate of future prices.

The discount rate reflects management's estimate of the Group's weighted average cost of capital ('WACC'). The WACC takes into account both debt and equity. The cost of equity is derived from the expected return on investment by the Group's investors. The cost of debt is based on its interest-bearing borrowings. Segment risk is incorporated by applying a beta factor based on publicly available market data. The post-tax discount rate applied to the Group's post-tax cash flow projections was 10.0% (2018: 10.0%). Management considers this to be the best estimate of a market participant's discount rate.

3. Segment information

Management has considered the requirements of IFRS 8 Operating Segments in regard to the determination of operating segments and concluded that the Group has two significant operating segments: the UK ('North Sea') and Malaysia. Operations are managed by location and all information is presented per geographical segment. The information reported to the Chief Operating Decision Maker does not include an analysis of assets and liabilities, and accordingly this information is not presented.

Year ended 31 December 2019 $'000	**North Sea**	**Malaysia**	**All other segments**	**Total segments**	**Adjustments and eliminations(i)**	**Consolidated**
Revenue:						
Revenue from contracts with customers	**1,530,343**	**145,749**	**–**	**1,676,092**	**–**	**1,676,092**
Other income	**10,500**	**–**	**486**	**10,986**	**(40,619)**	**(29,633)**
Total revenue	**1,540,843**	**145,749**	**486**	**1,687,078**	**(40,619)**	**1,646,459**
Income/(expenses):						
Depreciation and depletion	**(518,785)**	**(14,490)**	**(77)**	**(533,352)**	**–**	**(533,352)**
Net impairment (charge)/reversal to oil and gas assets	**(812,448)**	**–**	**–**	**(812,448)**	**–**	**(812,448)**
Impairment of investments	**(20)**	**–**	**–**	**(20)**	**–**	**(20)**
Exploration write offs and impairments	**(150)**	**–**	**–**	**(150)**	**–**	**(150)**
Segment profit/(loss)(ii)	**(470,351)**	**49,429**	**(4,142)**	**(425,064)**	**(42,704)**	**(467,768)**
Other disclosures:						
Capital expenditure(iii)	**164,818**	**15,837**	**–**	**180,655**	**–**	**180,655**

Year ended 31 December 2018 $'000	North Sea	Malaysia	All other segments	Total segments	Adjustments and eliminations(i)	Consolidated
Revenue:						
Revenue from contracts with customers	1,140,116	144,483	–	1,284,599	–	1,284,599
Other income	9,046	–	395	9,441	4,397	13,838
Total revenue	1,149,162	144,483	395	1,294,040	4,397	1,298,437
Income/(expenses):						
Depreciation and depletion	(411,624)	(30,767)	–	(442,391)	–	(442,391)
Net impairment (charge)/reversal to oil and gas assets	(125,009)	(1,037)	–	(126,046)	–	(126,046)
Impairment reversal of investments	(121)	–	–	(121)	–	(121)
Exploration write offs and impairments	(1,407)	–	–	(1,407)	–	(1,407)
Segment profit/(loss)(ii)	276,365	38,442	5,839	320,646	6,092	326,738
Other disclosures:						
Capital expenditure(iii)	167,070	15,806	–	182,876	–	182,876

(i) Finance income and costs and gains and losses on derivatives are not allocated to individual segments as the underlying instruments are managed on a Group basis
(ii) Inter-segment revenues are eliminated on consolidation. All other adjustments are part of the reconciliations presented further below
(iii) Capital expenditure consists of property, plant and equipment and intangible assets, including assets from the acquisition of subsidiaries

Reconciliation of profit/(loss):

	Year ended 31 December 2019 $'000	Year ended 31 December 2018 $'000
Segment profit/(loss)	**(425,064)**	320,646
Finance income	**2,416**	3,389
Finance expense	**(263,761)**	(236,142)
Gain/(loss) on oil and foreign exchange derivatives	**(42,704)**	6,092
Profit/(loss) before tax	**(729,113)**	93,985

Revenue from three customers relating to the North Sea operating segment each exceeds 10% of the Group's consolidated revenue arising from sales of crude oil, with amounts of $307.1 million, $266.1 million and $211.0 million per each single customer (2018: two customers; total of $580.5 million arising in the North Sea operating segment).

All of the Group's segment assets (non-current assets excluding financial instruments, deferred tax assets and other financial assets) are located in the United Kingdom except for $122.1 million located in Malaysia (2018: $111.7 million).

4. Remeasurements and exceptional items

Accounting policy
As permitted by IAS 1 (Revised): Presentation of Financial Statements, certain items of income or expense which are material are presented separately. Additional line items, headings, sub-totals and disclosures of nature and amount are presented to provide relevant understanding of the Group's financial performance.

The items that the Group separately presents as exceptional on the face of the statement of comprehensive income are those material items of income and expense which, because of the nature or expected infrequency of the events giving rise to them, merit separate presentation to allow shareholders to understand better the elements of financial performance in the year, so as to facilitate comparison with prior periods and to better assess trends in financial performance. Remeasurements relate to those items which are remeasured on a periodic basis and are applied consistently year-on-year. If an item is assessed as a remeasurement or exceptional item, then subsequent accounting to completion of the item is also taken through remeasurement and exceptional items. Management has exercised judgement in assessing the relevant material items disclosed as exceptional.

The following items are classified as remeasurements and exceptional items ('exceptional'):
- Unrealised mark-to-market changes in the remeasurement of open derivative contracts at each period end are recognised within remeasurements, with the recycling of realised amounts from remeasurements into Business performance income when a derivative instrument matures. Option premiums received or paid for commodity derivatives are recognised in remeasurements and amortised over the period of the option into Business performance revenue;
- Impairments on assets are remeasurements and are deemed to be exceptional in nature. Other non-routine write-offs/write-downs, where deemed material;
- Fair value accounting arising in relation to business combinations is deemed as exceptional in nature, as these transactions do not relate to the principal activities and day-to-day Business performance of the Group. The subsequent remeasurement of contingent assets and liabilities arising on acquisitions, including contingent consideration, are presented within remeasurements and are presented consistently year-on-year; and
- Other items that arise from time to time that are reviewed by management as non-Business performance and are disclosed further below.

Year ended 31 December 2019 $'000	**Fair value remeasurement(i)**	**Impairments and write offs(ii)**	**Other(iii)**	**Total**
Revenue and other operating income	**(65,375)**	**–**	**–**	**(65,375)**
Cost of sales	**(378)**	**–**	**–**	**(378)**
Net impairment (charge)/reversal on oil and gas assets	**–**	**(812,448)**	**–**	**(812,448)**
Other expenses	**(15,520)**	**(170)**	**(16,045)**	**(31,735)**
Finance costs	**–**	**–**	**(57,165)**	**(57,165)**
	(81,273)	**(812,618)**	**(73,210)**	**(967,101)**
Tax on items above	**31,735**	**250,235**	**21,490**	**303,460**
	(49,538)	**(562,383)**	**(51,720)**	**(663,641)**

Year ended 31 December 2018 $'000	Fair value remeasurement(i)	Impairments and write offs(ii)	Other(iii)	Total
Revenue and other operating income	97,432	–	–	97,432
Cost of sales	2,310	(592)	–	1,718
Net impairment (charge)/reversal on oil and gas assets	–	(126,046)	–	(126,046)
Other income	–	–	78,316	78,316
Other expenses	(9,590)	(1,528)	(3,597)	(14,715)
Finance costs	–	–	(28)	(28)
	90,152	(128,166)	74,691	36,677
Tax on items above	(36,962)	48,161	1,207	12,406
	53,190	(80,005)	75,898	49,083

(i) Fair value remeasurements include unrealised mark-to-market movements on derivative contracts and other financial instruments and the impact of recycled realised gains and losses (including option premiums) out of 'Remeasurements and exceptional items' and into Business performance profit or loss of $65.8 million. Other expenses relate to the fair value remeasurement of contingent consideration relating to the acquisition of Magnus and associated infrastructure of $15.5 million (note 22) (2018: $9.7 million)

(ii) Impairments and write offs include an impairment of tangible oil and gas assets totalling $637.5 million (note 10) (2018: impairment of $126.0 million), impairment of goodwill of $149.6 million (note 11) and impairment of intangible oil and gas assets totalling $25.4 million (note 12) (2018: $0.4 million)

(iii) Other expenses mainly relate to the provision for settlement of the historical KUFPEC claim of $15.6 million (2018: Net other income includes $74.3 million in relation to the step acquisition uplift of the original 25% equity acquired in 2017 and $1.3 million loss in relation to the revaluation of the option to purchase the Magnus oil field and other interests). Other finance costs mainly relate to the unwinding of contingent consideration from the acquisition of Magnus and associated infrastructure of $57.2 million

5. Revenue and expenses

(a) Revenue and other revenue

Accounting policy

Revenue from contracts with customers
The Group generates revenue through the sale of crude oil, gas and condensate to third parties, and through the provision of infrastructure to its customers for tariff income. Revenue from contracts with customers is recognised when control of the goods or services is transferred to the customer at an amount that reflects the consideration to which the Group expects to be entitled to in exchange for those goods or services. The Group has concluded that it is the principal in its revenue arrangements because it typically controls the goods or services before transferring them to the customer. The normal credit term is 30 to 90 days upon performance of the obligation.

Sale of crude oil, gas and condensate
The Group sells crude oil, gas and condensate directly to customers. The sale represents a single performance obligation, being the sale of barrels equivalent to the customer on taking physical possession or on delivery of the commodity into an infrastructure. At this point the title passes to the customer and revenue is recognised. The Group principally satisfies its performance obligations at a point in time; the amounts of revenue recognised relating to performance obligations satisfied over time are not significant. Transaction prices are referenced to quoted prices, plus or minus an agreed discount rate, if applicable.

Tariff revenue for the use of Group infrastructure
Tariffs are charged to customers for the use of infrastructure owned by the Group. The revenue represents the performance of an obligation for the use of Group assets over the life of the contract. The use of the assets is not separable as they are interdependent in order to fulfil the contract and no one item of infrastructure can be individually isolated. Revenue is recognised as the performance obligations are satisfied over the period of the contract, generally a period of 12 months or less, on a monthly basis based on throughput at the agreed contracted rates.

Other revenue
Other revenue includes rental income, which is recognised to the extent that it is probable economic benefits will flow to the Group and the revenue can be reliably measured.

The Group manages the risk of change in underlying market prices through the use of commodity derivative contracts, which are financial instruments designated at fair value through profit or loss (see note 15).

	Year ended 31 December 2019 $'000	Year ended 31 December 2018 $'000
Revenue from contracts with customers:		
Revenue from crude oil sales	**1,548,177**	1,237,600
Revenue from gas and condensate sales	**120,242**	43,063
Tariff revenue	**7,673**	3,936
Total revenue from contracts with customers	**1,676,092**	1,284,599
Rental income	**7,082**	7,205
Realised (losses)/gains on oil derivative contracts (see note 19)	**24,756**	(93,035)
Other operating revenue	**3,904**	2,236
Business performance revenue	**1,711,834**	1,201,005
Unrealised (losses)/gains on oil derivative contracts[(i)] (see note 19)	**(65,375)**	97,432
Total revenue and other operating income	**1,646,459**	1,298,437

(i) Unrealised gains and losses on oil derivative contracts are disclosed as fair value remeasurement items in the income statement (see note 4)

Disaggregation of revenue from contracts with customers

	Year ended 31 December 2019 $'000		Year ended 31 December 2018 $'000	
	North Sea	**Malaysia**	North Sea	Malaysia
Revenue from contracts with customers:				
Revenue from crude oil sales	**1,405,956**	**142,221**	1,096,581	141,019
Revenue from gas and condensate sales	**116,714**	**3,528**	39,599	3,464
Tariff revenue	**7,673**	**–**	3,936	–
Total revenue from contracts with customers	**1,530,343**	**145,749**	1,140,116	144,483

Contract balances
The following table provides information about receivables from contracts with customers. There are no contract assets or contract liabilities.

	2019 $'000	2018 $'000
Trade receivables (see note 16)	**117,149**	69,857

5. Revenue and expenses (continued)

(b) Cost of sales

Accounting policy

Production imbalances, movements in under/over-lift and movements in inventory are included in cost of sales. The under or over-lifted positions of hydrocarbons arising from production and lifting imbalances are valued at the lower of cost or net realisable value ('NRV') at the balance sheet date. An under-lift of production from a field is included in current receivables and an over-lift of production from a field is included in current liabilities.

	Year ended 31 December 2019 $'000	Year ended 31 December 2018 $'000
Production costs	**441,624**	396,880
Tariff and transportation expenses	**74,782**	68,446
Realised loss/(gain) on derivative contracts related to operating costs (see note 19)	**1,707**	615
Change in lifting position	**96,886**	(14,332)
Crude oil inventory movement	**5,967**	(10,761)
Depletion of oil and gas assets (see note 10)	**525,145**	437,104
Other cost of operations	**97,459**	48,068
Business performance cost of sales	**1,243,570**	926,020
Unrealised (gains)/losses on derivative contracts related to operating costs (i) (see note 19)	**378**	(2,310)
Other expenses	**–**	592
Total cost of sales	**1,243,948**	924,302

(i) Unrealised gains and losses on derivative contracts are disclosed as fair value remeasurement in the income statement (see note 4)

(c) General and administration expenses

	Year ended 31 December 2019 $'000	Year ended 31 December 2018 $'000
Staff costs (see note 5(f))	**90,764**	91,113
Depreciation (see note 10)	**8,207**	5,287
Other general and administration costs	**23,094**	32,764
Recharge of costs to operations and joint venture partners	**(114,404)**	(125,146)
Total general and administration expenses	**7,661**	4,018

(d) Other income

	Year ended 31 December 2019 $'000	Year ended 31 December 2018 $'000
Net foreign exchange gains	**–**	21,911
Other income	**3,446**	517
Business performance other income	**3,446**	22,428
Excess of fair value over consideration: Purchase option (see note 30)	**–**	(1,329)
Fair value gain on step acquisition (see note 30)	**–**	74,345
Contingent consideration release	**–**	5,300
Total other income	**3,446**	100,744

(e) Other expenses

	Year ended 31 December 2019 $'000	Year ended 31 December 2018 $'000
Net foreign exchange losses	**16,427**	–
Other	**5,454**	3,362
Business performance other expenses	**21,881**	3,362
Fair value changes in contingent consideration (see note 22)	**15,520**	9,590
Settlement provision (see note 23)	**15,630**	–
Write down of receivable	**415**	3,010
Exploration and evaluation expenses: Written off and impaired	**150**	1,407
Other expenses	**20**	708
Total other expenses	**53,616**	18,077

5. Revenue and expenses (continued)

(f) Staff costs

Accounting policy

Short-term employee benefits such as salaries, social premiums and holiday pay, are expensed when incurred. The Group's pension obligations consist of defined contribution plans. The Group pays fixed contributions with no further payment obligations once the contributions have been paid. The amount charged to the statement of comprehensive income in respect of pension costs reflects the contributions payable in the year. Differences between contributions payable during the year and contributions actually paid are shown as either accrued liabilities or prepaid assets in the balance sheet.

	Year ended 31 December 2019 $'000	Year ended 31 December 2018 $'000
Wages and salaries	**122,068**	104,781
Social security costs	**12,472**	10,278
Defined contribution pension costs	**12,491**	11,764
Expense of share-based payments (see note 21)	**5,888**	4,645
Other staff costs	**5,563**	4,731
Total employee costs	**158,482**	136,199
Contractor costs	**16,565**	16,724
Total staff costs	**175,047**	152,923
General and administration staff costs (see note 5(c))	**90,764**	91,113
Non general and administration costs	**84,283**	61,810
Total staff costs	**175,047**	152,923

The average number of persons employed by the Group during the year was 958, with 467 in the general and administration staff costs and 491 directly attributable to assets (2018: 839, 448 in general and administration and 391 directly attributable to assets).

(g) Auditor's remuneration

The following amounts were payable by the Group to its auditor, Ernst & Young LLP, during the year:

	Year ended 31 December 2019 $'000	Year ended 31 December 2018 $'000
Fees payable to the Company's auditor for the audit of the parent company and Group financial statements	**682**	721
Fees payable to the Company's auditor and its associates for other services:		
The audit of the Company's subsidiaries	**176**	108
Audit related assurance services (interim review)	**136**	134
Tax advisory services	**12**	5
Corporate finance services[(i)]	**–**	368
	324	615
Total auditor's remuneration	**1,006**	1,336

(i) Relates to reporting accountant's report on the unaudited pro forma financial information in the Company's combined prospectus and circular for the rights issue

6. Finance costs/income

Accounting policy

Borrowing costs are recognised as interest payable within finance costs in accordance with the effective interest method.

	Year ended 31 December 2019 $'000	Year ended 31 December 2018 $'000
Finance costs:		
Loan interest payable	**67,749**	93,413
Bond interest payable	**62,694**	64,243
Unwinding of discount on decommissioning provisions (see note 23)	**13,410**	12,617
Unwinding of discount on other provisions (see note 23)	**671**	917
Unwinding of discount on financial liabilities (see note 19(f))	**–**	72
Fair value (gain)/loss on financial instruments at FVPL (see note 19(b))	**–**	353
Finance charges payable under leases	**55,686**	55,837
Amortisation of finance fees on loans and bonds	**5,727**	8,525
Other financial expenses	**2,055**	1,666
	207,992	237,643
Less: amounts capitalised to the cost of qualifying assets	**(1,396)**	(1,529)
Business performance finance expenses	**206,596**	236,114
Unwinding of discounts on contingent consideration (see note 22)	**57,165**	28
Total finance costs	**263,761**	236,142
Finance income:		
Bank interest receivable	**1,511**	1,821
Unwinding of discount on financial asset (see note 19(f))	**905**	1,517
Other financial income	**–**	51
Total finance income	**2,416**	3,389

7. Income tax
(a) Income tax

Accounting policy
Current tax assets and liabilities are measured at the amount expected to be recovered from or paid to the taxation authorities, based on tax rates and laws that are enacted or substantively enacted by the balance sheet date.

The Group's operations are subject to a number of specific tax rules which apply to exploration, development and production. In addition, the tax provision is prepared before the relevant companies have filed their tax returns with the relevant tax authorities and, significantly, before these have been agreed. As a result of these factors, the tax provision process necessarily involves the use of a number of estimates and judgements including those required in calculating the effective tax rate. In considering the tax on exceptional items, the Group applies the appropriate statutory tax rate to each item to calculate the relevant tax charge on exceptional items.

Deferred tax is provided in full on temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the Group financial statements. However, deferred tax is not accounted for if it arises from initial recognition of an asset or liability in a transaction other than a business combination that at the time of the transaction affects neither accounting nor taxable profit or loss. Deferred tax is measured on an undiscounted basis using tax rates (and laws) that have been enacted or substantively enacted by the balance sheet date and are expected to apply when the related deferred tax asset is realised or the deferred tax liability is settled. Deferred tax assets are recognised to the extent that it is probable that future taxable profits will be available against which the temporary differences can be utilised.

Deferred tax liabilities are recognised for taxable temporary differences arising on investments in subsidiaries, except where the Group is able to control the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future.

The carrying amount of deferred income tax assets is reviewed at each balance sheet date. Deferred income tax assets and liabilities are offset only if a legal right exists to offset current tax assets against current tax liabilities, the deferred income taxes relate to the same taxation authority and that authority permits the Group to make a single net payment.

Production taxes
In addition to corporate income taxes, the Group's financial statements also include and disclose production taxes on net income determined from oil and gas production.

Production tax relates to Petroleum Revenue Tax ('PRT') within the UK and is accounted for under IAS 12 Income Taxes since it has the characteristics of an income tax as it is imposed under Government authority and the amount payable is based on taxable profits of the relevant fields. Current and deferred PRT is provided on the same basis as described above for income taxes.

Investment allowance
The UK taxation regime provides for a reduction in ring-fence supplementary charge tax where investment in new or existing UK assets qualify for a relief known as investment allowance. Investment allowance must be activated by commercial production from the same field before it can be claimed. The Group has both unactivated and activated investment allowance which could reduce future supplementary charge taxation. The Group's policy is that investment allowance is recognised as a reduction in the charge to taxation in the years claimed.

The major components of income tax (credit)/expense are as follows:

	Year ended 31 December 2019 $'000	Year ended 31 December 2018 $'000
Current income tax		
Current income tax charge	**354**	17,764
Adjustments in respect of current income tax of previous years	**(745)**	–
Current overseas income tax		
Current income tax charge	**20,894**	16,048
Adjustments in respect of current income tax of previous years	**(4,102)**	420
Total current income tax	**16,401**	34,232
Deferred income tax		
Relating to origination and reversal of temporary differences	**(277,198)**	(61,879)
Adjustments in respect of changes in tax rates	**–**	(4,404)
Adjustments in respect of deferred income tax of previous years	**(21,309)**	(2,304)
Deferred overseas income tax		
Relating to origination and reversal of temporary differences	**(953)**	612
Adjustments in respect of deferred income tax of previous years	**3,247**	450
Total deferred income tax	**(296,213)**	(67,525)
Income tax (credit)/expense reported in profit or loss	**(279,812)**	(33,293)

7. Income tax (continued)

(b) Reconciliation of total income tax charge

A reconciliation between the income tax charge and the product of accounting profit multiplied by the UK statutory tax rate is as follows:

	Year ended 31 December 2019 $'000	Year ended 31 December 2018 $'000
Profit/(loss) before tax	**(729,113)**	93,985
Statutory rate of corporation tax in the UK of 40% (2018: 40%)	**(291,645)**	37,594
Supplementary corporation tax non-deductible expenditure	**18,593**	20,284
Non-deductible expenditure/income[(i)]	**89,746**	(21,689)
Petroleum Revenue Tax (net of income tax benefit)	**–**	–
North Sea tax reliefs	**(84,273)**	(64,228)
Tax in respect of non ring-fence trade	**4,940**	691
Tax losses not recognised	**6,329**	1,509
Deferred tax rate changes	**–**	(4,404)
Adjustments in respect of prior years	**(22,909)**	(1,434)
Overseas tax rate differences	**(1,064)**	(673)
Share-based payments	**2,013**	899
Other differences	**(1,542)**	(1,842)
At the effective income tax rate of 38% (2018: 35%)	**(279,812)**	(33,293)

(i) The 2019 charge (2018: credit) is mainly due to the non-taxable expense (2018: income) in relation to the goodwill and non-taxable fair value movements on the acquisition of the 75% interest in the Magnus oil field; this is netted against the non-tax deductible depreciation on fixed assets

(c) Deferred income tax

Deferred income tax relates to the following:

	Group balance sheet		(Credit)/charge for the year recognised in profit or loss	
	2019 $'000	2018 $'000	**2019 $'000**	2018 $'000
Deferred tax liability				
Accelerated capital allowances	**1,057,805**	1,400,956	**(343,152)**	93,196
	1,057,805	1,400,956		
Deferred tax asset				
Losses	**(1,102,534)**	(1,212,988)	**110,455**	15,046
Decommissioning liability	**(284,057)**	(267,954)	**(16,103)**	(13,946)
Other temporary differences	**(226,333)**	(178,920)	**(47,413)**	(161,821)
	(1,612,924)	(1,659,862)		
Deferred tax expense			**(296,213)**	(67,525)
Net deferred tax (assets)/liabilities	**(555,119)**	(258,906)		
Reflected in the balance sheet as follows:				
Deferred tax assets	**(576,038)**	(286,721)		
Deferred tax liabilities	**20,919**	27,815		
Net deferred tax (assets)/liabilities	**(555,119)**	(258,906)		

Reconciliation of net deferred tax assets/(liabilities)

	2019 $'000	2018 $'000
At 1 January	**258,906**	335,578
Tax income/(expense) during the period recognised in profit or loss	**296,213**	67,525
Deferred taxes acquired	–	(144,197)
At 31 December	**555,119**	258,906

(d) Tax losses

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 tax losses and allowances in the UK can be utilised. All of the Group's ring-fence deferred tax assets are recognised as there are sufficient future profits forecast to utilise them fully. In accordance with IAS 12 Income Taxes, the Group assesses the recoverability of its deferred tax assets at each period end. Sensitivities have been run on the oil price assumption, with a 10% change being considered to be a reasonable possible change for the purposes of sensitivity analysis (see note 2). A 10% reduction in oil price would result in no change in the full recognition of deferred taxes, with headroom still available.

The Group has unused UK mainstream corporation tax losses of $297.8 million (2018: $287.5 million) for which no deferred tax asset has been recognised at the balance sheet date due to uncertainty of the creation of non ring-fence profits and therefore uncertainty over the recovery of these losses. In addition the Group has not recognised a deferred tax asset for the adjustment to bond valuations on the adoption of IFRS 9 (see note 2). The benefit of this deduction is taken over ten years with a deduction of $3.8 million being taken in the current period with the remaining benefit of $30.5 million remaining unrecognised.

The Group has unused Malaysian income tax losses of $12.2 million (2018: $9.4 million) arising in respect of the Tanjong Baram RSC for which no deferred tax asset has been recognised at the balance sheet date due to uncertainty of recovery of these losses.

No deferred tax has been provided on unremitted earnings of overseas subsidiaries, Finance Act 2009 exempted foreign dividends from the scope of UK corporation tax where certain conditions are satisfied.

7. Income tax (continued)

(e) Changes in legislation

Finance Act 2016 enacted a change in the mainstream corporation tax rate to 17% with effect from 1 April 2020. In the Budget statement on 11 March 2020 it was announced that the corporation tax rate will remain at 19% from 1 April 2020. As all UK mainstream corporation tax losses are not recognised there is no impact on the current year resulting from this change.

8. Earnings per share

The calculation of earnings per share is based on the profit after tax and on the weighted average number of Ordinary shares in issue during the period. Diluted earnings per share is adjusted for the effects of Ordinary shares granted under the share-based payment plans, which are held in the Employee Benefit Trust.

Basic and diluted earnings per share are calculated as follows:

	Profit/(loss) after tax		Weighted average number of Ordinary shares		Earnings per share	
	Year ended 31 December		Year ended 31 December		Year ended 31 December	
	2019 $'000	2018 $'000	**2019 million**	2018(i) million	**2019 $**	2018(i) $
Basic	**(449,301)**	127,278	**1,640.1**	1,381.8	**(0.274)**	0.092
Dilutive potential of Ordinary shares granted under share-based incentive schemes	**–**	–	**14.7**	37.8	**–**	(0.002)
Diluted	**(449,301)**	127,278	**1,654.8**	1,419.6	**(0.274)**	0.090
Basic (excluding exceptional items)	**214,340**	78,195	**1,640.1**	1,381.8	**0.131**	0.057
Diluted (excluding exceptional items)	**214,340**	78,195	**1,654.8**	1,419.6	**0.130**	0.055

(ii) Restated to reflect the recalculated weighted average number of Ordinary shares as a result of the 2018 rights issue

9. Dividends paid and proposed

The Company paid no dividends during the year ended 31 December 2019 (2018: none). At 31 December 2019, there are no proposed dividends (2018: none).

10. Property, plant and equipment

Accounting policy

Property, plant and equipment is stated at cost less accumulated depreciation and accumulated impairment charges.

Cost

Cost comprises the purchase price or cost relating to development, including the construction, installation and completion of infrastructure facilities such as platforms, pipelines and development wells and any other costs directly attributable to making that asset capable of operating as intended by management. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset.

The carrying amount of an item of property, plant and equipment is derecognised on disposal or when no future economic benefits are expected from its use. The gain or loss arising from the derecognition of an item of property, plant and equipment is included in the other operating income line item in the consolidated income statement when the asset is derecognised.

Development assets

Expenditure relating to development of assets including the construction, installation and completion of infrastructure facilities such as platforms, pipelines and development wells, is capitalised within property, plant and equipment.

Carry arrangements

Where amounts are paid on behalf of a carried party these are capitalised. Where there is an obligation to make payments on behalf of a carried party and the timing and amount are uncertain, a provision is recognised. Where the payment is a fixed monetary amount, a financial liability is recognised.

Borrowing costs

Borrowing costs directly attributable to the construction of qualifying assets, which are assets that necessarily take a substantial period of time to prepare for their intended use, are capitalised during the development phase of the project until such time as the assets are substantially ready for their intended use.

Depletion and depreciation

Oil and gas assets are depleted, on a field-by-field basis, using the unit of production method based on entitlement to proven and probable reserves, taking account of estimated future development expenditure relating to those reserves. Changes in factors which affect unit of production calculations are dealt with prospectively. Depletion of oil and gas assets is taken through cost of sales.

Depreciation on other elements of property, plant and equipment is provided on a straight-line basis, and taken through general and administration expenses, at the following rates:

Office furniture and equipment	Five years
Fixtures and fittings	Ten years
Right-of-use assets	Period of lease

Each asset's estimated useful life, residual value and method of depreciation are reviewed and adjusted if appropriate at each financial year end. No depreciation is charged on assets under construction.

10. Property, plant and equipment (continued)

Impairment of tangible and intangible assets (excluding goodwill)
At each balance sheet date, the Group reviews the carrying amounts of its oil and gas assets at field level basis to assess whether there is an indication that those assets may be impaired. If any such indication exists, the Group makes an estimate of the asset's recoverable amount. An asset's recoverable amount is the higher of its fair value less costs of disposal and its value in use. Discounted cash flow models comprising asset-by-asset life of field projections and risks specific to assets, using Level 3 inputs (based on IFRS 13 fair value hierarchy), have been used to determine the recoverable amounts. See 'Key estimates used in calculations'. The cash flows have been modelled on a post-tax basis at the Group's post-tax discount rate. If the recoverable amount of an asset is estimated to be less than its carrying amount, the carrying amount of the asset is reduced to its recoverable amount. An impairment loss is recognised immediately in the statement of comprehensive income.

Where an impairment loss subsequently reverses, the carrying amount of the asset is increased to the revised estimate of its recoverable amount, but only so that the increased carrying amount does not exceed the carrying amount that would have been determined had no impairment loss been recognised for the asset in prior years. A reversal of an impairment loss is recognised immediately in the statement of comprehensive income.

	Oil and gas assets $'000	Office furniture, fixtures and fittings $'000	Right-of-use assets (note 24) $'000	Total $'000
Cost:				
At 1 January 2018	8,070,694	57,716	–	8,128,410
Additions	178,627	2,856	–	181,483
Acquired (note 30)	745,350	–	–	745,350
Acquired: Change in fair value on step acquisition (see note 30)	123,909	–	–	123,909
Change in decommissioning provision (see notes 12 and 23)	30,194	–	–	30,194
Change in cost recovery provision (see note 23)	(7,947)	–	–	(7,947)
Change in financial carry liability (see note 19)	(1,066)	–	–	(1,066)
Change in estimate	(2,195)	–	–	(2,195)
At 31 December 2018 (as previously reported)	**9,137,566**	**60,572**	**–**	**9,198,138**
IFRS 16 recognition and reclassification[(i)] (see note 2)	**(771,975)**	**–**	**832,502**	**60,527**
At 1 January 2019	**8,365,591**	**60,572**	**832,502**	**9,258,665**
Additions	**149,503**	**3,324**	**24,587**	**177,414**
Change in decommissioning provision (see notes 12 and 23)	**40,097**	**–**	**–**	**40,097**
Change in cost recovery provision (see note 23)	**(5,895)**	**–**	**–**	**(5,895)**
Reclass within asset class	**(2,591)**	**(86)**	**–**	**(2,677)**
Reclass from/(to) other assets and intangibles (see note 12)	**1,064**	**(1,357)**	**–**	**(293)**
At 31 December 2019	**8,547,769**	**62,453**	**857,089**	**9,467,311**
Accumulated depletion and impairment:				
At 1 January 2018	4,242,697	37,091	–	4,279,788
Charge for the year	437,104	5,287	–	442,391
Impairment charge for the year	126,046	–	–	126,046
At 31 December 2018 (as previously reported)	**4,805,847**	**42,378**	**–**	**4,848,225**
IFRS 16 recognition and reclassification[(i)] (see note 2)	**(81,233)**	**–**	**81,233**	**–**
At 1 January 2019	**4,724,614**	**42,378**	**81,233**	**4,848,225**
Charge for the year	**438,242**	**4,453**	**90,657**	**533,352**
Impairment charge for the year	**637,500**	**–**	**–**	**637,500**
Reclass within asset class	**(2,591)**	**(86)**	**–**	**(2,677)**
Reclass from/(to) other assets and intangibles (see note 12)	**159**	**(177)**	**–**	**(18)**
At 31 December 2019	**5,797,924**	**46,568**	**171,890**	**6,016,382**
Net carrying amount:				
At 31 December 2019	**2,749,845**	**15,885**	**685,199**	**3,450,929**
At 31 December 2018	4,331,719	18,194	–	4,349,913
At 1 January 2018	3,827,997	20,625	–	3,848,622

(i) Following the adoption of IFRS 16 Leases, the Kraken FPSO lease asset has been reclassified to right-of-use assets

The net book value at 31 December 2019 includes $70.7 million (2018: $95.4 million) of pre-development assets and development assets under construction.

The amount of borrowing costs capitalised during the year ended 31 December 2019 was $1.4 million and relates to the Dunlin bypass project (2018: $1.5 million relating to the Dunlin bypass project). The weighted average rate used to determine the amount of borrowing costs eligible for capitalisation is 8.4% (2018: 7.7%).

10. Property, plant and equipment (continued)

Impairment testing of oil and gas assets
Impairments to the Group's producing oil and gas assets and reversals of impairments are set out in the table below:

	Impairment (charge)/reversal		Recoverable amount[(i)]	
	Year ended 31 December 2019 $'000	Year ended 31 December 2018 $'000	**31 December 2019 $'000**	31 December 2018 $'000
North Sea	**(637,500)**	(125,009)	**46,462**	158,890
Malaysia	**–**	(1,037)	**–**	41,488
Net impairment reversal/(charge)	**(637,500)**	(126,046)		

(i) Recoverable amount has been determined on a fair value less costs of disposal basis (see note 2 for further details of significant estimates and judgements made in relation to impairments). The amounts disclosed above are in respect of assets where an impairment (or reversal) has been recorded. Assets which did not have any impairment or reversal are excluded from the amounts disclosed

The impairment in the year related to North Sea assets. The impairments are attributable primarily to changes to the long-term oil price from $75.0/bbl to $70.0/bbl, revision to production profiles (see reserves and resources on page 26) in the Heather/Broom, Thistle/Deveron and the Dons fields and the anticipated cessation of production at Alma/Galia. Both the Heather/Broom and Thistle/Deveron fields were fully impaired as a result of the impairment assessment conditions as at 31 December 2019.

The Group's recoverable value of assets is highly sensitive, inter alia, to oil price achieved and production volumes. Sensitivities have been run on the oil price assumption, with a 10% change being considered to be a reasonable possible change for the purposes of sensitivity analysis (see note 2). A 10% reduction in oil price would increase the net impairment by approximately $388.0 million, with the additional impairment attributable to the fields in the North Sea.

11. Goodwill

Accounting policy
Cost
Goodwill arising on a business combination is initially measured at cost, being the excess of the cost of the business combination over the net fair value of the identifiable assets, liabilities and contingent liabilities of the entity at the date of acquisition. If the fair value of the net assets acquired is in excess of the aggregate consideration transferred, the Group reassesses whether it has correctly identified all of the assets acquired and all of the liabilities assumed and reviews the procedures used to measure the amounts to be recognised at the acquisition date. If the reassessment still results in an excess of the fair value of net assets acquired over the aggregate consideration transferred, the gain is recognised in profit or loss.

Impairment of goodwill
Following initial recognition, goodwill is stated at cost less any accumulated impairment losses. In accordance with IAS 36 Impairment of Assets, goodwill is reviewed for impairment annually or more frequently if events or changes in circumstances indicate that such carrying value may be impaired.

For the purposes of impairment testing, goodwill acquired is allocated to the CGU that is expected to benefit from the synergies of the combination. Each unit or units to which goodwill is allocated represents the lowest level within the Group at which the goodwill is monitored for internal management purposes. Goodwill, which has been acquired through business combinations, has been allocated to a single CGU, the UK Continental Shelf ('UKCS'), and this is therefore the lowest level at which goodwill is reviewed. The UKCS is a combination of oil and gas assets, as detailed within property, plant and equipment (note 10). Impairment is determined by assessing the recoverable amount of the CGU to which the goodwill relates.

The recoverable amounts of the CGU and fields have been determined on a fair value less costs of disposal basis. Discounted cash flow models comprising asset-by-asset life of field projections and risks specific to assets, using Level 3 inputs (based on IFRS 13 fair value hierarchy), have been used to determine the recoverable amounts. See 'Key estimates used in calculations' (note 2). The cash flows have been modelled on a post-tax basis at the Group's post-tax discount rate. Where the recoverable amount of the CGU is less than the carrying amount of the CGU and related goodwill, an impairment loss is recognised. Impairment losses relating to goodwill cannot be reversed in future periods.

A summary of goodwill is presented below:

	2019 $'000	2018 $'000
Cost and net carrying amount		
At 1 January	**283,950**	189,317
Acquisition (see note 30)	**–**	94,633
Impairment	**(149,550)**	–
At 31 December	**134,400**	283,950

On 1 December 2018, the Group acquired the remaining 75% interest in the Magnus oil field and associated interests. Goodwill of $94.6 million was recognised, representing the future economic benefits that EnQuest's expertise is expected to realise from the assets (see note 30). The historical goodwill balance arose from the acquisition of Stratic and PEDL in 2010 and the Greater Kittiwake Area asset in 2014.

Impairment testing of goodwill

An impairment charge of $149.6 million was taken in 2019 (2018: $nil). The impairment is attributable to changes in the underlying North Sea assets, as disclosed in 'impairment testing of oil and gas assets' (note 10). The goodwill value stated is the recoverable amount.

Sensitivity to changes in assumptions
The Group's recoverable value of assets is highly sensitive, inter alia, to oil price achieved and production volumes. Sensitivities have been run on the oil price assumption with a 5% reduction in oil price fully impairing goodwill.

12. Intangible oil and gas assets

Accounting policy

Exploration and appraisal assets

The Group adopts the successful efforts method of accounting for exploration and evaluation costs. Pre-licence costs are expensed in the period in which they are incurred. Expenditure directly associated with exploration, evaluation or appraisal activities is initially capitalised as an intangible asset. Such costs include the costs of acquiring an interest, appraisal well drilling costs, payments to contractors and an appropriate share of directly attributable overheads incurred during the evaluation phase. For such appraisal activity, which may require drilling of further wells, costs continue to be carried as an asset whilst related hydrocarbons are considered capable of commercial development. Such costs are subject to technical, commercial and management review to confirm the continued intent to develop, or otherwise extract value. When this is no longer the case, the costs are written off as exploration and evaluation expenses in the statement of comprehensive income. When exploration licences are relinquished without further development, any previous impairment loss is reversed and the carrying costs are written off through the statement of comprehensive income. When assets are declared part of a commercial development, related costs are transferred to property, plant and equipment. All intangible oil and gas assets are assessed for any impairment prior to transfer and any impairment loss is recognised in the statement of comprehensive income.

During the year ended 31 December 2019, the Group impaired for the write-off of historical exploration and appraisal expenditures totalling $25.4 million (2018: $0.4 million). During the year ended 31 December 2018, the Group relinquished licences previously impaired resulting in write-off of $63.5 million.

	Cost $'000	Accumulated impairment $'000	Net carrying amount $'000
At 1 January 2018	228,026	(175,923)	52,103
Additions	1,393	–	1,393
Write-off of relinquished licences previously impaired	(63,547)	63,547	–
Unsuccessful exploration expenditure written off	–	(1,009)	(1,009)
Change in decommissioning provision (see notes 10 and 23)	(286)	–	(286)
Impairment charge for the year	–	(398)	(398)
At 31 December 2018	**165,586**	**(113,783)**	**51,803**
Additions	**3,241**	**–**	**3,241**
Write-off of relinquished licences previously impaired	**(583)**	**583**	**–**
Unsuccessful exploration expenditure written off	**–**	**(150)**	**(150)**
Change in decommissioning provision (see notes 10 and 23)	**(2,218)**	**–**	**(2,218)**
Impairment charge for the year	**–**	**(25,398)**	**(25,398)**
Reclass within asset class	**8,645**	**(8,645)**	**–**
Reclass from/(to) tangible fixed assets (see note 10)	**293**	**(18)**	**275**
At 31 December 2019	**174,964**	**(147,411)**	**27,553**

13. Inventories

Accounting policy

Inventories of consumable well supplies and inventories of hydrocarbons are stated at the lower of cost and NRV, cost being determined on an average cost basis.

	2019 $'000	2018 $'000
Hydrocarbon inventories	**17,216**	23,183
Well supplies	**61,428**	77,349
	78,644	100,532

During 2019, inventories of $14.6 million (2018: $5.8 million) were recognised within cost of sales in the statement of comprehensive income.

14. Cash and cash equivalents

	2019 $'000	2018 $'000
Available cash		
Cash at bank	**137,365**	126,625
Short-term deposits	**6,849**	6,640
Total available cash	**144,214**	133,265
Ring-fenced cash		
Joint venture accounts	**32,365**	45,095
Operational accounts	**41,620**	58,840
Total ring-fenced cash	**73,985**	103,935
Total cash at bank and in hand	**218,199**	237,200
Restricted cash – Cash subject to currency controls or other legal restrictions		
Cash held in escrow	**1,611**	2,764
Cash collateral	**646**	640
Total restricted cash – Cash subject to currency controls or other legal restrictions	**2,257**	3,404
Total cash and cash equivalents	**220,456**	240,604

The carrying value of the Group's cash and cash equivalents is considered to be a reasonable approximation to their fair value due to their short-term maturities. Ring-fenced cash includes joint venture accounts and cash held in operational accounts, as detailed below.

14. Cash and cash equivalents (continued)

Short-term deposits

At 31 December 2019, $6.8 million (2018: $6.6 million) was placed on short-term deposit in order to cash collateralise the Group's letter of credit.

Joint venture accounts

Joint venture accounts include the cash called for the operations of the assets, from both EnQuest and partners, based on equity share.

Operational accounts

Operational accounts include cash balances that are available for the operating, investing and financing activities of the following specific assets. This cash includes:

- Sculptor Capital (previously Oz Management) working capital for use only for the activities of the ring-fenced 15% interest in the Kraken oil field (see note 18);
- SVT working capital for use only with the activities of SVT (see note 18);
- Tanjong Baram cash held in a Malaysian bank account which can only be used to pay cash calls for the Tanjong Baram asset and amounts related to the project finance loan (see note 18);
- Magnus asset working capital for use only for activities of Magnus and maintained for the repayment mechanism with BP for the contingent consideration (see note 22).

Restricted cash

Included within the cash balance at 31 December 2019 is restricted cash of $2.3 million (2018: $3.4 million). Of this, $1.6 million relates to cash held in escrow in respect of the unwound acquisition of the Tunisian assets of PA Resources (2018: $2.8 million) and the remainder relates to cash collateral held to issue bank guarantees in Malaysia.

15. Financial instruments and fair value measurement

Accounting policy

A financial instrument is any contract that gives rise to a financial asset of one entity and a financial liability or equity instrument of another entity. Financial instruments are recognised when the Group becomes a party to the contractual provisions of the financial instrument.

Financial assets and financial liabilities are offset and the net amount is reported in the consolidated statement of financial position if there is a currently enforceable legal right to offset the recognised amounts and there is an intention to settle on a net basis.

Financial assets

Financial assets are classified, at initial recognition, as amortised cost, fair value through other comprehensive income ('FVOCI'), or fair value through profit or loss ('FVPL'). The classification of financial assets at initial recognition depends on the financial assets' contractual cash flow characteristics and the Group's business model for managing them. The Group does not currently hold any financial assets at FVOCI i.e. debt financial assets.

Financial assets are derecognised when the contractual rights to the cash flows from the financial asset expire, or when the financial asset and substantially all the risks and rewards are transferred.

Financial assets at amortised cost

Trade receivables, other receivables and joint operation receivables are measured initially at fair value and subsequently recorded at amortised cost, using the effective interest rate ('EIR') method, and are subject to impairment. Gains and losses are recognised in profit or loss when the asset is derecognised, modified or impaired and EIR amortisation is included within finance costs.

The Group measures financial assets at amortised cost if both of the following conditions are met:

- The financial asset is held within a business model with the objective to hold financial assets in order to collect contractual cash flows; and
- The contractual terms of the financial asset give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

Prepayments, which are not financial assets, are measured at historical cost.

Impairment of financial assets

The Group recognises a provision for expected credit loss ('ECL'), where material, for all financial assets held at the balance sheet date. ECLs are based on the difference between the contractual cash flows due to the Group, and the discounted actual cash flows that are expected be received. Where there has been no significant increase in credit risk since initial recognition, the loss allowance is equal to 12-month expected credit losses. Where the increase in credit risk is considered significant, lifetime credit losses are provided. For trade receivables a lifetime credit loss is recognised on initial recognition where material.

The provision rates are based on days past due for groupings of customer segments with similar loss patterns (i.e. by geographical region, product type, customer type and rating) and is based on its historical credit loss experience, adjusted for forward-looking factors specific to the debtors and the economic environment. The Group evaluates the concentration of risk with respect to trade receivables and contract assets as low, as its customers are joint venture partners and there are no indications of change in risk. Generally, trade receivables are written off if past due for more than one year and are not subject to enforcement activity.

Financial liabilities

Financial liabilities are classified, at initial recognition, as amortised cost or at fair value through profit or loss.

Financial liabilities are derecognised when they are extinguished, discharged, cancelled or they expire. When an existing financial liability is replaced by another from the same lender on substantially different terms, or the terms of an existing liability are substantially modified, such an exchange or modification is treated as the derecognition of the original liability and the recognition of a new liability. The difference in the respective carrying amounts is recognised in the statement of profit or loss.

15. Financial instruments and fair value measurement (continued)

Financial liabilities at amortised cost
Loans and borrowings, trade payables and other creditors are measured initially at fair value net of directly attributable transaction costs and subsequently recorded at amortised cost, using the EIR method. Loans and borrowings are interest bearing. Gains and losses are recognised in profit or loss when the liability is derecognised and EIR amortisation is included within finance costs.

Financial instruments at fair value through profit or loss
The Group holds derivative financial instruments classified as held for trading, not designated as effective hedging instruments. The derivative financial instruments include forward currency contracts and commodity contracts, to address the respective risks. Derivatives are carried as financial assets when the fair value is positive and as financial liabilities when the fair value is negative.

Financial instruments at FVPL are carried in the statement of financial position at fair value with net changes in fair value recognised in the statement of profit or loss. Unrealised mark-to-market changes in the remeasurement of open derivative contracts at each period end is recognised within remeasurements, with the recycling of realised amounts from remeasurements into Business performance income when a derivative instrument matures. Option premium received or paid for commodity derivatives are recognised in remeasurements and amortised over the period of the option into Business performance revenue.

Financial assets with cash flows that are not solely payments of principal and interest are classified and measured at fair value through profit or loss, irrespective of the business model. All financial assets not classified as measured at amortised cost or FVOCI as described above are measured at FVPL. Financial instruments with embedded derivatives are considered in their entirety when determining whether their cash flows are solely payment of principal and interest.

The Group also holds contingent consideration (see note 22) and a listed equity investment (see note 19). The movements of both are recognised within remeasurements in the statement of profit or loss.

Fair value measurement
The following table provides the fair value measurement hierarchy of the Group's assets and liabilities:

31 December 2019	**Total $'000**	**Quoted prices in active markets (Level 1) $'000**	**Significant observable inputs (Level 2) $'000**	**Significant unobservable inputs (Level 3) $'000**
Financial assets measured at fair value:				
Derivative financial assets at FVPL				
Oil commodity derivative contracts	**288**	**–**	**288**	**–**
Foreign currency derivative contracts	**1,932**	**–**	**1,932**	**–**
Other financial assets at FVPL				
Quoted equity shares	**11**	**11**	**–**	**–**
Liabilities measured at fair value:				
Derivative financial liabilities at FVPL				
Oil commodity derivative contracts	**11,073**	**–**	**11,073**	**–**
Other financial liabilities measured at FVPL				
Contingent consideration	**657,261**	**–**	**–**	**657,261**
Liabilities for which fair values are disclosed				
Interest-bearing loans and borrowings	**661,638**	**–**	**–**	**661,638**
Obligations under leases	**716,166**	**–**	**–**	**716,166**
Retail bond	**195,948**	**195,948**	**–**	**–**
High yield bond	**655,462**	**655,462**	**–**	**–**

31 December 2018	Total $'000	Quoted prices in active markets (Level 1) $'000	Significant observable inputs (Level 2) $'000	Significant unobservable inputs (Level 3) $'000
Financial assets measured at fair value:				
Derivative financial assets at FVPL				
Oil commodity derivative contracts	54,733	–	54,733	–
Foreign currency derivative contracts	248	–	248	–
Carbon commodity derivative contracts	2,077	–	2,077	–
Other financial assets at FVPL				
Quoted equity shares	31	31	–	–
Liabilities measured at fair value:				
Derivative financial liabilities at FVPL				
Oil commodity derivative contracts	142	–	142	–
Other financial liabilities measured at FVPL				
Contingent consideration	660,436	–	–	660,436
Liabilities for which fair values are disclosed				
Interest-bearing loans and borrowings	1,050,167	–	–	1,050,167
Obligations under leases	708,950	–	–	708,950
Retail bond	156,764	156,764	–	–
High yield bond	534,363	534,363	–	–

Fair value hierarchy
All financial instruments for which fair value is recognised or disclosed are categorised within the fair value hierarchy, based on the lowest level input that is significant to the fair value measurement as a whole, as follows:

15. Financial instruments and fair value measurement (continued)

Level 1: Quoted (unadjusted) market prices in active markets for identical assets or liabilities;
Level 2: Valuation techniques for which the lowest level input that is significant to the fair value measurement is directly (i.e. as prices) or indirectly (i.e. derived from prices) observable;
Level 3: Valuation techniques for which the lowest level input that is significant to the fair value measurement is unobservable.

Derivative financial instruments are valued by counterparties, with the valuations reviewed internally and corroborated with readily available market data (Level 2). Contingent consideration is measured at FVPL using the Level 3 valuation processes disclosed in note 22. There have been no transfers between Level 1 and Level 2 during the period (2018: no transfers).

For the fair value of financial liabilities that are not measured at fair value (but fair value disclosures are required), the fair value of the bonds classified as Level 1 was derived from quoted prices for that financial instrument. Both interest-bearing loans and borrowings and obligations under finance leases were calculated using the discounted cash flow method to capture the present value (Level 3).

16. Trade and other receivables

	2019 $'000	2018 $'000
Current		
Trade receivables	**117,149**	69,857
Joint venture receivables	**119,519**	84,745
Under-lift position	**17,651**	81,173
VAT receivable	**6,887**	–
Other receivables	**3,374**	14,741
	264,580	250,516
Prepayments and accrued income	**14,922**	25,293
	279,502	275,809

The carrying value of the Group's trade, joint venture and other receivables as stated above are considered to be a reasonable approximation to their fair value largely due to their short-term maturities. Under-lift is valued at the lower of cost or NRV at the prevailing balance sheet date (note 5(b)).

Trade receivables are non-interest-bearing and are generally on 15 to 30 day terms. Joint venture receivables relate to amounts billable to, or recoverable from, joint venture partners. Receivables are reported net of any provisions for impairment with no provision necessary as at 31 December 2019 or 2018.

17. Trade and other payables

	2019 $'000	2018 $'000
Current		
Trade payables	**92,238**	162,686
Accrued expenses	**258,539**	296,758
Over-lift position	**46,201**	12,837
Joint venture creditors	**1,788**	1,701
VAT payable	**–**	23,543
Other payables	**21,089**	4,465
	419,855	501,990
Classified as:		
Current	**419,855**	483,781
Non-current	**–**	18,209
	419,855	501,990

The carrying value of the Group's trade and other payables as stated above is considered to be a reasonable approximation to their fair value largely due to the short-term maturities. Certain trade and other payables will be settled in currencies other than the reporting currency of the Group, mainly in Sterling.

Trade payables are normally non-interest-bearing and settled on terms of between 10 and 30 days. The Group has arrangements with various suppliers to defer payment of a proportion of its capital spend. All of these deferred payments fall due in 2020.

Accrued expenses include accruals for capital and operating expenditure in relation to the oil and gas assets and interest accruals.

18. Loans and borrowings

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

	2019			2018		
	Principal $'000	**Fees $'000**	**Total $'000**	Principal $'000	Fees $'000	Total $'000
Credit facility	**475,097**	**–**	**475,097**	799,444	–	799,444
Sculptor Capital facility	**122,912**	**(2,625)**	**120,287**	178,524	(3,325)	175,199
Crude oil prepayment	**–**	**–**	**–**	22,222	(111)	22,111
SVT working capital facility	**31,899**	**–**	**31,899**	15,747	–	15,747
Tanjong Baram project financing facility	**31,730**	**–**	**31,730**	31,730	–	31,730
Trade creditor loan	**–**	**–**	**–**	2,500	–	2,500
Total loans	**661,638**	**(2,625)**	**659,013**	1,050,167	(3,436)	1,046,731
Due within one year			**165,589**			311,261
Due after more than one year			**493,424**			735,470
Total loans			**659,013**			1,046,731

Credit facility

On 21 November 2016, the Group completed a loan restructuring and entered into an amended and restated credit agreement, which included the following terms:

- Commitments split into a term facility of $1.125 billion and a revolving facility of $75 million (together the 'credit facility');
- Maturity date of October 2021;
- Amortisation payable from 1 April 2018 first scheduled amortisation date;
- Borrowings subject to mandatory repayment out of excess cash flow (excluding amounts required for approved capital expenditure), assessed on a six-monthly basis;
- Borrowings up to $890.7 million subject to interest at USD LIBOR plus a margin of 4.75%, paid in cash;
- Borrowings in excess of $890.7 million subject to interest at USD LIBOR plus a margin of 5.25%, paid in cash, with a further 3.75% interest accrued and added to the Payment In Kind ('PIK') amount at maturity of each loan's maturity period;
- PIK amount repayable at maturity and subject to 9.0% interest, which is capitalised and added to the PIK amount on each 30 June and 31 December; and
- $12 million waiver fee payable to lenders on 31 March 2018.

At 31 December 2019, the carrying amount of the credit facility on the balance sheet was $477.4 million, comprising the loan principal drawn down of $460.0 million, $15.8 million of interest capitalised to the PIK amount and $1.6 accrued interest (note 17) (2018: carrying amount $802.7 million, principal drawn down $785.0 million, PIK $14.4 million and accrued interest $3.3 million).

At 31 December 2019, after allowing for letter of credit utilisation of $6.8 million, $68.2 million remained available for drawdown under the credit facility (2018: $6.6 million and $68.4 million, respectively).

Sculptor Capital facility (previously Oz Management facility)

On 24 September 2018, the Group entered into a $175.0 million financing facility with Sculptor Capital LP. The facility was drawn down in full and is repayable in five years from initial availability of the facility. Interest accrues at 6.3% annual effective rate plus one-month USD LIBOR. The financing is ring-fenced on a 15% interest in the Kraken oil field and will be repaid out of the cash flows associated with the interest over a maximum of five years.

Crude oil prepayment transaction

On 25 October 2017, the Group entered into an $80.0 million crude oil prepayment with Mercuria Energy Trading SA. Repayment was made in equal monthly instalments over 18 months, through the delivery of an aggregate of approximately 1.8 MMbbls of oil. EnQuest received the average Brent price over each month subject to a floor of $45/bbl and a cap of approximately $64/bbl. Interest on the prepayment was payable at one-month USD LIBOR plus a margin of 7.0%. The prepayment transaction was undertaken on an unsecured basis. The prepayment completed during 2019 with no liability outstanding as at 31 December 2019.

SVT working capital facility

On 1 December 2017, EnQuest NNS Limited entered into a £42.0 million revolving loan facility with a joint operator partner to fund the short-term working capital cash requirements on the acquisition of SVT and other interests. The facility is able to be drawn down against, in instalments, and accrues interest at 1.0% per annum plus GBP LIBOR. The facility is repayable three years from the initial availability of the facility.

Tanjong Baram project financing facility

On 25 October 2017, the Group entered into a $34.6 million financing facility in Malaysia with Castleton Commodities Merchant Asia Co. Pte Ltd. The facility is repayable within five years from the drawdown date on 28 February 2018 or following termination of the Risk Services Contract, and is secured against the Tanjong Baram asset. Interest is payable at USD LIBOR plus a margin of 8.0% per annum.

Trade creditor loan

In October 2016, the Group borrowed $40.0 million under a loan facility with a trade creditor to fund the settlement of deferred amounts for the Kraken project. The loan was repaid in full in 2019.

18. Loans and borrowings (continued)

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

	2019			2018		
	Principal $'000	**Fees $'000**	**Total $'000**	Principal $'000	Fees $'000	Total $'000
High yield bond	**746,056**	**(4,483)**	**741,573**	760,553	(6,475)	754,078
Retail bond	**225,747**	**(1,089)**	**224,658**	237,778	(1,574)	236,204
Total bonds due after more than one year	**971,803**	**(5,572)**	**966,231**	998,331	(8,049)	990,282

High yield bond
In April 2014, the Group issued a $650 million high yield bond. On 21 November 2016, the high yield bond was amended pursuant to a scheme of arrangement whereby all existing notes were exchanged for new notes. The new high yield notes continue to accrue a fixed coupon of 7.0% payable semi-annually in arrears. The interest will only be payable in cash if the 'Cash Payment Condition' is satisfied, being the average of the Daily Brent Oil Prices during the period of six calendar months immediately preceding the 'Cash Payment Condition Determination Date' is equal to or above $65/bbl. The 'Cash Payment Condition Determination Date' is the date falling one calendar month prior to the relevant interest payment date. If the 'Cash Payment Condition' is not satisfied, interest will not be paid in cash but instead will be capitalised and satisfied through the issue of additional high yield notes ('Additional HY Notes'). $27.5 million of accrued, unpaid interest as at the restructuring date was capitalised and added to the principal amount of the new high yield notes issued pursuant to the scheme. The maturity of the new high yield notes was extended to 15 April 2022 and the Company has the option to extend the maturity date of the new high yield notes to 15 April 2023. Further, the maturity date of the new high yield notes will be automatically extended to 15 October 2023 if the credit facility is not repaid or refinanced in full prior to 15 October 2020.

At the end of 2016, the modification was not considered to be significant under IAS 39. As a result, the change in contractual cash flows on the bonds were amortised over the new life of the bonds, rather than taken straight to profit or loss. Under IFRS 9, the refinancing is a modification of the debt in which the difference in contractual cash flows should be taken straight to profit or loss. The cash flows were reassessed and, on 1 January 2018 on the adoption of IFRS 9, an adjustment for $15.4 million was taken through opening reserves and through the amortised value of the bond. In accordance with the transitional provisions in IFRS 9, comparative figures have not been restated. At 1 January 2019, upon review of further information and clarification, this adjustment was updated. This resulted in an accounting adjustment of $14.5 million against the high yield bond, offset by adjustments through opening reserves and the bond interest accrual. There was no change in effective interest rate (see note 2).

The total carrying value of the bond as at 31 December 2019 is $754.8 million. This includes bond principal of $746.1 million, bond interest accrual of $11.0 million (note 17) and liability for the IFRS 9 Financial Instruments loss on modification of $2.2 million less unamortised fees of $4.5 million (2018: carrying value $765.1 million, bond principal $746.1 million, bond interest accrual $11.0 million, IFRS 9 modification liability $14.5 million less unamortised fees of $6.5 million). The fair value of the high yield bond is disclosed in note 15.

Retail bond
In 2013, the Group issued a £155 million retail bond. On 21 November 2016, the retail bond was amended pursuant to a scheme of arrangement whereby all existing notes were exchanged for new notes. The new retail notes continue to accrue a fixed coupon of 7.0% payable semi-annually in arrears. The interest will only be payable in cash if the 'Cash Payment Condition' is satisfied, being the average of the Daily Brent Oil Prices during the period of six calendar months immediately preceding the 'Cash Payment Condition Determination Date' is equal to or above $65/bbl. The 'Cash Payment Condition Determination Date' is the date falling one calendar month prior to the relevant interest payment date. If the 'Cash Payment Condition' is not satisfied, interest will not be paid in cash but instead will be capitalised and satisfied through the issue of additional retail notes ('Additional Retail Notes'). The maturity of the new retail notes was extended to 15 April 2022 and the Company has the option to extend the maturity date to 15 April 2023. Further, the maturity date of the new retail notes will be automatically extended to 15 October 2023 if the credit facility is not repaid or refinanced in full prior to 15 October 2020.

At the end of 2016, the modification was not considered to be significant under IAS 39. As a result, the change in contractual cash flows on the bonds were amortised over the new life of the bonds, rather than taken straight to profit or loss. Under IFRS 9, the refinancing is a modification of the debt in which the difference in contractual cash flows should be taken straight to profit or loss. The cash flows were reassessed and, on 1 January 2018 on the adoption of IFRS 9, an adjustment for $22.7 million was taken through opening reserves and through the amortised value of the bond. In accordance with the transitional provisions in IFRS 9, comparative figures have not been restated. At 1 January 2019, upon review of further information and clarification, this adjustment was updated. This resulted in an accounting adjustment of $18.9 million against the retail bond, offset by adjustments through opening reserves and the bond interest accrual. There was no change in effective interest rate (see note 2).

The total carrying value of the bond as at 31 December 2019 is $241.1 million. This includes bond principal of $225.7 million, bond interest accrual of $6.0 million (note 17) and liability for the IFRS 9 Financial Instruments loss on modification of $10.5 million less unamortised fees of $1.1 million (2018: carrying value $242.0 million, bond principal $218.9 million, bond interest accrual $5.8 million, IFRS 9 modification liability $18.9 million less unamortised fees of $1.6 million). The fair value of the retail bond is disclosed in note 15.

19. Other financial assets and financial liabilities

(a) Summary as at year end

	2019		2018	
	Assets $'000	**Liabilities $'000**	Assets $'000	Liabilities $'000
Fair value through profit or loss:				
Derivative commodity contracts	**288**	**11,073**	54,733	142
Derivative foreign exchange contracts	**1,932**	**–**	248	–
Derivative carbon contracts	**–**	**–**	2,077	–
Amortised cost:				
Other receivables	**6,863**	**–**	9,517	–
Total current	**9,083**	**11,073**	66,575	142
Fair value through profit or loss:				
Quoted equity shares	**11**	**–**	31	–
Amortised cost:				
Other receivables	**–**	**–**	5,958	–
Total non-current	**11**	**–**	5,989	–

(b) Income statement impact
The income/(expense) recognised for derivatives are as follows:

	Revenue and other operating income		Cost of sales		Finance costs	
Year ended 31 December 2019	**Realised $'000**	**Unrealised $'000**	**Realised $'000**	**Unrealised $'000**	**Realised $'000**	**Unrealised $'000**
Commodity options	**10,517**	**(55,513)**	**–**	**–**	**–**	**–**
Commodity swaps	**19,813**	**(10,021)**	**–**	**–**	**–**	**–**
Commodity futures	**(4,467)**	**159**	**–**	**–**	**–**	**–**
Commodity collar on prepayment transaction	**(1,107)**	**–**	**–**	**–**	**–**	**–**
Foreign exchange contracts	**–**	**–**	**(2,713)**	**1,684**	**–**	**–**
Carbon forwards	**–**	**–**	**1,006**	**(2,062)**	**–**	**–**
	24,756	**(65,375)**	**(1,707)**	**(378)**	**–**	**–**

	Revenue and other operating income		Cost of sales		Finance costs	
Year ended 31 December 2018	Realised $'000	Unrealised $'000	Realised $'000	Unrealised $'000	Realised $'000	Unrealised $'000
Commodity options	(29,309)	63,022	–	–	–	–
Commodity swaps	(47,740)	29,016	–	–	–	–
Commodity futures	(7,951)	84	–	–	–	–
Commodity collar on prepayment transaction	(8,035)	5,310	–	–	–	–
Foreign exchange contracts	–	–	(615)	248	–	–
Carbon forwards	–	–	–	2,062	–	–
Interest rate swap	–	–	–	–	(353)	–
	(93,035)	97,432	(615)	2,310	(353)	–

(c) Commodity contracts
The Group uses derivative financial instruments to manage its exposure to the oil price, including put and call options, swap contracts and futures.

For the year ended 31 December 2019, losses totalling $40.6 million (2018: gains of $4.4 million) were recognised in respect of commodity contracts designated as FVPL. This included gains totalling $24.8 million (2018: losses of $93.0 million) realised on contracts that matured during the year, and mark-to-market unrealised losses totalling $65.4 million (2018: gains of $97.4 million). Of the realised amounts recognised during the year, a gain of $4.9 million (2018: loss of $17.2 million) was realised in Business performance revenue in respect of the amortisation of premium income received on sale of these options. The premiums received are amortised into Business performance revenue over the life of the option.

In October 2017, the Group entered into an 18-month collar structure for $80.0 million. The collar included 18 separate call options and 18 separate put options, subject to a floor of $45/bbl and a cap of approximately $64/bbl. For the year ended 31 December 2019, a loss of $1.1 million was recognised in Business performance revenue (2018: loss of $8.0 million). The collar is now complete.

The mark-to-market value of the Group's open contracts as at 31 December 2019 was a liability of $10.8 million (2018: asset of $54.7 million).

(d) Foreign currency contracts
The Group enters into a variety of foreign currency contracts, primarily in relation to Sterling. During the year ended 31 December 2019, losses totalling $1.0 million (2018: losses of $0.4 million) were recognised in the income statement. This included realised loss totalling $2.7 million (2018: losses of $0.6 million) on contracts that matured in the year.

The mark-to-market value of the Group's open contracts as at 31 December 2019 was an asset of $1.9 million (2018: asset of $0.2 million).

19. Other financial assets and financial liabilities (continued)

(e) Carbon contracts
During the year the Group entered forward carbon contracts to manage its exposure to compliance with European emissions regulations. For the year ended 31 December 2018, the contracts were designated as at FVPL and gains and losses on these contracts are recognised as a component of cost of sales. The mark-to-market value of the Group's open contracts as at 31 December 2018 was $2.1 million.

During 2019, realised gains of $1.0 million (2018: $nil) and unrealised losses of $2.1 million (2018: gains $2.1 million) were recognised in respect of carbon commodity contracts designated as FVPL.

During 2019, the contracts entered were, and continue to be, held for the purpose of the receipt of non-financial items in accordance with the Group's expected purchase, sale or usage requirements, therefore are recognised as purchases within cost of sales under the 'own-use' exemption. These are therefore recognised directly within cost of sales.

(f) Other receivables and liabilities

	Other receivables $'000	Other liabilities $'000
At 1 January 2018	70,044	26,332
Exercised on acquisition	(20,970)	–
Change in fair value	(172)	(7,283)
Utilised during the year	(66,194)	(14,907)
Unwinding of discount	(1,081)	72
Foreign exchange	980	–
Classification update	32,899	(4,214)
At 31 December 2018	**15,506**	**–**
Additions	**–**	**–**
Change in fair value	**(20)**	**–**
Utilised during the year	**(9,517)**	**–**
Unwinding of discount	**905**	**–**
At 31 December 2019	**6,874**	**–**
Current	**6,863**	**–**
Non-current	**11**	**–**
	6,874	**–**

Other receivables

Comprised of:	**2019 $'000**	2018 $'000
BUMI receivable	**6,863**	15,475
Other	**11**	31
Total	**6,874**	15,506

In August 2016, EnQuest agreed with Armada Kraken PTE Ltd ('BUMI') that BUMI would refund $65 million (EnQuest's share being $45.8 million) of a $100.0 million lease prepayment made in 2014 for the FPSO for the Kraken field. This refund is receivable from 2018 onwards. Included within other receivables at 31 December 2019 is an amount of $6.9 million representing the discounted value of EnQuest's share of these repayments (2018: $15.5 million). A total of $9.5 million was collected during the period.

20. Share capital and premium

Accounting policy
Share capital and share premium
The balance classified as equity share capital includes the total net proceeds (both nominal value and share premium) on issue of registered share capital of the parent company. Share issue costs associated with the issuance of new equity are treated as a direct reduction of proceeds. The share capital comprises only one class of Ordinary share. Each Ordinary share carries an equal voting right and right to a dividend.

Merger reserve
Merger reserve represents the difference between the market value of shares issued to effect business combinations less the nominal value of shares issued. The merger reserve in the Group financial statements also includes the consolidation adjustments that arise under the application of the pooling of interest method.

Retained earnings
Retained earnings contain the accumulated results attributable to the shareholders of the parent company.

Share-based payments reserve
Equity-settled share-based payment transactions are measured at the fair value of the services received, and the corresponding increase in equity is recorded. EnQuest PLC shares held by the Group in the Employee Benefit Trust are recognised at cost and are deducted from the share-based payments reserve. Consideration received for the sale of such shares is also recognised in equity, with any difference between the proceeds from the sale and the original cost being taken to reserves. No gain or loss is recognised in the statement of comprehensive income on the purchase, sale, issue or cancellation of equity shares.

20. Share capital and premium (continued)

Authorised, issued and fully paid	Ordinary shares of £0.05 each Number	Share capital $'000	Share premium $'000	Total $'000
At 1 January 2019	**1,694,406,148**	**118,182**	**227,149**	**345,331**
Issuance of equity shares	**1,395,807**	**89**	**–**	**89**
At 31 December 2019	**1,695,801,955**	**118,271**	**227,149**	**345,420**

At 31 December 2019, there were 43,232,936 shares held by the Employee Benefit Trust (2018: 73,180,394). 1,012,658 shares were issued across 2019 to the Employee Benefit Trust with the remaining movement in the year due to shares used to satisfy awards made under the Company's share-based incentive schemes.

On 22 October 2018, the Company completed a rights issue, pursuant to which 508,321,844 new Ordinary shares were issued at a price of £0.21 per share, generating gross aggregate proceeds of $138.9 million. 485,477,620 of the new shares issued resulted from existing shareholders taking up their entitlement under the rights issue to acquire three new Ordinary shares for every seven Ordinary shares previously held. The Employee Benefit Trust acquired 22,126,481 shares pursuant to the rights issue. Following the admission to the market of an additional 508,321,844 Ordinary shares on 22 October 2018, there were 1,694,406,148 Ordinary shares in issue at the end of 2018.

21. Share-based payment plans

Accounting policy
Eligible employees (including Directors) of the Group receive remuneration in the form of share-based payment transactions, whereby employees render services in exchange for shares or rights over shares of EnQuest PLC.

The Directors of the Company have approved four share schemes for the benefit of Directors and employees, being a Deferred Bonus Share Plan, a Restricted Share Plan, a Performance Share Plan and a Sharesave Plan.

The cost of these equity-settled transactions is measured by reference to the fair value at the date on which they are granted. The fair value of awards is calculated in reference to the scheme rules at the 'market value', being the average middle market quotation of a share for the three immediately preceding dealing days as derived from the Daily Official List of the London Stock Exchange, provided such dealing days do not fall within any period when dealings in shares are prohibited because of any dealing restriction. The fair values of awards granted to employees during the year are based on the 'market value' on the date of grant, or date of invitation in respect to the Sharesave Plan.

The cost of equity-settled transactions is recognised over the vesting period in which the relevant employees become fully entitled to the award. The cumulative expense recognised for equity-settled transactions at each reporting date until the vesting date reflects the extent to which the vesting period has expired and the Group's best estimate of the number of equity instruments that will ultimately vest. The statement of comprehensive income charge or credit for a period represents the movement in cumulative expense recognised as at the beginning and end of that period.

In valuing the transactions, no account is taken of any service or performance conditions, other than conditions linked to the price of the shares of EnQuest PLC (market conditions) or 'non-vesting' conditions, if applicable. No expense is recognised for awards that do not ultimately vest, except for awards where vesting is conditional upon a market or non-vesting condition, which are treated as vesting irrespective of whether or not the market or non-vesting condition is satisfied, provided that all other performance conditions are satisfied. Equity awards cancelled are treated as vesting immediately on the date of cancellation, and any expense not previously recognised for the award at that date is recognised in the statement of comprehensive income.

The share-based payment expense recognised for each scheme was as follows:

	2019 $'000	2018 $'000
Deferred Bonus Share Plan	**303**	649
Restricted Share Plan	**580**	668
Performance Share Plan	**3,988**	2,126
Sharesave Plan	**858**	801
Executive Director bonus awards	**159**	401
	5,888	4,645

The following disclosure and tables show the number of shares potentially issuable under equity-settled employee share awards, including the number of options outstanding and those options which been exercised and are exercisable at the end of each year. The awards were adjusted at the time for the effect of the rights issue in 2018.

Deferred Bonus Share Plan ('DBSP')
Eligible employees are invited to participate in the DBSP scheme. Participants may be invited to elect or, in some cases, be required, to receive a proportion of any bonus in Ordinary shares of EnQuest (invested awards). Following such award, EnQuest will generally grant the participant an additional award over a number of shares bearing a specified ratio to the number of invested shares (matching shares). The awards granted will vest 33% on the first anniversary of the date of grant, a further 33% after year two and the final 34% on the third anniversary of the date of grant. Awards, both invested and matching, are forfeited if the employee leaves the Group before the awards vest.

The fair values of DBSP awards granted to employees during the year, based on the defined market value on the date of grant, are set out below:

	2019	2018
Weighted average fair value per share	**36p**	36p

21. Share-based payment plans (continued)

The following shows the movement in the number of share awards held under the DBSP scheme:

	2019 Number	2018 Number(ii)
Outstanding at 1 January	**2,147,103**	2,631,797
Granted during the year(i)	**-**	1,005,150
Exercised during the year(ii)	**(1,127,850)**	(1,415,219)
Forfeited during the year	**(93,743)**	(74,625)
Outstanding at 31 December	**925,510**	2,147,103
Exercisable at 31 December	-	14,014

(i) On 22 October 2018, at its discretion, the Company increased the number of shares receivable by participants in the DBSP by a factor of 1.17 so that the value of their rights under outstanding awards was not adversely affected by the rights issue. This resulted in the grant of 316,128 additional shares. The fair value of these awards is being expensed over the remaining vesting period of the original awards to which they relate

(ii) During the year the disclosure and underlying data was assessed and the reconciliation updated from reflecting vesting shares to exercised shares. This has resulted in updated comparative figures

The weighted average contractual life for the share awards outstanding as at 31 December 2019 was 0.6 years (2018: 0.9 years).

Restricted Share Plan ('RSP')

Under the RSP scheme, employees are granted shares in EnQuest over a discretionary vesting period at the discretion of the Remuneration Committee of the Board of Directors of EnQuest, which may or may not be subject to the satisfaction of performance conditions. Awards made under the RSP will vest over periods between one and four years. At present, there are no performance conditions applying to this scheme nor is there currently any intention to introduce them in the future.

The fair values of RSP awards granted to employees during the year, based on the defined market value on the date of grant, are set out below:

	2019	2018
Weighted average fair value per share	**31p**	32p

The following table shows the movement in the number of share awards held under the RSP scheme:

	2019 Number	2018 Number(ii)
Outstanding at 1 January	**12,672,753**	12,284,572
Granted during the year(i)	**45,303**	2,366,019
Exercised during the year(ii)	**(7,826,383)**	(884,217)
Forfeited during the year	**(43,374)**	(1,093,621)
Outstanding at 31 December	**4,848,299**	12,672,753
Exercisable at 31 December	**2,822,934**	4,037,914

(i) On 22 October 2018, at its discretion, the Company increased the number of shares receivable by participants in the RSP by a factor of 1.17 so that the value of their rights under outstanding awards was not adversely affected by the rights issue. This resulted in the grant of 1,812,650 additional shares. The fair value of these awards is being expensed over the remaining vesting period of the original awards to which they relate

(ii) During the year the disclosure and underlying data was assessed and the reconciliation updated from reflecting vesting shares to exercised shares. This has resulted in updated comparative figures

The weighted average contractual life for the share awards outstanding as at 31 December 2019 was 2.6 years (2018: 5.0 years).

Performance Share Plan ('PSP')

Under the PSP, the shares vest subject to performance conditions. The PSP share awards granted during the year had four sets of performance conditions associated with them: 30% of the award relates to Total Shareholder Return ('TSR') against a number of comparator group oil and gas companies listed on the FTSE 350, AIM Top 100 and Stockholm NASDAQ OMX; 30% relates to reduction in net debt; 30% relates to production growth; and 10% relates to 2P reserve additions over the three-year performance period. Awards will vest on the third anniversary.

The fair values of PSP awards granted to employees during the year, based on the defined market value on the date of grant and which allow for the effect of the TSR condition which is a market-based performance condition, are set out below:

	2019	2018
Weighted average fair value per share	**27p**	32p

The following table shows the movement in the number of share awards held under the PSP scheme:

	2019 Number	2018 Number(ii)
Outstanding at 1 January	**77,898,199**	65,192,493
Granted during the year(i)	**33,000,603**	27,700,837
Exercised during the year(ii)	**(19,644,786)**	(951,548)
Forfeited during the year	**(21,616,318)**	(14,043,583)
Outstanding at 31 December	**69,637,698**	77,898,199
Exercisable at 31 December	**3,852,953**	3,540,460

(i) On 22 October 2018, at its discretion, the Company increased the number of shares receivable by participants in the PSP by a factor of 1.17 so that the value of their rights under outstanding awards was not adversely affected by the rights issue. This resulted in the grant of 11,318,326 additional shares. The fair value of these awards is being expensed over the remaining vesting period of the original awards to which they relate

(ii) During the year the disclosure and underlying data was assessed and the reconciliation updated from reflecting vesting shares to exercised shares. This has resulted in updated comparative figures

The weighted average contractual life for the share awards outstanding as at 31 December 2019 was 6.3 years (2018: 4.0 years).

21. Share-based payment plans (continued)

Sharesave Plan

The Group operates an approved savings-related share option scheme. The plan is based on eligible employees being granted options and their agreement to opening a Sharesave account with a nominated savings carrier and to save over a specified period, either three or five years. The right to exercise the option is at the employee's discretion at the end of the period previously chosen, for a period of six months.

The fair values of Sharesave awards granted to employees during the year, based on the defined market value on the date the invitation for the scheme opens, are shown below:

	2019	2018
Weighted average fair value per share	**22p**	26p

The following shows the movement in the number of share options held under the Sharesave Plan:

	2019 Number	2019 Number[ii]
Outstanding at 1 January	**35,747,677**	12,834,269
Granted during the year[i]	**39,101,971**	26,069,708
Exercised during the year[ii]	**(6,385,608)**	(1,614,746)
Forfeited during the year	**(25,874,518)**	(1,541,554)
Outstanding at 31 December	**42,589,522**	35,747,677
Exercisable at 31 December	**2,879,900**	-

(i) On 22 October 2018, at its discretion, the Company increased the number of options receivable by participants in the Sharesave Plan by a factor of 1.17 so that the value of their rights under outstanding awards was not adversely affected by the rights issue. This resulted in the grant of 5,235,954 additional shares. The exercise price of outstanding options was also reduced by multiplying by a factor 0.8546. The incremental fair value of these adjustments is being expensed over the remaining vesting period of the options to which they relate

(ii) During the year the disclosure and underlying data was assessed and the reconciliation updated from reflecting vesting shares to exercised shares. This has resulted in updated comparative figures

The weighted average contractual life for the share options outstanding as at 31 December 2019 was 2.8 years (2018: 2.6 years).

Executive Director bonus awards

As detailed in the Directors' Remuneration Report, the remuneration of the Executive Directors includes the participation in an annual bonus plan. Any bonus amount in excess of 100% of salary will be deferred into EnQuest shares for two years, subject to continued employment.

The fair value of the Executive Director bonus awards granted during the year, based on the defined market value on the date of grant, are set out below:

	2019	2018
Weighted average fair value per share	**28p**	39p

The following table shows the movement in the number of share awards held under the Executive Director bonus plan:

	2019 Number	2018 Number[ii]
Outstanding at 1 January	**3,159,786**	2,445,722
Granted during the year[i]	**138,483**	714,064
Exercised during the year[ii]	**(1,334,815)**	-
Outstanding at 31 December	**1,963,454**	3,159,786
Exercisable at 31 December	**1,526,678**	1,949,074

(i) On 22 October 2018, at its discretion, the Company increased the number of shares receivable by participants in the PSP by a factor of 1.17 so that the value of their rights under outstanding awards was not adversely affected by the rights issue. This resulted in the grant of 459,112 additional shares. The fair value of these awards is being expensed over the remaining vesting period of the original awards to which they relate

(ii) During the year the disclosure and underlying data was assessed and the reconciliation updated from reflecting vesting shares to exercised shares. This has resulted in updated comparative figures

The weighted average contractual life for the share awards outstanding as at 31 December 2019 was 0.6 years (2018: 0.6 years).

22. Contingent consideration

During 2019, the Group reviewed the contingent consideration and, as a result, have disaggregated the contingent consideration from provisions in light of its underlying uncertainty regarding its timing and amount. This note encompasses all the required information on the liabilities in order to provide users with an enhanced understanding of the liabilities. The contingent consideration has been extracted from the provisions table, including the comparative information, as disclosed below.

	Magnus 25% $'000	Magnus 75% $'000	Magnus decommissioning -linked liability $'000	Total $'000
At 1 January 2018	69,754	–	–	69,754
Acquisitions (see note 30)	–	625,296	–	625,296
Change in fair value	9,723	–	–	9,723
Unwinding of discount	3,042	1,263	–	4,305
Utilisation	(48,642)	–	–	(48,642)
At 31 December 2018	**33,877**	**626,559**	–	**660,436**
Reclassification from provisions (see note 23)	**–**	**–**	**12,583**	**12,583**
At 1 January 2019	**33,877**	**626,559**	**12,583**	**673,019**
Change in fair value (see note 5(e))	**–**	**13,500**	**2,020**	**15,520**
Unwinding of discount (see note 6)	**914**	**54,993**	**1,258**	**57,165**
Utilisation	**(34,791)**	**(53,652)**	**–**	**(88,443)**
At 31 December 2019	**–**	**641,400**	**15,861**	**657,261**
Classified as:				
Current	**–**	**108,840**	**2,871**	**111,711**
Non-current	**–**	**532,560**	**12,990**	**545,550**
	–	**641,400**	**15,861**	**657,261**

75% Magnus acquisition contingent consideration
On 1 December 2018, EnQuest completed the acquisition of the additional 75% interest in the Magnus oil field ('Magnus') and associated interests (collectively the 'Transaction assets') (see note 30) which was part funded through a vendor loan and profit share arrangement with BP. This acquisition followed from the acquisition of initial interests completed in December 2017.

The consideration for the acquisition was $300 million, consisting of $100 million cash contribution, paid from the funds received through the rights issue undertaken in October 2018, and $200 million deferred consideration financed by BP. The deferred consideration, which is repayable solely out of cash flows which are in excess of operating cash flows from Magnus, is secured over the interests in the Transaction assets and accrues interest at a rate of 7.5% per annum on the deferred consideration. The consideration also included a contingent profit sharing arrangement whereby EnQuest and BP share the net cash flow generated by the 75% interest on a 50:50 basis, subject to a cap of $1 billion received by BP. Together, the deferred consideration and contingent profit sharing arrangement are known as contingent consideration.

The fair value of contingent consideration has been determined by calculating the present value of the future expected cash flows using the assumptions detailed in '*Key assumptions used in calculations*' (see note 2). The contingent consideration was fair valued at 31 December 2019, which resulted in an increase in fair value of $13.5 million, reflecting the Group's expectations of continued strong performance at Magnus, and unwinding of discount of $55.0 million was charged to finance costs during the period, both recognised through remeasurements and exceptional items in the consolidated income statement. The contingent profit sharing arrangement cap of $1 billion has been reached in the present value calculations at both year ends. A total of $53.7 million was repaid during 2019. At 31 December 2019, the contingent consideration was $641.4 million (31 December 2018: $626.6 million).

Management has considered alternative scenarios to assess the valuation of the contingent consideration including, but not limited to, the key accounting estimate relating to oil price and the interrelationship with production and the profit share arrangement. As detailed in key accounting estimates, a reduction or increase in the price assumptions of 10% are considered to be reasonably possible changes, resulting in a reduction of $97.8 million or an increase of $54.3 million to the contingent consideration, respectively (2018: reduction of $110.0 million and increase of $61.9 million, respectively). The change in value represents a change in timing of cash flows, with the contingent profit sharing arrangement cap of $1 billion reached in both sensitivities.

The payment of contingent consideration is limited to cash flows generated from Magnus. Therefore, no contingent consideration is payable if insufficient cash flows are generated over and above the requirements to operate the asset. By reference to the conditions existing at 31 December 2019, the maturity analysis of the loan is disclosed in Risk management and financial instruments – liquidity risk (note 27).

25% Magnus acquisition contingent consideration
On 1 December 2017, the acquisition of the initial 25% interest in the Magnus and associated interests was funded through a vendor loan from BP (see note 30). The loan was repayable solely out of cash flows, which are in excess of the operating cash flows from the acquired assets, and was secured over the interests in the Transaction assets. The loan accrued interest at a rate of 5.0% per annum on the base consideration. The fair value was estimated by calculating the present value of the future expected cash flows, based on a discount rate of 10.0% and assumed repayment of around three years. During 2018, a change in fair value of $9.7 million was recognised within finance costs. A total of $34.8 million was repaid during 2019 (2018: $48.6 million) with no remaining liability recognised as at 31 December 2019.

Magnus decommissioning-linked contingent consideration
As part of the Magnus and associated interests acquisition, EnQuest agreed to pay additional consideration in relation to the management of the physical decommissioning costs of Magnus. At 31 December 2019, the amount due to BP by reference to 30% of BP's decommissioning costs on Magnus on an after-tax basis was $15.9 million (2018: $12.6 million).

23. Provisions

Accounting policy

Decommissioning

Provision for future decommissioning costs is made in full when the Group has an obligation: to dismantle and remove a facility or an item of plant; to restore the site on which it is located; and when a reasonable estimate of that liability can be made. The Group's provision primarily relates to the future decommissioning of production facilities and pipelines.

A decommissioning asset and liability are recognised, within property plant and equipment and provisions respectively, at the present value of the estimated future decommissioning costs. The decommissioning asset is amortised over the life of the underlying asset on a unit of production basis over proven and probable reserves, included within depletion in the statement of comprehensive income. Any change in the present value of estimated future decommissioning costs is reflected as an adjustment to the provision and the oil and gas asset. The unwinding of the decommissioning liability is included under finance costs in the statement of comprehensive income.

These provisions have been created based on internal and third-party estimates. Assumptions based on the current economic environment have been made which management believe are a reasonable basis upon which to estimate the future liability. These estimates are reviewed regularly to take into account any material changes to the assumptions. However, actual decommissioning costs will ultimately depend upon future market prices for the necessary decommissioning works required, which will reflect market conditions at the relevant time. Furthermore, the timing of decommissioning liabilities is likely to depend on the dates when the fields cease to be economically viable. This in turn depends on future oil prices, which are inherently uncertain. See 'Key sources of estimation uncertainty' and 'Key assumptions used in calculations' in note 2.

Other

Provisions are recognised when: the Group has a present legal or constructive obligation as a result of past events; it is probable that an outflow of resources will be required to settle the obligation; and a reliable estimate can be made of the amount of the obligation.

	Decommissioning provision $'000	Cost recovery provision $'000	Surplus lease provision $'000	Other provisions $'000	Total $'000
At 1 January 2018	639,251	23,911	2,886	–	666,048
Additions during the year	–	–	–	41,856	41,856
Changes in estimates	29,908	(7,947)	–	657	22,618
Unwinding of discount	12,617	260	8	–	12,885
Utilisation	(10,036)	(5,261)	(409)	–	(15,706)
Classification update	–	(5,068)	–	4,214	(854)
Foreign exchange	–	–	(141)	–	(141)
At 31 December 2018	**671,740**	**5,895**	**2,344**	**46,727**	**726,706**
Adjustment on adoption of IFRS 16 (note 2)	**–**	**–**	**(2,344)**	**–**	**(2,344)**
Reclassification to contingent consideration (note 22)	**–**	**–**	**–**	**(12,583)**	**(12,583)**
At 1 January 2019	**671,740**	**5,895**	–	**34,144**	**711,779**
Additions during the year	**–**	**–**	**–**	**22,500**	**22,500**
Changes in estimates	**37,879**	**(5,895)**	**–**	**5,295**	**37,279**
Unwinding of discount	**13,410**	**–**	**–**	**671**	**14,081**
Utilisation	**(11,131)**	**–**	**–**	**(11,837)**	**(22,968)**
Foreign exchange	**–**	**–**	**–**	**288**	**288**
At 31 December 2019	**711,898**	**–**	**–**	**51,061**	**762,959**
Classified as:					
Current	**45,519**	**–**	**–**	**11,250**	**56,769**
Non-current	**666,379**	**–**	**–**	**39,811**	**706,190**
	711,898	**–**	**–**	**51,061**	**762,959**

Decommissioning provision

The Group's total provision represents the present value of decommissioning costs which are expected to be incurred up to 2042, assuming no further development of the Group's assets. At 31 December 2019, an estimated $155.6 million is expected to be utilised between one and five years, $339.8 million within six to ten years, and the remainder in later periods.

As described in the accounting policy above, the decommissioning provision estimates are highly dependent on future events. Sensitivities have been run on the discount rate assumption (see note 2), with a 0.5% change being considered to be a reasonable possible change, resulting in an approximate reduction and increase of $34.7 million and $31.8 million, respectively.

The Group enters into surety bonds principally to provide security for its decommissioning obligations. The surety bond facilities which expired in December 2019 were renewed for 12 months, subject to ongoing compliance with the terms of the Group's borrowings. At 31 December 2019, the Group held surety bonds totalling $131.6 million (2018: $123.2 million).

Cost recovery provision

As part of the KUFPEC farm-in agreement, a cost recovery protection mechanism was agreed with KUFPEC to enable KUFPEC to recoup its investment to the date of first production. If, on 1 January 2017, KUFPEC's costs to first production had not been recovered or deemed to have been recovered, EnQuest would pay KUFPEC an additional 20% share of net revenue. This additional revenue is to be paid until the capital costs to first production have been recovered. As at 31 December 2019, there was no further cost recovery, as per the agreement, and the provision was released against the corresponding balance in property, plant and equipment.

23. Provisions (continued)

Surplus lease provision
In June 2015, the Group entered a 20-year lease in respect of the Group's office building in Aberdeen, with part of the building subsequently being sub-let with a rent-free incentive. A provision has been recognised for the unavoidable costs in relation to the sub-let space. On the adoption of IFRS 16, the impact of a surplus or onerous lease is assessed as part of the value of the right-of-use asset, within property, plant and equipment. The provision was assessed on transition and taken through equity (see note 2).

Other provisions
In 2017, EnQuest had the option to receive $50 million from BP in exchange for undertaking the management of the physical decommissioning activities for Thistle and Deveron and making payments by reference to 6.0% of the gross decommissioning costs of Thistle and Deveron fields. The option was exercised in full during 2018 and recognised within provisions. At 31 December 2019, the amount due to BP by reference to 7.5% of BP's decommissioning costs on Thistle and Deveron on an after-tax basis was $39.8 million (2018: $33.6 million). Unwinding of discount of $0.9 million is included within finance income for the year ended 31 December 2019 (2018: $0.7 million).

During 2019, the Group finalised and settled the historical breach of warranty claims with KUFPEC, the Group's field partner in respect of Alma/Galia. The settlement completed all outstanding claims and a provision of $22.5 million was recognised for the payments to be made to KUFPEC. A total of $6.9 million had been provided in previous years, resulting in the remaining $15.6 million being taken to the statement of comprehensive income through remeasurements and exceptional items. A total of $11.2 million was paid during 2019. At 31 December 2019, the provision was $11.3 million.

24. Leases

Accounting policy applicable from 1 January 2019
As a lessee
The Group recognises a right-of-use asset and a lease liability at the lease commencement date.

The lease liability is initially measured at the present value of the lease payments that are not paid at the commencement date, discounted by using the rate implicit in the lease, or, if that rate cannot be readily determined, the Group uses its incremental borrowing rate.

Lease payments included in the measurement of the lease liability comprise:
- fixed lease payments (including in-substance fixed payments), less any lease incentives;
- variable lease payments that depend on an index or rate, initially measured using the index or rate at the commencement date;
- the amount expected to be payable by the lessee under residual value guarantees;
- the exercise price of purchase options, if the lessee is reasonably certain to exercise the options; and
- payments of penalties for terminating the lease, if the lease term reflects the exercise of an option to terminate the lease.

The lease liability is subsequently recorded at amortised cost, using the effective interest rate method. The liability is remeasured when there is a change in future lease payments arising from a change in an index or rate, if there is a change in the Group's estimate of the amount expected to be payable under a residual value guarantee, or if the Group changes its assessment of whether it will exercise a purchase, extension or termination option. When the lease liability is remeasured in this way, a corresponding adjustment is made to the carrying amount of the right-of-use asset, or is recorded in profit or loss if the carrying amount of the right-of-use asset has been reduced to zero. The Group did not make any such adjustments during the periods presented.

The right-of-use asset is measured at cost, which comprises the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or the site on which it is located, less any lease incentives received. Right-of-use assets are depreciated over the shorter period of lease term and useful life of the underlying asset. If a lease transfers ownership of the underlying asset or the cost of the right-of-use asset reflects that the Group expects to exercise a purchase option, the related right-of-use asset is depreciated over the useful life of the underlying asset. The depreciation starts at the commencement date of the lease.

The Group applies IAS 36 Impairment of Assets to determine whether a right-of-use asset is impaired and accounts for any identified impairment loss as described in the 'property, plant and equipment' policy.

Variable rents that do not depend on an index or rate are not included in the measurement of the lease liability and the right-of-use asset. The related payments are recognised as an expense in the period in which the event or condition that triggers those payments occurs and are included within 'cost of sales' or 'general and administration expenses' in the statement of profit or loss.

For leases within joint ventures, the Group assesses on a lease-by-lease basis the facts and circumstances. This relates mainly to leases of vessels. Where all parties to a joint operation jointly have the right to control the use of the identified asset and all parties have a legal obligation to make lease payments to the lessor, the Group's share of the right-of-use asset and its share of the lease liability will be recognised on the Group balance sheet. This may arise in cases where the lease is signed by all parties to the joint operation or the joint operation partners are named within the lease. However, in cases where EnQuest is the only party with the legal obligation to make lease payments to the lessor, the full lease liability and right-of-use asset will be recognised on the Group balance sheet. This may be the case if, for example, EnQuest, as operator of the joint operation, is the sole signatory to the lease. If the underlying asset is used for the performance of the joint operation agreement, EnQuest will recharge the associated costs in line with joint operating agreement.

As a lessor
When the Group acts as a lessor, it determines at lease inception whether each lease is a finance lease or an operating lease. Whenever the terms of the lease transfer substantially all the risks and rewards of ownership to the lessee, the contract is classified as a finance lease. All other leases are classified as operating leases.

When the Group is an intermediate lessor, it accounts for the head-lease and the sub-lease as two separate contracts. The sub-lease is classified as a finance or operating lease by reference to the right-of-use asset arising from the head-lease.

24. Leases (continued)

Rental income from operating leases is recognised on a straight-line basis over the term of the relevant lease. Initial direct costs incurred in negotiating and arranging an operating lease are added to the carrying amount of the leased asset and recognised on a straight-line basis over the lease term.

Amounts due from lessees under finance leases are recognised as receivables at the amount of the Group's net investment in the leases. Finance lease income is allocated to reporting periods so as to reflect a constant periodic rate of return on the Group's net investment outstanding in respect of the leases.

When a contract includes lease and non-lease components, the Group applies IFRS 15 to allocate the consideration under the contract to each component.

Accounting policy before 1 January 2019

Under IAS 17, the determination of whether an arrangement is or contains a lease is based on the substance of the arrangement at the inception date. The arrangement is assessed for whether fulfilment of the arrangement is dependent on the use of a specific asset or assets or the arrangement conveys a right to use the asset or assets, even if that right is not explicitly specified in an arrangement.

As a lessee

A lease is classified at the inception date as a finance lease or an operating lease. A lease that transfers substantially all the risks and rewards incidental to ownership to the Group is classified as a finance lease.

Finance leases are capitalised at the commencement of the lease at the fair value of the leased asset or, if lower, at the present value of the minimum lease payments. Lease payments are apportioned between finance charges and reduction of the lease liability so as to achieve a constant rate of interest on the remaining balance of the liability. Finance charges are recognised in finance costs in the income statement.

A leased asset is depreciated over the useful life of the asset. However, if there is no reasonable certainty that the Group will obtain ownership by the end of the lease term, the asset is depreciated over the shorter of the estimated useful life of the asset and the lease term. Lease charter payment credits, arising from the non-performance of the leased asset, are recognised as an operating expense in the income statement for the period to which they relate.

Some leases held by the Group contain extension options, exercisable only by the Group and not by the lessors. The Group assesses at lease commencement date whether it is reasonably certain to exercise the extension options and reassesses if there is a significant event or significant changes in circumstances within its control.

An operating lease is a lease other than a finance lease. Operating lease payments are recognised as an operating expense in the income statement on a straight-line basis over the lease term.

As a lessor

Leases in which the Group does not transfer substantially all the risks and rewards of ownership of an asset are classified as operating leases. Rental income arising is accounted for on a straight-line basis over the lease terms and is included in revenue in the statement of profit or loss due to its operating nature. Initial direct costs incurred in negotiating and arranging an operating lease are added to the carrying amount of the leased asset and recognised over the lease term on the same basis as rental income. Contingent rents are recognised as revenue in the period in which they are earned.

Right-of-use assets and lease liabilities

Set out below are the carrying amounts of the Group's right-of-use assets and lease liabilities and the movements during the period:

	Right-of-use assets $'000	Lease liabilities $'000
As at 31 December 2018	**–**	**708,950**
Finance lease reclassification	**690,742**	**–**
IFRS 16 recognition adjustment	**60,527**	**60,527**
Additions in the period	**24,587**	**24,587**
Depreciation expense	**(90,657)**	**–**
Interest expense	**–**	**55,686**
Payments	**–**	**(135,125)**
Foreign exchange movements	**–**	**1,541**
As at 31 December 2019	**685,199**	**716,166**
Current		**101,348**
Non-current		**614,818**
		716,166

The Group leases assets including the Kraken FPSO, property and oil and gas vessels, with a weighted average lease term of 7.1 years. The maturity analysis of lease liabilities are disclosed in note 27.

Amounts recognised in profit or loss

	Year ended 31 December 2019 $'000
Depreciation expense of right-of-use assets	**90,657**
Interest expense on lease liabilities	**55,689**
Rent expense – short-term leases	**2,646**
Rent expense – leases of low-value assets	**28**
Rent expense – variable lease payments not included in measurement of lease liabilities	**–**
Total amounts recognised in profit or loss	**149,020**

24. Leases (continued)

Amounts recognised in statement of cash flows

	Year ended 31 December 2019 $'000	Year ended 31 December 2018 $'000
Total cash outflow for leases	**135,125**	144,820

Leases as lessor (IFRS 16)

The Group sub-leases part of Annan House, the Aberdeen office. The sub-lease is classified as an operating lease, as all the risks and rewards incidental to the ownership of the right-of-use asset are not all substantially transferred to the lessee. Rental income recognised by the Group during 2019 was $1.3 million (2018: $1.1 million).

The following table sets out a maturity analysis of lease payments, showing the undiscounted lease payments to be received after the reporting date:

	2019 $'000	2018 $'000
Less than one year	**1,635**	1,540
One to two years	**1,762**	1,635
Two to three years	**1,762**	1,762
Three to four years	**1,762**	1,762
Four to five years	**1,762**	1,762
More than five years	**1,147**	2,909
Total undiscounted lease payments	**9,830**	11,370

25. Commitments and contingencies

Commitments

At 31 December 2019, the Group had capital commitments amounting to $17.9 million (2018: $15.7 million).

Contingencies

The Group becomes involved from time to time in various claims and lawsuits arising in the ordinary course of its business. Other than as discussed below, the Company is not, nor has been during the past 12 months, involved in any governmental, legal or arbitration proceedings which, either individually or in the aggregate, have had, or are expected to have, a material adverse effect on the Company's and/or the Group's financial position or profitability, nor, so far as the Company is aware, are any such proceedings pending or threatened.

The Group is currently engaged in discussions with EMAS, one of the Group's contractors on Kraken who performed the installation of a buoy and mooring system, in relation to the payment of approximately $15.0 million of variation claims which EMAS claims is due as a result of soil conditions at the work site being materially different from those reasonably expected to be encountered based on soil data previously provided. The Group is confident that such variation claims are not valid and that accordingly such amount is not due and payable by the Group under the terms of the contract with EMAS. The parties are currently in discussions pursuant to the dispute resolution process under the contract.

26. Related party transactions

The Group financial statements include the financial statements of EnQuest PLC and its subsidiaries. A list of the Group's principal subsidiaries is contained in note 28 to these Group financial statements.

Balances and transactions between the Company and its subsidiaries, which are related parties, have been eliminated on consolidation and are not disclosed in this note.

All sales to and purchases from related parties are made at normal market prices and the pricing policies and terms of these transactions are approved by the Group's management. With the exception of the transactions disclosed below, there have been no transactions with related parties who are not members of the Group during the year ended 31 December 2019 (2018: none).

Share subscription

In 2018, subscription for new Ordinary shares pursuant to the rights issue (see note 20) at the issue price of £0.21 per share:

- Double A Limited ('Double A'), a company beneficially owned by the extended family of Amjad Bseisu, took up its entitlement in the rights issue, subscribing for 43,849,727 shares;
- Double A participated in the rump placing for 5,000,000 shares; and
- Directors and key management personnel took up their entitlement in the rights issue, subscribing for 382,273 shares.

Office sub-lease

During the year ended 31 December 2019, the Group recognised $0.1 million (2018: $0.1 million) of rental income in respect of an office sub-lease arrangement with Levendi Investment Management, a company where 72% of the issued share capital is held by Amjad Bseisu.

Contracted services

During the year ended 31 December 2018, the Group obtained contracting services from Influit UK Production Solutions for a value of $0.06 million. No services were provided during 2019. Amjad Bseisu has an indirect interest in Influit UK Production Solutions.

26. Related party transactions (continued)

Compensation of key management personnel

The following table details remuneration of key management personnel of the Group. Key management personnel comprise of Executive and Non-Executive Directors of the Company and the Executive Committee.

	2019 $'000	2018 $'000
Short-term employee benefits	**7,584**	7,052
Share-based payments	**1,245**	1,300
Post-employment pension benefits	**199**	218
	9,028	8,570

27. Risk management and financial instruments

Risk management objectives and policies

The Group's principal financial assets and liabilities comprise trade and other receivables, cash and short-term deposits, interest-bearing loans, borrowings and finance leases, derivative financial instruments and trade and other payables. The main purpose of the financial instruments is to manage short-term cash flow and raise finance for the Group's capital expenditure programme.

The Group's activities expose it to various financial risks particularly associated with fluctuations in oil price, foreign currency risk, liquidity risk and credit risk. Management reviews and agrees policies for managing each of these risks, which are summarised below. Also presented below is a sensitivity analysis to indicate sensitivity to changes in market variables on the Group's financial instruments and to show the impact on profit and shareholders' equity, where applicable. The sensitivity has been prepared for periods ended 31 December 2019 and 2018, using the amounts of debt and other financial assets and liabilities held at those reporting dates.

Commodity price risk – oil prices

The Group is exposed to the impact of changes in Brent oil prices on its revenues and profits generated from sales of crude oil.

The Group's policy is to have the ability to hedge oil prices up to a maximum of 75% of the next 12 months' production on a rolling annual basis, up to 60% in the following 12-month period and 50% in the subsequent 12-month period.

Details of the commodity derivative contracts entered into during and open at the end of 2019 are disclosed in note 19.

The following table summarises the impact on the Group's pre-tax profit and total equity of a reasonably possible change in the Brent oil price, on the fair value of derivative financial instruments, with all other variables held constant.

	Pre-tax profit		Total equity	
	+$10/bbl increase $'000	-$10/bbl decrease $'000	+$10/bbl increase $'000	-$10/bbl decrease $'000
31 December 2019	**(22,894)**	**20,500**	**(22,894)**	**20,500**
31 December 2018	(40,310)	45,146	(40,310)	45,146

Foreign exchange risk

The Group is exposed to foreign exchange risk arising from movements in currency exchange rates. Such exposure arises from sales or purchases in currencies other than the Group's functional currency and the retail bond which is denominated in Sterling. To mitigate the risks of large fluctuations in the currency markets, the hedging policy agreed by the Board allows for up to 70% of the non-US Dollar portion of the Group's annual capital budget and operating expenditure to be hedged. For specific contracted capital expenditure projects, up to 100% can be hedged. Approximately 6% (2018: 3%) of the Group's sales and 95% (2018: 42%) of costs (including operating and capital expenditure and general and administration costs) are denominated in currencies other than the functional currency. In the prior year the accounting entries for the Magnus acquisition were in US Dollars, therefore reducing the ratio of non-US Dollar denominated costs.

The Group also enters into foreign currency swap contracts from time to time to manage short-term exposures.

The following table summarises the sensitivity to a reasonably possible change in the US Dollar to Sterling foreign exchange rate, with all other variables held constant, of the Group's profit before tax due to changes in the carrying value of monetary assets and liabilities at the reporting date. The impact in equity is the same as the impact on profit before tax. The Group's exposure to foreign currency changes for all other currencies is not material:

	Pre-tax profit	
	+$10% rate increase $'000	-$10% rate decrease $'000
31 December 2019	**(21,893)**	**21,893**
31 December 2018	(41,852)	41,852

27. Risk management and financial instruments (continued)

Credit risk
Credit risk is managed on a Group basis. Credit risk in financial instruments arises from cash and cash equivalents and derivative financial instruments where the Group's exposure arises from default of the counterparty, with a maximum exposure equal to the carrying amount of these instruments (see maturity table within liquidity risks below). For banks and financial institutions, only those rated with an A-/A3 credit rating or better are accepted. Cash balances can be invested in short-term bank deposits and AAA-rated liquidity funds, subject to Board-approved limits and with a view to minimising counterparty credit risks.

In addition, there are credit risks of commercial counterparties including exposures in respect of outstanding receivables. The Group trades only with recognised international oil and gas companies and at 31 December 2019 there were $2.4 million of trade receivables past due (2018: $5.0 million), $0.1 million of joint venture receivables past due (2018: $1.6 million) and $nil (2018: $nil) of other receivables past due but not impaired. Subsequent to year end, $2.4 million of these outstanding balances have been collected (2018: $4.6 million). Receivable balances are monitored on an ongoing basis with appropriate follow-up action taken where necessary.

Ageing of past due but not impaired receivables	**2019 $'000**	2018 $'000
Less than 30 days	**381**	4,649
30-60 days	**60**	16
60-90 days	**–**	8
90-120 days	**8**	–
120+ days	**2,056**	1,933
	2,505	6,606

At 31 December 2019, the Group had four customers accounting for 84% of outstanding trade receivables (2018: three customers, 81%) and two joint venture partners accounting for 26% of outstanding joint venture receivables (2018: two joint venture partners, 41%).

Liquidity risk
The Group monitors its risk to a shortage of funds by reviewing its cash flow requirements on a regular basis relative to its existing bank facilities and the maturity profile of its borrowings. Specifically, the Group's policy is to ensure that sufficient liquidity or committed facilities exist within the Group to meet its operational funding requirements and to ensure the Group can service its debt and adhere to its financial covenants. At 31 December 2019, $68.2 million (2018: $68.4 million) was available for drawdown under the Group's credit facility (see note 18).

The following tables detail the maturity profiles of the Group's non-derivative financial liabilities including projected interest thereon. The amounts in these tables are different from the balance sheet as the table is prepared on a contractual undiscounted cash flow basis and include future interest payments.

The payment of contingent consideration is limited to cash flows generated from Magnus (see note 22). Therefore, no contingent consideration is payable if insufficient cash flows are generated over and above the requirements to operate the asset and there is no exposure to liquidity risk. By reference to the conditions existing at the reporting period end, the maturity analysis of the loan is disclosed below.

Year ended 31 December 2019	**On demand $'000**	**Up to 1 year $'000**	**1 to 2 years $'000**	**2 to 5 years $'000**	**Over 5 years $'000**	**Total $'000**
Loans and borrowings	**–**	**228,991**	**527,419**	**4,121**	**–**	**760,531**
Bonds[(i)]	**–**	**67,545**	**67,545**	**1,035,022**	**–**	**1,170,112**
Contingent considerations	**–**	**114,152**	**89,607**	**266,563**	**621,929**	**1,092,251**
Obligations under finance leases (IFRS 16)	**–**	**152,306**	**132,294**	**350,492**	**281,915**	**917,007**
Trade and other payables	**–**	**326,035**	**–**	**–**	**46,763**	**372,798**
	–	**889,029**	**816,865**	**1,656,198**	**950,607**	**4,312,699**

Year ended 31 December 2018	On demand $'000	Up to 1 year $'000	1 to 2 years $'000	2 to 5 years $'000	Over 5 years $'000	Total $'000
Loans and borrowings	–	364,135	272,189	546,611	–	1,182,935
Bonds[(i)]	–	34,234	36,521	1,229,314	–	1,300,069
Contingent considerations	–	69,093	116,686	306,528	631,470	1,123,777
Obligations under finance leases (IAS 17)	–	93,169	69,689	243,811	302,282	708,951
Trade and other payables	–	419,855	18,209	–	50,412	488,476
	–	980,486	513,294	2,326,264	984,164	4,804,208

(i) Maturity analysis profile for the Group's bonds includes semi-annual coupon interest. This interest is only payable in cash if the average dated Brent oil price is equal to or greater than $65/bbl for the six months preceding one month before the coupon payment date (see note 18)

27. Risk management and financial instruments (continued)

The following tables detail the Group's expected maturity of payables and receivables for its derivative financial instruments. The amounts in these tables are different from the balance sheet as the table is prepared on a contractual undiscounted cash flow basis. When the amount receivable or payable is not fixed, the amount disclosed has been determined by reference to a projected forward curve at the reporting date.

Year ended 31 December 2019	**On demand $'000**	**Less than 3 months $'000**	**3 to 12 months $'000**	**1 to 2 years $'000**	**Over 2 years $'000**	**Total $'000**
Commodity derivative contracts	**1,849**	**6,398**	**4,387**	**-**	**-**	**12,634**
Foreign exchange derivative contracts	**-**	**(1,932)**	**-**	**-**	**-**	**(1,932)**
	1,849	**4,466**	**4,387**	**-**	**-**	**10,702**

Year ended 31 December 2018	On demand $'000	Less than 3 months $'000	3 to 12 months $'000	1 to 2 years $'000	Over 2 years $'000	Total $'000
Commodity derivative contracts	10,069	52,382	1,852	–	–	64,303
Chooser contract	–	249	–	–	–	249
Interest rate swaps	(837)	9,542	–	–	–	8,705
	9,232	62,173	1,852	–	–	73,257

Capital management

The capital structure of the Group consists of debt, which includes the borrowings disclosed in note 18, cash and cash equivalents and equity attributable to the equity holders of the parent company, comprising issued capital, reserves and retained earnings as in the Group statement of changes in equity.

The primary objective of the Group's capital management is to optimise the return on investment, by managing its capital structure to achieve capital efficiency whilst also maintaining flexibility. The Group regularly monitors the capital requirements of the business over the short, medium and long term, in order to enable it to foresee when additional capital will be required.

The Group has approval from the Board to hedge foreign exchange risk on up to 70% of the non-US Dollar portion of the Group's annual capital budget and operating expenditure. For specific contracted capex projects, up to 100% can be hedged. In addition, the Group's policy is to have the ability to hedge oil prices up to a maximum of 75% of the next 12 months' production on a rolling annual basis, up to 60% in the following 12-month period and 50% in the subsequent 12-month period. This is designed to reduce the risk of adverse movements in exchange rates and market prices eroding the return on the Group's projects and operations.

The Board regularly reassesses the existing dividend policy to ensure that shareholder value is maximised. Any future payment of dividends is expected to depend on the earnings and financial condition of the Company and such other factors as the Board considers appropriate.

The Group monitors capital using the gearing ratio and return on shareholders' equity as follows. Further information relating to the movement year-on-year is provided within the relevant notes and within the Financial Review (from page 11).

	2019 $'000	2018 $'000
Loans, borrowings and bond(i) (A) (see note 18)	**1,633,441**	2,048,498
Cash and short-term deposits (see note 14)	**(220,456)**	(240,604)
Net debt/(cash) (B)	**1,412,985**	1,807,894
Equity attributable to EnQuest PLC shareholders (C)	**559,061**	983,552
Profit/(loss) for the year attributable to EnQuest PLC shareholders (D)	**(449,301)**	127,278
Profit/(loss) for the year attributable to EnQuest PLC shareholders excluding exceptionals (E)	**214,340**	78,195
Gross gearing ratio (A/C)	**2.9**	2.1
Net gearing ratio (B/C)	**2.5**	1.8
Shareholders' return on investment (D/C)	**(80%)**	13%
Shareholders' return on investment excluding exceptionals (E/C)	**38%**	8%

(i) Principal amounts drawn, excludes netting off of fees (see note 18)

NOTES TO THE GROUP FINANCIAL STATEMENTS

For the year ended 31 December 2019

28. Subsidiaries

At 31 December 2019, EnQuest PLC had investments in the following subsidiaries:

Name of company	Principal activity	Country of incorporation	Proportion of nominal value of issued shares controlled by the Group
EnQuest Britain Limited	Intermediate holding company and provision of Group manpower and contracting/procurement services	England	100%
EnQuest Heather Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Thistle Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
Stratic UK (Holdings) Limited(i)	Intermediate holding company	England	100%
Grove Energy Limited[1]	Intermediate holding company	Canada	100%
EnQuest ENS Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest UKCS Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Norge AS(i)[2]	Exploration, extraction and production of hydrocarbons	Norway	100%
EnQuest Heather Leasing Limited(i)	Leasing	England	100%
EQ Petroleum Sabah Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Dons Leasing Limited(i)	Dormant	England	100%
EnQuest Energy Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Production Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Global Limited	Intermediate holding company	England	100%
EnQuest NWO Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EQ Petroleum Production Malaysia Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
NSIP (GKA) Limited[3]	Construction, ownership and operation of an oil pipeline	Scotland	100%
EnQuest Global Services Limited(i)[4]	Provision of Group manpower and contracting/procurement services for the International business	Jersey	100%
EnQuest Marketing and Trading Limited	Marketing and trading of crude oil	England	100%
NorthWestOctober Limited(i)	Dormant	England	100%
EnQuest UK Limited(i)	Dormant	England	100%
EnQuest Petroleum Developments Malaysia SDN. BHD(i)[5]	Exploration, extraction and production of hydrocarbons	Malaysia	100%
EnQuest NNS Holdings Limited(i)	Intermediate holding company	England	100%
EnQuest NNS Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Advance Holdings Limited(i)	Intermediate holding company	England	100%
EnQuest Advance Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Forward Holdings Limited(i)	Intermediate holding company	England	100%
EnQuest Forward Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%

(i) Held by subsidiary undertaking

The Group has three branches outside the UK (all held by subsidiary undertakings): EnQuest Global Services Limited (Dubai); EnQuest Petroleum Production Malaysia Limited (Malaysia); and EQ Petroleum Sabah Limited (Malaysia).

Registered office addresses:

1 Suite 2200, 1055 West Hastings Street, Vancouver, British Columbia, V6E 2E9
2 Fabrikkveien 9, Stavanger, 4033, Norway
3 Annan House, Palmerston Road, Aberdeen, Scotland, AB11 5QP, United Kingdom
4 Ground Floor, Colomberie House, St Helier, JE4 0RX, Jersey
5 c/o TMF, 10th Floor, Menara Hap Seng, No 1 & 3, Jalan P. Ramlee 50250 Kuala Lumpur, Malaysia

29. Cash flow information

Cash generated from operations

	Notes	**Year ended 31 December 2019 $'000**	Year ended 31 December 2018 $'000
Profit/(loss) before tax		**(729,113)**	93,985
Depreciation	5(c)	**8,207**	5,287
Depletion	5(b)	**525,145**	437,104
Exploration costs impaired/(reversed) and written off	4	**150**	1,407
Net impairment (reversal)/charge to oil and gas assets	4	**812,448**	126,046
Write down of inventory		**14,588**	5,837
Write down of asset	4	**415**	3,602
Loss on fair value of purchase option	4	**–**	1,329
Gain on step acquisition accounting for 25% of Magnus and other interests	4	**–**	(74,345)
Impairment (reversal)/charge to investments	4	**20**	121
Share-based payment charge	5(f)	**5,888**	4,645
Change in contingent consideration	22	**72,685**	14,028
Change in surplus lease provision		**–**	8
Change in decommissioning provision	23	**13,410**	12,617
Change in other provisions		**16,301**	(3,907)
Amortisation of option premiums	19	**(4,936)**	17,208
Unrealised (gain)/loss on commodity financial instruments	5(a)	**65,375**	(97,432)
Unrealised (gain)/loss on other financial instruments	5(b)	**378**	(2,310)
Unrealised exchange loss/(gain)		**15,587**	(21,911)
Net finance (income)/expense		**190,099**	219,191
Operating profit before working capital changes		**1,006,647**	742,510
Decrease/(increase) in trade and other receivables		**(78,056)**	6,844
(Increase)/decrease in inventories		**6,423**	22,255
(Decrease)/increase in trade and other payables		**59,604**	17,020
Cash generated from operations		**994,618**	788,629

Changes in liabilities arising from financing activities

	Loans and borrowings (see note 18) $'000	**Bonds (see note 18) $'000**	**Lease liabilities (see note 24) $'000**	**Total $'000**
At 1 January 2018	(1,219,675)	(944,875)	(797,933)	(2,962,483)
Adjustment on adoption of IFRS 9	–	(38,117)	–	(38,117)
At 1 January 2018	(1,219,675)	(982,992)	(797,933)	(3,000,600)
Cash movements:				
Cash flows	357,072	–	144,820	501,892
Additions	(175,000)	–	–	(175,000)
Non-cash movements:				
Foreign exchange adjustments	814	11,745	–	12,559
Capitalised PIK	(13,179)	(16,220)	–	(29,399)
Unwinding of finance discount	–	–	(55,837)	(55,837)
Other non-cash movements	(199)	(10,864)	–	(11,063)
Principal reported as at 31 December 2018	**(1,050,167)**	**(998,331)**	**(708,950)**	**(2,757,448)**
Unamortised fees	**3,436**	**8,049**	**–**	**11,485**
Accrued interest	**(3,268)**	**(16,810)**	**–**	**(20,078)**
Carrying value as at 31 December 2018	**(1,049,999)**	**(1,007,092)**	**(708,950)**	**(2,766,041)**
Adjustment on adoption of IFRS 9/IFRS 16	**-**	**16,811**	**(60,527)**	**(43,716)**
At 1 January 2019	**(1,049,999)**	**(990,281)**	**(769,477)**	**(2,809,757)**
Cash movements:				
Repayments of loans and borrowings	**394,025**	**–**	**–**	**394,025**
Repayment of lease liabilities	**–**	**–**	**135,125**	**135,125**
Cash interest paid in year	**64,370**	**67,485**	**–**	**131,855**
Non-cash movements:				
Additions	**–**	**–**	**(24,587)**	**(24,587)**
Unwinding of finance discount	**(67,749)**	**(62,694)**	**(55,686)**	**(186,129)**
Fee amortisation	**(811)**	**(2,591)**	**–**	**(3,402)**
Foreign exchange adjustments	**(1,049)**	**(6,879)**	**(1,541)**	**(9,469)**
Other non-cash movements	**(69)**	**(1,023)**	**–**	**(1,092)**
At 31 December 2019	**(661,282)**	**(995,983)**	**(716,166)**	**(2,373,431)**

Reconciliation of carrying value

	Loans and borrowings (see note 18) $'000	**Bonds (see note 18) $'000**	**Lease liabilities (see note 24) $'000**	**Total $'000**
Principal	(661,638)	(971,803)	(716,166)	(2,349,607)
Unamortised fees	2,625	5,572	–	8,197
Accrued interest (note 17)	(2,269)	(29,752)	–	(32,021)
At 31 December 2019	**(661,282)**	**(995,983)**	**(716,166)**	**(2,373,431)**

30. Business combinations

Accounting policy
Business combinations are accounted for using the acquisition method, in accordance with IFRS 3 Business Combinations. The cost of an acquisition is measured as the aggregate of the consideration transferred, measured at acquisition date fair value, and the amount of any controlling interest in the acquiree. Those petroleum reserves and resources that are able to be reliably valued are recognised in the assessment of fair values on acquisition. Other potential reserves, resources and rights, for which fair values cannot be reliably determined, are not recognised.

Each identifiable asset and liability is measured at its acquisition date fair value based on guidance in IFRS 13 Fair Value Measurement. The standard defines fair value as the price that would be received to sell an asset or transfer a liability in an orderly fashion between willing market participants at the measurement date. If the initial accounting for a business combination is incomplete by the end of the reporting period in which the combination occurs, the Group reports provisional amounts for the items for which the accounting is incomplete. Finalisation of acquisition fair values, during the measurement period of 12 months from acquisition date, are adjusted against the amounts recognised on acquisition where they qualify as measurement period adjustments.

Where consideration for the acquisition includes a contingent consideration arrangement and is within the scope of IFRS 9, this is recognised as a financial asset or liability at fair value through profit or loss. The contingent consideration is carried in the statement of financial position at fair value with net changes in fair value recognised in the statement of profit or loss, through ‘remeasurements and exceptional items’ as the transactions do not relate to the principal activities and day-to-day Business performance of the Group and is presented consistently year-on-year.

Acquisitions in 2018
Acquisition of 75% interest in Magnus oil field and associated interests
On 1 December 2018, EnQuest completed the acquisition from BP of the remaining 75% interest in the Magnus oil field (‘Magnus’), an additional 9.0% interest in Sullom Voe Oil terminal and supply facility (‘SVT’) and other additional interests in associated infrastructure (collectively the ‘Transaction assets’), constituting a business. This acquisition followed from the acquisition of initial interests completed in December 2017. The transaction is in keeping with EnQuest’s strategy of maximising value from late life assets with significant remaining resource potential.

The consolidated financial statements include the fair values of the identifiable assets and liabilities as at the date of acquisition. The financial results for 2018 include the results of the assets for the one-month period from the acquisition date. Accounts receivable are recognised at gross contractual amounts due, as they relate to large and creditworthy customers. Historically, there has been no significant uncollectible accounts receivable in the Transaction assets.

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

	Fair value recognised on acquisition $’000
Assets	
Property, plant and equipment (see note 10)	745,350
Inventory	50,977
Trade and other receivables (see note 16)	2,927
Liabilities	
Trade and other payables (see note 17)	(44,617)
Financial liabilities (see note 19)	(8,370)
Deferred tax liability (see note 7)	(94,634)
Total identifiable net assets	**651,633**
Technical goodwill arising on acquisition	94,633
Purchase option derecognition	(20,970)
Purchase consideration	**725,296**
Purchase consideration transferred:	
Cash transferred	100,000
Deferred consideration: Vendor loan	116,530
Contingent consideration: Future cash flow share arrangement	508,766
Total purchase consideration	**725,296**

Goodwill arising on acquisition
The option to purchase the remaining 75% in Magnus and other interests was included with the acquisition of the initial 25% interest. As at 31 December 2017, the option was recognised as a financial asset of $22.3 million. The option was revalued on exercise on 1 December 2018 to the fair value of the acquisition assets, resulting in a financial asset of $21.0 million. The revaluation of the option in the year resulted in an expense of $1.3 million and has been recognised in the statement of comprehensive income through other income in ‘Remeasurements and exceptional items’. The option value captures the ability of EnQuest to extend the life of existing mature assets and from the Group’s ability to maximise the value from the late life assets with significant remaining resource potential and the increase in underlying oil prices during the year.

On acquisition, the option was derecognised as part of the acquisition assets and liabilities. The goodwill of $94.6 million arises principally due to the requirement to recognise deferred tax assets and liabilities for the difference between the assigned fair values and the tax bases of assets acquired and liabilities assumed in a business combination. The assessment of the fair value of property, plant and equipment is based on cash flows after tax. Nevertheless, in accordance with IAS 12 sections 15 and 19, a provision is made for deferred tax corresponding to the tax rate multiplied with the difference between the acquisition cost and the tax base. The offsetting entry to this deferred tax is goodwill. Hence, goodwill arises as a technical effect of deferred tax (‘technical goodwill’). None of the goodwill recognised will be deductible for income tax purposes.

30. Business combinations (continued)

Fair value of consideration

The consideration for the acquisition of the Transaction assets was $300 million, consisting of $100 million cash contribution, paid from the funds received through the rights issue undertaken in October 2018, and $200 million deferred consideration financed by BP, which are to be repaid out of future cash flows from the assets. With an effective date of 1 January 2017, the deferred consideration was adjusted for the interim period and working capital adjustments, resulting in contingent consideration of $116.5 million as at 1 December 2018. The deferred consideration is secured over the interests in the Transaction assets and accrues interest at a rate of 7.5% per annum on the base consideration.

The consideration also included a cash flow sharing arrangement whereby EnQuest and BP share the net cash flow generated by the 75% interest on a 50:50 basis, subject to a cap of $1 billion received by BP. The present value of the contingent future cash flow share arrangement over the estimated life of the field resulted in the recognition of contingent consideration of $508.8 million.

The present value of the deferred and contingent profit share consideration is calculated from the future expected cash flows, at a discount rate of 10.0%. These are recognised within contingent consideration (see note 22).

From the date of acquisition to the end of 2018, the Transaction assets contributed $41.7 million of revenue and a $1.2 million gain to the profit before tax from continuing operations of the Group. If the combination had taken place at the beginning of 2018, revenue from continuing operations would have been an additional $264.7 million and the profit before tax from continuing operations would have been an additional $103.7 million. In determining these amounts, management has assumed that the fair value adjustments, determined provisionally, that arose on the date of acquisition would have been the same if the acquisition had occurred on 1 January 2018.

Fair value uplift

The acquisition of the remaining 75% interest is considered a step acquisition as per IFRS 3 Business Combinations. The property, plant and equipment acquired with the initial 25% has been fair valued as at 1 December 2018, recognising an uplift of $123.9 million to property, plant and equipment and a corresponding deferred tax liability of $49.6 million. The gain on uplift of $74.3 million has been recognised through other income in ‘Remeasurements and exceptional items’ in the statement of comprehensive income.

31. Subsequent events

Recent market events has resulted in a fall in oil prices and the forward curve, which has been considered within the groups going concern and viability statement (see note 2). If oil prices remain at or below their current levels for an extended period of time, and/or future forecasts for oil prices are lower than those as at 31 December 2019, this would adversely impact our future financial results. A review of fixed asset carrying amounts will be performed during 2020 as part of our interim impairment review based on the prevailing market conditions. Please refer to note 10 for sensitivity analysis regarding the impairments recorded in 2019.

GLOSSARY – NON-GAAP MEASURES

The Group uses Alternative Performance Measures ('APMs') when assessing and discussing the Group's financial performance, financial position and cash flows that are not defined or specified under IFRS. The Group uses these APMs, which are not considered to be a substitute for or superior to IFRS measures, to provide stakeholders with additional useful information by adjusting for exceptional items and certain re-measurements which impact upon IFRS measures or, by defining new measures, to aid the understanding of the Group's financial performance, financial position and cash flows.

Business performance net profit attributable to EnQuest PLC shareholders	2019 $'000	2018 $'000
Reported net profit/(loss) (A)	**(449,301)**	127,278
Adjustments – remeasurements and exceptional items (note 4):		
Unrealised (losses)/gains on oil derivative contracts (note 19)	**(65,375)**	97,432
Unrealised (gains)/losses on foreign exchange derivative contracts (note 19)	**1,684**	(248)
Unrealised (gains)/losses on carbon derivative contracts (note 19)	**(2,062)**	(2,062)
Net impairment (charge)/reversal to oil and gas assets (note 10, 11 and note 12)	**(812,448)**	(126,046)
Unwind of contingent consideration (note 22)	**(57,165)**	(9,590)
Change in contingent consideration (note 22)	**(15,520)**	–
KUFPEC provision (note 23)	**(15,630)**	–
Contingent consideration release	**–**	5,300
Excess of fair value over consideration: Purchase option (note 30)	**–**	(1,329)
Write down of receivable (note 4)	**(415)**	(3,010)
Exploration and evaluation expenses: Written off and impaired (note 11)	**(150)**	(1,407)
Other exceptional items	**(20)**	3,292
Pre-tax remeasurements and exceptional items (B)	**(967,101)**	36,677
Tax on remeasurements and exceptional items (C)	**303,460**	12,406
Post-tax remeasurements and exceptional items (D = B + C)	**(663,641)**	49,083
Business performance net profit attributable to EnQuest PLC shareholders (A - D)	**214,340**	78,195

EBITDA	2019 $'000	2018 $'000
Reported profit/(loss) from operations before tax and finance income/(costs)	**(467,768)**	326,738
Adjustments:		
Pre-tax remeasurements and exceptional items	**909,936**	(36,677)
Depletion and depreciation (note 5(b) and note 5(c))	**533,352**	442,391
Inventory revaluation	**14,588**	5,837
Net foreign exchange (gain)/loss (note 5(d) and note 5(e))	**16,427**	(21,911)
Business performance EBITDA (E)	**1,006,535**	716,378

EBITDA is calculated on a Business performance basis, and is calculated by taking profit/(loss) from operations before tax and finance income/(costs) and adding back depletion, depreciation, foreign exchange movements, inventory revaluation and the realised gain/(loss) on foreign currency and derivatives related to capital expenditure.

Total cash and available facilities	2019 $'000	2018 $'000
Available cash	**144,214**	159,646
Ring-fenced cash	**73,985**	77,554
Restricted cash	**2,257**	3,404
Total cash and cash equivalents (F) (note 14)	**220,456**	240,604
Available credit facilities	**535,000**	860,000
Credit facility – Drawn down (appendix)	**(460,000)**	(785,000)
Letter of credit (note 14)	**(6,849)**	(6,640)
Available undrawn facility (G)	**68,151**	68,360
Total cash and available facilities (F + G)	**288,607**	308,964

Net debt	2019 $'000	2018 $'000
Borrowings (note 18):		
Credit facility – Drawn down	**460,000**	785,000
Credit facility – PIK	**15,097**	14,444
Sculptor Capital facility	**120,287**	175,199
Crude oil prepayment	**–**	22,111
SVT working capital facility	**31,899**	15,747
Tanjong Baram project financing facility	**31,730**	31,730
Trade creditor loan	**–**	2,500
Borrowings (H)	**659,013**	1,046,731
Bonds (note 18):		
High yield bond	**741,573**	754,078
Retail bond	**224,658**	236,204
Bonds (I)	**966,231**	990,282
Non-cash accounting adjustments:		
Unamortised fees on loans and borrowings	**2,625**	3,436
Unamortised fees on bonds	**5,572**	8,049
Accounting adjustment due to IFRS 9 Financial Instruments	**–**	(33,407)
Non-cash accounting adjustments (J)	**8,197**	(21,922)
Debt (H + I + J) (K)	**1,633,441**	2,015,091
Less: Cash and cash equivalents (note 14) (E)	**220,456**	240,604
Net debt/(cash) (K – F) (L)	**1,412,985**	1,774,487

GLOSSARY – NON-GAAP MEASURES

Net debt/EBITDA	2019 $'000	2018 $'000
Net debt (L)	**1,412,985**	1,744,487
Business performance EBITDA (E)	**1,006,535**	716,378
Net debt/EBITDA (L / E)	**1.4**	2.5

Cash capex	2019 $'000	2018 $'000
Reported net cash flows (used in)/from investing activities	**(257,838)**	(318,613)
Adjustments:		
Consideration on exercise of Magnus acquisition option	**–**	100,000
Repayment of Magnus contingent consideration – Profit share	**21,581**	–
Interest received	**(1,225)**	(1,599)
Cash capex	**(237,482)**	(220,213)

Free cash flow	2019 $'000	2018 $'000
Net cash flows from/(used in) operating activities	**962,271**	794,431
Net cash flows from/(used) in investing activities	**(257,838)**	(318,613)
Net cash flows from/(used) in financing activities	**(729,996)**	(403,560)
Adjustments:		
Proceeds of loans and borrowings	**–**	(219,900)
Repayment of loans and borrowings	**394,025**	402,008
Rights Issues proceeds received	**–**	(138,926)
Magnus cash acquisition	**–**	100,000
Free cash flow	**368,462**	215,440

Revenue sales	2019 $'000	2018 $'000
Revenue from crude oil sales (note 5) (M)	**1,548,177**	1,237,600
Revenue from gas and condensate sales (note 5) (N)	**120,242**	43,063
Realised (losses)/gains on oil derivative contracts (note 5) (P)	**24,756**	(93,035)

Barrels equivalent sales	2019 kboe	2018 kboe
Sales of crude oil (Q)	**24,098**	17,823
Sales of gas and condensate	**4,082**	116
Total sales (R)	**28,180**	17,939

Average realised prices(i)	2019 $/boe	2018 $/boe
Average realised oil price, excluding hedging (M / Q)	**64.2**	69.4
Average realised oil price, including hedging ((M + P) / Q)	**65.3**	64.2
Average realised blended price, excluding hedging ((M + N) / R)	**59.2**	71.4
Average realised blended price, including hedging ((M + N + P) / R)	**60.1**	66.2

(i) Classification of average realised oil price has been enhanced in the year, excluding those condensate barrels which were included in prior years

Operating costs	2019 $'000	2018 $'000
Reported cost of sales	**1,243,948**	924,302
Adjustments:		
Pre-tax remeasurements and exceptional items	**(378)**	1,718
Depletion of oil and gas assets	**(525,145)**	(437,104)
(Credit)/charge relating to the Group's lifting position and inventory	**(102,853)**	25,093
Other cost of sales	**(97,459)**	(48,068)
Operating costs	**518,113**	465,941
Realised (gain) / loss on derivative contracts	**(1,707)**	(615)
Operating costs directly attributable to production	**516,406**	465,326
Comprising of:		
Production costs (S)	**441,624**	396,880
Tariff and transportation expenses (T)	**74,782**	68,446
Operating costs directly attributable to production	**516,406**	**465,326**

Barrels equivalent produced	2019 kboe	2018 kboe
Total produced (working interest) (U)	**25,041**	20,238

Unit opex	2019 $/boe	2018 $/boe
Production costs (S / U)	**17.6**	19.6
Tariff and transportation expenses (T / U)	**3.0**	3.4
Total unit opex ((S + T) / U)	**20.6**	23.0